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COMMONWEALTH OF PENNSYLVANIA **MEMO**
Department of Environmental Protection
Southwest Regional Office

TO Air Quality Permit File PA-65-00990C

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DATE December 16, 2014

RE Review of Plan Approval Application
Tenaska Pennsylvania Partners, LLC
Westmoreland Generating Station
South Huntingdon Township, Westmoreland County
APS 828023 Auth 1001276 PF 716802

Background

On November 6, 2013, the Department received a plan approval application from Trinity Consultants on behalf of Tenaska Pennsylvania Partners, LLC (Tenaska) to construct and temporarily operate a natural gas-fired combined cycle power plant in South Huntingdon Township, Westmoreland County. The proposed power plant is a single 2 on 1 combined cycle configuration consisting of two Mitsubishi "J" class combined cycle combustion turbines (CCCTs). Each CCCT will serve a single steam turbine generator and be equipped with heat recovery steam generators (HRSG) with supplemental 400 MMBTU/hr natural gas-fired duct burners. The two HRSGs will collectively serve the one steam turbine generator. Approximate maximum plant nominal generating capacity is 930 – 1,065 MW. The proposed plan approval includes the following equipment:

- Two (2) 3,147 MMBtu/hr Mitsubishi "J" class combined cycle combustion turbines serving one steam turbine generator equipped with heat recovery steam generators (HRSG) with supplemental 400 MMBtu/hr natural gas fired duct burners.
- One (1) 245 MMBtu/hr natural gas-fired auxiliary boiler.
- One (1) 2,000 ekW diesel-fired emergency generator engine.
- One (1) 575 bhp diesel-fired emergency fire pump engine.
- Cooling tower controlled by drift eliminators.

The proposed facility will also include two diesel storage tanks (5,000 and 1,000 gallon capacities), three (3) 1,000 gallon lube oil storage tanks (one for each combustion turbine and one for the steam turbine), and one (1) 30,000 gallon anhydrous ammonia storage tank. Electric power production at the facility will be provided by the CCCTs and the steam turbine generator. A combustion turbine operates by using ambient air as the primary working gas. Initially, air is inducted into a series of compressor stages to increase its overall potential energy. The high-pressure air exiting the compressor then passes into a low-NOx burner unit, where it is mixed with the fuel (natural gas). The combustion turbines will not combust any other fuel. The premixed working gases are then subjected to a near constant pressure combustion process. This increases the working gas combustion temperature, further increasing potential energy. Following combustion, the working gases are expanded and cooled through a series of turbine stages that drive the turbine blade shaft. Part of the energy extracted by the spinning turbine blades is used to drive the compressor stages to allow for a continuous process, and the remaining energy is used to spin an electro-magnetic generator; thereby producing electricity.

The J-class designation to the proposed units represents the turbine inlet temperature. According to *Mitsubishi Heavy Industries Technical Review Vol. 49 No. 1 (March 2012)*[1], MHI has developed the world's first J-class turbine which has an inlet temperature of 1,600° C. The higher inlet temperature improves thermal efficiency and reliability. According to the above referenced document, "The M501J gas turbine was designed with a turbine inlet temperature of 1,600°C by integrating the proven component technologies used in the 1,400°C F-series and the 1,500°C G and H-series turbines." Combined cycle efficiency from the G-class turbine to the J-class has increased from 58% to 61.5% or higher.

Since the exhaust gases exiting the turbine blade stages are still at temperatures significantly above ambient conditions, they represent additional available energy. The waste heat from the turbine exhaust is routed to the HRSG. Each HRSG has an associated duct burner that can be used to raise the temperature of the turbine exhaust gas for additional steam and power generation under certain operating conditions. The duct burners operate as a natural gas diffusion flame process. Steam produced by the HRSGs is expanded through a steam turbine to drive another electro-magnetic generator, creating additional electricity. Exhaust from the steam generator is then sent to a condenser to condense the steam for eventual re-use. The condenser circulating water will be cooled using a mechanical draft wet cooling tower with drift eliminators.

Emissions resulting from the combustion of natural gas in the CCCTs consist of criteria pollutants (nitrogen oxides, carbon monoxide, sulfur dioxide, volatile organic compounds, and particulate matter), greenhouse gases, and hazardous air pollutants. Emissions from each combustion turbine (CT) and HRSG duct burner unit will pass through a selective catalytic reduction (SCR) unit and oxidation catalyst to reduce NOx, CO, VOC, and HAPs before being released to the atmosphere through a common stack. There will be no bypass stack for the CT exhaust; therefore emissions will be controlled at all possible times. The SCR unit will employ ammonia as a reducing agent for the control of NOx emissions.

Cooling tower emissions consist of particulate matter, particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), and particulate matter with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$), originating from the dissolved solids (e.g. calcium, magnesium, etc.) that are assumed to crystalize and form airborne particles as the cooling tower water "drift" vaporizes. Particulate emissions from the cooling tower will be minimized by drift eliminators.

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[1] https://www.mhi-global.com/company/technology/review/pdf/e491/e491018.pdf

The proposed facility will also include one 245 MMBtu/hr auxiliary boiler and an electric fuel gas heater. The auxiliary boiler will be fired by pipeline quality natural gas only. Tenaska has proposed to limit the usage of the auxiliary boiler to 50% utilization (4,380 hours/year equivalent however Tenaska requests a capacity limitation rather than hours of operation).

Tenaska has proposed two diesel-fired emergency engines; an emergency generator and an emergency fire pump engine. The emergency generator will have a maximum output of 2 MW. The maximum rating of the fire pump engine will be 575 bhp. Both proposed engines are certified to applicable emissions standards and will operate solely in emergency situations and for required maintenance and testing.

Proposed storage tanks are two diesel tanks (one for each emergency engine), three lube-oil tanks (one for each turbine), and one 30,000 gallon anhydrous ammonia tank (for SCR).

Regulatory Analysis

Federal

40 CFR Part 52 – Prevention of Significant Deterioration – see page 12 under New Source Review (NSR).

New Source Performance Standards (NSPS) from 40 CFR Part 60 Subpart Da – Standards of Performance for Electric Utility Steam Generating Units does not apply to this facility. Per 40 CFR §60.40Da(e)(1), "Affected facilities (*i.e.* heat recovery steam generators used with duct burners) associated with a stationary combustion turbine that are capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel are subject to this subpart except in cases when the affected facility (*i.e.* heat recovery steam generator) meets the applicability requirements of and is subject to subpart KKKK of this part." The HRSGs used with steam generators associated with the stationary combustion turbines meet the requirements and will be subject to subpart KKKK.

NSPS from 40 CFR Part 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units applies to the auxiliary boiler and does not apply to the HRSGs with duct burners associated with the combustion turbines.

Auxiliary Boiler – Per 40 CFR § 60.40b(a), "The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr))." The proposed 245 MMBtu/hr natural gas-fired auxiliary boiler meets the applicability criteria and is therefore subject to this subpart. The limits established in this plan approval will ensure compliance with the NOx, SO_2, and PM limits in this subpart.

CCCTs – Per 40 CFR § 60.40b(i), the HRSGs with duct burners associated with the combustion turbines are subject to subpart KKKK and therefore not subject to subpart Db.

NSPS from 40 CFR Part 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units does not apply to the proposed units at this facility. Per 40 CFR § 60.40c(a), this subpart applies to units less than 100 MMBtu/hr but greater than 10 MMBtu/hr. All proposed steam generating units at this facility are greater than 100 MMBtu/hr; therefore this subpart does not apply.

NSPS from 40 CFR Part 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 does not apply to the proposed storage units at this facility. Per 40 CFR 60.110(a), the affected facility to which this subpart applies is each storage vessel with a capacity greater than 75 m^3 that is used to store volatile organic liquid. The proposed storage tanks that may store volatile organic liquids are less than 75 m^3.

NSPS from 40 CFR Part 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE) applies to the proposed emergency generator and fire pump diesel-fired engines. Per 40 CFR 60.4200(a)(2), the provisions of this subpart are applicable to "Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or
(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006."

Emergency Generator Engine – The emergency generator engine will commence construction (be ordered) after July 11, 2005, and be manufactured after April 1, 2006; therefore the emergency generator engine is subject to subpart IIII. Per §60.4205(b), owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement or less than 30 liters per cylinder must comply with the emission standards in §60.4202. Per §60.4202(a)(2), engines greater than 50 bhp must be certified to the emission standards in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants. Per 40 CFR 89.112, the applicable certification standards for units greater than 560 kW are 6.4 g/kW-hr NOx+NMHC, 3.5 g/kW-hr CO, and 0.20 g/kW-hr PM. The applicant has proposed limits equal to or more stringent than these limits.

575 bhp Fire Pump Engine – The fire pump engine will commence construction after July 11, 2005, and will be a certified National Fire Protection Association fire pump engine manufactured after July 1, 2006; therefore the fire pump engine is subject to subpart IIII. Per §60.4205(c), owners and operators of fire pump engines with a displacement less than 30 liters per cylinder must comply with the emission standards in table 4 of subpart IIII. For units ($300 \leq HP < 600$), the applicable emission standards are 7.8 g/bhp-hr NMHC+NOx, 2.6 g/bhp-hr CO, and 0.40 g/bhp-hr PM for model years 2008 and earlier, and 3.0 g/bhp-hr NMHC+NOx and 0.15 g/bhp-hr PM for model years 2009+ (model years 2009-2011 with a rated speed greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines). The applicant has proposed limits equal to or more stringent than the 2009+ limits of this subpart.

Per 40 CFR §60.4211(c), Tenaska has proposed to comply with the requirements of subpart IIII by purchasing engines which are certified to meet the applicable emission standards. Per 40 CFR §60.4207(b), Tenaska has proposed use diesel fuel with a sulfur content of no more than 15 ppm and with a minimum cetane index of 40 or maximum aromatic content of 35 volume percent (from 40 CFR 80.510(b)). Furthermore, each engine will be equipped with a non-resettable hour meter; routine maintenance checks and readiness testing is limited to

100 hours per year and usage for emergency purposes will not restricted as required by NSPS IIII; however this plan approval will limit total operation to 500 hours per year. Emergency engines may also be used for up to 50 hours per year of non-emergency use, excluding use for peak shaving or producing power for sale. These 50 hours of non-emergency use count towards the 100 hours for maintenance and readiness testing.

NSPS from 40 CFR Part 60 Subpart JJJJ – Standards of Performance for Stationary Spark Ignition (SI) Internal Combustion Engines (ICE) does not apply to any proposed sources at this facility. Tenaska has not proposed to install any SI ICE.

NSPS from 40 CFR Part 60 Subpart GG – Standards of Performance for Stationary Gas Turbines does not apply to the proposed turbines at this facility. The proposed units will be subject to NSPS Subpart KKKK and are therefore exempt from NSPS Subpart GG per 40 CFR §60.4305(b).

NSPS from 40 CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines applies to the proposed turbines at this facility. Per 40 CFR §60.4305, this subpart applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr based upon the higher heating value (HHV) of the fuel, and which commenced construction after February 18, 2005. The proposed turbines will commence construction after the above date and have a HHV heat input of approximately 3,147 MMBtu/hr. This subpart also applies to emissions from the associated HRSGs and duct burners. Applicable requirements from this subpart include emission limitations; testing, reporting, and recordkeeping requirements; and work practice standards. Since the proposed CCCTs are subject to subpart KKKK, they are exempt from the requirements of subpart GG, Da, Db, and Dc.

For units greater than 850 MMBtu/hr, applicable NOx emissions, including associated HRSG and duct burners, are limited to 15 ppm @ 15% O_2 or 54 nanograms per joule (ng/J) of useful output (0.43 lb/MWh). Tenaska has proposed a more stringent NOx limit of 2.0 ppm @ 15% O_2.

Per 40 CFR §60.4330(a)(2), for SO_2 emissions, each combustion turbine must comply with one of the following; limit emissions to less than 110 ng/J gross output, or burn fuel which contains total potential sulfur equal or less than 26 ng/J (0.060 lb SO_2 /MMBtu) heat input. Tenaska will comply with the SO_2 emission limitations by combusting pipeline quality natural gas with sulfur content less than 0.25 gr/100 scf. Note the tariff sheet from Texas Eastern limits sulfur content to 5 gr/100 scf; however Tenaska has provided additional data from Texas Eastern showing, on average, sulfur content is less than 0.25 gr/100 scf (0.035 lb/MMBtu based on 1020 Btu/scf at 60° F). The proposed emission limits of 2.7 lb/hr with duct burners and 2.4 lb/hr without duct burners which is equivalent to a limit of 0.00086 lb/MMBtu for this size unit. Compliance with the plan approval SO_2 limit will ensure compliance with the limit in this subpart. In addition to keeping records of the current, valid purchase contract, tariff sheet, or transportation contract obtained from the natural gas supplier, this plan approval will require Tenaska to sample and analyze the sulfur content on an annual basis in accordance with 25 Pa. Code §127.12b. This is based upon the applicant's proposed frequency. The Department may change the sampling frequency based upon the analysis and stack test results.

Per to 40 CFR §60.4333(a), Tenaska will be required to operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

To demonstrate compliance with the NOx emission limits, Tenaska will install CEMS for NOx satisfying the requirements specified in 40 CFR §60.4340(b)(1). Tenaska will be required to comply with the CEMS requirements specified in 40 CFR §60.4345 and the excess emissions requirements specified in 40 CFR §60.4350.

NSPS from 40 CFR Part 60 Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units may potentially apply to this facility. On Sept. 20, 2013, the Environmental Protection Agency issued a new proposal for carbon pollution from new power plants. After considering more than 2.5 million comments from the public about the 2012 proposal and consideration of recent trends in the power sector, EPA is changing some aspects of its approach. EPA is proposing to set separate standards for natural gas-fired turbines and coal-fired units. This action proposes standards for natural gas-fired stationary combustion turbines based on modern, efficient natural gas combined cycle technology as the best system of emission reduction. If/when finalized, the proposed CCCTs may be subject to this rule. This rule is projected to become final in January 2015. When finalized, Tenaska may be subject to a limit of 1000 lb CO2/MWh proposed in subpart TTTT. Tenaska has proposed a more stringent plan approval limit of 876 lb CO2/MWh.

National Emission Standards for Hazardous Air Pollutants (NESHAPS) Subpart Q – for Industrial Process Cooling Towers does not apply to the proposed cooling tower. Per 40 CFR 63.400(a), "The provisions of this subpart apply to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals and are either major sources or are integral parts of facilities that are major sources as defined in §63.401." The proposed cooling tower will not utilize chromium-based water treatment chemicals and will be located at an area source of HAPs (<10 tons of a single HAP and <25 tons of total HAPs); therefore this subpart will not apply.

