Homer City Generation

Prevention of Significant Deterioration Permit Application

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1. Introduction

Homer City Generation, L.P. (Homer City) is proposing a project to construct and operate up to seven (7) combined-cycle combustion turbines (CCs) and up to ten (10) simple cycle aeroderivative gas turbines (ADGTs) at the Homer City Generating Station ("the Station"), located in Indiana County, Pennsylvania. Construction and operation of the new CCs and ADGTs will also include new ancillary equipment such as auxiliary boiler(s), emergency generator(s), emergency fire water pump engine(s), cooling towers, and fuel gas heater(s). The new CCs and ADGTs, in final configuration, along with all associated ancillary equipment, will be herein referred to as the "Project" or "Homer City Generation". The new CCs and ADGTs will be fueled only by natural gas and will not use oil as a backup fuel. Each CC and ADGT will be equipped with a selective catalytic reduction (SCR) to minimize nitrogen oxide (NO_X) emissions and an oxidation catalyst to minimize emissions of carbon monoxide (CO), volatile organic compound (VOC), and organic hazardous air pollutants (HAPs).

The Station is the site of a now retired coal-fired generating plant and an existing "major source" of criteria air pollutants. The Project constitutes a "major modification" under Prevention of Significant Deterioration (PSD) permitting requirements as to certain pollutants. As such, Homer City is applying to the Pennsylvania Department of Environmental Protection (PADEP) for a Plan Approval authorizing construction and operation of the Project. Homer City will use emission offsets, associated with the retirement of the coal-fired boilers, to "net out" of new source review (NSR) for NO_X, SO_2, and CO. Lead (Pb) emissions from the Project will not exceed the PSD Significant Emission Rate (SER) threshold. As such, the Project will be subject to PSD requirements under the NSR program only for emissions of particulate matter (PM), particulate matter (PM) equal to and less than 10 microns in diameter (PM_{10}), PM equal to and less than 2.5 microns in diameter ($PM_{2.5}$), sulfuric acid mist (SAM or H_2SO_4), and greenhouse gases (GHG). Pennsylvania is located in the Ozone Transport Region (OTR), and the Project will be subject to Non-attainment NSR (NNSR) for VOC emissions

This introduction and the other components of this document constitute the application for an air permit authorizing construction and operation of the Project. This application and supporting analyses address the applicable permitting requirements for the Project and demonstrate the Project will comply with applicable state/federal air regulations.

1.1 Facility Description and Location

The Homer City Generating Station is located at 1750 Power Plant Road, on approximately 2,400 acres in Indiana County, Pennsylvania, approximately 4 kilometers (2.5 miles) southwest of the town of Homer City, Pennsylvania. Originally, three (3) coal-fired steam generating units were operated at Homer City. Units 1, 2, and 3 were retired in July of 2023.

Figure 1-1 and **Figure 1-2** are aerial maps showing the location of the Project at Homer City Generating Station. The land use surrounding the Project consists of a mix of mostly forested and agricultural areas. The topography surrounding the Project, as indicated in the topographic map in **Figure 1-3**, is characterized by mostly rolling hills with two ridgelines located to the southeast (Chestnut Ridge and Laurel Ridge). A plot plan showing the proposed general arrangement of the Project is presented in **Appendix B**.

The geographical coordinates for the approximate center of Homer City:

- Universal Transverse Mercator (UTM) Easting: 652,600 meters;
- Universal Transverse Mercator (UTM) Northing: 4,486,300 meters;
- UTM Zone: 17 (North American Datum (NAD): 1983);
- Elevation Above Mean Sea Level (AMSL): Approximately 1,200 feet AMSL.

Figure 1-1. Location of Homer City (Aerial)

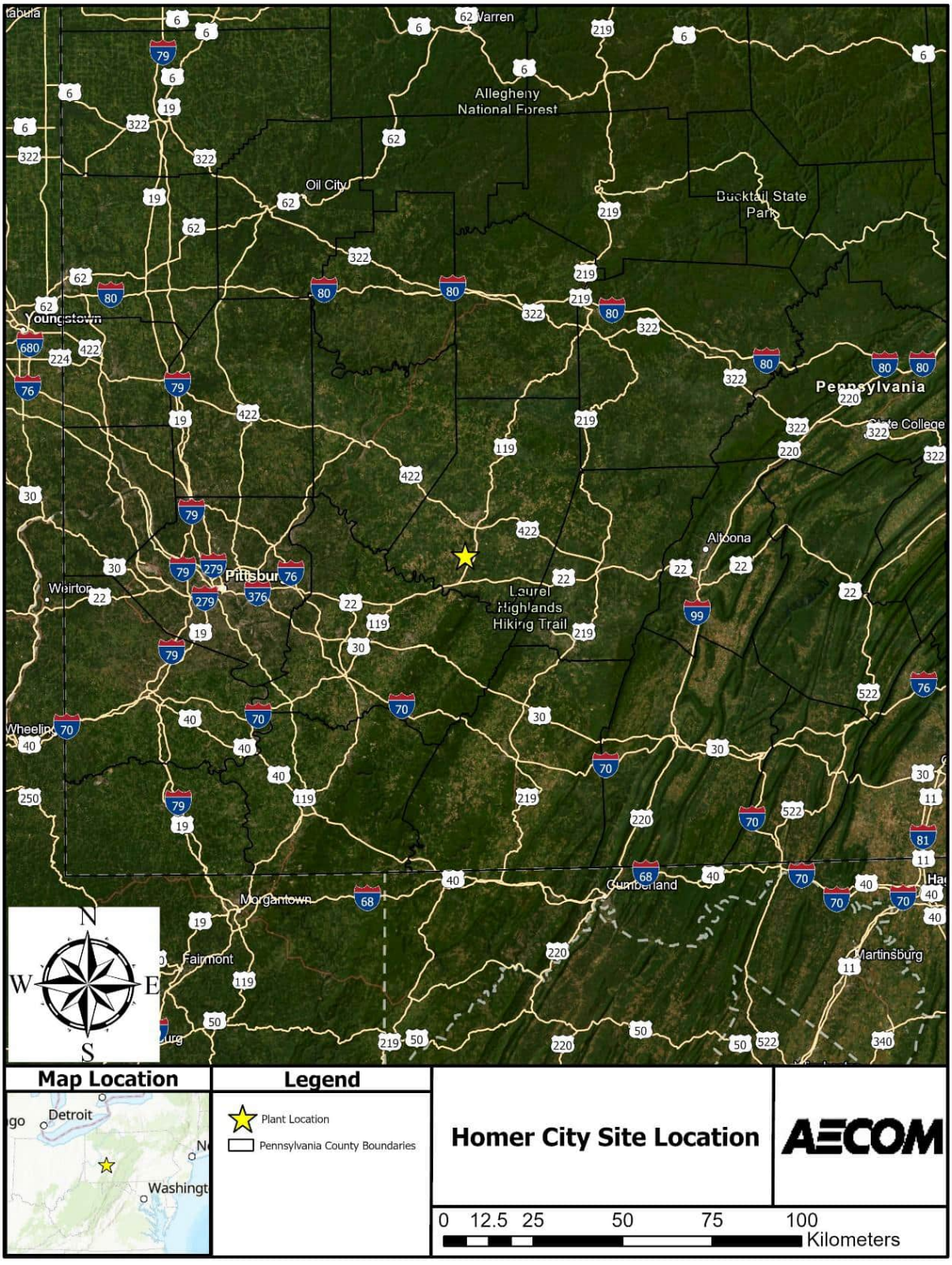
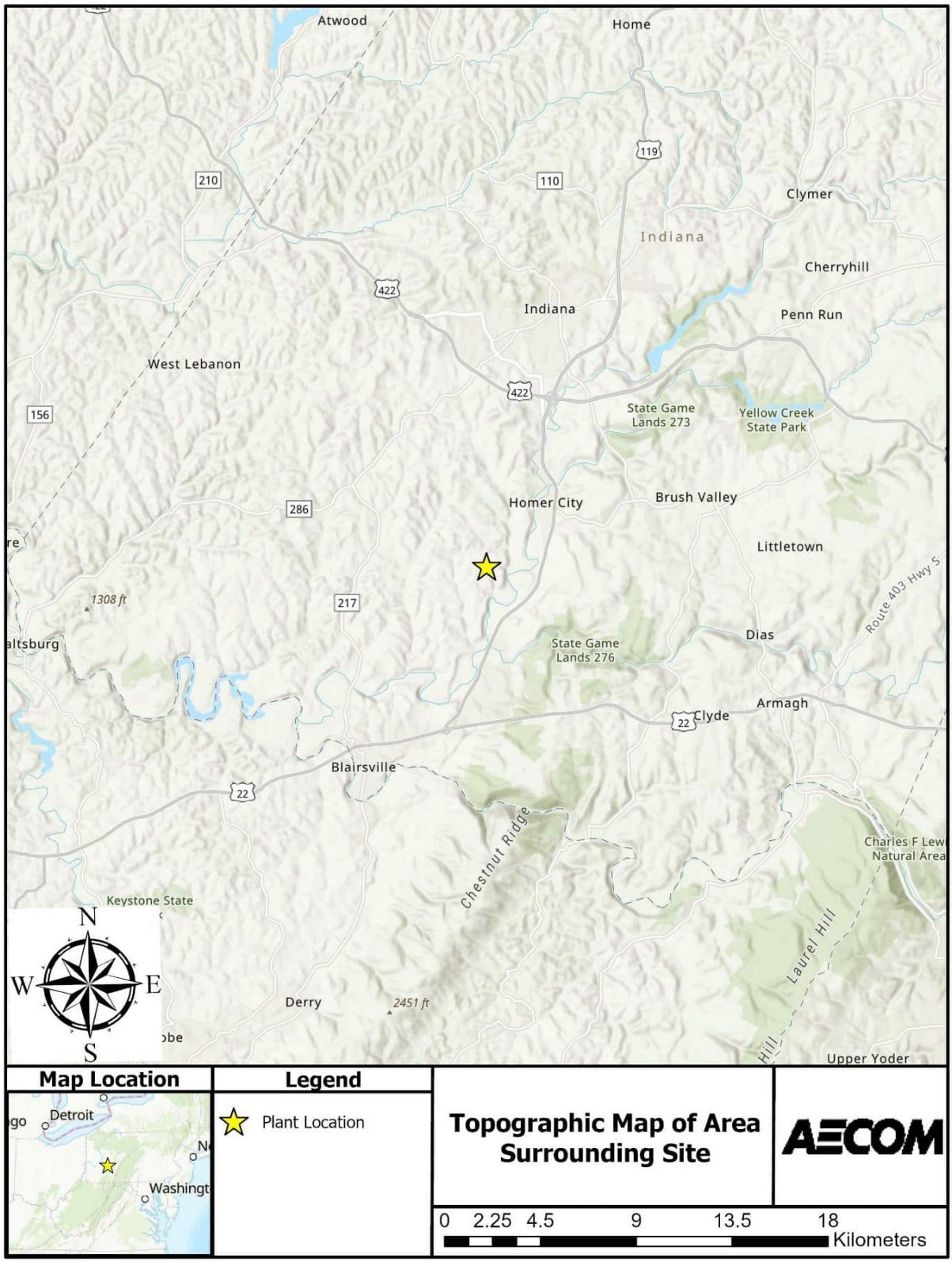


Figure 1-2. Location of Homer City (Aerial, zoom)



Figure 1-3. Location of Homer City (Topography)



1.2 Project Description

The Project consists of seven (7) CCs along with up to ten (10) ADGTs. The CCs are GE Vernova (GE) 7HA.02 units and the ADGTs are Mitsubishi Power FT8 Gas Turbine MOBILEPAC units. The CCs and ADGTs are the primary sources of air emissions associated with the Project. The ancillary pieces of equipment being proposed for the Project are listed below:

- Three (3) auxiliary boilers rated at approximately 67 million British thermal units per hour (MMBtu/hr) each, operating on pipeline quality natural gas;
- Ten (10) emergency generator engines (reciprocating internal combustion engines [RICE]) rated at approximately 2,500 electrical kilowatts (kWe) each, operating on ultra-low sulfur diesel fuel (ULSD);
- Two (2) emergency generator engines (RICE) rated at approximately 1,000 electrical kilowatts (kWe) each, operating on ULSD fuel;
- One (1) emergency fire-water pump engine (RICE) rated at approximately 400 brake horsepower (bhp), operating on ULSD;
- Seven (7) fuel gas heaters each rated at approximately 10.8 MMBtu/hr operating on pipeline quality natural gas;
- Seven (7) cooling towers, with eight (8) cells each; and
- Fugitive emissions from gas-insulated switchgear (GIS) and natural gas piping components.

Additionally, the facility will utilize storage tanks which are exempt from Plan Approval. Each emergency generator engine and the fire water pump will have its own ULSD fuel tank – exact capacities of these tanks are not known at this time but are expected to be greater than 2,000 gallons for the 2,500 kWe generator engines and less than 2,000 gallons for the 1,000 kWe generator engines and fire water pump. Each CC will have two lubricating oil tanks, approximately 6,300 gallons for each combustion turbine and 6,300 gallons for each steam turbine. Each ADGT will have two lubricating oil tanks, approximately 37 gallons for each combustion turbine and approximately 60 gallons for each generator.

1.3 Facility Classification

The facility is classified under the Standard Industrial Classification (SIC) code system as Electric Services, 4911, and classified under the North American Industrial Classification Systems (NAICS) as Fossil Fuel Electric Power Generation, 221112. Based on the facility's potential to emit, Homer City will continue to be classified as a "major stationary source."

1.4 Document Organization

The balance of this document is divided into sections which address each component of the NSR and NNSR air quality review process. The outline below provides an overview of the contents of each of the remaining sections.

Section 2.0 – Process Description provides a general description of the primary process by which power will be produced at this site, as well as a description of the associated equipment.

Section 3.0 – PSD/NNSR Applicability Determination and Emissions Summary presents a detailed review of air emissions which will occur at the Project site due to the operation of the proposed new emission sources. The section also present the PSD applicability analysis are it relates to NSR and NNSR.

Section 4.0 – Requirements and Standards presents a discussion of potentially applicable State and Federal air regulations.

Section 5.0 - Control Technology Review presents the best available control technology determination for the pollutants for which PSD or NNSR permitting is required, including a detailed evaluation of all potential control options for each pollutant.

Section 6.0 – Class II Area Air Quality Modeling Analysis Procedures summarizes the dispersion modeling methodology and manner in which the predicted impacts were compared to applicable standards. Specifically, this section discusses the modeling input data and the various modeling scenarios evaluated.

Section 7.0 – Class II Area Significant Impact Level (SIL) Analysis Results presents the results of the Class II Area SIL modeling results performed for the Project.

Section 8.0 – Class II Area Cumulative Impact Assessment Results presents the results of the Class II Area cumulative air dispersion modeling analysis performed for the Project. This section compares the modeled concentrations to the applicable standards.

Section 9.0 – Other Requirements Potentially Applicable to Air Permits Authorizing Construction contains supplemental information regarding the potential impacts of the Project. Specifically, this section discusses the potential for impacts to Class I areas and soils and vegetation.

Section 10.0 - References include a list of the documents relied upon during the preparation of this document.

Appendices – Appendices A, B, C, and D provide PADEP permit application forms, plot plan, emission calculations, and supporting BACT/LAER information. Additional information, figures and diagrams, dispersion modeling files, and supplemental materials supporting the information presented in the application are provided in Appendices E, F, and G.

2. Process Description

As stated in **Section 1**, Homer City plans to construct and operate the following primary equipment:

- Seven (7) GE Vernova 7HA.02 (GE 7HA.02) combined cycle CTs (CC), each with a nominally rated 1,034 MMBtu/hr duct burner. Each CC train has an ISO base rating of approximately 525 MWe (net, turbine only) and 633 MWe (net, with duct burners). Each CC will be equipped with SCR and oxidation catalyst,
- Ten (10) Mitsubishi FT8 MOBILEPAC simple cycle aero-derivative combustion turbines (ADGT). The generator for each turbine will have a maximum ISO rating not to exceed 25 MWe over the range of possible operating levels and ambient temperatures. Each CT turbine will be equipped with SCR and oxidation catalyst.

Associated equipment associated with the Project includes:

- Three (3) natural gas-fueled auxiliary boilers with heat input capacity of 67 MMBtu/hr each operating on pipeline quality natural gas,
- Ten (10) emergency generators (RICE) rated at approximately 2,500 electrical kilowatts (kWe) each, operating on ULSD,
- Two (2) emergency generators (RICE) rated at approximately 1,000 electrical kilowatts (kWe) each, operating on ULSD,
- One (1) emergency fire-water pump (RICE) rated at approximately 400 brake horsepower (bhp), operating on ULSD,
- Seven (7) cooling towers consisting of eight (8) cells per tower,
- Seven (7) natural gas-fired fuel gas heaters each with a heat input rating of approximately 10.8 MMBtu/hr operating on pipeline quality natural gas,
- Fugitive emissions from gas-insulated switchgear (GIS) and natural gas piping components, and
- ULSD, lubricating oil, 19% aqueous ammonia, and water storage tanks all exempt from Plan Approval.

2.1 Combustion Turbines (Combined-Cycle)

The proposed GE 7HA.02 units will provide between 527-634 MWe of ISO capacity at full load, per turbine depending on the duct burner firing rate. Each proposed CC unit is comprised of five major sections: the compressor, the combustor, the power turbine, the heat recovery stream generator, and the steam turbine, as described below:

- In the compressor section, ambient air is drawn through a filter (and under certain meteorological conditions, the evaporative cooler) to clean (and cool) the air. The air is then compressed and directed to the combustor section.
- In the combustor section, a mixture of fuel and air is introduced and combusted. Hot gases from combustion are mixed with additional air from the compressor section and directed to the power turbine section at high temperature and pressure. The combustor is a dry low-NO_X (DLN) design.
- In the power turbine section, the hot exhaust gases expand and rotate the turbine blades, which are coupled to a shaft. The rotating shaft drives the compressor and the generator, which generates electricity.
- In the HRSG section, heat is recovered from the power turbine section and is used to convert water into steam. The HRSG section also contains a series of duct burners to provide for additional heat, if required to make additional steam. The HRSG section also contains the SCR and oxidation catalysts for emissions control.
- The steam turbine section operates similarly to the power turbine section, except that steam is used from the HRSG to drive the turbine blades to produce additional electricity.

In addition to DLN, the emission control technologies for the proposed CT units include SCR to control NO_X emissions, as well as an oxidation catalyst to control CO, VOC, and organic HAP emissions.

2.2 Combustion Turbines (Simple-Cycle)

The proposed FT8 units will provide no more than 25 MW of ISO capacity at full load over a range of ambient temperatures, per turbine and each turbine will serve a power generator that is capable of generating no greater than 25 MWe of electricity. Each proposed CT unit is comprised of three major sections: the compressor, the combustor, and the power turbine, as described below:

- In the compressor section, ambient air is drawn through a filter (and under certain meteorological conditions, the evaporative cooler) to clean (and cool) the air. The air is then compressed and directed to the combustor section.
- In the combustor section, a fuel and air mixture is introduced and combusted. Hot gases from combustion are mixed with additional air from the compressor section and directed to the power turbine section at high temperature and pressure. Water is injected into the combustor to help control NO_X emissions.
- In the power turbine section, the hot exhaust gases expand and rotate the turbine blades, which are coupled to a shaft. The rotating shaft drives the compressor and the generator, which generates electricity.

In addition to water injection, the emission control technologies for the proposed CT units include SCR to control NO_X emissions, as well as an oxidation catalyst to control CO, VOC, and organic HAP emissions.

2.3 Auxiliary Boilers

Auxiliary boilers will be used to assist the CC units while in startup mode. The boilers can provide steam to help heat up the steam turbine seals and bearings prior to and while the turbine is ramping up. This will help the CC units ramp up in a faster manner than if the steam turbine seals and bearings were cold. The boilers will fire natural gas exclusively and will be equipped with ultra-low NO_X burners and be limited to a 5% annual utilization factor (438 hours per boiler).

2.4 Diesel-Fired Emergency Generator Engines

The Project will include ten (10) ULSD-fired emergency generator engines with a standby rating of 2,500 kWe certified to Tier 4 emission standards. The engines will be operated for a maximum of 500 hours per year, including being limited to 100 hours per year for maintenance and readiness testing, regulatory applicability is discussed further in **Section 4**. Seven (7) engines will service the GE 7HA.02 units and a single engine will each be dedicated to water treatment, maintenance/office buildings, and gas-insulated switchgear areas.

The Project will also include two (2) ULSD-fired emergency generator engines with a standby rating of 1,000 kWe certified to Tier 4 emission standards. The engines will be operated for a maximum of 500 hours per year, including being limited to 100 hours per year for maintenance and readiness testing, regulatory applicability is discussed further in **Section 4**. These two (2) generators will service the ten (10) FT8 units.

2.5 Diesel-Fired Fire Water Pump Engine

The Project will include one (1) ULSD-fired fire water pump engine rated at approximately 400 bhp. The engine will be operated for emergency purposes for a maximum of 500 hours per year, including 100 hours per year for maintenance and readiness testing, 50 hours of which may be used in non-emergency situations, regulatory applicability is discussed further in **Section 4**.

2.6 Fuel Gas Heaters

The Project will include seven (7) natural gas-fired fuel gas heaters, each with a heat input capacity of approximately 10.8 MMBtu/hr and be used to warm up the incoming natural gas fuel to prevent freezing of the gas regulating valves under certain gas system operating conditions. The heaters will fire natural gas exclusively and use ultra-low NO_X burners to control NO_X emissions.

2.7 Cooling Towers

Each CC turbine train will have a bank of eight (8) cooling tower cells to condense the outlet of the steam turbine back into water. The water will be recirculated back into the HRSG to be turned back into steam. Each cooling tower cell will be equipped with a drift eliminator filter to reduce the liquid drift emitted from each cell.

2.8 Fugitive SF_6 from Gas-Insulated Switchgear

The proposed project will include gas-insulated switchgear (GIS) with a total installed capacity of 90,300 pounds of sulfur hexafluoride (SF_6), which is a known greenhouse gas (GHG). There will be a maximum leak rate of less than 0.5% annually.

2.9 Fugitive GHG from Natural Gas Piping Components

The Project will use natural gas piping which components (i.e., valves, flanges) may emit small amounts of fugitive GHGs in the form of methane (CH_4) and carbon dioxide (CO_2) due to potential equipment leaks.

2.10 Plan Approval Exempt Storage Tanks

Additionally, the facility will utilize VOC containing storage tanks which are exempt from Plan Approval. Each emergency generator engine and the fire water pump will have its own ULSD fuel tank – exact capacities of these tanks are not known at this time but are expected to be greater than 2,000 gallons for the 2,500 kWe generator engines and less than 2,000 gallons for the 1,000 kWe generator engines and fire water pump. Each CC will have two lubricating oil tanks, approximately 6,300 gallons for each combustion turbine and 6,300 gallons for each steam turbine. Each ADGT will have two lubricating oil tanks, approximately 37 gallons for each combustion turbine and approximately 60 gallons for each generator. The ULSD and lubricating oils will each have vapor pressures less than 1.5 psia under actual storage conditions.

Nine (9) 35,000 gallon tanks will be used to store 19% aqueous ammonia for the SCR systems. Two (2) 650,000 gallon tanks will be used to store demineralized water and a single 400,00 gallon tank for fire water. These tanks will not be used to store VOC containing materials and are exempt from Plan Approval.

3. PSD/NNSR Applicability Determination and Emissions Summary

This section contains the Prevention of Significant Deterioration (PSD) and Non-attainment New Source Review (NNSR) applicability determination for the Project and discusses the basis and methodology for the calculation of air pollutant emission rates for the proposed sources. Per 40 CFR 52.21 and 25 Pa. Code Chapter 127, Subchapter D, the proposed modification is subject to the provisions of PSD if the net emissions increase for specific pollutants exceeds specified thresholds. A netting analysis was prepared for each PSD pollutant to summarize the emissions increases and creditable decreases associated with the Project and other projects during the contemporaneous period. The results of this netting analysis were used to determine which pollutants are subject to PSD and which pollutants "net out" of PSD applicability.

The procedures used in determining the potential emissions from the Project are based on information provided by the turbine manufacturer, other equipment vendor data, emission limitations specified by the applicable New Source Performance Standards, emission factors documented in EPA's "Compilation of Air Pollution Emission Factors, AP-42," and proposed Best Available Control Technology (BACT) emission limits. Operational limitations (as appropriate) have been accounted for in estimating potential annual emissions.

The emissions impact of a project occurring during the contemporaneous period is based on the potential emission rates and creditable emission decreases provided in the permit applications for those projects. These are discussed in more detail in Section 3.3.

Detailed emissions calculations for each emission source are presented in **Appendix C** (Tables C-1 to C-25). **Appendix J** includes vendor letters/specifications for each piece of equipment that validates data used to calculated emissions for the Project.

3.1 Project Emissions

3.1.1 Combustion Turbines

The main sources of emissions for the Project are the seven (7) GE 7HA.02 and ten (10) FT8 MOBILEPAC units. The following section presents the potential emission rates of these units. Additional emissions information at various loads, ambient temperatures, and operating conditions (e.g., with duct firing and evaporative cooling), as provided by the turbine manufacturer, are provided in **Appendix C** (Tables C-3 to C-12).

The GE combustion turbines are each equipped with dry low-NO_X combustors and SCR and the duct burners will be equipped with low NO_X burners to achieve controlled emissions of NO_X to 2.0 ppmvd @ 15% O_2 with and without duct burner firing over all steady state operating loads. This low NO_X emission limit can be achieved at an ammonia slip level of 5.0 ppmvd @ 15% O_2. Each GE turbine is also equipped with an oxidation catalyst to limit emissions of organic pollutants. VOC will be limited to concentrations of 1.5 ppmvd @ 15% O_2 with duct firing and 1.0 ppmvd @ 15% O_2 without duct firing over all steady state operating loads. CO will be limited to concentrations of 2.0 ppmvd @ 15% O_2 with and without duct firing over all steady state operating loads. Natural gas fuel sulfur content will be limited to 0.5 grains per 100 scf, which will limit per turbine emissions of SO_2, H_2SO_4, and particulate matter (PM, PM_{10} and $PM_{2.5}$). With duct firing, SO_2 emissions will be limited to 6.5 lb/hr, H_2SO_4 will be limited to 4.6 lb/hr, and $PM/PM_{10}/PM_{2.5}$ will be limited to 24.1 lb/hr. Without duct firing, SO_2 emissions will be limited to 5.0 lb/hr, H_2SO_4 will be limited to 3.4 lb/hr, and $PM_{10}/PM_{2.5}$ will be limited to 12.2 lb/hr.

Each of the GE 7HA.02 units is proposed to be operated up to 8,760 hr/yr with 8,760 hr/year to include duct burner firing. **Table 3-1** presents the maximum hourly emissions (lb/hr) and the annual emissions (tons per year) for criteria pollutants. Detailed emissions calculations are provided in **Appendix C** (Tables C-3 to C-6).

The FT8 combustion turbines are each equipped with water injection and SCR to achieve controlled emissions of NO_X to 2.5 ppmvd @ 15% O_2 over all steady state operating loads. This low NO_X emission limit can be achieved at an ammonia slip level of 5.0 ppmvd @ 15% O_2. Each FT8 turbine is also equipped with an oxidation catalyst to limit emissions of organic pollutants. CO will be limited to a maximum of 9.35 lb/hr and VOC will be limited to a maximum of 3.12 lb/hr. Natural gas fuel sulfur content will be limited to 0.5 grains per 100 scf, which will limit per turbine emissions of SO_2, H_2SO_4, and particulate matter (PM_{10} and $PM_{2.5}$). SO_2 emissions will be limited to 0.42 lb/hr, H_2SO_4 will be limited to 0.64 lb/hr, and PM/PM_{10}/$PM_{2.5}$ will be limited to 3.0 lb/hr. The FT-8 turbine manufacturer provided data on turbines which have been remanufactured and new turbines. At this time, it is not known how many of each type of turbine will be installed. As a result, a composite worst case of each turbine was compiled and used for emissions estimating purposes.

Each of the FT8 units is proposed to be operated up to 8,760 hr/yr. **Table 3-2** presents the maximum hourly emissions (lb/hr) and the annual emissions (tons per year). Detailed emissions calculations are provided in **Appendix C** (Tables C-7 to C-12).

3.1.1.1 Turbine Startup/Shutdown and Annual Emissions

The Project has the capability to start up each GE 7HA.02 and FT8 unit independently with no more than two (2) GE 7HA.02 and two (2) FT8 units starting within 1 hour. Pollutant-specific annual emission rates for the GE 7HA.02 and FT8 units were calculated based on vendor provided emissions data at 59ºF and the maximum of either 8,760 hr/year of continuous operation or emissions which include the maximum anticipated number of startup/shutdown events and the remaining hours at normal operating conditions, whichever is higher.

Annual emissions resulting from startup/shutdown operations for the proposed GE 7HA.02 units are based on an anticipated worst-case per unit annual schedule of 14 cold starts/year, 40 warm starts/year, 200 hot starts/year and 254 shutdowns/year. Under this assumption, the annual time associated with startup and shutdown accounts for approximately 207 hours per year per unit. Factoring in the downtime associated with each event, 72 hours for a cold start and 48 hours for a warm start, the remaining 5,625 hours per year were assumed to be under annual average normal operating conditions. The warm and cold start downtime is based on GE data and has been assumed to be 48 and 72 hours respectively.

Annual emissions resulting from startup/shutdown operations for the proposed FT8 units are based on an anticipated worst-case annual schedule of 150 starts/year. Under this assumption, the annual time associated with startup and shutdown accounts for approximately 99 hours per year per unit. The remaining 8,662 hours per year were assumed to be under annual average normal operating conditions.

Table 3-3. and **Table 3-4** presents the annual emissions (tons/year) of criteria pollutants, respectively, for the GE 7HA.02 and FT8 units for two cases:

(1) Continuous operations at 8,760 hours per year in normal operations.

(2) Continuous operations at 5,625 or 8,662 hours per year in normal operations and 207 and 99 hours per year in startup/shutdown operations per unit for the GE 7HA.02 and FT8 turbines, respectively.

The maximum GE 7HA.02 and FT8 emissions for all pollutants except for CO and VOC occur during 8,760 hours of normal continuous operation.

Table 3-5 presents the annual hazardous air pollutant (HAP) emission estimates for the GE 7HA.02 and FT8 units. AP-42 emission factors were used to calculate the HAP emissions with the exception of formaldehyde which was calculated based on vendor provided emissions data. The emissions calculations assume 8,760 hours per year of continuous operation.

Table 3-1. Proposed GE 7HA.02: Hourly and Annual Emissions

Pollutant	Maximum Hourly Emissions Rate Per CC during Normal Operations[1][2]		Potential Annual Emissions Rate Per CC during Normal Operations[1][3]
	With Duct Firing (lb/hr/CC)	Without Duct Firing (lb/hr/CC)	(tons/year/CC)
NO_X	33.20	25.90	141.04
CO	20.20	15.80	85.85
VOC	8.70	4.50	36.79
TSP[4]	24.10	19.00	100.74
$PM_{10}/PM_{2.5}$[4]	24.10	19.00	100.74
SO_2	6.50	5.00	27.59
H_2SO_4	4.70	3.40	19.71
Lead	0.0022	0.0017	0.0094
GHGs (CO_2e)[5]	536,457	418,574	2,277,505

(1) See Appendix C for detailed calculations.
(2) Maximum hourly emissions (lbs per hr) are based on natural gas firing at 100% load for the worst-case ambient temperature scenario.
(3) Annual emissions (tons per year) are based on a 100% capacity factor firing natural gas based on 100% normal full load at 59 degrees F.
(4) TSP/PM_{10}/$PM_{2.5}$ are all assumed to include both filterable and condensable PM emissions.
(5) CO_2e is the equivalent number of tons of CO_2 emissions with the same global warming potential as one ton of another greenhouse gas. CO_2e includes CO_2 emissions, CH_4 emissions as CO_2e, and N_2O emissions as CO_2e.

Table 3-2. Proposed FT8: Hourly and Annual Emissions

Pollutant	Maximum Hourly Emissions Rate Per CT during Normal Operations[1][2] (lb/hr/ADGT)	Potential Annual Emissions Rates Per CT during Normal Operations[1][3] (tons/year/ ADGT)
NO_X	2.79	12.05
CO	9.35	23.43
VOC	3.12	5.04
TSP[4]	3.00	13.14
$PM_{10}/PM_{2.5}$[4]	3.00	13.14
SO_2	0.42	1.80
H_2SO_4	0.64	2.77
Lead	0.00015	0.00064
GHGs (CO_2e)[5]	35,812	154,773

(1) See Appendix C for detailed calculations.
(2) Maximum hourly emissions (lbs per hr) are based on natural gas firing at 100% load for the worst-case ambient temperature scenario.
(3) Annual emissions (tons per year) are based on a 100% capacity factor firing natural gas based on 100% normal full load at 59 degrees F.
(4) TSP/PM_{10}/$PM_{2.5}$ are all assumed to include both filterable and condensable PM emissions.
(5) CO_2e is the equivalent number of tons of CO_2 emissions with the same global warming potential as one ton of another greenhouse gas. CO_2e includes CO_2 emissions, CH_4 emissions as CO_2e, and N_2O emissions as CO_2e.

Table 3-3. GE 7HA.02 Annual Emissions

Pollutant	Potential Annual Emission Rates (Per GE 7HA.02 Unit) [1]			Total for 7 GE 7HA.02 Units [1]
	Annual Emissions for Continuous Operation (tpy)	Annual Emissions with Startup and Shutdown (tpy)	Worst-Case Annual Emissions (tpy)	Worst-Case Annual Emissions (Total) (tpy)
NO_X	141.04	108.19	141.04	987.25
CO	85.85	110.63	110.63	774.40
VOC	36.79	39.34	39.34	275.41
TSP	100.74	65.94	100.74	705.18
PM_{10} / $PM_{2.5}$	100.74	65.94	100.74	705.18
SO_2	27.59	17.94	27.59	193.16
H_2SO_4	19.71	12.81	19.71	137.97
Lead	9.38E-03	6.11E-03	9.38E-03	6.57E-02
GHG (CO_2e)	2,277,505	1,482,025	2,277,505	15,942,537

(1) See Appendix C for detailed calculations.

Table 3-4. FT8 Annual Emissions

Pollutant	Potential Annual Emission Rates (Per FT8 Unit) [1]			Total for 10 FT8 Units [1]
	Annual Emissions for Continuous Operation (tpy)	Annual Emissions with Startup and Shutdown (tpy)	Worst-Case Annual Emissions (tpy)	Worst-Case Annual Emissions (Total) (tpy)
NO_X	12.05	13.20	13.20	132.00
CO	23.43	25.74	25.74	257.45
VOC	5.04	5.11	5.11	51.13
TSP	13.14	13.25	13.25	132.45
PM_{10} / $PM_{2.5}$	13.14	13.25	13.25	132.45
SO_2	1.80	1.79	1.80	17.96
H_2SO_4	2.77	2.75	2.77	27.75
Lead	6.35E-04	6.32E-04	6.35E-04	6.35E-03
GHG (CO_2e)	154,773	153,953	154,773	1,547,728

(1) See Appendix C for detailed calculations.

Table 3-5. Annual Potential Hazardous Air Pollutant (HAP) Emissions

Pollutant	Annual Potential HAP Emissions[1] (tpy)	
	GE 7HA.02	FT8
Arsenic	0.03	2.55E-03
Beryllium	1.58E-03	1.53E-04
Cadmium	0.14	0.01

Pollutant	Annual Potential HAP Emissions[1] (tpy)	
	GE 7HA.02	FT8
Chromium (total)	0.18	0.02
Cobalt	0.01	1.07E-03
Lead	0.07	6.38E-03
Manganese	0.05	4.85E-03
Mercury	0.03	3.32E-03
Nickel	0.28	0.03
Selenium	3.15E-03	3.06E-04
1,3-Butadiene	0.03	2.80E-03
Acetaldehyde	2.68	0.26
Acrolein	0.43	0.04
Benzene	0.80	0.08
Ethylbenzene	2.14	0.21
Formaldehyde	29.3	2.85
Naphthalene	0.09	8.46E-03
Polycyclic Aromatic Hydrocarbons (PAHs)	0.15	0.01
Propylene Oxide	1.94	0.19
Toluene	8.71	0.85
Xylene	4.29	0.42
TOTAL	**51.29**	**4.99**

(1) See Appendix C for detailed calculations.

3.1.2 Ancillary Sources

The Project will include twelve (12) ULSD-fired emergency generator engines and one (1) ULSD-fired fire water pump engine which will be operated for emergency purposes, maintenance and readiness testing, and other allowed non-emergency situations. Three (3) natural gas-fired auxiliary boilers will also be installed to assist the CC units while in startup mode. In addition, seven (7) natural gas-fired fuel gas heaters will also be installed to warm the incoming natural gas fuel to prevent freezing of the gas regulating valves under certain gas system operating conditions, and seven (7) 8-cell cooling towers will be installed. Sulfur hexafluoride (SF_6) containing circuit breakers will also be installed. Emissions of criteria pollutants and HAPs from the ancillary equipment are presented in **Table 3-6** and detailed emissions calculations are provided in **Appendix C** (Tables C-13 to C-25).

