pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

COMMONWEALTH OF PENNSYLVANIA
October 2, 2020

SUBJECT: Application Review Memo for Plan Approval 18-00033B
Renovo Energy Center, LLC
Renovo Generation Station
Renovo Borough, Clinton County

TO: Muhammad Q. Zaman MQZ
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On December 30, 2019, Renovo Energy Center, LLC (REC) submitted a plan approval application to construct a natural-gas-fired combined cycle power plant consisting of two (2) identical 1 x 1 powerblocks where each powerblock consists of a 3,541 MMBtu/hr (high heating value, HHV) natural gas-fired combustion turbine (CT) and steam turbine (ST) with a 1,005 MMBtu/hr peak input (HHV) natural gas-fired duct burner (DB) and a heat recovery steam generator (HRSG). Ancillary equipment for the proposed Renovo Generation Plant located in Renovo Borough, Clinton County also includes:

- one (1) 2,206 brake horsepower (bhp) diesel-fired Caterpillar model 3512C emergency generator engine
- one (1) 237 bhp diesel-fired Clarke/John Deere model JU6H-UFAD88 fire pump engine
- two (2) 66 MMBtu/hr natural gas-fired auxiliary boilers
- three (3) 15 MMBtu/hr natural gas-fired water bath heaters
- one (1) 3 MMBtu/hr natural gas-fired dew point gas heater
- one (1) 3,500,000-gallon ultra-low sulfur diesel fuel (ULSD) storage tank
- two (2) 20,000-gallon lube oil storage tanks
- two (2) 26,000-gallon aqueous ammonia storage tanks
- one (1) 2,500-gallon ULSD storage tank (emergency generator engine)
- one (1) 350 gallon ULSD storage tank (fire pump engine)
- twelve (12) sulfur hexafluoride-containing high voltage circuit breakers

The Department submitted a technical deficiency letter to REC on May 8, 2020, to request additional information or clarification on discrepancies found within the application. REC responded to the technical deficiency letter on May 25, 2020. REC also responded on July 1, 2020, to a June 18, 2020, Department e-mail requesting additional clarifications.

In the application submittal, REC proposed three (3) options for construction of CTs at the proposed Renovo Generation Station from three (3) separate manufacturers: General Electric (GE), Siemens and Mitsubishi. Upon review of the three (3) options, the Department agrees with REC's determination that the GE option is the lowest emitting of the three options with respect to criteria pollutants. Below in Table 1 are the annual potential emissions from each option.

Table 1 – Annual Potential Emissions from Each Combustion Turbine

Pollutant	General Electric Option Tons/year	Siemens Option Tons/year	Mitsubishi Option Tons/Year
Nitrogen Oxides (NO_x)	174.83	177.70	128.45
Carbon Monoxide (CO)	161.74	345.63	563.02
Volatile Organic Compounds (VOCs)	50.35	88.83	251.08
Sulfur Oxides (SO_x)	25.10	18.95	8.68
Particulate Matter ($PM/PM_{10}/PM_{2.5}$)	102.18	83.43	68.94
Hazardous Air Pollutants (HAPs)	8.11	9.08	8.58
Sulfuric Acid (H_2SO_4)	15.35	6.72	16.19
Carbon Dioxide equivalent (CO_2e)	2,427,746	1,817,821	1,750,467
Ammonia	129.72	99.74	100.16

Emissions in Table 1 are based on 720 hours of operation in any 12 consecutive month period while firing on ULSD with the remainder of the year fired on natural gas for the CT, HRSG and DB for the General Electric. The Siemens and Mitsubishi emission are based on the previous plan approval issuance without a DB. Included are the emissions during startup and shutdown (SUSD) of each CT. This will be evaluated later in this memo.

REC proposes constructing two (2) identical GE model 7AH.02 natural gas/ULSD-fired powerblocks cable of producing a combined nominally rated peak power of 1,240 Megawatts (MW) of electricity. One powerblock will supply electricity to the Pennsylvania, New Jersey, Maryland (PJM) power grid, while the other powerblock will supply power to the New York Independent System Operator (NYISO) power grid. The maximum heat input rating of each CT is 3,541 MMBtu/hr (high heating value, HHV) on natural gas and 3,940 MMBtu/hr (HHV) on ULSD. When coupled with the duct burner the powerblock has a nominal peak rating of 4,529 MMBtu/hr while firing natural gas.

In the combined cycle process, ambient air is drawn into the compressor element of each of the CTs through a high-efficiency air filtration and silencing system. Inlet evaporative cooling may take place during periods of warm ambient temperature and low relative humidity to further enhance overall production capability of the CTs. After the evaporative cooler section, the air enters the compressor section where it is compressed and channeled to the fuel/mix combustion stage of the CT. This section of the CT is commonly referred to as the gas generator section. The gas generator is the component that generates criteria and hazardous air pollutant emissions by means of the fuel combustion process. A transition duct within the CT directs the flow of hot gases from the gas generator to the power section of the turbine. Gas generator combustion products (hot gases) expand through the stages of the power turbine where the thermodynamic, or gas energy, is converted to mechanical power. This power is transmitted through rotation of the shaft to the generator for the CT, which is directly coupled to the power turbine. The generator takes this rotational motion and converts it to electricity. The hot exhaust gases produced in the CTs are directed into two HRSGs through an exhaust transition duct, where the waste heat is captured and converted into steam energy before the exhaust gases exit the vertical stack for each HRSG. The transition duct houses a 1,005 MMBtu/hr peak rated natural gas-fired DB that will be utilized to increase the exhaust gas temperature prior to the HRSG. The DBs will optimize the overall efficiency of the plant to produce the nominal 1,240 MW of electrical power. All the usable steam produced in the HRSGs is extracted by the STs to produce additional electrical power. Once the steam does its work in the STs, it is exhausted and condensed in two (2) individual air-cooled condensers (ACCs), one for each powerblock. ACCs reduce particulate matter emissions and the need for water withdrawal. The cycle is a closed loop system as the condensate is reused as feed water to the HRSGs.

REC proposes controlling the nitrogen oxides (NO_x) emissions using a dry low-NO_x (DLN) combustor and selective catalytic reduction (SCR) while firing either natural gas or ULSD. In addition, the CT will be equipped with water injection at the combustors and utilized while firing ULSD. To control the carbon monoxide (CO) and volatile organic compounds (VOCs) emissions, REC proposes utilizing combustion controls and oxidation catalysts, regardless of which powerblock option is selected. The DLN optimizes combustion temperature, combustion zone residence time, and combustion zone free oxygen to control formation of NO_x. SCR involves the injection of ammonia into the flue gas downstream of the CTs and then passing the flue gas through a catalyst bed. The ammonia reacts with the nitrogen oxides to form nitrogen and water. The function of the catalyst is to lower the activation energy of the NO_x decomposition reaction and accelerate the reduction of NO_x to nitrogen and water vapor. The ammonia injection flow rate is electronically controlled and is determined by the measured NO_x rates to comply with the NO_x emission limitation. The ammonia slip, which occurs as a result of unreacted ammonia, will be monitored to demonstrate compliance with the ammonia slip emission limitation. Combustion controls utilize proper operations to improve the oxidation process and minimize incomplete combustion.

Flame temperatures from distillate fuels are generally higher than that of natural gas and thus will produce higher NOx emission due to the formation of Thermal NOx. Thermal NOx is formed at higher combustion temperature with the reaction of the nitrogen within the combustion air/fuel mixture. Water injection is utilized for distillate fuels to lower the flame temperature, thus lowering the potential of Thermal NOx.

REC proposes monitoring the NOx emissions from the exhaust of each powerblock by utilizing a continuous emission monitoring system (CEMS), which will be described in detail later in this review memo.

The CO and VOCs are oxidized through the use of a precious metal catalyst and optimum temperatures. The typical pressure differential across the bed of the catalyst will be between 0.7

to 1.0 inches of water. REC is required to monitor and record the catalyst inlet temperature and pressure differential of each oxidation catalyst. The CO emissions will be monitored using CEMS and the VOCs emissions will be EPA reference method tested to demonstrate compliance with their respective emission limitations.

The 2,206 brake horsepower (bhp) diesel-fired Caterpillar model 3512C emergency generator engine and the 237 bhp diesel-fired Clarke/John Deere model JU6H-UFAD88 fire pump engine will be restricted to a maximum of 500 hours and 250 hours of operation in any 12 consecutive month period, respectively. The maximum sulfur content of the diesel fuel fired in these engines will be 15 ppm. Fuel certifications will be used to demonstrate compliance with the maximum sulfur content limitation.

REC is proposing to construct two (2) 66 MMBtu/hr natural gas-fired boilers to provide the necessary steam to both units for startup. For the boilers, REC is proposing ultra-low NO_x burners and flue gas recirculation (FGR) to control the emissions from each proposed boiler. No add-on controls are being proposed by REC for each boiler, at this time.

Each water bath heater is rated at 15 MMBtu/hr and will be fired on natural gas. The dew point gas heater is rated at 3 MMBtu/hr and will be fired on natural gas. Each unit will be equipped with an ultra-low NO_x burner. REC is not proposing any additional control for each unit.

The storage tanks consist of two (2) 20,000-gallon lube-oil tanks, two (2) 26,000-gallon ammonia storage tanks and one (1) 3,500,000-gallon ULSDF storage tank and two small ULSD tanks for the emergency generator and fire pump engines.

The proposed air-contaminant sources and control devices are all subject to the plan approval requirements pursuant to 25 Pa. Code Sections 127.1 and 127.11 and must satisfy the Best Available Technology (BAT) requirements of 25 Pa. Code Sections 127.1 and 127.12.

New Source Performance Standards (NSPS) Regulations (40 CFR Part 60)

Subpart D: Fossil-Fuel-Fired Steam Generators

The HRSGs and DBs are not subject to the federal Standards of Performance for New Stationary Sources, 40 CFR Part 60 Subpart D Section 60.40 through 60.46 (Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971). Since the HRSGs and DBs are subject to 40 CFR Part 60 Subpart KKKK, these sources are not subject to Subpart D pursuant to 40 CFR Section 60.40(e).

Subpart Da: Electric Utility Steam Generating Units

The HRSGs and DBs are not subject to the federal Standards of Performance for New Stationary Sources, 40 CFR Part 60 Subpart Da Sections 60.40Da through 60.52Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978). Since the HRSGs and DBs are associated with stationary combustion turbines that are capable of combusting more than 250 MMBtu/hr heat input of natural gas/ULSD and meet the applicability requirements of, and are subject to 40 CFR Part 60

Subpart KKKK, these sources are not subject to 40 CFR Part 60 Subpart Da Section 60.40Da(e)(1).

Subpart Db: Industrial-Commercial-Institutional Steam Generating Units

The steam generating units are not subject to Subpart Db of the federal Standards of Performance for New Stationary Sources, 40 CFR Part 60 Subpart Db Sections 60.40b through 60.49b (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units). Since the HRSGs and DBs are associated with stationary combustion turbines that meet the applicability requirements of 40 CFR Part 60 Subpart KKKK, these sources are not subject to 40 CFR Section 60.40b(i).

Subpart Dc: Small Industrial-Commercial-Institutional Steam Generating Units

The HRSGs and DBs are not subject to Subpart Dc of the federal Standards of Performance for New Stationary Sources, 40 CFR Part 60 Subpart Dc Sections 60.40c through 60.48c (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units). Since the steam generating units have a maximum design heat input capacity greater than 100 MMBtu/hr, these sources are not subject to 40 CFR Part 60 Subpart Dc pursuant to 40 CFR Section 60.40c(a).

The two (2) 66 MMBtu/hr Cleaver Brooks natural gas-fired boilers are subject to the requirements of 40 CFR Part 60 Subpart Dc. Pursuant to 40 CFR Section 60.42c, REC has proposed to use only pipeline quality natural gas as fuel for the boilers where the natural gas will have a maximum sulfur content of 0.4 grains/100 standard cubic foot (scf). With a sulfur content not in excess of 0.4 gr/100 scf, the potential SO_2 emissions are conservatively calculated to be 0.0012 lb/MMBtu heat input while firing natural gas. REC has elected to enter into a contract with the fuel supplier requiring the sulfur content to not exceed 0.4 gr/100 scf for natural gas plus REC will receive certifications from the fuel supplier indicating the sulfur content, thus complying with 40 CFR Sections 60.48c(e) regarding sulfur content monitoring. REC will be required to maintain records on the monthly fuel consumption of the boiler pursuant to 40 CFR Section 60.48c(g)(2).

Since the proposed boiler is only firing natural gas, the source is not subject to any particulate matter (PM) emission limitation as specified in 40 CFR Section 60.43c.

Subpart Kb: Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

The following storage tanks proposed for this facility (two (2) 15,000-gallon lube oil tanks and two (2) 26,000-gallon ammonia tanks) are not subject to the federal Standards of Performance for New Stationary Sources, 40 CFR Part 60 Subpart Kb Sections 60.110b through 60.117b Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984. The lube oil storage tank is less than 19,813 gallons (as with the two small ULSD tanks) and ammonia is not a VOC. Therefore, pursuant to 40 CFR Section 60.110b(a), these storage tanks are not subject to Subpart Kb.

The 3,500,000-gallon ULSD storage tank is not subject to the requirements of 40 Part 60 Subpart Kb. Pursuant to 40 CFR 60.110(b), the subpart does not apply to "storage vessels with a capacity greater than or equal to 151 m^3 (39,890 gallons) storing a maximum true vapor pressure less than 3.5 kilopascals (kPa)." The true vapor pressure of the ULSD at worst case ambient conditions would be 0.19 kPa at 37.8°C (100°F), which will not exceed the 3.5 kPa requirements of Subpart Kb. Therefore, the subject tank is not subject to the requirements of 40 CFR Part 60 Subpart Kb.

Subpart IIII: Stationary Compression Ignition Combustion Engines

The emergency engines are subject to the federal Standards of Performance for New Stationary Sources, 40 CFR Part 60 Subpart IIII Sections 60.4200 through 60.4219 (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines). These engines are compression ignition internal combustion engines. The 2,206 bhp emergency generator engine is subject to Subpart IIII as per 40 CFR Section 60.4200(a)(2)(i) because it has a manufacture date after April 1, 2006, and is not a fire pump engine. The 237 bhp fire pump engine is subject to Subpart IIII as per 40 CFR Section 60.4200(a)(2)(ii) because it is manufactured after July 1, 2006, as a certified National Fire Protection Association (NFPA) fire pump engine. Both engines will, as proposed, have a model year of 2017. As per 40 CFR Section 60.4200(a)(4), these engines are subject to the requirements in 40 CFR Section 60.4208.

Pursuant to 40 CFR Section 60.4205(b), emergency generator engines with a displacement of less than 30 liters per cylinder must comply with the emission standards specified in 40 CFR Section 60.4202 for all pollutants. 40 CFR Section 60.4202(a)(2) requires emergency generator engines to comply with the emission standards specified in 40 CFR Sections 89.112 and 89.113. 40 CFR Section 89.112(a) requires the 2,206 bhp (1,500 kW) emergency generator engine to comply with a NO_x+NMHC emission limit of 6.4 g/kW-hr (4.8 g/bhp-hr), a CO emission limit of 3.5 g/kW-hr (2.6 g/bhp-hr), and a PM emission limit of 0.20 g/kW-hr (0.15 g/bhp-hr). REC is proposing these emission limits: a NO_x emission limit of 4.48 g/bhp-hr, a VOC emission limit of 0.16 g/bhp-hr, a CO emission limit of 0.87 g/bhp-hr, and a $PM/PM_{10}/PM_{2.5}$ emission limit of 0.04 g/bhp-hr. REC has provided documentation indicating that the proposed emergency generator engine will be EPA Tier 2 certified.

Pursuant to 40 CFR Section 60.4205(c), the fire pump engine, with a displacement of less than 30 liters per cylinder must comply with the emission standards specified in Table 4 of Subpart IIII for all pollutants. Table 4 of Subpart IIII requires the 237 bhp (176 kW) fire pump engine to comply with a NO_x+NMHC emission limit of 4.0 g/kW-hr (3.0 g/bhp-hr), CO emission limit of 3.5 g/kW-hr (2.6 g/bhp-hr), and a PM emission limit of 0.20 g/kW-hr (0.15 g/bhp-hr). REC is proposing these emission limits: a NO_x+NMHC emission limit of 2.7 g/bhp-hr, a VOC emission limit of 0.10 g/bhp-hr, CO emission limit of 0.9 g/bhp-hr, and a $PM/PM_{10}/PM_{2.5}$ emission limit of 0.10 g/bhp-hr. REC, up to this point, has not been able to obtain documentation indicating that the proposed fire pump engine is EPA Tier 3 certified. However, REC has indicated that the certification will be provided once the vendor is chosen. The plan approval will include a condition requiring REC to submit this certification to the Department prior to constructing the fire pump engine. 40 CFR Section 60.4206 requires REC to operate and maintain these engines to meet the specified emission limits over the entire life of the engines.

REC has proposed to equip both engines with a non-resettable hour meter and to keep records of the number of hours each engine is operated and why each engine was operated to meet 40 CFR Sections 60.4209(a) and 60.4214(b) even though not required (because they meet non-emergency engine limits).

40 CFR Section 60.4207(b) requires REC to use diesel fuel that meets the requirements of 40 CFR Section 80.510(b), which limits the sulfur content of the diesel fuel to a maximum 15 ppm, and requires a minimum cetane index of 40 or limits the aromatic content to a maximum of 35 volume percent. REC proposed a maximum sulfur content of 15 ppm and a minimum cetane index of 40 or a maximum aromatic content of 35. REC will keep records to demonstrate compliance with these requirements.

Subpart KKKK-Stationary Combustion Turbines

The CTs, HRSGs and DBs are subject to the Standards of Performance for New Stationary Sources, 40 CFR Part 60 Subpart KKKK Sections 60.4300 through 60.4420 (Standards of Performance for Stationary Combustion Turbines) because they will be constructed after February 18, 2005, and the CTs have a heat input at peak load greater than 10 MMBtu/hr based on the higher heating value of the fuel, as per 40 CFR Section 60.4305(a). 40 CFR Section 60.4305(b) exempts the stationary combustion turbines from the requirements of 40 CFR Part 60 Subpart GG as well as the HRSGs and DBs from the requirements of 40 CFR Part 60 Subparts Da, Db, and Dc.

Pursuant to 40 CFR Section 60.4320, REC will comply with the NO_x emission limitation of 15 parts per million, dry volume (ppmdv) at 15% oxygen (O_2) for each CT while firing natural gas and 42 ppmdv @ 15%O_2 while firing ULSD, by proposing to limit the NO_x emissions to 2.0 ppmdv @ 15% O_2 while firing natural gas and 4.0 ppmdv @ 15% O_2 while firing ULSD. REC proposes that each NO_x emission limitation applies at all normal operating times. The HRSGs and DBs will not be operated independently of the CTs.