NESHAPS Subpart YYYY – for Stationary Combustion Turbines does not apply to the proposed turbines. Per 40 CFR §63.6085 a person is subject to this subpart if they own or operate a stationary combustion turbine located at a major source of HAP emissions. The proposed facility will be an area source of HAPs; therefore this subpart will not apply.

NESHAPS Subpart ZZZZ – for Stationary Reciprocating Internal Combustion Engines (RICE) from 40 CFR Part 63 applies to each of the proposed diesel-fired engines at this facility. Per 40 CFR § 63.6585, a person is subject to this subpart if they own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand. This facility will be an area source of HAP emissions and does not include stationary RICE test cells/stands. Therefore each engine will be subject to 40 CFR 63 Subpart ZZZZ.

Per 40 CFR § 63.6590(2)(iii), each proposed engine is classified as a "new" stationary RICE since construction will commence after June 12, 2006. Per 40 CFR § 63.6590(c)(1), "new" stationary RICE have no further requirements under 40 CFR 63 Subpart ZZZZ, and meet the requirements of this part by meeting the requirements of 40 CFR Part 60 Subpart IIII.

NESHAPS Subpart DDDDD – for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters does not apply. The proposed facility will be an area source of HAPs; therefore this subpart will not apply.

NESHAPS Subpart JJJJJJ – for Industrial, Commercial, and Institutional Boilers Area Sources does not apply to the HRSGs with duct burners or the auxiliary boiler. The proposed units will combust natural gas only and per §63.11195(e), gas-fired boilers are not subject to this subpart.

NESHAPS Subpart UUUUU – for Coal- and Oil-Fired Electric Utility Steam Generating Units (Mercury and Air Toxics Standards (MATS) Rule) does not apply to this facility. On December 21, 2011, EPA announced standards to limit mercury, acid gases and other toxic pollution from power plants. The final rule became effective on April 16, 2012. The MATS rule reduces emissions of heavy metals, including mercury (Hg), arsenic (As), chromium (Cr), and nickel (Ni); and acid gases, including hydrochloric acid (HCl) and hydrofluoric acid (HF). The proposed power plant will only burn natural gas only. Therefore, the proposed power plant is not subject to the MATS rule pursuant to 40 CFR § 63.9983(b).

40 CFR Part 64 – Compliance Assurance Monitoring (CAM) Regulations – CAM applies to pollutant-specific emissions units at major sources that are required to obtain a Part 70 or Part 71 permit (i.e. Title V permit) if the following criteria are met:

> (1) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant (or a surrogate thereof), other than an emission limitation or standard that is exempt under paragraph (b)(1) of this section;
>
> (2) The unit uses a control device to achieve compliance with any such emission limitation or standard; and
>
> (3) The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source. For purposes of this paragraph, "potential pre-control device emissions" shall have the same meaning as "potential to emit," as defined in §64.1, except that emission reductions achieved by the applicable control device shall not be taken into account.

CAM does not apply to the NOx emissions from the powerblocks (i.e. CCCTs with HRSGs and duct burners), per 40 CFR Section 64.2(b)(1)(i), because the NOx emissions are subject to emission limitations and standards pursuant to Section 111 of the federal Clean Air Act (NSPS Subpart KKKK). CAM does not apply to CO, as per 40 CFR Section 64.2(b)(1)(vi), since CO will be monitored by CEMS. Pre-control VOC emissions exceed the major source threshold. Tenaska is required to submit a complete CAM plan for the oxidation catalysts pursuant to 40 CFR Sections 64.1 through 64.10 with the Part 70 (Title V) operating permit application.

Neither of the emergency engines are subject to CAM because all three criteria specified in 40 CFR Section 64.2(a)(1-3) are not met. Specifically, 40 CFR Section 64.2(a)(2), because these engines will not be equipped with control devices.

40 CFR Part 68 – Chemical Accident Prevention Provisions applies to the proposed storage of anhydrous ammonia at this facility. In accordance with 40 CFR § 68.130, Table 1, the storage of more than 10,000 pounds of anhydrous ammonia triggers the Chemical Accident Prevention Provisions found at 40 CFR Part 68.

Tenaska has proposed to store a maximum capacity of 30,000 gallons of anhydrous ammonia (approximately 154,500 lbs); therefore this part applies.

40 CFR Parts 72-78 – Acid Rain Program (ARP) Regulations – Per 40 CFR Section 72.6(a)(3)(i), the facility is subject to the Title IV Acid Rain Program since it will include new *utility units*, as defined in 40 CFR 72.2, and the units will serve a generator that produces electricity for sale. Accordingly, Tenaska will be required to submit a complete Acid Rain permit application at least 24 months prior to commencing operation per 40 CFR 72.30(b)(2)(ii).

40 CFR Part 96 – Clean Air Interstate Rule (CAIR) and 40 CFR Part 97 – Cross-State Air Pollution Rule (CSAPR)

On March 10, 2005, EPA issued the Clean Air Interstate Rule (CAIR). This rule provides states with a solution to the problem of power plant pollution that drifts from one state to another. On July 6, 2011, EPA finalized the Cross-State Air Pollution Rule (CSAPR) to replace CAIR. On August 21, 2012, the U.S. Court of Appeals for the D.C. Circuit vacated CSAPR and EPA reverted back to the previous rule for regulating interstate pollution, CAIR. On June 26, 2014, the U.S. government filed a motion with the U.S. Court of Appeals for the D.C. Circuit to lift the stay of the Cross State Air Pollution Rule. While the Court considers the motion, CAIR remains in place and no immediate action from States or affected sources is expected[2].

Due to the capacity of the proposed plant, Tenaska will be subject to the requirements whichever interstate air pollution transport rule is in place. Tenaska will be required to meet the applicable requirements of the rule which is in effect at the time operation commences.

Environmental Justice

Under the guidance of the Environmental Justice Advisory Work Group, the Department developed the EJ Enhanced Public Participation Policy[3]. The policy was created to ensure that EJ communities have the opportunity to participate and be involved in a meaningful manner throughout the permitting process when companies propose permitted facilities in their neighborhood or when existing facilities expand their operations. Appendix A of the policy includes a list of permits which trigger the EJ Enhanced Public Participation Policy. According to Appendix A – 2, Trigger Air Permits include new major sources of hazardous air pollutants or criteria pollutants; therefore this application is considered a "Trigger Permit."

The proposed facility is to be located in South Huntingdon Township, Westmoreland County, which is not designated as an Environmental Justice area. The nearest Environmental Justice (EJ) area is located in East Huntingdon, approximately 3 to 3.5 miles away. PSD modeling determined the proposed project will not cause a significant impact within the nearby EJ area. Subsequent modeling was performed based upon the Department's request to ensure the project does not violate the 1-hour NO_2 NAAQS during periods of startup and shutdown. Although the revised modeling (assuming startup and shutdown emissions occur every hour) does not show a violation of the NAAQS, it does exceed the significance level in the EJ area. The

[2] http://www.epa.gov/cleanairinterstaterule/
[3] http://www.elibrary.dep.state.pa.us/dsweb/Get/Version-48671/012-0501-002.pdf

Department's Office of Environmental Advocate will ensure the enhanced public participation requirements of the EJ Policy are met.

State

25 Pa. Code §§ 123.1, 123.2, and 123.31 – Prohibition of certain fugitive emissions, fugitive particulate matter, and odor emission limitations apply to this facility and will be included as plan approval conditions.

25 Pa. Code §§ 123.11 and 123.13 – Particulate Matter Emissions will apply to this facility and be included as plan approval conditions. The following table summarizes the applicable limit for each source.

Table 1: PM Emissions Standards Summary

Source	Citation	PM Emission Limit (lb/MMBtu heat input)	Proposed Emission Rate (lb/MMBtu heat input)
Combustion Turbines	25 Pa. Code §123.13(c)(1)(iii)[a]	0.02	0.0039
Duct Burners	25 Pa. Code §123.11(a)(2)[b]	0.13	
• Emergency Generator • Fire Pump Engine	25 Pa. Code §123.13(c)(1)(i)[c]	0.04	0.02
Auxiliary Boiler	25 Pa. Code §123.11(a)(2)[d]	0.165	0.0075

[a] Processes with effluent gas greater than 300,000 dry standard cubic feet per minute .
[b] Determined by $A=3.6E^{-0.56}$ where E equals the heat input of the combustion unit (400 MMBtu/hr).
[c] Processes with effluent gas less than 150,000 dry standard cubic feet per minute.
[d] Determined by $A=3.6E^{-0.56}$ where E equals the heat input of the combustion unit (245 MMBtu/hr).

Tenaska has proposed a PM emission limitation of 0.0039 lb/MMBtu/hr from the combined firing of the combustion turbine and duct burner. Compliance with the proposed combined PM emission rate ensures compliance with the individual limitations of §§ 123.11 and 123.13.

25 Pa. Code § 123.21 – Sulfur Compound Emissions will apply to the proposed combustion turbines, emergency generator and fire pump engines. Per §123.21(b), SO_2 in the effluent gas is limited to less than 500 ppmv. Based on the proposed emission rates and exhaust flow rates, the engines and turbine will comply with this emission limit.

25 Pa. Code § 123.22(a)(1) will apply to the proposed duct burners and auxiliary burners. SO_2 from a combustion unit shall not exceed 4 lb/MMBtu of heat input over any 1-hour period. The proposed SO2 limits in this plan approval application ensure compliance with the requirements of § 123.22(a)(1).

25 Pa. Code § 123.22(a)(2) requires commercial fuel oil No. 2 and lighter to contain a maximum sulfur content of 0.5% (5,000 ppm) through June 30, 2016, and a maximum sulfur content of 500 ppm beginning July 1, 2016. Compliance with the NSPS IIII requirement to use diesel fuel with less than 15 ppm sulfur will ensure compliance with the requirements of § 123.22(a)(2).

25 Pa. Code § 123.31 – Odor Emissions Limitations will apply to this facility and be included as a plan approval condition. Per §123.31(b), a person may not permit the emission into the outdoor atmosphere of any malodorous air contaminants from any source, in such a manner that the malodors are detectable outside the property of the person on whose land the source is being operated. Tenaska has proposed to comply with the requirements of §123.31 by combusting pipeline quality natural gas and ultra-low sulfur diesel fuel only.

25 Pa. Code §123.41 – Visible Emissions Limitations will apply to this facility and be included as a plan approval condition. Per §123.41, visible emissions are limited to:

(1) Equal to or greater than 20% for a period or periods aggregating more than 3 minutes in any 1 hour.
(2) Equal to or greater than 60% at any time.

In accordance with **25 Pa. Code §127.12b,** and pursuant to the requirements of Prevention of Significant Deterioration provisions in 40 CFR § 52.21 and of 25 Pa. Code § 127.83, as well as the best available technology provisions in 25 Pa. Code § 127.1 and other recent plan approvals for similar sources, visible emissions from each powerblock will be limited to the following:

(1) Equal to or greater than 10% for a period or periods aggregating more than 3 minutes in any 1 hour.
(2) Equal to or greater than 10% for a period or periods aggregating more than 6 minutes during startup and shutdown.

To ensure continued compliance with the above visible, fugitive, and malodorous emission requirements, the Department will require the permittee in accordance with 25 Pa. Code §127.12b, to conduct facility-wide inspections for the presence of any visible stack emissions, fugitive emissions, and any potentially objectionable odors at the property line at a minimum of once each operating day, during daylight hours, and while the sources are operating. If visible stack emissions, fugitive emissions, and/or potentially objectionable odors are apparent, the permittee shall take corrective action. Records of each inspection shall be maintained in a log and at the minimum include the date, time, name and title of the observer, along with any corrective action taken as a result.

For the purposes of this plan approval, the following definitions related to startups and shutdowns apply:

(a) Startup is defined as the period beginning when fuel begins flowing to the combustion turbine and ending when the combustion process, air pollution control equipment, and associated control systems have attained normal operating conditions.
(b) Shutdown is defined as the period beginning when the combustion turbine exits dry low NOx (DLN) mode and ending when fuel flow ceases.
(c) Cold Startup is defined as a startup in which the powerblock (which includes both the combustion turbines and the steam turbine) did not operate during the previous 72 hours.
(d) Warm Startup is defined as a startup in which the powerblock last operated between 8 and 72 hours prior to startup.
(e) Hot Startup is defined as a startup in which the powerblock operated during the previous 8 hours.

In order to minimize emissions during startup and shutdown, each startup event will be limited to one hour in duration, each shutdown event will be limited to one half hour in duration, and the total startup and shutdown duration for each combined cycle combustion turbine will be limited to 495 hours in any consecutive 12-month period. In order to accurately calculate annual emissions, records of the time, date, and duration of each startup and shutdown will be required.

25 Pa. Code §123.51 – Nitrogen Compound Emissions Monitoring Requirements applies to combustion units with a rated heat input of 250 MMBtu/hr or greater and with an annual average capacity factor of greater than 30%. The proposed duct burners will be subject to this section. Per §123.51(b), each unit will be required to have continuous emissions monitoring system (CEMS) installed to monitor emissions of NOx. Tenaska has proposed to install and operate each CEMS in accordance with Chapter 139, Subchapter C.

NOx Allowance Requirements under Chapter 123 will not apply. Per 25 Pa. Code §123.121, NOx allocations for the NOx allowance control periods starting May 1, 2003, will be distributed in accordance with Chapter 145 (relating to interstate pollution transport reduction). Note that Tenaska incorrectly states in this application that they will be subpart to NOx allowance requirements under the provisions of Chapter 123.

25 Pa. Code § 127.1 – New air contamination sources shall control emissions to the maximum extent, consistent with best available technology (BAT) as determined by the Department as of the date of issuance of the plan approval for the new source. All proposed sources meet the definition of a new source as defined under 25 Pa. Code §121.1 and therefore must meet BAT. BAT is further discussed below.

25 Pa. Code § 127.11 – Approval by the Department is required to allow the construction of an air contamination source or the installation of an air cleaning device on an air contamination source.

25 Pa. Code § 127.12b(c) – The plan approval must incorporate the monitoring, recordkeeping and reporting provisions required by Chapter 139 (relating to sampling and testing). Based on other recent plan approvals for similar sources, this plan approval will require testing within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup for NOx, CO, VOC (with and without duct burners), formaldehyde, PM (filterable and condensable), PM_{10} (filterable and condensable), $PM_{2.5}$ (filterable and condensable), sulfuric acid mist, SO_2, and ammonia slip. Subsequent testing for VOC, formaldehyde and PM (filterable and condensable) will be required no less often than every two years after initial testing. The frequency for subsequent testing is consistent with other recent plan approvals for similar sources. The testing frequency may be revised based upon the satisfactory demonstration of compliance with the emission limitations by the owner/operator. Subsequent testing will not be required for NOx, CO, and ammonia slip since they will be required to be monitored with the CEMS. Since the applicant has assumed all particulate matter emissions from the combustion turbines is $PM_{2.5}$, the Department will not require separate testing for PM, PM_{10}, and $PM_{2.5}$ for subsequent tests. Sulfuric acid mist and SO_2 emissions will be calculated based upon the measured sulfur content of the natural gas, therefore subsequent testing will not be required for those pollutants.