3.1.2.1 Auxiliary Boilers

The facility will include three (3) natural gas-fired auxiliary boilers, each with a heat input rating of 67 MMBtu/hr. The boilers are being permitted with a 5% annual operating capacity factor. Therefore, annual emissions are based on this limitation. Emissions of criteria pollutants and HAPs from the auxiliary boiler are presented in **Table 3-6** and detailed emission calculations are presented in **Appendix C** (Tables C-13 and C-14).

3.1.2.2 Emergency Engines

The Project will include ten (10) 2,500 kWe emergency generators, two (2) 1,000 kWe emergency generators and one (1) 400 bhp emergency fire water pump engine. The ULSD-fired emergency generators will meet the Tier 4

emission requirements in EPA's Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 40 CFR Part 60, Subpart IIII and 40 CFR 1039. The engines will also meet the applicable requirements of 40 CFR Part 63, Subpart ZZZZ.

The fire water pump engine and the emergency generators will operate for emergency purposes and for limited periods of routine testing, maintenance, and other non-emergency purposes. The fire water pump engine and emergency generators are considered emergency engines and will be operated for no more than 500 hours per year.

Emissions of criteria pollutants and HAPs from the emergency engines are presented in **Table 3-6** and detailed emissions calculations can be found in **Appendix C** (Tables C-15 to C-20).

3.1.2.3 Fuel Gas Heaters

The Project will also include seven (7) natural gas-fired fuel gas heaters, each with a heat input rating of approximately 10.8 MMBtu/hr, to support the proposed CC units. Emissions of criteria pollutants and HAPs from the natural gas-fired fuel gas heaters are also presented in **Table 3-6** and detailed emissions calculations are presented in **Appendix C** (Tables C-21 and C-22).

3.1.2.4 Cooling Tower

Seven (7) wet mechanical draft cooling towers with plume abatement will be incorporated to provide water to the steam turbine condensers. Particulate matter emissions will be controlled by high efficiency drift eliminators which will limit drift to 0.0005% of the recirculated water rate. TSP, PM_{10}, and $PM_{2.5}$ emissions from the cooling towers are presented in **Table 3-6** and detailed emissions calculations are presented in **Appendix C** (Table C-23).

3.1.2.5 Gas-Insulated Switchgear

The Project will include GIS which hold approximately 3,000 lbs Sulfur hexafluoride (SF_6) per bay and the Project will require 23 bays for a total installed capacity of 69,000 lbs of SF_6. There will be a maximum leak rate of less than 0.5% annually. SF_6 emissions from the GIS are presented in **Table 3-6** and detailed emissions calculations are presented in **Appendix C** (Table C-24).

3.1.2.6 Fugitive Natural Gas Leaks

The project will include natural gas piping which will have mechanical connections and components which over time may potentially leak small amounts of GHG from the methane contained in natural gas. As an estimation of potential emissions, emission factors were taken from Table 2-4 from the Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017) for equipment in gas service. This estimate may overstate the actual amount, as it theoretically counts every component as leaking at once. Since exact component counts are not yet known for the project, an estimate was made by scaling up component counts from the Fairview Energy Center Plan Approval application. Detailed emissions calculations are presented in **Appendix C** (Table C-25).

Table 3-6. Annual Potential Criteria Pollutant and HAP Emissions from Ancillary Sources

	Potential Emissions (tpy)[1]							
Pollutant	**Auxiliary Boilers**	**Fuel Gas Heaters**	**Emergency Generator 2,500 kW**	**Emergency Generator 1,000 kW**	**Emergency Fire Water Pump**	**Cooling Towers**	**Gas Insulated Switchgear**	**Fugitive Leaks**
NOx	2.16	9.92	10.00	0.82	0.66	--	--	--
CO	3.63	12.23	52.26	4.27	0.57	--	--	--
VOC	0.24	1.65	2.84	0.23	0.66	--	--	--
TSP	0.33	1.59	0.45	0.037	0.033	3.13	--	--
PM_{10}	0.33	1.59	0.41	0.034	0.030	2.20	--	--

Pollutant	Potential Emissions (tpy)[1]							
	Auxiliary Boilers	Fuel Gas Heaters	Emergency Generator 2,500 kW	Emergency Generator 1,000 kW	Emergency Fire Water Pump	Cooling Towers	Gas Insulated Switchgear	Fugitive Leaks
$PM_{2.5}$	0.33	1.59	0.40	0.034	0.030	0.0071	--	--
SO_2	0.062	0.46	0.11	0.0090	0.0012	--	--	--
Lead	2.16E-05	1.62E-04	--	--	--	--	--	--
GHG (CO_2e)	5,237	39,329	10,401	849	114	--	4,054	1,205
HAPs	0.08	0.61	0.10	0.008	0.003			

(1) Emissions reflect total from all proposed pieces of equipment.

Table 3-7. Total Project Potential to Emit of Criteria Pollutants (tpy)

	TSP	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2e
GE 7HA.02 (7 units total)	705.18	705.18	705.18	987.25	774.40	275.41	193.16	137.97	6.57E-02	15,942,537
FT8 MOBILPAC (10 units total)	132.45	132.45	132.45	132.00	257.45	51.13	17.96	27.75	6.35E-03	1,547,728
Auxiliary Boilers (3 units total)	0.33	0.33	0.33	2.16	3.63	0.24	0.062	0.0009	2.16E-05	5,237
Fuel Gas Heaters (7 units total)	1.59	1.59	1.59	9.92	12.23	1.65	0.46	0.0071	1.62E-04	39,329
Emergency Generators (2,500 kW) (10 units total)	0.45	0.41	0.40	10.00	52.26	2.84	0.11	0.0084	--	10,401
Emergency Generators (1,000 kW) (2 units total)	0.037	0.034	0.034	0.82	4.27	0.23	0.0090	0.00069	--	849
Fire-water Pump Engine (1 unit total)	0.033	0.030	0.030	0.66	0.57	0.66	0.0012	0.000093	--	114
Cooling Towers	3.13	2.20	0.0071	--	--	--	--	--	--	--
GIS Equipment	--	--	--	--	--	--	--	--	--	4,054
Fugitive Leaks	--	--	--	--	--	--	--	--	--	1,205
Facility Total	843.19	842.23	840.02	1,142.80	1,104.80	332.16	211.76	165.73	7.22E-02	17,551,454

Table 3-8. Annual Project Potential to Emit of HAP

Emission Source Description	HAP PTE (tpy)
GE 7HA.02 Units	51.29
FT8 Units	4.98
Associated Equipment	0.80
Combined HAP	57.08
Largest Single HAP	32.20 (Formaldehyde)

Table 3-7 provides the Project annual criteria pollutant potential to emit based on the maximum emitting scenario for the proposed emission units presented in **Table 3-3.** and **Table 3-4** along with the potential to emit for associated equipment presented in **Table 3-6**.

Table 3-8 provides the Project annual HAP potential to emit based on the proposed emission units presented in **Table 3-5** and **Table 3-6**.

Section 3.2 presents the creditable emission decrease associated with the coal plant shutdown followed by the PSD/NNSR applicability determination in **Section 3.3**. Total HAP potential to emit from the Project will exceed 25 tons/year, and individual HAP potential to emit will exceed 10 tons per year (see **Appendix C**: Table C-2 for details).

3.2 Creditable Emissions Decreases

Homer City has recently retired all elements of the coal-fired power plant. Due to this shutdown, creditable emission decreases are available within the contemporaneous period to be used in a netting analysis for the Project. Based on annual operating data, Homer City has defined calendar years 2021 and 2022 as the baseline period for the creditable emission decreases for Units 1, 2, and 3, as this period was representative of typical operations within a 5-year period prior to the anticipated commencement of construction. Homer City is currently undergoing a Title V modification removing all existing coal-fired related emission sources, thus making the emission reductions federally enforceable.

The creditable emission decreases for Units 1, 2, and 3 are based on the average of the annual emission estimates of PSD pollutants for calendar years 2021 and 2022. The annual emission estimates are consistent with the values submitted in the PADEP Inventories. The NO_x and SO_2 are based on continuous emissions monitor (CEM) data for Units 1, 2, and 3. Annual emissions for TSP, PM_{10}, CO, VOC, and H_2SO_4 are based on the annual heat input for calendar years 2021 and 2022 and stack test data. NOx emissions have been discounted for compliance with RACT as implemented by the FIP. This discount applies the 30-day facility-wide rolling NOx lb/MMBtu limitation on top of the unit specific lb/day limitations imposed by the FIP. The creditable emission decreases are summarized in **Table 3-9** and in **Appendix C**: Table C-1 of this document.

Table 3-9. Creditable Emission Decreases Associated with Coal Plant Shutdown

		Actual Emissions (ton/yr)							
Unit	**Calendar Year**	**TSP**	**PM_{10}**	**$PM_{2.5}$**	**NO_x**	**CO**	**VOC**	**SO_2**	**H_2SO_4**
Unit 1	2021	86.1	86.1	86.1		1,169.9	4.8	1,399.1	2.6
Unit 1	2022	71.8	71.8	71.8		974.9	4.0	1,208.8	2.2
Unit 2	2021	68.6	68.6	68.6		1,228.7	4.5	1,243.6	0.6
Unit 2	2022	8.9	8.9	8.9		329.4	1.2	343.3	0.2
Unit 3	2021	97.2	97.2	97.2		2,128.9	3.9	2,092.5	24.3
Unit 3	2022	107.8	107.8	107.8		2,361.3	4.3	2,633.8	27.0
Unit 1	2-Year Average	78.9	78.9	78.9		1,072.4	4.4	1,304.0	2.4
Unit 2	2-Year Average	38.7	38.7	38.7		779.0	2.9	793.5	0.4
Unit 3	2-Year Average	102.5	102.5	102.5		2,245.1	4.1	2,363.2	25.6
Unit 1-3 (Total)	**2-Year Average**	**220.2**	**220.2**	**220.2**	**2,031.8**	**4,096.5**	**11.3**	**4,460.6**	**28.4**

3.3 PSD and Non-Attainment New Source Review Applicability Determination Summary

A PSD applicability determination was prepared for each applicable PSD pollutant using the Project emissions summarized in **Table 3-7** and the creditable emission decreases in **Table 3-9**. NNSR was considered for SO_2 because Indiana County is a nonattainment area for the 2010 1-hr SO_2 NAAQS. However, on September 13, 2024, the United States Environmental Protection Agency (US EPA) issued a rule approving the state implementation plan (SIP) revision submitted by the Commonwealth of Pennsylvania related to the Indiana Co. 1-hour SO_2 non-attainment designation. A NNSR determination was also prepared for NO_x and VOC because the facility is located in the Ozone Transport Region (OTR) and is treated as a moderate nonattainment area for ozone. The Project is deemed to be subject to PSD/NNSR review if the sum of the emissions from the Project emission increases and decreases during the contemporaneous period exceeds the pollutant-specific thresholds defined as a "significant net increase" in 40 CFR 51.166 (for PSD pollutants) and in 40 CFR 51.165 and 25 Pa. Code Chapter 127, Subchapter E (for NNSR pollutants).

The potential Project emissions will exceed the PSD and NNSR applicability thresholds for several pollutants. Consequently, a netting analysis was completed to determine which pollutants fall below the "significant net increase" thresholds and therefore "net out" of PSD/NNSR applicability. The results of the Project netting analysis are provided in **Table 3-10** for PSD pollutants and **Table 3-11** for NNSR pollutants.

The Project will be subject to PSD review for PM_{10}, $PM_{2.5}$, H_2SO_4 and GHG and NNSR for VOC.

Table 3-10. Net Change in Emission Increases Compared to PSD Significant Emission Rates

	TSP	PM_{10}	$PM_{2.5}$	NO_x	CO	H_2SO_4	Lead	CO_2e
Project Total	843.19	842.23	840.02	1,142.80	1,104.80	165.73	7.22E-02	17,551,454
Creditable Emission Decreases	220.2	220.2	220.2	2,031.8	4,096.5	28.4	--	--
Project Net Increase	623.0	622.0	619.8	-889.0	-2,991.7	137.3	--	--
PSD Significance Emission Rate (ton/yr)	25	15	10	40	100	7	0.6	75,000
PSD Review Triggered?	Yes	Yes	Yes	No	No	Yes	No	Yes

Table 3-11. Net Change in Emission Increases Compared to NNSR Significant Emission Rates

	NO_x	VOC	SO_2
Project Total	1,142.80	332.16	211.76
Creditable Emission Decreases	2,031.8	11.3	4,460.6
Facility Total Less ERCs/Netting	-889.0	320.9	-4,248.8
NNSR Significance Emission Rate (ton/yr)	40	40	40
NNSR Review Triggered?	No	**Yes**	No

4. Applicable Regulations

As described in the previous sections, the Project consists of the following sources of air emissions:

- Seven (7) GE 7HA.02 CC combustion turbines with supplemental duct burner firing;
- Ten (10) Mitsubishi Power FT8 Gas Turbine MOBILEPAC;
- Three (3) auxiliary boilers rated at 67 MMBtu/hr each, operating on pipeline quality natural gas;
- Ten (10) emergency generator engines rated at 2,500 kWe each, operating on ULSD;
- Two (2) emergency generator engines rated at 1,000 kWe each, operating on ULSD;
- One (1) emergency fire-water pump rated at 400 bhp, operating on ULSD;
- Seven (7) fuel gas heaters each rated at 6.3 MMBtu/hr operating on pipeline quality natural gas;
- Seven (7) cooling towers, with eight (8) cells each; and
- Fugitive emissions from gas insulated switchgear (GIS) and natural gas piping components.

This section identifies the federal and state air quality regulations that will govern construction and operation of the Project. Specifically, the following regulations and standards were reviewed for applicability to the Project:

- National Ambient Air Quality Standards (NAAQS);
- Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Regulations;
- Good Engineering Practice (GEP) Stack Height Regulations;
- New Source Performance Standards (NSPS);
- National Emission Standards for Hazardous Air Pollutants (NESHAP);
- Compliance Assurance Monitoring (CAM);
- Acid Rain Program Regulations (ARP);
- Risk Management Program (RMP);
- Cross-State Air Pollution Rule (CSAPR);
- Greenhouse Gas Reporting Program (GHGRP); and
- PADEP, Air Division – Bureau of Air Quality.

The Federal regulatory programs, as administered and delegated by the US EPA, have been developed under the authority of the Clean Air Act (CAA or Act) and its amendments. These regulatory programs have been adopted by PADEP (25 Pa. Code § 127.83). The following subsections review the key elements of the regulatory programs and the impact they have on the permitting and operation of the Project. Discussion of other applicable PADEP regulatory requirements is also included in this section.

4.1 Prevention of Significant Deterioration (PSD) Program

4.1.1 PSD Applicability

For PSD applicability, the Project's potential to emit (PTE) is reviewed to determine whether it constitutes a major stationary source or a major modification. Homer City was defined as a major stationary source because it is one of the 28 major source types, and it had the potential to emit more than 100 tons per year of at least one NSR regulated pollutant. For pollutants currently in attainment, a major modification is defined as a physical or operational change at a major source that results in a net increase in emissions above the PSD significant emission rates, as identified in **Table 4-1**.

For pollutants currently subject to NA-NSR, the major source thresholds are potential emissions of 50 tons per year for VOCs and 100 tons per year of NO_X.

Table 4-1. PSD Significant Emission Rates

Pollutant	Significant Emission Rate[1] (tpy)
CO	100
NO_X	40
SO_2	40
PM	25
PM_{10}	15
$PM_{2.5}$	10
O_3	40 of VOC or NO_X
Lead (Pb)	0.6
Fluorides (excluding HF)	3
Sulfuric Acid Mist (H_2SO_4)	7
Total Reduced Sulfur (including H_2S)	10
Reduced Sulfur Compounds (including H_2S)	10
Greenhouse Gases (as CO_2e)	75,000

(1) Source: 40 CFR 52 and 25 PA Code 121.1

The Project will have emission increases above the applicable significance levels for PM, PM_{10}, $PM_{2.5}$, VOC, H_2SO_4, and GHG, as previously shown in **Table 3-10**. Therefore, PSD (or, for VOCs, NNSR) review is required only for these pollutants. In addition, **Table 3-10** shows that the Project will not be subject to PSD review for SO_2, CO, and NO_X and also not subject to NNSR for NO_X. However, VOC emission will be subject to NNSR (see **Table 3-11**) and will apply Lowest Achievable Emission Rate (LAER) control technology, as addressed in **Section 5**, and will obtain offsets for the affected pollutants.

4.1.2 PSD Program Requirements

The following sections provide a summary of the application requirements for projects subject to permitting under PSD.

BACT and LAER

The requirements for BACT and LAER were promulgated within the framework of the PSD regulations in the 1977 CAA Amendments. Guidelines for the evaluation of BACT and LAER can be found in US EPA's Air Pollution Control Cost Manual (EPA 2018) and in the Draft New Source Review Workshop Manual (EPA 1990). These guidelines were drafted by US EPA as a framework or tool for the BACT/LAER process. EPA has also published guidance on BACT for greenhouse gas emissions (http://www.epa.gov/nsr/ghgpermitting.html). PADEP has adopted US EPA's PSD requirements (25 Pa. Code § 127.83). The BACT analysis for the Project is presented in Section 5.

Air Quality Monitoring Requirements

A PSD permit application must contain an analysis of existing ambient air quality data in the affected area for all regulated pollutants that the Project has the potential to emit in significant amounts. The analysis of existing air quality can be air monitoring data from either a state-operated or private network, or by a pre-construction monitoring program that is specifically designed to collect data in the vicinity of the proposed source.

Source Impact Analysis

A source impact analysis must be performed for a proposed project for each pollutant that triggers PSD review in order to demonstrate that the Project will not cause or contribute to a violation of any NAAQS or any applicable maximum allowable increase over the baseline concentration in any area. PSD regulations specify that new major sources or modifications to existing major sources may change baseline air quality only by a defined amount. This

limited incremental degradation is known as a PSD increment. PSD increments have been established for Class I and Class II areas. **Table 4-2** lists the PSD increments for those pollutants subject to PSD review. The allowable change, or increment, is dependent on the classification of the area in which the action is to take place. When PSD regulations were first promulgated, three area classifications were proposed based on criteria set in the 1977 CAA.

Class I areas are federally protected areas and include specifically defined national parks, national forests, and wilderness areas. Class III increments are the least restrictive of the three PSD Classes, but to date, no Class III areas have been officially designated. The remainder (and vast majority) of the country (including Indiana County) is designated as a Class II area.

The PSD regulations specifically provide for the use of atmospheric dispersion modeling in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with NAAQS and allowable PSD increments. Designated US EPA models, identified in 40 CFR Part 51, Appendix W, must normally be used in performing air quality analyses (US EPA, 2024a). Use of anything other than EPA-approved models requires written approval and opportunity for public notice and comment prior to use. Guidance for the use and application of dispersion models is presented in the US EPA publication Guideline on Air Quality Models (GAQM, 40 CFR Part 51, Appendix W). The source impact analysis for criteria pollutants may be limited to only the new or modified sources if a net increase in impact due to the new or modified source is below the significant impact levels (SILs) presented in **Table 4-2**.

Various periods of meteorological data can be utilized for an impact analysis. A minimum 1-year period of onsite data, or a 5-year period of representative meteorological data is normally required.

Table 4-2. PSD Increments and Significant Impact Levels (µg/m^3)

		PSD Increments (µg/m^3)		Significant Impact Levels (µg/m^3)	
Pollutant	**Averaging Period**	**Class I**	**Class II**	**Class I**	**Class II**
PM_{10}	24-hour(2)	8	30	0.3	5
	Annual(1)	4	17	0.2	1
$PM_{2.5}$	24-hour(2)	2	9	0.27	1.2
	Annual(1)	1	4	0.03	0.13

1. Not to be exceeded (PSD Increment).
2. Not to be exceeded more than once per year (PSD Increment).

In addition to the standard air quality analyses, federal regulations require that applicants of PSD projects conduct an analysis of the impairment to visibility and the effects on soils and vegetation that would occur as a result of project construction and operation. Impacts due to commercial, residential, industrial, and other growth in the vicinity of the Project also must be addressed to the extent they are a result of the proposed action. These additional requirements are addressed in **Section 9** of this application.

4.2 Ambient Air Quality Classification

The 1970 CAA provides EPA with specific authority to establish NAAQS for six common air pollutants in order to protect public health (primary standards) and welfare (secondary standards). The federally promulgated standards, adopted by PADEP (25 Pa. Code § 131.2), are presented in **Table 4-3** for those pollutants for which the Project is subject to PSD review.

Table 4-3. National Ambient Air Quality Standards

Pollutant	Averaging Period	Primary Standard ($\mu g/m^3$)	Secondary Standard ($\mu g/m^3$)
PM_{10}	24-hour(1)	150	150
$PM_{2.5}$	24-hour(2)	35	35
	Annual(3)	9	15

1. Not to be exceeded more than an average of one day per year over three years.
2. Compliance with the 24-hour standard is demonstrated when the 3-year average (5-year average in a modeling demonstration) of the 98th-percentile (8th High) 24-hour concentration is below the standard.
3. Not to be exceeded by the arithmetic average of the annual arithmetic averages from 3 successive years.

Source: EPA 40 CFR 50

The 1990 CAA Amendments call for a review of the ambient air quality of all regions of the United States. By March 15, 1991, states were required to file with EPA designations of all areas as either attainment, nonattainment, or unclassifiable. Areas of the country that had monitored air quality levels equal to or better than these standards (i.e., ambient concentrations less than a standard) as of March 15, 1991, became designated as "attainment areas," while those areas where monitoring data indicated air quality concentrations greater than the standards became classified as "nonattainment areas."

The designation of “unclassifiable” indicates that there is insufficient monitoring data to demonstrate that the area has attained the federal standards; however, the limited data available indicates that the standard has been achieved. Areas with this classification are treated by the EPA as attainment areas for permitting purposes.

The Project will be located in Indiana County, and the current federal air quality classifications for the Project site are listed in **Table 4-4** for each criteria pollutant subject to PSD review. The designation of an area is important for a proposed project as it is a factor that, in part, determines whether a pollutant is subject to Prevention of Significant PSD review or NA-NSR.

Table 4-4. Classification of Indiana County, PA, for each Criteria Pollutant Subjec to PSD Review

Pollutant	Attainment Status
Particulate Matter < 10 µm (PM_{10})	Unclassifiable/Attainment
Particulate Matter < 2.5 µm ($PM_{2.5}$)	Unclassifiable/Attainment

Source: 40 CFR 81.301.

Major new sources or major modifications to existing major sources located in attainment or unclassifiable areas are required to obtain a PSD permit prior to initiation of construction. Similar sources located in areas designated as nonattainment (or that adversely impact such areas) are required to undergo permitting under the provisions of the NNSR program. In either case, it is necessary as a first step to determine the air quality classification of a project site. For the Project, only PSD review is applicable because the attainment status for Indiana County is either unclassifiable/attainment or unclassifiable for all applicable pollutants, except for NO_X and VOC. As-stated, since Pennsylvania is located in the OTR, the Project must be reviewed for NNSR applicability for NO_X and VOC emissions.

4.3 Good Engineering Practice (GEP) Stack Height Analysis

The 1977 CAA requires that the degree of emission limitation required for control of any pollutant not be affected by a stack which exceeds the GEP height (EPA 1985). These requirements are described in more detail in **Section 6.4**.

4.4 Federal Regulations

4.4.1 40 CFR Part 60 New Source Performance Standards (NSPS)

4.4.1.1 Subpart A – General Provisions

All affected sources which are subject to a NSPS under 40 CFR Part 60 are subject to the general provisions of 40 CFR Part 60 Subpart A, unless those provisions are specifically excluded by an applicable source-specific NSPS. Since the Project will be subject to at least one NSPS, the permittee will be required to comply with applicable provisions of Subpart A. Subpart A contains initial notification, performance testing, monitoring, and recordkeeping requirements for the subparts, as applicable.

4.4.1.2 Subpart Kc – Volatile Organic Liquid Storage Vessels (Including Petroleum Liquids Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After October 4, 2023

As part of the Project, the new facility will have storage tanks for the ultra-low sulfur distillate oil that will be used in the proposed emergency generator and fire water pump engines and storage tanks for turbine lubricating oils. 40 CFR Part 60, Subpart Kc regulates storage vessels with a capacity greater than 75.7 cubic meters (m^3) (20,000 gallons) that are used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after October 4, 2023. However, Subpart Kc does not apply to storage vessels of any size storing a liquid with a maximum true vapor pressure less than 0.25 psia (1.7 kPa absolute). The Project is not expected to have organic liquid storage tanks greater than 20,000 gallons of storage capacity. Additionally, the ULSD and lubricating oils to be stored on site all have vapor pressures less than 0.25 psia.

4.4.1.3 Subpart IIII –Stationary Compression Ignition Internal Combustion Engines

The emergency generator and fire water pump engine are subject to the emission standards in 40 CFR Part 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. GPC will comply with the emission standards by purchasing an engine certified by the manufacturer to the emission standards in 40 CFR 60.4202, as applicable, for the same model year and maximum engine power. The emergency generator engines will be voluntarily subject to Tier 4 standards under 40 CFR Part 1039 and the fire water pump engine will be subject to standards under Subpart IIII. The Project will comply with all applicable Subpart IIII monitoring, recordkeeping, and reporting requirements. Since the engines will be designated and operated as emergency engines, they will only be operated in emergency circumstances and for a maximum of 100 hours per year for maintenance and readiness testing, 50 hours of which may be used in non-emergency situations. For purposes of estimating emissions from these units, 500 hours per year is used, inclusive of emergency operations.

4.4.1.4 Subpart KKKK / KKKKa – Stationary Combustion Turbines

The proposed CT units will be subject to 40 CFR Part 60, Subpart KKKK, which establishes NO_X and SO_2 emission limits for stationary combustion turbines that commence construction, modification, or reconstruction after February 18, 2005 and have a heat input at peak load equal to or greater than 10 MMBtu/hr based on the higher heating

value. EPA has also proposed a replacement to KKKK, KKKKa which was published as a proposed regulation in the Federal Register on December 13, 2024.

4.4.1.4.1 Emission Limits for NO_X

Under the current Subpart KKKK, the proposed CC units are subject to NO_X emission standards for turbines with heat inputs > 850 MMBtu/hr of 15 ppmvd @ 15% O_2, when firing natural gas based on a 30-operating day rolling average. The proposed ADGT units are subject to NO_X emission standards for turbines with heat inputs between 850 and 50 MMBtu/hr of 25 ppmvd @ 15% O_2, when firing natural gas based on a 4-hour rolling average.

Under the proposed Subpart KKKKa, if finalized as approved, the CC units would become subject to a NO_X emission standard of 3 ppmvd @ 15% O_2 and the ADGT units would become subject to a NO_X emission standard of 3 ppmvd @ 15% O_2. Each of these emission limits are based on a 4-hour rolling average.

As discussed in the BACT analysis in Section 5.0, the proposed CC units will reduce NO_X emissions using DLN and SCR to comply with Subpart KKKK/KKKKa. The ADGT units will reduce NO_X emissions using water injection and SCR to comply with Subpart KKKK/KKKKa. Compliance with the Subpart KKKK/KKKKa emissions standards will be verified based on CEMS data.

4.4.1.4.2 Emission Limits for SO_2

The proposed CT units will be subject to either an emission limit of 0.9 lb/MWh gross output or a limit on the use of any fuel that contains the total potential sulfur emissions in excess of 0.06 lb SO_2/MMBtu heat input. This limit is from the existing Subpart KKKK and is unchanged in the proposed KKKKa regulation.

The Project will comply with the input-based emission standard for SO_2 by utilizing pipeline quality natural gas which has a sulfur content lower than needed to meet the 0.06 lb SO_2/MMBtu limit.

4.4.1.5 Subpart TTTTa – Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

NSPS TTTTa applies to combustion turbines which have base load ratings of greater than 250 MMBtu/hr heat input from fossil fuel(s) and serve a generator or generators capable of selling greater than 25 MWe to a utility power distribution system. Greenhouse gas emissions from the CC turbines will be subject to regulation under Subpart TTTTa, which requires combustion turbines to meet emission limits based on their electric sales capacity. The CC units will have to meet an emission limitation of 800 lbs CO_2/MWh based on gross energy output or 820 lbs CO_2/MWh, based on net energy output. The limits will be based on the amount of CO_2 reported through Part 75 monitoring and the measured gross electrical generation of the units.

The ADGT units will not be subject to this regulation, as they have a base load heat input capacity of greater than 250 MMBtu/hr but will serve a generator with a nameplate capacity of 25 MWe, not greater than 25 MWe.

4.4.1.6 Part 60 Appendices

Appendix A of Part 60 contains source stack testing methods and procedures. The requirements for which methods to use are contained in the individual NSPS Subparts.

Appendices B and F of Part 60 contain CEMS performance specifications and quality assurance procedures. The Project will use CEMS for monitoring NO_X, CO, and O_2 as a diluent gas. However, NOx and O_2 CEMS will be subject to more stringent requirements under Part 75.

4.4.2 40 CFR Part 61 National Emission Standards for Hazardous Air Pollutants (NESHAP)

Part 61 contains regulations with specific requirements for the control of beryllium, vinyl chloride, asbestos, and other specific industrial sources. The Project is not subject to any requirements under Part 61.

4.4.3 40 CFR Part 63 NESHAP

4.4.3.1 Subpart A – General Provisions

The general provisions of Subpart A apply to sources which are subject to any regulation under Part 63. Standards can apply to major sources of HAPs which have emissions of any individual HAP greater than 10 tons per year or greater than 25 tons of combined HAPs or area sources (i.e., non-major sources). The Project will be a major source of HAPs and as described below; the Project will be subject to three NESHAP standards.

4.4.3.2 Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

The Combustion Turbine MACT standard (Subpart YYYY) applies to stationary combustion turbines at major sources of HAP. The proposed CC and CT units are each subject to a formaldehyde emission limit of 91 parts per billion by volume, dry (ppbvd), corrected to 15% O_2, and other associated requirements, including initial notification and testing. Both the combined cycle and the simple cycle turbines will use an oxidation catalyst for controlling formaldehyde.

4.4.3.3 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

The emergency generators and fire water pump engine are subject to 40 CFR Part 63, Subpart ZZZZ and will comply with the applicable requirements of that subpart by complying with the applicable requirements. The fire water pump engine is only subject to requirements under 40 CFR Part 60 Subpart IIII per 40 CFR §63.6590(c)(6) as a new emergency stationary RICE with a site rating of less than 500 bhp located at a major source of HSP emissions. No initial notification is required for the emergency fire water pump engine because it has a site rating of less than 500 bhp. The emergency generator engines are subject to limited requirements under subpart ZZZZ, which are only required to submit initial notification requirements of §63.6645(f) as a new emergency stationary RICE with a site rating of more than 500 bhp located at a major source of HAP emissions, per §63.6590(b)(1)(i)

4.4.3.4 Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

The Industrial Boiler MACT (Subpart DDDDD) applies to boilers and process heaters constructed or reconstructed after June 4, 2010, and located at major sources of HAP.

The auxiliary boilers are subject units under the regulation as they will generate steam. The proposed auxiliary boilers are part of the designed to burn gas 1 fuels subcategory and have a heat input rating of greater than 10 MMBtu/hr. Therefore, the proposed auxiliary boilers are not subject to the emission limits in Tables 1 and 2 or 11 through 13, or the operating limits in Table 4. However, the proposed auxiliary boilers are subject to the work practice standard outlined in Table 3, where it is required that a tune-up is performed annually unless the unit has a continuous oxygen trim system at which point tune-ups can be conducted every five years.

“Process heaters” are defined in Subpart DDDDD as “…an enclosed device using controlled flame, and the unit’s primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials.” The proposed fuel gas heaters qualify as process heaters and will be subject to Subpart DDDDD.

The proposed fuel gas heaters are part of the designed to burn gas 1 fuels subcategory and have a heat input rating of greater than 10 MMBtu/hr. Therefore, the proposed fuel gas heaters are not subject to the emission limits in Tables 1 and 2 or 11 through 13, or the operating limits in Table 4. However, the proposed auxiliary boilers are subject to the work practice standard outlined in Table 3, where it is required that a tune-up is performed annually unless the unit has a continuous oxygen trim system at which point tune-ups can be conducted every five years.

4.4.4 40 CFR Part 64 Compliance Assurance Monitoring (CAM)

Part 64 applies to pollutant-specific emission units which have emissions of pollutants which:

1) are subject to an emission limit or standard, other than an emission limitation or standard listed as exempt under 40 CFR 64.2(b)(1);
2) use a control device to achieve compliance with that emission limit or standard; and
3) have potential pre-control device emissions in the amount required to classify the unit as a major source under Part 70 of the Clean Air Act (CAA) (i.e., the Title V permitting program).

CAM applicability, if required, a CAM Plan will be submitted as required as part of the initial Title V Operating Permit application.

4.4.5 40 CFR Part 68 Risk Management Program (RMP), Section 112(r)

Risk management plans are required when storing quantities of listed materials above listed thresholds. The Project will not store any listed materials is quantities greater than the listed threshold amounts. The ammonia for the SCR systems will be 19% aqueous ammonia, below the 20% threshold amount for the RMP program.

4.4.6 40 CFR Part 70 Operating Permit

The Project will be subject to regulation under 25 Pa. Code Chapter 127, Subchapter G. An application for a Title V Operating permit will be submitted within 120 days of notification by PADEP in accordance with 25 Pa. Code §127.505.

4.4.7 40 CFR Part 72 Acid Rain Program

The proposed CC units meet the definition of an affected Phase II “utility unit” under the Acid Rain Program (ARP) (40 CFR 72.6) because they are fossil fuel-fired combustion devices used to generate electricity for sale, and their capacity serves generators that exceed 25 MWe. The ADGT turbines are exempt under the 40 CFR 72.7(a) new unit exemption as they will each serve a generator with a nameplate capacity of 25 MWe or less, does not burn coal or coal-derived fuel, and will burn gaseous fuel with an annual average sulfur content of 0.05 wt% or less.

The primary applicable requirements under the ARP include:

- Amend the existing Phase II Acid Rain Permit for Homer City to include the new combustion turbine units;
- Install CEMS and fuel flow meters on the proposed CC and CT units to demonstrate compliance with the requirements specified in 40 CFR Part 75; and
- Hold allowances equivalent to annual SO_2 emissions.

An Acid Rain permit application must be submitted 24 months before the units commence commercial operation and include the deadline for monitoring certification (90 days after commencement of commercial operation). The Acid Rain permit application is provided in **Appendix H**.

Homer City will meet the applicable Acid Rain requirements that become effective after the issuance of the Acid Rain permit and will include the new applicable units in its Title IV Acid Rain monitoring plan, as required under 40 CFR Part 72.

4.4.8 40 CFR Part 75 Continuous Emissions Monitoring

Part 75 implements requirements for sources which are required by other regulations such as the Acid Rain Program or CSAPR such as to install and operate CEMS or otherwise follow the emissions calculation guidelines within Part 75. Each of the proposed CCs will each be equipped with CEMS for monitoring NO_X and O_2. Part 75 provides additional calculation methodologies for calculation of CO_2 and SO_2 from natural gas-fired sources based on the amount of fuel combusted. CEMS quality assurance requirements under Part 75 are considered more stringent than under Part 60.

4.4.9 40 CFR Part 97 Cross-State Air Pollution Rule

Emissions trading programs for NO_X and SO_2 are covered under this Part. Sevel programs which are no longer in use (NO_X Budget and CAIR) are still included in the regulations but are no longer applicable to sources. The emissions trading program is place is the Cross-State Air Pollution Rule (CSAPR). Seven separate regulations have been promulgated under CSAPR including various incarnations of SO_2 and ozone season NO_X. Currently, Pennsylvania is subject to Subpart AAAAA (CSAPA NO_X Annual Trading Program) for annual NO_X emissions trading, Subpart CCCCC (CSAPR SO_2 Group 1 Trading Program) for annual SO_2 emissions trading, and Subparts EEEEE (CSAPR NO_X Ozone Season Group 2 Trading Program) and GGGGG (CSAPR NO_X Ozone Season Group 3 Trading Program) for ozone season NO_X emissions trading. Each trading program is set up in a similar manner, providing sources with allowances and requiring that sources acquire additional allowances if required. New sources subject to the program are provided allocations from the new source set aside pool. When the allocations are re-calculated, the new sources are folded into the program and are provided allocations similar to existing sources. Currently, the ozone season programs are under judicial review and allowances issued under Subpart GGGGG are on hold and Subpart EEEEE is is place in the interim[1].