Pursuant to 40 CFR Section 60.4330(a)(2), REC will comply with the SO_2 emission limitation where the CTs shall not burn any fuel which contains a sulfur content that could result in total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu of heat input while firing either natural gas or ULSD. To achieve this, REC has proposed to use only pipeline quality natural gas as fuel for the CTs where the natural gas will have a maximum sulfur content of 0.4 grains/100 standard cubic foot (scf) and ULSDF with a sulfur content of less than 15 ppm. With a sulfur content not in excess of 0.4 gr/100 scf the potential SO_2 emissions are conservatively calculated to be 0.0012 lb/MMBtu heat input while firing natural gas. As for the ULSD, REC is proposing not to fire either CT with diesel fuel having a sulfur content greater than 15 ppm. The SO_x emission while firing ULSD will equate to 0.0018 lb/MMBtu of heat input.

REC has elected to enter into a contract with the fuel supplier requiring the sulfur content to not exceed 0.4 gr/100 scf for natural gas and 15 ppm for ULSD plus REC will receive certifications from the fuel supplier indicating the sulfur content, thus complying with 40 CFR Sections 60.4360 and 60.4365 regarding sulfur content monitoring.

To demonstrate compliance with the NO_x emission limits, REC will install CEMS for NO_x satisfying the requirements specified in 40 CFR Section 60.4335(b)(1). REC will be required to comply with the CEMS requirements specified in 40 CFR Sections 60.4345 and the excess emissions requirements specified in 40 CFR Section 60.4350.

Pursuant to 40 CFR Section 60.4333, REC is 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.

REC is required to prepare a proper parameter monitoring plan as specified in 40 CFR Section 60.4355.

REC is required to submit the applicable reports to the Department and the United States Environmental Protection Agency (EPA) in order to demonstrate compliance with 40 CFR Sections 60.4375 and 60.4395. The facility will comply with the *excess emissions* requirements and *monitor downtime* for NO_x emissions as specified in 40 CFR Section 60.4380.

REC is also required to perform the initial performance test requirements as specified in 40 CFR Section 60.4405.

The fuel vendor will be required to conduct fuel sampling in order to demonstrate compliance with the potential SO_2 emissions. The fuel sampling must be conducted following the applicable procedures specified in 40 CFR Section 60.4415. REC will be required to obtain the fuel sampling reports from the vendor every six months to demonstrate compliance with the sulfur content limitation to satisfy the BAT requirements. These reports, along with the calculations and supporting documentation demonstrating compliance with the SO_2 emission limitation, will be required to be kept by REC for at least five (5) years and provided to the Department.

Subpart TTTT: Electric Utility Generating Units

The proposed facility is subject to Subpart TTTT of the federal Standards of Performance for New Stationary Sources, 40 CFR 60.5508 through 60.5580 (Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units). REC is proposing a CO_2 emission rate of 872 lb/MWh. This emission rate complies with the emission limitation as specified in Subpart TTTT.

REC is required to comply with the general requirements specified in 40 CFR Section 60.5525. The proposed powerblock options will have a CEMS that measures the CO_2 emissions. REC is required to comply with the monitoring and data collecting requirements in 40 CFR Section 60.5535. REC is required to demonstrate compliance and determine excess emissions using the requirements in 40 CFR Section 60.5540. REC is required to comply with the notifications, records, and reports requirements in 40 CFR Sections 60.5550 through 60.5565. REC is required to comply with the general provisions in 40 CFR Section 60.5570.

Source Category NESHAP Regulations (40 CFR Part 63)

Subpart YYYY: Stationary Combustion Turbines

The CTs are not subject to Subpart YYYY of the federal National Emission Standards for Hazardous Air Pollutants for Source Categories, 40 CFR Part 63 Subpart YYYY Sections 63.6080 through 63.6175 (National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines) because they will not be located at a major facility of hazardous air pollutant (HAP) emissions as demonstrated in Table 1 of this memo. Furthermore, as published in the August 18, 2004, edition of the *Federal Register,* the EPA issued a final rule to stay the effectiveness of Subpart YYYY for stationary lean premix gas-fired combustion turbines. There has been no regulatory action by the EPA since the August 18, 2004, date. Both powerblocks proposed by REC are stationary lean premix gas-fired combustion turbines.

Subpart ZZZZ: Stationary Reciprocating Internal Combustion Engines

Each emergency engine is subject to Subpart ZZZZ of the federal National Emission Standards for Hazardous Air Pollutants for Source Categories, 40 CFR Part 63 Subpart ZZZZ Sections 63.6580 through 63.6675 (National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines). These engines meet the definition of stationary RICE as defined in 40 CFR Section 63.6585(a) and will be located at an area source of HAPs as that term is defined in 40 CFR Section 63.6585(c). These engines are classified as new engines, as per 40 CFR Section 63.6590(a)(2)(iii), because they will be constructed after June 12, 2006, at an area source of HAPs. However, 40 CFR Section 63.6590(c)(1) states that to comply with Subpart ZZZZ, these stationary RICE need only comply with 40 CFR Part 60 Subpart IIII Section 60.4200 through 60.4219.

Subpart DDDDD: Industrial, Commercial, and Institutional Boilers and Process Heaters

The HRSGs and DBs are not subject to the federal National Emission Standards for Hazardous Air Pollutants for Source Categories, 40 CFR Part 63 Subpart DDDDD Sections 63.7480 through 63.7575 (National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters), as per 40 CFR Section 63.7485, because they will not be located at a major facility of hazardous air pollutant (HAP) emissions as demonstrated in Table 1 of this memo.

Subpart JJJJJJ: Industrial, Commercial, and Institutional Boilers Area Sources

The HRSGs and DBs are not subject to Subpart JJJJJJ of the federal National Emission Standards for Hazardous Air Pollutants for Source Categories, 40 CFR 63.11193 through 63.11237 (National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and

Institutional Boilers Area Sources). These air-contaminant sources are fired only on natural gas; therefore, they are not subject to Subpart JJJJJJ as per 40 CFR Section 63.11195(e).

Compliance Assurance Monitoring (CAM) Regulations (40 CFR Part 64)

Each powerblock (i.e. CTs, HRSGs and DBs) is subject to the requirements of Compliance Assurance Monitoring (CAM), 40 CFR Part 64 Sections 64.1 through 64.10. NO_x, CO, VOCs, and formaldehyde (HCHO) are the only pollutants controlled by the proposed control devices (i.e. SCR for NO_x, and oxidation catalysts for CO, VOCs, and HCHO). CAM does not apply to the NO_x emissions from the powerblocks, as per 40 CFR Section 64.2(b)(1)(i), because the NO_x emissions are subject to emission limitations and standards pursuant to Section 111 of the federal Clean Air Act (40 CFR Part 60 Subpart KKKK) and monitored by CEMS. CAM does not apply to the VOC and HCHO emissions from the powerblocks because the pre-control emissions from each powerblock are less than 50 tpy and 10 tpy, respectively. CAM does not apply to CO, as per 40 CFR Section 64.2(b)(1)(vi), since CO will be monitored by CEMS.

Neither of the emergency engines or auxiliary boilers 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 the engines and boilers will not be equipped with control devices.

The facility is not required to submit a CAM plan for the any source at the facility at this time.

Acid Rain Program (ARP) Regulations (40 CFR Parts 72-78)

The facility is subject to the Title IV Acid Rain Program, as per 40 CFR Section 72.6(a)(3)(i). This is because the facility will contain new utility units, as that term is defined in 40 CFR Section 72.2, and the units will serve a generator that produces electricity for sale. Pursuant to 40 CFR Section 72.9(a)(1)(i), REC is required to submit a complete Acid Rain permit application in accordance with the deadlines specified in 40 CFR Section 72.30(b)(2)(ii), which requires REC to submit this application for the new units at least 24 months before the date on which the unit commences operation. REC indicated in the plan approval application that they will submit the appropriate paperwork to apply for the Acid Rain permit. The Acid Rain permit application will be reviewed by the Department and EPA, and upon approval the Acid Rain permit will be included in the facility's Title V operating permit. The facility is not subject to 40 CFR Part 76 – Acid Rain Nitrogen Oxides Emission Reduction Program, as per 40 CFR Section 76.1, because the proposed units can only be fired on natural gas, not coal.

Cross-State Air Pollution Rule (CSAPR) Regulations (40 CFR Part 97)

40 CFR Part 97 was established by the EPA for EGUs rated greater than 25 MW to reduce the NOx, SOx and Ozone emissions that could be transported downwind to other states to help in establishing attainment with the 8-hour National Ambient Air Quality Standards (NAAQS) for these air pollutants. REC has determined that the proposed CTs are subject to the requirements of 40 CFR Part 97 Subparts AAAAA, BBBBB and CCCCC.

40 CFR Part 97 Subpart AAAAA Sections 97.401 through 97.435 pertain to the CSAPR NOx Annual Trading Program for EGU units with a nameplate rating greater than 25 MW producing electricity for sale. The proposed CTs are CSAPR NO_x Annual Units pursuant to 40 CFR Section 97.404(a)(1) because these utility units will commence operation after January 1, 2005, and have a nameplate rating greater than 25 MW producing electricity for sale. 40 CFR Section 97.21(a) requires REC to submit a complete NO_x Budget permit application by the deadline specified in 40 CFR Section 97.21(b), which requires a complete application at least 18 months before the date on which the unit commences operation. REC will be required to monitor the NO_x emissions from each powerblock on a continuous basis and these results be used to calculate allocation of CSAPR NO_x Annual allowances pursuant to 40 CFR Sections 97.411(b)(1) and 97.412 to determine compliance with the CSAPR NO_x Annual emission limitation and assurance provision pursuant to 40 CFR Section 97.406(c). REC will utilize a Continuous Emission Monitoring System (CEMS) to monitor the NO_x emissions from each powerblock pursuant to 40 CFR Part 75. This will be discussed further in detail later in this review memo. Compliance with 40 CFR Part 75 will comply with the monitoring, reporting and recordkeeping requirements of 40 CFR Sections 97.430 through 97.435 for NO_x emissions.

40 CFR Part 97 Subpart BBBBB Sections 97.501 through 97.535 pertain to the CSAPR NO_x Ozone Season Group 1 Trading Program for EGU units with a nameplate rating greater than 25 MW producing electricity for sale. The proposed CTs are CSAPR NO_x Ozone Season Group 1 Units pursuant to 40 CFR Section 97.504(a)(1) because these utility units will commence operation after January 1, 2005, have a nameplate capacity greater than 25 MW producing electricity for sale. REC will be required to monitor the NO_x emissions from each powerblock on a continuous basis and these results be used to calculate allocation of CSAPR NO_x Annual allowances pursuant to 40 CFR Sections 97.511(b)(1) and 97.512 to determine compliance with the CSAPR NO_x Ozone Season Group 1 allowance allocations pursuant to 40 CFR Section 97.506(c). REC will comply with the monitoring, reporting and recordkeeping requirements of 40 CFR Sections 97.530 through 97.535 for NO_x Ozone emissions.

40 CFR Part 97 Subpart CCCCC Sections 97.601 through 97.635 pertain to the CSAPR SO2 Group 1 Trading Program for EGU units that have a nameplate rating greater than 25 MW producing electricity for sale. The proposed CTs are CSAPR SO2 Group 1 Units pursuant to 40 CFR Section 97.604(a)(1) because these utility units will commence operation after January 1, 2005, have a nameplate rating greater than 25 MW producing electricity for sale. REC will be required to monitor the SO2 emissions from each powerblock on a continuous basis and these results be used to calculate allocation of CSAPR SO2 Annual allowances pursuant to 40 CFR Sections 97.611(b)(1) and 97.612 to determine compliance with the CSAPR SO2 Group 1 allowances available for deduction pursuant to 40 CFR Section 97.606(c). REC will comply with the monitoring, reporting and recordkeeping requirements of 40 CFR Sections 97.630 through 97.635 for SO2 emissions.

Mandatory Greenhouse Gas Reporting Regulations (40 CFR Part 98)

The proposed facility is subject to the requirements specified in 40 CFR Part 98, as per 40 CFR Section 98.2 because this facility will emit greater than 25,000 metric tons of carbon dioxide equivalent (CO2e) in any 12 consecutive month period.

Greenhouse Gas Tailoring Rule Regulations

The proposed facility is major for greenhouse gases (GHGs), as per 40 CFR Section 52.21(b)(49)(b)(iv)(a), because it has the potential to emit greater than 75,000 tpy of CO2e.

25 Pa. Code Chapter 123 Regulations

Each combustion unit in Source 031 is subject to the PM emission limitation (0.345 pounds per million Btu of heat input) in 25 Pa. Code Section 123.11(a)(2). Based on the use of natural gas as fuel for each unit, these combustion units will comply with the emission limit.

Each combustion unit in Sources 032 and 033 is subject to the PM emission limitation (0.40 pounds per million Btu of heat input) in 25 Pa. Code Section 123.11(a)(1). Based on the use of natural gas as fuel for each unit, these combustion units will comply with the emission limit.

Each combustion unit in Sources 031, 032 and 033 is subject to the SO_x emission limitation (4 pounds per million Btu of heat input over a 1-hour period) in 25 Pa. Code Section 123.22. Based on the use of natural gas as fuel for each unit, these combustion units will comply with the emission limit.

Each emergency engine is subject to the PM emission limitation (0.04 gr/dscf) in 25 Pa. Code Section 123.13(c)(1)(i). Based on the proposed emission rates and flow rates (dscfm) these engines will comply with the emission limit.

Each emergency engine is subject to the SO_2 emission limitation (500 ppmdv) in 25 Pa. Code Section 123.21(b). Based on their respective SO_2 emission rates (lb/min) and exhaust flow rates, these engines will comply with the emission limit. Compliance with this limitation is further ensured by the use of ULSD fuel.

The CTs and DBs are subject to the PM emission limitation specified in 25 Pa. Code Section 123.13(c)(1)(iii), which establishes a PM emission limit of 0.02 gr/dscf. Based on a review of numerous operating scenarios presented in the application for both natural gas and ULSD firing, the exhaust from each CT, HRSG and DB complies with 25 Pa. Code Section 123.13(c)(1)(iii) for both natural gas and ULSD fuel with the grain loading for each scenario being an order of magnitude less than the allowable limit.

The CTs and DBs are subject to the SO_2 emission limitation of 500 ppmdv established in 25 Pa. Code Section 123.21(b). REC proposes a SO_2 emission rate limitation of 0.0012 lb/MMBtu when firing natural gas. REC proposes a SO_2 emission rate limitation of 0.0018 lb/MMBtu when firing ULSD. The proposed SO_2 emission rates established pursuant to BACT and BAT s will ensure compliance with 25 Pa. Code Section 123.21(b).

On September 1, 2020, 25 Pa. Code Section 123.22 was revised to limit the sulfur content on commercially available No.2 Oil/diesel fuel to 15 ppm (0.00015%) for use in combustion units.

The regulation has allowances for depletion of inventory and other variances. However, as a new facility, combustion units at the Renovo Energy will be subject to this new standard.

25 Pa. Code Chapter 129 Regulations

REC is proposing to construct several storage tanks at the facility: one (1) 3,500,00-gallon ULSD storage tank, two (2) 20,000-gallon lube oil tanks, two (2) 26,000-gallon aqueous ammonia storage tanks, one (1) 2,500-gallon ULSD tank and one (1) 350-gallon ULSD storage tank. The ULSD and lube oil each have a vapor pressure less than 1.5 psia under actual storage conditions, thus not subject to the requirements of 25 Pa. Code Sections 129.56 and 129.57. Ammonia is not considered an organic compound and not subject to the requirements of 25 Pa. Code Section 129.57.

New Source Review (NSR)/Prevention of Significant Deterioration (PSD)

The proposed facility is a fossil-fuel-fired steam electric plant of more than 250 MMBtu/hr heat input and therefore subject to the requirements of 40 CFR Part 52 Section 52.21. To further determine applicability, the air-contaminant emissions increases resulting from the project are accounted for in Step 1 of the NSR/PSD applicability determination. The proposed facility is a brand-new facility; therefore, the emissions increase in Step 1 is equal to the potential air-contaminant emissions. Next, contemporaneous increases and decreases are accounted for in Step 2. Again, the proposed facility is a brand-new facility; therefore, there are no contemporaneous increases or decreases need to be taken into account. Table 2 shows the results of the applicability determination on a pollutant-by-pollutant basis. The potential emissions from all sources of the project are included in Table 2.

Table 2 - NNSR/PSD Determination

Pollutant	Potential Emissions Tons/year	NNSR Threshold Tons/year	PSD Threshold Tons/year	Major Emission	
				NNSR	PSD
Nitrogen Oxides	363.54	100	100	**YES**	**YES**
Carbon Monoxide	335.97	N/A	100	**N/A**	**YES**
Total PM	212.63	N/A	100	**N/A**	**YES**
PM_{10}	212.63	N/A	100	**N/A**	**YES**
$PM_{2.5}$	212.63	N/A	100	**N/A**	**YES**
Sulfur Oxides	53.84	N/A	100	**N/A**	**NO**
Ozone (VOC)	104.49	50	100	**YES**	**YES**

Therefore, pursuant to 25 Pa. Code Sections 127.201(c) and 40 CFR Section 52.21(b)(1)(i), the proposed facility is a major stationary source subject to NNSR and PSD requirements, respectively.

In accordance with the requirements of PSD, a Class I area impact analysis is required to be conducted if requested by the land manager of any national park or wilderness area within 300 kilometers of a proposed PSD source. Although the manager of Shenandoah National Park (the nearest Class I Area at approximately 271 kilometers) as well as the manager of Dolly Sods and Otter Creek Wilderness Areas were notified, neither expressed an interest in having the analysis completed. Additionally, PSD also requires a visibility and growth analysis, as well as an impact analysis on soils and vegetation. These analyses concluded no adverse impact on local visibility, no significant increase in air contaminant emissions resulting from growth and minimal impacts on local soils and vegetation. Based on the results of the analyses, the facility as proposed would appear to comply with the requirements of PSD.

Nonattainment New Source Review (NNSR)

The proposed facility is subject to the NNSR requirements of 25 Pa. Code Sections 127.201 through 127.217 since the facility is located in an ozone transport region and has the potential to emit greater than 100 tons of NOx and 50 tons of VOCs in any 12 consecutive month period. Therefore, the NO_x and VOC emissions must satisfy the Lowest Achievable Emission Rate (LAER) of the NNSR requirements. Additionally, the company will be required to purchase Emission Reduction Credits (ERCs) to offset the NO_x and VOC emission increases at a ratio of 1.15 to 1 as specified in 25 Pa. Code Sections 127.205(4) and 127.210 for flue emissions.

In accordance with 25 Pa. Code Section 127.205(5), REC submitted an analysis of alternative sites, sizes, production processes, and environmental control techniques for the proposed facility.

On August 24, 2016, EPA published a final rule for *40 CFR Parts 50, 51, and 93 Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements*. EPA has determined that VOC and ammonia emissions will be considered as precursors for $PM_{2.5}$ emissions for nonattainment NSR purposes. However, the location of the proposed facility, Clinton County, is considered to be in attainment for $PM_{2.5}$ emissions. Therefore, the proposed facility will not be subject to any requirements of the aforementioned rule.