25 Pa. Code §129.56 for storage tanks greater than 40,000 gallons capacity containing VOCs will not apply to the proposed storage tanks at this facility since they are each less than 40,000 gallons.

25 Pa. Code §129.57 for storage tanks less than or equal to 40,000 gallons capacity containing VOCs will not apply to the proposed storage tanks at this facility. The provisions of this section apply to above ground stationary storage tanks with a capacity equal to or greater than 2,000 gallons which contain VOCs with vapor pressure greater than 1.5 psia. The three (3) 1,000 gallon lube oil and one (1) 1,000 gallon diesel storage tanks are not subject since they are less than 2,000 gallons and do not contain VOCs with vapor pressure greater than 1.5 psia. The one (1) 5,000 gallon diesel and 30,000 gallon ammonia storage tanks are not subject since they do not contain VOCs with vapor pressure greater than 1.5 psia.

25 Pa. Code §§ 129.201 through 129.203 establish additional NOx requirements for boilers, stationary combustion turbines, and stationary internal combustion engines located in Bucks, Chester, Delaware, Montgomery, or Philadelphia counties. This facility is proposed to be located in Westmoreland County, therefore these sections do not apply.

25 Pa. Code Chapter 135 establishes requirements for recordkeeping and reporting of annual emissions and will be applicable to the proposed facility. Annual source reports will be required to be submitted by March 1 of each year for the preceding calendar year.

25 Pa. Code Chapter 139 establishes requirements for sampling and testing and will be applicable to the proposed sources at this facility. In addition to testing, the CEMS required for the combustion turbines by 25 Pa. Code §123.51(b) will be subject to the requirements of 25 Pa. Code § 139.5(f).

25 Pa. Code Chapter 145 – Interstate Pollution Transport Reduction – 25 Pa. Code §145.201 incorporates by reference the CAIR NOx Annual Trading Program and CAIR NOx Ozone Season Trading Program as a means of mitigating the interstate transport of fine particulates and NOx, and the CAIR SO_2 Trading Program as a means of mitigating the interstate transport of fine particulates and SO_2. This subchapter also establishes general provisions and the applicability, allowance and supplemental monitoring, recordkeeping and reporting provisions.

Applicability of CAIR and its successor CSAPR are discussed above. As previously discussed, the CAIR program is not expected to still be in effect at the time this facility commences operation. This facility will be subject to whichever program is in place at the time operation commences and will determine specific requirements under the applicable program at that time.

New Source Review (NSR)

Prevention of Significant Deterioration (PSD) Review

Per 40 CFR §52.21(a)(2)(i) and §52.21(a)(2)(ii), any project at a new major stationary source (as defined in paragraph (b)(1) of this section) or the major modification of any existing major stationary source in an area designated as attainment or unclassifiable under the federal Clean Air Act must comply with the applicable requirements of 40 CFR Part §52.21, *Prevention of Significant Deterioration of Air Quality (PSD).* A major stationary source is defined as either:

(a) A source in one of the 28 source categories identified in 40 CFR 52.21 that has a potential to emit 100 tons or more per year of any regulated NSR pollutant;
(b) Any other stationary source that has the potential to emit 250 tons or more per year of a regulated NSR pollutant; or
(c) Any physical change which would constitute a major stationary source by itself.

Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input are listed as one of the 28 source categories; therefore the threshold is 100 tpy of any regulated NSR pollutant for the proposed facility. Sources on the list are also required to include fugitive emissions in determining whether the source is a major stationary source.

This proposed facility is estimated to have potential emissions in excess of 100 tpy for one or more regulated NSR pollutants and will therefore be considered a new major source with respect to the PSD program. A project at a major facility for any one regulated NSR pollutant is required to be evaluated for all NSR pollutants to determine if PSD requirements are to be applied. Emission increases from this project are accounted for in step 1 and are equal to the PTE. Step 2 takes into account contemporaneous increases or decreases; however since this is a new facility there are no contemporaneous emissions to consider. Table 2 below summarizes the PSD applicability for the proposed project.

Table 2: PSD Applicability Summary

Pollutant	Baseline Emissions	Project Emissions[a]	Net Emissions Change	Major Source Threshold	Significant Emission Rate	PSD (Yes/No)
PM	0	96	96	100	25	Yes
PM_{10}	0	92	92	100	15	Yes
SO_2	0	23	23	100	40	No
NO_2	0	373	373	100	40	Yes
CO	0	2,310	2,310	100	100	Yes
CO_2e	0	3,827,574	3,827,574	100,000	75,000	Yes
Sulfuric Acid Mist	0	15.2	15.2	100	7	Yes

[a] Project emissions rounded up for PSD applicability summary.

As shown in Table 2 above, a best available control technology (BACT) analysis is required for all PSD pollutants. In accordance with 40 CFR §52.21(b), "*Best available control technology* means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."

Non-Attainment New Source Review

On May 19th, 2007, the Department adopted revised New Source Review regulations in 25 Pa. Code Chapter 127 Subchapter E. Per 25 Pa. Code §127.201(a), "A person may not cause or permit the construction or modification of an air contamination facility in a nonattainment area or having an impact on a nonattainment area unless the Department… has determined that the requirements of this subchapter have been met."

25 Pa. Code §127.201(c) specifies that "The NSR requirements of this subchapter also apply to a facility located in an attainment area for ozone and within an ozone transport region that emits or has the potential to emit at least 50 tpy of VOC or 100 tpy of NOx. A facility within either an unclassifiable/attainment area for ozone or within a marginal or incomplete data nonattainment area for ozone or within a basic nonattainment area and located within an ozone transport region will be considered a major facility and shall be subject to the requirements applicable to a major facility located in a moderate nonattainment area."

25 Pa. Code §127.201(g)(1) specifies that "Beginning January 1, 2011, or an earlier date established by the Administrator of the EPA, condensable PM shall be accounted for in applicability determinations and for $PM_{2.5}$ and PM-10 emission limitations established in a plan approval or operating permit issued under this chapter." Per 25 Pa. Code §127.202(a), "The special permit requirements in this subchapter apply to an owner or operator of a facility to which a plan approval will be issued by the Department after May 19, 2007, except for PM2.5, which will apply after September 3, 2011."

Per 40 CFR § 81.339, South Huntingdon Township, Westmoreland County is classified as an area of nonattainment for the 8-hour ozone, annual $PM_{2.5}$, and 24-hour $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS). The entire Commonwealth of Pennsylvania is considered a "moderate" ozone nonattainment area for NOx and VOCs because Pennsylvania is a jurisdiction in the Ozone Transport Region established by operation of law under Section 184 of the Clean Air Act. Recognized precursor pollutants for $PM_{2.5}$ are SO_2, NO_x, VOC, and ammonia (NH_3); and for ozone are NOx and VOC. For purposes of NNSR, Tenaska is considered major if the PTE exceeds 100 tons of NOx, 50 tons of VOCs, 100 tons of SO_2, or 100 tons of $PM_{2.5}$ per year. Table 3 below summarizes the NNSR applicability for this project.

Table 3: NNSR Applicability Analysis

Pollutant	Baseline Emissions	Project Emissions	Net Emissions Change	NNSR Major Source Threshold	NNSR (Yes/No)
NOx	0	373	373	100	Yes
SO_2	0	23	23	100	No
$PM_{2.5}$	0	89	89	100	No
VOC	0	1,251	1,251	50	Yes

As shown in Table 3 above, potential emissions of NOx and VOC exceed the NNSR major source thresholds. Since the proposed PTE is less than 100 tpy for SO_2 and $PM_{2.5}$ (including condensable), NNSR is not triggered for these pollutants. This plan approval will contain Federally enforceable emission standards limiting SO_2 and $PM_{2.5}$ (including condensable) below the major source threshold. NNSR requirements for NOx and VOC include Lowest Achievable Emission Rate (LAER) and purchasing Emission Reduction Credits (ERCs). In accordance with 25 Pa. Code §121.1, LAER is defined as:

(i) The rate of emissions based on the following, whichever is more stringent:
   (A) The most stringent emission limitation which is contained in the implementation plan of a state for the class or category of source unless the owner or operator of the proposed source demonstrates that the limitations are not achievable.
   (B) The most stringent emission limitation which is achieved in practice by the class or category of source.

(ii) The application of the term may not allow a new or proposed modified source to emit a pollutant in excess of the amount allowable under an applicable new source standard of performance.

In accordance with 25 Pa. Code §§ 127.205(4) and 127.210, Tenaska will be required to purchase ERCs to offset the NOx and VOC emission increases associated with this project at a ratio of 1.15:1. Based on the PTE, the following table represents the required ERCs to be purchased:

Table 4: ERC Calculation

Pollutant	PTE	Ratio	ERCs
NOx	373	1.15	429
VOC	1251	1.15	1439

In accordance with 25 Pa. Code § 127.205(5), an analysis shall be conducted of alternative sites, sizes, production processes, and environmental control techniques for the proposed facility, which demonstrates that the benefits of the proposed facility significantly outweigh the environmental and social costs imposed within this Commonwealth as a result of its location, construction or modification.

Alternative Sites

Future potential environmental regulations with their predicted effects may potentially lead to the retirements of numerous older fossil fuel power plants throughout the United States with particular impact on the plants in the PJM Interconnection due to the age, size, efficiency, and existing pollution control technologies installed on many of the facilities in that region. The region of the PJM Interconnection includes the movement of electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. The predicted retirements combined with the anticipated growth in the region indicate a regional need for additional clean power generation sources. These clean power generation sources are to be a combination of future generation fossil-fuel-fired plants with greater efficiencies and lower environmental impacts (primarily those powered by natural gas) along with a mix of renewable resources.

The discovery and increasingly widespread use of an economic process to extract natural gas from shale is predicted to make the Marcellus region a major supply basin for natural gas production. Pennsylvania has a high production level of shale derived natural gas compared to other northeastern United States that currently allow shale-drilling activities.

Location in the PJM area closer to the major load centers on the eastern seaboard lessens the transmission line losses and potential need for additional transmission upgrades compared to locations in the more western parts of the PJM system. As transmission line losses increase, the need for more generation increases to serve the same need at the end of the transmission and distribution systems. Likewise, smaller losses mean less generation is needed to meet those needs.

Tenaska has considered sites at various locations in Pennsylvania taking regional factors into consideration including being located near major interstate natural gas transmission pipelines and high voltage transmission lines. Location near this type of infrastructure decreases the environmental impact associated with connecting the power plant to the source of fuel supply and potential need for extensive transmission line work to accommodate the additional electric generation. Other considerations included selecting a proposed location with minimal impact to threatened or endangered species or species of special concern, without impacts to wetlands, and without land use changes. Selecting a location near a body of water that could be used as a source of cooling water was also considered. Tenaska surveyed four areas in Pennsylvania during their initial screening. Considering the above factors, two sites were selected; Westmoreland County and Lebanon County and plan approvals were submitted for each. The plan approval for the Lebanon County location has since been withdrawn as Tenaska has selected the Westmoreland location to minimize additional natural gas transmission infrastructure, maximize distance from residences, and avoid areas previously mined for coal (due to subsidence concerns).

The proposed project site satisfies the criteria described above. Southwestern Pennsylvania has a high volume of natural gas production and the proposed location is in proximity to the Texas Eastern transmission pipeline and high voltage electric transmission system reducing the amount of infrastructure expansion. Furthermore, the applicant has shown through modeling that this project, as proposed, will not cause or contribute to a violation of any health based standard or impair soils or vegetation in the area.

Alternative Sizes

A significant factor in determining the size of the proposed project was the anticipated demand for electric power in the region selected for the project. Projected fossil-fuel fired plant retirements along with forecasted load growth in the PJM system were analyzed. During the development of this project, Tenaska analyzed various configurations and different size units to most efficiently produce power with limited environmental impacts. Tenaska determined the proposed capacity of 930 – 1,065 MW to be the most cost efficient capacity within the construction constraints while limiting potential environmental impact. A smaller unit would potentially require additional generating capacity to be built elsewhere potentially increasing the overall environmental and social impact.

Alternative Production Processes

Production processes to be considered include renewable energy technologies (e.g. solar, biomass, and wind power) and fossil fuels. Renewable energy processes were removed from consideration because they could not produce adequate amounts of electrical power needed to meet the expected energy demands resulting from the anticipated coal-fired plant retirements. Furthermore, Pennsylvania does not provide the appropriate geographic and climatological conditions necessary to provide electrical power when needed at this capacity.

Fossil fuel plants using coal or oil were removed from consideration because the costs to comply with the anticipated environmental regulations (on a $/kW basis) were much higher than a comparably sized natural gas plant. Further, even with the installation of control technologies on coal or oil plants, the resulting environmental impacts were still greater than a comparably sized natural gas plant.

Other natural gas power generation processes (e.g. reciprocating engines, boilers, combustion turbines) and energy recovery cycles (e.g. simple-cycle, combined-cycle, combined heat and power) were also considered. Combustion turbines in combined-cycle operation were determined to be the most efficient and cost effective for the proposed capacity. Tenaska considered various combustion turbine, HRSG, and control system designs and manufacturers and has chosen a 2-on-1 configuration with HRSG for the overall efficiency, flexibility, and capacity required.

Alternative Control Technologies

A detailed discussion and analysis of the alternative control technologies is included in the BACT/LAER/BAT analyses below. Tenaska was required to perform a BACT analysis for criteria pollutants since the proposed project is subject to PSD. Furthermore, Tenaska is subject to LAER for NOx and VOC; LAER is generally considered to be the most stringent level of control required under the Clean Air Act. Based on the results of the analyses, the project will employ air pollution control technology equivalent to or more stringent than other similar sources throughout the United States. The project will also be fueled exclusively with natural gas, which will result in lower emission of criteria pollutants, such as NOx, SO_2, PM, and CO_2, compared to alternative fossil fuels.

LAER/BACT/BAT Analysis

Tenaska has used EPA's RACT/BACT/LAER Clearinghouse (RBLC) to search for projects of similar size and nature as the proposed project. A number of projects were identified and determined by the Department to be of close, but not identical, size and nature as the proposed project. The following is a summary of the LAER/BACT/BAT determinations and their respective emission limits made by the Department, taking into consideration available control technologies, other recent plan approvals, and the RBLC.