4.4.1040 CFR Part 98 Greenhouse Gas Reporting Program

This federal reporting program is applicable to sources which emit greater than 25,000 metric tonnes of carbon dioxide equivalent emissions. It is expected that Homer City will emit more than this threshold and will be subject to reporting. The CC and ADGT combustion turbines which are subject to the Acid Rain Program will be reported under Subpart D, which links CO_2 emissions already reported to EPA through the ECMPS Part 75 reporting system to Part 98. Other combustion sources not reporting to the Acid Rain Program (i.e., auxiliary boilers and fuel gas heaters) will report emissions under Subpart C. The fire water pump and emergency generators are exempt from reporting as emergency use equipment.

4.5 Applicable Pennsylvania Rules and Regulations

4.5.1 25 Pa. Code Chapter 121 – General Provisions

This chapter contains definitions which are used when a term is not explicitly defined in another chapter. It also contains other general administrative requirements.

[1] 89 FR 87960, November 6, 2024.

4.5.2 25 Pa. Code Chapter 122 – National Standards of Performance for New Stationary Sources

This chapter cross-references NSPS standards promulgated under 40 CFR Part 60. No additional requirements are contained in this chapter.

4.5.3 25 Pa. Code Chapter 123 – Standards for Contaminants

This chapter contains several generally applicable regulations for various activities.

Sections 123.1 and .2 contain limitations on fugitive particulate matter emissions from certain outdoor operations.

Section 123.11 conatin limitations on particulate matter from combustion installations. The CC turbines have heat inputs greater than 600 MMBtu and are subject to an emission limit of 0.1 lb/MMBtu. The ADGT turbines are subject to an emission limit of .14 lb/MMBtu. The auxiliary boilers are subject to emission limit of 0.34 lb/MMBtu based on a heat input of 67 MMBtu/hr. The fuel gas heaters, emergency generators, and fire water pump are each subject to an emission limit of 0.4 lb/MMBtu because they each have heat inputs between 2.5 and 50 MMBtu//hr. Section 123.13 conatins limitations on particulate matter from ceratin named processes. Cooling towers are not a named process in Section 123.13.

Sections 123.21 and .22 contain limitations on sulfur emissions from combustion units. Sulfur dioxide is restricted to 500 ppmvd and the use of No. 2 fuel oil and lighter (i.e. diesel) is restricted to a maximum sulfur content of 15 oomw (0.0015% by weight). The emeregncy generator and fire water pump will only use 15 ppmw sulfur fuel. The monitoring requirements of 123.25 do not apply to the units at Homer City because they do not burn solid fuel and do not have installed SO_2 pollution control equipment..

Section 123.31 contains a general limiation of ododous emissions.

Sections 123.41 through .46 contain limiations on visible emissions (i.e., opacity). Visible emissions are limited to less than 60% at any time and less than 20% for a period aggregating more than 3 minuted in any hour.

Section 123.51 contains a requirement that combustion units with rated heat inputs greater than 250 MMBtu/hr and an annual capacity factor greater than 30% must install continuous monitorign equipment for nitrogen oxides. Both the CC and CT turbines will install CEMS for montoring NO_X emissions.

Sections 123.101 through .121 contain provisions for the NO_X Budget trading program which was discontinued, replaced by CSAPR, and is no longer in effect.

4.5.4 25 Pa. Code Chapter 124 – National Standards for Hazardous Air Pollutants

This chapter cross-references NESHAP standards promulgated under 40 CFR Part 61. No additional requirements are contained in this chapter.

4.5.5 25 Pa. Code Chapter 126 – Motor Vehicle and Fuels Programs

This chpater establishes votor vehicle fuel limiations on oxygenate containe and volatility requirements. It also contains geenral requirements for motor vehcile and heavy equipment diesel vehcile sales and testing. This chapter does not directly apply to the Project.

4.5.6 25 Pa. Code Chapter 127 – Construction, Modification, Reactivation and Operation of Sources

Subchapter A contains general requirements related to operational flexibility provided by Section 502(b)(10) of the Clean Air Act.

Subchapter B contains requirements for Plan Approval. Application requirements are provided in 25 Pa. Code 127.12 and require that new sources of air pollution be minimized through application of Best Available Technology (BAT). Source exemptions are contained in 127.14 which list source types and categories for which Plan Approval is not required. 127.14(a)(8) is a general category of "Other sources and classes of sources determined to be of minor significance by the Department". The current list of is contained in PADEP guidance document number 275-2101-003, which includes storage vessels containing non-VOC, non malodorous, or non-hazardous air pollutant materials and storage vessels containing VOCs which have capacities less than 10,000 gallons, unless subject to §129.57. The ULSD tanks for the emergency generator engines and fire water pump engine, the turbine lube oil tanks, the 19% aqueous ammonia tank, and demineralized water tanks all meet exemption criteria.

Subchapter D contains requirements for federal PSD review which is incorporated by reference by 25 Pa. Code 127.83. As shown in Section 3, the Project will be subject to PSD review for PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and GHG as CO_2e. BACT will be required for each of these pollutants and is provided in Section 5.

Subchapter E contains requirements for New Source Review in nonattainment areas. Indiana County is considered moderate nonattainment for ozone based on being located within the ozone transport region. As described previously, the Project will have potential emissions of greater than the significant thresholds for NO_X and VOC. However, the net increase in NO_X will be less than the 100 ton/year significant threshold because of the use of ERCs from the retired coal units. The net increase of VOCs will be greater than the 50 ton/year significant threshold after the application of ERCs from the retired coal units. Emissions of VOCs will require the application LAER, and emissions offsets will be acquired at a 1.15:1 ratio. An analysis of special permit requirements required by 25 Pa. Code 127.205(5) is provided at the end of this section of the application.

Subchapter F contains requirements for non-Title V Operating Permits. These requirements are not applicable to the Project, as it will be subject to the Titel V Operating Permit program.

Subchapter G contains requirements for Title V Operating Permits. These requirements will be applicable to the Project in the future. Homer City will apply for a Titel V Permit within 120 days of notification by PADEP in accordance with 25 Pa. Code §127.505.

Subchapter H contains requirements for general plan approvals and operating permits. These requirements are not applicable to the Project.

Subchapter I contains permitting fees for Plan Approval and Title V Operating Permits. The Project will have a total permit application fee of $50,000, specified as follows:

$2,500 per §127.702(b)(2) for sources requiring approval under Subchapter B for Plan Approval

$7,500 per §127.702(c)(2) for sources requiring approval under Subchapter E for NSR

$7,500 per §127.702(d)(2) for sources requiring NSPS or NESHAP approval (max of 3 regulations)

$32,500 per §127.702(f)(2) for sources requiring approval sunder Subchapter D for PSD

Subchapter J adopts general conformity requirements under 40 CFR Part 93. These requirements are not applicable to the Project, as it is subject to the PADEP air permitting program.

4.5.6.1 Special Permit Requirements

As required by 25 Pa. Code §127.205, seven items are listed as special permit requirements for issuance of a plan approval.

- §127.205(1) requires that a new or modified facility comply with LAER;

Section 5 of this application contains an analysis of LAER for VOC emissions.

- §127.205(2) a responsible official from the applicant shall certify that each facility located within Pennsylvania and is subject to Subchapter E shall be in compliance or on a schedule of compliance;

A compliance certification form is included in Appendix A, signed by a responsible official.

- §127.205(3) and §127.205(4) requires that increases in net emissions of an NNSR pollutant by obtaining ERCs at a 1.15:1 ratio for sources in the Transport Region;

ERCs will be obtained at a rate which will equal the new increase of VOC emissions from the project multiplied by 1.15. Homer City is in the process of acquiring sufficient VOC ERCs to satisfy the increase in net emissions including the 1.15:1 ratio.

- §127.205(5) requires that permit applications for new or modified facilities must include an analysis of alternative sites, sizes, production processes, and environmental control techniques;

Permit applications for new or modified facilities must include an analysis of alternative sites, sizes, production processes, and environmental control techniques. **Section 4.5.6.2** contains this information.

- §127.205(6) contains additional requirements for sources which are located within a nonattainment area and a zone to which economic development should be targeted;

The Homer City site is not located in a zone to which economic development should be targeted, per reference maps provided showing Qualified Opportunity Zones[2] or Keystone Opportunity Zone[3].

- §127.205(7) allows PADEP to determine whether BAT requirements equivalent to BACT or LAER.

Section 5 of this application contains an analysis of LAER, BACT, and BAT.

4.5.6.2 Alternative Sites, Sizes, Production Processes, Environmental Control Techniques

As required by 25 Pa. Code §127.205(5), permit applications for new or modified facilities must include an analysis of alternative sites, sizes, production processes, and environmental control techniques.

No alternative sites were under consideration for this project to redevelop the Homer City Generating Station. Siting the Project at the current Homer City site allows the Project to help make up the retirement and decommissioning of the 2,000 MWe coal facility. Redevelopment of the former coal-fired plant offers access to high voltage power lines, has an available water supply for providing cooling water, and is already zoned for power plant operations. Siting the facility at this location is preferrable to a greenfield site or a brownfield site which is not capable of hosting a power plant without building capable high voltage transmission line capacity.

Different size combustion turbines were under consideration for the combined cycle units. However, Homer City could not receive sufficient guarantees that multiple large turbines could be provided in a timely manner. The selected CC turbines were sized to meet projected market needs in both the PJM and NYISO regions. Selection of 1x1 configuration (one combustion turbine to one steam turbine) for the CC units was preferred to 2x1 or 3x1 configurations due to projected dispatch. The smaller ADGT combustion turbines were chosen because they are rapidly deployable and can be set up quickly.

Different production processes and/or fuels would not provide for the same available power as the proposed facility or result in lower emissions. Use of large simple cycle combustion turbines do not have the same efficiency as combined cycle turbines. The mix of large CC turbines and smaller ADGTs allow the Project to rapidly adjust to

[2] https://dced.pa.gov/programs-funding/federal-funding-opportunities/qualified-opportunity-zones/
[3] https://dced.pa.gov/business-assistance/keystone-opportunity-zones/

fluctuating power needs in the area and can supply power in right sized increments if called upon to maintain grid stability. Use of oil or coal instead of natural gas would result in higher emissions of most pollutants than what is being proposed. Onshore wind or solar power plants would result in lower emissions, but have limitations based on being intermittently available without requiring a form additional energy storage capacity. Wind and solar also cannot provide the same amount of electricity as the proposed Project within the same footprint. The proposed project can provide approximately 4,678 MWe within a footprint of approximately 200 acres, roughly 0.04 acres/MW. A comparable onshore wind power projects would need approximately 385,500 acres at 82.4 acres/MW[4] while a comparable solar project would need approximately 13,380 acres at 2.86 acres/MW[5].

Alternative control techniques are discussed in Section 5 for LAER, BACT, and BAT. Homer City is proposing to install a combination of dry low-NO_X combustors, SCR, and oxidation catalyst on the CC turbines, water injection, SCR, and oxidation catalyst on the ADGT units, low NO_X burners on the auxiliary boilers and fuel gas heaters, and drift eliminators on the cooling towers. The emergency engines will be certified to meet the most stringent applicable requirements of NSPS IIII. No technically feasible alternative control techniques have been identified that would result in better pollution control performance.

Other considerations associated with the proposed Project are positive economic impact that the facility will have on the community. Workers commuting to the site and staying in the area during construction will bring a positive contribution to the area. Reuse of the former coal power plant into a gas-fired power plant will result in reuse of property which would otherwise be difficult to rehabilitate for another purpose. Visually, the proposed stacks of the CC units will have a far lower impact than the coal plant stacks and hyperbolic cooling towers.

Homer City proposes to construct a nominal 4,688 MWe generating station. The proposed emissions controls will meet LAER and BAT and VOC ERCs will be obtained to offset the increase in net emissions at the 1.15:1 ratio.

4.5.7 25 Pa. Code Chapter 128 – Alternative Emissions Reductions Limitations

This chapter contains requirements for sources which implement a “bubble” alternative emission reduction option from EPA’s policy statement from December 31, 1979. This chapter does not apply to the Project.

4.5.8 25 Pa. Code Chapter 129 – Standards for Sources

This chapter contains requirements for certain classes of sources, sources which are located within specified geographies, or RACT regulations for NO_X and VOC.

Sections 129.51-129.77 contain requirements for controlling sources of VOCs. The only portion which may be applicable to the Project is 129.57 which regulates aboveground storage tanks with storage capacities less than or equal to 40,000 gallons and greater than or equal to 2,000 gallons which contain VOC liquids with vapor pressures greater than 1.5 psia (10.5 kPa). Turbine lube oils and ultra-low sulfur distillate fuel oil are not believed to have vapor pressures greater than 1.5 psia under actual storage conditions.

Current RACT requirements for sources are contained in Sections 129.111-129.115. Presumptive RACT requirements for sources are in 129.112.

Requirements under Sections 129.201-129.205 contain additional NO_X requirements, but only apply to boilers, turbines, and engines which are located within Bucks, Chester, Delaware, Mongomery, or Philadelphia counties. These regulations do not apply to the Project.

[4] https://www.energy.gov/sites/prod/files/2015/03/f20/wv_full_report.pdf
[5] https://www.energy.gov/sites/default/files/2022-01/lbnl_ieee-land-requirements-for-utility-scale-pv.pdf

4.5.9 25 Pa. Code Chapter 130 – Standards for Products

This chapter contains requirements for facilities which produce products for commercial sale. This chapter does not apply to Homer City.

4.5.1025 Pa. Code Chapter 131 – Ambient Air Quality Standards

This chapter contains ambient air quality standards for the state in addition to cross-referencing EPA's promulgated NAAQS. Additional air quality standards are established for settled particulate (total), beryllium, fluorides, and hydrogen sulfide. Modeling demonstrating compliance with EPA NAAQS are provided in Section 8 of this application.

4.5.1125 Pa. Code Chapter 133 – Local Air Pollution Agencies

This chapter allows PADEP to establish local level jurisdiction to carry out an air pollution control program from a county, municipality, or group of municipalities. This chapter does not have any direct effect on the Project.

4.5.1225 Pa. Code Chapter 135 – Reporting of Sources

This chapter contains requirements for sources to report emissions on an annual basis to PADEP. Homer City will comply with the appliable portions of the emission reporting and recordkeeping requirements contained in this chapter.

4.5.1325 Pa. Code Chapter 137 – Air Pollution Episodes

Chapter 137 contains requirements for PADEP to prevent the excessive buildup and air pollution episodes and

4.5.1425 Pa. Code Chapter 139 – Sampling and Testing

Chapter 139 contains requirements for source sampling from stationary sources. These requirements will be required to be followed in addition to those required by federal requirements under NSPS Subpart KKKK.

4.5.1525 Pa. Code Chapter 141 – Variances and Alternate Standards

Chapter 141 does not impose any substantive requirements on the Project.

4.5.1625 Pa. Code Chapter 143 – Disbursements from the Clean Air Fund

Chapter 143 does not impose any substantive requirements on the Project.

4.5.1725 Pa. Code Chapter 145 – Interstate Pollution Transport Reduction

Chapter 145 contains requirements implementing emission trading programs and other limitations for reducing the transport of interstate pollution. Subchapter A implementing the NOx Budget trading program is no longer appliable since it has been replaced by the Clean Air Interstate Tule (CAIR) in Subchapter D. However, the CAIR regulation has also been replaced, with the Cross-State Air Pollution Rule (CSAPR). CSAPR is implemented through the federal regulations in 40 CFR Part 97, Subparts AAAAA, CCCCC, and GGGGG. See Section 4.10 for additional information on those programs.

Subchapters B and C apply to large stationary internal combustion engines and cement manufacturing, respectively. Large stationary internal combustion engines are defined as rich burn or lean burn stationary combustion engine

equal to or greater than 2,400 bhp, diesel engine equal to or greater than 3,000 bhp, or a dual-fuel stationary combustion engine equal to or greater than 4,400 bhp. In addition to the horsepower threshold, an engine also must produce 153 or more tons of NOx during an ozone season. The proposed stationary internal combustion engines for the Project do not meet these requirements.

Subchapter D contains requirements for the CAIR NO_X and SO_2 trading programs. These programs are no longer applicable since they have been replaced by CSAPR. CSAPR is implemented through the federal regulations in 40 CFR Part 97, Subparts AAAAA, CCCCC, and GGGGG. See Section 4.10 for additional information on those programs.

Subchapter E contains requirements for Pennsylvania's participation in the Regional Greenhouse Gas Initiative (RGGI). This is a multi-regional effort to reduce carbon dioxide emissions from large sources in the northeast. This regulation applies to units which serve an electricity generator with a nameplate capacity equal to or greater than 25 MWe. This would potentially apply to all of the combustion turbines proposed in this application. However, the Commonwealth Court of Pennsylvania ruled that the state's participation in the RGGI program requires legislation to be adopted by the Pennsylvania General Assembly prior to rulemaking by PADEP. The Commonwealth Court 's decision has been appealed to the state Supreme Court. A final ruling on the appear has not yet been decided. If the RGGI program is re-instituted, the Project will comply with the applicable monitoring, recordkeeping, reporting, and emissions trading provisions.

5. Control Technology Review

5.1 Technical Approach

5.1.1 Overview

Pennsylvania and federal PSD regulations require a Best Available Control Technology (BACT) analysis for each new major source or major modification at an existing major source that will result in a significant net emissions increase of a NSR regulated pollutant. As described in Section 3 of this application, the projected net emissions increases associated with the Project are sufficient to trigger PSD review for PM, PM_{10}, $PM_{2.5}$, sulfuric acid mist, and GHG (as CO_2e).

Federal PSD regulations, as incorporated by reference in 25 Pa Code §127.83, define BACT as:

> *…an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR part 60, 61, or 63. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.*

Nonattainment NSR (NNSR) regulations, per 25 Pa. Code Chapter 127, require a Lowest Achievable Emission Rate (LAER) be applied in lieu of BACT for NSR regulated pollutants which are considered to be in nonattainment with the NAAQS. The process for determining LAER is similar to BACT, except that it does not allow consideration for economic and/or energy costs. As described in **Section 3** of this application, the Project will only have a net increase and be subject to LAER review for VOC.

Regardless of whether BACT or LAER requirements apply, sources are required by 25 Pa. Code §127.1 and §127.12(a)(5) to apply Best Available Technology (BAT) to control air emissions. BAT is not explicitly defined in 25 Pa. Code Article III Air Resources regulations but generally follow federal BACT requirements for evaluation of controls. Net emissions increases of CO, NO_X, SO_2, and lead do not trigger review under PSD or nonattainment and will be subject to BAT only. The BACT and LAER analyses in Section 5 are proposed to also satisfy BAT.

5.1.2 BACT/LAER/BAT Assessment Methodology

The following sections describe the five steps of the top-down approach and provide detail on the BACT/LAER/BAT assessment methodology utilized in preparing the control technology analysis for the Project.

Step 1

The first step is to define the spectrum of process and/or add-on control options potentially applicable to the emissions unit and pollutant under review. There is no specific methodology that is required to be used to identify all available control options for a given source or pollutant. The most comprehensive source of this information, however, is EPA's RACT/BACT/LAER Clearinghouse (RBLC). This searchable database of emission control

technology determinations is maintained by EPA, and as such, is generally the starting point for developing a list of potentially available control options.

Step 2

The second step is to evaluate the technical feasibility of the control options identified in the first step and to reject those that can be demonstrated as technically infeasible based on an engineering evaluation or on chemical or physical principles. In accordance with EPA's 1990 Workshop Manual (US EPA, 1990), two key concepts are evaluated to determine whether an undemonstrated control option is technically feasible: "availability" and "applicability." A control option is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available control option is "applicable" if it can reasonably be installed and operated on the source type under consideration. A control option that is available and applicable is technically feasible. The following criteria are considered in determining technical feasibility: previous commercial-scale demonstrations, precedent based on issued PSD permits, state requirements for similar sources, technology transfer, and engineering evaluations for the control options or work practice standards considered.

Step 3

The third step involves ranking each technically feasible control option in decreasing order of overall control effectiveness considering specific operating constraints of the emission unit in question. After determining what control efficiency is achievable with each technically feasible control option, the alternatives are ranked into a hierarchy from most to least effective. Depending on the pollutant and the source, the Step 3 ranking can present an array of control options, along with information such as control efficiencies (% pollutant removed or controlled), expected emission rate (tons/year, pounds/hour), expected emission reduction (tons/year), economic impacts (cost effectiveness), and adverse environmental and energy impacts. However, an applicant proposing the top control option as BACT need not provide cost and other detailed information regarding other control options.

Step 4

The fourth step consists of an objective evaluation of the energy, environmental, and economic impacts of each technically feasible control technology. This step applies to BACT/BAT only, as LAER does not take factors discussed in this step into consideration. The economic evaluation is carried out using procedures outlined in the EPA's Office of Air Quality Planning and Standards (OAQPS) Air Pollution Control Cost Manual.[6,7] The economic evaluation considers the annualized control cost (in dollars per ton of emissions removed) for the proposed source for each control option evaluated. If the top control option is determined to be cost ineffective or to cause adverse energy or environmental impacts, that control option is rejected and the analysis is performed on the next most stringent control option until the technology or emissions level under consideration cannot be eliminated based on source-specific environmental, energy, or economic impacts.

Step 5

The final step is to summarize the selection of BACT and emission limitations or work practices to be incorporated into the permit along with recommended monitoring and compliance demonstration requirements, including averaging times.

[6] EPA, *EPA Air Pollution Control Cost Manual*, at Sec. 1, Ch. 2 (7th ed. 2018).

[7] New and emerging technologies, such as CCS and co-firing low-GHG hydrogen, which are evaluated as part of the GHG BACT review for the proposed CT units, are generally not addressed in EPA's cost manual. Annualized costs for these control options were estimated using the publicly available references cited and adjusted to be consistent with the methodology in the manual.

5.2 Combined Cycle Combustion Turbine BACT/LAER/BAT Review

5.2.1 Nitrogen Oxides

5.2.1.1 Formation

NO_X emissions from proposed CT units generally consist of two components: oxidation of atmospheric nitrogen in the combustion air (thermal NO_X and prompt NO_X) and conversion of fuel bound nitrogen (fuel NO_X). NO_X emissions mostly originate as nitric oxide (NO), which is generated by the combustion processes. NO emissions are subsequently further oxidized "in-stack" and in the atmosphere to the more stable NO_2 molecule.

Thermal NO_X results from the oxidation of atmospheric nitrogen during high temperature combustion and its formation is primarily a function of combustion temperature, residence time, and air/fuel ratio.

Prompt NO_X is formed near the combustion flame front in the oxidation of intermediate combustion products. Prompt NO_X comprises a small portion of total NO_X in conventional near stoichiometric combustors but increases during fuel-lean conditions. Prompt NO_X, therefore, is an important consideration with respect to low-NO_X combustors that use lean fuel mixtures.

Fuel NO_X is due to the oxidation of non-elemental nitrogen contained in the fuel. Unlike thermal NO_X, fuel NO_X formation is less dependent on combustion variables such as temperature or residence time. Currently, there are no combustion controls or pre-combustion fuel treatment technologies available to reduce fuel NO_X emissions. For this reason, certain NO_X emissions standards contain an allowance for fuel-bound nitrogen as part of the emissions limit.[8]

NO_X emissions from combustion sources fired with distillate oil are typically higher than from those fired with natural gas due to higher combustion flame temperatures and fuel-bound nitrogen content. Natural gas may contain molecular nitrogen (N_2); however, the molecular nitrogen found in natural gas does not contribute significantly to fuel NO_X formation. Natural gas generally contains a negligible amount of fuel-bound nitrogen.

5.2.1.2 Step 1 – Identify NO_X Control Options

A search of the RBLC was conducted to identify NOx BAT determinations for large natural gas-fired combined-cycle turbine units (larger than 25 MW) permitted in the past eleven years (i.e., since 2014). The results of these RBLC searches are summarized in **Appendix D**, Table D-1. Potentially available control options to reduce NO_X emissions from the proposed CC units include combustion controls, such as good operating practices, dry low-NO_X (DLN) combustors and water or steam injection, and post-combustion add-on controls, such as selective noncatalytic reduction (SNCR), nonselective catalytic reduction (NSCR), and selective catalytic reduction (SCR). Each identified control option is discussed further below.

Water or Steam Injection

Water or steam injection was determined by EPA to be the best technology for control of NO_X emissions from stationary turbine units when the national emissions standards for this source category were first established in 1977.[9] This control option involves the injection of water or steam into the combustor to decrease peak combustion temperature. The injected water or steam acts as a heat sink by diluting the combustion gas and absorbing heat needed to vaporize water. In doing so, peak flame temperature, combustion zone residence time, free oxygen, and thermal NO_X are reduced.

However, water or steam injection is typically suitable only for combustion of fuel oil as flame temperatures are higher than for natural gas combustion. Natural gas also has an inherently low nitrogen content compared to fuel

[8] For example, see NSPS Subpart GG, 40 CFR 60.332(a)(1) through (4).
[9] 42 Fed. Reg. 53782, 53785 (Oct. 3, 1977).

oil. Because the proposed CCs will only fire natural gas, water or steam injection will not be discussed further in this analysis.

Dry Low NOx Combustors

Combustion controls that utilize combustor design and/or operational features to reduce NO_X emissions without injecting an inert diluent (water or steam) are generically referred to as "dry" low-NO_X (DLN) measures. Design features of DLN combustors are vendor-specific but generally seek to reduce thermal NO_X formation by controlling peak combustion temperature, combustion zone residence time, and combustion zone free oxygen concentration. Designs include staged combustion and pre-mixing air and fuel prior to injection into the combustion zone. DLN measures produce a lean, pre-mixed flame that burns at a lower temperature with less excess oxygen than conventional combustors.

Good Operating Practices

Proper equipment design and proper operation and maintenance will ensure other controls such as DLN combustors are working effectively and will minimize NO_X emissions from the proposed CT units.

Selective Noncatalytic Reduction

SNCR involves the gas phase reaction of NO_X in the exhaust gas stream with injected ammonia or urea, in the absence of a catalyst, to yield nitrogen and water vapor. Ammonia or urea is injected into a hot exhaust gas stream at a location specifically chosen to achieve the optimum reaction temperature and residence time. The overall reaction schemes for both urea and ammonia systems can be expressed as follows:

$$CO(NH_2)_2 + 2\ NO + \tfrac{1}{2}O_2 = 2N_2 + CO_2 + 2\ H2O \quad (1)$$

$$4\ NH_3 + 6NO = 5N_2 + 6\ H2O \quad (2)$$

Typical removal efficiencies for SNCR range from 30 percent to 50 percent and higher when coupled with combustion controls (US EPA, 2003). An important consideration for SNCR is operating temperature range. The temperature range required for this control option to be effective is approximately 1,600 to 2,000°F (US EPA, 2019a). Operation at temperatures below this range results in ammonia slip. Operation at temperatures above this range results in oxidation of ammonia, forming additional NO_X emissions. Therefore, the SNCR injection system must be located such that operating temperatures are consistently within the identified range.

Nonselective Catalytic Reduction

NSCR uses a catalyst reaction to simultaneously reduce NO_X, CO, and VOC to water, carbon dioxide, and nitrogen without injection of a reagent such as ammonia. The conversion occurs in two sequential steps, with the reactions for CO and VOC occurring first since they more readily react with oxygen than with NO_X. However, to ensure NO_X reduction in the second step, this control option must be applied to exhaust gas streams with low oxygen content (less than 0.5% O_2).

Selective Catalytic Reduction

SCR is a post-combustion emission control process which involves removal of NO_X in a catalytic reactor. In the SCR process, ammonia reacts with nitrogen oxides and oxygen to form nitrogen and water. The SCR process converts nitrogen oxides to nitrogen and water by the following chemical reactions:

$$4\ NO + 4\ NH3 + O2 \rightarrow 4\ N2 + 6\ H2O \quad (1)$$

$$6\ NO + 4\ NH3 \rightarrow 5\ N2 + 6\ H2O \quad (2)$$

$$2\ NO2 + 4\ NH3 + O2 \rightarrow 3\ N2 + 6\ H2O \quad (3)$$

$$6\ NO2 + 8\ NH3 \rightarrow 7\ N2 + 12\ H2O \quad (4)$$

$$NO + NO2 + 2\ NH3 \rightarrow 2\ N2 + 3\ H2O \quad (5)$$

A catalyst is required to lower the activation energy at which NO_X decomposition occurs. Technical factors that must be considered with this control option include increased turbine backpressure, thermal considerations for structures

and materials including shock/stress during startup, catalyst masking/blinding, reported catalyst failure due to "crumbling," design of the ammonia injection system, and ammonia slip.

For most SCR catalyst configurations, the optimum operating temperature of the system is between 700 and 850°F. However, CC units typically produce exhaust gas temperatures that exceed 1100°F. Consequently, this control option requires the use of a high-temperature catalyst and the use of tempering air to reduce the temperature of the turbine exhaust prior to it being introduced into the SCR reactor. SCR catalyst materials lose activity over time, necessitating catalyst cleaning or replacement.

5.2.1.3 Step 2 – Eliminate Technically Infeasible NO_X Control Options

DLN Combustors

Use of DLN combustors is inherent to the Project and technically feasible.

Good Operating Practices

Use of good operating practices is inherent to the Project and technically feasible.

Selective Non-catalytic Reduction

SNCR is not a technically feasible control option for NO_X emissions from the proposed CC units since it has not been demonstrated in practice and is not both an available *and* applicable control option. Based on the RBLC search results, SNCR has not been installed and operated successfully on the type of source under review; in the utility industry. For utility boilers, ammonia is injected into the furnace where temperatures remain high enough for the NO_X reduction reaction to occur (between 1,600 and 2,000°F). The temperature of the exhaust gas from the proposed CC units is too low for SNCR to be effective and it would not be practical or reasonable to further heat the exhaust gas so that this control option may be applied. Therefore, SNCR is not applicable to the proposed CT units. Accordingly, SNCR is not technically feasible.

Nonselective Catalytic Reduction

NSCR is also not a technically feasible control option for NO_X emissions from the proposed CC units since it has not been demonstrated in practice and is not both an available *and* applicable control option. Based on the RBLC review, NSCR has not been installed and operated successfully on the type of source under review; this control option is most commonly applied to nonroad and stationary rich-burn spark-ignition internal combustion engines (SI ICE). For rich-burn SI ICE, air-to-fuel ratio controllers are used to maintain the low levels of excess oxygen necessary (less than 0.5%) for NSCR to be an effective control option for NO_X emissions. The oxygen content of the exhaust gas from proposed CC units will typically be 8-13%. Therefore, NSCR is not applicable to the proposed CT units. Accordingly, NCSR is not technically feasible.

Selective Catalytic Reduction

SCR can be made technically feasible by tempering the exhaust gas from the proposed CC units with ambient air to be within the temperature range necessary for this control option to be applicable. This control option has been demonstrated in practice for similar large combined-cycle turbines. Based on the RBLC search results, 141 units were identified and 131 of those units employed SCR as a control technology. Therefore, SCR is applicable to the proposed CC units and technically feasible.

5.2.1.4 Step 3 – Rank Remaining NO_X Control Options

No ranking of control options is required as all available and technically feasible control options for NO_X emissions from the proposed CC units are included in the Project.

5.2.1.5 Step 4 – Evaluation of NO_X Control Options

The top control options are being proposed for NO_X emissions from the proposed combined-cycle units. Therefore, no further evaluation of the energy, environmental, and economic impacts of the control options is required. However, consideration of those impacts could result in a different BAT determination for other sources or projects in areas not subject to Pennsylvania BAT or a similar standard that requires use of SCR.

5.2.1.6 Step 5 – Select NO_X BAT for Combined Cycle Combustion Turbines

To comply with NSPS Subpart KKKK, the proposed CC units will be subject to a NO_X emission standard of 15 ppmvd while firing natural gas.[10] These emissions standards serve as the BAT floor.

NO_X BAT for the proposed CC units is based on use of DLN combustors, good operating and maintenance practices, and SCR. Based on the RBLC search results, NO_X emission limits for CC units with similar controls range from 2 to 3 ppmvd while firing natural gas. Based on this information, the following will be proposed as NO_X BAT for each of the proposed CC units:

- 2 ppmvd NO_X or less, corrected to 15% O_2, with or without duct firing, based on a 1-hour block average, excluding periods of startup and shutdown, and
- 141 tons NO_X or less during any 12-month consecutive period, including periods of startup and shutdown.

Compliance with these emissions limits shall be demonstrated by use of a CEMS installed and operated in accordance with 40 CFR Part 75.

For periods of startup and shutdown, turbines are not able to achieve maximum combustion efficiency and exhaust temperatures are not high enough for the SCR to be effective. Therefore, alternative NO_X BAT is proposed for these scenarios as follows:

- Cold start: 200 lb NO_X per event, not to exceed 70 minutes,
- Warm start: 200 lb NO_X per event, not to exceed 70 minutes,
- Hot start: 110 lb NO_X per event, not to exceed 30 minutes, and
- Shutdown: 16 lb NO_X per event, not to exceed 12 minutes.

Startup means the period of time from when fuel is first fired to when the load has been achieved at which it has been demonstrated, by a CEMS or during compliance testing, that the emission limits can be met during steady-state operations (i.e., the minimum emissions compliance load or MECL). Cold and hot starts are defined as being preceded by over 72 and within 8 hours of the previous shutdown, respectively. Due to the more variable nature of a warm start (occurring between 8 and 72 hours of the previous shutdown), proposed NO_X BAT for warm start events is the same as those proposed for cold starts.

Shutdown means the period of time from MECL to when firing of fuel has ceased.

5.2.2 Carbon Monoxide

5.2.2.1 Formation

CO emissions from the proposed CC units may be generated during combustion as a result of incomplete conversion of carbon-containing compounds to CO_2 and water. CO emission rates are principally influenced by equipment operating conditions; elevated CO emissions may be the result of low combustion temperature, insufficient combustor residence time, and/or low operating loads.

5.2.2.2 Step 1 – Identify CO Control Options

To determine BAT for CO, search of the RBLC was performed to identify potentially available control options and emission limitations for CO for large natural gas-fired combined-cycle turbine units (larger than 25 MW) which were permitted in the past eleven years (i.e., since 2014). The results of these RBLC searches are summarized in **Appendix D**, Table D-2.

[10] Except as otherwise noted, all numerical emissions standards and limits for all pollutants referred to in this BACT/LAER/BAT analysis in terms of parts per million by volume dry (ppmvd) are corrected to 15% O_2.

Potentially available control options to reduce CO emissions from large CCs include combustion controls, good combustion practices, and post-combustion add-on controls such as an oxidation catalyst. Each are discussed in the following sections.

Combustion Controls and Good Operating Practices

As discussed in previous sections of this application, CO emissions may result from incomplete combustion. Proper equipment design, proper operation, and optimization of the combustion air systems (e.g., compressor inlet guide vane control) to achieve good combustion efficiency will minimize CO emissions from the proposed CC units.

Oxidation Catalyst

An oxidation catalyst uses excess air to convert CO emissions to CO_2 in the presence of catalyst without the use of a reagent. Catalyst effectiveness can be affected by the residence time within the catalyst to complete the conversion. Other technical considerations for employing this add-on control option include reactor design, operating temperature, back pressure of the system and its impact on performance, and catalyst life. Oxidation catalysts operate effectively in a relatively narrow temperature range typically between 600 to 800°F. Because turbines can produce exhaust gas temperatures that exceed 1100°F, exhaust gases must be tempered with ambient air to avoid permanently damaging (sintering) the catalyst. At lower operating temperatures, CO conversion efficiency falls off rapidly.

5.2.2.3 Step 2 – Eliminate Technically Infeasible CO Control Options

Use of combustion controls and good operating practices is inherent to the Project and technically feasible.

The use of an oxidation catalyst is also included in the Project because it is necessary to comply with the emissions standards found in 40 CFR 63 Subpart YYYY. Like the SCR, the oxidation catalyst will be made technically feasible by tempering the exhaust gas from the proposed CC units with ambient air to be within the temperature range necessary for this control option to be applicable. Based on the RBLC results, 128 of the 136 entries with identifiable control methods were able to demonstrate an oxidation catalyst as a control option for its combined-cycle gas turbines.

5.2.2.4 Step 3 – Rank Remaining CO Control Options

No ranking of control options is required, as all available and technically feasible control options for CO emissions from the proposed CC units are included in the Project.

5.2.2.5 Step 4 – Evaluation of CO Control Options

The top control options are being proposed for CO emissions from the proposed CC units. Therefore, no further evaluation of the energy, environmental, and economic impacts of the control options is required. However, consideration of those impacts could result in a different BAT determination for other sources or projects not subject to MACT Subpart YYYY or a similar standard that requires use of oxidation catalyst.

5.2.2.6 Step 5 – Select CO BAT for Combined Cycle Combustion Turbines

No BACT floor exists for CO emissions from the proposed CC units since EPA does not regulate this pollutant under NSPS Subpart KKKK. Consequently, there is no BACT or BAT floor limit.