Alternative Sites

Due to the forecasted electrical demand in the service area and the anticipated retirement of older inefficient coal-fired power plants in the next several years, REC is proposing to construct the power plant in Pennsylvania. REC evaluated alternate sites and chose to locate the proposed facility in Pennsylvania. The information supporting REC's reasons, as provided in the application, follows. First, 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 and NYISO Interconnections due to the age, size, efficiency, and existing pollution control technologies installed on many of the facilities in that region. For instance, the coal-fired power plant, Sunbury Generation, located in Union County shut down in 2013. 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 region of the NYISO Interconnection includes New York state. The predicted retirements combined with the anticipated growth in each 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.

Pennsylvania's increasingly widespread use of an economically favorable process to extract natural gas from shale rock is predicted to make the Marcellus region a continuing major supply basin for natural gas production. Pennsylvania far outpaces the other areas in the northeastern United States that currently allow shale-drilling activities.

Location in the PJM and NYISO areas 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 or southern parts of the PJM and NYISO systems. 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.

With Pennsylvania identified as the location of the power plant using the regional factors described above, REC next focused on areas within Pennsylvania taking local factors into consideration. Homer City, Juniata, Susquehanna and Moshannon/Leidy/Milesburg were the areas that REC concentrated for the site of the proposed power plant.

Homer City was a choice because of the number of coal-fired power plants with the area that could be displaced by a high efficiency gas-turbine combined cycle power plant. Areas to the north of Homer City were considered residential with steep/undulating terrain. There were no suitable sites within the Homer City area to construct the proposed power plant.

Juniata area which consists of Juniata/Roxbury/Lewistown/Harrisburg areas. This area does have access to 500kV transmission lines as well as a gas transmission line, however the area was comprised of residential areas and large production farmland which REC considered difficult in placement of a power plant. In addition, there was opposition in these areas to construct the proposed power plant. Area to the north was considered unsuitable due to the steep/undulating terrain in less populated areas.

For the proposed project, REC looked also to sites within the shale gas production areas that are located near major interstate natural gas transmission pipelines. Location near this type of infrastructure decreases the environmental impact associated with connecting the power plant to the source of fuel supply. REC then looked for locations near high voltage transmission lines with emphasis on locations near multi-circuit substations. Location near these types of infrastructure lessens the potential for extensive transmission work to accommodate the additional electric generation. Extensive transmission work increases environmental impacts, especially construction of new transmission lines. Finally, REC looked for industrial land use areas where a power plant could be sited without impact to threatened or endangered species or species of special concern, without impacts to wetland, and without land use changes. Location near a water body that could be used as a source of cooling water was an important, but secondary, consideration because other cooling alternatives could be used if location near a water body was not possible.

Clinton County is one of the shale gas production areas in Pennsylvania and the Dominion Transmission lines run through the county from west to east just north of the proposed facility. REC followed the pipeline to an intersection point where the pipeline was near the high voltage electric transmission system (in Clinton County, the high voltage electric transmission systems consist of 115 kV lines and 230 kV lines) and the Susquehanna River. Once this specific location was identified, REC looked to land use compatibility issues. REC found an abandoned railroad industrial area in the borough of Renovo that was suitable in size for construction of the proposed power plant. As a secondary consideration, from the perspective of connecting to one of the transmission lines that are in proximity to the proposed site, the site was located on the same side of the Susquehanna River as the potential natural gas supply pipeline to lessen any environmental concerns associated with a pipeline river crossing. Subsequent siting analysis confirmed the lack of impact to threatened and endangered species and species of special concern and confirmed that the project could be built and operated without impact to wetlands.

Approximately 68 acres of land were available for purchase at reasonable terms at the abandoned railyard in Renovo Borough. The 68-acre parcel was the site of the former PRR/Philadelphia & Erie railroad car renovation facility which closed in 1980. According to Department records, several smaller businesses have utilized the parcel as an industrial site since its closure in 1980. The Department has considered this site a Brownfield which has completed the necessary work under the Act 2, Land Recycling and Environmental Remediation Standards Act.

Alternative Sizes

REC had considered alternative sizes and more efficient models from several manufacturers of CTs as part of the NNSR review. There are several models that offer a wide range of MW output. The most common approximate rating for this type of configuration was around 500 MW for a single unit in the combined cycle configuration. Smaller sized electrical output units were not of the newest technology and were less efficient than the newest models.

The most common design capacity is a 1,000 MW multi-unit power plant. REC looked at a single 500 MW unit, but determined that it is not as cost effective to build as a 1,200 MW facility and would require higher market pricing to survive. With the near-by transmission lines, REC would be able to deliver the 1,200 MW range to the electrical grids.

REC looked at the 1,500 MW capacity for the site in Renovo Borough and concluded that two factors inhibited them to propose this size facility. First, was the unavailability to connect to high voltage transmission lines (345 or 500 kV) at this output level. The area has plenty of 230 kV transmission lines which have a limiting factor in the transportation of higher load like 1,500 MW. Second was the area of the site for the proposed power plant. REC would need additional land to construct a third CT unit and the facility was restricted to the 68-acre property for the proposed site and therefore was limited to only two (2) CT units.

Consequentially, REC selected a facility which will incorporate two (2) CT units with a total capacity of approximately 1,200 MW to utilize the most efficient technology today.

Alternative Production Processes

Alternative production processes are 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 fossil plant retirements caused by new environmental regulations. Further, with respect to solar and wind resources, both depend on weather and climatic conditions, and will not necessarily provide electrical power when needed.

Fossil fuel plants using coal were removed from consideration because the costs to comply with the 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. Compared to fuel oil or coal, natural gas is a relatively clean and efficient fuel that can reduce relative impacts on air quality (e.g. reduce emissions of nitrogen oxides, sulfur dioxide, particulate matter, and carbon dioxide) to generate the same amount of electricity. In addition, the overall footprint of a comparably sized coal plant is significantly larger than that of a natural gas plant.

Alternative Control Technologies

The information regarding REC's analysis of alternate control technologies, as provided in the application, follows.

A detailed discussion and analysis of the alternative control technologies is contained in the BACT/LAER/BAT analyses. Based on the results of the analyses, the project will employ advanced, state-of-the-art air pollution control technology to be among the best-controlled and lowest-emitting power plants of its size to be constructed and operated in the United States. The project will be fueled primarily with natural gas with a limited amount of ULSD, which will result in significantly lower emission of criteria pollutants, such as NO_x, SO_2, PM, and CO_2 compared to alternative fossil fuels.

Mercury and Air Toxics Standards (MATS) Rule

On December 16, 2011, EPA promulgated a regulation known as the mercury and air toxics standards (MATS) for power plants (*40 CFR Part 63 Sections 63.9980 through 63.10042 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units*). The MATS rule reduces allowable 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 fire natural gas with limited amounts of generation firing ULSD. Therefore, the proposed power plant is not subject to the new MATS rule pursuant to 40 CFR Section 63.9983(b) and the definition of a "natural gas-fired electric utility steam generating unit" pursuant to 40 CFR Section 63.10042.

Environmental Justice

The location of the project is in Clinton County, which does not contain any areas designated as Environmental Justice areas. The closest Environmental Justice area is Porter Township, Lycoming County. Porter Township is approximately 18 miles, straight-line distance, southeast from the project. Nonetheless, the Department opted to utilize some elements of the Environmental Justice requirements, such as public meetings. The public will also be given the opportunity to request a public hearing when the project's intent to issue plan approval is published in the *Pennsylvania Bulletin*.

LAER/BACT/BAT Analysis

EPA's RACT/BACT/LAER Clearinghouse (RBLC) was used to search for projects of similar size and nature as those of the proposed project. The following projects were identified in the RBLC and determined by the Department to be of close, but not identical, size and nature as those of the proposed project:

1. PSEG Fossil, LLC - Sewaren Generating Station. The permit for this project was issued April 26, 2016. The New Jersey Department of Environmental Protection reports that this facility is under construction.

2. Panda Power, LLC – Patriot Generating Station. The permit for this project was issued December 13, 2013. The Pennsylvania Department of Environmental Protection reports that this facility has begun commercial operation.

3. Hummel Station, LLC. The permit for this project was issued April 1, 2013. The Pennsylvania Department of Environmental Protection reports that this facility is still under construction. (Not included in RBLC)

4. Panda Power, LLC – Liberty Generating Station. The permit for this project was issued January 31, 2013. The Pennsylvania Department of Environmental Protection reports that this facility has begun commercial operation.

5. ESC Tioga, LLC – Tioga Generating Station. The permit for this project was issued August 20, 2019. The Pennsylvania Department of Environmental Protection reports that this facility has not begun construction as of this date. (Not included in the RBLC)

The characteristics of the fuel gas (e.g. sulfur content, individual constituents, etc.) unique to this project were all taken into consideration in the LAER/BACT/BAT analyses.

REC claimed that when there is insufficient operating history at a facility, such as those above, the air-contaminant emission limitations established for those facilities should not be used to establish as a LAER/BACT emissions limitations because these emission limitations have not been demonstrated to be achievable. The Department agrees only in part that emission limitations established for those projects are premature to establish as LAER/BACT emission rates for the proposed project. However, the Panda Liberty and Patriot projects have been operating for a few years and have also received EPA reference method testing so that conclusions can be drawn from their operating history.

The Panda Power, LLC – Liberty Generation Station project was identified in the RBLC and determined by the Department to be comparable for the natural gas firing, but not identical, in size and nature as that of the proposed project. This project was comprised of two (2) 2,980 MMBtu/hr (HHV) Siemens natural gas-fired CTs with HRSGs each equipped with a 164 MMBtu/hr (HHV) natural-gas-fired DB. The NO_x emissions are controlled using DLN and SCR while the CO and VOC emissions are controlled using an oxidation catalyst. This project has a NO_x emission limitation of 2 ppmdv @ 15% O_2, CO emission limitation of 2 ppmdv @ 15% O_2 without DB firing, VOC emission limitation of 1.0 ppmdv @ 15% O_2 without DB firing, sulfur content limitation of 0.4 grains/100scf, NH_3 slip emission limitation of 5 ppmdv @ 15% O_2, and opacity emission limitations of 10%. The CO and NO_x emissions are monitored with CEMS. An initial EPA reference method test was required to demonstrate compliance with the NO_x, CO, VOC, NH_3 slip and opacity emission limitations. The CTs at Panda Liberty, LLC were EPA reference method tested in June 2016. Test results indicate compliance with all emission limits.

The Hummel Station, LLC project was determined by the Department to be close for the natural gas firing, but not identical, in size and nature as that of the proposed project. The permit for the project was issued April 1, 2013. The project was comprised of two (2) 2,397 MMBtu/hr (HHV) Siemens model 5000F5 DLN natural gas-fired CT with a HRSG, each equipped with a 204 MMBtu/hr (HHV) natural-gas-fired DB. The NO_2 emissions are controlled using DLN and SCR while the CO and VOC emissions are controlled using an oxidation catalyst. The project has a NO_x emission limitation of 2 ppmdv @ 15% O_2, CO emission limitation of 2.0 ppmdv @ 15% O_2 with and without DB firing, VOC emission limitation of 1.0 ppmdv @ 15% O_2 without DB firing, PM emission limitation of 0.0088 lb/MMBtu, SO_2 emission limitation of 0.0024 lb/MMBtu, NH_3 slip emission limitation of 5 ppmdv @ 15% O_2, and opacity emission limitations of 10% to less than 20% for 2 minutes during any one hour. The CO, NO_x, NH_3, and SO_2 emissions are monitored with CEMS. An initial EPA reference method test is required to demonstrate compliance with the NO_x, CO, VOC, NH_3 slip and opacity emission limitations.

The Panda Power, LLC – Patriot Generation Station project was identified in the RBLC and determined by the Department to be comparable for the natural gas firing and very close in size and nature as that of the proposed project. This project was comprised of two (2) 3,007 MMBtu/hr Siemens natural gas-fired CTs with HRSGs each equipped with a 164 MMBtu/hr (HHV) natural-gas-fired DB. The NO_x emissions are controlled using DLN and SCR while the CO and VOC emissions are controlled using an oxidation catalyst. This project has a NO_x emission limitation of 2 ppmdv @ 15% O_2, CO emission limitation of 2 ppmdv @ 15% O_2 without DB firing, VOC emission limitation of 1.0 ppmdv @ 15% O_2 without DB firing, sulfur content limitation of 0.4 grains/100scf, NH_3 slip emission limitation of 5 ppmdv @ 15% O_2, and opacity emission limitations of 10%. The CO and NO_x emissions are monitored with CEMS. An initial EPA reference method test was required to demonstrate compliance with the NO_x, CO, VOC, NH_3 slip and opacity emission limitations. The CTs at Panda Patriot, LLC have been EPA reference method tested.

The PSEG Fossil, LLC – Sewaren Generation Station project was identified in the RBLC and determined by the Department to be identical for the CT proposed in the REC project for both the natural gas and ULSD firing and in CT capacity and manufacturer model. This project was comprised of one (1) 3,311 MMBtu/hr (HHV-natural gas)/3,452 MMBtu/hr (HHV-ULSD) GE model 7AH.02 natural gas/ULSD-fired CT with HRSG equipped with a 730 MMBtu/hr (HHV) natural-gas-fired DB. The NO_x emissions are controlled using DLN and SCR while the CO and VOC emissions are controlled using an oxidation catalyst. This project has a NO_x emission limitation of 2 ppmdv @ 15% O_2 while firing natural gas and 4 ppmdv @ 15% O_2 while firing ULSD, CO emission limitation of 2 ppmdv @ 15% O_2 without DB firing, VOC emission limitation of 1.0 ppmdv @ 15% O_2 without DB firing, sulfur content limitation of 0.75 grains/100scf for natural gas and 15 ppm for ULSD, NH_3 slip emission limitation of 5 ppmdv @ 15% O_2, and opacity emission limitations of 20% for more than 10 consecutive seconds. The CO and NO_x emissions are monitored with CEMS. An initial EPA reference method test was required to demonstrate compliance with the NO_x, CO, SO_x, PM, VOC, NH_3 slip and opacity emission limitations. According to the New Jersey Department of Environmental Protection the project is currently under construction.

ESC Tioga, LLC – Tioga Generation Station project was approved by the Department via plan approval on August 19, 2019, and determined by the Department to be identical for the CT and DB proposed in the REC project for the natural gas in CT capacity and manufacturer model. This project was comprised of one (1) 3,445 MMBtu/hr (HHV-natural gas) CT with HRSG equipped with a 1,024 MMBtu/hr (HHV) natural-gas-fired DB. The NO_x emissions are controlled using DLN and SCR while the CO and VOC emissions are controlled using an oxidation catalyst. This project has a NO_x emission limitation of 2 ppmdv @ 15% O_2 while firing natural gas, CO emission limitation of 0.9 ppmdv @ 15% O_2 without DB firing and 1.5 ppmdv @15% O_2 with the DB, VOC emission limitation of 0.7 ppmdv @ 15% O_2 without DB firing and 1.6 ppmdv @15% O_2 with the DB, sulfur content limitation of 0.4 grains/100scf for natural gas, NH_3 slip emission limitation of 5 ppmdv @ 15% O_2, and opacity emission limitations of 20% for more than 10 consecutive seconds. The CO and NO_x emissions are monitored with CEMS. An initial EPA reference method test will be required to demonstrate compliance with the NO_x, CO, SO_x, PM, VOC, NH_3 slip and opacity emission limitations. As stated above, the permittee has not commenced construction of the proposed facility.

The following LAER/BACT/BAT determinations were made by the Department by taking the PSEG Fossil, LLC, Panda Power, LLC, Hummel Station, LLC and ESC Tioga. LLC projects with their respective emission limitations, designs, and intended scopes, into consideration.

LAER/BACT/BAT Analysis for NO_x

The facility-wide potential NOx emissions are greater than the pollutant specific PSD and NNSR NO_x emission threshold of 100 tpy. Therefore, the air-contaminant sources at the facility are subject to LAER of the NNSR provisions in 25 Pa. Code Sections 127.201 through 127.217 and BACT of the PSD provisions in 40 CFR Section 52.21. Additionally, the air-contaminant sources are subject to the BAT provisions specified in 25 Pa. Code Sections 127.1 and 127.12.

NO_x emissions are a result of the formation of three different types of NO_x – thermal NO_x, fuel bound NO_x and Prompt NO_x. Thermal NO_x is formed when the nitrogen in the air is oxidized. The major factors affecting the formation of thermal NO_x are combustion temperature, concentration of oxygen in the combustion air, and residence time. Fuel NO_x results from the oxidation of nitrogen in the fuel being combusted. For natural gas combustion, there is generally minimal fuel NO_x formation while ULSD has more nitrogen in the fuel than natural gas and therefore will have a slightly higher emission rate. Prompt NO_x is a third possible formation mechanism where early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals in the fuel form prompt NO_x. However, the contribution of prompt NO_x to overall NOx formation is negligible. NO_x emissions can be controlled through the use of combustion controls and post-combustion add-on controls.

Source 031- Auxiliary Boilers

REC has evaluated control options to minimize NO_x emissions from the proposed auxiliary boilers including fuel selection, low NO_x burners, flue gas recirculation (FGR), ultra-low NO_x burners and add-on controls.

REC is proposing to utilize natural gas, with its inherently low nitrogen content, as fuel for each boiler, to minimize the amount of amount of natural gas fired in both boilers to not exceed 145,200 MMBtu in any 12 consecutive month period (excluding initial shakedown period). Based on the maximum rated heat input of 66 MMBtu/hr, this would equate to 2,200 hours of operation in any 12 consecutive month period for each boiler. REC has indicated that each boiler will be equipped with a fuel meter to monitor the amount of natural gas fired in the proposed boilers which will be recorded on a daily basis.

Low NO_x burners are designed to mix the air and fuel in multiple stages by utilizing a specially designed nozzle/diffuser to achieve the proper flame pattern to minimize the amount of nitrogen oxides formed in the combustion chamber. FGR is a process in which a portion of the exhaust gas is recirculated back to the combustion chamber to mix with incoming combustion air to introduce inert exhaust gases to absorb combustion heat and reduce oxygen in the combustion air to reduce thermal NO_x formation. Ultra-low NO_x burners use a combination of lean-premix combustion, fuel staging and zoned internal gas recirculation. Low NO_x burners in combination with FGR typically have low formation of NO_x. However, ultra-low NO_x burners can reduce the formation of NO_x even lower than low NO_x burners with FGR. REC is proposing to utilize ultra-low NO_x burners in the proposed boilers with an emission rate of 0.006 lb/MMBtu of rated heat input to satisfy the requirements of LAER/BACT/BAT.

SCR uses the injection of ammonia into the exhaust stream after which the exhaust stream then passes through a catalyst bed where a chemical reaction between the NO_x emissions and the ammonia to form nitrogen (N_2) gas and water vapor. A typical control efficiency for a SCR unit is 90%. The optimum exhaust gas temperature range for SCR units is between 500 to 1,000°F. A molar ratio of 1.0 to 1.3 is typically used to maximize NO_x control and minimize ammonia slip. Ammonia slip is caused by incomplete reactions within the catalyst. Ammonia emissions will be discussed further in this memo. To optimize the NO_x control and minimize ammonia slip, these systems employ a feedback control system where analyzers typically measure NO_x emissions in the exhaust stream and adjust the ammonia injection rate accordingly. Based on the

90% removal efficiency and the limited use, the amount of NO_x that would be controlled equates to 0.40 tons in any 12 consecutive month period. SCR is cost prohibitive for units of this size to control the minimal amount of NO_x. In addition, the RBLC reports no SCR being used to control NO_x emissions on boilers of this size. The Department agrees that the use of SCR is not warranted for the proposed boilers.