NOx LAER/BACT/BAT Analysis – Powerblocks

The facility-wide potential emissions are greater than the PSD and NNSR NOx emission threshold of 100 tpy; therefore, the sources at this facility are subject to the PSD BACT provisions in 40 CFR § 52.21 and NNSR LAER provisions in 25 Pa. Code § 127.201 through 127.217.

In combustion processes, NOx is primarily formed by two mechanisms: fuel NOx and thermal NOx. NOx formation from natural gas combustion is primarily thermal NOx. Since pipeline quality natural gas contains little or no fuel-bound nitrogen, fuel NOx is not a major contributor to NOx emissions from natural gas-fired combustion turbines. Thermal NOx is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and react to form NOx. Factors affecting the formation of thermal NOx are combustion temperature, concentration of oxygen in the inlet air, and residence time. Prompt NOx is a third possible formation mechanism where early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals in the fuel form prompt NOx. However, the contribution of prompt NOx to overall NOx formation is negligible.

Identification of Potential Control Techniques (BACT)

NOx reduction can be accomplished by two general methodologies: combustion control techniques and post-combustion control methods. Combustion control techniques incorporate fuel or air staging that reduce peak flame temperature and/or introduce combustion products that limit initial NOx formation. Several post-combustion NOx control technologies are potentially applicable to the proposed facility. These technologies employ various strategies to chemically reduce NOx to N_2 with or without the use of a catalyst. NOx control technologies analyzed by Tenaska for the powerblocks include EMx/SCONOx, catalytic combustion (XONON), selective catalytic reduction (SCR), selective non-catalytic reduction (NSCR), water/steam injection, dry low-NOx burners, and good combustion controls.

EMx/SCONOx uses platinum-based catalyst coated with potassium carbonate to oxidize CO to CO_2 and NO to NO_2. NO_2 then absorbs onto the catalyst to form potassium nitrate. Periodically, the catalyst is regenerated with hydrogen gas that converts the compounds back to potassium carbonate, water, and nitrogen. To maintain continuous operation, the system is divided into sections separated by louvers, with on section offline at all times for regeneration.

XONON replaces the typical combustor in a combustion turbine with a catalytic combustor, limiting the temperature of combustion to reduce NOx formation.

Selective Catalytic Reduction (SCR) is a post-combustion gas treatment process in which a reducing agent such as ammonia (NH_3) is injected into the exhaust upstream of a catalyst bed. NH_3 and NOx react on the catalyst bed to form diatomic nitrogen and water vapor. According to information received by the applicant on November 11, 2014, the typical operating range for SCR is 450 to 780° F, with the optimum zone beginning at approximately 600° F. Injection of ammonia below 500° F may lead to ammonia slip. During steady state operation based upon this project design and SCR placement, the temperature across the SCR is estimated to be in the range of 550 to 750° F, depending primarily on turbine load. During startup, the temperature across the SCR is expected to rise from ambient to 550° F. During shutdown, the temperature across the SCR is expected to provide residual control efficiency until the temperature falls below 550° F.

Selective Non-Catalytic Reduction (SNCR) is a post-combustion control technology based on the reaction of urea ($CO(NH_2)$) or ammonia with NOx. Urea or ammonia is injected into the combustion gas path to reduce NOx to nitrogen and water. The optimal temperature range for SNCR is approximately 1,600 to 2,000° F. Operation at temperatures below this range results in ammonia slip. Operation above this range results in oxidation of ammonia, forming additional NOx.

Elimination of Technically Infeasible Control Options (BACT)

EMx/SCONOx has not been demonstrated on powerblocks similarly sized to the units proposed at this facility. Tenaska concludes that there is insufficient operating history of this control technology on units this size, therefore this control is considered technically infeasible.

Similarly, XONON is not commercially available on large units as proposed in this project. Therefore, XONON has also been determined to be technically infeasible.

Ranking of Remaining Control Options (BACT)

The remaining control technologies are ranked in order of control efficiency in Table 4 below.

Table 5: Remaining NOx Control Options

Pollutant	Control Technology	Potential Control Efficiency (%)
NOx	SCR	50-95
	SNCR[a]	40-60
	Water/Steam Injection	30-50
	Good Combustion Controls	Base

[a] Note that due to the high exhaust temperature requirement of SNCR, it can be argued that SNCR is considered technically infeasible for the proposed units.

Selection

The BACT determination for control of NOx is good combustion practices and SCR. The proposed emission limitation is 2.0 ppmvd corrected to 15% O_2 based on a 3-hour averaging period. Review of the RBLC database and other recent plan approvals for similar sources indicates that the proposed NOx emission limit satisfies LAER for this type of source. Tenaska will also be required to continuously monitor and record the NOx emission rate, the SCR pressure differential, inlet and outlet temperatures, and ammonia injection rate to ensure proper operation. Maintenance will also be required per the manufacture's recommendation. In addition to the above requirements, Tenaska will visually inspect the catalyst during planned outages and clean/replace as needed.

CO BACT/BAT Analysis – Powerblocks

CO emissions are a by-product of incomplete combustion due to insufficient oxygen availability, poor air/fuel mixing, reduced combustion temperature, and/or reduced combustion gas residence time.

Identification of Potential Control Techniques

Tenaska has identified the following potential control technologies for CO; EMx/SCONOx, oxidation catalyst, and good combustion controls. For a description of EMx/SCONOx please refer to the NOx analysis above.

Oxidation Catalysts oxidize CO in the exhaust stream by utilizing a precious metal catalyst. Oxidation efficiency depends on temperature, exhaust flow rate (since sufficient residence time is required for oxidation to occur), and catalyst composition. Also, sulfur and other compounds may foul the catalyst leading to decreased efficiency. According to the applicant, the oxidation catalyst for each unit is expected to be placed within the HRSG in an optimal temperature range of 550 to 750° F. The exact catalyst location, and therefore the exact temperature range, will be determined during final design considering the required control efficiencies for CO and VOC, as each is optimized at different temperatures.

Good Combustion Practices include optimization of the combustion chamber designs and operations to improve the oxidation process and minimize incomplete combustion. This includes utilizing lean combustion to produce a cooler flame temperature while still ensuring good air/fuel mixing with excess air to achieve complete combustion.

Elimination of Technically Infeasible Control Options

EMx/SCONOx has the potential to reduce CO emissions; however this technology was previously determined to be technically infeasible for NOx for the proposed units. Similarly, for CO, EMx/SCONOx has not been demonstrated on powerblocks similarly sized to the units proposed at this facility.

Selection

Good combustion practices have been successfully demonstrated to control CO emissions on units of similar size and configuration. Tenaska has therefore determined this to be BACT for this type of source. Tenaska has argued that the addition of an oxidation catalyst for controlling CO emissions is beyond the range of cost effectiveness for BACT. Based on Tenaska's analysis, the addition of an oxidation catalyst would cost $2,836/ton of CO removed. The Department has determined this is within the cost effectiveness for BAT; and has therefore determined oxidation catalyst for this source is BAT.

Tenaska originally proposed CO emission rates of 12.6 ppmvd @ 15% O_2 with duct burners and 10 ppmvd @ 15% O_2 without duct burners. With the proper installation and use of the oxidation catalysts, the units can't physically reach the originally proposed CO exhaust concentration. Therefore Tenaska formally revised the proposed CO emission rate to 2.0 ppmvd @ 15% O_2 with and without duct burners on September 11, 2014.

Based on the provided manufacturer's information along with review of the RBLC and BAT for other recently issued plan approvals for similar sources, the Department has determined the appropriate CO emission rate is 2.0 ppmvd @ 15% O_2 on a 3-hour averaging period. The proposed control technologies of good combustion practices and oxidation catalyst and the resulting emission rate are equivalent to or more stringent than other recent determinations. Tenaska will also be required to continuously monitor and record the pressure differential across the oxidation catalyst as well as the catalyst inlet and outlet temperatures to ensure proper operation. Maintenance will be required per the manufacture's recommendation. In addition to the above requirements, Tenaska will visually inspect the catalyst during planned outages and clean/replace as needed.

VOC LAER/BAT Analysis – Powerblocks

VOC emissions are a result of incomplete combustion of fuels caused by reduced combustion temperature and decreased residence time within the combustion zone. Inefficient combustion leads to the formation of aldehydes, aromatic carbon compounds, and various other organic compounds by several mechanisms. The potential control technologies for VOC are the same as those for CO, described above. Similarly to the CO determination, BAT for VOC is good combustion practices and installation and operation of an oxidation catalyst.

Based on the manufacturer's specifications, Tenaska proposed two separate VOC LAER limits, one for operation with duct burners and one without duct burners. The original proposed emission rates were 3.1 ppmvd @ 15% O_2 with duct burners and 1.4 ppmvd @ 15% O_2 without duct burners. Tenaska subsequently formally revised the emission rate with duct burners to 2.4 ppmvd @ 15% O_2 on September 11, 2014.

After review of the RBLC, there many similar sized and configured units, however not the exact units proposed. VOC emission limits range from 1.0 ppmvd to over 10 ppmvd, however the only rates that have been verified are 5.0 ppmvd and greater (RBLC ID CT-0151). RBLC ID NJ-0043 for the Liberty Generating Station in Union County, New Jersey established a case-by-case VOC limit of 1.7 ppmvd for a 3,202 MMBtu/hr CCCT with duct burners and the RBLC states this emission rate has been verified. However, the Department has contacted Aliya Khan of the NJ DEP Air Quality Permitting Program and has discovered that the Liberty Generating Station has never been constructed and therefore the emission rates have not been verified. The proposed VOC emission rates of 2.4 ppmvd @ 15% O_2 with duct burners and 1.4 ppmvd @ 15% O_2 without duct burners on a 3-hour averaging period have been determined to satisfy LAER.

PM/PM_{10} BACT/BAT and $PM_{2.5}$ BAT Analysis – Powerblocks

Total PM emissions, including condensable PM, are a result of noncombustible trace constituents in the fuel, unburned hydrocarbons that agglomerate to form particles, and miscellaneous particles existing in the ambient air used for combustion. Condensable particulate results from sulfur in the fuel and the resultant sulfuric acid, NOx being oxidized to nitric acid, and high molecular weight organics.

Identification of Potential Control Techniques

Tenaska has analyzed various post-combustion control techniques for the control of particulate matter including cyclones, electrostatic precipitator (ESP), baghouse/fabric filters, and wet scrubbers. Tenaska has also analyzed the use of good combustion practices and use of low sulfur fuel.

Elimination of Technically Infeasible Control Options

Tenaska has determined that the use of add-on controls to reduce particulate matter emissions is technically infeasible. This is because of the high operating temperatures, high exhaust flow rates, fine particulate distribution, and inherently low uncontrolled emission rates due to low ash and sulfur content of natural gas. Also, a review of the RBLC showed no combined cycle units equipped with add-on controls.

Selection

Tenaska has determined that good combustion practices with the use of low ash/low sulfur natural gas to satisfy LAER/BACT/BAT for the proposed units. Tenaska has proposed a total PM emission rate of 0.0039 lb/MMBtu/hr on a 3-hour averaging period. After review of the RBLC and other recent plan approvals, the Department has determined this is an appropriate emission rate.

H_2SO_4 BACT and SO_2 BAT Analysis – Powerblocks

Sulfuric acid mist (H_2SO_4) emissions result from the reaction of SO_3, formed from the oxidation of SO_2 with water. Uncontrolled H_2SO_4 and SO_2 emissions both depend on the sulfur content of the fuel. H_2SO_4 emissions also depend on the oxidation of SO_2 to SO_3, followed by the subsequent conversion of SO_3 to H_2SO_4 when water vapor is present. H_2SO_4 emissions are not necessarily dependent upon combustion turbine properties such as size or burner design.

Identification of Potential Control Techniques

Tenaska has analyzed post-combustion add-on controls to reduce SO_2 and H_2SO_4 including flue gas desulfurization (FGD) scrubber and dry sorbent injection. Tenaska has also analyzed the use of low sulfur fuel. FGD scrubbers remove sulfur compounds from exhaust streams by using an alkaline reagent to form sulfate and sulfate salts. The reaction of SO_2 with the alkaline can be performed using either a wet or dry contact system. Dry sorbent injection involves the reaction of a calcium or sodium-based sorbent with SO_2 and SO_3. The reduced availability of SO_2 and SO_3 in the exhaust stream reduces H_2SO_4. The use of low sulfur fuel decreases the amount of sulfur in the system which decreases emissions of sulfur compounds including H_2SO_4.

Elimination of Technically Infeasible Control Options

No applications have been identified of FGD scrubbers or dry sorbent injection on natural gas-fired combustion turbines due to low SO_2 and H_2SO_4 emissions. Due to the low concentration of H_2SO_4 in the exhaust gas, neither the FGD scrubber nor dry sorbent injection would provide measurable emission reduction. Based on the insufficient operating history of these control technologies on similar units, Tenaska considers these methods technically infeasible. This is consistent with determinations listed in the RBLC and other recent plan approvals.

Selection

Due to the elimination of all add-on control options, Tenaska has determined the appropriate control technology to be combustion of pipeline quality natural gas with low sulfur content. Based upon review of achievable emission limits, Tenaska has determined that the H_2SO_4 BACT emission rate for normal operation is a limit of 5.7 E-04 lb/MMBtu HHV on a 3-hour average basis. Tenaska has identified more stringent limits in the RBLC for similar sized units, however since no add-on controls are proposed, the H_2SO_4 emissions are based primarily on the sulfur content of the natural gas available in the region and the conversion of SO_2 to SO_3 and SO_3 to H_2SO_4. Therefore the proposed BACT emission limit of 5.7 E-04 lb/MMBtu HHV on a 3-hour average basis is appropriate.

Combustion of pipeline quality natural gas also meets the SO_2 BAT requirements. This also meets the SO_2 standards under NSPS Subpart KKKK. Tenaska has based SO_2 PTE on an average sulfur content of 0.25 gr/100 scf. This is lower than Texas Eastern's maximum FERC tariff content of 5 gr/100 scf. Tenaska has provided supporting data showing the sulfur content is, on average, much lower than 0.25 gr/100 scf. To be conservative emissions have been based upon the highest sulfur content out of the provided data. This is consistent with the RBLC which contains limits ranging up to 2 gr/100 scf for similar units. Note Tenaska is not subject to BACT for SO_2.

BACT/BAT Analysis for Greenhouse Gases (GHGs) - Powerblocks

In EPA's current view, Tailoring Rule "Step 1" sources remain subject to PSD BACT requirements for GHG as well as other pollutants. For new "anyway" sources (such as Tenaska), EPA intends to continue applying PSD BACT requirements to GHG emissions if the source emits or has the potential to emit at least 75,000 tpy GHGs[4]. EPA acknowledges that the Supreme Court said the agency would need to justify a "de minimis" GHG emissions threshold above which BACT may be applied to "anyway" sources, but to ensure compliance with the Clean Air Act at present and until there are further developments at the D.C. Circuit, EPA will continue to apply the 75,000 tpy threshold.