CO BAT for the proposed CC units is based on use of combustion controls, good operating practices, and use of an oxidation catalyst. Based on the RBLC search results, CO emission limits for CC units with similar controls range from 0.9 to 15 ppmvd while firing natural gas. However, due to uncertainties with continuous measurements using CEMS at values below 2 ppm, Homer City is proposing to meet a value of 2 ppm with and without duct firing over all normal operating loads. Based on this information, the following is proposed as the CO limit for each of the proposed CC units:

- 2.0 ppmvd CO or less, corrected to 15% O_2, with or without duct firing. This limit is based on a 1-hour block average, excluding periods of startup and shutdown,

- 110.6 tons CO or less during any 12-month consecutive period, including periods of startup and shutdown.

Compliance with these emissions limits shall be demonstrated by use of a CEMS installed and operated in accordance with 40 CFR Part 60.

For periods of startup and shutdown, turbines are not able to achieve maximum combustion efficiency and exhaust temperatures are not high enough for the oxidation catalyst to be effective. Therefore, alternative CO BAT is proposed for these scenarios as follows:

- Cold start: 830 lb CO per event, not to exceed 70 minutes,
- Warm start: 830 lb CO per event, not to exceed 70 minutes,
- Hot start: 215 lb CO per event, not to exceed 30 minutes, and
- Shutdown: 185 lb CO per event, not to exceed 12 minutes.

Similar to the proposed startup emission limits for NO_X, due to the more variable nature of a warm start, proposed CO BAT for warm start events is the same as those proposed for cold starts.

5.2.3 Volatile Organic Compounds

5.2.3.1 Formation

VOC emissions from the proposed CC units are influenced by the same factors which affect CO emissions formation discussed in **Section 5.2.2**.

5.2.3.2 Step 1 – Identify VOC Control Options

Potentially available control options for VOC emissions for combined-cycle turbines are the same as those discussed above for CO—combustion controls, good combustion practices, and post-combustion add-on control in the form of an oxidation catalyst. A search of the RBLC was conducted to identify VOC LAER determinations for large natural gas-fired combined-cycle turbine units (larger than 25 MW) permitted in the past eleven years (i.e., since 2014). The results of these RBLC searches are summarized in **Appendix D**, Table D-3.

Combustion Controls and Good Operating Practices

Similar to CO, VOC emissions may result from incomplete combustion. Proper equipment design, proper operation, and optimization of the combustion air systems to achieve good combustion efficiency will minimize VOC emissions from the proposed CC units.

Oxidation Catalyst

An oxidation catalyst uses excess air to convert organic compounds to CO_2 in the presence of catalyst without the use of a reagent. Technical considerations for employing this add-on control option are the same as those discussed above for CO.

5.2.3.3 Step 2 – Eliminate Technically Infeasible VOC Control Options

Use of combustion controls and good operating practices is inherent to the Project and technically feasible.

The use of an oxidation catalyst is also included in the Project because it is necessary to comply with the emissions standards found in 40 CFR 63 Subpart YYYY. Like the SCR, the oxidation catalyst will be made technically feasible by tempering the exhaust gas from the proposed CT units with ambient air to be within the temperature range necessary for this control option to be applicable. Based on the RBLC results, 111 of the 121 entries with identifiable control methods were able to demonstrate an oxidation catalyst as a control option for its combined-cycle gas turbines.

5.2.3.4 Step 3 – Rank Remaining VOC Control Options

No ranking of control options is required as all available and technically feasible control options for VOC emissions for the proposed CC units are included in the Project.

5.2.3.5 Step 4 – Evaluation of VOC Control Options

The top control options are being proposed for VOC emissions from the proposed CC units. In addition, because VOC emissions are subject to LAER requirements, evaluations of the energy, environmental, and economic impacts are not taken into account.

5.2.3.6 Step 5 – Select VOC LAER for Combined Cycle Combustion Turbines

VOC LAER for the proposed CCs is based on good combustion practices and an oxidation catalyst. Based on the RBLC search results, VOC emission limits for CC units with similar controls range between 0.7 to 4.0 ppmvd when firing natural gas. Based on this information, the following is being proposed as VOC LAER for each of the proposed CC units:

- 1.5 ppmvd VOC or less, corrected to 15% O_2, with duct firing, excluding periods of startup and shutdown.
- 1.0 ppmvd VOC or less, corrected to 15% O_2, without duct firing, excluding periods of startup and shutdown,
- 39.3 tons VOC or less during any 12-month consecutive period, including periods of startup and shutdown.

These proposed limits are consistent with determinations found in the RBLC for CCs of similar model and are based on stack testing using EPA Reference Method 18 or Method 25A. Stack testing will be conducted after initial startup followed by subsequent stack tests every five years.

Multiple facilities were identified in the RBLC search with VOC emission limits less than 1.5 ppmvd with duct firing and 1.0 ppm without duct firing. Several facilities, including Lincoln Land Energy Center, Calcasieu Pass LNG Project, CBSG Station, and SR Bertron Electric Generating Station, have much smaller turbines and/or duct burners and are therefore not comparable for this analysis. Renaissance Energy Center, New Covert Generating Facility, and Greensville Power Station each have different model CTs, which have inherently differing emissions profiles. C4GT, LLC, West Deptford Energy Station, and Rolling Hills Generating, LLC were either never constructed or the Project for that facility was never installed. For CTs of the same model, a limit 1.5 ppmvd has been demonstrated in the RBLC as LAER for VOC emissions, achieved through the use of good combustion practices and an oxidation catalyst. Several operating facilities of comparable size have been demonstrated in practice as LAER.

For periods of startup and shutdown, turbines are not able to achieve maximum combustion efficiency and exhaust temperatures are not high enough for the oxidation catalyst to be effective. Therefore, alternative VOC LAER is proposed for these scenarios as follows:

- Cold start: 105 lb VOC (as methane) per event, not to exceed 70 minutes,
- Warm start: 105 lb VOC (as methane) per event, not to exceed 70 minutes,
- Hot start: 66 lb VOC (as methane) per event, not to exceed 30 minutes,
- Shutdown: 55 lb VOC (as methane) per event, not to exceed 12 minutes.

Similar to the proposed startup emission limits for NO_X and CO, due to the more variable nature of a warm start, proposed CO LAER for warm start events is the same as those proposed for cold starts.

5.2.4 Particulate Matter

5.2.4.1 Formation

PM emissions from the proposed CC units include both filterable and condensable particles. Filterable PM is formed from impurities contained in fuels, dust in the ambient air, and from incomplete combustion, while condensable PM

is primarily attributable to high molecular weight VOC (unburned hydrocarbons) and the conversion of fuel sulfur to sulfates when catalyst-based add-on controls are used.

5.2.4.2 Step 1 – Identify PM Control Options

A search of the RBLC was performed to identify potentially available control options for PM (including total PM, PM_{10}, and $PM_{2.5}$) emissions from the proposed CC units. The results of these RBLC searches are summarized in **Appendix D**, Tables D-4 through D-6. Based on this review, no add-on control options were identified. Identified control methods include some combination of use of clean fuels (i.e., fuels with inherently low sulfur content), good combustion practices, and inlet air filters as BACT. Generally, conventional add-on controls often applied to solid fuel boilers, such as baghouses, electrostatic precipitators, and scrubbers, have not been applied to gas-fired CTs because the use of clean fuels inherently results in a low level of PM emissions.[11] Add-on PM controls are also inherently less effective on turbines because the majority of their PM emissions are condensable and exist as a gas in the stack, which would pass through a majority of add-on PM controls.[12] Accordingly, only the use of cleans fuels, good combustion practices, and inlet air filters are considered further.

5.2.4.3 Step 2 – Eliminate Technically Infeasible PM Control Options

Use of clean fuels (with inherently low sulfur content), good combustion practices, and inlet air filters are inherent to the proposed combined-cycle CTs and technically feasible.

5.2.4.4 Step 3 – Rank Remaining PM Control Options

No ranking of control options is required, as the use of clean fuels, good combustion practices, and inlet air filters are the only technically feasible control options for PM emissions from the proposed CT units and achieve the highest level of PM control.

5.2.4.5 Step 4 – Evaluation of PM Control Options

All identified and technically feasible control options are being proposed for control of PM emissions from the proposed CC units. Therefore, no further evaluation of the impacts of the PM control options is required.

5.2.4.6 Step 5 – Select PM BACT for Combined Cycle Combustion Turbines

Proposed BACT for the CCs is based on the use of clean fuels, good combustion practices, and inlet air filters. Based on the RBLC search results, emission limits for CC units with similar controls range from 9.7 to 25.1 lb/hr for PM_{10} and $PM_{2.5}$ without duct firing, and 4.9 to 36.3 lb/hr with duct firing. Based on this information, the following is proposed as PM BACT for each of the CC units:

- Total PM/PM_{10}/$PM_{2.5}$, containing filterable and condensable PM, equal to or less than 0.0054 lb/MMBtu, and 24.1 lb/hr, with or without duct firing.
- 101 tons PM or less during any 12-month consecutive period, including periods of startup and shutdown.

The proposed limits are based on an average natural gas sulfur content of 0.5 grains/100 scf and base load operation of the CCs and assume that the emission rates of PM_{10} and $PM_{2.5}$ are equivalent to that of total PM. As specified by the manufacturer, lb/hr emission rates of PM at part load operation are expected to decrease and lb/MMBtu emission rates are not expected to exceed those of base load operation. Compliance with the proposed limits is based on stack testing using EPA Reference Methods 201/201A and 202. Stack testing will be conducted after initial startup followed by subsequent stack tests every five years.

[11] When EPA originally proposed national standards for turbine units in NSPS Subpart GG, EPA stated that "particulate emissions from stationary gas turbines are minimal" and noted that add-on controls for PM are not typically installed on CT units and are cost prohibitive. See 44 Fed. Reg. 52792, 52798 (Sept. 10, 1979); EPA, *Standards Support and Envtl. Impact Statement Volume 1: Proposed Standards of Performance for Stationary Gas Turbines*, at 8-6 (Sept. 1977). Additionally, when EPA proposed to update the standards in NSPS Subpart KKKK, EPA declined to establish standards for PM because "…[PM] emissions are negligible with natural gas firing due to the low sulfur content of natural gas." 70 Fed. Reg. 8314, 8321 (Feb. 18, 2005). At the time, EPA also noted that no CT units permitted since 2003 utilized add-on controls.

[12] AP-42 Section 3.1.3.3

Multiple facilities were identified in the RBLC search with PM, PM_{10}, and $PM_{2.5}$ emission limits less than 0.0054 lb/MMBtu or less than 24.1 lb/hr. Total PM limits for several facilities are only for filterable PM only and do not include condensable PM. Many of these facilities either have much smaller turbines and/or duct burners or have different model turbines, resulting in inherently differing emissions profiles and rendering them not comparable for this analysis. Some facilities were never constructed. In addition, limits for some facilities are based on unknown natural gas sulfur contents or listed with a sulfur content lower than 0.5 grains of sulfur per 100 standard cubic feet. Historic variability in the sulfur content of natural gas supplied to the facility may persist upon installation of the proposed CCs, causing variability in PM emissions which are outside the facility's control.

For periods of startup and shutdown, turbines are not able to achieve maximum combustion efficiency. Therefore, alternative PM BACT is proposed for these scenarios as follows:

- Cold start: 14.2 lb PM per event, not to exceed 70 minutes,
- Warm start: 14.2 lb PM per event, not to exceed 70 minutes,
- Hot start: 6.1 lb PM per event, not to exceed 30 minutes,
- Shutdown: 2.4 lb PM per event, not to exceed 12 minutes.

Similar to the proposed startup emission limits for NO_X, CO, and VOC, due to the more variable nature of a warm start, proposed PM BACT for warm start events is the same as those proposed for cold starts.

5.2.5 Sulfur Dioxide

5.2.5.1 Formation

SO_2 is formed from the oxidation of sulfur compounds contained in fuel during the combustion process. Because natural gas has a relatively low sulfur content compared with other combustible fuels, such as coal or heavy fuel oils, SO_2 emissions are minimal from natural gas-fired equipment, including combustion turbines.

5.2.5.2 Step 1 – Identify SO_2 Control Options

To determine BAT for SO_2, a search of the RBLC was conducted to identify available control options for SO_2 emissions from large natural gas-fired combined-cycle turbine units (larger than 25 MW) permitted in the past eleven years (i.e., since 2014). The results of these RBLC searches are summarized in **Appendix D**, Table D-7. Control methods identified include good combustion practices and the use of clean fuels with inherently low sulfur content. Add on control technologies, including scrubbers and flue gas desulfurization, are commonly used to control SO_2 emissions from sources which combust high-sulfur fuels, and have not been found to be applied to combined-cycle turbines. Therefore, only the use of good combustion practices and clean fuels is evaluated further.

5.2.5.3 Step 2 – Eliminate Technically Infeasible SO_2 Control Options

Use of clean fuels with inherently low sulfur content and good combustion practices are inherent to the Project and technically feasible.

5.2.5.4 Step 3 – Rank Remaining SO_2 Control Options

No ranking of control options is required since all technically feasible control options will be employed for SO_2 emissions from the proposed CC units.

5.2.5.5 Step 4 – Evaluation of SO_2 Control Options

All technically feasible control options are being proposed for SO_2 emissions from the proposed CC units. Therefore, no further evaluation of the impacts of the control options is required.

5.2.5.6 Step 5 – Select SO_2 BAT for Combined Cycle Combustion Turbines

SO_2 BAT for the proposed CC units is based on use of clean fuels with inherently low sulfur content and good combustion practices. Therefore, proposed SO_2 BAT for the CCs is the use of pipeline quality natural gas and good combustion practices. Pipeline quality natural gas, as defined in 40 CFR 72.2, contains 0.5 grains of sulfur or less per 100 standard cubic feet. Based on this sulfur content, SO_2 emissions will not exceed 0.0014 lb/MMBtu when firing natural gas.

The average sulfur content of natural gas will be verified periodically through documentation provided by the supplier.

5.2.6 Sulfuric Acid Mist

5.2.6.1 Formation

Sulfuric acid mist (SAM), or H_2SO_4, emissions from the proposed CC units occur as a result of oxidation of SO_2 to SO_3 as high temperature exhaust gas passes across the surfaces of the SCR and oxidation catalyst. The SO_3 then hydrates to form H_2SO_4 in the presence of water vapor.

5.2.6.2 Step 1 – Identify SAM Control Options

A search of the RBLC was performed to identify potentially available control options for SAM emissions from the proposed combined-cycle turbine units. The results of these RBLC searches are summarized in **Appendix D**, Table D-8. Potentially available control options for SAM emissions include the use of clean fuels with inherently low sulfur content and good combustion practices. Conventional add-on controls for SAM often applied to solid fuel boilers, such as baghouses with sorbent injection and scrubbers, have never been applied to gas-fired combustion turbines because the use of clean fuels inherently results in a low level of SAM emissions (approximately 0.2 ppmvd in the exhaust gas for clean fuels).

5.2.6.3 Step 2 – Eliminate Technically Infeasible SAM Control Options

Use of clean fuels with inherently low sulfur content and good combustion practices are inherent to the Project and technically feasible.

5.2.6.4 Step 3 – Rank Remaining SAM Control Options

No ranking of control options is required since all technically feasible control options will be employed for SAM emissions from the proposed CC units.

5.2.6.5 Step 4 – Evaluation of SAM Control Options

All technically feasible control options are being proposed for SAM emissions from the proposed CC units. Therefore, no further evaluation of the impacts of the control options is required.

5.2.6.6 Step 5 – Select SAM BACT for Combined Cycle Combustion Turbines

No BACT floor exists for SAM emissions from the proposed CC units since EPA does not regulate this pollutant under NSPS Subpart KKKK.

SAM BACT for the proposed CC units is based on use of clean fuels with inherently low sulfur content and good combustion practices. Therefore, proposed SAM BACT for the combined-cycle CTs is the use of pipeline quality natural gas and good combustion practices.

Pipeline quality natural gas, as defined in 40 CFR 72.2, contains 0.5 grains of sulfur or less per 100 standard cubic feet. Based on this sulfur content, SAM emissions will be limited to 0.001 lb/MMBtu and when firing natural gas.

The average sulfur content of natural gas will be verified periodically through documentation provided by the supplier.

5.2.7 Greenhouse Gases

5.2.7.1 Formation

GHG emissions that result from the combustion of clean fuels in the proposed CT units include CO_2, CH_4, and N_2O. CO_2 is a necessary product of combustion from fuels containing carbon. For example, the theoretical combustion equation for CH_4, the primary component of natural gas, is:

$$CH_4 + 2\ O_2 \rightarrow CO_2 + 2\ H_2O$$

Consequently, CO_2 emissions are an essential and intended product of the chemical reaction between the fuel and the oxygen in which it burns and are not a byproduct caused by impurities in the fuel or by incomplete combustion. CH_4 emissions result from unburned natural gas, where CH_4 is a primary component. Formation of N_2O is a product of incomplete oxidation, particularly when combustion fuel mixtures are too lean. Once formed, the N_2O is readily destroyed due to the relatively high concentration of H radicals, and therefore, the N_2O emissions from premixed gas flames like those in DLN combustors are found experimentally to be very small (generally less than 1 ppm). However, any mechanisms which decrease the H atom concentration in the N_2O formation zone can increase N_2O emissions; these mechanisms include lowering the flame combustion temperature, air-to-fuel staging, and injection of ammonia, urea, or other amine or cyanide species into the exhaust stream, all of which are common NO_X control measures. Therefore, reductions in NO_X can result in incremental increases in N_2O emissions.

5.2.7.2 Step 1 – Identify GHG Control Options

The RBLC database lists technologies and corresponding emission limits that have been approved by regulatory agencies in permitting actions. These results are summarized in **Appendix D**, Table D-9. Based on the RBLC search results, no add-on control options for GHGs were identified. Many facilities listed a combination of use of clean fuels, efficient design, and good combustion practices as BACT for CO_2 and CO_2(e) emissions from combined-cycle turbines. In addition, this analysis considers co-firing low-GHG hydrogen and carbon capture and sequestration (CCS) as potential control options for the proposed CT units based on a recent EPA rulemaking proposal. Each of these control options for GHGs is discussed in further detail below.

Use of Clean Fuels

The use of fuel with lower ratios of carbon content to energy released during combustion will result in lower CO_2 emissions per energy output. Natural gas has a lower ratio of CO_2 emissions per energy output when compared to other commonly burned fossil fuels, including coal and fuel oil. The use of clean fuels (pipeline quality natural gas) is inherent to the Project and a feasible method of reducing CO_2 emissions from combined-cycle CTs.

Efficient Design

EPA established the use of efficient design with good operating practices as the best system of emission reduction (BSER) for new baseload combined-cycle CT units in NSPS Subpart TTTT. Efficient design is also inherent to the Project. The proposed GE 7HA.02 CTs feature the latest advancements in turbine technology and are capable of achieving a net efficiency of 63.4% while burning natural gas in a 1x1 combined-cycle configuration. The proposed CT units will also be equipped with evaporative cooling, which reduces the power required to compress the inlet air before it is used in combustion, thus increasing overall efficiency during certain operating conditions, especially on hot days. Additionally, the proposed CC units will be equipped with sophisticated instrumentation to control all aspects of operation, including fuel flow rate and burner operations, to achieve high efficiency and low emissions.

Good Combustion, Operating, and Maintenance Practices

Good combustion, operating, and maintenance practices are also inherent to the Project and are identified as control methods for the control of CO_2, CH_4, and N_2O. As the proposed CC units are operated, they will inevitably experience performance degradation and efficiency loss over time. The proposed CC units will be equipped with a high efficiency filtration system for the inlet air which reduces contaminants that cause compressor fouling, one of the primary causes of efficiency loss. To address the compressor fouling that does occur, the proposed CC units will be equipped with a water wash system to clean the compressors while on- or off-line.

The proposed CC units will also be maintained under a maintenance program designed and implemented by the OEM. Maintenance programs are important for efficiency as well as long-term reliability and are based on a schedule determined by the number of hours of operation and/or turbine starts. Such programs commonly include three basic maintenance levels: combustion inspections, hot gas path inspections, and major overhauls. Combustion inspections are the most frequent of the maintenance cycles and include combustor tuning to maintain highly efficient, low-emissions operation. Hot gas path inspections and major inspections occur on manufacturer-prescribed schedules and involve inspection and possible replacement of internal parts, including compressor or turbine blades, to restore lost performance.

Use of Low-GHG Hydrogen

Previously the EPA proposed co-firing 30% low-GHG hydrogen by 2032 as BSER for both intermediate load and baseload CT units; however, on April 25, 2024, EPA finalized NSPS Subpart TTTTa and stated that the "Agency is not finalizing the proposed BSER pathway of low-GHG hydrogen co-firing at this time." EPA cited uncertainties regarding projected costs and availability of low-GHG hydrogen and estimated that future hydrogen costs were higher than at proposal.[13] Since the NSPS for low-GHG hydrogen was not finalized, highly efficient combined-cycle generation remains the BACT "floor". Low-GHG hydrogen requires the production of the hydrogen fuel through use of a low CO_2 emission technology, such as a renewable energy-powered process or a fossil fuel-powered process paired with carbon capture and storage; without low CO_2 emission technology for hydrogen generation, the reductions in GHG emissions are not significant. In addition, the low-GHG hydrogen fuel itself is not currently commercially available.

The proposed GE 7HA.02 CTs will be capable of co-firing up to a blend of 30% hydrogen with some physical modifications. However, low-GHG hydrogen fuel itself is not commercially available at this time and therefore is not considered further for the purposes of BACT. Homer City is investigating the possibility of generating hydrogen on site and is leaving space at the facility to potentially accommodate hydrogen production. However, no current technology is capable of producing the amount of hydrogen to operate the CC turbines on a continuous basis.

Carbon Capture and Sequestration

In Subpart TTTTa, finalized on April 25, 2024, EPA included CCS as a BSER under certain conditions, but not for all affected facilities. Specifically, beginning in 2032, CCS would become the BSER for base load combustion turbines. CCS requires the integration of a variety of processes and equipment to separate and capture CO_2 from the exhaust stream, compress and transport the CO_2 to a suitable storage location, and pump the CO_2 deep underground.

Based on the discussion above, the following potential control options for CO_2 emissions from the proposed CT units were considered as part of this BACT analysis:

- Use of clean fuels;
- Efficient design;
- Good combustion, operating, and maintenance practices;
- Use of low-GHG hydrogen as a fuel; and
- Carbon capture and sequestration (CCS).

The technical feasibility of each of these control options is discussed in the following section.

5.2.7.3 Step 2 – Eliminate Technically Infeasible GHG Control Options

Use of Clean Fuels, Efficient Design, and Good Combustion, Operating, and Maintenance Practices

Use of clean fuels, efficient design, and good combustion, operating, and maintenance practices are all inherent to the Project and technically feasible.

[13] 2024-09233 (89 FR 39798)

Use of Low-GHG Hydrogen

Hydrogen co-firing is a promising, but still emerging, technology. However, for purposes of a BACT determination, low-GHG hydrogen is not technically feasible because it is neither "available" nor "applicable" as defined by EPA.

Hydrogen co-firing is an emerging technology that has not been demonstrated in practice. To date, there have been a handful of known test burns of hydrogen blended with natural gas in CTs. However, most, if not all, of these test burns were conducted for short periods of time using temporary blending systems due to the lack of hydrogen availability. Moreover, the test burns that have been conducted have used hydrogen that would not qualify as low-GHG hydrogen, due to the even more limited availability of low-GHG hydrogen and therefore did not result in any meaningful reduction in overall GHG emissions. Since these test burns were only temporary in nature and failed to use low-GHG hydrogen, the tests do not suggest that this control option is applicable. According to EPA guidance, applicants need not consider "technologies which have not yet been applied to (or permitted for) full scale operations (US EPA, 1990)." Since hydrogen co-firing has not been demonstrated in practice, it does not constitute a demonstrated and potentially applicable control technology for the proposed CT units.

With respect to "availability," low-GHG hydrogen cannot be obtained through any known commercial channels in the vicinity of the Project. Pipeline gas quality specifications, in particular higher heating value (HHV), will prevent blending the volumes of hydrogen that would be required by the proposed CT units into the existing natural gas infrastructure that would serve Homer City.[14] Currently, there are no developers planning to build out the significant infrastructure necessary to make use of low-GHG hydrogen a commercially available control option for the proposed CT units. Thus, low-GHG hydrogen is not an available control option, and therefore cannot be an applicable control option for the CT units. Accordingly, low-GHG hydrogen is not technically feasible.

Carbon Capture and Sequestration

CCS is an integrated suite of technologies with the potential to work together to capture (separate and purify) CO_2 from stationary source emissions, compress and transport it to a suitable location, and then pump it into deep underground geologic formations for safe, secure, and permanent storage. Geologic storage refers specifically to the process by which CO_2 is pumped underground into rocks such that it is permanently trapped and cannot enter the atmosphere. Captured CO_2 can also be transported and pumped into oil fields and utilized for enhanced oil recovery (EOR).

For CCS to be technically feasible, each individual step in the process (capture and compression, transportation, and storage) must be technically feasible. The integrated suite of components must also be technically feasible in the sense that components have been demonstrated to work together without interfering with the essential operation of the units. Accordingly, any potential barriers to the successful integration of these components must be considered in determining whether CCS is technically feasible.

Post-combustion carbon capture technology typically involves the use of scrubbing exhaust gases with an amine solvent. This technology has been demonstrated to be effective in the oil and gas industry and has shown potential to be effective on coal-fired units in the power sector but has not been effectively demonstrated on combined-cycle CTs. Because CTs take in additional ambient air for functions other than combustion, such as cooling of turbine compressor blades, CO_2 concentrations in the exhaust streams of CTs are lower than that of coal-fired boilers, making carbon capture by way of amine solvent more difficult. Other technologies for carbon capture are currently under development, including polymeric membranes and combined use of membranes and solvents. However, these technologies are either still under development or are not suitable for CTs due to lower CO_2 concentrations in the exhaust stream.

[14] The pipeline specification is 980 Btu/scf HHV. See Transcontinental Gas Pipeline Company, LLC, FERC Gas Tariff, Fifth Revised Volume No. 1, Part IV - General Terms and Conditions, Section 3 – Quality, 3(b). Blending 30% low-GHG hydrogen with natural gas results in a heating value of approximately 810 Btu/scf. However, the pipeline specification applies to the gas offered at the point of delivery (e.g., just upstream of the point of injection), making direct injection of hydrogen impossible.

CCS technologies and capabilities were investigated by several federal agencies and their findings were included in the "Report of the Interagency Task Force on Carbon Capture and Storage" (August 2010).[15] The report findings at the time concluded that cost-effective deployment of CCS would occur only if the technology is commercially available and supported by a national policy framework. The report also presented that while technology is available, current CCS technologies are expensive and energy intensive, which can significantly degrade the overall efficiency of a power plant and drive up the cost of electricity (COE) by about 75 to 80 percent because the CO_2 capture process uses a significant amount of energy produced from the plant. More recent capture of CO_2 in flue gas streams has been demonstrated on multiple coal-fired power plants in North America, including for Boundary Dam in Saskatchewan, Canada, and Petra Nova in Texas. However, both projects experienced significant carbon capture equipment issues and downtime, resulting in both facilities underperforming when compared to their target goals, and neither project has been demonstrated as an economically viable control method for CO_2 emissions[16]. In addition, issues associated with Petra Nova's CCS facility contributed to over 25% of the plant's 367 outage days during its first three years of operation.[17]

As mentioned previously, storage and transport must also be technically and economically viable for CCS to be considered technically feasible as potential BACT. Infrastructure must exist to transport captured CO_2 to a location with suitable geology to be used for storage. Pipelines carrying CO_2 exist or are under development in several states throughout the midwestern U.S., primarily for use in the oil and gas industry. Currently, there is no existing pipeline infrastructure in Pennsylvania to support CO_2 transportation to a suitable storage location, and the construction of pipeline infrastructure for the Project alone would be impractical and economically infeasible.

Due to the challenges with carbon capture technology when applied to combined-cycle CTs and the lack of commercially available CO_2 transportation methods, CCS is not considered technically feasible for the Project.

5.2.7.4 Step 3 – Rank Remaining GHG Control Options

No ranking of control options is required since all technically feasible control options will be employed for GHG emissions from the proposed combined-cycle CT units.

5.2.7.5 Step 4 – Evaluation of GHG Control Options

The use of clean fuels, efficient design, and good combustion, operating, and maintenance practices are all technically feasible control options, all of which will be implemented in this Project. Therefore, no further evaluation of energy, environmental, and economic impacts for these control options is required.

5.2.7.6 Step 5 – Select GHG BACT for Combined Cycle Combustion Turbines

GHG (CO_2e) BACT for the proposed combined-cycle CT units is based on the use of clean fuels, efficient design, and good combustion, operating, and maintenance practices. NSPS Subpart TTTTa sets a limit of 800 lb CO_2/MWe for large base load units. Consistent with how BACT has been handled for other combined-cycle CT units, a GHG BACT limit of 802 lb CO_2e/MWh-gross is being proposed, which will be demonstrated based on TTTTa requirements based on 12-month rolling average, with allowance for emissions of CH_4 and N_2O. This limit is also intended to cover emissions of CH_4 and N_2O, which will contribute to CO_2e totals. Compliance with the proposed GHG BACT limit will be demonstrated by continuously monitoring heat input according to 40 CFR Part 75, Appendix D, and using emission factors to calculate monthly emissions. The emission factor for CO_2 will be based on 40 CFR Part 75, Appendix G, Eq. G-4, while emissions of CH_4 and N_2O will be based on the current emission factors in 40 CFR Part 98, Table C-2 and the current global warming potentials in 40 CFR Part 98, Table A-1.

[15] https://www.energy.gov/fecm/articles/ccstf-final-report
[16] https://ieefa.org/resources/carbon-capture-boundary-dam-3-still-underperforming-failure
[17] https://www.reuters.com/article/business/environment/problems-plagued-us-co2-capture-project-before-shutdown-document-idUSKCN2523K7/

5.2.8 Ammonia

5.2.8.1 Formation

Emissions of NH_3 from CTs, commonly called ammonia slip, occur when unreacted ammonia injected during the SCR process is present in the exhaust stream. Improper optimization of SCR parameters can result in incomplete chemical reactions, and therefore excess or unreacted ammonia.

5.2.8.2 Step 1 – Identify NH_3 Control Options

Because BAT for NO_X is based on the use of SCR technology a BAT analysis for NH_3 is also necessary for the proposed CTs. To determine BAT for NH_3, search of the RBLC was performed to identify potentially available control options and emission limitations for large natural gas-fired combined-cycle turbine units (larger than 25 MW) which were permitted in the past eleven years (i.e., since 2014). The results of these RBLC searches are summarized in **Appendix D**, Table D-10.

No add-on control technologies were identified in the RBLC for the control of NH_3 emissions from combined-cycle turbines. Applicable control methods include the use of good combustion practices and SCR optimization.

5.2.8.3 Step 2 – Eliminate Technically Infeasible NH_3 Control Options

Use of good combustion practices and SCR optimization are inherent to the proposed combined-cycle CTs and technically feasible.

5.2.8.4 Step 3 – Rank Remaining NH_3 Control Options

No ranking of control options is required, as the use of good combustion practices and SCR optimization are the only technically feasible control options for NH_3 emissions from the proposed CC units and achieve the highest level of NH_3 control.

5.2.8.5 Step 4 – Evaluation of NH_3 Control Options

All identified and technically feasible control options are being proposed for control of NH_3 emissions from the proposed CC units. Therefore, no further evaluation of the impacts of the NH_3 control options is required.

5.2.8.6 Step 5 – Select NH_3 BAT for Combined Cycle Combustion Turbines

No BACT floor exists for NH_3 emissions from the proposed CT units since EPA does not regulate this pollutant under NSPS Subpart KKKK. Consequently, there is no BACT or BAT floor limit.

NH_3 BAT for the proposed CT units is based on use of good operating practices and SCR optimization. Based on the RBLC search results, NH_3 emission limits for combined-cycle CT units with similar controls range from 2 to 5 ppmvd while firing natural gas. Based on this information, the following is proposed as the ammonia slip limit for each of the proposed CC units:

- 5 ppmvd NH_3 or less, corrected to 15% O_2, with or without duct firing. This limit is based on the average of three 1-hour stack tests, and

Three facilities were identified in the RBLC with NH_3 emission limits lower than the proposed limit of 5 ppmvd. These include the Killingly Energy Center, which was not constructed, and CPV Towantic, LLC and Salem Harbor Station. The Salem Harbor turbines significantly smaller than the proposed CCs. The turbines at CVP Towantic are GE Model 7HA.01 units and are permitted with a 2 ppmvd @ 15% O_2 ammonia slip. This predecessor to the proposed 7HA.02 units has a lower operating temperature which results lower NO_X emissions from the turbine exhaust. The comparatively higher uncontrolled NO_X emissions from the 7HA.02 turbine itself leads to straining the capabilities of the SCR system to maintain an outlet concentration of 2.0 ppmvd @ 15%O_2.

For combined cycle turbines of comparable size, a limit 5 ppmvd has been demonstrated as the maximum achievable reduction in NH_3 emissions, as demonstrated through use of good operating practices and SCR optimization.

5.3 Simple Cycle Combustion Turbine BACT/LAER/BAT Review

5.3.1 Nitrogen Oxides

5.3.1.1 Formation

NO_X formation mechanisms for fuel-burning equipment such as the proposed simple-cycle turbine units are generally the same as those discussed above for the proposed combined cycle CT units in **Section 5.2.1**.

Step 1 – Identify NO_X Control Options

A search of the RBLC was conducted to identify NOx BACT determinations for large natural gas-fired simple-cycle CT units (including both larger than and less than 25 MWe) permitted in the past twelve years (i.e., since 2013). The results of these RBLC searches are summarized in **Appendix D**, Table D-11. Potentially available control options to reduce NO_X emissions from the proposed CT units include combustion controls, such as dry low-NO_X (DLN) combustors and water or steam injection, and post-combustion add-on controls, such as selective noncatalytic reduction (SNCR), nonselective catalytic reduction (NSCR), and selective catalytic reduction (SCR). Each is discussed in the following sections.

Water or Steam Injection

Water or steam injection was determined by EPA to be the best technology for control of NO_X emissions from stationary CT units when the national emissions standards for this source category were first established in 1977.[18] This control option involves the injection of water or steam into the combustor to decrease peak combustion temperature. The injected water or steam acts as a heat sink by diluting the combustion gas and absorbing heat needed to vaporize water. In doing so, peak flame temperature, combustion zone residence time, free oxygen, and thermal NO_X are reduced.

Dry Low NOx Combustors

Combustion controls that utilize combustor design and/or operational features to reduce NO_X emissions without injecting an inert diluent (water or steam) are generically referred to as “dry” low-NO_X (DLN) measures. Design features of DLN combustors are vendor-specific but generally seek to reduce thermal NO_X formation by controlling peak combustion temperature, combustion zone residence time, and combustion zone free oxygen concentration. Designs include staged combustion and pre-mixing air and fuel prior to injection into the combustion zone. DLN measures produce a lean, pre-mixed flame that burns at a lower temperature with less excess oxygen than conventional combustors.

Selective Noncatalytic Reduction

SNCR involves the gas phase reaction of NO_X in the exhaust gas stream with injected ammonia or urea, in the absence of a catalyst, to yield nitrogen and water vapor. Ammonia or urea is injected into a hot exhaust gas stream at a location specifically chosen to achieve the optimum reaction temperature and residence time. The overall reaction schemes for both urea and ammonia systems can be expressed as follows:

$$CO(NH_2)_2 + 2\ NO + ½O_2 = 2N_2 + CO_2 + 2\ H2O \quad (1)$$

$$4\ NH_3 + 6NO = 5N_2 + 6\ H2O \quad (2)$$

Typical removal efficiencies for SNCR range from 30 percent to 50 percent and higher when coupled with combustion controls (US EPA, 2003). An important consideration for SNCR is operating temperature range. The temperature range required for this control option to be effective is approximately 1,600 to 2,000°F.[19] Operation at temperatures below this range results in ammonia slip. Operation at temperatures above this range results in

[18] 42 Fed. Reg. 53782, 53785 (Oct. 3, 1977).

[19] *EPA Air Pollution Control Cost Manual Section 4 – NOx Controls, Chapter 1 – Selective Non-Catalytic Reduction, 2019.*

oxidation of ammonia, forming additional NO_X emissions. Therefore, the SNCR injection system must be located such that operating temperatures are consistently within the identified range.

Nonselective Catalytic Reduction

NSCR uses a catalyst reaction to simultaneously reduce NO_X, CO, and VOC to water, carbon dioxide, and nitrogen without injection of a reagent such as ammonia. The conversion occurs in two sequential steps, with the reactions for CO and VOC occurring first since they more readily react with oxygen than with NO_X. However, to ensure NO_X reduction in the second step, this control option must be applied to exhaust gas streams with low oxygen content (less than 0.5% O_2).