SNCR injects ammonia into the exhaust stream; however, SNCR does not use a catalyst. The optimum temperature range for SNCR units is between 1,600 and 2,100 °F for the ammonia to react with the NO_x. This required temperature window is higher than the expected flue gas temperature range from the proposed boiler of 800 to 1,000°F; therefore, REC concludes that SNCR is not technically feasible. The Department agrees with REC's conclusion that using SNCR on the proposed boiler is not considered technically feasible due to the temperature constraints.

Source 032 – Water Bath Heaters

REC is proposing to construct three (3) natural gas-fired water bath heaters to heat the incoming natural gas to prevent freezing, condensation or possible hydrate formation within the lines. Each unit will be rated at 15 MMBtu/hr of heat input. REC indicated that no more than two of the three heaters will be operational at any time. The dormant heater will be utilized as a backup in the event one of the primary units fails to operate. Therefore, REC will only be authorized to operate no more than two (2) water bath heaters incorporated in Source 032 at a time.

REC has evaluated control options to minimize NO_x emissions from the proposed water bath heater including fuel selection, low NO_x burners, FGR and add-on controls.

REC is proposing to utilize natural gas with a low NO_x burner to minimize the amount of NO_x emissions from the proposed heater with an emission rate of 0.011 lb/MMBtu. Ultra-low NO_x burners are not available for this size heater (15 MMBtu/hr). REC is not proposing any throughput or hourly limitations on the proposed heater. The total annual emissions will equate to 1.44 tons in any 12 consecutive month period, based on 8,760 hours of operation. Each proposed heater with an emission rate of 0.011 lb/MMBtu of rated heat input which will satisfy the requirements of LAER/BACT/BAT.

Based on the 90% removal efficiency for SCR and the size of the heater, NO_x reduction equates to 0.65 tons per year. SCR is cost prohibitive for units of this size to control the minimal amount of NO_x. In addition, the RBLC reports no SCR being used to control NO_x emissions on heaters of this size. The Department agrees that the use of SCR is not warranted for the proposed heater.

SNCR injects ammonia into the exhaust stream; however, SNCR does not use a catalyst. The optimum temperature range for SNCR units is between 1,600 and 2,100 °F for the ammonia to react with the NO_x. This required temperature window is higher than the expected temperature range from the proposed heater of 800 to 1,000°F; therefore, REC concludes that SNCR is not technically feasible. The Department agrees with REC's conclusion that using SNCR on the proposed heater is not considered technically feasible due to the temperature constraints.

Source 033 – Dew Point Gas Heater

REC has evaluated control options to minimize NO_x emissions from the proposed dew point gas heater including fuel selection, low NO_x burners, FGR and add-on controls.

REC is proposing to utilize natural gas with a low NO_x burner to minimize the amount of NO_x emissions from the proposed heater with an emission rate of 0.033 lb/MMBtu. Ultra-low NO_x burners are not available for this size heater (3 MMBtu/hr). REC is not proposing any throughput or hourly limitations on the proposed heater. The annual emissions will equate to 0.43 tons. REC is proposing to utilize low NO_x burners in the proposed heater with an emission rate of 0.033 lb/MMBtu of rated heat input which will satisfy the requirements of LAER/BACT/BAT.

Based on the 90% removal efficiency for SCR and the size of the heater, NO_x reduction equates to 0.39 tons. SCR is cost prohibitive for units of this size to control the minimal amount of NO_x. In addition, the RBLC reports no SCR being used to control NO_x emissions on heaters of this size. The Department agrees that the use of SCR is not warranted for the proposed heater.

SNCR injects ammonia into the exhaust stream; however, SNCR does not use a catalyst. The optimum temperature range for SNCR units is between 1,600 and 2,100 °F for the ammonia to react with the NO_x. This required temperature window is higher than the expected flue gas temperature range from the proposed heater of 800 to 1,000°F; therefore, REC concludes that SNCR is not technically feasible. The Department agrees with REC’s conclusion that using SNCR on the proposed heater is not considered technically feasible due to the temperature constraints.

Sources P101 and P102 – Combined Cycle Combustion Turbines

REC has evaluated control options to minimize NO_x emissions within the combustion zone of each CT, including fuel selection, water/steam injection, and dry low-NOx (DLN) combustors.

REC proposes to use natural gas, with its inherently low nitrogen content, as the primary fuel for the powerblocks to minimize NO_x emissions. However, REC is proposing utilize ULSD as fuel for each CT unit up to 720 hours of operation and a 40 hour limitation for SUSD for each unit in any 12 consecutive month period. This would be done in the event of a natural gas curtailment.

DLN combustors are designed to premix the air and fuel prior to entry into the combustion chamber. This promotes a lower flame temperature due to a homogenous mixture of the air/fuel and a lack of a flame front. The residence time in the combustion chamber is reduced with the use of DLN combustors, which limits the amount of oxygen in the air/fuel mixture to combine with nitrogen to form NO_x emission. REC is proposing to utilize DLN combustors to control the NO_x emission from each CT unit which will satisfy the requirements of LAER/BACT/BAT.

Water/steam injection reduces NO_x emissions by being injected into the combustor where it lowers the flame temperature. REC explains that water/steam injection is typically not used on natural-gas-fired turbines due to the low nitrogen content of natural gas and that dry low-NOx (DLN) combustors provide an equivalent or higher level of NOx control. DLN combustors are prominently used on natural-gas-fired turbines and are identified as NO_x control devices in the RBLC. However, REC is proposing to utilize water injection to control the NO_x emissions while firing ULSD. Water injection typically can reduce NO_x emissions while firing ULSD by 80 to 85%. REC has concluded that water/steam injection is technically feasible for ULSD firing only. REC concludes that water/steam injection is a feasible option in controlling NO_x emissions while firing ULSD only along with utilization of DLN combustors which satisfies the requirements of LAER/BACT/BAT.

REC evaluated several add-on control device/methods to control the NO_x emissions with those being XONON™, selective catalytic reduction (SCR), EM_x™, and selective non-catalytic reduction (SNCR).

XONON™ uses a catalyst to control NO_x which is typically utilized on smaller turbines but has not been demonstrated on powerblocks of this size. The RBLC does not identify XONON™ as a technology used on powerblocks close to the size of those proposed for this project. REC concluded that there is insufficient operating history for XONON™ on powerblocks of this size; therefore, XONON™ is considered technically infeasible. The Department is not aware of the use of XONON™ on powerblocks of the size proposed for this project. The Department agrees with REC's conclusion that using XONON™ on the proposed powerblocks is technically infeasible.

EM_x™ is a technology that uses only a catalyst to reduce NOx emissions. REC explains that EMx™ has not been used on powerblocks similarly sized as those proposed for this project. It only has been utilized on smaller sized CT (below 43 MW) and REC concludes that there is insufficient operating history for EMx™ on powerblocks of this size; therefore, EMx™ is considered technically infeasible. The RBLC does not identify EMx™ being used to control NO_x emissions from powerblocks of similar size to those proposed for this project. The Department is not aware of the use of EMx™ on powerblocks of the size proposed for this project. The Department agrees with REC's conclusion that using EMx™ on the proposed powerblocks is technically infeasible.

SNCR injects ammonia into the exhaust stream; however, SNCR does not use a catalyst. The optimum exhaust gas temperature range for SNCR units is between 1,600 and 2,100 °F for the ammonia to react with the NO_x. This required temperature window is higher than the expected temperature range from the powerblocks of 1,030 °F to 1,170 °F; therefore, REC concludes that SNCR is not technically feasible. The Department agrees with REC's conclusion that using SNCR on the proposed powerblocks is not considered technically feasible due to the temperature constraints.

SCR uses the injection of ammonia (NH_3) into the exhaust stream after which the exhaust stream then passes through a catalyst bed where a chemical reaction between the NO_x emissions and the ammonia form nitrogen (N_2) gas and water vapor. A typical control efficiency for a SCR unit is 90% or greater. The optimum exhaust gas temperature range for SCR units is between 500 to 1,000°F. A NH_3/NO_x molar ratio of 1.0 to 1.3 is typically used to maximize NO_x control and minimize ammonia slip. Ammonia slip occurs due to an incomplete reaction within the catalyst in which unreacted ammonia passes, or slips, into the exhaust stream. Ammonia emissions will be discussed further in this memo. SCR has been successfully demonstrated on powerblocks of similar size to those proposed for this project. To optimize the NO_x control and minimize ammonia slip, these systems employ a feedback control system where analyzers typically measure NO_x emissions in the exhaust stream and adjust the ammonia injection rate accordingly. The RBLC reports SCR being used to control NO_x emissions on powerblocks of close, but not identical, size and design to those proposed for this project. REC is proposing to utilize SCR to control NO_x emissions at an emission rate of 2 ppmdv @ 15% O_2 while firing natural gas and 4 ppmdv @ 15% O_2 while firing ULSD.

The PSEG Fossil, LLC, Panda Power, LLC and Hummel Station, LLC projects all utilized SCR to control NO_x emissions and established a NO_x emission limit of 2 ppmdv @ 15% O_2 applicable at all normal operating times while firing natural gas. In the RBLC, PSEG Fossil, LLC has the capability of firing on ULSD but has a NO_x emission rate of 4 ppmdv @ 15% O_2. This proposed emission rate satisfies the requirements of LAER/BACT/BAT.

REC concludes that using SCR and the NO_x emission limits monitored by a 1-hour CEMS represent LAER/BACT/BAT. The Department agrees with REC's conclusion that using SCR and the NO_x emission limits monitored by a 1-hour CEMS represent LAER/BACT/BAT. The ammonia alarms discussed above will be utilized to ensure efficient control of NO_x emissions. REC will monitor and record the pressure differential across the SCR catalyst and set alarms to indicate improper function.

The Department has determined that a NO_x emission limitation of 2.0 ppmdv @ 15% O_2 while firing natural gas and 4 ppmdv @ 15% O_2 while firing ULSD, coupled with 1-hour CEMS monitoring and recording, satisfies the requirements of LAER/BACT/BAT.

REC will be required to perform an initial EPA reference method test to demonstrate compliance with the NO_x emission limitations as specified above. Additionally, REC will be required record the fuel usage, heat input, hours of operation on a monthly basis, catalyst inlet and outlet temperatures and pressure differential on a continuous basis. REC will be required to submit these records to the Department on a quarterly basis.

In the application, REC provided information indicating that a cold start is defined as restart occurring after an extended shutdown (generally greater than 72 hours). A warm start is a restart occurring after a weekend shutdown (generally 8 to 72 hours). A hot start is a restart occurring after an overnight shutdown (generally less than 8 to 12 hours). REC will be required to keep records identifying each startup and shutdown, the type of startup (cold, warm, or hot), date, time, and the duration of each startup and shutdown.

REC proposes the following definitions: "Startup event" is the period of time of transient operation from initiation of combustion firing until the unit reaches steady state operation. "Shutdown event" is the period of time of transient operation from the initial lowering of CT output (below 50 percent operating load) until the point at which the combustion process has stopped. "Steady-state operation" is operation of the CT when the rate of change in load over time is essentially zero during periods when loads are above 50% firing rate. "Transient operation" is operation of the CT when the rate of change in load over time is less than or greater than zero. The definition of transient operation shall include, but is not limited to, startup and shutdown events, shifts between loads, and equipment cleaning. The Department agrees with the proposed definitions. Based on modeling performed by REC, the total combined hours of startups and shutdowns for each powerblock will be limited to 460 hours or less in any 12 consecutive month period while firing natural gas and 40 hours while firing ULSD.

Source P103 - Emergency Generator Engine

The analysis for the 2,206 bhp emergency generator engine compared the proposed emission rate limitations with those established in the Department's *General Plan Approval and General Operating Permit for Diesel or No. 2 fuel-fired Internal Combustion Engines* (GP-9), Subpart IIII of the federal NSPS, and for other similar emergency engines identified in the RBLC.

REC proposes a NO_x emission rate of 4.48 g/bhp-hr. GP-9 limits NO_x emissions to 6.9 g/bhp-hr and Subpart IIII (by reference to 40 CFR Part 89) limits NO_x+NHMC to 4.77 g/bhp-hr. The RBLC identifies NO_x emission limits ranging from 0.22 g/bhp-hr to 8.5 g/bhp-hr. REC proposes a NO_x emission limit of 4.48 g/bhp-hr and 5.45 tpy for the emergency generator engine. In light of the review done by the Department and the fact that the emergency generator engine will be restricted to operate not more than 500 hours per year, and will also be subject to a more restrictive 100 hours per year under Subpart IIII for non-emergency use, the Department agrees with REC's conclusion that the proposed emission limits and hours of operation limits satisfy the requirements of LAER/BACT/BAT.

Source P104 – Fire Pump Engine

The analysis for the 237 bhp fire pump engine was done by comparing the proposed emission rate limitations with those established in the Department's *General Plan Approval and General Operating Permit for Diesel or No. 2 fuel-fired Internal Combustion Engines* (GP-9), Subpart IIII of the federal NSPS, and for other similar emergency engines identified in the RBLC.

REC proposes a NO_x emission rate of 2.7 g/bhp-hr. Both GP-9 and Subpart IIII limit NO_x emissions to 6.9 g/bhp-hr. The RBLC identifies NO_x emission limits ranging from 0.22 g/bhp-hr to 8.5 g/bhp-hr. REC proposes that a NO_x emission limit of 2.7 g/bhp-hr and 0.18 tpy for the fire pump engine. Based on the review done by the Department and the fact that the fire pump engine will be restricted to operate not more than 250 hr/yr, the Department agrees with REC's conclusion that the proposed emission limits and hours of operation satisfy the requirements of LAER/BACT/BAT.

BACT/BAT Analysis for CO

The facility-wide potential CO emissions are greater than the pollutant specific PSD SER of 100 tpy. Therefore, the air-contaminant sources at the facility are subject to BACT of the PSD provisions in 40 CFR Section 52.21. Additionally, the air-contaminant sources are subject to the BAT provisions specified in 25 Pa. Code Sections 127.1 and 127.12.

CO emissions are a result of incomplete combustion of fuels caused by reduced combustion temperature and decreased residence time within the combustion zone. As part of the CO BACT and BAT review, REC investigated the use of combustion controls and add-on control devices to minimize CO emissions from the CTs. Combustion controls 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.

Source 031- Auxiliary Boilers

REC evaluated control options to minimize CO emissions from the proposed auxiliary boiler including fuel selection and add-on controls.

REC is proposing to utilize natural gas as fuel for the boiler to minimize the amount of CO emissions from the proposed source. As stated previously, REC is proposing to limit the total combined amount of natural gas fired in the boiler to not exceed 145,200 MMBtu in any 12 consecutive month period. REC is proposing the CO emission rate from either of the proposed boilers will not exceed 0.036 lb/MMBtu of rated heat input. The RBLC did identify oxidation catalyst as an add-on control at the IPL – Sutherland Generating Station in Marshalltown, Iowa with an emission rate of 0.0164 lb/MMBtu of rated heat input.

REC performed the technical feasibility analysis for add-on controls and determined that the use of an oxidation catalyst is technically feasible on this size boiler. However, REC performed an economic feasibility analysis and determined that, based on the amount of CO removed due to the limited amount of fuel fired in both boilers, that the installation of an oxidation catalyst is economically infeasible. Both boilers have the potential to emit 2.61 tons in any 12 consecutive month period and based on a 70% CO removal efficiency, the tons removed would equate to 1.83 tons. The cost per ton removed would equate to $5,686. The Department agrees with the REC conclusion that installation of an oxidation catalyst is economically infeasible for the proposed boilers.

REC is proposing a CO emission rate of 0.036 lb/MMBtu of rated heat input for each boiler which will satisfy the requirements of BACT and BAT.

Source 032 – Water Bath Heaters

REC evaluated control options to minimize CO emissions from the proposed water bath heater including fuel selection and add-on controls.

REC is proposing to utilize natural gas as fuel for each proposed heater with a CO emission rate of 0.037 lb/MMBtu. REC is not proposing any throughput or hourly limitations on each proposed heater. However as stated previously, REC will only operate no more than two (2) units at a time. The annual emissions will equate to 2.43 tons in any 12 consecutive month period. REC is proposing a CO emission rate of 0.037 lb/MMBtu of rated heat input which will satisfy the requirements of BACT and BAT.

REC evaluated add-on controls for each heater by using an oxidation catalyst. They stated that only good combustion practices were BACT and BAT for units of this size. The RBLC did not list any units of similar size with an oxidation catalyst, but only listed the implementation of good combustion practices as BACT and BAT. The Department agrees with REC that good combustion practices with a CO emission rate of 0.037 lb/MMBtu of rated heat input which will satisfy the requirements of BACT and BAT.

Source 033 – Dew Point Gas Heater

REC evaluated control options to minimize CO emissions from the proposed water bath heater including fuel selection and add-on controls.

REC is proposing to utilize natural gas as fuel for each proposed heater with a CO emission rate of 0.082 lb/MMBtu. REC is not proposing any throughput or hourly limitations on the proposed heater. The annual emissions will equate to 1.08 tons in any 12 consecutive month period. REC is proposing a CO emission rate of 0.082 lb/MMBtu of rated heat input which will satisfy the requirements of BACT and BAT for this size of combustion source.

REC evaluated add-on controls for each heater by using an oxidation catalyst. They stated that only good combustion practices were BACT and BAT for units of this size. The RBLC did not have any units of similar size with an oxidation catalyst, but it only listed implementation of good combustion practices as BACT and BAT. The Department agrees with REC that good combustion practices with a CO emission rate of 0.082 lb/MMBtu of rated heat input which will satisfy the requirements of BACT and BAT.

Sources P101 and P102 – Combined Cycle Combustion Turbines

REC evaluated control options to minimize CO emissions of each CT and DB, including fuel selection, combustion chamber design, EM_x™ and oxidation catalyst.

CO emissions are a result of incomplete combustion of fuels caused by reduced combustion temperature and decreased residence time within the combustion zone. As part of the CO BACT and BAT review, REC investigated the use of combustion controls and add-on control devices to minimize CO emissions from the CTs and DBs. Combustion controls 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.

REC provided the information that combustion controls – optimization of the combustion chamber designs and operations to improve the oxidation process and minimize incomplete combustion – have been successfully demonstrated to control CO emissions on CTs and DBs of identical size and configuration, thus representing BACT. The RBLC identifies combustion controls being used on numerous projects. The Department agrees that combustion controls can successfully control CO emissions on CTs and DBs of this size and configuration. Based on these facts, the Department agrees with REC's conclusion that combustion controls, which utilize lean combustion to produce a cooler flame temperature while still ensuring good air/fuel mixing with excess air to achieve complete combustion, are technically feasible and represent BACT and BAT.