Identification of Potential Control Techniques

Potential GHGs control technologies identified include carbon capture and sequestration (CCS), increased turbine efficiency, fuel selection, and good combustion practices.

CCS for the powerblock would involve post-combustion capture of CO_2 emissions. Carbon capture can potentially be achieved with low pressure scrubbing of CO_2 from the exhaust stream with solvents (e.g. amines or ammonia), solid sorbents, or membranes. However, only solvents have been used to date on a commercial scale while the others have been used in research and development only.

Increased Turbine Efficiency – In general, turbines which operate at higher firing temperatures (i.e. large turbines) have the highest efficiencies. Increasing the efficiency of the turbines directly decreases GHG emissions as less fuel is combusted per unit output.

Fuel Selection – Fuels containing less carbon have lower potential GHG emissions as fewer carbon atoms are available.

Good Combustion Practices – Good combustion and operating practices are a potential method to control GHGs by improving the fuel efficiency of the combustion turbines. Good operating practices include proper maintenance and tune-up of the combustion turbines per the manufacturer's specifications.

Elimination of Technically Infeasible Control Options

Carbon capture is an established process in some industry sectors but not in the power generation industry. CCS has been used intermittently on a small scale at a few coal-fired power plants to control CO_2 emissions on very small slip streams. However, CCS is not generally feasible or demonstrated in practice to control full stream emissions from power generation, especially natural gas combined style plants. Although CCS is considered infeasible, Tenaska has further evaluated CCS based upon guidance from EPA. Use of efficient combustion turbines, selecting a low-carbon fuel, and good combustion practices are considered technically feasible.

[4] http://www.epa.gov/nsr/documents/20140724memo.pdf

Economic, Energy, and Environmental Impacts

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. According to EPA's March 2011, PSD guidance document, "EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible. However, there may be cases at present where the economics of CCS are more favorable (for example, where the captured CO_2 could be readily sold for enhanced oil recovery), making CCS a more viable option under Step 4. In addition, as a result of the ongoing research and development described in the Interagency Task Force Report noted above, CCS may become less costly and warrant greater consideration in Step 4 of the BACT analysis in the future."

Furthermore, "taking account of the current limited data and consequent uncertainty concerning the costs of GHG BACT, it is reasonable to anticipate that the cost effectiveness numbers (in \$/ton of CO_2e) for the control of GHGs will be significantly lower than those of the cost effectiveness values for controls of criteria pollutants that have evolved over time."

The costs associated with CCS can be broken down into the three categories that the CCS process is divided: CO_2 capture, CO_2 transport, and CO_2 storage. Tenaska has based the CCS cost estimation primarily on cost factors obtained from the CCS Task Force Report. The cost analysis carried out in the report identifies a range of costs associated with each component of CCS. To be conservative, Tenaska has used the lowest, most applicable factors for use in the cost estimation.

Capture and compression costs vary widely depending on what type of combustion equipment and process is used at the facility. Of the power plant configurations for which cost factors are provided in the CCS Task Force Report, the factor for a new natural gas combined cycle facility is taken to be the most applicable. Capture and compression costs typically use either a "CO_2 captured" or a "CO_2 avoided" basis. The CO_2 captured basis accounts for all CO_2 that is removed from the processes a result of the installation and use of a control technology, without including any losses during transport and storage or emissions from the control technology itself. A CO_2 avoided basis takes into account the CO_2 losses during transport and storage as well as CO_2 emissions from equipment associated with the implementation of the CCS system. Tenaska has determined it is more appropriate to use the CO_2 captured estimates since the BACT analysis is based on emissions from a single source (i.e. direct emissions from the CCCTs) and does not account for secondary emissions (e.g. GHG emissions generated from the act of compressing the CO_2 to pipeline pressures).

The CO_2 transport costs presented in the CCS Task Force Report (i.e. \$1/tonne to \$3/tonne CO_2) are based on a pipeline length of 100 miles. Tenaska has assumed that this factor may be linearly scaled up for longer pipeline lengths. The hypothetical length of a CO_2 pipeline associated with the proposed project is approximately 487 miles (the minimum distance to CO_2 sequestration well). As such, Tenaska has adjusted the CO2 transport cost factor proportionally upward.

As presented in the CCS Task Force Report, the costs associated with the storage of CO_2 show large variability. The report presents a cost range of $0.40 up to $20.00 per tonne of CO_2 stored. Tenaska has used $0.40/tonne as a conservative estimate. Based upon the above information, Tenaska has provided the following costs associated with CCS. The full analysis is included in Appendix F of this plan approval application.

- CO_2 capture and compression: $112.11/ton
- CO_2 transport: $10.40/ton
- CO_2 storage: $0.39/ton
- Total: $122.91/ton

Tenaska has estimated the capital cost to be approximately $320 million with a total annual cost of approximately $401 million. Tenaska concludes that the adverse energy, environmental, and economic impacts are significant and outweigh the environmental benefits of CCS. Therefore, Tenaska concludes that CCS exceeds BACT/BAT requirement standards and that BACT/BAT is good combustion practices.

Selection

Tenaska has proposed combustion of natural gas, high turbine efficiency, and good combustion practices. PA-37-00337A for the proposed Hickory Run Energy, LLC facility in Lawrence County issued on April 23, 2013 (among other recent plan approvals), includes a limit of 1,000 lbs CO_2/MWh based on a 12-operating month annual average basis. This limit is consistent with EPA's determination as part of the proposed NSPS Subpart TTTT. Tenaska has proposed a more stringent combustion turbine BACT limitation of 876 lbs CO_2/MWh at full load based on a 3-hour averaging period. The Department has determined the proposal meets BACT/BAT.

BAT Analysis for Ammonia - Powerblocks

Ammonia is used as a reagent in the SCR for NOx control. Ammonia slip is the ammonia that doesn't react in the SCR and exhausts into the atmosphere. The higher the NOx control efficiency usually requires greater amounts of ammonia which results in higher levels of ammonia slip. For optimum SCR efficiency, NOx and ammonia slip concentrations are measured continuously and adjusted by automated control systems. Therefore BAT for ammonia has been determined to be good combustion practices and continuous monitoring. To ensure good combustion and appropriate ammonia injection, Tenaska has proposed an ammonia slip emission limit of 5.0 ppmvd at 15% O_2. The Department has determined the proposed control technology meets BAT. Furthermore, although Tenaska is not subject to BACT for ammonia, the proposed emission limit is consistent with similar sources found in the RBLC. Based on the above analysis, the following table lists a summary of the CCCT LAER/BACT/BAT analysis.

Table 6: Powerblock LAER/BACT/BAT Summary

Pollutant	Technology	Emission Limit
NOx	SCR+DLN	2.0 ppmvd @ 15% O2, 3-hour average
CO	Oxidation Catalyst and Good Combustion Practices	2.0 ppmvd @ 15% O2, 3-hour average
PM	Good Combustion Practices	0.0039 lb/MMBtu, 3-hour average
PM_{10}	Good Combustion Practices	0.0039 lb/MMBtu, 3-hour average
$PM_{2.5}$	Good Combustion Practices	0.0039 lb/MMBtu, 3-hour average
VOC	Oxidation Catalyst and Good Combustion Practices	2.4 ppmvd @ 15% O2, 3-hour average w/duct burner
		1.4 ppmvd @ 15% O2, 3-hour average w/o duct burner
H_2SO_4	Low Sulfur Fuel	5.7E-04 lb/MMBtu HHV, 3-hour average
GHG	Good Combustion Practices	876 lbs CO2/MWh, 3-hour average
NH_3	Good Engineering Practices	5.0 ppmvd @ 15% O2, 3-hour average

Ancillary Equipment LAER/BACT/BAT Analysis

Similar control technologies to those evaluated for the CCCTs have been evaluated for the other proposed combustion sources at this facility. A more detailed analysis can be found in Section 6 of this plan approval application, titled Ancillary Equipment Control Technology Analysis.

Auxiliary Boiler

CO BACT Analysis

Based on the control technology evaluation and review of the RBLC and other recent plan approvals, good combustion and operating practices along with an emission limit of 0.037 lb/MMBtu has been determined to be appropriate BACT for the proposed auxiliary boiler.

Tenaska and the Department have identified a limited number of similar sources in the RBLC with oxidation catalysts; however based upon the proposed unit's rated capacity, 50% operational limitation, and uncontrolled emission rate, Tenaska has determined oxidation catalyst for the proposed unit would cost $7,940/ton of CO removed which is considered beyond the reasonable cost effectiveness.

NOx LAER Analysis

Based on the control technology evaluation and review of the RBLC and other recent plan approvals, ultra-low NOx burners along with an emission limit of 0.011 lb/MMBtu has been determined to be LAER for the proposed auxiliary boiler. Note that this emission limit is based upon a NOx exhaust concentration of 9 ppmvd @ 3% O_2. Since the proposed manufacturer has not been selected, whether or not the unit will utilize flue gas recirculation is unknown at this time. Regardless, Tenaska has proposed to select a unit capable of meeting the proposed rate which is consistent with the RBLC and other recent plan approvals.

PM/PM_{10} BACT Analysis and $PM_{2.5}$ LAER Analysis

Based on the control technology evaluation and review of the RBLC and other recent plan approvals, combustion of natural gas and good combustion practices, along with an emission limit of 0.0075 lb/MMBtu on a 3-hour averaging period has been determined to be appropriate for the proposed auxiliary boiler.

VOC LAER Analysis

Based on the control technology evaluation and review of the RBLC and other recent plan approvals, combustion of natural gas and good combustion practices, along with an emission limit of 0.0054 lb/MMBtu on a 3-hour averaging period has been determined to be LAER for the proposed auxiliary boiler.

H_2SO_4 BACT and SO_2 BAT Analysis

Based on the control technology evaluation and review of the RBLC and other recent plan approvals, combustion of pipeline quality natural gas has been determined to be appropriate for control of H_2SO_4 and SO_2 from the proposed auxiliary boiler. This plan approval will also incorporate an emissions limit of 9.20E-06 lb/MMBtu H_2SO_4.

In addition to the above emission limits, visible emissions will be limited to the following based upon BAT and other recent plan approvals:

(1) Equal to or greater than 10% for a period or periods aggregating more than 3 minutes in any 1 hour.
(2) Equal to or greater than 30% at any time.

Furthermore, Tenaska has proposed to limit the operation of the auxiliary boiler by 50%. Rather than limiting the hours of operation, Tenaska has suggested an annual capacity limitation. Based upon the rated capacity of the boiler of 245 MMBtu/hr, natural gas Btu content of 1,020 Btu/scf, and an operation time of 4,380 hours per year; the resulting annual fuel usage shall not exceed 1,052 MMscf/yr.

Internal Combustion Engines

Tenaska has proposed two (2) diesel-fired engines; one (1) 2,000 kW emergency generator and one (1) 575 bhp fire-water pump. Both units will be used for emergency use only (except for weekly readiness testing that is expected to typically last approximately 30 minutes) and will meet the applicable NSPS Subpart IIII requirements. This includes use of diesel fuel meeting the requirements of 40 CFR 80.510(b) for non-road diesel fuel (i.e. maximum sulfur content of 15 ppm and either a minimum cetane index of 40 or a maximum aromatic content of 35% by volume). Each engine will also be required to be equipped with a nonresettable hour meter and to maintain records of fuel usage on a 12-month rolling basis. Consistent with NSPS IIII, testing will not be required for the emergency engines; however the Department may require testing if there is reason to believe are, or may be, in excess of the limits established in this plan approval.

CO BACT Analysis

The BACT determination for the emergency generator is good combustion practices and an emission limit of 0.29 g/bhp-hr on a 3-hour averaging period based on the manufacturer's specifications. The BACT determination for the fire pump engine is good combustion practices and an emission limit of 0.67 g/bhp-hr based on the manufacturer's specifications. For these size engines, NSPS Subpart IIII establishes an emission standard of 2.61 g/bhp-hr and *General Plan Approval and General Operating Permit for Diesel or No. 2 fuel-fired Internal Combustion Engines* (GP-9) limits CO emissions to 2.0 g/bhp-hr; therefore the Department has determined the proposed limits along with good combustion practices satisfy BACT and BAT.

NOx LAER/BACT Analysis

The LAER/BACT determination for the emergency generator is good combustion practices and an emission limit for NOx +NMHC of 4.8 g/bhp-hr based on the manufacturer's specifications which is equivalent to the applicable NSPS Subpart IIII emission standard of 6.4 g/kW-hr (4.8 g/bhp-hr). The LAER/BACT determination for the fire pump engine is good combustion practices and an emission limit for NOx +NMHC of 3.0 g/bhp-hr based on the manufacturer's specifications which is which is equivalent to the NSPS Subpart IIII emission standard of 4.0 g/kW-hr (3.0 g/bhp-hr). Based upon the proposed emission rates and the operational limitation (500 hours/year), Tenaska has determined that post combustion controls (i.e. SCR, NSCR) are economically infeasible for emergency engines. The proposed limits are consistent with NSPS IIII, other recent plan approvals, and review of the RBLC.

VOC LAER Analysis

The determination for the emergency generator is good combustion practices and an emission limit of 0.11 g/bhp-hr based on the manufacturer's specifications. The determination for the fire pump engine is good combustion practices and an emission limit of 0.086 g/bhp-hr based on the manufacturer's specifications. NSPS Subpart IIII establishes an emission standard for NOx +NMHC of 4.8 g/bhp-hr for the emergency engine and 3.0 g/bhp-hr for the fire pump engine. GP-9 limits total hydrocarbon emissions to 1.0 g/bhp-hr. After review the Department has determined the proposed limits are consistent with NSPS IIII, other recent plan approvals, and review of the RBLC.

Cooling Tower

The proposed cooling tower is a multi-cell, mechanical induced draft cooling tower that will be used to reject heat from cooling water for the condensate system and other plant uses. Particulate matter is emitted from wet cooling towers because the water circulating in the tower contains small amounts of dissolved solids (e.g. calcium, magnesium, etc.) that crystallize and form airborne particles as the water drift leaves the cooling tower and evaporates.

Identification of Potential Control Techniques

Potentially available control options for reducing particulate matter emissions from mechanical draft cooling towers include options to minimize dissolved solids in the cooling water and add-on controls such as advanced drift eliminators.

Elimination of Technically Infeasible Control Options

All control options identified are technically feasible.