Selective Catalytic Reduction

SCR is a post-combustion emission control process which involves removal of NO_X in a catalytic reactor. In the SCR process, ammonia reacts with nitrogen oxides and oxygen to form nitrogen and water. The SCR process converts nitrogen oxides to nitrogen and water by the following chemical reactions:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O \quad (1)$$

$$6\ NO + 4\ NH_3 \rightarrow 5\ N_2 + 6\ H_2O \quad (2)$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O \quad (3)$$

$$6\ NO_2 + 8\ NH_3 \rightarrow 7\ N_2 + 12\ H_2O \quad (4)$$

$$NO + NO_2 + 2\ NH_3 \rightarrow 2\ N_2 + 3\ H_2O \quad (5)$$

A catalyst is required to lower the activation energy at which NO_X decomposition occurs. Technical factors that must be considered with this control option include increased turbine backpressure, thermal considerations for structures and materials including shock/stress during startup, catalyst masking/blinding, reported catalyst failure due to "crumbling," design of the ammonia injection system, and ammonia slip.

For most SCR catalyst configurations, the optimum operating temperature of the system is between 700 and 850°F. However, simple cycle CT units typically produce exhaust gas temperatures that exceed 1100°F. Consequently, this control option requires the use of high-temperature catalysts and the use of tempering air to reduce the temperature of the turbine exhaust prior to it being introduced into the SCR reactor. SCR catalyst materials lose activity over time, necessitating catalyst cleaning or replacement.

5.3.1.2 Step 2 – Eliminate Technically Infeasible NO_X Control Options

Use of Water/Steam Injection and DLN Combustors

Use of DLN combustors and water injection is inherent to the Project and technically feasible.

Selective Non-catalytic Reduction

SNCR is not a technically feasible control option for NO_X emissions from the proposed CT units since it has not been demonstrated in practice and is not both an available *and* applicable control option. Based on the RBLC search results, SNCR has not been installed and operated successfully on the type of source under review; in the utility industry, this control option is typically applied to electric steam generating units (i.e., boilers). For utility boilers, ammonia is injected into the furnace where temperatures remain high enough for the NO_X reduction reaction to occur (between 1,600 and 2,000°F). The temperature of the exhaust gas from the proposed CT units is too low for SNCR to be effective and it would not be practical or reasonable to further heat the exhaust gas so that this control option may be applied. Therefore, SNCR is not applicable to the proposed CT units. Accordingly, SNCR is not technically feasible.

Nonselective Catalytic Reduction

NSCR is also not a technically feasible control option for NO_X emissions from the proposed CT units since it has not been demonstrated in practice and is not both an available *and* applicable control option. Based on the RBLC review, NSCR has not been installed and operated successfully on the type of source under review; this control option is most commonly applied to nonroad and stationary rich-burn spark-ignition internal combustion engines (SI ICE).

For rich-burn SI ICE, air-to-fuel ratio controllers are used to maintain the low levels of excess oxygen necessary (less than 0.5%) for NSCR to be an effective control option for NO_X emissions. The oxygen content of the exhaust gas from proposed CT units will typically be 13-16%. Therefore, NSCR is not applicable to the proposed CT units. Accordingly, NCSR is not technically feasible.

Selective Catalytic Reduction

The use of SCR is included in the Project because it is necessary to comply with Pennsylvania, Best Available Technology (BAT), which is defined as equipment, devices, methods or techniques as determined by the Department which will prevent, reduce or control emissions of air contaminants to the maximum degree possible and which are available or may be made available. The emission limits for NO_X emissions from the proposed CT units can be less than 2.5 ppmvd, corrected to 15% O_2, based on a 30-operating day rolling average. The use of SCR can be made technically feasible by tempering the exhaust gas from the proposed CT units with ambient air to be within the temperature range necessary for this control option to be applicable. This control option has been demonstrated in practice for similar large simple cycle turbines. Based on the RBLC search results, 47 units were identified and 7 of those units employed SCR as a control technology. Therefore, SCR is applicable to the proposed CT units and technically feasible.

5.3.1.3 Step 3 – Rank Remaining NO_X Control Options

No ranking of control options is required as all available and technically feasible control options for NO_X emissions from the proposed CT units are included in the Project.

5.3.1.4 Step 4 – Evaluation of NO_X Control Options

The top control options are being proposed for NO_X emissions from the proposed CT units. Therefore, no further evaluation of the energy, environmental, and economic impacts of the control options is required. However, consideration of those impacts could result in a different BAT determination for other sources or projects in areas not subject to Pennsylvania BAT or a similar standard that requires use of SCR.

5.3.1.5 Step 5 – Select NO_X BACT/BAT for Combustion Turbines

To comply with NSPS Subpart KKKK, the proposed simple-cycle CT units will be subject to a NO_X emission standard of 25 ppmvd while firing natural gas. These emissions standards serve as the BAT floor.

NO_X BAT for the proposed CT units is based on use of clean fuels, DLN combustors, water injection, and SCR. Based on the RBLC search results, NO_X emission limits for simple-cycle CT units with similar controls range from 2.5 to 32.7 ppmvd while firing natural gas. Based on this information, the following will be proposed as NO_X BAT for each of the proposed CT units:

- 2.5 ppmvd NO_X or less, corrected to 15% O_2, when firing natural gas based on a 1-hour rolling average (CEMS), excluding periods of startup, shutdown, or fuel switching,
- 12 tons NO_X or less during any 12-month consecutive period, including periods of startup and shutdown,
- Emissions shall be controlled by use of an SCR system.

Compliance with these emissions limits shall be demonstrated by use of a CEMS installed and operated in accordance with 40 CFR Part 60.

Startup means the period of time from when fuel is first fired to when the load has been achieved at which it has been demonstrated, by a CEMS or during compliance testing, that the emission limits can be met during steady-state operations (i.e., the minimum emissions compliance load or MECL), not to exceed 30 minutes for natural gas and 14.4 lb/event based on 4-hour rolling average.

Shutdown means the period of time from MECL to when firing of fuel has ceased, not to exceed 9 minutes for natural gas and 2.8 lb/event based on 4-hour rolling average.

In determining the 1-hour block NO_X emissions rate, one-hour average emissions will be based on at least 30 minutes of normal operation (i.e., after startup and before shutdown) to ensure partial operating hours contain at least one valid measurement based on operation during a full quadrant of an hour.

5.3.2 Carbon Monoxide

5.3.2.1 Formation

CO emissions from the proposed CT units may be generated during combustion as a result of incomplete conversion of carbon-containing compounds to CO_2 and water. CO emission rates are principally influenced by equipment operating conditions; elevated CO emissions may be the result of low combustion temperature, insufficient combustor residence time, and/or low operating loads.

5.3.2.2 Step 1 – Identify CO Control Options

A search was performed using the RBLC to identify CO BAT determinations for large natural gas-fired simple-cycle CT units (including both larger than and less than 25 MWe) permitted in the past twelve years (i.e., since 2013). Relevant existing and proposed federal and state emissions standards were also considered, as well as recently issued new source review permits and associated applications, if available, for similar sources, and discussions with original equipment manufacturer (OEMs) and owner/operators of simple-cycle CT units to identify potentially available control options for CO emissions from the proposed CT units. The results of these searches are summarized in **Appendix D**, Table D-12.

Potentially available control options to reduce CO emissions from the proposed CT units include combustion controls, good combustion practices, and post-combustion add-on controls such as an oxidation catalyst. Each are discussed in the following sections.

Combustion Controls and Good Operating Practices

As noted above, CO emissions may result from incomplete combustion. Proper equipment design, proper operation, and optimization of the combustion air systems (e.g., compressor inlet guide vane control) to achieve good combustion efficiency will minimize CO emissions from the proposed CT units.

Oxidation Catalyst

An oxidation catalyst uses excess air to convert CO emissions to CO_2 in the presence of catalyst without the use of a reagent. Technical considerations for employing this add-on control option include reactor design, operating temperature, back pressure of the system and its impact on performance, and catalyst life. Oxidation catalysts operate effectively in a relatively narrow temperature range typically between 600 to 800°F. As discussed above, simple-cycle CT units typically produce exhaust gas temperatures that exceed 1100°F. Consequently, the exhaust gas must be tempered with ambient air to avoid permanently damaging (sintering) the catalyst. At lower operating temperatures, CO conversion efficiency falls off rapidly.

5.3.2.3 Step 2 – Eliminate Technically Infeasible CO Control Options

Use of combustion controls and good operating practices is inherent to the Project and technically feasible.

The use of an oxidation catalyst is included in the Project because it is necessary to comply with the CT MACT standards (40 CFR 63 Subpart YYYY). Like the SCR, the oxidation catalyst will be made technically feasible by tempering the exhaust gas from the proposed CT units with ambient air to be within the temperature range necessary for this control option to be applicable.

5.3.2.4 Step 3 – Rank Remaining CO Control Options

No ranking of control options is required, as all available and technically feasible control options for CO emissions from the proposed CT units are included in the Project.

5.3.2.5 Step 4 – Evaluation of CO Control Options

The top control options are being proposed for CO emissions from the proposed CT units. Therefore, no further evaluation of the energy, environmental, and economic impacts of the control options is required. However, consideration of those impacts could result in a different BAT determination for other sources or projects not subject to the CT MACT or a similar standard that requires use of oxidation catalyst.

5.3.2.6 Step 5 – Select CO BACT/BAT for Combustion Turbines

No BACT floor exists for CO emissions from the proposed CT units since EPA does not regulate this pollutant under NSPS Subpart KKKK. Consequently, there is no BACT or BAT limit.

CO BAT for the proposed CT units is based on use of clean fuels, good combustion practices and oxidation catalyst. Based on the RBLC search results, CO emission limits for simple-cycle CT units with oxidation catalysts ranged from 5.0 to 30.7 ppmvd while firing natural gas. Aeroderivative turbines similar to the proposed CT units were identified at five facilities, Bayonne Energy Center, Westar Energy-Emporia Energy Center, Lonesome Creek Generating Station, Pioneer Generating Station, and Pueblo Airport Generating Station, hourly emission limits ranged from 7.21 lb/hr and 36.0 lb/hr for normal operations. These facilities proposed CO BACT as: (1) oxidation catalyst, (2) use of natural gas, and (3) efficient combustion. Based on this information, the following is proposed as the CO limit for each of the proposed simple-cycle CT units:

- 9.35 lbs/hr CO or less, corrected to 15% O_2, when firing natural gas based on a 1-hour block average (CEMS), excluding periods of startup and shutdown, and
- 23.4 tons CO or less during any 12-month consecutive period, including periods of startup and shutdown
- Emissions shall be controlled by use of an oxidation catalyst and good combustion practices.

Compliance with these emissions limits shall be demonstrated by use of a CEMS installed and operated in accordance with 40 CFR Part 60.

Startup means the period of time from when fuel is first fired to when the load has been achieved at which it has been demonstrated, by a CEMS or during compliance testing, that the emission limits can be met during steady-state operations (i.e., the minimum emissions compliance load or MECL), not to exceed 30 minutes for natural gas and 27.7 lb/event.

Shutdown means the period of time from MECL to when firing of fuel has ceased, not to exceed 9 minutes for natural gas and 6.7 lb/event.

5.3.3 Volatile Organic Compounds

5.3.3.1 Formation

VOC emissions from the proposed CT units are influenced by the same factors that impact CO emissions discussed above.

5.3.3.2 Step 1 – Identify VOC Control Options

Potentially available control options for VOC emissions from the proposed CT units are the same as those discussed above for CO—combustion controls, good combustion practices, and post-combustion add-on controls, such as an oxidation catalyst. A search of the RBLC was conducted to identify VOC LAER determinations for large natural gas-fired simple-cycle CT units (including both larger than and less than 25 MWe) permitted in the past twelve years (i.e., since 2013). The results of these RBLC searches are summarized in **Appendix D**, Table D-13.

Combustion Controls and Good Operating Practices

Like CO, VOC emissions may result from incomplete combustion. Proper equipment design, proper operation, and optimization of the combustion air systems to achieve good combustion efficiency will minimize VOC emissions from the proposed CT units.

Oxidation Catalyst

An oxidation catalyst uses excess air to convert organic compounds to CO_2 in the presence of catalyst without the use of a reagent. Technical considerations for employing this add-on control option are the same as those discussed above for CO.

5.3.3.3 Step 2 – Eliminate Technically Infeasible VOC Control Options

Use of combustion controls and good operating practices is inherent to the Project and technically feasible.

The use of an oxidation catalyst is also included in the Project because it is necessary to comply with the combustion turbine MACT standards. Like the SCR, the oxidation catalyst will be made technically feasible by tempering the exhaust gas from the proposed CT units with ambient air to be within the temperature range necessary for this control option to be applicable. Based on the RBLC results, one facility, Bayonne Energy Center, was able to demonstrate an oxidation catalyst as a control option for its simple cycle gas turbines.

5.3.3.4 Step 3 – Rank Remaining VOC Control Options

No ranking of control options is required as all available and technically feasible control options for VOC emissions from the proposed CT units are included in the Project.

5.3.3.5 Step 4 – Evaluation of VOC Control Options

The top control options are being proposed for VOC emissions from the proposed CT units. In addition, because VOC emissions are subject to LAER requirements, evaluations of the energy, environmental, and economic impacts are not taken into account.

5.3.3.6 Step 5 – Select VOC LAER for Combustion Turbines

VOC LAER for the proposed CT units is based on use of clean fuels, good combustion practices, and an oxidation catalyst. Based on the RBLC search results, other aeroderivative turbines were identified at Bayonne Energy Center (as Rolls Royce Trent 60) and Westar Energy-Emporia Energy Center (as GE LM6000) with emission limits of 1.65 lb/hr based on average of three 1-hr stack tests every 5 years and 5.80 lb/hr at full load, respectively. These facilities proposed VOC BACT as: (1) oxidation catalyst, (2) use of natural gas, and (3) efficient combustion. No other FT8 MOBILEPAC turbine was identified in the RBLC. Based on this information, the following is being proposed as VOC LAER for each of the proposed simple-cycle CT units:

- 3.75 lbs/hr VOC or less, corrected to 15% O_2, when firing natural gas, based on the average of a 3-run stack test using EPA Reference Method 25A. Emissions shall be controlled by use of an oxidation catalyst and good combustion practices.

Stack testing will be conducted after initial startup followed by subsequent stack tests every five years. Compliance with the VOC LAER emission limits for the proposed CT units will be assured as long as the CO emissions are in compliance with the corresponding CO BAT emission limits.

5.3.4 Particulate Matter

5.3.4.1 Formation

PM emissions from the proposed CT units include both filterable and condensable particles.[20] Filterable PM is formed from impurities contained in fuels, dust in the ambient air, and from incomplete combustion, while condensable PM is primarily attributable to high molecular weight VOC (unburned hydrocarbons) and the conversion of fuel sulfur to sulfates when catalyst-based add-on controls are used.

[20] For the purposes of BACT, emission limits for PM include only filterable PM, while emission limits for PM_{10} and $PM_{2.5}$ are required to include both filterable and condensable fractions. In this BACT analysis, the term "PM" is meant to include both PM_{10} and $PM_{2.5}$ unless otherwise noted.

5.3.4.2 Step 1 – Identify PM Control Options

A search was performed using EPA's control technology database, which also considered relevant existing and proposed federal and state emissions standards to identify potentially available control options for PM emissions from the proposed simple-cycle CT units. The results of these RBLC searches are summarized in **Appendix D**, Tables D-14 through D-16. Based on this review, no add-on control options were identified. Instead, many facilities listed some variation of use of clean fuels (which inherently have low sulfur content) and good combustion practices as BACT. Generally, conventional add-on controls often applied to solid fuel boilers, such as baghouses, electrostatic precipitators, and scrubbers, have not been applied to gas-fired combustion turbines because the use of clean fuels inherently results in a low level of PM emissions.[21] Accordingly, only the use of cleans fuels and good combustion practices are considered further.

5.3.4.3 Step 2 – Eliminate Technically Infeasible PM Control Options

Use of clean fuels (with inherently low sulfur content) and good combustion practices are inherent to the Project and technically feasible.

5.3.4.4 Step 3 – Rank Remaining PM Control Options

No ranking of control options is required, as use of clean fuels and good combustion practices are the only available and technically feasible control options for PM emissions from the proposed CT units.

5.3.4.5 Step 4 – Evaluation of PM Control Options

The top control options are being proposed for PM emissions from the proposed CT units. Therefore, no further evaluation of the impacts of the PM control options is required.

5.3.4.6 Step 5 – Select PM BACT for Combustion Turbines

Like VOC, no BACT floor exists for PM emissions from the proposed CT units since EPA does not regulate this pollutant under NSPS Subpart KKKK.

PM BACT for the proposed CT units is based on use of clean fuels with inherently low sulfur content and good combustion practices. Based on the RBLC search results, total PM emission limits for simple-cycle CT units with similar controls range from 0.003 to 0.015 lb/MMBtu for PM_{10} and $PM_{2.5}$ when firing natural gas. Based on this information, the following is proposed as PM BACT for each of the simple-cycle CT units:

- Total PM, containing filterable and condensable PM, equal to or less than 0.009 lb/MMBtu, or 3.0 lb/hr, when firing natural gas, based on the average of a 3-run stack test using EPA Reference Methods 5 and 202.

Since the PM BACT is based on the use of clean fuels with inherently low sulfur content, an initial stack test after commissioning, followed by testing once every five (5) years after initial testing.

[21] When EPA originally proposed national standards for CT units in NSPS Subpart GG, EPA stated that "particulate emissions from stationary gas turbines are minimal" and noted that add-on controls for PM are not typically installed on CT units and are cost prohibitive. See 44 Fed. Reg. 52792, 52798 (Sept. 10, 1979); EPA, *Standards Support and Envtl. Impact Statement Volume 1: Proposed Standards of Performance for Stationary Gas Turbines*, at 8-6 (Sept. 1977). Additionally, when EPA proposed to update the standards in NSPS Subpart KKKK, EPA declined to establish standards for PM because "…[PM] emissions are negligible with natural gas firing due to the low sulfur content of natural gas." 70 Fed. Reg. 8314, 8321 (Feb. 18, 2005). At the time, EPA also noted that no CT units permitted since 2003 utilized add-on controls.

5.3.5 Sulfur Dioxide

5.3.5.1 Formation

SO_2 is formed from the oxidation of sulfur compounds contained in fuel during the combustion process. Because natural gas has a relatively low sulfur content compared with other combustible fuels, such as coal or heavy fuel oils, SO_2 emissions are minimal from natural gas-fired equipment, including combustion turbines.

5.3.5.2 Step 1 – Identify SO_2 Control Options

To determine BAT for SO_2, a search of the RBLC was conducted to identify available control options for SO_2 emissions from large natural gas-fired simple-cycle CT units (including both larger than and less than 25 MWe) permitted in the past twelve years (i.e., since 2013). The results of these RBLC searches are summarized in **Appendix D**, Table D-17. Control methods identified include good combustion practices and the use of clean fuels with inherently low sulfur content. Add on control technologies, including scrubbers and flue gas desulfurization, are commonly used to control SO_2 emissions from sources which combust high-sulfur fuels, and have not been found to be applied to simple-cycle CTs. Therefore, only the use of good combustion practices and clean fuels is evaluated further.

5.3.5.3 Step 2 – Eliminate Technically Infeasible SO_2 Control Options

Use of clean fuels with inherently low sulfur content and good combustion practices are inherent to the Project and technically feasible.

5.3.5.4 Step 3 – Rank Remaining SO_2 Control Options

No ranking of control options is required since all technically feasible control options will be employed for SO_2 emissions from the proposed CT units.

5.3.5.5 Step 4 – Evaluation of SO_2 Control Options

All technically feasible control options are being proposed for SO_2 emissions from the proposed CT units. Therefore, no further evaluation of the impacts of the control options is required.

5.3.5.6 Step 5 – Select SO_2 BAT for Simple Cycle Combustion Turbines

SO_2 BAT for the proposed CT units is based on use of clean fuels with inherently low sulfur content and good combustion practices. Therefore, proposed SO_2 BAT for the simple-cycle CTs is the use of pipeline quality natural gas and good combustion practices. Pipeline quality natural gas, as defined in 40 CFR 72.2, contains 0.5 grains of sulfur or less per 100 standard cubic feet. Based on this sulfur content, SO_2 emissions will not exceed 0.0014 lb/MMBtu when firing natural gas.

The sulfur content of natural gas will be verified periodically through documentation provided by the supplier.

5.3.6 Sulfuric Acid Mist

5.3.6.1 Formation

Sulfuric acid mist (SAM), or H_2SO_4, emissions from the proposed CT units occur as a result of oxidation of SO_2 to SO_3 as high temperature exhaust gas passes across the surfaces of the SCR and oxidation catalyst. The SO_3 then hydrates to form H_2SO_4 in the presence of water vapor.

5.3.6.2 Step 1 – Identify SAM Control Options

The only potentially available control option for SAM emissions from the proposed CT units is use of clean fuels with inherently low sulfur content and good combustion practices. Conventional add-on controls for SAM often applied to solid fuel boilers, such as baghouses with sorbent injection and scrubbers, have never been applied to gas-fired

combustion turbines because the use of clean fuels inherently results in a low level of SAM emissions (approximately 0.2 ppmvd in the exhaust gas for clean fuels).

5.3.6.3 Step 2 – Eliminate Technically Infeasible SAM Control Options

Use of clean fuels with inherently low sulfur content and good combustion practices are inherent to the Project and technically feasible.

5.3.6.4 Step 3 – Rank Remaining SAM Control Options

No ranking of control options is required since all technically feasible control options will be employed for SAM emissions from the proposed CT units.

5.3.6.5 Step 4 – Evaluation of SAM Control Options

All technically feasible control options are being proposed for SAM emissions from the proposed CT units. Therefore, no further evaluation of the impacts of the control options is required.

5.3.6.6 Step 5 – Select SAM BACT for Combustion Turbines

No BACT floor exists for SAM emissions from the proposed CT units since EPA does not regulate this pollutant under NSPS Subpart KKKK.

SAM BACT for the proposed CT units is based on the use of clean fuels with inherently low sulfur content and good combustion practices. Therefore, proposed SAM BACT for the simple-cycle CTs is the use of pipeline quality natural gas and good combustion practices.

Pipeline quality natural gas, as defined in 40 CFR 72.2, contains less than 0.5 grains sulfur per 100 standard cubic feet. Based on this sulfur content, SAM emissions will be less than 0.0022 lb/MMBtu when firing natural gas (based on average of three (3) test runs).

The sulfur content of each fuel will be verified periodically through documentation provided by the supplier.

5.3.7 Greenhouse Gases

5.3.7.1 Formation

GHG formation for combustion sources are discussed in Section 5.2.7.1. GHGs are emitted as a product of natural gas combustion or emitted as unburned fuel.

5.3.7.2 Step 1 – Identify GHG Control Options

The RBLC database lists technologies and corresponding emission limits that have been approved by regulatory agencies in permitting actions. These results are summarized in **Appendix D**, Table D-19. Based on the RBLC search results, no add-on control options were identified. Many facilities listed some variation of use of clean fuels (natural gas), efficient design, and good combustion practices as BACT for CO_2 and $CO_2(e)$ emissions. Such control options form the basis for GHG BACT for similar simple-cycle CTs. In addition, this analysis considers co-firing low-GHG hydrogen and carbon capture and sequestration (CCS) as potential control options from the proposed CT units based on a recent EPA rulemaking proposal. Each of these control options is discussed in further detail below.

Use of Clean Fuels and Highly Efficient Simple Cycle Generation

EPA established the use of clean fuels and highly efficient simple cycle generation as the best system of emission reduction (BSER) for new non-baseload CT units in NSPS Subpart TTTTa. Use of clean fuels is inherent to the Project and serves as the BACT “floor” for the proposed simple-cycle CT units.

Efficient Design

In NSPS Subpart TTTTa, EPA determined that highly efficient simple cycle generation is the BSER for intermediate loads, which is also inherent to the Project. The CT technology that will be used for the Project represents an

evolution in technology advancements over previous designs. Among other things, the advancements associated with the proposed CT units include higher pressure ratios, increased firing temperatures, and advanced thermal barrier coatings. Additionally, the proposed CT units will be equipped with sophisticated instrumentation to control all aspects of operation, including fuel flow rate and burner operations, to achieve high efficiency and low emissions.

Good Combustion, Operating, and Maintenance Practices

Good combustion, operating, and maintenance practices are also inherent to the Project. As the proposed CT units are operated, they will inevitably experience performance degradation and efficiency loss over time. As a preventative measure, the proposed CT units will be equipped with a high efficiency filtration system for the inlet air which reduces contaminants that cause compressor fouling, one of the primary causes of efficiency loss. To address the compressor fouling that does occur, the proposed CT units can perform a water wash to clean the compressors while on- or off-line.

The proposed CT units will also be maintained under a maintenance program designed and implemented by the original equipment manufacturer (OEM). Maintenance programs are important for efficiency as well as long-term reliability and are based on a schedule determined by the number of hours of operation and/or turbine starts. Such programs commonly include three basic maintenance levels: combustion inspections, hot gas path inspections, and major overhauls. Combustion inspections are the most frequent of the maintenance cycles and include combustor tuning to maintain highly efficient, low-emissions operation. Hot gas path inspections and major inspections occur on manufacturer-prescribed schedules and involve inspection and possible replacement of internal parts, including compressor or turbine blades, to restore lost performance.

Use of Low-GHG Hydrogen

Previously the EPA proposed co-firing 30% low-GHG hydrogen by 2032 as BSER for both intermediate load and baseload CT units; however, on April 25, 2024, EPA finalized NSPS Subpart TTTTa and stated that the "Agency is not finalizing the proposed BSER pathway of low-GHG hydrogen co-firing at this time." EPA cited uncertainties regarding projected costs and availability of low-GHG hydrogen and estimated that future hydrogen costs were higher than at proposal.[22] Since the NSPS for low-GHG hydrogen was not finalized, the use of clean fuels and high efficient simple cycle generation remains the BACT "floor". Low-GHG hydrogen requires the production of the hydrogen fuel through use of a low CO_2 emission technology, such as a renewable energy-powered process or a fossil fuel-powered process paired with carbon capture and storage; without low CO_2 emission technology for hydrogen generation, the reductions in GHG emissions are not significant. In addition, the low-GHG hydrogen fuel itself is not commercially available.

However, unlike the proposed CC units, the proposed CT units are not capable of co-firing low-GHG hydrogen. Therefore, this is not an available option for the CT units.

Carbon Capture and Sequestration

In Subpart TTTTa, finalized on April 25, 2024, EPA included carbon capture and storage (CCS) as a BSER option for base load combustion turbines, but not for intermediate and low load combustion turbines. CCS requires the integration of a variety of processes and equipment to separate and capture CO_2 from the exhaust stream, compress and transport the CO_2 to a suitable storage location, and pump the CO_2 deep underground.

Based on the discussion above, the following potential control options for CO_2 emissions from the proposed CT units were considered as part of this BACT analysis:

- Use of clean fuels;
- Efficient design;
- Good combustion, operating, and maintenance practices;
- Use of low-GHG hydrogen as a fuel; and
- Carbon capture and sequestration (CCS).

[22] 2024-09233 (89 FR 39798)

The technical feasibility of each of these control options is discussed in the following section.

5.3.7.3 Step 2 – Eliminate Technically Infeasible GHG Control Options

Use of Clean Fuels, Efficient Design, and Good Combustion, Operating, and Maintenance Practices

Use of clean fuels, efficient design, and good combustion, operating, and maintenance practices are all inherent to the Project and technically feasible.

Use of Low-GHG Hydrogen

Hydrogen co-firing is a promising, but still emerging, technology. However, for purposes of a BACT determination, low-GHG hydrogen is not technically feasible because it is neither "available" nor "applicable" as defined by EPA.

Hydrogen co-firing is an emerging technology that has not been demonstrated in practice. To date, there have been a handful of known test burns of hydrogen blended with natural gas in CTs, which include units at Georgia Power Companies McDonough-Atkinson Steam-Electric Generating Plant (Plant McDonough). However, most, if not all, of these test burns were conducted for short periods of time using temporary blending systems due to the lack of hydrogen availability.[23] Moreover, the test burns that have been conducted have used hydrogen that would not qualify as low-GHG hydrogen, due to the even more limited availability of low-GHG hydrogen, and therefore did not result in any meaningful reduction in overall GHG emissions. Since these test burns were only temporary in nature and failed to use low-GHG hydrogen, the tests do not suggest that this control option is applicable. According to EPA guidance (US EPA, 1990), applicants need not consider "technologies which have not yet been applied to (or permitted for) full scale operations." Since hydrogen co-firing has not been demonstrated in practice, it does not constitute a demonstrated and potentially applicable control technology for the proposed CT units.

With respect to "availability," low-GHG hydrogen cannot be obtained through any known commercial channels in the vicinity of the Project. Pipeline gas quality specifications, in particular higher heating value (HHV), will prevent blending the volumes of hydrogen that would be required by the proposed CT units into the existing natural gas infrastructure that would serve Homer City.[24] Currently, there are no developers planning to build out the significant infrastructure necessary to make use of low-GHG hydrogen a commercially available control option for the proposed CT units. Thus, low-GHG hydrogen is not an available control option, and therefore cannot be an applicable control option for the CT units. Accordingly, low-GHG hydrogen is not technically feasible.

Carbon Capture and Sequestration

CCS is an integrated suite of technologies with the potential to work together to capture (separate and purify) CO_2 from stationary source emissions, compress and transport it to a suitable location, and then pump it into deep underground geologic formations for safe, secure, and permanent storage. Geologic storage refers specifically to the process by which CO_2 is pumped underground into rocks such that it is permanently trapped and cannot enter the atmosphere. Captured CO_2 can also be transported and pumped into oil fields and utilized for enhanced oil recovery (EOR).

For CCS to be technically feasible, each individual step in the process (capture and compression, transportation, and storage) must be technically feasible. The integrated suite of components must also be technically feasible in the sense that components have been demonstrated to work together without interfering with the essential operation of the units. Accordingly, any potential barriers to the successful integration of these components must be considered in determining whether CCS is technically feasible.

[23] For example, the short-term test burn at Plant McDonough was conducted at a maximum of approximately 20% hydrogen co-firing by volume for less than a full hour. The test was conducted on a single train of a 2-on-1 combined-cycle unit and required significant on-site oversight and involvement by the OEM.

[24] The pipeline specification is 980 Btu/scf HHV. See Transcontinental Gas Pipeline Company, LLC, FERC Gas Tariff, Fifth Revised Volume No. 1, Part IV - General Terms and Conditions, Section 3 – Quality, 3(b). Blending 30% low-GHG hydrogen with natural gas results in a heating value of approximately 810 Btu/scf. However, the pipeline specification applies to the gas offered at the point of delivery (e.g., just upstream of the point of injection), making direct injection of hydrogen impossible.

To date, CCS has not been demonstrated in practice on a combustion turbine. Furthermore, no research and development has been completed for implementation of CCS on simple-cycle CTs because the exhaust gas from a simple-cycle CT is too hot for post-combustion carbon capture and requires significant cooling for amine-based solvent or membrane separation. Therefore, CCS is not an "applicable" control option. EPA has specifically recognized the unresolved challenges associated with attempting to apply CCS to simple-cycle combustion turbines like those included in the Project.[25] Furthermore, when EPA finalized Subpart TTTTa, on April 25, 2024, to include BSER of 90% CCS beginning in 2032, this determination was only for base load units. The simple cycle combustion turbines will not operate at base load conditions. Accordingly, CCS is not technically feasible.

5.3.7.4 Step 3 – Rank Remaining GHG Control Options

No ranking of control options is required since all technically feasible control options will be employed for GHG emissions from the proposed CT units.

5.3.7.5 Step 4 – Evaluation of GHG Control Options

The use of clean fuels, efficient design, and good combustion practices are all technically feasible control options, all of which will be implemented in this Project. Therefore, no further evaluation of energy, environmental, and economic impacts for these control options is required.

5.3.7.6 Step 5 – Select GHG BACT for Combustion Turbines

GHG (CO_2e) BACT for the proposed simple cycle CT units is based on the use of clean fuels, efficient design, and good combustion, operating, and maintenance practices. Consistent with how BACT has been handled for other simple-cycle CT units, a GHG BACT limit of 1,425 lb/MW-hr of CO_2e is being proposed, which will be demonstrated with a CEMS based on 12-month rolling average. This limit is also intended to cover emissions of CH_4 and N_2O, which will contribute to CO_2e totals. Compliance with the proposed GHG BACT limit will be demonstrated by continuously monitoring heat input and using emission factors to calculate monthly emissions. The emission factor for CO_2 will be based on 40 CFR Part 75, Appendix G, Eq. G-4, while emissions of CH_4 and N_2O will be based on the current emission factors in 40 CFR Part 98, Table C-2 and the current global warming potentials in 40 CFR Part 98, Table A-1.

5.3.8 Ammonia

5.3.8.1 Formation

Emissions of NH_3 from CTs, commonly called ammonia slip, occur when unreacted ammonia injected during the SCR process is present in the exhaust stream. Improper optimization of SCR parameters can result in incomplete chemical reactions, and therefore excess or unreacted ammonia.

5.3.8.2 Step 1 – Identify NH_3 Control Options

Because BAT for NO_X is based on the use of SCR technology a BAT analysis for NH_3 is also necessary for the proposed CTs. To determine BAT for NH_3, search of the RBLC was performed to identify potentially available control options and emission limitations for large natural gas-fired simple-cycle CT units (larger than 25 MW) which were permitted in the past twelve years (i.e., since 2013). No RBLC results were found for ammonia, but because PADEP requires a BAT analysis to be performed, this Project has included a BAT analysis for the simple-cycle turbines for completeness purposes. Since NH_3 RBLC results were not available for simple-cycle turbines, the BAT analysis was based on combined-cycle RBLC results, which identified good combustion practices and SCR optimization as control options.

[25] 88 Fed. Reg. at 33286 (May 23, 2023) ("[C]urrently available post-combustion amine-based carbon capture systems require that the exhaust from a combustion turbine be cooled prior to entering the carbon capture equipment. The most energy efficient way to do this is to use a HRSG, which is an integral component of a combined cycle turbine system but is not incorporated in a simple cycle unit.").

5.3.8.3 Step 2 – Eliminate Technically Infeasible NH_3 Control Options

Use of good combustion practices and SCR optimization are inherent to the proposed simple-cycle CTs and technically feasible.

5.3.8.4 Step 3 – Rank Remaining NH_3 Control Options

No ranking of control options is required, as the use of good combustion practices and SCR optimization are the only technically feasible control options for NH_3 emissions from the proposed CT units and achieve the highest level of NH_3 control.

5.3.8.5 Step 4 – Evaluation of NH_3 Control Options

All technically feasible control options are being proposed for control of NH_3 emissions from the proposed simple-cycle CT units. Therefore, no further evaluation of the impacts of the NH_3 control options is required.

5.3.8.6 Step 5 – Select NH_3 BAT for Combined Cycle Combustion Turbines

No BACT floor exists for NH_3 emissions from the proposed CT units since EPA does not regulate this pollutant under NSPS Subpart KKKK. Consequently, there is no BACT or BAT floor limit.

NH_3 BAT for the proposed CT units is based on use of good operating practices and SCR optimization. Based on vendor provided information, the following is proposed as the NH_3 limit for each of the proposed simple-cycle CT units:

- 5 ppmvd NH_3 or less, corrected to 15% O_2. This limit is based on an average of three 1-hour stack tests.

5.4 Auxiliary Boiler BACT/LAER/BAT Review

5.4.1 Nitrogen Oxides

5.4.1.1 Formation

NOx formation mechanisms for combustion sources are discussed in Section 5.2.1.1. The primary front-end combustion control method for boilers is the use of burners that are specifically designed to limit NOx formation. SCR and selective non-catalytic reduction (SNCR) can be used to remove NOx from boiler flue gas once it has been formed.

5.4.1.2 Step 1 – Identify NO_X Control Options

A search of the RBLC was conducted to identify NOx BAT determinations for small natural-gas fired auxiliary boilers (less than 100 MMBtu/hr) permitted in the past twelve years (i.e., since 2013). The results of these RBLC searches are summarized in **Appendix D**, Table D-20.

Low and Ultra NOx Burners

Burners specifically designed to minimize thermal NOx formation, generically referred to as Low NOx Burners (LNGs), control the mixing of fuel and air in a pattern that is intended to maintain low flame temperature and oxygen concentration in the flame zone. Some burner designs seek to control the flame shape in order to minimize the reaction of nitrogen in the combustion air with oxygen at the peak flame temperature. Others use air staging and/or fuel staging to develop flames that have fuel-rich and air-rich regions in order to reduce thermal NOx formation. The flame from an LNB is typically elongated compared to the short, intense flame produced by a conventional burner. According to the EPA (US EPA, 1998), LNBs on natural gas-fired sources have emissions that are between 40 and 85% lower than with conventional burners, with an emission range of between 0.05 and 0.14 lb/MMBtu (approximately 50 to 140 ppm).