EM_x™ uses a platinum-based catalyst coated with potassium carbonate to oxidize CO. The EMx™ is subject to reduced performance and deactivation due to exposure to sulfur oxides. The RBLC does not identify any CTs, of identical size and configuration as those proposed by REC, equipped with EMx™. Furthermore, the Department is unaware of any CTs and DBs identical to the size and configuration of those proposed by REC equipped with EMx™. Therefore, EMx™ is not technically feasible.

Oxidation catalysts oxidize CO in the exhaust stream by utilizing a precious metal catalyst. The oxidation catalysts require operating temperatures within the range of 700°F to 1,100°F to achieve maximum CO control efficiency. Typical pressure losses across the catalyst range from 0.7 to 1.0 inches of water. REC explains that oxidation catalysts are the most effective technology to control CO emissions on CTs and DBs of this size and configuration, thus representing BACT and BAT. The RBLC identifies oxidation catalysts being used on numerous projects similar to this project. Based on these facts, the Department agrees with REC's assessment that oxidation catalysts are technically feasible and represent BACT and BAT. Oxidation catalysts are also shown to be economically feasible on project of this type. REC will be required to monitor the pressure differential across the catalyst and inlet and outlet exhaust temperatures on a continuous basis. Additionally, REC will be required to operate and maintain the catalysts according to the manufacturer's specifications. REC will be required to set the alarms associated with the oxidation catalysts so that they are triggered at a point within the permit limits to prevent any exceedance.

The PSEG Fossil, LLC, Panda Power, LLC and Hummel Station projects all utilized oxidation catalyst to control CO emissions and they established a CO emission limit of 2 ppmdv @ 15% O_2 applicable at all normal operating times while firing natural gas. However, in the ESC Tioga, LLC plan approval the CO emission rates were established as 0.9 ppmdv @ 15% O_2 for the CT only and 1.5 ppmdv @ 15% O_2 for both the CT and DB. In the RBLC, PSEG Fossil, LLC, which has the capability of firing ULSD, established a CO emission rate of 2 ppmdv @ 15% O_2 without DBs.

In the December 30, 2019, submittal, REC proposed a CO emission limit of 2.0 ppmdv for both the CT and DB for each system, while firing on natural gas. The Department sent a technical deficiency letter to REC on May 8, 2020, stating that the proposed CO emission limit of 2.0 ppmdv @ 15% O_2 for both CT and DB while firing on natural gas did not satisfy the requirements of BACT and BAT. REC re-evaluated the CO emission limits and, in a response dated May 28, 2020, proposed a revised CO emission limits of 0.9 ppmdv @ 15% for the CT only and 1.5 ppmdv @ 15% O_2 for both the CT and DB while firing on natural gas. The Department has determined that a CO emission limitation of 0.9 ppmdv @ 15% for the CT only and 1.5 ppmdv @ 15% O_2 for both the CT and DB while firing on natural gas and 2.0 ppmdv @ 15% O_2 while firing on ULSD coupled with 1-hour CEMS monitoring satisfy BACT and BAT. REC concludes that using oxidation catalyst emission limits monitored by a 1-hour CEMS satisfies the requirements of both BACT and BAT and the Department agrees with REC's conclusion.

REC will be required to perform an initial EPA reference method test to demonstrate compliance with the CO emission limitations as specified above. Additionally, REC will be required record the fuel usage, heat input, hours of operation on a monthly basis, catalyst inlet and outlet temperatures and pressure differential on a continuous basis. REC will be required to submit these records to the Department on a quarterly basis.

Source P103 - Emergency Generator Engine

The analysis for the emergency generator engine compared the proposed emission rate limitations with those established in the Department's *General Plan Approval and General Operating Permit for Diesel or No. 2 fuel-fired Internal Combustion Engines* (GP-9), Subpart IIII of the federal NSPS, and for other similar emergency engines identified in the RBLC.

REC proposes a CO emission rate of 1.23 g/bhp-hr. GP-9 limits CO emissions to 2.0 g/bhp-hr and Subpart IIII limits CO to 2.61 g/bhp-hr. The RBLC identifies CO emission limits ranging from 0.22 g/bhp-hr to 8.5 g/bhp-hr. REC proposes a CO emissions limit of 1.23 g/bhp-hr and 1.50 tpy for the emergency generator engine. Based on the review done by the Department and the fact that the emergency generator engine will be restricted to operate not more than 500 hours per year, the Department agrees with REC's conclusion that the proposed emission limits and hours of operation satisfy the requirements of BACT and BAT.

Source P104 – Fire Pump Engine

The analysis for the fire pump engine compared the proposed emission rate limitations with those established in the Department's *General Plan Approval and General Operating Permit for Diesel or No. 2 fuel-fired Internal Combustion Engines* (GP-9), Subpart IIII of the federal NSPS, and for other similar emergency engines identified in the RBLC.

REC proposes a CO emission rate of 0.90 g/bhp-hr. GP-9 limits CO emissions to 2.0 g/bhp-hr and Subpart IIII limits CO to 2.61 g/bhp-hr. The RBLC identifies CO emission limits ranging from 0.22 g/bhp-hr to 8.5 g/bhp-hr. REC proposes a CO emissions limit of 0.90 g/bhp-hr and 0.06 tpy for the fire pump engine. Based on the review done by the Department and the fact that the fire pump engine will be restricted to operate not more than 250 hr/yr, the Department agrees with REC's conclusion that the proposed emission limits and hours of operation satisfy the requirements of BACT and BAT.

The CO emissions from both emergency engines (generator and fire pump) will be calculated based on actual fuel usage. Both engines will be equipped with non-resettable hour meters. REC will keep records of both fuel usage and hours of operation. The Department is not requiring testing to demonstrate compliance with the emission limitations for either of the emergency engines due to the annual hourly limitation. REC will be required to provide the Department with the records and emissions calculations (including supporting documentation) demonstrating compliance with the emission limitations on a quarterly basis. REC has proposed that the duration of each readiness test of the emergency engines shall not exceed 30 minutes, to not conduct readiness testing simultaneously within the same hour, and to not conduct readiness testing during startup or shutdown of the powerblocks.

BAT Analysis for SO2 and H2SO4

The proposed facility-wide SO_2 emissions are not subject to BACT because they are less than the PSD significant emission rate of 40 tons per year. The proposed facility-wide H_2SO_4 emissions are not subject to BACT because they are less than the PSD significant emission rate of 7 tpy. Therefore, the SO_2 and H_2SO_4 emissions from the air-contaminant sources are subject to the BAT provisions specified in 25 Pa. Code Sections 127.1 and 127.12.

Source 031- Auxiliary Boiler

REC is proposing to utilize natural gas as fuel for the boiler in order to minimize the amount of SO_2 emissions from the proposed source. As stated previously, REC is proposing to limit the amount of natural gas fired in each boiler to not exceed 145,200 MMBtu in any 12 consecutive month period and the sulfur content not to exceed 0.4 grains per 100scf. Based on the sulfur content limitation, REC is proposing the SO_2 emission rate from the proposed boiler will not exceed 0.0012 lb/MMBtu of rated heat input. The annual SO_2 emissions from each boiler would equate to 0.09 tons in any 12 consecutive month period. REC researched the RBLC to find out if there are any add-on controls for boilers of this size for SO_2 emissions and determined that there were no add-on controls for SO_2 emissions, but that low sulfur content fuel was the primary method for controlling the SO_2 emissions. The Department agrees with REC's determination that a fuel with low sulfur content should be utilized to control SO_2 emissions from the proposed source.

REC is proposing a SO_2 emission rate of 0.0012 lb/MMBtu of rated heat input which satisfies the requirements of BAT.

Sulfuric Acid (H_2SO_4) emissions are formed when SO_3 emissions combine with water vapor at a point beyond the combustion zone of the boiler. Because REC is utilizing natural gas as fuel with an inherent low sulfur content, REC is proposing that the H_2SO_4 emission rate will be 0.000092 lb/MMBtu of heat input. Based on the fuel limitation above, the potential to emit a total combined 13 pounds in any 12 consecutive month period. REC researched the RBLC to find out if there are any add-on controls for boilers of this size for H_2SO_4 emissions and determined that there were no add-on controls for H_2SO_4 emissions, but that low sulfur content fuel was the primary method for controlling the H_2SO_4 emissions. The Department agrees that selection of natural as fuel and limiting the amount of fuel to be fired in each boiler satisfies the requirements of BAT.

Source 032 – Water Bath Heaters

REC is proposing to utilize natural gas as fuel for each heater to minimize the amount of SO_2 emissions from the proposed sources. As stated previously, REC is proposing to operate only one unit at a time and the sulfur content not to exceed 0.4 grains per 100scf. Based on the sulfur content limitation, REC is proposing the SO_2 emission rate from each heater will not exceed 0.0012 lb/MMBtu of rated heat input. The annual SO_2 emissions from each heater would equate to 0.08 tons in any 12 consecutive month period. REC researched the RBLC to determine if there are any add-on controls for heaters of this size for SO_2 emissions and concluded that there were no add-on controls for SO_2 emissions, but that low sulfur content fuel was the primary method for controlling the SO_2 emissions. The Department agrees with REC's determination that a fuel with low sulfur content should be utilized to control SO_2 emissions from the proposed sources.

REC is proposing a SO_2 emission rate of 0.0012 lb/MMBtu of rated heat input which satisfies the requirements of BAT.

REC is proposing that the H_2SO_4 emission rate will be 0.001 lb/MMBtu of heat input. Based on the fuel limitation above, each boiler will have the potential to emit less than 131 pounds (0.065 tons) in any 12 consecutive month period. REC researched the RBLC to find out if there are any add-on controls for heaters of this size for H_2SO_4 emissions and determined that there were no add-on controls for H_2SO_4 emissions, but that low sulfur content fuel was the primary method for controlling the H_2SO_4 emissions. The Department agrees that selection of natural as fuel and limiting the amount of fuel to be fired in each heater satisfies the requirements of BAT.

Source 033 – Dew Point Gas Heater

REC is proposing to utilize natural gas as fuel for the heater to minimize the amount of SO_2 emissions from the proposed source. As stated previously, REC is proposing to utilize natural gas with a sulfur content not to exceed 0.4 grains per 100scf. Based on the sulfur content limitation, REC is proposing the SO_2 emission rate from each heater will not exceed 0.0012 lb/MMBtu of rated heat input. The annual SO_2 emissions from each heater would equate to 31 pounds in any 12 consecutive month period. REC researched the RBLC to find out if there are any add-on controls for heaters of this size for SO_2 emissions and determined that there were no add-on controls for SO_2 emissions, but that low sulfur content fuel was the primary method for controlling the SO_2 emissions. The Department agrees with REC's determination that a fuel with low sulfur content should be utilized to control SO_2 emissions from the proposed sources.

REC is proposing a SO_2 emission rate of 0.0012 lb/MMBtu of rated heat input which satisfies the requirements of BAT.

REC is proposing that the H_2SO_4 emission rate will be 0.001 lb/MMBtu of heat input. Based on the fuel limitation above, each boiler will have the potential to emit less than 26 pounds (0.01 tons) in any 12 consecutive month period. REC researched the RBLC to find out if there are any add-on controls for heaters of this size for H_2SO_4 emissions and determined that there were no add-on controls for H_2SO_4 emissions, but that low sulfur content fuel was the primary method for controlling the H_2SO_4 emissions. The Department agrees that selection of natural as fuel and limiting the amount of fuel to be fired in each heater satisfies the requirements of BAT.

Sources P101 and P102 – Combined Cycle Combustion Turbines

REC investigated the two methods of minimizing SO_2 and H_2SO_4 emissions including the use of fuels with low sulfur content and add-on control devices known as flue gas desulfurization (FGD) systems. SO_2 emissions occur as a result of combusting fuels which contain sulfur. SO_2 generally remains in the gaseous phase; however, a small portion may be oxidized to SO_3. The SO_3 can combine with water vapor to form H_2SO_4.

The typical sulfur content of pipeline quality natural gas is approximately 2.0 grains per 100 scf. REC is proposing to use natural gas with a sulfur content not to exceed 0.4 grains per 100 scf. REC and the fuel supplier will enter into a contract stipulating that the sulfur content of the fuel will not exceed 0.4 gr/100 scf. The fuel supplier will sample the fuel and provide certifications to REC demonstrating compliance with this sulfur content requirement. REC will be required to obtain such reports and keep them for at least five years and provide them to the Department upon request. Based on a natural gas sulfur content of 0.4 gr/100 scf, the potential SO_2 emission rate as proposed by REC will be 0.0012 lb/MMBtu assuming that all of the sulfur will convert to SO_2. This would equate to 5.43 lb/hr based on the 4,529 MMBtu/hr rated heat input for the CT and DB combined and the annual emission would equate to 20.47 tons based on 7,540 hours of operation for each unit.

REC is proposing a SO_x emissions rate of 0.0018 lb/MMBtu of rated heat input while firing ULSD based on a sulfur content of 15 ppm maximum. This would equate to 7.09 lb/hr based on the 3,940 MMBtu/hr rated heat input and the annual emissions would equate to 2.55 tons based on 720 hours of operation. Total annual SO_x emissions from each CT and DB would equate to 26.74 tons in any 12 consecutive month period based on 720 hours of operation while firing ULSD with the remainder of the hours firing natural gas along with SUSD emissions.

REC evaluated several add-on control devices/methods to control the SO_x emissions which included dry sorbent injection, wet scrubbing systems, spray dryer adsorbers and selective non-catalytic reduction (SNCR). REC concluded that there is no known operating history for these types of control devices identified in the RBLC and that it would be cost prohibitive to install an add-on control due to the low emissions rates. REC proposes that the sulfur content of each fuel utilized would satisfy the requirements of BAT. After researching the RBLC, there are no known add-on control devices for SO_x emissions for these systems that would be economically feasible.

The total annual H_2SO_4 emissions from each CT equate to 17.70 tons while firing natural gas and 1.71 tons while firing ULSD. The RBLC search results for controlling H_2SO_4 emissions indicate the use of natural gas and ULSD with low sulfur content as the control description.

The Department agrees with REC’s conclusion that limiting the sulfur content to 0.4 grains/100 scf for natural gas and 15 ppm for ULSD will satisfy the requirements of BAT for SO_x emissions.

The Department has determined that a SO_x emission limitation of 0.0012 lb/MMBtu while firing natural gas and 0.0018 lb/MMBtu while firing ULSD satisfies BAT.

The Department recommends EPA reference method testing be used to demonstrate compliance with the SO_2 and H_2SO_4 emission limitations. The SO_2 and H_2SO_4 emissions will be calculated based on actual fuel usage, heat input, and sulfur content. REC will keep records of fuel usage, heat input, sulfur content, emissions calculations (including supporting documentation), and hours of operation for at least five years and provide them to the Department on a quarterly basis.

Source P103 - Emergency Generator Engine

The analysis for the emergency generator engine compared the proposed emission rate limitations with those established in the Department's *General Plan Approval and General Operating Permit for Diesel or No. 2 fuel-fired Internal Combustion Engines* (GP-9), Subpart IIII of the federal NSPS, and for other similar emergency engines identified in the RBLC.

REC proposes a SO_x emission rate of 0.022 lb/hr based on the 15 ppm sulfur content limitation of the ULSD and the engine fuel consumption rate. GP-9 limits the sulfur content of diesel fuel not to exceed 0.3%, by weight, which equates to 300 ppm. By utilizing the ULSD, REC is proposing a much lower sulfur content than that of the GP-9 limit. Subpart IIII does not limit SO_x emissions but does limit the sulfur content of the fuel pursuant to 40 CFR Section 80.510(b), which limits the sulfur content to 15 ppm maximum. REC will be compliant with this requirement. REC is proposing to limit the maximum hours of operation to not exceed 500 hours in any 12 consecutive month period. The annual SO_x emissions would equate to 11 pounds in any 12 consecutive month period. The RBLC did not identify controls for SO_x emissions from emergency engines. Based on the review done by the Department and the fact that the emergency generator engine will be restricted to operate not more than 500 hr/yr, the Department agrees with REC's conclusion that the proposed emission limits, sulfur content and hours of operation satisfy the requirements of BAT.

Source P104 – Fire Pump Engine

REC proposes a SO_x emission rate of 0.003 lb/hr based on the 15 ppm sulfur content limitation of the ULSD and the fuel consumption rate of the engine. GP-9 limits the sulfur content of diesel fuel not to exceed 0.3%, by weight, which equates to 300 ppm. By utilizing the ULSD, REC is proposing a much lower sulfur content than that of the GP-9 limit. Subpart IIII does not limit SO_x emissions but does limit the sulfur content of the fuel pursuant to 40 CFR Section 80.510(b), which limits the sulfur content to 15 ppm maximum. REC will be compliant with this requirement. REC is proposing to limit the maximum hours of operation to not exceed 250 hours in any 12 consecutive month period. The annual SO_x emissions would equate to less than 1 pound in any 12 consecutive month period. The RBLC did not identify controls for SO_x emissions from emergency engines. Based on the review done by the Department and the fact that the fire pump engine will be restricted to operate not more than 250 hr/yr, the Department agrees with REC's conclusion that the proposed emission limits, sulfur content and hours of operation satisfy the requirements of BAT.

BACT/BAT Analysis for $PM/PM_{10}/PM_{2.5}$ (including condensable PM)

The facility-wide potential $PM/PM_{10}/PM_{2.5}$ (including condensable PM) emissions are greater than the pollutant specific PSD PM_{10} significant emission rate of 15 tpy and $PM_{2.5}$ significant emission rate of 10 tpy. Therefore, the air-contaminant sources at the facility are subject to the BACT of the PSD provisions in 40 CFR Section 52.21. Additionally, the air-contaminant sources are subject to the BAT provisions specified in 25 Pa. Code Sections 127.1 and 127.12.

Total PM ($PM/PM_{10}/PM_{2.5}$ including condensable PM) emissions are a result of noncombustible trace constituents in the fuel, unburned hydrocarbons that agglomerate to form particles, and the inlet air supply that is mixed with the fuel prior to combustion which contains dust particles. PM emissions can also result from the formation of ammonium salts (sulfates and nitrates) due to the conversion of SO_2 to SO_3, which then may react with ammonia to form ammonium sulfate and NO_x, which may also react with ammonia to form ammonium nitrate salts. Ammonium salts are very fine particulate, typically in the sub-micron size range. Condensable organics may also be measured as particulate since both filterable and condensable fractions are captured in the stack testing. REC proposes that all of the particulate matter emitted from the CTs is conservatively assumed to be less than 2.5 microns in diameter (i.e. $PM=PM_{10}=PM_{2.5}$).

Source 031- Auxiliary Boilers

REC is proposing to utilize natural gas as fuel for each 66 MMBtu/hr boiler along with good combustion practices to minimize the amount of $PM/PM_{10}/PM_{2.5}$ emissions from the proposed boilers. As stated previously, REC is proposing to limit the amount of natural gas fired in each boiler to not exceed 145,200 MMBtu in any 12 consecutive month period. REC is proposing the $PM/PM_{10}/PM_{2.5}$ emission rate from the proposed boiler will not exceed 0.0019 lb/MMBtu of rated heat input. The annual $PM/PM_{10}/PM_{2.5}$ emissions from each boiler would equate to 276 pounds (0.14 tons). REC researched the RBLC to find out if there are any add-on controls for boilers of this size for $PM/PM_{10}/PM_{2.5}$ emissions and determined that there were no add-on controls for $PM/PM_{10}/PM_{2.5}$ emissions. The low emissions generally do not warrant control due to utilizing natural gas as fuel for each boiler. The Department agrees with REC's determination of using natural gas and good combustion practices to control $PM/PM_{10}/PM_{2.5}$ emissions from the proposed source.