Selection

Tenaska has proposed to utilize advanced drift eliminators for the proposed mechanical cooling tower PM as PM_{10} BACT as well as $PM_{2.5}$ limits of 1.5 lb/hr, 0.75 lb/hr, and 0.002 lb/hr, respectively. The proposed rates are based upon a 0.0005% drift rate and a maximum total dissolved solids concentration of 2,000 ppm based upon the pending NPDES permit limit. Tenaska has proposed to continually monitor and minimize circulating water TDS to reduce potential particulate emissions and ensure continued compliance with the proposed emission rates. This determination is consistent with or more stringent than other recent plan approvals and sources identified in the RBLC.

Circuit Breakers

Sulfur hexafluoride (SF_6) is a greenhouse gas with a global warming potential (GWP) of 23,900 commonly used in circuit breaker as a high voltage insulator and circuit-interrupting medium. According to EPA's website[5], electric transmission and distribution make up for 4% of U.S. fluorinated gas emissions. Progress has been made in finding SF_6 alternatives for use in low and medium voltage applications; however the inertness and dielectric properties of SF_6 are such that no effective substitutes are known for high voltage applications at this time.

Therefore it is imperative to control potential leaks to the maximum extent possible. Tenaska has proposed to use state-of-the-art circuit breaker technology with a totally enclosed pressure system to minimize leaks, as well as the implementation of leak detection to ensure that SF_6 leaks are repaired as soon as possible.

In addition to requiring a leak detection and repair (LDAR) program for the circuit breakers, the Department considered the requirement to monitor potential leaks in the natural gas piping components to minimize methane emissions. After review of other recent plan approvals for similar sources and considering the minimal amount of emissions expected from natural gas piping components leaks, natural gas LDAR will not be required in this plan approval.

Air Quality Modeling Analysis

Concurrently with this plan approval application, the applicant has submitted a modeling analysis. According to Summary of Air Quality Analysis for Prevention of Significant Deterioration dated August 1, 2014, from the Departments Air Quality Modeling Section, "The DEP's technical review concludes that Tenaska's air quality analysis satisfies the requirements of the PSD rules and is consistent with the U.S. Environmental Protection Agency's (EPA) *Guideline on Air Quality Models* (40 CFR Part 51, Appendix W) and the EPA's air quality modeling policy and guidance. Furthermore, the DEP's technical review concludes that Tenaska's air quality

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[5] http://epa.gov/climatechange/ghgemissions/gases/fgases.html

analysis demonstrates, pursuant to 40 CFR § 52.21(k), that Tenaska's proposed emissions will not cause or contribute to air pollution in violation of the National Ambient Air Quality Standards (NAAQS) for CO, NO_2, and PM-10, and the PSD increment standards for NO_2 and PM-10. In addition, the analysis demonstrates, pursuant to 40 CFR § 52.21(o), that Tenaska's proposed emissions, in conjunction with anticipated emissions due to general commercial, residential, industrial, and other growth associated with Tenaska's proposed facility, will not impair visibility, soils, and vegetation. Furthermore, the analysis demonstrates, pursuant to 40 CFR § 52.21(p), that Tenaska's proposed emissions will not adversely affect air quality related values (AQRV), including visibility, in federal Class I areas."

Other Agencies

The facility is proposed to be located within 300 km of four Class I areas:

- Otter Creek Wilderness (approximately 128 km south)
- Dolly Sods Wilderness (approximately 134 km south)
- Shenandoah National Park (approximately 195 km southeast)
- James River Face (approximately 287 km south)

In accordance with 40 CFR 52.21(p)(2), "The Federal Land Manager and the Federal official charged with direct responsibility for management of such lands have an affirmative responsibility to protect the air quality related values (including visibility) of such lands and to consider, in consultation with the Administrator, whether a proposed source or modification will have an adverse impact on such values." Otter Creek Wilderness, Dolly Sods Wilderness, and James River Face are managed by the United States Forest Service (USFS) and Shenandoah National Park is managed by the National Park Service (NPS). On August 22, 2012, Tenaska notified the USFS and NPS of the proposed project details, potential emissions, and requested concurrence that that a Class I AQRV analysis is unnecessary based on the emissions and distances from the above listed areas. Tenaska also calculated the Q (emissions) over D (distance) value to be approximately 6.5 which is less than the screening threshold of 10 based on Section 3.2 of the 2010 Federal Land Managers' Air Quality Related Values Work Group (FLAG) guidance document. Note that when this notification was submitted, Tenaska was still considering a few different combustion turbine configurations and used worst case potential emissions which were higher than those currently proposed. On August 31, 2012, Tenaska received a response from the USFS stating that "Based on the emissions and distances from James River Face, Dolly Sods and Otter Creek Wilderness described in the attached email, the Forest Service anticipates that modeling would not show any significant additional impacts to air quality related values (AQRV) at the wilderness. Therefore, we are not requesting that a Class I AQRV analysis be included in the PSD permit application." To date, no response was received from the NPS. To ensure the NPS is aware of the project, the Department forwarded Tenaska's original notification to the NPS on November 14, 2014. The Department also sent copies of the application to both the NPS and USFS on December 5, 2014.

Although a Class I analysis was not requested, Tenaska performed a screening analysis to ensure that the proposed project does not contribute to exceedance of the Class I area increment standards and SILs. As stated above under "Air Quality Modeling Analysis," the Department agreed "...the analysis demonstrates, pursuant to 40 CFR § 52.21(p), that Tenaska's proposed emissions will not adversely affect air quality related values (AQRV), including visibility, in federal Class I areas."

Sources, Control Devices, and Emissions

Emission were calculated by the applicant for the proposed natural gas-fired CCCTs based upon the turbine manufacturer's emissions data and recommendations, SCR control efficiency, oxidation catalyst control efficiencies, AP-42 Chapters 1.4 and 3.1 emission factors, and 40 CFR Part 98 Subpart C emission factors. Emissions were calculated at 8,760 hours at full load and considering the maximum allowable startup/shutdown time of 495 hours to determine the worst case scenario for each pollutant. Potential emissions account for the maximum hours of operation of the duct burners of 5,200 hours per year. NOx emissions during normal operation will be controlled by selective catalytic reduction. VOC and CO emissions will be controlled by oxidation catalysts. The oxidation catalysts are also expected to control HCHO emissions however the manufacturer has not guaranteed a control efficiency. HCHO emissions were based upon stack test data from a similar unit with a safety factor. Emissions from the powerblock in Table 7 below include two 3,147 MMBtu/hr combined cycle combustion turbines with 400 MMBtu/hr duct burners and one steam turbine generator.

Table 7: Powerblock PTE (tpy)

Pollutant	Normal Operation[a] (8,760 hours)	Normal Operation[a] (8,265 hours)	Startup/Shutdown (495 hours)	Worst Case PTE[b]
NOx	224.0	212.0	147	359
CO	135.0	127.7	2,161	2,289
VOC	69.88	67.00	1,181	1,248
HCHO[c]	8.63	8.15		8.63
Total HAPs	21.05	20.06		21.05
Total PM	84.86	81.59		84.86
Total PM10	84.86	81.59		84.86
Total PM2.5	84.86	81.59		84.86
H2SO4	15.20	14.57		15.20
SO2[d]	22.50	21.40		22.50
NH3	193.84	183.45		193.84
GHGs (as CO2e)	3,643,636	3,449,446	314,364	3,763,810

[a] Potential emissions account for a maximum of 5,200 hours with duct burners.
[b] Worst case PTE for NOx, CO, and VOC results from scenario with maximum amount of startups/shutdowns.
[c] Highest single HAP.
[d] SO2 emissions based upon a natural gas sulfur content of 0.25 gr/scf.

Powerblock startup durations vary based upon the temperature of components downstream of the combustion turbines, most notably the heat recovery system and steam turbine. This equipment needs to be warmed slowly to avoid thermal stress, and is typically achieved by ramping the combustion turbine slowly with several hold points at less than normal minimum load. Emissions are also affected since the control devices must reach a minimum temperature and/or exhaust flow rate before they are effective. Actual emissions from the powerblocks are expected to be lower than those in Table 7 since Tenaska was not able to receive manufacturer guaranteed emissions rates and control efficiencies during startup/shutdown due to the variable nature of these conditions. Startup/shutdown emissions were conservatively estimated based upon manufacturer's recommendations after analyzing instantaneous rates over time. Startup/shutdown emissions were calculated based upon actual operational data on a lb/event basis rather than a short term rate since the rate is not consistent over the duration of the event. Actual NOx and CO emissions will be determined using CEMS. It has been determined the effective way to limit startup/shutdown emissions is to limit the duration of startup/shutdown and to require the operation of the control devices at all possible times. Therefore, each startup event will be limited to one hour and each shutdown will be limited to one half hour, and the total duration of all startups and shutdowns will be limited to 495 hours on a 12-month rolling basis. Incorporation of the above startup/shutdown emissions in the facility-wide PTE limit also ensures there is no violation of the NAAQS.

Other potential sources at this facility include a 245 MMBtu/hr natural gas-fired auxiliary boiler, 2,000 kW diesel-fired emergency generator, 575 bhp diesel-fired fire pump engine, emissions from the cooling tower, and diesel storage and lube oil tanks. Note that tank emissions are not explicitly shown in Table 8 below. Potential emissions from the tanks are: 1.65E-04 tpy VOC from the three (3) 1,000 gallon lube oil tanks, 2.36E-03 tpy VOC from the 5,000 gallon diesel storage tank for the emergency generator, and 1.65E-04 tpy VOC from the 1,000 gallon diesel storage tank for the fire pump engine. Detailed emission calculations are included in Appendix B of this plan approval application and addendums received on April 22, 2014, and September 12, 2014. The Department determined the applicant's emission calculations are acceptable. Table 8 below lists the facility-wide PTE.

Table 8: Facility-Wide PTE (tpy)

Pollutant	Powerblocks	Auxiliary Boiler[a]	Emergency Generator	Fire Pump	Cooling Tower	Facility-Wide
NOx	359	5.76	7.05	0.82	-	**372.63**
CO	2289	19.85	0.54	0.21	-	**2,309.60**
VOC	1248	2.89	0.20	0.03	-	**1,251.12**
HCHO[b]	8.63	0.04	3.75E-04	1.13E-05	-	**8.67**
Total HAPs	21.05	0.99	0.02	5.05E-03	-	**22.07**
Total PM	84.86	4.00	0.09	0.03	6.58	**95.56**
Total PM10	84.86	4.00	0.08	0.03	3.29	**92.26**
Total PM2.5	84.86	4.00	0.08	0.03	0.009	**88.98**
H2SO4	15.2	4.94E-03	2.18E-04	5.05E-03	-	**15.20**
SO2	22.5	0.32	0.01	1.74E-03	-	**23.00**
NH3	193.84	-	-	-	-	**193.84**
GHGs (as CO2e)	3,763,810	62,829	778	156	-	**3,827,574**

[a] Auxiliary boiler PTE on a tons per year basis is based upon maximum operation of 4,380 hours/year. This plan approval will include a tpy limit for the auxiliary boiler as well as a total fuel usage limit to ensure the above emissions are not exceeded.
[b] Highest single HAP.

Conclusions and Recommendations

Tenaska has shown that the proposed natural gas-fired combined cycle power plant located in South Huntingdon Township, Westmoreland County meets the requirements of 40 CFR Part 52.21 (related to Prevention of Significant Deterioration), 25 Pa. Code Subchapter E (related to New Source Review), and Best Available Technology. Tenaska has also shown that the proposed facility will not cause or contribute to air pollution in violation of the NAAQS, will not impair visibility, soils, and vegetation, and will not adversely affect air quality related values (AQRV), including visibility, in federal Class I areas. Therefore I recommend issuance of a plan approval with the following special conditions.

Special Conditions

Site Level Plan Approval Requirements

1. No person may permit air pollution as that term is defined in the act [25 Pa. Code §121.7].

2. The permittee may not permit the emission into the outdoor atmosphere of a fugitive air contaminant contrary to 25 Pa. Code §123.1.

3. The permittee may not permit fugitive particulate matter to be emitted into the outdoor atmosphere from a source specified in §123.1(a)(1)–(9) if the emissions are visible at the point the emissions pass outside the permittee's property [25 Pa. Code §123.2].

4. The permittee may not allow the emission into the outdoor atmosphere of any malodorous air contaminants from any source, in such a manner that the malodors are detectable outside the permittee's property [25 Pa. Code §123.31].

5. The permittee shall not allow the emission into the outdoor atmosphere of visible air contaminants in such a manner that the opacity of the emission is either of the following [25 Pa. Code §123.41]:

   (a) Equal to or greater than 20% for a period or periods aggregating more than 3 minutes in any one hour.
   (b) Equal to or greater than 60% at any time.

6. The limitations of §123.41 (relating to limitations) shall not apply to a visible emission in any of the following instances [25 Pa. Code §123.42]:

   (a) When the presence of uncombined water is the only reason for failure of the emission to meet the limitations.
   (b) When the emission results from the operation of equipment used solely to train and test persons in observing the opacity of visible emissions.
   (c) When the emission results from sources specified in §123.1(1)–(9).
   (d) N/A

7. The emissions from all sources and associated air cleaning devices installed and operated under this authorization shall not exceed any of the following on a 12-month rolling sum basis:

   (a) Nitrogen Oxides (NOx): 373.00 tpy
   (b) Carbon Monoxide (CO): 2310.00 tpy
   (c) Sulfur Oxides (SOx): 23.00 tpy
   (d) Volatile Organic Compounds (VOC): 1251.00 tpy
   (e) Particulate Matter (PM): 96.00 tpy
   (f) Particulate Matter with an aerodynamic diameter less than 10 microns (PM10): 92.00 tpy
   (g) Particulate Matter with an aerodynamic diameter less than 2.5 microns (PM2.5): 89.00 tpy
   (h) Sulfuric Acid Mist (H2SO4): 15.20 tpy
   (i) Ammonia (NH3): 194.00 tpy

(j) Total Hazardous Air Pollutants (HAPs): 22.07 tpy
(k) Greenhouse Gases, expressed as Carbon Dioxide Equivalent (CO2e): 3,827, 574 tpy

8. Performance testing shall be conducted as follows [25 Pa. Code §127.12b and §139.11]:

   (a) The Permittee shall submit three copies of a pre-test protocol to the Department for review at least 45 days prior to the performance of any EPA reference method stack test. The Permittee shall submit three copies of a one-time protocol to the Department for review for the use of a portable analyzer and may repeat portable analyzer testing without additional protocol approvals provided that the same method and equipment are used. All proposed performance test methods shall be identified in the pre-test protocol and approved by the Department prior to testing.