Ultra-Low NOx Burner (ULNB) designs were developed in response to a commercial demand for industrial steam generating units and boilers located in ozone nonattainment areas to achieve the emissions performance of SCR at a lower capital cost and without the requirement to use ammonia or urea as a NOx reducing reagent. In addition to features designed to minimize thermal NOx formation, ULNBs typically employ internal flue gas recirculation, rapid air/fuel mixing or other design features that minimize or eliminate the formation of fuel-rich regions within the burner flame, thereby essentially eliminating the formation of prompt NOx. ULNBs have been demonstrated to be capable of meeting NOx emission limits in the 9 ppm range.

Selective Catalytic Reduction

Described in more detail in Section 5.2.1.1, SCR involves the catalytically-promoted conversion of NOx in the flue gas of a combustion unit to elemental nitrogen and water using an injected reducing agent (ammonia or urea). The principal considerations associated with the potential use of SCR on small natural gas-fired boilers are whether a suitable location within the boiler tube passes exists within the required temperature zone, and the relatively high capital and operating costs relative to the amount NOx reduction potential.

Selective Non-Catalytic Reduction

SNCR is another post-combustion process that has been used to control NOx emissions from certain combustion process applications. This process involves the thermally-driven reduction of NOx using direct injection of a reducing agent (ammonia or urea) directly into the flue gas of the combustion process. The reducing agent must be injected where the flue gas temperature is in the range of 1,300 to 2,100°F, with an optimum operating temperature zone between 1,600 and 1,900°F. According to the EPA, these temperature restrictions make SNCR infeasible on small boilers because the necessary residence time within the appropriate temperature window cannot be achieved by boilers with heat input capacities below 100 MMBtu/hr.[26]

5.4.1.3 Step 2 – Eliminate Technically Infeasible NO_X Control Options

A review of the RBLC was conducted to identify and assess the emissions performance of available alternatives to control NOx emissions from small (<100 MMBtu/hr heat input capacity) natural gas-fired boilers. The RBLC search results are presented in **Appendix D**, Table D-20. A total of 81 natural gas-fired boilers with emission limits for NOx in this size range were identified. The emission control alternative that is identified as BACT for NOx was included in 75 of these listings. LNBs or ULNBs (either alone or in combination with other alternatives) were identified as BACT for 63 listings, flue gas recirculation for 32 listings, and SCR in combination with LNBs was identified for one facility, which is the FG LA Complex in St. James Parish, Louisiana. However, according to the RBLC results, the permit for FG LA Complex was issued on 1/06/2020 and has not been constructed. SCR has not been shown to be used in practice; therefore, it has been identified as technically infeasible. While SCR can result in NOx reductions of up to 90%, it has a high capital cost and is not economically feasible on boilers with a heat input capacity of less than 100 MMBtu/hr with low potential NOx emissions due to the use of natural gas.

Accordingly, LNBs, ULNBs, and flue gas recirculation are considered technically feasible emission control alternatives for the auxiliary boiler.

5.4.1.4 Step 3 – Rank Remaining NO_X Control Options

ULNBs and LNBs are considered equivalent and representative of the top level of NOx controls for small boilers. Flue gas recirculation is the next technically feasible control option.

5.4.1.5 Step 4 – Evaluation of NO_X Control Options

All technically feasible control options are being proposed for NOx emissions from the auxiliary boiler units. Therefore, no further evaluation of the impacts of the NOx control options is required.

[26] 54 Fed. Reg. 24,792, 24,798 (June 9, 1989).

5.4.1.6 Step 5 – Select NO_X BAT for Auxiliary Boilers

NO_X BAT for the natural gas-fired auxiliary boiler units is based on use of LNBs and flue gas recirculation. Based on the RBLC search results, NO_X emission limits for boiler units with similar controls range from 0.0011 to 0.100 lb/MMBtu while firing natural gas. Based the final design for this unit not yet being available, the NO_X BAT limit for each of the proposed auxiliary boilers is 0.05 lb/MMBtu based on AP-42 Table 1.4-2.

5.4.2 Carbon Monoxide and Volatile Organic Compounds

5.4.2.1 Formation

As noted in Section 5.2.2.1, CO and VOC emissions from combustion sources are a result of incomplete combustion of the carbon-containing compounds in the fuel. The primary factors that affect the formation and emission of CO and VOC from natural gas-fired boilers are the temperature of the boiler's combustion zone and the residence time of the fuel and combustion products within this zone. Higher combustion zone temperatures and longer residence times lead to more complete combustion and lower CO and VOC emissions.

5.4.2.2 Step 1 – Identify CO and VOC Control Options

A review of the RBLC was conducted to identify available alternatives to control CO and VOC emissions from small natural gas-fired boilers (<100 MMBtu/hr) permitted in the past twelve years (i.e., since 2013). The RBLC search results are summarized in **Appendix D**, Tables D-21 and D-22. Potentially available control options to reduce CO and VOC emissions from the proposed auxiliary boilers include oxidation catalysts, good combustion practices, and burner design. Each are discussed in the following sections.

Oxidation Catalyst

As discussed in the previous sections, an oxidation catalyst system is a post-combustion technology that removes CO and VOC from the exhaust gas of a combustion source. Such systems must be installed in an appropriate location within the tube passes of a boiler where the exhaust gas temperature is within the appropriate range, which varies depending on catalyst formulation. Further, effective oxidation catalyst control requires a limited space velocity across the surface of the catalyst and to limit pressure drop across the catalyst grid. For these reasons, there are few examples of the application of oxidation catalyst systems to control CO and VOC emissions from small natural gas-fired boilers.

Good Combustion Practices and Burner Design

The fundamental design criteria for fuel burners is to maximize combustion efficiency and thereby minimize the formation of products of incomplete combustion. Good combustion practices thus optimize combustion and heat liberation with specific burner design features (such as optimization of the combustion air-to-fuel ratio and promotion of complete air/fuel mixing) that results in minimization of CO and VOC formation.

5.4.2.3 Step 2 – Eliminate Technically Infeasible CO and VOC Control Options

Oxidation catalyst, good combustion practices, and burner design are all technically feasible for CO and VOC Control.

5.4.2.4 Step 3 – Rank Remaining CO and VOC Control Options

No ranking of control options is required since all technically feasible control options will be employed for CO and VOC emissions for the proposed auxiliary boilers units.

5.4.2.5 Step 4 – Evaluation of CO and VOC Control Options

The top control options are being proposed for CO and VOC emissions from the proposed auxiliary boiler units. Therefore, no further evaluation of the energy, environmental, and economic impacts of the control options is required.

5.4.2.6 Step 5 – Select CO and VOC BACT/LAER/BAT for Auxiliary Boilers

CO and VOC BACT/LAER/BAT for the proposed auxiliary boiler units is based on the use of good combustion practices, efficient burner design, and oxidation catalyst. Based on the RBLC search results, CO and VOC emission limits for natural gas-fired auxiliary boiler units with similar controls range from 0.0035 to 0.279 lb/MMBtu and 0.0015 to 0.142 lb/MMBtu, respectively. Based the final design for this unit not yet being available, the following is proposed as CO BAT and VOC LAER/BAT for each of the boiler units based on AP-42 Table 1.4-2:

- 0.08 lb/MMBtu emission limit of CO.
- 0.00539 lb/MMBtu emission limit for VOC.

5.4.3 Particulate Matter

5.4.3.1 Formation

As with particulate matter from combustion turbines, particulate matter emissions from natural gas-fired boilers consist of both filterable and condensable (back-half) particles. The following subsections present the BACT assessment for particulate matter (including total PM, PM10, and PM2.5) emissions from the proposed natural gas-fired auxiliary boiler.

5.4.3.2 Step 1 – Identify PM Control Options

EPA concluded that uncontrolled particulate matter emissions from small natural gas-fired boilers are very low. As a consequence, the Agency concluded at the time the NSPS for Small Industrial-Commercial-Institutional Steam Generating Units (i.e., 40 CFR 60, Subpart Dc) were proposed that application of add-on particulate matter controls to small natural gas-fired units would impose significant costs, and that "…the use of any conventional PM control technology to reduce PM emissions from small natural gas-fired steam generating units is considered unreasonable…"[27]

A review of the RBLC was conducted to identify available particulate matter control alternatives for small natural gas-fired boilers (<100 MMBtu/hr) permitted in the past twelve years (i.e., since 2013). The RBLC search results are presented in **Appendix D**, Tables D-23 through D-25; a total of 69 natural gas-fired boilers with heat inputs less than 100 MMBtu/hr were identified. The particulate matter emission control alternatives identified as BACT was included in 62 of these listings. The listings included efficient boiler design, good combustion practices (either alone or in conjunction with the use of pipeline quality natural gas) as BACT.

5.4.3.3 Step 2 – Eliminate Technically Infeasible PM Control Options

The use of efficient boiler design and good combustion practices are technically feasible and will ensure proper air/fuel mixing ratio to minimize emissions from incomplete combustion, which can lead to formation of PM emissions. Using pipeline quality natural gas is also a technically feasible option, which emits significantly less PM during combustion compared to fuel oil.

There are several post combustion technologies, such as fabric filters and cyclones, for the control of PM emissions that are generally available; however, none are considered practical or technically and economically feasible for natural gas fired boilers of this size. These post combustion controls are typically used to control PM emissions from fuel oil combustion which tends to have high concentrations of PM emissions. The emissions of PM from natural gas-firing will be comparatively lower. The RBLC search also indicates that there are no BACT requirements for TPM, PM10, or PM2.5 requiring post combustion controls for small natural gas-fired auxiliary boilers.

[27] 54 Fed. Reg. 24,792, 24,798 (June 9, 1989).

5.4.3.4 Step 3 – Rank Remaining PM Control Options

No ranking of control options is required since all technically feasible control options will be employed for PM emissions for the proposed auxiliary boilers units.

5.4.3.5 Step 4 – Evaluation of PM Control Options

The top control options are being proposed for PM emissions from the proposed auxiliary boiler units. Therefore, no further evaluation of the energy, environmental, and economic impacts of the control options is required.

5.4.3.6 Step 5 – Select PM BACT for Auxiliary Boilers

PM BACT for the proposed auxiliary boiler units is based on the use of pipeline quality natural gas, good combustion practices, and efficient burner design. Based on the RBLC search results, TPM, PM_{10}, and $PM_{2.5}$ emission limits for natural gas-fired auxiliary boiler units with similar controls range from 0.0019 to 0.0175 lb/MMBtu, 0.0005 to 0.0148 lb/MMBtu, and 0.0004 to 0.0100 lb/MMBtu, respectively. Based the final design for this unit not yet being available, the limit of 0.0075 lb/MMBtu is proposed as PM10/PM2.5 BACT for each of the boiler units based on AP-42 Table 1.4-2.

5.4.4 Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM)

5.4.4.1 Formation

Like the CTs mentioned above, SO_2 is formed from the oxidation of sulfur compounds contained in fuel during the combustion process. Since natural gas has a relatively low sulfur content compared with other combustible fuels, such as coal or heavy fuel oils, SO_2 emissions are minimal from natural gas-fired equipment, including auxiliary boilers. Sulfuric acid mist (SAM), or H_2SO_4, emissions from the proposed natural gas-fired auxiliary boiler occur as a result of oxidation of sulfur contained within the fuel.

5.4.4.2 Step 1 – Identify SO_2 and SAM Control Options

To determine BAT/BACT for SO_2 and SAM, a search of the RBLC was conducted to identify available control options for SO_2 and SAM emissions from natural gas-fired auxiliary boilers, less than 100 MMBtu/hr, permitted in the past twelve years (i.e., since 2013). The results of these RBLC searches are summarized in **Appendix D**, Tables D-26 and D-27. Control methods identified include good combustion practices and the use of clean fuels with inherently low sulfur content. Add on control technologies, including scrubbers and flue gas desulfurization, are commonly used to control SO_2 and SAM emissions from sources which combust high-sulfur fuels, and have not been found to be applied to auxiliary boilers less than 100 MMBtu/hr. Therefore, only the use of good combustion practices and clean fuels is evaluated further.

5.4.4.3 Step 2 – Eliminate Technically Infeasible SO_2 and SAM Control Options

Use of clean fuels with inherently low sulfur content and good combustion practices are inherent to the Project and technically feasible.

5.4.4.4 Step 3 – Rank Remaining SO_2 and SAM Control Options

No ranking of control options is required since all technically feasible control options will be employed for SO_2 and SAM emissions from the proposed natural gas-fired auxiliary boilers.

5.4.4.5 Step 4 – Evaluation of SO_2 and SAM Control Options

All technically feasible control options are being proposed for SO_2 and SAM emissions from the proposed natural gas-fired auxiliary boilers. Therefore, no further evaluation of the impacts of the control options is required.

5.4.4.6 Step 5 – Select SO_2 and SAM BAT/BACT for Auxiliary Boilers

SO_2 and SAM BAT/BACT determinations for the proposed natural gas-fired auxiliary boilers are based on the RBLC results, which consistently identified the use of clean fuels with inherently low sulfur content and good combustion practices as BACT. Therefore, the Project is proposing SO_2 BAT and SAM BACT as use of pipeline quality natural gas and good combustion practices. Pipeline quality natural gas, as defined in 40 CFR 72.2, contains 0.5 grains of sulfur or less per 100 standard cubic feet. Based on this sulfur content when firing natural gas, SO_2 and SAM emissions will not exceed 0.0014 lb/MMBtu and 0.0022 lb/MMBtu, respectively.

The sulfur content of natural gas will be verified periodically through documentation provided by the supplier.

5.4.5 Greenhouse Gases

5.4.5.1 Formation

GHG formation for combustion sources are discussed in Section 5.2.7.1. GHGs are emitted as a product of natural gas combustion or emitted as unburned fuel.

5.4.5.2 Step 1 – Identify GHG Control Options

There is currently no technically feasible add-on control technology to reduce GHG emissions from the auxiliary boiler. A search of the RBLC was conducted to identify small natural gas-fired boilers with BACT determinations for GHGs permitted in the past twelve years (i.e., since 2013). The results of this search are provided in **Appendix D**, Table D-28. A total of 70 small natural gas-fired boilers that meet these criteria were identified. The measures concluded to be representative of BACT are described in 60 of these listings; these include the use of lower carbon-emitting fuels or pipeline quality natural gas (19 listings), good combustion and/or operating practices (39 listings), and efficient boiler design (5 listings).

5.4.5.3 Step 2 – Eliminate Technically Infeasible GHG Control Options

Efficient boiler design, pipeline quality natural gas, and good combustion/operating practices are all technically feasible to control GHG emissions from natural gas-fired boilers. For the purposes of this BACT analysis, efficient boiler design, pipeline quality natural gas, and good combustion/operating practices are being considered together.

5.4.5.4 Step 3 – Rank Remaining GHG Control Options

No ranking of control options is required since all technically feasible control options will be employed for GHG emissions for the proposed auxiliary boilers units.

5.4.5.5 Step 4 – Evaluation of GHG Control Options

The top control options are being proposed for GHG emissions from the proposed auxiliary boiler units. Therefore, no further evaluation of the energy, environmental, and economic impacts of the control options is required.

5.4.5.6 Steps 5 – Select GHG BACT for Auxiliary Boilers

GHG BACT for the proposed auxiliary boiler units will be based on the use of efficient boiler design, pipeline quality natural gas, and good combustion practices.

5.5 Emergency Generator and Fire Water Pump Engine BACT/LAER/BAT Review

Equipment associated with the Project includes:

- Ten (10) diesel fuel-fired emergency generator engines each with standby rating of approximately 3,633 bhp (2,710 kWm),

- Two (2) diesel fuel-fired emergency generator engines each with a standby rating of approximately 1,483 bhp (1,106 kWm), and
- One (1) diesel fuel-fired water pump engine with a continuous rating of approximately 400 bhp (298 kWm).

5.5.1 General

In 1994, EPA began regulating emissions of NO_X, PM, CO, and nonmethane hydrocarbons (NMHC) from nonroad engines through a phased approach and has since issued multiple tiers of emission standards for various categories of engines. For new and in-use nonroad compression ignition (CI) engines, EPA issued four tiers of emission standards: Tiers 1, 2, 3, and 4. Once EPA sets emission standards for an engine category, manufacturers must produce engines that meet those standards within the timeframe of the corresponding implementation schedule. The original Tier 1, 2, and 3 standards were adopted in 40 CFR Part 89. EPA has since migrated regulatory requirements for these engines to 40 CFR part 1039 along with the Tier 4 standards.

Stationary engines are generally built to the same specifications as nonroad engines and are subject to the same tiered emission standards through NSPS Subpart IIII. To meet these standards, manufactures employ one of two types of emission control strategies: engine-based technologies and aftertreatment-based technologies. Engine-based technologies include inlet air cooling, fuel injection rate controls, injection timing retard, exhaust gas recirculation, control of air/fuel ratio, and control of air consumption. Collectively, these technologies are referred to as engine design, combustion controls, and good combustion practices, and are the basis for current Tier 2 and Tier 3 engine standards. Aftertreatment-based technologies include the use of SCR and catalyzed diesel particulate filters (CDPF) in conjunction with ULSD and are the basis for the current Tier 4 standards.

NSPS Subpart IIII requires owners and operators of stationary CI internal combustion engines (ICE) that use diesel fuel to purchase engines certified to meet the emission standard applicable to the engine category for the same model year and maximum engine power as well as to use ULSD, with limited exceptions. At a minimum, the proposed emergency generators must be certified to Tier 2 standards, while the fire water pump engine must be certified to Tier 3 standards.[28] However, to satisfy LAER requirements, the emergency generators and fire water pump engine will be certified to Tier 4 standards.

5.5.2 Nitrogen Oxides

5.5.2.1 Formation

NOx formation mechanisms for combustion sources are discussed in Section 5.2.1.1; and as with other fuel combustion sources, NOx emissions from emergency diesel engines are the result of incomplete combustion of the carbon-containing compounds in the fuel. NOx emission rates from the proposed emergency generator and fire water pump engine are influenced by engine design and operational features which promote fuel combustion efficiency.

5.5.2.2 Step 1 – Identify NO_X Control Options

As discussed above, available control options for NO_X emissions from the proposed emergency generators and fire water pump engine are limited to those that are included with the selection of Tier 2, Tier 3, and Tier 4 engines. Based on the RBLC search results provided in **Appendix D**, Table D-29, there were 143 listings with control options, out of which 117 identified Tier 2 or 3 as a control option, and 5 identified Tier 4 as a control option.

[28] See 40 CFR 60.4202(a)(2) and 40 CFR 60.4202(b)(2) for the emergency generators (Tier 2) and 40 CFR 60.4202(d), Table 4 to 40 CFR Part 60 Subpart IIII, and Table 3 to Appendix I in 40 CFR Part 1039 (Tier 3).

5.5.2.3 Step 2 – Eliminate Technically Infeasible NO_X Control Options

Purchasing Tier 4 emergency generators and a Tier 4 fire water pump engine are inherent to the Project and technically feasible. Tier 4 engines with similar power ratings appear to be commercially available based on a review of EPA's annual certification database for nonroad CI engines.[29]

5.5.2.4 Step 3 – Rank Remaining NO_X Control Options

In EPA's phased approach to regulating emissions from nonroad engines, each tier requires more stringent emissions reductions than the previous one. EPA Tier 4 has the highest level of control effectiveness, whereas EPA Tier 2 is less stringent.

5.5.2.5 Step 4 – Evaluation of NO_X Control Options

The top control options are being proposed for emissions of NOx from the proposed emergency generators and fire water pump engine. Therefore, no evaluation of the control options is required.

5.5.2.6 Step 5 – Select NO_X BACT for Emergency Generator and Fire Water Pump Engines

NO_X BACT for the proposed emergency generator and fire water pump engine is based on compliance with NSPS Subpart IIII and EPA Tier 4 standards. The Project is proposing to install emergency generators certified to Tier 4 standards and a fire water pump engine certified to NSPS IIII fire pump standards and operate and maintain each according to manufacturer's emission-related instructions. The proposed emergency generator engines will be operated for emergency purposes for a maximum of 500 hours per year, including 100 hours per year for maintenance checks and readiness testing, 50 hours of which may be used in non-emergency situations, while the proposed fire water pump engine will be operated for a maximum of 500 hours per year. Additionally, both the proposed emergency generator and fire water pump engines will exclusively use ULSD as fuel. The proposed emergency generators and emergency fire pump engine will meet emission rates of 0.5 g/bhp-hr NOx (converted from 0.67 g/kW-hr from 40 CFR 1039.101, Table 1) and 3.0 g/bhp-hr NOx (from 40 CFR 60 Subpart IIII, Table 4), respectively. The certified NO_X limit for fire pump engines is actually a combined limit for NO_X plus non-methane hydrocarbons (i.e., VOCs).

5.5.3 Carbon Monoxide

5.5.3.1 Formation

CO formation mechanisms for combustion sources are discussed in Section 5.2.2.1; and as with other fuel combustion sources, CO emissions from diesel engines are the result of incomplete combustion of the carbon-containing compounds in the fuel. CO emissions from the proposed emergency generators and fire water pump engine are influenced by engine design and operational features which promote fuel combustion efficiency and complete combustion.

5.5.3.2 Step 1 – Identify CO Control Options

As discussed in Section 5.5.1, available control options for CO emissions from the proposed emergency generators and fire water pump engine are limited to those that are included with the selection of Tier 2, Tier 3, and Tier 4 engines Based on the RBLC search results provided in **Appendix D**, Table D-30, there were nine (9) listings for Tier 4 engines, and four (4) listings for Tier 2 or 3 engines as control options. It should be noted, however, that the CO emission standard for Tier 2, 3, and 4 engines for the same engine category and model year with similar power ratings are identical (3.5 g/kW-hr).[30]

[29] Annual Certification Data for Vehicles, Engines, and Equipment, Nonroad Compression Ignition (NRCI) Engines, available online at https://www.epa.gov/system/files/documents/2023-01/nonroad-compression-ignition-2011-present.xlsx.

[30] See Tables 2 and 3 to Appendix I in 40 CFR Part 1039 for Tier 2 and 3 standards, respectively, and Table 1 of 40 CFR 1039.101 for Tier 4 final standards.

5.5.3.3 Step 2 – Eliminate Technically Infeasible CO Control Options

Purchasing Tier 4 emergency generators and a Tier 4 fire water pump engine are inherent to the Project and technically feasible. Tier 4 engines with similar power ratings appear to be commercially available based on a review of EPA's annual certification database for nonroad CI engines.

5.5.3.4 Step 3 – Rank Remaining CO Control Options

In EPA's phased approach to regulating emissions from nonroad engines, each tier requires more stringent emissions reductions than the previous one. However, in the case of CO, the emissions standard for each tier is identical.

5.5.3.5 Step 4 – Evaluation of CO Control Options

The top control options are being proposed for emissions of CO from the proposed emergency generators and fire water pump engine. Therefore, no evaluation of the control options is required.

5.5.3.6 Step 5 – Select CO BACT/BAT for Emergency Generator and Fire Water Pump Engine

CO BACT/BAT for the proposed emergency generator and fire water pump engine is based on compliance with NSPS Subpart IIII. The Project is proposing to install emergency generators certified to Tier 4 standards and a fire water pump engine certified to NSPS IIII fire pump standards and operate and maintain each according to manufacturer's emission-related instructions. The proposed emergency generator will be operated for emergency purposes for a maximum of 500 hours per year, including 100 hours per year for maintenance checks and readiness testing, 50 hours of which may be used in non-emergency situations, while the proposed fire water pump engine will be operated for a maximum of 500 hours per year. Additionally, both the proposed emergency generator and fire water pump engine will exclusively use ULSD as fuel. The proposed emergency generators and emergency fire pump engine will meet emission rates of 2.6 g/bhp-hr (converted from 3.5 g/kW-hr from 40 CFR 1039.101, Table 1) CO and 2.6 g/bhp-hr CO (from 40 CFR 60 Subpart IIII, Table 4), respectively.

5.5.4 Volatile Organic Compounds

5.5.4.1 Formation

VOC emissions from the proposed emergency generator and fire water pump units are influenced by the same factors that impact CO emissions discussed above.

5.5.4.2 Step 1 – Identify VOC Control Options

Potentially available control options for VOC emissions from the proposed emergency generator and fire water pump engines units are the same as those discussed above for CO— Tier 2, Tier 3, and Tier 4 engines. A search of the RBLC was conducted to identify VOC LAER determinations for similar emergency generators and fire water pump engines permitted in the past twelve years (i.e., since 2013). The results of these RBLC searches are summarized in **Appendix D**, Table D-31.

5.5.4.3 Step 2 – Eliminate Technically Infeasible VOC Control Options

Purchasing Tier 4 emergency generators and a Tier 4 fire water pump engine are inherent to the Project and technically feasible. Tier 4 engines with similar power ratings appear to be commercially available based on a review of EPA's annual certification database for nonroad CI engines.

5.5.4.4 Step 3 – Rank Remaining VOC Control Options

In EPA's phased approach to regulating emissions from nonroad engines, each tier requires more stringent emissions reductions than the previous one. Tier 4 has the highest level of control effectiveness, whereas Tier 2 has the lowest.

5.5.4.5 Step 4 – Evaluation of VOC Control Options

The top control options are being proposed for emissions of VOC from the proposed emergency generators and fire water pump engine. Therefore, no evaluation of the control options is required.

5.5.4.6 Step 5 – Select VOC LAER for Emergency Generator and Fire Water Pump Engine

VOC LAER for the proposed emergency generator and fire water pump engine is based on compliance with NSPS Subpart IIII and lowest emission limits identified in practice. The Project is proposing to install emergency generators certified to Tier 4 standards and a fire water pump engine certified to NSPS IIII fire pump standards and operate and maintain each according to manufacturer's emission-related instructions. The proposed emergency generator will be operated for emergency purposes for a maximum of 500 hours per year, including 100 hours per year for maintenance checks and readiness testing, 50 hours of which may be used in non-emergency situations, while the proposed fire water pump engine will be operated for a maximum of 500 hours per year. Additionally, both the proposed emergency generator and fire water pump engine will exclusively use ULSD as fuel. The proposed emergency generators and emergency fire pump engine will meet emission rates of 0.14 g/bhp-hr (converted from 0.19 g/kW-hr from 40 CFR 1039.101, Table 1) VOC and 3.0 g/bhp-hr VOC (from 40 CFR 60 Subpart IIII, Table 4), respectively. The certified limit for fire pump engines is actually a combined limit for non-methane hydrocarbons (i.e., VOCs) plus NO_X.

5.5.5 Particulate Matter

5.5.5.1 Formation

PM emissions from the proposed emergency generator and fire water pump engine may consist of inorganic matter present in the fuel (e.g., ash, metals, etc.) and high molecular weight unburned hydrocarbons (soot). Generally, PM emissions are minimized by the use of clean fuels with negligible ash and sulfur content, such as ULSD, in conjunction with engine design and operational features to promote complete fuel combustion.

5.5.5.2 Step 1 – Identify PM Control Options

As discussed above, in addition to use of ULSD, available control options for PM emissions from the proposed emergency generator and fire water pump engine are limited to efficient engine design, limited operating hours, Tier 2, Tier 3, or Tier 4 engines. Based on the RBLC search results provided in **Appendix D**, Table D-32, there were several facilities that proposed the use of efficient engine design, ULSD, Tier 2, and limiting operating hours as BACT/LAER. There were no cases in which Tier 4 was identified as BACT/LAER for TPM; the Project has nonetheless evaluated technical feasibility and other factors for this control option.

5.5.5.3 Step 2 – Eliminate Technically Infeasible PM Control Options

The use of ULSD, efficient engine design, limited operating hours, and Tier 4 engines are inherent to the proposed emergency generators and fire pumps and technically feasible.

5.5.5.4 Step 3 – Rank Remaining PM Control Options

No ranking of control options is required, as all available and technically feasible control options for PM emissions from the proposed emergency generators and fire pumps are included in the Project.

5.5.5.5 Step 4 – Evaluation of PM Control Options

The top control options are being proposed for PM emissions from the proposed emergency generators and fire pumps. Therefore, no further evaluation of the impacts of the PM control options is required.

5.5.5.6 Step 5 – Select PM BACT for Emergency Generator and Fire Water Pump Engine

PM BACT/BAT for the proposed emergency generator and fire water pump engine is based on compliance with NSPS Subpart IIII and EPA Tier 4 standards. The Project is proposing to install emergency generators certified to Tier 4 standards and a fire water pump engine certified to NSPS IIII fire pump standards and operate and maintain each according to manufacturer's emission-related instructions. In addition, the proposed PM BACT/BAT will include use of ULSD, and the proposed emergency generator will be operated for emergency purposes for a maximum of 500 hours per year, including 100 hours per year for maintenance checks and readiness testing, 50 hours of which may be used in non-emergency situations, while the proposed fire water pump engine will be operated for a maximum of 500 hours per year. The proposed emergency generators and emergency fire pump engine will meet emission rates of 0.03 g/bhp-hr (converted from 0.04 g/kW-hr from 40 CFR 1039.101, Table 1) VOC and 0.15 g/bhp-hr PM (from 40 CFR 60 Subpart IIII, Table 4), respectively.

5.5.6 Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM)

5.5.6.1 Formation

Emissions of SO_2 occur as a result of the oxidation of sulfur-containing compounds in the fuel during the combustion process, some of which can further react with water vapor to form SAM. SO_2 and SAM emissions from combustion of ULSD are very low due to the low percentage of sulfur in the fuel.

5.5.6.2 Step 1 – Identify SO_2 and SAM Control Options

As discussed in Section 5.5.1, EPA requires the use of ULSD in nearly all CI engines and the proposed emergency generators and fire water pump engines will be required to use ULSD for compliance with NSPS Subpart IIII.[31] Because of this, conventional add-on controls are not commercially available, which was also verified based on the RBLC search results, summarized in **Appendix D**, Tables D-33 and D-34. The RBLC results consistently indicated ULSD fuels and efficient combustion or good combustion practices as part of BACT for SO_2 and SAM. While SO_2 emissions are not greater than the PSD significance level, PADEP requires BAT; therefore, BAT analysis for SO_2 for the emergency generators and fire pumps is included for completeness purposes.

5.5.6.3 Step 2 – Eliminate Technically Infeasible SO_2 and SAM Control Options

The use of ULSD and good combustion practices are inherent to the proposed emergency generators and fire pumps and technically feasible.

5.5.6.4 Step 3 – Rank Remaining SO_2 and SAM Control Options

No ranking of control options is required, as all available and technically feasible control options for SO_2 and SAM emissions from the proposed emergency generators and fire pumps are included in the Project.

5.5.6.5 Step 4 – Evaluation of SO_2 and SAM Control Options

The top control options are being proposed for SO_2 and SAM emissions from the proposed emergency generators and fire pumps. Therefore, no further evaluation of the impacts of SO_2 and SAM control options are required.

5.5.6.6 Step 5 – Select SO_2 and SAM BAT/BACT for Emergency Generator and Fire Water Pump Engine

SO_2 BAT and SAM BACT for the proposed emergency generators and fire water pump engines are based on exclusive use of ULSD and good combustion practices. The engines will fire ULSD with a maximum sulfur content of 0.0015%, which complies with the diesel fuel sulfur content standards specified in NSPS Subpart IIII and 25 PA. Code §123.22.

[31] 40 CFR 60.4207 & 40 CFR 1090.305

5.5.7 Greenhouse Gases

5.5.7.1 Formation

As with the proposed CT units, GHG emissions that result from the combustion of ULSD in the proposed emergency generator and fire water pump engine include GHGs (i.e. CO_2, CH_4, and N_2O).

5.5.7.2 Step 1 – Identify GHG Control Options

While some engine-based technologies may promote fuel efficiency, EPA's tiered emission standards for CI ICE do not address GHG emissions directly. Based on the RBLC search results provided in **Appendix D**, Table D-35, no add-on control options were identified that would reduce GHG emissions from the proposed emergency generators and fire water pump engine. Instead, many facilities listed some variation of use of clean fuels (natural gas and distillate oil), good combustion practices, and limiting annual operating hours as BACT for GHG emissions.

Potential control options not considered in this BACT analysis included use of natural gas. Relative to ULSD, natural gas inherently results in lower GHG emissions on a heat input basis. However, natural gas cannot be stored onsite and may not be available during an emergency, including when the emergency itself is unavailability of natural gas. Because natural gas is less likely to be available in the emergency circumstances during which the emergency engines and fire pump are needed, that option will not be considered further in this analysis, as it would interfere with the intended function of the units. Accordingly, use of ULSD, good combustion practices, and limiting annual operating hours are the only potentially available control options for GHG emissions from the proposed emergency generator and fire water pump engine.

5.5.7.3 Step 2 – Eliminate Technically Infeasible GHG Control Options

Exclusive use of ULSD as fuel and limiting annual operating hours for the proposed emergency generators and fire water pump engine are inherent to the Project and technically feasible.

5.5.7.4 Step 3 – Rank Remaining GHG Control Options

No ranking of control options is required, as all available and technically feasible control options for GHG emissions from the proposed emergency generators and fire pump engine are included in the Project.

5.5.7.5 Step 4 – Evaluation of GHG Control Options

The top control options are being proposed for emissions of GHG from the proposed emergency generators and fire water pump engine. Therefore, no evaluation of the control options is required.

5.5.7.6 Steps 5 – Select GHG BACT for Emergency Generator and Fire Water Pump Engine

GHG BACT for the proposed emergency generator and fire water pump engine is based on the exclusive use of ULSD as fuel and limiting annual operating hours. The proposed emergency generators will each be operated for emergency purposes for a maximum of 500 hours per year, including 100 hours per year for maintenance checks and readiness testing, 50 hours of which may be used in non-emergency situations, while the proposed fire water pump engines will each be operated for a maximum of 500 hours per year.

5.6 Fuel Gas Heater BACT/LAER/BAT Review

5.6.1 Nitrogen Oxides

5.6.1.1 Formation

NO_X formation mechanisms for fuel-burning equipment such as the proposed fuel gas heaters are generally the same as those discussed above for the proposed CT units, although thermal NO_X is expected to be the basis for the majority of NO_X emissions from such heaters.

5.6.1.2 Step 1 – Identify NO_X Control Options

NOx emissions from fuel burning equipment can be controlled through two types of emission control strategies: combustion controls and add-on controls. Combustion controls address thermal NOx directly by reducing peak flame temperature by, for example, staging combustion and/or recirculating flue gas to reduce the oxygen content of the combustion air. Add-on controls employ various strategies to reduce NOx emissions to water and nitrogen, which often includes the use of reagents in the presence of a catalyst. Based on the RBLC search results provided in **Appendix D**, Table D-36, no add-on control options were identified. Many facilities listed some variation of use of clean fuels (such as natural gas), good combustion practices (e.g., tune-ups), and combustion controls (such as low or ultra-low NOX burners), as BACT. Add-on controls potentially applicable to the proposed fuel gas heaters include SCR, selective non-catalytic reduction (SNCR), and non-selective catalytic reduction (NSCR).

5.6.1.3 Step 2 – Eliminate Technically Infeasible NO_X Control Options

Use of Clean Fuels, Good Combustion Practices, and Combustion Controls

Use of natural gas, good combustion practices, and ultra-low NO_X burners are inherent to the Project and technically feasible.

Selective Catalytic Reduction (SCR), Selective Non-catalytic Reduction (SNCR), Non-selective catalytic reduction (NSCR)

As discussed in the BACT analyses for the proposed CT units, SCR, SNCR, and NSCR are all forms of post-combustion add-on controls that reduce NO_X emissions to water and nitrogen, as follows:

- SCR – Injection of nitrogen-based reagent (e.g., ammonia or urea) in the presence of a catalyst
- SNCR – Similar to SCR, except no catalyst is used and higher operating temperatures are required
- NSCR – Catalyst reaction without use of a reagent in exhaust gas with low oxygen content

The Project is unaware of any case in which these add-on controls have been installed and operated successfully on small fuel-burning equipment similar to the proposed fuel gas heaters. Combustion controls such as low or ultra-low NO_X burners, with or without flue gas recirculation, are the most effective controls that can be obtained through commercial channels for such units. Therefore, add-on controls are not considered available. Additionally, both SNCR and NSCR are not applicable based on the physical and chemical characteristics of the exhaust gas from the proposed fuel gas heaters. For SNCR, the exhaust gas is not hot enough for this add-on control to be effective. For NSCR, the oxygen content of the exhaust gas is too high for this add-on control to be effective and the proposed fuel gas heaters cannot be tuned to such low levels of excess air without causing excessive unburned hydrocarbons, soot, smoke, and CO emissions. Accordingly, SCR, SNCR, and NSCR are not technically feasible.

5.6.1.4 Step 3 – Rank Remaining NO_X Control Options

No ranking of control options is required, as use of natural gas, good combustion practices, and ultra-low NO_X burners are the only available and technically feasible control options for NO_X emissions from the proposed fuel gas heaters.