REC is proposing a $PM/PM_{10}/PM_{2.5}$ emission rate of 0.0019 lb/MMBtu of rated heat input which satisfies the requirements of BACT and BAT.

Source 032 – Water Bath Heaters

REC is proposing to utilize natural gas as fuel for each 15 MMBtu/hr heater along with good combustion practices to minimize the amount of $PM/PM_{10}/PM_{2.5}$ emissions from the proposed heaters. As stated previously, REC is proposing to operate no more than two (2) units at a time. REC is proposing the $PM/PM_{10}/PM_{2.5}$ emission rate from each proposed boiler will not exceed 0.0019 lb/MMBtu of rated heat input. The annual $PM/PM_{10}/PM_{2.5}$ emissions from each boiler would equate to 249 pounds (0.12 tons). REC researched the RBLC to find out if there are any add-on controls for heaters of this size for $PM/PM_{10}/PM_{2.5}$ emissions and determined that there were no add-on controls for $PM/PM_{10}/PM_{2.5}$ emissions. The low emissions generally do not warrant control due to utilizing natural gas as fuel for each heater. The Department agrees with REC's determination of using natural gas and good combustion practices to control $PM/PM_{10}/PM_{2.5}$ emissions from the proposed source.

REC is proposing a $PM/PM_{10}/PM_{2.5}$ emission rate of 0.0019 lb/MMBtu of rated heat input which satisfies the requirements of BACT and BAT.

Source 033 – Dew Point Gas Heater

REC is proposing to utilize natural gas as fuel for the 3 MMBtu/hr heater along with good combustion practices to minimize the amount of $PM/PM_{10}/PM_{2.5}$ emissions from the proposed heater. REC is proposing the $PM/PM_{10}/PM_{2.5}$ emission rate from the proposed boiler will not exceed 1.9 lb/MMscf of fuel or 0.0018 lb/MMBtu of rated heat input. The annual $PM/PM_{10}/PM_{2.5}$ emissions from the boiler would equate to 48 pounds (0.02 tons). REC researched the RBLC to find out if there are any add-on controls for heaters of this size for $PM/PM_{10}/PM_{2.5}$ emissions and determined that there were no add-on controls for $PM/PM_{10}/PM_{2.5}$ emissions. The low emissions generally do not warrant control due to utilizing natural gas as fuel for each heater. The Department agrees with REC's determination of using natural gas and good combustion practices to control $PM/PM_{10}/PM_{2.5}$ emissions from the proposed source.

REC is proposing a $PM/PM_{10}/PM_{2.5}$ emission rate of 0.0018 lb/MMBtu of rated heat input which satisfies the requirements of BACT and BAT.

Sources P101 and P102 – Combined Cycle Combustion Turbines

As part of the total PM BACT and BAT review, REC investigated the use of combustion controls, fuels with little or no ash and sulfur, and high-efficiency CT air inlet filters to minimize total $PM/PM_{10}/PM_{2.5}$ emissions from the CTs. REC explains that electrostatic precipitators (ESPs) and baghouses have never been used on CTs, thus making their use considered technically infeasible. REC concludes that the use of fuel with little or no ash and sulfur and high-efficiency CT air inlet filters represent BACT/BAT. Review of the RBLC reveals that using natural gas with a low sulfur content is the dominant control type for PM for these types of operations. The Department is not aware of the use of ESPs or baghouses on CTs of the size proposed for this project. The Department agrees with REC's assessment that using ESPs or baghouses on the proposed CTs are not considered technically feasible.

REC proposes a total PM emission rate of 0.0050 lb/MMBtu (22.50 lb/hr) while firing natural gas and 0.013 lb/MMBtu (51.2 lb/hr) while firing ULSD. The maximum potential $PM/PM_{10}/PM_{2.5}$ emissions would equate to 110.84 tons in any 12 consecutive month period for each CT and DB unit including SUSD emissions.

These proposed limits are based on fuel sulfur content, and SO_3 formation and conversion to ammonium sulfates and nitrates, with addition of organic condensables. As discussed above in the BAT for SO_2 and H_2SO_4 analysis, the low sulfur content satisfies the requirements of BAT in the formation of condensables.

Both Moxie (Panda) projects both established $PM/PM_{10}/PM_{2.5}$ emission limits at 0.0057 lb/MMBtu while firing natural gas. As for PSEG Fossil, LLC Sewaren, that project established the $PM/PM_{10}/PM_{2.5}$ emissions at 14.4 lb/hr without DBs while firing natural gas and 60.6 lb/hr while firing ULSD. The proposed $PM/PM_{10}/PM_{2.5}$ emissions from REC will satisfy the requirements of BACT and BAT.

An opacity limitation of 10% for any 3-minute block average for normal operation and an opacity limitation of 10% for any 6-minute block average for startups/shutdowns will be incorporated to satisfy BACT and BAT.

REC will be required to monitor and record the pressure differential across the inlet air filters as well as operate and maintain them according to the manufacturer's specifications.

The Department has concluded that the proposed total PM emission limit 0.0050 lb/MMBtu while firing on natural gas and 0.013 lb/MMBtu while firing on ULSD along with the use of ultra-low sulfur fuel and high-efficiency inlet air filters satisfy BACT and BAT.

The total PM emissions will be calculated based on actual fuel usage, heat input, and sulfur content. REC will keep records of fuel usage, heat input, sulfur content, emission calculations (including supporting documentations), and hours of operation for at least five years and provide them to the Department on a quarterly basis.

Source P103 – Emergency Generator Engine

The analysis for the emergency generator engine compared the proposed emission rate limitations with those established in the *General Plan Approval and General Operating Permit for Diesel or No. 2 fuel-fired Internal Combustion Engines* (GP-9), Subpart IIII of the federal NSPS, and for other similar emergency engines identified in the RBLC.

REC proposed a $PM/PM_{10}/PM_{2.5}$ emission rate limitation of 0.13 g/bhp-hr. GP-9 limits PM to 0.4 g/bhp-hr and Subpart IIII limits PM to 0.15 g/bhp-hr. The RBLC identifies PM limits ranging from 0.07 g/bhp-hr to 0.35 g/bhp-hr. REC proposes to limit the operation of the engine to not exceed 500 hours in any 12 consecutive month period, which would equate to an annual emission of 0.16 tons. Based on the review done by the Department, and the fact that the emergency generator engine will be restricted to operate not more than 500 hours in any 12 consecutive month period, this proposed rate satisfies the requirements of BACT and BAT.

The $PM/PM_{10}/PM_{2.5}$ emissions will be calculated based on actual fuel usage and the engine will be equipped with non-resettable hour meter. REC will keep records of fuel usage, fuel composition, emissions calculations (including supporting documentation), and hours of operation. REC will be required to provide the Department with the certifications and calculations, including supporting documentation, demonstrating compliance with the emission limitations on a quarterly basis.

Source P104 – Fire Pump Engine

The analysis for the fire pump engine compared the proposed emission rate limitations with those established in the *General Plan Approval and General Operating Permit for Diesel or No. 2 fuel-fired Internal Combustion Engines* (GP-9), Subpart IIII of the federal NSPS, and for other similar emergency engines identified in the RBLC.

REC proposes a $PM/PM_{10}/PM_{2.5}$ emission rate limitation of 0.10 g/bhp-hr. GP-9 limits PM to 0.4 g/bhp-hr and Subpart IIII limits PM to 0.15 g/bhp-hr. The RBLC identifies PM limits ranging from 0.07 g/bhp-hr to 0.35 g/bhp-hr. REC proposes to limit the operation of the engine to not exceed 250 hours in any 12 consecutive month period, which would equate to an annual emission of 0.01 ton. Based on the review done by the Department, and the fact that the fire pump engine will be restricted to operate not more than 250 hours in any 12 consecutive month period, the requirements of BACT and BAT are satisfied.

The PM/PM_{10}/$PM_{2.5}$ emissions will be calculated based on actual fuel usage and the engine will be equipped with a non-resettable hour meter. REC will keep records of fuel usage, fuel composition, emissions calculations (including supporting documentation), and hours of operation. REC will be required to provide the Department with the certifications and calculations, including supporting documentation, demonstrating compliance with the emission limitations on a quarterly basis.

LAER/BACT/BAT Analysis for VOC

The facility-wide potential VOC emissions are greater than the pollutant specific PSD and NNSR VOC emission threshold of 50 tpy. Therefore, the air-contaminant sources at the facility are subject to LAER of the NNSR provisions in 25 Pa. Code Sections 127.201 through 127.217 and BACT of the PSD provisions in 40 CFR Section 52.21. Additionally, the air-contaminant sources are subject to the BAT provisions specified in 25 Pa. Code Sections 127.1 and 127.12.

Source 031- Auxiliary Boilers

REC is proposing to utilize natural gas as fuel for each boiler along with good combustion practices to minimize the amount of VOC emissions from the proposed boilers. As stated previously, REC is proposing to limit the amount of natural gas fired in each boiler to not exceed 145,200 MMBtu in any 12 consecutive month period. REC is proposing the VOC emission rate from the proposed boiler will not exceed 0.002 lb/MMBtu of rated heat input. The annual VOC emissions from each boiler would equate to 0.15 tons. REC researched the RBLC to find out if there are any add-on controls for boilers of this size for VOC emissions and determined that there were no add-on controls to control VOC emissions. The low emissions generally do not warrant control due to utilizing natural gas as fuel for each boiler. In addition, REC stated that an oxidation catalyst, like the one analyzed in the previous CO analysis, would control VOC emissions. However, due to low VOC emissions, the control device economic feasibility dollar/ton removal would be even higher than that for CO emissions where that was determined to be economically infeasible. The Department agrees with REC’s determination that using natural gas, good combustion practices and limiting the amount of fuel fired to control VOC emissions from the proposed sources satisfies the requirements of LAER/BACT/BAT.

REC is proposing a VOC emission rate of 0.002 lb/MMBtu of rated heat input which satisfies the requirements of LAER/BACT/BAT.

Source 032 – Water Bath Heaters

REC is proposing to utilize natural gas as fuel for each heater along with good combustion practices to minimize the amount of VOC emissions from the proposed heaters. As stated previously, REC is proposing to operate no more than two (2) heaters at a time. REC is proposing the VOC emission rate from each proposed heater will not exceed 0.005 lb/MMBtu of rated heat input. The annual VOC emissions from each heater would equate to 657 pounds (0.33 tons). REC researched the RBLC to find out if there are any add-on controls for heaters of this size to control VOC emissions and determined that there were no add-on controls for VOC emissions. The low emissions generally do not warrant control due to utilizing natural gas as fuel for each heater. The Department agrees with REC's determination that using natural gas along with good combustion practices to control VOC emissions from the proposed source satisfies the requirements of LAER/BACT/BAT.

REC is proposing a VOC emission rate of 0.005 lb/MMBtu of rated heat input which satisfies the requirements of LAER/BACT/BAT.

Source 033 – Dew Point Gas Heater

REC is proposing to utilize natural gas as fuel for the heater along with good combustion practices to minimize the amount of VOC emissions from the proposed heater. REC is proposing the VOC emission rate from the proposed boiler will not exceed 5.5 lb/MMscf of fuel or 0.005 lb/MMBtu of rated heat input. The annual VOC from the heater would equate to 131 pounds (0.07 tons). REC researched the RBLC to find out if there are any add-on controls for heaters of this size to control VOC emissions and determined that there were no add-on controls for VOC emissions. The low emissions generally do not warrant control due to utilizing natural gas as fuel for each heater. The Department agrees with REC's determination that using natural gas along with good combustion practices to control VOC emissions from the proposed source satisfies the requirements of LAER/BACT/BAT.

REC is proposing a VOC emission rate of 0.005 lb/MMBtu of rated heat input which satisfies the requirements of LAER/BACT/BAT.

Sources P101 and P102 – Combined Cycle Combustion Turbines

VOC emissions are a result of incomplete combustion of fuels caused by reduced combustion temperature and decreased residence time within the combustion zone. As part of the VOC LAER/BACT/BAT review, REC investigated the use of combustion controls and add-on control devices to minimize VOC emissions from the CTs. Combustion controls 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. The add-on control devices in REC's review include EM_x™ and oxidation catalysts.

Combustion controls, EM_x™ and oxidation catalysts were analyzed in the BACT/BAT analysis for CO above and determined to not be technically feasible. This determination now applies to LAER too.

In the December 30, 2019, submittal, REC proposed a VOC emission limit of 1.0 ppmdv for both the CT and DB for each system, while firing on natural gas and 2.0 ppmdv @ 15% O_2 while firing on ULSD. The Department sent a technical deficiency letter to REC on May 8, 2020, stating that the proposed VOC emission limit of 1.0 ppmdv @ 15% O_2 for both CT and DB while firing on natural gas did not satisfy the requirements of LAER, BACT and BAT. REC re-evaluated the VOC emission limits. In a response dated May 28, 2020, REC proposed a revised

VOC emission limits of 0.7 ppmdv @ 15% for the CT only and 1.6 ppmdv @ 15% O_2 for both the CT and DB while firing on natural gas. The Department has determined that a VOC emission limitation of 0.7 ppmdv @ 15% for the CT only and 1.6 ppmdv @ 15% O_2 for both the CT and DB while firing on natural gas and 2.0 ppmdv @ 15% O_2 while firing on ULSD coupled with 1-hour CEMS monitoring satisfy LAER, BACT and BAT. REC concludes that using oxidation catalyst emission limits monitored by a 1-hour CEMS satisfies the requirements of both BACT and BAT and the Department agrees with REC's conclusion.

The Department has determined that a VOC emission limitation of 0.7 ppmdv @ 15% for the CT only and 1.6 ppmdv @ 15% O_2 for both the CT and DB while firing on natural gas and 2.0 ppmdv @ 15% O_2 while firing on ULSD satisfies the requirements of LAER/BACT/BAT.

REC will be required to perform EPA reference method testing to demonstrate compliance with the total VOC emission limitations.

Source P103 – Emergency Generator Engine

The analysis for the emergency generator engine compared the proposed emission rate limitations with those established in the *General Plan Approval and General Operating Permit for Diesel or No. 2 fuel-fired Internal Combustion Engines* (GP-9), Subpart IIII of the federal NSPS, and for other similar emergency engines identified in the RBLC.

REC proposes a VOC emission rate limitation of 0.80 g/bhp-hr. Both GP-9 and Subpart IIII limit VOC emissions to 1.0 g/bhp-hr. The RBLC identifies VOC limits ranging from 0.07 g/bhp-hr to 0.35 g/bhp-hr. REC proposes to limit the hours of operation to not exceed 500 hours in any 12 consecutive month period, which would equate to an annual emission of 0.97 tons. Based on the review done by the Department and the fact that the emergency generator engine will be restricted to operate not more than 500 hours in any 12 consecutive month period, the requirements of LAER/BACT/BAT are satisfied.

The VOC emissions will be calculated based on actual fuel usage and the engine will be equipped with non-resettable hour meter. REC will keep records of fuel usage, fuel composition, emissions calculations (including supporting documentation), and hours of operation. REC will be required to provide the Department with the certifications and calculations, including supporting documentation, demonstrating compliance with the emission limitations on a quarterly basis.

Source P104 – Fire Pump Engine

The analysis for the fire pump engine compared the proposed emission rate limitations with those established in the *General Plan Approval and General Operating Permit for Diesel or No. 2 fuel-fired Internal Combustion Engines* (GP-9), Subpart IIII of the federal NSPS, and for other similar emergency engines identified in the RBLC.

REC proposes a VOC emission rate limitation of 0.10 g/bhp-hr. Both GP-9 and Subpart IIII limits VOC emissions to 1.0 g/bhp-hr. The RBLC identifies VOC limits ranging from 0.07 g/bhp-hr to 0.35 g/bhp-hr. REC proposes to limit the hours of operation to not exceed 250 hours in any 12 consecutive month period, which would equate to an annual emission of 0.01 ton. Based on the review done by the Department and the fact that the fire pump engine will be restricted to operate not more than 250 hours in any 12 consecutive month period, the requirements of LAER/BACT/BAT are satisfied.

The VOC emissions will be calculated based on actual fuel usage and the engine will be equipped with non-resettable hour meter. REC will keep records of fuel usage, fuel composition, emissions calculations (including supporting documentation), and hours of operation. REC will be required to provide the Department with the certifications and calculations, including supporting documentation, demonstrating compliance with the emission limitations on a quarterly basis.

Source P105 – Storage Tanks

The storage tanks included in Source P105 are one (1) 3,500,000-gallon ULSD storage tank, two (2) 20,000-gallon lube oil storage tanks and two (2) 26,000-gallon aqueous ammonia storage tanks. Ammonia is not considered as a VOC, but the emissions will be analyzed in detail below in this review memo. REC is proposing to install a floating roof in the ULSD tank to minimize evaporation loss in the tank. As stated previously, ULSD and lube oil have a vapor pressure of less than 1.5 psia. REC performed emission calculations for the filling, draining and breathing losses for each tank through the EPA Tanks 4.09d program. The ULSD tank equated to 84.5 pounds (0.04 tons) of VOC emissions based on 10 turnovers while firing the CTs on ULSD for 720 hours. The two (2) lube oil tanks have the potential to emit less than 0.01 tons in any 12 consecutive month period. REC proposes a combined total annual VOC emission limit of 0.04 tpy from the lube oil tanks and diesel tanks. This was calculated using the TANKS 4.0.9d program. The Department considers this quantity of emissions to be insignificant; therefore, the Department concludes that this emission limitation satisfies the requirements of LAER/BACT/BAT. REC will be required to keep records of the materials stored in these tanks and the emissions calculations, including supporting documentation, to demonstrate compliance with the emissions limitation for at least five years and made available to the Department. These records will be submitted to the Department on a quarterly basis.

BAT Analysis for Hazardous Air Pollutants (HAPs)

The air-contaminant sources are subject to the BAT provisions specified in 25 Pa. Code Sections 127.1 and 127.12. The NESHAP analyses are discussed previously in the NESHAP Regulations (40 CFR Part 63) section.

Source 031- Auxiliary Boilers

REC is proposing to utilize natural gas as fuel along with good combustion practices for each boiler, to minimize the amount of HAP emissions from the proposed boilers. As stated above, REC is proposing to limit the amount of natural gas fired in each boiler to not exceed 145,200 MMBtu in any 12 consecutive month period. REC determined that hexane is the most abundant HAP from the combustion of natural gas. The hexane emission rate from the proposed boiler will not exceed 0.0017 lb/MMBtu of rated heat input. The annual hexane emissions from each boiler would equate to 247 pounds (0.12 tons). The low emissions generally do not warrant control due to utilizing natural gas as fuel for each boiler. In addition, REC stated that an oxidation catalyst, like the one analyzed in the CO and VOC analysis above, would control VOC/HAP emissions. The Department agrees with REC's determination that using natural gas, good combustion practices and limiting the amount of fuel fired to control HAP emissions from the proposed sources meets BAT.