   (b) The Permittee shall notify the Regional Air Quality Manager at least 15 days prior to any performance test so that an observer may be present at the time of the test. Notification shall also be sent to the Division of Source Testing and Monitoring. Notification shall not be made without prior receipt of a protocol acceptance letter from the Department.

   (c) Pursuant to 40 CFR Part 60.8(a), a complete test report shall be submitted to the Department no later than 60 calendar days after completion of the on-site testing portion of an emission test program.

   (d) Pursuant to 25 Pa. Code Section 139.53(b) a complete test report shall include a summary of the emission results on the first page of the report indicating if each pollutant measured is within permitted limits and a statement of compliance or non-compliance with all applicable permit conditions. The summary results will include, at a minimum, the following information:

      (1) A statement that the owner or operator has reviewed the report from the emissions testing body and agrees with the findings.
      (2) Permit number(s) and condition(s) which are the basis for the evaluation.
      (3) Summary of results with respect to each applicable permit condition.
      (4) Statement of compliance or non-compliance with each applicable permit condition.

   (e) Pursuant to 25 Pa. Code § 139.3 all submittals shall meet all applicable requirements specified in the most current version of the Department's Source Testing Manual.

   (f) All testing shall be performed in accordance with the provisions of Chapter 139 of the Rules and Regulations of the Department of Environmental Protection.

   (g) Pursuant to 25 Pa. Code Section 139.53(a)(1) and 139.53(a)(3) all submittals, besides notifications, shall be accomplished through PSIMS*Online available through https://www.depgreenport.state.pa.us/ecomm/Login.jsp when it becomes available. If internet submittal cannot be accomplished, three copies of the submittal shall be sent to the Pennsylvania Department of Environmental Protection, Bureau of Air Quality, Division of Source Testing and Monitoring, 400 Market Street, 12th Floor Rachael Carson State Office Building, Harrisburg, PA 17105-8468 with deadlines verified through document postmarks.

(h) The permittee shall ensure all federal reporting requirements contained in the applicable subpart of 40 CFR are followed, including timelines more stringent than those contained herein. In the event of an inconsistency or any conflicting requirements between state and the federal, the most stringent provision, term, condition, method or rule shall be used by default.

9. Visible emissions may be measured using either of the following [25 Pa. Code §123.43]:

(a) A device approved by the Department and maintained to provide accurate opacity measurements.
(b) Observers, trained and qualified to measure plume opacity with the naked eye or with the aid of devices approved by the Department.

10. The permittee shall conduct a facility-wide inspection for the presence of any visible stack emissions, fugitive emissions, and any potentially objectionable odors at the property line at a minimum of once each operating day, during daylight hours, and while the sources are operating. If visible stack emissions, fugitive emissions, and/or potentially objectionable odors are apparent, the permittee shall take corrective action. Records of each inspection shall be maintained in a log and at the minimum include the date, time, name and title of the observer, along with any corrective action taken as a result [25 Pa. Code §127.12b].

11. The permittee shall implement a sulfur hexafluoride (SF6) leak detection program to minimize SF6 leaks as follows:

(a) Circuit breakers are to be state-of-the-art sealed enclosed-pressure circuit breakers equipped with low-pressure alarms that are triggered when 10% of the SF6 by weight has escaped.
(b) When alarms are triggered, the facility shall take corrective action as soon as practicable to fix the circuit breaker units to a like-new state to prevent the emission of SF6 to the maximum extent possible.

12. The permittee shall maintain the following comprehensive and accurate records [25 Pa. Code §127.12b]:

(a) Facility-wide emissions on a 12-month rolling basis for NOx, CO, SOx, VOC, PM, PM10, PM2.5, H2SO4, NH3, HAPs, HCHO, and CO2e.
(b) Amount of fuel used by each combustion unit, engine, and turbine on a 12-month rolling basis.
(c) Hours of operation of each source on a 12-month rolling basis.
(d) Results of facility-wide inspections including the date, time, name, and title of the observer, along with any corrective action taken as a result.
(e) Copies of the manufacturer's recommended maintenance schedule for each air source and air cleaning device.
(f) All maintenance performed on each source and air cleaning device.
(g) Copies of the current, valid purchase contract, tariff sheet, or transportation contract obtained from the natural gas supplier with the sulfur content of the natural gas.
(h) Results of the annual natural gas sulfur content analyses.
(i) Amount of sulfur hexafluoride (SF6) dielectric fluid added to each circuit breaker unit on a monthly basis.
(j) The date and time that each alarm associated with the circuit breaker is activated, the corrective action taken to remedy the problem associated with each alarm, and the date the corrective action remedied the problem.

13. All logs and required records shall be maintained on site, or at an alternative location acceptable to the Department, for a minimum of five years and shall be made available to the Department upon request [25 Pa. Code §127.12b].

14. Annual emissions reporting shall be conducted as follows [25 Pa. Code §135.3]:

    (a) A person who owns or operates a source to which this chapter applies, and who has previously been advised by the Department to submit a source report, shall submit by March 1 of each year a source report for the preceding calendar year. The report shall include information for all previously reported sources, new sources which were first operated during the preceding calendar year and sources modified during the same period which were not previously reported.

    (b) A person who receives initial notification by the Department that a source report is necessary shall submit an initial source report within 60 days after receiving the notification or by March 1 of the year following the year for which the report is required, whichever is later.

    (c) A source owner or operator may request an extension of time from the Department for the filing of a source report, and the Department may grant the extension for reasonable cause.

15. The annual emission report shall include all emissions information for all previously reported sources and new sources which were first operated during the preceding calendar year. Emissions data including, but not limited to the following, shall be reported: carbon monoxide (CO), oxides of nitrogen (NOx), particulate matter less than 10 micrometers in diameter (PM10), particulate matter less than 2.5 micrometers in diameter (PM2.5), sulfur dioxide (SO2), volatile organic compounds including formaldehyde (VOC), total hazardous air pollutants (HAP), speciated individual HAP emissions, sulfuric acid mist (H2SO4), and greenhouse gases, expressed as CO_2e. The statement shall also contain a certification by a company officer or the plant manager that the information contained in the statement is accurate [25 Pa. Code §127.12b].

16. Malfunction reporting shall be conducted as follows [25 Pa. Code §127.12b]:

    (a) For purpose of this condition a malfunction is defined as any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment or source to operate in a normal or usual manner that may result in an increase in the emission of air contaminants. Examples of malfunctions may include, but are not limited to: large dust plumes, heavy smoke, a spill or release that results in a malodor that is detectable outside the property of the person on whose land the source is being operated.

    (b) When the malfunction poses an imminent and substantial danger to the public health and safety or the environment, the notification shall be submitted to the Department no later than one hour after the incident commences.

    (c) All other malfunctions that must be reported under subsection (a) shall be reported to the Department no later than the next business day.

    (d) The report shall describe the:

(1) Name and location of the facility;
(2) Nature and cause of the malfunction or breakdown;
(3) Time when the malfunction or breakdown was first observed;
(4) Expected duration of excess emissions; and
(5) Estimated rate of emissions.

(e) Malfunctions shall be reported to the Department at the following address:

PA DEP
Office of Air Quality
400 Waterfront Drive
Pittsburgh, PA 15222-4745
412-442-4000

(f) The owner or operator shall notify the Department immediately upon completion when corrective measures have been accomplished.

(g) Subsequent to the malfunction, the owner/operator shall submit a full written report to the Department including the items identified in (d) and corrective measures taken on the malfunction within 15 days, if requested.

17. The Facility is subject New Source Performance Standards from 40 CFR Part 60 Subparts Db, IIII, and KKKK and National Emission Standards for Hazardous Air Pollutants from 40 CFR Part 63 Subpart ZZZZ. In accordance with 40 CFR §60.4, copies of all requests, reports, applications, submittals and other communications regarding the engines shall be forwarded to both EPA and the Department at the addresses listed below unless otherwise noted.

Director
Air Protection Section
Mail Code 3AP00
US EPA, Region III
1650 Arch Street
Philadelphia, PA 19101-2029

PA DEP
Air Quality Program
400 Waterfront Drive
Pittsburgh, PA 15222-4745

18. The permittee shall construct, operate, and maintain all air contamination sources and air cleaning devices authorized under this Plan Approval in accordance with the manufacturer's specifications and recommended maintenance schedules [25 Pa. Code § 127.12b].

19. In accordance with 25 Pa. Code § 127.201 through § 127.217, the permittee shall secure 429 tons per year of NOx emission reduction credits (ERCs) and 1,439 tons per year of VOC ERCs. The ERCs shall be properly generated, certified by the Department, and processed through the registry no later than the date approved by the Department for commencement of operation of the proposed facility [25 Pa. Code § 127.12b].

20. The permittee shall comply with all applicable requirements of New Source Performance Standards from 40 CFR Part 60 Subparts Db, IIII, and KKKK and National Emission Standards for Hazardous Air Pollutants from 40 CFR Part 63 Subpart ZZZZ [25 Pa. Code § 127.12b].

21. The permittee shall comply with all applicable requirements under 40 CFR Part 68 related to the Chemical Accident Prevention Provisions [25 Pa. Code § 127.12b].

22. The permittee shall comply with all applicable requirements under 40 CFR Part 64 related to Compliance Assurance Monitoring (CAM) [25 Pa. Code § 127.12b].

23. The permittee shall comply with all applicable requirements under 40 CFR Parts 72-78 related to the Acid Rain Program [25 Pa. Code § 127.12b].

24. The permittee shall comply with all applicable requirements under 40 CFR Part 96 related to the Clean Air Interstate Rule (CAIR) and 40 CFR Part 97 related to the Cross State Air Pollution Rule (CSAPR) [25 Pa. Code § 127.12b].

25. The permittee shall comply with all applicable requirements under 40 CFR Part 98 related to the Mandatory Greenhouse Gas Reporting Rule [25 Pa. Code § 127.12b].

26. This plan approval is to allow construction and temporary operation of a combined cycle natural gas-fired power plant known as the Westmoreland Generating Station by Tenaska Pennsylvania Partners, LLC located in South Huntingdon Township, Westmoreland County [25 Pa. Code § 127.12b].

27. New air contamination sources and air cleaning devices authorized for construction and temporary operation under this plan approval include [25 Pa. Code § 127.12b]:

    - Two (2) 3,147 MMBtu/hr Mitsubishi "J" class combined cycle combustion turbines serving one steam turbine generator equipped with heat recovery steam generators (HRSG) with supplemental 400 MMBtu/hr natural gas fired duct burners; controlled by SCR and oxidation catalysts.
    - One (1) 245 MMBtu/hr natural gas-fired auxiliary boiler.
    - One (1) 2,000 ekW diesel-fired emergency generator engine.
    - One (1) 575 bhp diesel-fired emergency fire pump engine.
    - Cooling tower controlled by drift eliminators.

28. Upon determination by the permittee that the air contamination sources and air cleaning devices covered by this plan approval are in compliance with all conditions of the plan approval, the permittee shall contact the Department's technical reviewer and schedule the Initial Operating Permit Inspection [25 Pa. Code §127.12b].

29. Upon completion of the Initial Operating Permit Inspection and determination by the Department that the permittee is in compliance with all conditions of the plan approval, the permittee shall submit a Title V Operating Permit (TVOP) application for this Facility within 120 days [25 Pa. Code §127.12b].

30. The permittee shall submit requests to extend the temporary operation periods at least 15 days prior to the expiration date of any authorized period of temporary operation [25 Pa. Code §127.12b].

31. If, at any time, the Department has cause to believe that air contaminant emissions from the sources listed in this plan approval may be in excess of the limitations specified in, or established pursuant to this plan approval or the permittee's operating permit, the permittee may be required to conduct test methods and procedures deemed necessary by the Department to determine the actual emissions rate. Such testing shall be conducted in accordance with 25 Pa. Code Chapter 139, where applicable, and in accordance with any restrictions or limitations established by the Department at such time as it notifies the company that testing is required [25 Pa. Code §127.12b].

Combined Cycle Units (Source IDs 101 and 102)

32. Definitions [25 Pa. Code §127.12b]:

(a) *Startup* is defined as the period beginning when fuel begins flowing to the combustion turbine and ending when the combustion process, air pollution control equipment, and associated control systems have attained normal operating conditions.
(b) *Shutdown* is defined as the period beginning when the combustion turbine exits DLN mode and ending when fuel flow ceases.
(c) *Normal operation* is defined as all times except startup and shutdown.

33. During normal operation, emissions from each combined cycle combustion turbine, Source IDs 101 and 102, shall not exceed [25 Pa. Code §127.12b]:

33. During normal operation, emissions from each combined cycle combustion turbine, Source IDs 101 and 102, shall not exceed [25 Pa. Code §127.12b]:

Pollutant	Emission Rate
NOx	2.0 ppmvd
	26.5 lb/hr
CO	2.0 ppmvd
	15.9 lb/hr
VOC	2.4 ppmvd w/duct burners
	1.4 ppmvd w/o duct burners
	9.4 lb/hr
Total PM	0.0039 lb/MMBtu
	11.8 lb/hr
Total PM10	0.0039 lb/MMBtu
	11.8 lb/hr
Total PM2.5	0.0039 lb/MMBtu
	11.8 lb/hr
H2SO4	5.74E-04 lb/MMBtu
	1.8 lb/hr
SO2	2.7 lb/hr
NH3	5.0 ppmvd
	22.9 lb/hr
GHGs	876 lbs CO2/MWh

[1]ppmdv = parts per million volume on a dry gas basis, corrected to 15 percent O2.
[2]ppmdv and lb/MMBtu limits based upon a 3-hour averaging time.

34. At all times, including startup and shutdown, emissions from each combined cycle combustion turbine, Source IDs 101 and 102, shall not exceed the following on a 12-month rolling basis [25 Pa. Code §127.12b]:

Pollutant	Emission Rate (tpy)
NOx	179.5
CO	1,144.5
VOC	624
HAPs	10.5
Total PM	42.5
Total PM10	42.5
Total PM2.5	42.5
H2SO4	7.5
SO2	11.25
NH3	96.9
GHGs (as CO2e)	1,881,905

35. At no time shall NOx emissions exceed 380 lb/hr from each combined cycle combustion turbine to ensure compliance with the 1-hour average NO2 NAAQS [25 Pa. Code §127.12b].

36. The permittee may not permit the emission into the outdoor atmosphere of visible air contaminants in such a manner that the opacity of the emission is either of the following [25 Pa. Code §127.12b]:

    (a) Equal to or greater than 10% for a period or periods aggregating more than 3 minutes in any 1 hour.
    (b) Equal to or greater than 10% for a period or periods aggregating more than 6 minutes during startup and shutdown.