5.6.1.5 Step 4 – Evaluation of NO_X Control Options

The top control options are being proposed for NO_X emissions from the proposed fuel gas heaters. Therefore, no evaluation of the NO_X control options is required.

5.6.1.6 Step 5 – Select NO_X BAT for Fuel Gas Heaters

NO_X BAT for the proposed fuel gas heaters is based on the exclusive use of natural gas, good combustion practices, and ultra-low NO_X burners. Based on the RBLC search results, NO_X emission limits for natural gas-fired fuel gas heaters with a heat input rating of less than 30 MMBtu/hr range from 0.010 to 0.150 lb/MMBtu.

Based on this information and vendor data, the Project is proposing a NO_X BAT limit of 25 ppmvd, corrected to 3% O_2, or 0.0304 lb/MMBtu, to be demonstrated by monitoring NO_X emissions while emissions of CO are optimized during biennial tune-ups under the Industrial Boiler MACT.[32] Measurements of NO_X (and O_2) will be conducted using the procedures of ASTM D 6522, CTM-030, or EPA reference methods 7E and 3A.

5.6.2 Carbon Monoxide

5.6.2.1 Formation

CO emissions from the proposed fuel gas heaters may result from incomplete conversion of carbon-containing compounds during combustion and are principally influenced by equipment operating conditions.

5.6.2.2 Step 1 – Identify CO Control Options

CO emissions from fuel burning equipment can be controlled through two types of emission control strategies: good combustion practices and add-on controls. For sources such as the proposed fuel gas heaters, there is typically a trade-off between emissions of NOx and CO. For instance, higher combustion temperatures and residence times may lead to more complete fuel combustion and thus lower CO emissions, but these control techniques may result in excessive NOx emissions. Good combustion practices strive to optimize emissions for both pollutants. Add-on controls may employ various types of catalysts to oxidize CO emissions to CO_2. Based on the RBLC search results provided in **Appendix D**, Table D-37, no add-on control options were identified. Many facilities listed some variation of use of clean fuels such as natural gas and good combustion practices. Add-on controls potentially applicable to the proposed fuel gas heaters include oxidation catalysts.

5.6.2.3 Steps 2 – Eliminate Technically Infeasible CO Control Options

Use of Clean Fuels and Good Combustion Practices

Use of natural gas and good combustion practices are inherent to the Project and technically feasible.

Oxidation Catalyst

Oxidation catalysts are add-on controls which convert emissions of CO to CO_2 in the presence of a catalyst without the addition of any chemical reagent. The Project is unaware of any case in which these add-on controls have been installed and operated successfully on small fuel-burning equipment like the proposed fuel gas heaters. As discussed above, only combustion controls for NOx emissions from small process heaters are commercially available. Therefore, oxidation catalysts are not technically feasible. However, available combustion controls for such units are typically offered with performance guarantees for CO emissions.

5.6.2.4 Step 3 – Rank Remaining CO Control Options

No ranking of control options is required, as use of natural gas and good combustion practices are the only available and technically feasible control options for CO emissions from the proposed fuel gas heaters.

[32] The proposed NO_X BAT limit, in conjunction with the proposed CO BAT and VOC LAER limits, are based on vendor design information and are equivalent to "state-of-the-art" (SOTA) emission levels for natural gas-fired boiler and process heaters in the state of New Jersey. See State of the Art (SOTA) Manual for Boilers and Process Heaters, State of New Jersey, Department of Environmental Protection, Air Quality Permitting Element, July 1997, last revised February 2004.

5.6.2.5 Step 4 – Evaluation of CO Control Options

The top control options are being proposed for CO emissions from the proposed fuel gas heaters. Therefore, no evaluation of the CO control options is required.

5.6.2.6 Step 5 – Select CO BAT for Fuel Gas Heaters

CO BACT for the proposed fuel gas heaters is based on the exclusive use of natural gas and good combustion practices. Based on the RBLC search results, CO emission limits for natural gas-fired fuel gas heaters with a heat input rating of less than 30 MMBtu/hr range from 0.036 to 0.111 lb/MMBtu. As previously mentioned, good combustion practices seek to optimize emissions for both NO_X and CO emissions

Based on this information, the Project is proposing a CO BAT limit of 50 ppmvd, corrected to 3% O_2, or 0.0370 lb/MMBtu, to be demonstrated by using a portable analyzer to monitor emissions of CO during biennial tune-ups under the Industrial Boiler MACT.[33] Measurements of CO (and O_2) will be conducted using the procedures of ASTM D 6522, CTM030, or EPA reference methods 10 and 3A.

5.6.3 Volatile Organic Compounds

5.6.3.1 Formation

Like CO, VOC emissions from the proposed fuel gas heaters may result from incomplete combustion of hydrocarbon in fuel and are principally influenced by equipment operating conditions.

5.6.3.2 Step 1 – Identify VOC Control Options

VOC emissions from fuel-burning equipment have similar considerations and can be controlled through good combustion practices and add-on controls. Based on the RBLC search results provided in **Appendix D**, Table D-38, no add-on control options were identified. Many facilities listed some variation of use of clean fuels such as natural gas and good combustion practices. Add-on controls potentially applicable to the proposed fuel gas heaters include oxidation catalysts.

5.6.3.3 Steps 2 – Eliminate Technically Infeasible VOC Control Options

Use of Clean Fuels and Good Combustion Practices

Use of natural gas and good combustion practices are inherent to the Project and technically feasible.

Oxidation Catalyst

Oxidation catalysts are add-on controls which convert emissions of organic compounds to CO_2 in the presence of a catalyst without the addition of any chemical reagent. The Project is unaware of any case in which these add-on controls have been installed and operated successfully on small fuel-burning equipment like the proposed fuel gas heaters. Therefore, oxidation catalysts are not technically feasible. However, available combustion controls for such units are typically offered with performance guarantees for VOC emissions.

5.6.3.4 Step 3 – Rank Remaining VOC Control Options

No ranking of control options is required, as use of natural gas and good combustion practices are the only available and technically feasible control options for VOC emissions from the proposed fuel gas heaters.

5.6.3.5 Step 4 – Evaluation of VOC Control Options

The top control options are being proposed for VOC emissions from the proposed fuel gas heaters. Therefore, no evaluation of the VOC control options is required.

[33] *Id.*

5.6.3.6 Step 5 – Select VOC BACT/LAER/BAT for Fuel Gas Heaters

VOC LAER for the proposed fuel gas heaters is based on the exclusive use of natural gas and good combustion practices. Based on the RBLC search results, VOC emission limits for natural gas-fired fuel gas heaters with a heat input rating of less than 30 MMBtu/hr range from 0.005 to 0.050 lb/MMBtu.

Vendor information indicates that VOC emissions from the proposed fuel gas heaters should not exceed 0.005 lb/MMBtu each. In addition, emissions of CO will be optimized during biennial tune-ups required by the Industrial Boiler MACT as LAER.

5.6.4 Particulate Matter

5.6.4.1 Formation

PM emissions from fuel-burning equipment such as the proposed fuel gas heaters generally occur in the same manner as those discussed above for the proposed CT units, except that sulfates are expected to have a negligible contribution to the condensable portion of PM.

5.6.4.2 Step 1 – Identify PM Control Options

Based on the RBLC search results provided in **Appendix D**, Tables D-39 through D-41, no add-on control options were identified. Generally, conventional add-on controls often applied to solid fuel boilers, such as baghouses, electrostatic precipitators, and scrubbers, have not been applied to gas-fired fuel-burning equipment like the fuel gas heaters since combustion of natural gas inherently results in low levels of emissions.[34] Instead, many facilities listed some variation of use of clean fuels such as natural gas and good combustion practices as BACT. Accordingly, these control options are the only options considered further.

5.6.4.3 Step 2 – Eliminate Technically Infeasible PM Control Options

Use of natural gas and good combustion practices are inherent to the Project and technically feasible.

5.6.4.4 Step 3 – Rank Remaining PM Control Options

No ranking of control options is required, as use of natural gas and good combustion practices are the only available and technically feasible control options for PM emissions form the proposed fuel gas heaters.

5.6.4.5 Step 4 – Evaluation of PM Control Options

The top control options are being proposed for PM emissions from the proposed fuel gas heaters. Therefore, no evaluation of the PM control options is required.

5.6.4.6 Step 5 – Select PM BACT/BAT for Fuel Gas Heaters

PM BACT/BAT for the proposed fuel gas heaters is based on the exclusive use of natural gas and good combustion practices. Based on the RBLC search results, PM emission limits for natural gas-fired fuel gas heaters with a heat input rating of less than 30 MMBtu/hr range from 0.005 to 0.010 lb/MMBtu. Furthermore, vendor information indicates that TPM emissions from the proposed fuel gas heaters should not exceed 0.005 lb/MMBtu.

[34] When EPA proposed national standards for small industrial, commercial, and institutional boilers and process heaters in NSPS Subpart Dc, EPA stated that "[b]ecause of [the] low uncontrolled PM emission levels, the application of any type of PM control technology to small natural gas-fired… units would impose significant costs for no benefit. Consequently, the use of any conventional PM control technology to reduce PM emissions from small natural gas-fired… units is considered unreasonable…" 54 Fed. Reg. 24798 (June 9, 1989).

5.6.5 Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM)

5.6.5.1 Formation

Like the CTs mentioned above, SO_2 is formed from the oxidation of sulfur compounds contained in fuel during the combustion process. Since natural gas has a relatively low sulfur content compared with other combustible fuels, such as coal or heavy fuel oils, SO_2 emissions are minimal from natural gas-fired equipment, including fuel gas heaters. Sulfuric acid mist (SAM), or H_2SO_4, emissions from the proposed fuel gas heaters occur as a result of oxidation of sulfur contained within the fuel.

5.6.5.2 Step 1 – Identify SO_2 and SAM Control Options

To determine BAT/BACT for SO_2 and SAM, a search of the RBLC was conducted to identify available control options for SO_2 and SAM emissions from fuel gas heaters, permitted in the past twelve years (i.e., since 2013). The results of these RBLC searches are summarized in **Appendix D**, Tables D-42 and D-43. Control methods identified include good combustion practices and the use of clean fuels with inherently low sulfur content. Add on control technologies, including scrubbers and flue gas desulfurization, are commonly used to control SO_2 and SAM emissions from sources which combust high-sulfur fuels, and have not been found to be applied to fuel gas heaters. Therefore, only the use of good combustion practices and clean fuels is evaluated further.

5.6.5.3 Step 2 – Eliminate Technically Infeasible SO_2 and SAM Control Options

Use of clean fuels with inherently low sulfur content and good combustion practices are inherent to the Project and technically feasible.

5.6.5.4 Step 3 – Rank Remaining SO_2 and SAM Control Options

No ranking of control options is required since all technically feasible control options will be employed for SO_2 and SAM emissions from the proposed fuel gas heaters.

5.6.5.5 Step 4 – Evaluation of SO_2 and SAM Control Options

All technically feasible control options are being proposed for SO_2 and SAM emissions from the proposed fuel gas heaters. Therefore, no further evaluation of the impacts of the control options is required.

5.6.5.6 Step 5 – Select SO_2 and SAM BAT/BACT for Fuel Gas Heaters

SO_2 and SAM BAT/BACT determinations for the proposed fuel gas heaters are based on the RBLC results, which consistently identified the use of clean fuels with inherently low sulfur content and good combustion practices as BACT. Therefore, the Project is proposing SO_2 BAT and SAM BACT as use of pipeline quality natural gas and good combustion practices. Pipeline quality natural gas, as defined in 40 CFR 72.2, contains 0.5 grains of sulfur or less per 100 standard cubic feet. Based on this sulfur content when firing natural gas, SO_2 and SAM emissions will not exceed 0.0014 lb/MMBtu and 0.0022 lb/MMBtu, respectively.

The sulfur content of natural gas will be verified periodically through documentation provided by the supplier.

5.6.6 Greenhouse Gases

5.6.6.1 Formation

As with the proposed CT units, GHG emissions that result from the combustion of natural gas in the proposed fuel gas heaters include CO_2, CH_4, N_2O.

5.6.6.2 Step 1 – Identify GHG Control Options

Based on the RBLC search results provided in **Appendix D**, Table D-44, no add-on control options were identified that would reduce GHG emissions from the proposed fuel gas heaters. Instead, many facilities listed some variation

of use of clean fuels (natural gas and ultra-low sulfur distillate oil) and good combustion practices as BACT for GHG emissions.

5.6.6.3 Step 2 – Eliminate Technically Infeasible GHG Control Options

Exclusive use of natural gas and good combustion practices for the proposed fuel gas heaters are inherent to the Project and technically feasible.

5.6.6.4 Step 3 – Rank Remaining GHG Control Options

No ranking of control options is required, as the exclusive use of natural gas and good combustion practices are the only available and technically feasible control options for GHG emissions from the proposed fuel gas heaters.

5.6.6.5 Step 4 – Evaluation of GHG Control Options

The top control options are being proposed for emissions of GHG from the proposed fuel gas heaters. Therefore, no evaluation of the control options is required.

5.6.6.6 Steps 5 – Select GHG BACT for Fuel Gas Heaters

No BACT floor exists for emissions from the proposed fuel gas heaters, so GHG BACT is based on the exclusive use of natural gas as fuel and good combustion practices. In addition, the Project is proposing to perform biennial tune-ups required by the Industrial Boiler MACT as GHG BACT.

5.7 Cooling Tower BACT Review

5.7.1 Particulate Matter

5.7.1.1 Formation

Particulate matter is formed most commonly from wet or evaporative cooling towers. Typically, warm air passes through the cooling tower and causes the liquid water from the towers to be entrained in the air stream as “drift” droplets. The drift droplets evaporate and produce PM_{10} emissions because of the dissolved solids left behind in the droplets.

5.7.1.2 Step 1 – Identify PM Control Options

Drift eliminators are the most common PM control option available for wet or evaporative cooling towers. Based on the RBLC search for the past twelve years (i.e. since 2013), there were 49 listings for cooling towers of which 46 had control methods. All 46 listings with PM controls identified drift eliminators as a control method for cooling towers. The results of these RBLC searches are summarized in **Appendix D**, Tables D-45 through D-47.

5.7.1.3 Step 2 – Eliminate Technically Infeasible PM Control Options

Drift eliminators are inherent to the operations of the proposed cooling towers and technically feasible.

5.7.1.4 Step 3 – Rank Remaining PM Control Options

No ranking of control options is required because there is only one technically feasibly control option for the cooling towers.

5.7.1.5 Step 4 – Evaluation of PM Control Options

The top (and only) control option is being proposed for PM emissions from the proposed cooling towers. Therefore, no further evaluation of the impacts of the PM control options is required.

5.7.1.6 Step 5 – Select PM BACT for Cooling Towers

PM BACT for the proposed cooling towers are based on drift eliminators with a drift rate no more than 0.0005% and a total dissolved solids (TDS) concentration of no more than 3,000 ppmw.

5.8 SF_6 from Electrical Equipment BACT Review

5.8.1 SF_6

5.8.1.1 Formation

SF_6 is an extremely potent greenhouse gas which is commonly used for electrical insulation in high voltage equipment. Its unique dielectric properties make it useful for voltage electrical insulation, current interruption, and arc quenching, and it is relied on heavily by electric utilities. Emissions of SF_6 occur from potential equipment leaks. These leaks are projected to be minimal, and the International Electrotechnical Commission Standard 62271-1 for SF_6 leak rates in new high voltage equipment to 0.5% per year[35]. The Project will have 25 bays of GIS equipment with an aggregate 90,300 of pounds of SF_6.

5.8.1.2 Step 1 – Identify SF_6 Control Options

Three options have been identified as potential control options for SF_6 leaks from high voltage equipment, including vacuum circuit breakers, SF_6 alternatives, and state-of-the-art breakers with leak detection systems. Vacuum circuit breakers use vacuum interrupters for switching functions and dry air as an insulation medium. Alternative gas mixtures have also been identified and demonstrated to have similar dielectric properties as SF_6. These alternatives have also been demonstrated to be effective at higher voltages. The final option for SF_6 control is the use of state-of-the-art circuit breakers with leak detection. These circuit breakers feature an enclosed pressure system and can guarantee leak rates at less than 0.5%.

5.8.1.3 Step 2 – Eliminate Technically Infeasible SF_6 Control Options

According to EPA's SF_6 Emission Reduction Partnership for Electric Power Systems, vacuum circuit breakers are not commercially available or technically feasible at voltages greater than 145 kV. Alternative gases are a currently emerging technology. Common trade names for identified alternatives include g^3, AirPlus, and CleanAir (also known as Blue portfolio)[36]. Both g^3 and AirPlus contain polyfluoroalkyl substances (PFAS), which are manufactured by 3M. g3 contains 3M's Novec 4710 (C_4F_7N) and AirPlus contains 3M's Novec 5110 ($C_5F_{10}O$). The manufacturing of both these PFAS Novec compounds are being discontinued by the end of 2025[37]. Blue portfolio technology, developed by Siemens Energy, uses a mixture of nitrogen and oxygen coupled with vacuum switching technology, but is currently available only for application up to 145 kV and is not available for use in the proposed project which requires higher voltages. Due to both technological limitations and future availability of identified products, currently alternative gases for SF_6 are considered technically infeasible for high voltage equipment associated with the Project.

The use of state-of-the-art circuit breakers and leak detection to control the release of SF_6 is considered technically feasible and is inherent to the Project. EPA also recommends the use of new and/or upgraded equipment, which feature tighter seals and reduced leaks, as well as the use of leak detection to ensure any leaks can be repaired immediately.

5.8.1.4 Step 3 – Rank Remaining SF_6 Control Options

No ranking of control options is necessary as all technically feasible options are being implemented by the Project.

[35] https://www.epa.gov/system/files/documents/2022-05/leakrates_circuitbreakers.pdf
[36] https://dilo.com/blog/article/alternatives-to-sf6-gas-what-are-the-available-options
[37] https://www.besttechnologyinc.com/wp-content/uploads/3M-Novec-PFAS-announcement-EMSD.pdf
https://news.3m.com/2022-12-20-3M-to-Exit-PFAS-Manufacturing-by-the-End-of-2025

5.8.1.5 Step 4 – Evaluation of SF_6 Control Options

All technically feasible control options are being proposed for control of SF_6 emissions from circuit breakers. Therefore, no evaluation of control options is required

5.8.1.6 Step 5 – Select SF_6 BACT for Electrical Equipment

Proposed BACT for the control of SF_6 emissions from high voltage equipment is the use of state-of-the-art circuit breakers which feature enclosed pressure systems and the use leak detection. These circuit breakers will be equipped with low pressure alarms which will trigger when 10% of SF_6 has escaped. Routine maintenance and inspections will also be performed to ensure circuit breakers are operating properly, and any leaks discovered will be repaired promptly.

5.9 Summary of Proposed Control Technology Limits

Table 5-1 provides a summary of the BACT and BAT determinations for each applicable pollutant and piece of equipment. **Table 5-2** summarizes LAER determinations for each applicable pollutant and piece of equipment.

Table 5-1. Proposed BACT/BAT Emission Limits and Compliance Demonstration Methods

Pollutant	Fuel	Control	Limit	Units	Averaging Period	BACT/BAT
GE 7HA.02 & HRSG with or without DB						
$PM/PM_{10}/PM_{2.5}$	Natural Gas	Use of clean fuels, good combustion practices, and inlet air filters	0.0054	lb/MMBtu	Average of 3 test runs	BACT/BAT
NOx	Natural Gas	DLN combustors, good operating and maintenance practices, and SCR	2.0	ppmvd @15% O_2	1-hour block	BAT
CO	Natural Gas	Combustion controls, good operating practices, and oxidation catalyst	2.0	ppmvd @15% O_2	1-hour block	BAT
SO_2	Natural Gas	Clean fuels with low sulfur content and good combustion practices	0.0014	lb/MMBtu	N/A	BAT
H_2SO_4	Natural Gas	Clean fuels with low sulfur content and good combustion practices	0.0010	lb/MMBtu	N/A	BACT/BAT
$CO_2(e)$	Natural Gas	Clean fuels, efficient design, and good combustion, operating, and maintenance practices	802.0	lb $CO_2(e)$/MWh-gross	12-month rolling average	BACT/BAT
NH_3	Natural Gas	Good operating practices and SCR optimization	5.0	ppmvd @15% O2	Average of three 1-hr stack tests	BAT
FT8 MOBILEPAC						
$PM/PM_{10}/PM_{2.5}$	Natural Gas	Clean fuels with low sulfur content and good combustion practices	0.009	lb/MMBtu	3-run stack test	BACT/BAT
NOx	Natural Gas	Use of clean fuels, DLN combustors, water injection, and SCR	2.5	ppmvd @15% O_2	1-hr rolling average	BAT
CO	Natural Gas	Clean fuels, good combustion practices, and oxidation catalyst	9.35	lb/hr @ 15% O_2	1-hr block average	BAT
SO_2	Natural Gas	Clean fuels with low sulfur content and good combustion practices	0.0014	lb/MMBtu	N/A	BAT
H_2SO_4	Natural Gas	Clean fuels with low sulfur content and good combustion practices	0.0022	lb/MMBtu	Average of 3 test runs	BACT/BAT
$CO_2(e)$	Natural Gas	Clean fuels, efficient design, and good combustion, operating, and maintenance practices	1,425.0	lb $CO_2(e)$/MWh-gross	N/A	BACT/BAT
NH_3	Natural Gas	Good operating practices and SCR optimization	5.0	ppmvd @15% O2	Average of three 1-hr stack tests	BACT/BAT
Auxiliary Boiler						
$PM/PM_{10}/PM_{2.5}$	Natural Gas	Pipeline quality natural gas, good combustion practices, and efficient burner design	0.0075	lb/MMBtu		BACT/BAT
NOx	Natural Gas	Low NOx Burner and flue gas recirculation	0.05	lb/MMBtu		BAT
CO	Natural Gas	Good combustion practices, efficient burner design, and oxidation catalyst	0.08	lb/MMBtu		BAT
SO_2	Natural Gas	Pipeline quality natural gas and good combustion practices	0.0014	lb/MMBtu		BAT
H_2SO_4	Natural Gas	Pipeline quality natural gas and good combustion practices	0.0022	lb/MMBtu		BACT/BAT
$CO_2(e)$	Natural Gas	Efficient boiler design, pipeline quality natural gas, and good combustion practices				BACT/BAT
Fuel Gas Heater						
$PM/PM_{10}/PM_{2.5}$	Natural Gas	Exclusive use of natural gas and good combustion practices	0.0050	lb/MMBtu		BACT/BAT
NOx	Natural Gas	Exclusive use of natural gas, good combustion practices, and ultra-low NOx burners	0.0304	lb/MMBtu		BAT
CO	Natural Gas	Exclusive use of natural gas and good combustion practices	0.0370	lb/MMBtu		BAT
SO_2	Natural Gas	Pipeline quality natural gas and good combustion practices	0.0014	lb/MMBtu		BAT
H_2SO_4	Natural Gas	Pipeline quality natural gas and good combustion practices	0.0022	lb/MMBtu		BACT/BAT
$CO_2(e)$	Natural Gas	Exclusive use of natural gas and good combustion practices				BACT/BAT

Pollutant	Fuel	Control	Limit	Units	Averaging Period	BACT/BAT
Emergency Generator						
$PM/PM_{10}/PM_{2.5}$	ULSD	Compliance with NSPS Subpart IIII, Tier 4 engine, and ULSD	0.03	g/bhp-hr		BACT/BAT
NOx	ULSD	Compliance with NSPS Subpart IIII and ULSD	0.5	g/bhp-hr		BACT/BAT
CO	ULSD	Compliance with NSPS Subpart IIII and ULSD	2.6	g/bhp-hr		BAT
SO_2	ULSD	Exclusive use of ULSD and good combustion practices	0.0015	% sulfur content		BAT
H_2SO_4	ULSD	Exclusive use of ULSD and good combustion practices	0.0015	% sulfur content		BACT/BAT
$CO_2(e)$	ULSD	Exclusive use of ULSD as fuel and limiting annual operating hours				BACT/BAT
Fire Water Pump						
$PM/PM_{10}/PM_{2.5}$	ULSD	Compliance with NSPS Subpart IIII, Tier 4 engine, and ULSD	0.15	g/bhp-hr		BACT/BAT
NOx	ULSD	Compliance with NSPS Subpart IIII and ULSD	3.0	g/bhp-hr		BACT/BAT
CO	ULSD	Compliance with NSPS Subpart IIII and ULSD	2.6	g/bhp-hr		BAT
SO_2	ULSD	Exclusive use of ULSD and good combustion practices	0.0015	% sulfur content		BAT
H_2SO_4	ULSD	Exclusive use of ULSD and good combustion practices	0.0015	% sulfur content		BACT/BAT
$CO_2(e)$	ULSD	Exclusive use of ULSD as fuel and limiting annual operating hours				BACT/BAT
Cooling Tower						
$PM/PM_{10}/PM_{2.5}$	N/A	Drift eliminators	0.0005	% drift rate		BACT/BAT
$PM/PM_{10}/PM_{2.5}$	N/A	Drift eliminators	3000	TDS ppmw		BACT/BAT
GIS Equipment						
$CO_2(e)$	N/A	State-of-the-art GIS equipment and leak detection systems				BACT/BAT

Table 5-2. Proposed LAER Emission Limits and Compliance Demonstration Methods

Pollutant	Fuel	Operation Mode/Unit	Control	Limit	Units	Averaging Period
VOC	Natural Gas	GE 7HA.02 & HRSG with DB	Good combustion practices and oxidation catalyst	1.5	ppmvd @ 15% O_2	Average of 3-run stack test
VOC	Natural Gas	GE 7HA.02 & HRSG without DB	Good combustion practices and oxidation catalyst	1.0	ppmvd @ 15% O_2	Average of 3-run stack test
VOC	Natural Gas	FT8 MOBILEPAC	Clean fuels, good combustion practices, and oxidation catalyst	3.75	lb/hr @ 15%O_2	Average of 3-run stack test
VOC	Natural Gas	Auxiliary Boiler	Good combustion practices, efficient burner design, and oxidation catalyst	0.0054	lb/MMBtu	
VOC	Natural Gas	Fuel Gas Heater	Exclusive use of natural gas and good combustion practices	0.0050	lb/MMBtu	
VOC	ULSD	Emergency Generator	Compliance with NSPS Subpart IIII, Tier 4, and ULSD	0.14	g/bhp-hr	
VOC	ULSD	Fire Water Pump	Compliance with NSPS Subpart IIII, Tier 4, and ULSD	3.0	g/bhp-hr	

6. Class II Area Air Quality Modeling Analysis Procedures

6.1 Overview

Homer City conducted dispersion modeling analysis in accordance with the US EPA's *Guideline on Air Quality Models* (US EPA 2024a) (GAQM), which is contained in 40 CFR Part 51, Appendix W, as well as the modeling protocol submitted on March 10, 2025. PADEP issued the modeling protocol acceptance letter on March 17, 2025. **Appendix I** includes the modeling protocol and PADEP's approval letter.

The Project is subject to PSD review for TSP, PM_{10}, $PM_{2.5}$, H_2SO_4, and GHG. The Project is also subject to NNSR for VOC. Therefore, associated dispersion modeling analyses will be conducted only for PM_{10} and $PM_{2.5}$. There are no modeling requirements for TSP, H_2SO_4, VOC (NNSR applies), and GHGs. The modeling analysis will address impacts associated with secondary $PM_{2.5}$ as described further in **Section 6.8**.

The US EPA has determined that the permitting process can be streamlined by identifying a quantitative threshold below which impacts to air quality may be deemed insignificant and therefore will not cause or contribute to an exceedance of a NAAQS or PSD Increment.[38] Accordingly, US EPA has defined concentrations, called "significant impact levels" (SILs, see **Table 4-2**), that are used as a tool to streamline the evaluation of whether a major new source or modification may cause or contribute to an exceedance of a NAAQS or PSD increment for any pollutant subject to PSD review. Importantly, EPA has confirmed that permitting authorities need not show that the difference between background concentrations and the relevant NAAQS is greater than the SIL value before applying one of the recommended $PM_{2.5}$ SIL values because they are universally applicable to a range of conditions, including those where a substantial portion of the NAAQS or PSD increment is known to be consumed.[39]

For those pollutants which have maximum modeled concentrations at or below the applicable SIL indicate Project impacts are insignificant and therefore will not cause or contribute to an exceedance of the NAAQS or PSD increment. If modeling indicated that SILs may be exceeded for some pollutants and averaging periods, then a cumulative impact modeling assessment was performed. The results of the cumulative modeling were compared to the NAAQS and PSD increments (see **Table 4-2** and **Table 4-3**), as applicable.

All model input and output files are included with this application submittal to PADEP in the modeling archive contained in **Appendix E**.

6.2 Modeling Source Approach and Configurations

The air dispersion modeling analysis was conducted with emission rates and flue gas exhaust characteristics (flow rate and temperature) determined to represent the worst-case operating conditions for the Project. The air dispersion modeling analysis was performed considering both normal operations and startup/shutdown of both proposed GE 7HA.02 and FT8 units, which were each modeled as point sources.

6.2.1 CT Units Normal Operations

During normal operations (excluding periods of startup and shutdown), emission rates and flue gas characteristics for each turbine unit vary as a function of type of operating load and ambient temperature. Since emission rates

[38] US EPA Memorandum, Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program, Attachment, at 3 (Apr. 17, 2018) ("2018 EPA SIL Guidance").

[39] Id. at 10.

and flue gas characteristics for a given operating load vary as a function of ambient temperature, data was derived for the following ambient temperatures and operating scenarios for each turbine:

GE 7HA.02

- 5 operating scenarios
    1. base load (~100 load) with duct burners (DB),
    2. base load (~100 load) no DB,
    3. intermediate load (~75% load),
    4. minimum emission compliance load (MECL, ~35-45% load)
    5. Startup and shutdown
- 7 ambient temperatures (105°F, 90°F, 70°F, 59°F, 52°F, 20°F, and -20°F)

FT8

- 3 operating scenarios
    1. base load (~100 load),
    2. intermediate load (~75% load),
    3. MECL, ~50% load)
    4. Startup and shutdown
- 3 ambient temperatures (90°F, 59°F, and 30°F)

A summary of the exhaust data and emission rates for each ambient temperature and operating scenario for each GE 7HA.02 and FT8 is provided in **Table 6-1** and **Table 6-2,** respectively. In order to conservatively calculate ground-level concentrations, a composite "worst-case" set of emission rates and exhaust parameters will be used in the modeling as an initial approach for each turbine. For each turbine operating load, the highest pollutant-specific emission rate coupled with the lowest exhaust temperature and exhaust flow rate was selected.

Table 6-3 and **Table 6-4** summarize the worst-case emission parameters for each turbine, respectively. This data was used to perform an analysis for the turbines without any additional Project sources to determine which operating scenario results in the highest ground-level concentrations. The scenario resulting in the highest modeled concentration for each pollutant and averaging period was then used in subsequent SIL, NAAQS, and PSD increment modeling, as applicable. If baseload operations is not the scenario that results in the highest modeled concentration, both the baseload and the scenario with the highest modeled concentration will be included in the SIL any subsequent cumulative modeling. As discussed further in **Section 6.2.2**, startup and shutdown operations were included in the analysis to determine the scenario that results in the highest modeled concentration.

Table 6-1. GE 7HA.02 Stack Exhaust Parameters and Emission Rates

Load/Scenario[1]	Ambient Temp. (ºF)	Stack Height (ft)	Stack Dia. (ft)	Exit Temp. (ºF)	Exit Velocity (fps)	Maximum Hourly Emissions (lb/hr) [2]	
						PM_{10}	$PM_{2.5}$
Base Load 100% + DB	-20°F,	190.0	23.0	169.9	68.88	24.1	24.1
Base Load 100% + DB	20°F,	190.0	23.0	170.5	69.61	23.7	23.7
Base Load 100% + DB	52°F,	190.0	23.0	172.0	68.20	23.2	23.2
Base Load 100% + DB	59°F,	190.0	23.0	171.6	67.49	23.0	23.0
Base Load 100% + DB	70°F,	190.0	23.0	172.2	67.37	22.9	22.9
Base Load 100% + DB	70°F,	190.0	23.0	172.4	67.52	22.9	22.9
Base Load 100% + DB	90°F,	190.0	23.0	170.1	64.87	22.2	22.2
Base Load 100% + DB	90°F,	190.0	23.0	172.2	67.22	22.8	22.8
Base Load 100% + DB	105°F,	190.0	23.0	166.5	60.18	21.1	21.1
Base Load 100% + DB	105°F,	190.0	23.0	172.3	67.29	22.8	22.8
Base Load 100%	-20°F,	190.0	23.0	172.9	68.31	18.7	18.7
Base Load 100%	20°F,	190.0	23.0	171.8	68.88	19.0	19.0
Base Load 100%	52°F,	190.0	23.0	174.8	67.67	18.7	18.7

Load/Scenario[1]	Ambient Temp. (ºF)	Stack Height (ft)	Stack Dia. (ft)	Exit Temp. (ºF)	Exit Velocity (fps)	Maximum Hourly Emissions (lb/hr) [2]	
						PM_{10}	$PM_{2.5}$
Base Load 100%	59°F,	190.0	23.0	174.6	66.98	18.6	18.6
Base Load 100%	70°F,	190.0	23.0	177.1	67.08	18.4	18.4
Base Load 100%	70°F,	190.0	23.0	177.2	67.21	18.5	18.5
Base Load 100%	90°F,	190.0	23.0	177.6	64.86	17.5	17.5
Base Load 100%	90°F,	190.0	23.0	179.6	67.17	18.3	18.3
Base Load 100%	105°F,	190.0	23.0	175.3	60.30	16.3	16.3
Base Load 100%	105°F,	190.0	23.0	180.4	67.33	18.3	18.3
Intermediate Load 75%	-20°F,	190.0	23.0	169.2	54.56	14.9	14.9
Intermediate Load 75%	20°F,	190.0	23.0	168.2	54.30	14.9	14.9
Intermediate Load 75%	52°F,	190.0	23.0	168.7	53.12	14.7	14.7
Intermediate Load 75%	59°F,	190.0	23.0	168.5	52.61	14.6	14.6
Intermediate Load 75%	70°F,	190.0	23.0	170.9	52.51	14.4	14.4
Intermediate Load 75%	90°F,	190.0	23.0	172.5	51.48	13.7	13.7
Intermediate Load 75%	105°F,	190.0	23.0	172.4	49.46	12.9	12.9
MECL 45%	-20°F,	190.0	23.0	163.8	41.09	10.8	10.8
MECL 35%	20°F,	190.0	23.0	162.8	35.11	8.5	8.5
MECL 30%	52°F,	190.0	23.0	162.3	34.53	8.3	8.3
MECL 30%	59°F,	190.0	23.0	162.6	34.31	8.2	8.2
MECL 30%	70°F,	190.0	23.0	164.9	34.25	8.1	8.1
MECL 30%	90°F,	190.0	23.0	166.7	34.17	7.8	7.8
MECL 30%	105°F,	190.0	23.0	167.3	34.97	8.0	8.0

Note: Data are provided per emission unit unless otherwise noted.
(1) Data presented are for multiple operating scenarios and several ambient temperatures.
(2) Hourly emissions reflect operation of a single GE 7HA.02 unit firing natural gas.

Table 6-2. FT8 Stack Exhaust Parameters and Emission Rates

Load/Scenario[1]	Ambient Temp. (ºF)	Stack Height (ft)	Stack Dia. (ft)	Exit Temp. (ºF)	Exit Velocity (fps)	Maximum Hourly Emissions (lb/hr) [2]	
						PM_{10}	$PM_{2.5}$
Base Load (100%)	-18.4	90.0	13.0	699.22	46.10	3.0	3.0
Base Load (100%)	-10.0	90.0	13.0	718.29	46.33	3.0	3.0
Base Load (100%)	4.0	90.0	13.0	750.41	46.70	3.0	3.0
Base Load (100%)	10.0	90.0	13.0	764.12	46.86	3.0	3.0
Base Load (100%)	20.0	90.0	13.0	786.94	47.13	3.0	3.0
Base Load (100%)	30.0	90.0	13.0	800.33	47.67	3.0	3.0
Base Load (100%)	40.0	90.0	13.0	800.33	48.61	3.0	3.0
Base Load (100%)	48.0	90.0	13.0	800.33	49.38	3.0	3.0
Base Load (100%)	59.0	90.0	13.0	800.0	50.47	3.0	3.0
Base Load (100%)	64.4	90.0	13.0	800.33	51.01	3.0	3.0
Base Load (100%)	70.0	90.0	13.0	800.33	51.58	3.0	3.0
Base Load (100%)	80.0	90.0	13.0	800.33	52.61	3.0	3.0
Base Load (100%)	90.0	90.0	13.0	800.33	53.66	3.0	3.0
Base Load (100%)	100.0	90.0	13.0	800.33	54.75	3.0	3.0
Base Load (100%)	107.0	90.0	13.0	800.33	54.40	3.0	3.0

Load/Scenario[1]	Ambient Temp. (ºF)	Stack Height (ft)	Stack Dia. (ft)	Exit Temp. (ºF)	Exit Velocity (fps)	Maximum Hourly Emissions (lb/hr) [2]	
						PM_{10}	$PM_{2.5}$
Base Load (100%)	120.0	90.0	13.0	800.33	53.66	3.0	3.0
Intermediate Load (75%)	30.0	90.0	13.0	766.62	40.45	3.0	3.0
Intermediate Load (75%)	59.0	90.0	13.0	800.33	41.86	3.0	3.0
Intermediate Load (75%)	90.0	90.0	13.0	800.33	44.45	3.0	3.0
MECL (65%)	30.0	90.0	13.0	749.67	37.60	3.0	3.0
MECL (50%)	59.0	90.0	13.0	793.48	34.28	3.0	3.0
MECL (50%)	90.0	90.0	13.0	800.33	36.92	3.0	3.0

Note: Data are provided per emission unit unless otherwise noted.
(1) Data presented are for multiple operating scenarios and several ambient temperatures. Minimum gas exit temperature and velocity between new and refurbished engines.
(2) Hourly emissions reflect operation of a single FT8 unit firing natural gas.