I do not recommend establishing a HAP emission limitation for the boilers because controlling VOC emissions will ensure controlling HAP emissions.

Source 032 – Water Bath Heaters

REC is proposing to utilize natural gas as fuel along with good combustion practices for the heaters, to minimize the amount of HAP emissions from the proposed boilers. REC has calculated that hexane is the most abundant HAP from the combustion of natural gas. The hexane emission rate from the proposed heater will not exceed 0.0017 lb/MMBtu of rated heat input. The annual hexane emissions from each heater would equate to 223 pounds (0.11 tons). The low emissions generally do not warrant control due to utilizing natural gas as fuel for each heater. In addition, REC stated that an oxidation catalyst, like the one analyzed in the CO and VOC analysis above, would control VOC/HAP emissions. The Department agrees with REC's determination that using natural gas, good combustion practices and limiting the amount of fuel fired to control HAP emissions from the proposed sources meets BAT.

I do not recommend establishing a HAP emission limitation for the heaters because controlling VOC emission will ensure controlling HAP emissions.

Source 033 – Dew Point Gas Heater

REC is proposing to utilize natural gas as fuel along with good combustion practices for the heater, to minimize the amount of HAP emissions from the proposed heater. REC has calculated that hexane is the most abundant HAP from the combustion of natural gas. The hexane emission rate from the proposed heater will not exceed 0.0017 lb/MMBtu of rated heat input. The annual hexane emissions from each boiler would equate to 45 pounds (0.02 tons). The low emissions generally do not warrant control due to utilizing natural gas as fuel for the heater. In addition, REC stated that an oxidation catalyst, like the one analyzed in the CO and VOC analysis above, would control VOC/HAP emissions. The Department agrees with REC's determination that a natural gas, good combustion practices and limiting the amount of fuel fired to control HAP emissions from the proposed sources meets BAT.

I do not recommend establishing a HAP emission limitation for the heater because controlling VOC emission will ensure controlling HAP emissions.

Sources P101 and P102 – Combined Cycle Combustion Turbines

The vast majority of HAPs emitted from the CTs are also VOCs. They will be controlled by the oxidation catalysts by at least 30%. REC explains that the formaldehyde (HCHO) emissions are expected to be controlled by at least 60%.

REC calculates a combined total of 9.94 tpy post-control HAP emissions from each CT and DB. Of this, 2.19 tpy is formaldehyde, 0.98 tpy is toluene, 1.69 tpy is manganese and 3.68 tpy is hexane. REC proposes that these annual emission limits along with the use of oxidation catalysts represents BAT. The Department agrees that these annual emission limits and the use of oxidation catalysts satisfy the requirements of BAT.

The Department has determined that 9.94 tpy post-control HAP emissions from each CT and DB and 2.19 tpy of formaldehyde satisfy the requirements of BAT. I recommend a short-term limit for formaldehyde not to exceed 0.58 lb/hr to satisfy BAT.

REC will be required to EPA reference method test for formaldehyde emissions only to demonstrate compliance with the formaldehyde emission limitation. REC will keep records of fuel usage, hours of operation, and the emission calculations, including supporting documentation, to demonstrate compliance with the emission limitations. REC will be required to provide the Department with the records demonstrating compliance with the emission limitations on a quarterly basis.

Source P103 – Emergency Generator Engine

REC provided vendor data for the type of emergency generator engine and there are no HAP emission data from the vendor. HAP emission from a diesel-fired engine calculates, using AP-42 emission factors, a combined total of 0.004 tpy of HAP emissions. REC proposes that the hourly operational restriction represent BAT. The Department agrees that hourly restriction satisfies the requirements of BAT.

BAT Analysis for Ammonia (NH_3) Slip

There are no PSD or NNSR thresholds for Ammonia (NH_3) emissions; therefore, the NH_3 slip emissions are only subject to the BAT provisions specified in 25 Pa. Code Sections 127.1 and 127.12.

Sources P101 and P102 – Combined Cycle Combustion Turbines

NH_3 slip occurs as a result of ammonia being injected in the exhaust gas stream where not all of the ammonia reacts with the NO_x. REC explains that the RBLC does not report any add-on control technologies (such as wet scrubbers) for CTs and that none have been identified in other research as well. The Department is unaware of wet scrubbers being used on CTs of this size and design. The NH_3 slip can be minimized through effective process controls to optimize the NH_3 injection rate and maximize efficiency of the reactions. The examples of optimization provided by REC include refinement of the injection grid distribution pattern, additional injection nozzles and use of a feed-forward process control loop that would include monitoring both inlet and outlet NO_x emissions CEMS. The goal is to provide more precise control than found in more conventional control systems. Additionally, REC analyzed the possibility of increasing the SCR catalyst volume to maximize the NO_x control efficiency. However, an increase in catalyst volume results in an increase in back pressure, which could result in a reduction in CT combustion and operation efficiency. REC proposes to optimize the catalyst volume to maximize the catalytic reaction and minimize NH_3 slip while adhering to the CT vendor's back pressure constraints. REC proposes to use NH_3 injection system process optimization and catalyst volume optimization to minimize NH_3 slip. REC proposes that incorporating these into the project, along with a 5 ppmdv @ 15% O_2 NH_3 slip emission limitation coupled with 1-hour NH_3 slip CEMS monitoring, satisfies the requirements of BAT. The SCR system will monitor the operation to adjust accordingly, where varying the NH_3 injection levels will cause some small amounts of NH_3 to pass through unreacted. Based on these reasons, REC proposes that a 5 ppmdv @ 15% O_2 NH_3 slip emission limitation with 1-hour CEMS monitoring satisfies the requirements of BAT. The Department is unaware of any NH_3 slip emission limitations more stringent than 5 ppmdv @ 15% O_2 for comparably sized and designed CTs. The BAT analysis for NH_3 slip is case-by-case based on the facts surrounding the specific project. Therefore, the Department has concluded that 5 ppmdv @ 15% O_2, 31.71 lb/hr NH_3 slip emission limitation for each CT unit along with the use of the optimization procedures discussed above (refinement of the injection grid distribution pattern, additional injection nozzles, and use of a feed-forward process control loop that would include monitoring both inlet and outlet NO_x emissions CEMS using a 1-hour averaging period) satisfies the requirements of BAT. REC will monitor and use ammonia alarms that indicate when ammonia is not being vaporized sufficiently.

BACT/BAT/PSD Analysis for Sulfur Hexafluoride (SF_6)

REC is proposing to construct circuit breakers at the switchyard of the proposed facility. The air contaminant from circuit breakers is sulfur hexafluoride (SF_6) which is a greenhouse gas. The global warming potential of SF_6 is 22,800 times that of CO_2 according the 40 CFR Part 98. REC has calculated that the potential SF_6 emissions from the circuit breaker will equate to 16 pounds in any 12 consecutive month period. This would equate to a CO_2e of 182 tons in any 12 consecutive month period. Circuit breakers at the facility shall be state-of-the-art sealed enclosed-pressure circuit breakers equipped with low-pressure alarms and a low-pressure lockout where the alarms are triggered when 10% of the sulfur hexafluoride (SF_6) (by weight) has escaped. When the alarms are triggered, the permittee shall take immediate corrective action and fix the circuit breaker units to a like new state in order to prevent the emission of sulfur hexafluoride (SF_6) to the maximum extent practicable. These type of enclosures and monitoring systems will satisfy the requirements of BACT/BAT/PSD.

Modeling Analysis

REC has performed the air quality modeling analyses for the proposed project. The results of the analyses conclude that the proposed project will not significantly contribute to air pollution in violation of applicable National Ambient Air Quality Standards (NAAQS) for CO, NO_2, $PM_{2.5}$, and PM_{10}, and the PSD increment standards for NO_2, $PM_{2.5}$, and PM_{10}, will not have significant impacts on visibility, soils/vegetation and secondary growth and will not adversely affect air quality related values, including visibility in federal Class I and II areas. Please see the memo on the Summary of Air Quality Analyses for Prevention of Significant Deterioration from Mr. Daniel Roble, Air Quality Engineering Specialist for the Department of Environmental Protection, dated July 31, 2020, for further information on the review. The Department's review of the analyses concludes that the air quality analysis methodology is consistent with the "Guideline on Air Quality Models" (Guideline) codified in appendix W to 40 CFR Part 51, associated USEPA modeling policy and guidance, and PA DEP recommendations.

Potential Emissions

Below in Table 3 are the total combined emissions for the facility.

Table 3 – Facility-Wide Potential Emissions (Tons/year)

Source	NO_x	CO	SO_x	PM	VOC	HAPs	NH_3	H_2SO_4	CO_2e
031	0.88	2.61	0.18	0.28	0.30	0.24	---	0.01	16,967
032	1.44	4.86	0.16	0.24	0.66	0.12	---	---	7,677
033	0.43	1.08	0.02	0.02	0.07	0.02	---	---	1,502
P101	177.58	162.93	26.74	105.96	51.22	9.94	138.68	17.70	2,709,297
P102	177.58	162.93	26.74	105.96	51.22	9.94	138.68	17.70	2,709297
P103	5.45	1.50	<0.01	0.16	0.97	<0.01	---	---	585
P104	0.18	0.06	<0.01	0.01	0.01	---	---	---	34
P105	---	---	---	---	0.04	---	---	---	---
Ct Brkrs	---	---	---	---	---	---	---	---	182
Total Emissions	**363.54**	**335.97**	**53.84**	**212.63**	**104.49**	**20.26**	**277.36**	**35.41**	**5,445,541**

Notes:
1. PM emissions include PM_{10} and $PM_{2.5}$ emissions
2. 031 emissions based on 145,200 MMBtu for each boiler
3. 032 emissions based on no more than two units operating 8,760 hours each
4. 033 emissions based on 8.760 hours of operation
5. P101 and P102 emissions each based on 7,540 hours on natural gas and 720 hours on ULSD with 460 hours of SUSD on natural gas and 40 hours of SUSD on ULSD
6. P103 emissions based on 500 hours operation
7. P104 emissions based on 250 hours operation
8. Circuit breakers included for CO2e calculation purposes only

Conclusion

Based on the review of the application and the supplemental information supplied by REC, I believe that the sources proposed for construction and operation at the site located in Renovo Borough, Clinton County satisfy the requirements of LAER, BACT, BAT and all other applicable state and federal regulations. The sources are listed as follows:

- two (2) identical 1 x 1 powerblocks where each powerblock consists of a 3,541 MMBtu/hr (high heating value, HHV) natural gas-fired combustion turbine (CT) and steam turbine (ST) with a 1,005 MMBtu/hr peak input (HV) natural gas-fired duct burner (DB) and a heat recovery steam generator (HRSG).

- one (1) 2,206 brake horsepower (bhp) diesel-fired Caterpillar model C3512 emergency generator engine
- one (1) 237 bhp diesel-fired Clarke/John Deere model JU6H-UFAD88 fire pump engine
- two (2) 66 MMBtu/hr natural gas-fired auxiliary boilers
- three (3) 15 MMBtu/hr natural gas-fired water bath heaters
- one (1) 3 MMBtu/hr natural gas-fired dew point gas heater
- one (1) 3,500,000-gallon ultra-low sulfur diesel fuel (ULSD) storage tank
- two (2) 20,000-gallon lube oil storage tanks
- two (2) 26,000-gallon aqueous ammonia storage tanks
- one (1) 2,500-gallon ULSD storage tank (emergency generator engine)
- one (1) 350 gallon ULSD storage tank (fire pump engine)
- twelve (12) sulfur hexafluoride-containing high voltage circuit breakers

I recommend the following conditions be included in the plan approval.

1) Pursuant to the best available control technology of the Prevention of Significant Deterioration provisions in 40 CFR Section 52.21 and of 25 Pa. Code Section 127.83 and the lowest achievable emission rate of the New Source Review Regulation provisions in 25 Pa. Code Sections 127.201 through 127.217 as well as the best available technology provisions in 25 Pa. Code Sections 127.1 and 127.12:
    a) The air contaminant emissions from the exhaust of each boiler incorporated in Source 031 shall not exceed the following limitations:
        i) Nitrogen Oxides (NO_x, expressed as NO_2) – 0.006 lb/MMBtu and 0.44 tpy
        ii) Carbon Monoxide (CO) – 0.036 lb/MMBtu and 2.61 tpy
        iii) Volatile Organic Compound – 0.002 lb/MMBtu and 0.15 tpy
        iv) Particulate Matter less than 10 microns in diameter (PM10) – 0.0019 lb/MMBtu and 0.14 tpy
    b) Each boiler in Source 031 shall only utilize natural gas as fuel and fire no more than 145,200 MMBtu of natural gas in either boiler in any 12 consecutive month period.
    c) Each boiler incorporated in Source 031 shall be equipped with ultra-low NO_x burners and flue gas recirculation.
    d) Source 031 shall be operated in accordance with the manufacturer's specifications and good operating practices.

2) The permittee shall conduct an EPA EPA reference method test within 180 days of the startup of each boiler incorporated in Source 031 for nitrogen oxides and carbon monoxide to demonstrate compliance with the emission limitations.

3) Pursuant to 40 CFR Section 60.48c(g), the permittee shall keep records of the amount of natural gas fired in each boiler incorporated in Source 031 on a daily basis.

4) Each boiler in incorporated in Source 031 is subject to the requirements of 40 CFR Part 60 Subpart Dc Sections 60.40c through 60.48c. The permittee shall comply with all applicable requirements of 40 CFR Part 60 Subpart Dc Sections 60.40c through 60.48c.

5) Pursuant to the best available control technology of the Prevention of Significant Deterioration provisions in 40 CFR Section 52.21 and of 25 Pa. Code Section 127.83 and the lowest achievable emission rate of the New Source Review Regulation provisions in 25 Pa. Code Sections 127.201 through 127.217 as well as the best available technology provisions in 25 Pa. Code Sections 127.1 and 127.12:
   a) The air contaminant emissions from the exhaust of each heater incorporated in Source 032 shall not exceed the following limitations:
      i) nitrogen oxides – 0.011 lb/MMBtu and 0.72 tpy
      ii) carbon monoxide – 0.037 lb/MMBtu and 2.43 tpy
      iii) volatile organic compound – 0.005 lb/MMBtu and 0.33 tpy
      iv) particulate matter less than 10 microns in diameter (PM10) – 0.0019 lb/MMBtu and 0.12 tpy
   b) The permittee shall only operate no more than two (2) heaters incorporated in Source 032 at a time.
   c) Each heater incorporated in Source 032 shall be equipped with a low NO_x burner.
   d) Each heater incorporated in Source 032 shall only utilize natural gas as fuel.
   e) Source 032 shall be operated in accordance with the manufacturer's specifications and good operating practices.

6) Pursuant to the best available control technology of the Prevention of Significant Deterioration provisions in 40 CFR Section 52.21 and of 25 Pa. Code Section 127.83 and the lowest achievable emission rate of the New Source Review Regulation provisions in 25 Pa. Code Sections 127.201 through 127.217 as well as the best available technology provisions in 25 Pa. Code Sections 127.1 and 127.12:
   a) The air contaminant emissions from the exhaust of Source 033 shall not exceed the following limitations:
      i) nitrogen oxides – 0.033 lb/MMBtu and 0.43 tpy
      ii) carbon monoxide – 0.082 lb/MMBtu and 1.08 tpy
      iii) volatile organic compound – 0.005 lb/MMBtu and 0.07 tpy
   b) Source 033 shall only utilize natural gas as fuel.
   c) Source 033 shall be operated in accordance with the manufacturer's specifications and good operating practices.

7) Pursuant to the best available control technology of the Prevention of Significant Deterioration provisions in 40 CFR Section 52.21 and of 25 Pa. Code Section 127.83 and the lowest achievable emission rate of the New Source Review Regulation provisions in 25 Pa. Code Sections 127.201 through 127.217 as well as the best available technology provisions in 25 Pa. Code Sections 127.1 and 127.12:
   a) Emissions from the exhaust of Control Devices C101A, C101B, C102A and C102B associated with Sources P101 and P102, respectively, shall not exceed the limits specified below while firing natural gas:
      i.) nitrogen oxides – 2.0 ppmdv corrected to 15% O_2 and 33.30 lb/hr
      ii.) carbon monoxide – 0.9 ppmdv corrected to 15% O_2 and 7.00 lb/hr for the CT only and 1.5 ppmdv corrected to 15% O_2 and 15.20 lb/hr for both the CT and DB

iii.) volatile organic compounds - 0.7 ppmdv corrected to 15% O_2 and 3.10 lb/hr for the CT only and 1.6 ppmdv corrected to 15% O_2 and 9.30 lb/hr for both the CT and DB
iv.) sulfur dioxide - 0.0012 lb/MMBtu and 5.43 lb/hr
v.) total (filterable and condensable) particulate matter - 0.0050 lb/MMBtu and 22.50 lb/hr
vi.) formaldehyde – 0.58 lb/hr
vii.) sulfuric acid - 0.0009 lb/MMBtu and 4.07 lb/hr
viii.) ammonia slip - 5 ppmdv corrected to 15% O_2 and 32.34 lb/hr

b) emissions from the exhaust of Control Devices C101A, C101B, C102A and C102B associated with Sources P101 and P102, respectively, shall not exceed the limits specified below while firing ULSD:
i.) nitrogen oxides – 4.0 ppmdv corrected to 15% O_2 and 59.60 lb/hr
ii.) carbon monoxide - 2.0 ppmdv corrected to 15% O_2 and 18.10 lb/hr
iii.) volatile organic compounds - 2.0 ppmdv corrected to 15% O_2 and 10.40 lb/hr
iv.) sulfur dioxide - 0.0018 lb/MMBtu and 7.09 lb/hr
v.) total (filterable and condensable) particulate matter - 0.0122 lb/MMBtu and 48.20 lb/hr
vi.) sulfuric acid - 0.0012 lb/MMBtu and 4.62 lb/hr
vii.) ammonia slip - 5 ppmdv corrected to 15% O_2 and 28.98 lb/hr

(c) The nitrogen oxides, carbon monoxide and ammonia emissions limits shall be established as a one-hour period.
(d) Unless otherwise specified herein, the above emissions limits shall apply at all times except for periods of startup and shutdown.
(e) The applicable sulfur dioxide requirements in 40 CFR Section 60.4330 are streamlined into this permit condition.

8) The permittee shall install, certify, maintain and operate continuous emission monitoring systems (CEMS) for nitrogen oxides, carbon monoxide, carbon dioxide 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 Chapter 139 and the Department's "Continuous Source Monitoring Manual." No CEMS or flow monitoring system may however be installed unless Phase I approval has first been obtained from the Department.

9) The permittee shall submit a Phase I application to the Department for all CEMS and flow monitoring systems to be associated with each combined cycle powerblock at least 180 days prior to the expected commencement of operation of each respective unit.