37. Average fuel sulfur content shall not exceed 0.25 gr/100 scf natural gas on a monthly basis [25 Pa. Code §127.12b].

38. Operation of Source IDs 101 and 102 with duct burners shall not exceed 5,200 hours per year [25 Pa. Code §127.12b].

39. Each combined cycle combustion turbine (Source IDs 101 and 102) shall be equipped with DLN burners, selective catalytic reduction, and oxidation catalysts [25 Pa. Code §127.12b].

40. The permittee shall operate all air cleaning devices at all times once operating parameters (temperature, flow, etc.) are sufficient for proper operation [25 Pa. Code §127.12b].

41. Startups and shutdowns [25 Pa. Code §127.12b]:

    (a) The durations of startups and shutdowns shall be minimized to the maximum extent possible.
    (b) Total startup and shutdown duration for each combined cycle combustion turbine shall not exceed 495 hours in any consecutive 12-month period.
    (c) Each startup event shall not exceed one hour in duration.
    (d) Each shutdown shall not exceed one half hour in duration.

42. Within 180 days after initial startup, the permittee shall conduct EPA reference method stack testing for NOx, CO, VOC (with and without duct burners), formaldehyde, PM (filterable and condensable), PM10 (filterable and condensable), PM2.5 (filterable and condensable), sulfuric acid mist, SO2, and ammonia slip in accordance with the requirements of 25 Pa. Code §139 [25 Pa. Code §127.12b].

43. The permittee shall conduct subsequent EPA reference method stack testing for VOC, formaldehyde and PM (filterable and condensable) no less often than every two years after initial testing [25 Pa. Code §127.12b].

44. The permittee shall conduct Department approved CO2 stack testing every 25,000 hours of operation [25 Pa. Code §127.12b]

45. The permittee shall install, certify, maintain and operate continuous emission monitoring systems (CEMS) for nitrogen oxides, carbon monoxide, and ammonia emissions as well as volumetric flow on the exhaust of

each combined-cycle powerblock in accordance with all applicable requirements specified in 25 Pa. Code §139 and the Department's Continuous Source Monitoring Manual [25 Pa. Code §127.12b].

(a) Initial Application (Phase I): Proposal[s] containing information as listed in the Phase I section of the Department's Continuous Source Monitoring Manual for the CEMS[s] must be submitted at least 180 days prior to the planned initial source startup date.

(b) Performance Testing (Phase II): Testing as listed in the Phase II section of the Department's Continuous Source Monitoring Manual must be completed for the CEMS[s] no later than 180 days after initial source startup date and no later than 60 days after source achieves normal process capacity.

(c) Final Approval (Phase III): The final report of testing as listed in the Phase III section of the Department's Continuous Source Monitoring Manual must be submitted to the Bureau no later than 60 days after completion of testing.

(d) The owner or operator of the source shall not be issued an operating permit until the CEMS has received Phase III approval, in writing from the Department, when installation of a CEMS is made a condition of the plan approval. Until Phase III Department approval is obtained, operation shall be covered solely under condition of a plan approval.

46. Monitoring requirements [25 Pa. Code §123.51]

(a) This section applies to combustion units with a rated heat input of 250 million Btus per hour or greater and with an annual average capacity factor of greater than 30%.

(b) Sources subject to this section shall install, operate and maintain continuous nitrogen oxides monitoring systems and other monitoring systems to convert data to required reporting units in compliance with Chapter 139, Subchapter C (relating to requirements for continuous in-stack monitoring for stationary sources).

(c) Sources subject to this section shall submit results on a regular schedule and in a format acceptable to the Department and in compliance with Chapter 139, Subchapter C.

(d) Continuous nitrogen oxides monitoring systems installed under the requirements of this section shall meet the minimum data availability requirements in Chapter 139, Subchapter C.

(e) The Department may exempt a source from the requirements of subsection (b) if the Department determines that the installation of a continuous emission monitoring system would not provide accurate determination of emissions or that installation of a continuous emission monitoring system cannot be implemented by a source due to physical plant limitations or to extreme economic reasons. A source exempted from the requirements of subsection (b) shall satisfy alternative emission monitoring and reporting requirements proposed by the source and approved by the Department which provide oxides emission data that is representative of actual emissions of the source.

(f) Sources subject to this section shall comply by October 20, 1993, unless the source becomes subject to the requirements later than October 20, 1990. For sources which become subject to the requirements after October 20, 1990, the source has 36 months from the date the source becomes subject to this section. The Department may issue orders providing a reasonable extension of time for sources that have made good faith efforts to install, operate and maintain continuous monitoring devices, but that have been unable to complete the operations within the time period provided.

47. The permittee shall continuously monitor the oxygen level in the stack effluent [25 Pa. Code §127.12b].

48. The permittee shall continuously monitor and record the pressure differential across the oxidation catalyst as well as the catalyst inlet and outlet temperatures. Visible and audible alarms shall be utilized to indicate improper operation [25 Pa. Code §127.12b].

49. The permittee shall continuously monitor and record the selective catalytic reduction pressure differential as well as inlet and outlet temperatures. Visible and audible alarms shall be utilized to indicate improper operation [25 Pa. Code §127.12b].

50. The permittee shall maintain the following comprehensive and accurate records [25 Pa. Code §127.12b]:

(a) Actual heat input and power output on a 12-month rolling basis.
(b) The number of startups and shutdowns and the dates each occur.
(c) Duration of each startup and shutdown event.
(d) The type of each startup (i.e. cold, warm, or hot).
(e) Pressure differential and inlet and outlet temperature across the oxidation catalysts.
(f) Pressure differential, inlet and outlet temperature across the selective catalytic reduction system and ammonia injection rate.
(g) Duct burner hours of operation.
(h) Requirements established in 25 Pa. Code §139 Subchapter C, requirements for source monitoring for stationary sources.
(i) Requirements in the most recent version of the Department's Continuous Source Monitoring Manual.

51. Within 30 days of the selection of the specific manufacturer and model of the control devices (SCR and oxidation catalyst), the permittee shall submit the specifications to the Department [25 Pa. Code §127.12b].

52. The permittee shall comply with all applicable requirements of 40 CFR Part 60, Subpart KKKK [40 CFR § 60.4300 through § 60.4420].

<u>Auxiliary Boiler (Source ID 031)</u>

53. The emissions from the auxiliary boiler shall not exceed the following [25 Pa. Code §127.12b]:

(a) NOx: 0.011 lb/MMBtu or 5.76 tpy on a 12-month rolling basis.
(b) CO: 0.037 lb/MMBtu or 19.85 tpy on a 12-month rolling basis.
(c) VOC: 0.0054 lb/MMBtu or 2.89 tpy on a 12-month rolling basis.

(d) Total PM: 0.0075 lb/MMBtu or 4.00 tpy on a 12-month rolling basis.
(e) Total PM10: 0.0075 lb/MMBtu or 4.00 tpy on a 12-month rolling basis.
(f) Total PM2.5: 0.0075 lb/MMBtu or 4.00 tpy on a 12-month rolling basis.
(g) H_2SO_4: 9.20E-06 lb/MMBtu or 4.94E-03 tpy on a 12-month rolling basis.
(h) SO_2: 0.0006 lb/MMBtu or 0.32 tpy on a 12-month rolling basis.

Compliance with the above emission limits ensures compliance with 25 Pa. Code §§ 132.11 and 132.22.

54. Total fuel usage of the auxiliary boiler shall not exceed 1,052 MMscf/yr on a 12-month rolling basis [25 Pa. Code §127.12b].

55. The permittee shall not allow the emission into the outdoor atmosphere of visible air contaminants in such a manner that the opacity of the emission is either of the following [25 Pa. Code §123.41]:

(a) Equal to or greater than 10% for a period or periods aggregating more than 3 minutes in any one hour.
(b) Equal to or greater than 30% at any time.

56. The permittee shall comply with all applicable requirements of 40 CFR Part 60, Subpart Dc [40 CFR § 60.40c through § 60.48c].

<u>Emergency Diesel Generator (Source ID 103)</u>

57. The emissions from the emergency diesel generator shall not exceed the following [25 Pa. Code §127.12b]:

(a) NOx: 28.22 lb/hr or 7.05 tpy on a 12-month rolling basis.
(b) CO: 2.14 lb/hr or 0.54 tpy on a 12-month rolling basis.
(c) VOC: 0.81 lb/hr or 0.20 tpy on a 12-month rolling basis.
(d) Total PM: 0.37 lb/hr or 0.09 tpy on a 12-month rolling basis.
(e) Total PM10: 0.33 lb/hr or 0.08 tpy on a 12-month rolling basis.
(f) Total PM2.5: 0.33 lb/hr or 0.08 tpy on a 12-month rolling basis.
(g) SO_2: 0.04 lb/hr or 0.01 tpy on a 12-month rolling basis.

58. Operation of the emergency diesel generator shall not exceed 500 hours on a 12-month rolling basis [25 Pa. Code §127.12b].

59. Sulfur content of the diesel fuel combusted by the emergency diesel generator shall not exceed 15 ppm [25 Pa. Code §127.12b].

60. The permittee shall maintain records of the fuel certification reports for each delivery of fuel to verify compliance with the fuel restriction requirements [25 Pa. Code §127.12b].

61. The permittee shall comply with all applicable requirements of 40 CFR Part 60, Subpart IIII [40 CFR § 60.4200 through § 60.4219].

62. The permittee meets the requirements of 40 CFR Part 63, Subpart ZZZZ by meeting the requirements of 40 CFR Part 60, Subpart IIII [25 Pa. Code §127.12b].

Emergency Fire Pump Engine (Source ID 104)

63. The emissions from the emergency fire pump engine shall not exceed the following [25 Pa. Code §127.12b]:

(a) NOx: 3.30 lb/hr or 0.82 tpy on a 12-month rolling basis.
(b) CO: 0.85 lb/hr or 0.21 tpy on a 12-month rolling basis.
(c) VOC: 0.11 lb/hr or 0.03 tpy on a 12-month rolling basis.
(d) Total PM: 0.13 lb/hr or 0.03 tpy on a 12-month rolling basis.
(e) Total PM10: 0.11 lb/hr or 0.03 tpy on a 12-month rolling basis.
(f) Total PM2.5: 0.11 lb/hr or 0.03 tpy on a 12-month rolling basis.
(g) SO2: 0.007 lb/hr or 0.002 tpy on a 12-month rolling basis.

64. Operation of the emergency fire pump engine shall not exceed 500 hours on a 12-month rolling basis [25 Pa. Code §127.12b].

65. Sulfur content of the diesel fuel combusted by the fire pump engine shall not exceed 15 ppm [25 Pa. Code §127.12b].

66. The permittee shall maintain records of the fuel certification reports for each delivery of fuel to verify compliance with the fuel restriction requirements [25 Pa. Code §127.12b].

67. The permittee shall comply with all applicable requirements of 40 CFR Part 60, Subpart IIII [40 CFR § 60.4200 through § 60.4219].

68. Compliance with 40 CFR Part 60, Subpart IIII assures compliance with 40 CFR Part 63, Subpart ZZZZ [25 Pa. Code §127.12b].

Cooling Tower (Source ID 105)

69. The emissions from the cooling tower shall not exceed the following [25 Pa. Code §127.12b]:

(a) Total PM: 1.5 lb/hr or 6.57 tpy on a 12-month rolling basis.
(b) Total PM10: 0.75 lb/hr or 3.29 tpy on a 12-month rolling basis.
(c) Total PM2.5: 0.002 lb/hr or 0.009 tpy on a 12-month rolling basis.

70. Total dissolved solids (TDS) of the cooling tower water shall not exceed 2,000 ppm [25 Pa. Code §127.12b].

71. The permittee shall install and maintain drift eliminators with a manufacturer's guaranteed drift rate of less than 0.0005% of the circulating water flow rate [25 Pa. Code §127.12b].

72. The permittee shall sample, analyze, and record the circulating water TDS content on a monthly basis [25 Pa. Code §127.12b].

73. The permittee shall continuously monitor and record the circulating water and make up water flow rates on a 24-hour average [25 Pa. Code §127.12b].

74. The permittee shall maintain the following comprehensive and accurate records [25 Pa. Code §127.12b]:

(a) Monthly circulating water TDS content.
(b) Daily circulating water and make up water flow rates.
(c) PM, PM10, and PM2.5 emissions on a 12-month rolling basis based upon the measured parameters.

NSPS Subpart KKKK (Source IDs 101 and 102)

75. §60.4320 What emission limits must I meet for nitrogen oxides (NOX)?

(a) You must meet the emission limits for NOx specified in Table 1 to this subpart [15 ppm @ 15% O2 or 54 nanograms per joule (ng/J) of useful output (0.43 lb/MWh)].
(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X.

76. §60.4330 What emission limits must I meet for sulfur dioxide (SO2)?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;
(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement; or
(3) N/A

(b) N/A

77. §60.4333 What are my general requirements for complying with this subpart?
(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

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

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

78. §60.4340 How do I demonstrate continuous compliance for NO_X if I do not use water or steam injection?

(a) If you are not using water or steam injection to control NO_X emissions, you must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NO_X emission result from the performance test is less than or equal to 75 percent of the NO_X emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO_X emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or
(2) N/A

79. §60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

(a) Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

80. §60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) N/A [Not simple-cycle]

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total

electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW.

(3) N/A

(g) N/A
(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in §60.4380(b)(1).

81. §60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

82. §60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. 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.

83. §60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

NSPS Subpart IIII (Source IDs 103 and 104)

84. §60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) N/A

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or
(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(b) N/A

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) N/A

(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

85. §60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) N/A

(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.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) N/A

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in §60.4212.

(f) N/A

86. §60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 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 (a)(1) through (2) of this section.

(1) N/A

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) N/A

(c) [Reserved]

(d) N/A

(e) N/A

(f) N/A

(g) N/A

(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

87. §60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 over the entire life of the engine.

88. §60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) N/A

(b) Beginning October 1, 2010, 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.

(c) [Reserved]

(d) N/A

(e) N/A

89. §60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) N/A

(c) N/A

(d) N/A

(e) N/A

(f) N/A

(g) N/A

(h) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

90. §60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you 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) N/A

91. §60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you 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.

(b) N/A

(c) If you are an 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), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) 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.

(d) N/A

(e) N/A

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (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, 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 in 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 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) through (iii) 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) 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.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii)Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(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 and emergency demand response provided in

paragraph (f)(2) 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.

(ii) [Reserved]

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) N/A

(2) N/A

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must

conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

92. §60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the equation in §60.4212(c).

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) N/A

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

93. §60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) N/A

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) N/A

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §60.4211(f)(2)(ii) and (iii) or that operates for the purposes specified in §60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in §60.4211(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §60.4211(f)(2)(ii) and (iii).

(vi) Hours spent for operation for the purposes specified in §60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in §60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in §60.4.

94. §60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.