10) Pursuant to the best available control technology requirements of the Prevention of Significant Deterioration provisions in 40 CFR Section 52.21 and of 25 Pa. Code Section 127.83 and the lowest achievable emission rate of the New Source Review Regulation provisions in 25 Pa. Code Sections 127.201 through 127.217 as well as the best available technology provisions in 25 Pa. Code Sections 127.1 and 127.12, emissions from Sources P101 and P102 shall not exceed the following limits:

a) nitrogen oxides while firing on natural gas:
   i) 53 lbs per hot start;
   ii) 81 lbs per warm start;
   iii) 123 lbs per cold start;
   iv) 14 lbs per shutdown;
   v) 25.20 tons in any 12-consecutive month period;
b) nitrogen oxides while firing on ULSD:
   i) 112 lbs per hot start;
   ii) 172 lbs per warm start;
   iii) 221 lbs per cold start;
   iv) 43 lbs per shutdown;
   v) 5.40 tons in any 12-consecutive month period;
c) volatile organic compounds while firing on natural gas:
   i) 22 lbs per hot start;
   ii) 24 lbs per warm start;
   iii) 53 lbs per cold start;
   iv) 19 lbs per shutdown;
   v) 11.40 tons in any 12-consecutive month period;
d) volatile organic compounds while firing on ULSD:
   i) 30 lbs per hot start;
   ii) 33 lbs per warm start;
   iii) 141 lbs per cold start;
   iv) 7 lbs per shutdown;
   v) 1.0 tons in any 12-consecutive month period;
e) carbon monoxide while firing on natural gas:
   i) 177 lbs per hot start;
   ii) 190 lbs per warm start;
   iii) 699 lbs per cold start;
   iv) 152 lbs per shutdown:
   v) 90.80 tons in any 12-consecutive month period;
f) carbon monoxide while firing on ULSD:
   i) 273 lbs per hot start;
   ii) 286 lbs per warm start;
   iii) 704 lbs per cold start;
   iv) 48 lbs per shutdown;
   v) 8.40 tons in any 12-consecutive month period;
g) total (filterable and condensable) particulate matter (PM per PM_{10} per $PM_{2.5}$) while firing on natural gas:
   i) 4.0 lbs per hot start;
   ii) 7.3 lbs per warm start;
   iii) 8.3 lbs per cold start;
   iv) 3.0 lbs per shutdown;
   v) 2.70 tons in any 12-consecutive month period;
h) total (filterable and condensable) particulate matter (PM per PM_{10} per $PM_{2.5}$) while firing on ULSD:
   i) 16 lbs per hot start;

ii) 32 lbs per warm start;
iii) 36 lbs per cold start;
iv) 10 lbs per shutdown;
v) 1.10 tons in any 12-consecutive month period;

i) These emission limits apply only during startup and shutdown events associated with Sources P101 and P102. These emission rates are included as part of, and not in addition to, the annual emission limits for Sources P101 and P102, respectively.

j) For the purposes of demonstrating compliance with these emission limits, the term “startup” and “shutdown” are defined as follows:
   i) A cold start is defined as a restart occurring 72 hours or more after shutdown and shall not be in excess of 45 minutes in duration.
   ii) A warm start is defined as a restart occurring between 8 to 72 hours after shutdown and shall not be in excess of 40 minutes in duration.
   iii) A hot start is defined as a restart occurring less than 8 hours after shutdown and shall not be in excess of 20 minutes in duration.
   iv) Shutdown is defined as the period between the time that the combined cycle powerblock drops below 60 percent operating level. Shutdown shall not occur for more than 12 minutes in duration.
   v) The permittee shall record the time, date, justification, and duration of each startup and shutdown.

11) Pursuant to the best available technology requirements of 25 Pa. Code Sections 127.1 and 127.12, the permittee shall monitor and keep records of the amount and type of fuel used each month in each of the combined cycle powerblocks as well as the monthly heat input and hours of operation. All information to satisfy this recordkeeping requirement shall be kept for a minimum of five (5) years and shall be made available to the Department upon request.

12) Pursuant to the best available control technology of the Prevention of Significant Deterioration provisions in 40 CFR Section 52.21 and of 25 Pa. Code Section 127.83, as well as the best available technology provisions in 25 Pa. Code Sections 127.1 and 127.12, each combined cycle powerblock shall be fired on either natural gas or ultra-low sulfur diesel (ULSD) fuel. The sulfur content of the natural gas shall not exceed 0.4 grains/100 scf and the sulfur content of the ULSD shall not exceed 15 ppm.

13) Pursuant to 25 Pa. Code Section 127.12b, (a) the permittee shall keep accurate and comprehensive records of the following to demonstrate compliance with the fuel requirements specified above under part I. Restrictions for each combined cycle powerblock:

a) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel and ULSD, specifying that the maximum total sulfur content of the natural gas is 0.4 grain/100 scf or less AND minimum percent methane composition equals 70% by volume for natural gas or the fuel has a lower heating value between 950 and 1,100 British thermal units per standard cubic foot for natural gas and the total sulfur content of the ULSD is 15 ppm or less; OR

b) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 0.4 grain/100 scf AND minimum percent methane composition equals 70% by volume or the fuel has a lower heating value between 950 and 1,100 British thermal units per standard cubic foot and the sulfur content of the ULSD is 15 ppm or less.
c) With additional authority for this item taken from 40 CFR 70.6, the records of the fuel sampling performed in this paragraph shall include the following;
   i) The date, place, and time of sampling;
   ii) The date(s) analyses were performed;
   iii) The company or entity that performed the analyses;
   iv) The analytical techniques or methods used;
   v) The results of such analyses; and
   vi) The operating conditions as existing at the time of sampling or measurement.
   vii) All information to satisfy this recordkeeping requirement shall be kept for a minimum of five (5) years and shall be made available to the Department upon request.

14) Pursuant to the best available control technology of the Prevention of Significant Deterioration provisions in 40 CFR Section 52.21 and of 25 Pa. Code Section 127.83, as well as the best available technology provisions in 25 Pa. Code Sections 127.1 and 127.12, emissions from the operation of each individual combined cycle powerblock shall not exceed in any 12 consecutive month period the limits specified below:
   a) nitrogen oxides – 177.58 tons
   b) carbon monoxide – 162.93 tons
   c) volatile organic compounds – 51.22 tons
   d) total (filterable and condensable) particulate matter – 105.96 tons
   e) sulfur oxides – 26.74 tons
   f) total combined hazardous air pollutants – 9.94 tons
   g) formaldehyde – 2.53 tons
   h) ammonia – 138.68 tons
   i) sulfuric acid – 17.70 tons
   j) greenhouse gases – 2,709,297 tons

15) The permittee shall conduct initial EPA reference method testing within 180 days of the startup of each combined cycle powerblock and subsequent testing every two years from the previous tests for nitrogen oxides, carbon monoxide, ammonia slip, volatile organic compounds (including formaldehyde), sulfur oxides (SO_2), sulfuric acid mist, total (filterable and condensable) particulate matter as well as keep record of the monthly emissions of sulfur oxides (SO_2), sulfuric acid mist, total (filterable and condensable) particulate matter to demonstrate compliance with the emission limitations.

16) The Department will evaluate the actual emission rates and may revise the allowable emission limitations based upon demonstrated performance (CEMS data, stack tests results), and/or subsequently promulgated applicable requirements during the first five years of operation. Any revision of the allowable emission limitations shall be accomplished by permit modification provided that the revised allowable emission limitations do not exceed

levels at which the lowest achievable emission rate (LAER), best available control technology (BACT) and best available technology (BAT) were evaluated, do not exceed the level at which the facility impacts were modeled, and that are not a result of a physical change at the facility or change in mode of operation.

17) Pursuant to the best available control technology of the Prevention of Significant Deterioration provisions in 40 CFR Section 52.21 and of 25 Pa. Code Section 127.83, as well as the best available technology provisions in 25 Pa. Code Sections 127.1 and 127.12, the emission of visible air contaminants from the operation of each combined cycle powerblock shall not be in excess of 10% opacity for any 3-minute block period for normal operation and 10% opacity for any 6-minute block period for startups/shutdowns.

18) Pursuant to the best available technology requirements of 25 Pa. Code Section 127.1 and 127.12:
   a) The inlet temperature, outlet temperature, and pressure differential across the SCR catalyst shall be monitored and recorded on a continuous basis. Visual and audible alarms shall be utilized to indicate improper operation.
   b) The pre-control and post-control NO_x emissions shall be monitored by the feed-forward process control loop to ensure maximum achievable control efficiency and minimum NH_3 slip.
   c) The pressure differential across the oxidation catalyst as well as the catalyst inlet and outlet temperatures shall be monitored and recorded on a continuous basis (1-hour average). Visual and audible alarms shall be utilized to indicate improper operation. The pressure differential and temperature ranges will be established based upon the recorded data and the stack testing.
   d) An oxygen monitor shall be placed in each stack to monitor oxygen levels to ensure maximum achievable combustion efficiency.
   e) High efficiency inlet air filters shall be used in the air inlet section of each combined cycle powerblock.
   f) The permittee shall monitor the pressure differential across the inlet air filters and record it on a weekly basis.
   g) All air-contaminant sources and control devices shall be maintained and operated in a manner consistent with good air pollution control practices and in accordance with the manufacturer's recommendations as well as manufacturer's maintenance plan.
   h) The total combined hours of startups and shutdowns for each combined cycle powerblocks while firing natural gas shall not exceed 460 hours in any 12 consecutive month period.
   i) The total combined hours of startups and shutdowns for each combined cycle powerblocks while firing ULSD shall not exceed 40 hours in any 12 consecutive month period.

19) Pursuant to the best available control technology of the Prevention of Significant Deterioration provisions in 40 CFR Section 52.21 and of 25 Pa. Code Section 127.83 and the lowest achievable emission rate of the New Source Review Regulation provisions in 25 Pa. Code Sections 127.201 through 127.217 as well as the best available technology

provisions in 25 Pa. Code Sections 127.1 and 127.12, each combustion turbine associated with a powerblock shall be equipped with dry-low-NO_x (DLN) combustors.

20) Pursuant to the best available control technology of the Prevention of Significant Deterioration provisions in 40 CFR Section 52.21 and of 25 Pa. Code Section 127.83 and the lowest achievable emission rate of the New Source Review Regulation provisions in 25 Pa. Code Sections 127.201 through 127.217 as well as the best available technology provisions in 25 Pa. Code Sections 127.1 and 127.12, Source P101 and P102 shall only be fired on ULSD fuel no more than 720 hours in any 12 consecutive month period.

21) The permittee shall comply with all applicable SO_2 monitoring requirements specified in 40 CFR Section 60.4360, 60.4365, and 60.4370.

22) The permittee shall comply with all applicable monitoring requirements specified in 40 CFR Sections 60.4340, 60.4345, and 60.4350.

23) Pursuant to the best available technology requirements of 25 Pa. Code Section 127.1 and 127.12, the permittee shall 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 malfunctions pursuant to 40 CFR Section 60.4333.

24) The permittee shall comply with the applicable testing requirements specified in 40 CFR Sections 60.4400, 60.4405, and 60.4415.

25) The permittee shall comply with the reporting requirements specified in 40 CFR Sections 60.4375 and 60.4380.

26) The permittee shall submit a complete Acid Rain (Title IV) permit application in accordance with the deadlines specified in 40 CFR Section 72.30(b)(2)(ii).

27) The permittee shall comply with the applicable requirements of 40 CFR Part 97.

28) The permittee shall submit a complete NO_x Budget permit application in accordance with 40 CFR Section 97.21(b)(1)(ii).

29) The permittee shall comply with the applicable Mandatory GHG Reporting requirements of 40 CFR Part 98.

30) The facility shall comply with the requirements in 40 CFR Part 98 Subpart D, (40 CFR Sections 98.40 through 98.48).

31) Source P101 and P102 are subject to the requirements of 40 CFR Part 60 Subpart KKKK Section 60.4300 through 60.4420. The permittee shall comply with all applicable requirements of 40 CFR Part 60 Subpart KKKK Sections 60.4300 through 60.4420.

32) Sources P101 and P102 are subject to the requirements of 40 CFR Part 60 Subpart TTTT Section 60.5508 through 60.5580. The permittee shall comply with all applicable requirements of 40 CFR Part 60 Subpart TTTT Sections 60.5508 through 60.5580.

33) Pursuant to the new source review provisions in 25 Pa. Code Sections 127.201 through 127.217, the permittee shall purchase and apply 408.4 tons per year of NO_x emission reduction credits (ERCs) and 120.2 tons per year of VOC ERCs prior to commencing operation of any source at the facility to offset the total of the net increase in potential to emit. The permittee shall certify to the Northcentral Regional Office of the Department the amount of ERCs purchased, the company from which the ERCs were purchased, and the effective date of transfer of the ERCs. The purchase and application of the NOx and VOC ERCs shall be tracked in the Department's ERC registry system. Failure to purchase and apply the ERCs prior to commencing operation at the facility shall make this plan approval null and void.

34) Pursuant to the requirements of 40 CFR Section 60.4205(b) and 60.4211(c), Sources P103 and P104 shall be EPA certified to meet the emissions standards that are specified in 40 CFR Section 89.112 and 89.113 for the same model year and maximum engine power.

35) Pursuant to the best available control technology of the Prevention of Significant Deterioration provisions in 40 CFR Section 52.21 and of 25 Pa. Code Section 127.83 and the lowest achievable emission rate of the New Source Review Regulation provisions in 25 Pa. Code Sections 127.201 through 127.217 as well as the best available technology provisions in 25 Pa. Code Sections 127.1 and 127.12:
   a) The air contaminant emissions from the exhaust of Source P103 shall not exceed the following limitations:
      i) nitrogen oxides – 4.48 g/hp-hr and 5.45 tpy
      ii) carbon monoxide – 1.23 g/hp-hr and 1.50 tpy
      iii) volatile organic compound – 0.80 g/hp-hr and 0.97 tpy
      iv) particulate matter – 0.13 g/hp-hr and 0.16 tpy.
   b) The air contaminant emissions from the exhaust of Source P104 shall not exceed the following limitations:
      i) nitrogen oxides – 2.7 g/bhp-hr and 0.18 tpy
      ii) carbon monoxide – 0.90 g/bhp-hr and 0.06 tpy
      iii) volatile organic compound – 0.10 g/bhp-hr and 0.01 tpy
      iv) particulate matter – 0.10 g/bhp-hr and 0.01 tpy
   c) Source P103 shall not be operated greater than 500 hours in any 12 consecutive month period.
   d) Source P104 shall not be operated greater than 250 hours in any 12 consecutive month period.

36) Pursuant to the best available technology requirements of 25 Pa. Code Section 127.1 and 127.12:
   a) the total hours of operation of Source P103 and Source P104 shall not exceed 500 hours and 250 hours in any 12-consecutive month period, respectively.

b) The duration of each readiness test associated with the engines shall be no more than 30 minutes.
c) There shall be no simultaneous readiness testing of the engine-generator and fire pump engine within the same hour.
d) There shall be no readiness testing of the engines during the startup or shutdown of the combined cycle powerblocks
e) The visible emissions from Sources P103 and P104 shall not exceed 15% for any 3-minute block period and 50% at any time.
f) The permittee shall only use ultra-low sulfur diesel fuel (15 ppm sulfur maximum) pursuant to 40 CFR Part 80 Subpart I, to operate Sources P103 and P104.
g) Sources P103 and P104 shall be equipped with a non-resettable hour meter that accurately monitors each engine's hours of operation.
h) The permittee shall keep accurate and comprehensive records of the following information for Source P103 and P104:
    i) the supporting information and calculations used to demonstrate that the emissions of particulate matter and sulfur oxides from the exhaust of the engine comply with the best available technology emissions limitations as well as the requirements in 25 Pa. Code Section 123.13 and 123.21, respectively;
    ii) the fuel certification reports for each delivery of diesel fuel
    iii) the stack test reports, if required.

37) Pursuant to the requirements of 40 CFR Section 60.4211(f), the operation of Source P103 shall not be used for peak shaving or to generate income by supplying power to an electric grid or otherwise supply non-emergency power as part of a financial arrangement with another entity.

38) Pursuant to 40 CFR Section 60.4206, the permittee shall operate and maintain Source P103 and P104 to achieve the emission standards specified in 40 CFR Section 89.112 and 89.113 over the entire life of the engine. Any testing used to verify compliance with this work practice restriction shall be performed in accordance with 40 CFR Part 60 Subpart IIII, including 40 CFR Section 60.4212, and Department-approved test methods and procedures.

39) Pursuant to 40 CFR Section 60.4210(f), Source P103 and P104 shall meet the labeling requirements in Section 60.4210(f).

40) Pursuant to 40 CFR Section 60.4211(c), Source P103 and P104 shall be installed and configured according to the manufacturer's emission-related specifications.

41) The permittee shall record the hours that Sources P103 and P104 operated through the non-resettable hour meter and shall calculate the 12-consecutive month total hours of operation, including supporting documentation, to verify compliance with the operational restriction specified in this permit on a monthly basis. Additionally, the permittee shall record the time of operation of the engine and the reason the engine was in operation during that time. The information used to demonstrate compliance with this condition shall be kept for a minimum of five years and shall be made available to the Department upon request.

42) The permittee shall not store any liquid containing volatile organic compounds (VOC) with a vapor pressure greater than 1.5 psia (10.5 kilopascals) under actual storage conditions in each storage tank associated with Source P105 unless each of the tanks are equipped with pressure relief valve which is maintained in good operating condition and which are set to release at no less than 0.7 psig of pressure or 0.3 psig of vacuum, or the highest possible pressure and vacuum in accordance with state or local fire codes or the National Fire Prevention Association guidelines or other national consensus standards acceptable to the Department.

43) The permittee shall keep a record of the vapor pressure of the contents of each storage tank associated with Source P105 unless the respective tank is equipped with pressure relief valves that meets the requirement in this permit relating to pressure release settings. All information used to demonstrate compliance with this permit condition shall kept for minimum of five (5) years and shall be made available to the Department upon request.

44) Pursuant to the best available control technology requirements of the Prevention of Significant Deterioration provisions in 40 CFR Section 52.21 and of 25 Pa. Code Section 127.83 and the best available technology provisions of 25 Pa. Code Sections 127.1 and 127.12, the combined total sulfur hexafluoride (SF_6) emissions from all of the circuit breakers used at the facility shall not exceed 16 pounds in any 12 consecutive month period. Additionally, the greenhouse gas emissions, expressed as CO_2e, from all of the circuit breakers used at the facility shall not exceed 183 tons in any 12 consecutive month period.

45) Pursuant to the best available control technology requirements of the Prevention of Significant Deterioration provisions in 40 CFR Section 52.21 and of 25 Pa. Code Section 127.83 and the best available technology provisions of 25 Pa. Code Sections 127.1 and 127.12, the circuit breakers at the facility shall be state-of-the-art sealed enclosed-pressure circuit breakers equipped with low-pressure alarms and a low-pressure lockout where the alarms are triggered when 10% of the sulfur hexafluoride (SF_6) (by weight) has escaped. When the alarms are triggered, the permittee shall take immediate corrective action and fix the circuit breaker units to a like new state in order to prevent the emission of sulfur hexafluoride (SF_6) to the maximum extent practicable.