Table 6-3. GE 7HA.02 Composite Worst-Case Data[1] Modeling Inputs

Parameter		Value			
Load (%)		**Base Load (100%) + DB**	**Base Load (100%)**	**Intermediate Load (75%)**	**MECL (50%)**
Stack Height (ft)		190.0	190.0	190.0	190.0
Stack Diameter (ft)		23.0	23.0	23.0	23.0
Exit Temperature (°F)		166.5	171.8	168.2	162.3
Exit Velocity (ft/sec)		60.18	60.30	49.46	34.17
Pollutant Emissions Per Unit (lb/hr)	**PM_{10}**	24.10	19.00	14.89	10.75
	$PM_{2.5}$	24.10	19.00	14.89	10.75

Note: Data are provided per emission unit unless otherwise noted.
(1) The values in the table represent the worst-case stack parameters and the emission rates for the operating loads taken from Table 6-1.

Table 6-4. FT8 Composite Worst-Case Data[1] Modeling Inputs

Parameter		Value		
Load (%)		**Base Load (100%)**	**Intermediate Load (75%)**	**MECL (50%)**
Stack Height (ft)		90.0	90.0	90.0
Stack Diameter (ft)		13.0	13.0	13.0
Exit Temperature (°F)		699.22	766.62	749.67
Exit Velocity (ft/sec)		46.10	40.45	34.28
Pollutant Emissions Per Unit (lb/hr)	**PM_{10}**	3.0	3.0	3.0
	$PM_{2.5}$	3.0	3.0	3.0

Note: Data are provided per emission unit unless otherwise noted.
(1) The values in the table represent the worst-case stack parameters and the emission rates for the three operating loads taken from Table 6-2.

6.2.2 CT Units Startup and Shutdown

In addition to assessing air quality impacts associated with proposed turbine during normal operational, startup and shutdown operations were also considered for modeling the pollutants with short-term standards (PM_{10}, and $PM_{2.5}$). Given the variable duration of startup and shutdown events for a combined-cycle turbine, data was derived to estimate pollutant emission rates during cold, hot, and warm starts in addition to shutdowns for the GE 7HA.02 turbine. For the FT8 turbines, data was only derived for startup and shutdown events since the event duration for a simple-cycle turbine is less.

Table 6-5 and **Table 6-6** provide a summary of the startup and shutdown data for each turbine respectively. Also included in **Table 6-5** and **Table 6-6** are normal operations at each turbine's MECL. Since stack exhaust characteristics at MECL will be similar to those during startup and/or shutdown, impacts associated with startup and shutdown were only evaluated when the hourly emissions during startup and shutdown are higher than at MECL. As shown in **Table 6-5** and **Table 6-6,** the hourly emissions at MECL (over the range of ambient temperatures) are lower than startup emissions for PM_{10} and $PM_{2.5}$. As such, the startup scenario was also evaluated to determine the scenario with the highest modeled concentration for PM_{10} and $PM_{2.5}$.

Table 6-5. GE 7HA.02 Startup and Shutdown Emissions (per turbine)

Parameter	Cold Start	Warm Start	Hot Start	Shutdown	MECL
Event Duration (minutes)	70	60	30	12	
Emissions per Event (lbs)					
PM_{10}	14.2	12.2	6.1	2.4	
$PM_{2.5}$	14.2	12.2	6.1	2.4	
Hourly Emissions (lbs/hr)					
PM_{10}	12.2	12.2	12.2	12.0	10.4
$PM_{2.5}$	12.2	12.2	12.2	12.0	10.4

Table 6-6. FT8 Startup and Shutdown Emissions (per turbine)

Parameter	Start	Shutdown	MECL
Event Duration (minutes)	30	9	
Emissions per Event (lbs)			
PM_{10}	2.5	0.9	
$PM_{2.5}$	2.5	0.9	
Hourly Emissions (lbs/hr) (assumes 2 startup and shutdown events per hour)			
PM_{10}	4.9	1.8	3.0
$PM_{2.5}$	4.9	1.8	3.0

Since startups for each turbine take (one) 1 hour of less (except cold start of the GE 7HA.02 turbine that take 70 minutes), the worst-case hourly emission rates from **Table 6-5** and **Table 6-6** were used in the modeling of PM_{10} and $PM_{2.5}$ 24-hour averaging periods. For the 24-hour averaging period, the following conservative assumptions were made:

(1) The GE 7HA.02 turbines are starting up 24 hours per day with a maximum of two (2) turbines starting up simultaneously while the remaining turbines operate at base load and
(2) The FT8 turbines were starting up 24 hours per day and two (2) times per hour with a maximum of two turbines starting up simultaneously while the remaining turbines operate at base load.

6.2.3 Associated Equipment

The Project will also consist of three (3) auxiliary boilers and seven (7) natural gas heaters, which were modeled as vertical, unobstructed point sources. Because the performance data for the auxiliary boilers and natural gas heaters is not expected to be affected by ambient conditions, only one set of parameters will be modeled (e.g., stack parameters and emission rates associated with 100% load). For short-term modeling, the auxiliary boilers and fuel gas heaters were modeled using their proposed permitted hourly emission rate. For annual modeling, the modeled emission rates for these units reflects the permitted operating capacity which is 5% for the auxiliary boilers and 100% for the natural gas heaters. **Table 6-7** includes the stack parameters and emission rates for the auxiliary boilers and fuel gas heaters.

The Project will also include ten (10) 2,500 kW emergency generators, two (2) 1,000 kW emergency generators, and one (1) emergency fire-water pump engine, which will each be modeled as point sources. The emergency generators and fire-water pump engine are considered emergency units and will be operated for a maximum of 500 hours per year, including being limited to 100 hours per year for maintenance and readiness testing. For annual modeling, the emission rates will reflect the annual operating hour limitations. **Table 6-7** includes the emergency generators and fire-water pump engine stack parameters and emission rates.

Finally, the Project will also consist of seven (7) new cooling towers, each with eight (8) cells. Each cooling tower cell will be modeled as a vertical, unobstructed point source, and it is assumed emissions per cell is equivalent to one-eighth of total emissions from each of the seven (7) cooling tower units. **Table 6-7** includes the cooling tower stack parameters and emission rates.

Table 6-7. Source Parameters and Criteria Pollutant Emission Rates for Ancillary Sources

Source ID	Stack Height (ft)	Stack Diameter (ft)	Exit Temp. (°F)	Exit Velocity (fps)	Hourly Emissions (lb/hr/unit)(1)	
					PM_{10}	$PM_{2.5}$
Auxiliary Boiler	55.0	4.00	344.0	28.17	0.4992	0.4992
Gas Heater	15.0	2.50	670.0	11.66	0.0469	0.0469
Emergency Generators (2,500 kW)	20.0	1.20	964.0	66.67	0.1656	0.1607
Emergency Generators (1,000 kW)	20.0	1.20	889.5	118.85	0.06765	0.0656
Fire Water Pumps	12.0	0.50	826.0	187.93	0.1219	0.1183
Cooling Towers (2)	55.0	34.00	110.0	24.38	8.98E-03	2.88E-05

Note: Data are provided per emission unit.
(1) Hourly emission rates/calculations based on vendor information.
(2) Emissions represent per cell emissions - 1/8 of a single cooling tower block's total emissions.

6.3 Model Selection and Options

The suitability of an air quality dispersion model for a particular application is dependent upon several factors. The following selection criteria were evaluated:

- stack height relative to nearby structures;
- dispersion environment;
- representative meteorological data; and

- local terrain.

The US EPA GAQM prescribes a set of approved models for regulatory applications for a wide range of source types and dispersion environments. AERMOD is US EPA's recommended refined dispersion model for simple and complex terrain for receptors within 50 kilometers (km) of a modeled source and is capable of handling the source geometry, terrain, and dispersion environment associated with the Project. Representative meteorological data with suitable data capture for various meteorological parameters is needed to run AERMOD.

Based on a review of the factors described in the following sections of this protocol, the latest version of AERMOD (version 24142) (US EPA 2024b) was used to assess air quality impacts for the Project. AERMOD was to assess air quality impacts of PM_{10}, and $PM_{2.5}$ at receptors located within 20 km of the Project site. AERMOD was run with default model options in the CONTROL pathway, unless otherwise noted or discussed with PADEP. AERMOD was also applied without using any urban source options as discussed in **Section 6.5**.

6.4 Building Downwash and GEP Height Analysis

The US EPA modeling guidelines require the evaluation of the potential for physical structures to affect the dispersion of emissions from stack emission points. The exhaust from stacks that are located within specified distances of buildings, and whose physical heights are below specified levels, may be subject to "aerodynamic building downwash" under certain meteorological conditions. If this is the case, a model capable of simulating this effect must be employed.

The analysis used to evaluate the potential for building downwash is referred to as a physical "Good Engineering Practice" ("GEP") stack height analysis. Stacks with heights below physical GEP are considered to be subject to building downwash. In the absence of influencing structures, a "default" GEP stack height is creditable up to 65 meters (213 feet) per the *Guideline for Determination of Good Engineering Practice Stack Height* (US EPA, 1985). Any portion of a stack above the maximum of the physical or default GEP height cannot be used in the dispersion modeling analysis for purposes of comparison to US EPA's ambient impact criteria.

A GEP stack height analysis was performed for all point sources included in the modeling in accordance with US EPA's guidelines (US EPA, 1985). Per the guidelines, the physical GEP height ("H_{GEP}") is determined from the dimensions of all buildings that are within the region of influence using the following equation:

$$H_{GEP} = H + 1.5L$$

where:

H = height of the structure within 5L of the stack which maximizes H_{GEP}, and
L = lesser dimension (height or projected width) of the structure.

For a squat structure (*i.e.,* height less than projected width), the formula reduces to:

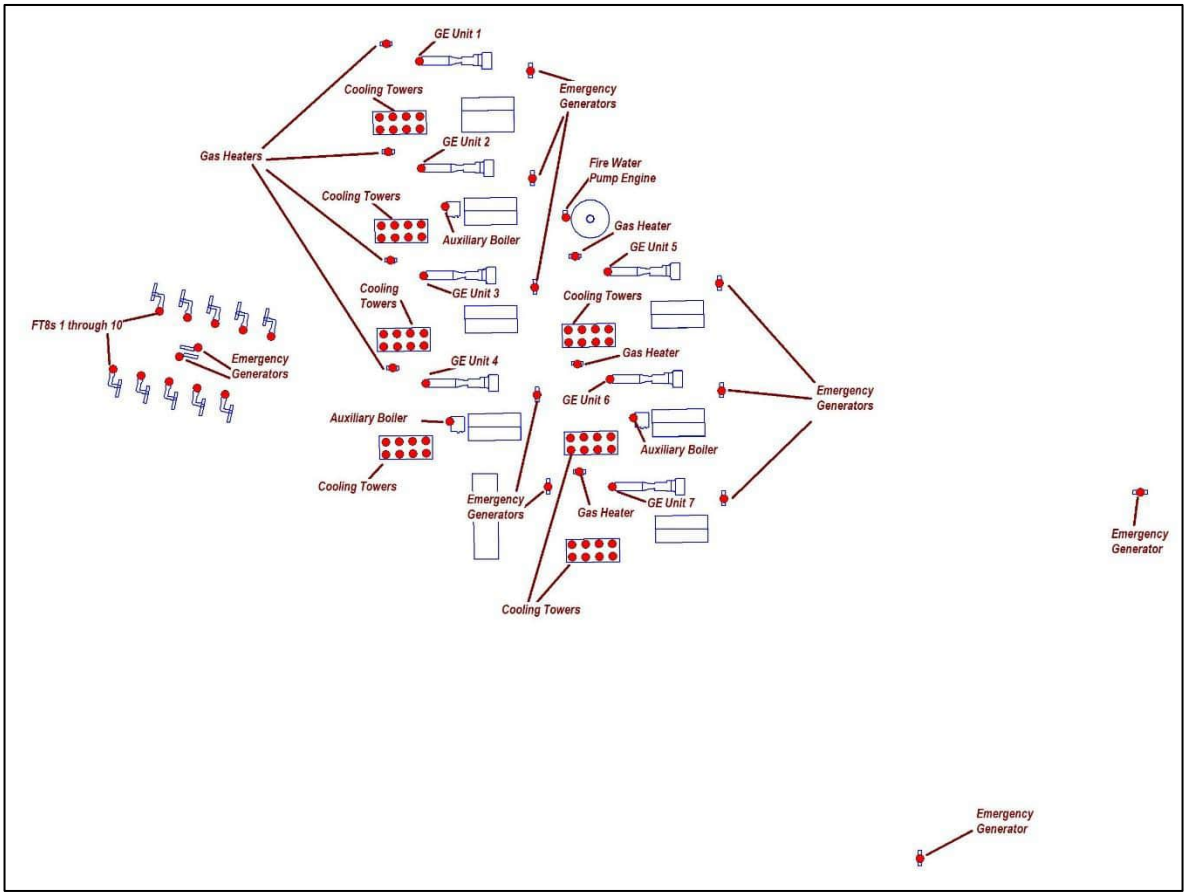
$$H_{GEP} = 2.5H$$

Both the height and width of the structure are determined from the frontal area of the structure projected onto a plane perpendicular to the direction of the wind. In all instances, the GEP stack height is based on the plane projections of any nearby building which result in the greatest justifiable height. For purposes of the GEP analysis, nearby refers to the "sphere of influence," defined as five times the height or width of the building, whichever is less, downwind from the trailing edge of the structure.

The current Project design has all modeled stacks less than 65 meters. As such, all Project stacks were modeled using their actual stack height. In addition, the EPA's Building Profile Input Program (BPIP-Version 04274) version that is appropriate for use with PRIME algorithms in AERMOD was used to incorporate wind-direction-specific building dimensions for input to AERMOD. Building coordinates and stack locations was developed using site plan drawings, aerial photographs, and GIS software. All relevant building structures were included in the BPIP modeling

for both new and existing stacks at the Plant, as applicable. **Figure 6-1** illustrates the buildings and sources included in the GEP/BPIP analysis.

Figure 6-1. Buildings and Sources Included in the BPIP Analysis



6.5 Dispersion Environment

6.5.1 Land Use Analysis

The application of AERMOD requires characterization of the local (within 3 km) dispersion environment as either urban or rural based on prevalent land use. According to US EPA modeling guidelines (US EPA, 2024a), if more than 50 percent of an area within a 3-km radius of the proposed project is classified as rural, then a rural modeling application is required. Conversely, if more than 50% of the area is urban, an urban dispersion adjustment can be used.

Using the Auer method recommended by the US EPA (US EPA, 2024a), urban land use types are classified as categories I1, I2, C1, R2, and R3. **Table 6-8** describes these categories and maps them to reasonably equivalent USGS 2016 National Land Cover Database (NLCD) categories. While the Auer method and NLCD do not use the same terms to define their categories, the similarities between the five Auer categories and NLCD categories 23 and 24 are apparent. Thus, it is reasonable to classify NLCD categories 23 and 24 as urban land use. A visual comparison of the 2023 (the most recent version) NCLD land use types to recent aerial imagery from Google™ Earth indicates only insignificant changes to the land use within 3 km since 2023. **Figure 6-2** displays the 2023 NLCD data superimposed over aerial imagery within 3 km of the Plant.

The NLCD data were processed with US EPA's AERSURFACE processor (version 24142) to determine the different land use types within 3 km of the Station. AERSURFACE is typically used to process NLCD data for input to AERMET, the AERMOD model's meteorological data processor. In this case, AERSURFACE output in the form of the pixel count for each of NLCD's land use types was used to determine the total pixel count of urban land use types within 3 km.

As noted above, urban land use types were assumed to be NLCD categories 23 and 24: "Developed, Medium Intensity" and "Developed, High Intensity", respectively. The pixel count for these categories was 2.59% of the total pixel count for all categories. Thus, the overwhelming majority (>90%) of the 3 km area around the Plant can be classified as rural land use and AERMOD was not applied with any urban source options. **Table 6-9** provides the pixel counts as reported in the AERSURFACE output along with respective percentages.

Table 6-8. Comparison of Auer and NLCD Land Use Categories

Auer Urban Land Use Categories[1]			USGS 2016 NLCD Categories[2]	
Type	**Use and Structure**	**Vegetation**	**Category**	**Description**
R2	Dense single/multi-family	< 30%	23	Developed, Medium Intensity – Areas with a mixture of constructed materials and vegetation. Impervious surfaces account for 50% to 79% of the total cover. These areas most commonly include single-family housing units.
R3	Multi-family, two story	< 35%	24	Developed, High Intensity – Highly developed areas where people reside or work in high numbers. Examples include apartment complexes, row houses and commercial/industrial. Impervious surfaces account for 80% to 100% of the total cover.
I1	Heavy Industrial	< 5%		
I2	Light/moderate industrial	< 5%		
C1	Commercial	< 15%		

Notes:
[1] US EPA, 2024a.
[2] Multi-Resolution Land Characteristics Consortium (MRLC).
https://www.mrlc.gov/data/legends/national-land-cover-database-class-legend-and-description

Table 6-9. AERSURFACE Surface Roughness Output

USGS 2016 NLCD Category	Description	Pixel counts	Percent of Total Pixels
0	Missing, Out-of-Bounds, or Undetermined	0	0%
11	Open Water	118	0.38%
12	Perennial Ice/Snow	0	0%
21	Developed, Open Space	1802	5.74%
22	Developed, Low Intensity	1488	4.74%
23	**Developed, Medium Intensity**	**720**	**2.29%**
24	**Developed, High Intensity**	**95**	**0.30%**
31	Barren Land (Rock/Sand/Clay)	2441	7.77%
32	Unconsolidated Shore	0	0%
41	Deciduous Forest	12860	40.94%
42	Evergreen Forest	2	0.01%
43	Mixed Forest	510	1.62%
51	Dwarf Scrub	0	0%
52	Shrub/Scrub	154	0.49%
71	Grasslands/Herbaceous	166	0.53%
72	Sedge/Herbaceous	0	0%
73	Lichens	0	0%

USGS 2016 NLCD Category	Description	Pixel counts	Percent of Total Pixels
74	Moss	0	0%
81	Pasture/Hay	4557	14.51%
82	Cultivated Crops	6437	20.49%
90	Woody Wetlands	61	0.19%
91	Palustrine Forested Wetland	0	0%
92	Palustrine Scrub/Shrub Wetland	0	0%
93	Estuarine Forested Wetland	0	0%
94	Estuarine Scrub/Shrub Wetland	0	0%
95	Emergent Herbaceous Wetland	1	0%
96	Palustrine Emergent Wetland	0	0%
97	Estuarine Emergent Wetland	0	0%
98	Palustrine Aquatic Bed	0	0%
99	Estuarine Aquatic Bed	0	0%
	Total	**31412**	**2.59%**

Urban land use types are shown in red, bold text.
Source: AERSURFACE

6.5.2 Terrain

The US EPA's GAQM requires that the differences in terrain elevations between the stack base and model receptor locations be considered in the modeling analyses. There are three types of terrain:

- simple terrain – locations where the terrain elevation is at or below the exhaust height of the stacks to be modeled;
- intermediate terrain – locations where the terrain is between the top of the stack and the modeled exhaust "plume" centerline (this varies as a function of plume rise, which in turn, varies as a function of meteorological condition);
- complex terrain – locations where the terrain is above the plume centerline.

Figure 6-3 provides a topographic map of the area in the vicinity of the Project site. The area near the Station is characterized as consisting of all terrain types relative to the modeled stacks.

Figure 6-2. NLCD Land Use (2023)

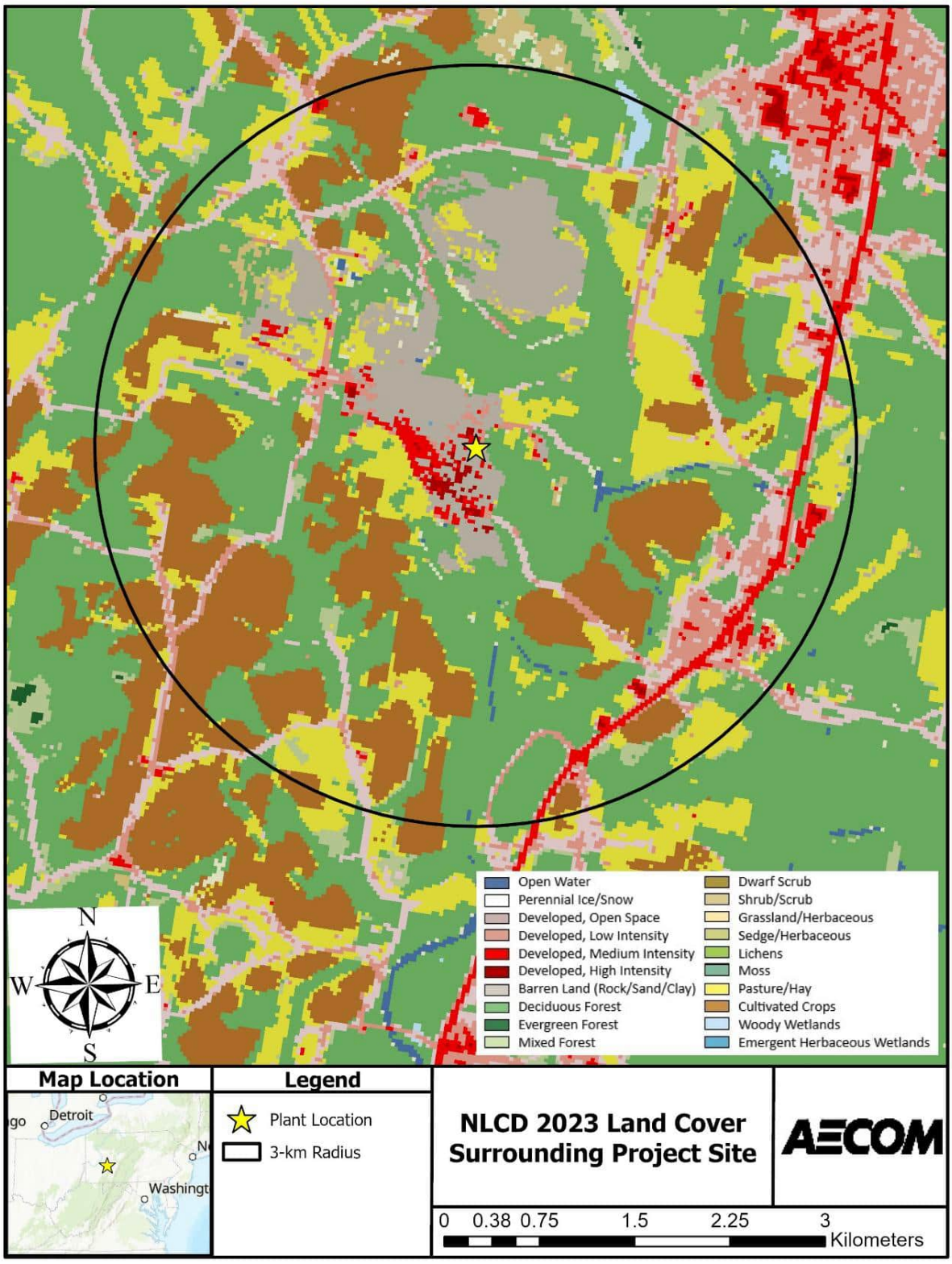
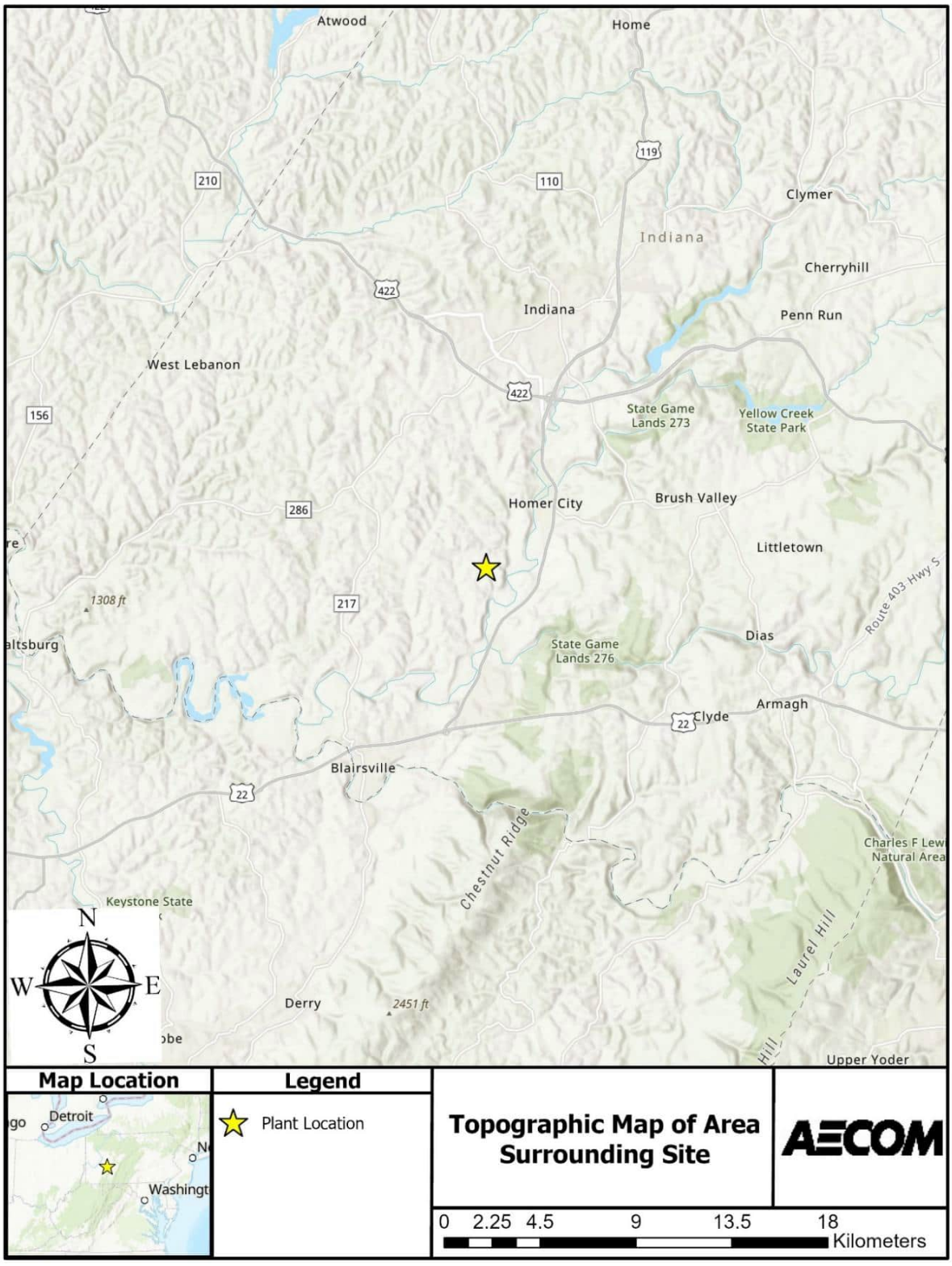


Figure 6-3. Topographic Map of Project Site Area



6.6 Meteorological Data

Homer City proposed to use five years (2020-2024) of near-surface meteorological data from the John Murtha Johnstown-Cambria County Airport (Johnstown Airport) along with concurrent upper-level data from Pittsburgh International Airport for this modeling demonstration. The meteorological data from Johnstown Airport was processed by PADEP using AERMET version 24142 using regulatory options including the adjusted u-star option.

Historically the Johnstown Airport meteorological data has been used for air dispersion modeling demonstrations at Homer City, including as recently as to support the redesignation of the Indiana County non-attainment area for 1-hour SO_2 to attainment (US EPA, 2024c). Past modeling has focused on dispersion from Homer City's approximately 800-foot coal-boiler stacks. In 2012, ERM conducted a robust evaluation (ERM, 2012) of nearby meteorological data for Homer City modeling and concluded that the Johnstown Airport was the most representative dataset available for modeling plumes emitted from the tall stacks. With it being more than 12 years removed from that evaluation and the lower stack heights from the Project compared to the coal stacks, an updated analysis was warranted. The following **Sections (6.6.1 through 6.6.3)** describes the updated analysis that was performed to identify the most representative meteorological dataset for use in dispersion modeling of the Project.

6.6.1 Review of Available Meteorological Data

The 2012 ERM report identified five locations of meteorological stations within approximately 80 kilometers (50 miles) of Homer City. These included Automated Surface Observing Systems (ASOS) at Pittsburgh International Airport and Johnstown Airport, an Automated Weather Observing System (AWOS) at Indiana County Airport, and two research-based multi-level towers (Ash Valley and Manor Tower). There has since been one additional meteorological dataset, Ash Site #1, located between Seward and Conemaugh Generating Stations in southeast Indiana County. The Ash Site #1 was a 1-year dataset from September 2015 through August 2016 that consisted of a 100-meter tower and SOund Detection And Ranging (SODAR) system (AECOM, 2015).

Table 6-10 provides the approximate distance to Homer City and most recent available data periods for each potential meteorological dataset. Both the Ash Valley and Ash Site #1 locations were sited to capture localized, terrain-driven effects in the vicinity of Conemaugh and Seward stations and would not be suitable for Homer City. Indiana County Airport has a history of reporting a higher number (greater than 30%) of calm winds as it does not record sub-hourly measurements like ASOS sites. For these reasons, the Ash Valley, Ash Site #1, and Indiana County Airport sites would not be representative of conditions at Homer City. With other meteorological stations much closer in proximity to Homer City than Pittsburgh International Airport, this site is also not considered as the best fit. This leaves Manor Tower and Johnstown Airport as candidates to be further evaluated.

Table 6-10. Meteorological Stations Near Homer City

Meteorological Site	Distance (Direction) from Homer City	Recent Data Period Available
Pittsburgh Airport	85 km (west of Homer City)	2019-2023 (recent 5-years)
Johnstown Airport	38 km (southeast of Homer City)	2020-2024 (recent 5-years)
Indiana County Airport	15 km (northeast of Homer City)	2019-2023 (recent 5-years)
Ash Tower	17.8 km (southeast of Homer City)	August 1990 – July 1991
Manor Tower	9.9 km (northeast of Homer City)	August 1990 – July 1991
Ash Site #1	18 km (southeast of Homer City)	September 2015 – August 2016

Source: ERM 2012; AECOM 2015

6.6.2 Comparison of Surface Characteristics

Key data inputs to the processing of meteorological data for dispersion models include surface roughness, albedo, and Bowen ratio. EPA has developed a tool, AERSURFACE, that can estimate these parameters for a given location based upon digitized land cover data and corresponding lookup tables. AERSURFACE User's Guide recommends a default radial distance of 1 km from the meteorological station or source location to evaluate surface roughness. Albedo and Bowen ratio are assessed within a 10 km by 10 km distance. **Table 6-11** lists the albedo, surface roughness, and Bowen ratios for Johnstown Airport, Homer City, and Manor Tower.

The surface roughness was computed using the AERSURFACE tool and National Land Cover Data (NLCD) available from the U.S. Geological Survey (USGS, 2024). In late 2024, USGS updated their NLCD files to new annual products. These newer NLCD products were used to generate the surface roughness values listed in **Table 6-11**. The NLCD files for 2021 were used for the AERSURFACE processing of the Johnstown Airport and Homer City as it represented the most recent meteorological data year available for modeling. The 1991 NLCD files were used to process the AERSURFACE for Manor tower as that dataset spanned from August 1990 through July 1991.

It is well documented (Karvounis et al., 2007; Faulkner et al., 2008) that dispersion models are typically most sensitive to changes in surface roughness compared to albedo or Bowen ratios. **Figure 6-4** illustrates the differences of surface roughness by season between the Manor Tower and the other two sites (Johnstown Airport and Homer City). Due to the more forested surroundings at Manor Tower, the surface roughness values are approximately an order of magnitude higher than those at both Johnstown Airport and Homer City. The more forested surroundings of the Manor Tower location can also be seen in aerial imagery, as shown in **Figure 6-5**, **Figure 6-6**, and **Figure 6-7** for Manor Tower, Johnstown Airport, and Homer City, respectively. Given the vastly different surface roughness conditions compared to the Project location, the Manor Tower is not considered the most representative meteorological dataset for dispersion modeling at Homer City.

Table 6-11. Comparison of Surface Characteristics at Johnstown Airport, Homer City, and Manor Tower

	Johnstown Airport[1]			Homer City[1]			Manor Tower[2]		
Seasons	Albedo	Surface Roughness (m)	Bowen Ratio	Albedo	Surface Roughness (m)	Bowen Ratio	Albedo	Surface Roughness (m)	Bowen Ratio
Winter	0.17	0.077	0.91	0.17	0.088	0.88	0.17	0.197	0.91
Spring	0.16	0.106	0.58	0.15	0.111	0.53	0.16	0.295	0.60
Summer	0.16	0.142	0.43	0.17	0.152	0.41	0.17	0.451	0.38
Fall	0.16	0.124	0.91	0.17	0.149	0.88	0.17	0.447	0.91

[1] Values based on land cover from 2021 (most recent meteorological year available for Johnstown)
[2] Values based on land cover from 1991

Figure 6-4. Surface Roughness by Season

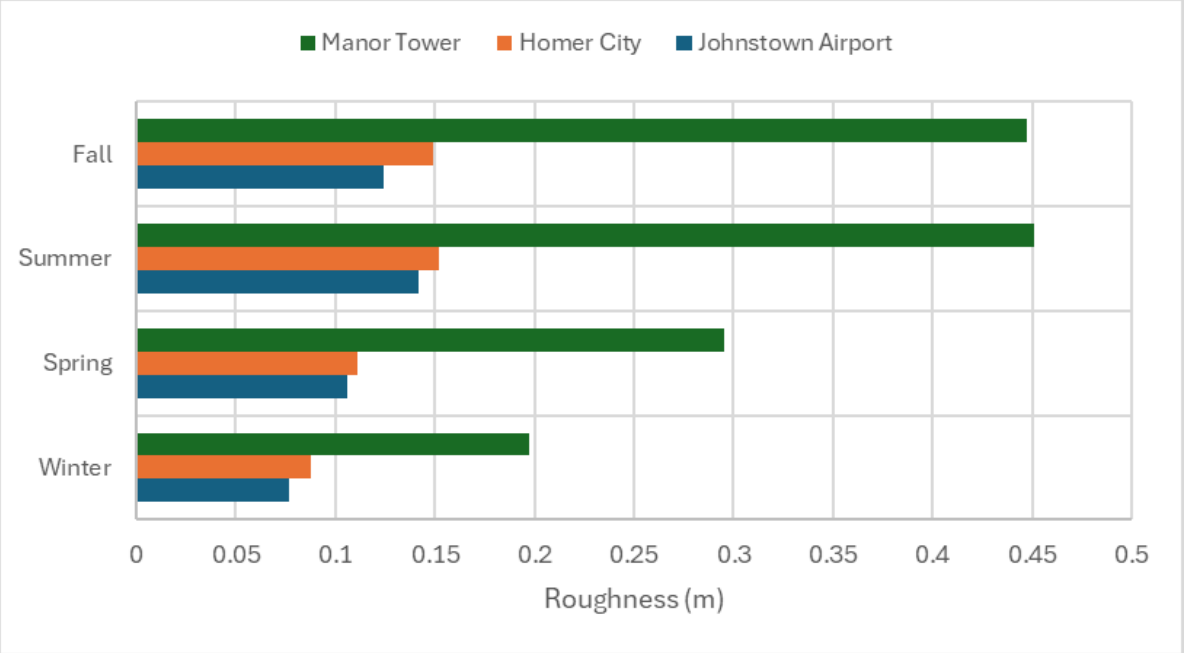


Figure 6-5. Aerial Image of Manor Tower



Figure 6-6. Aerial Image of Johnstown Airport

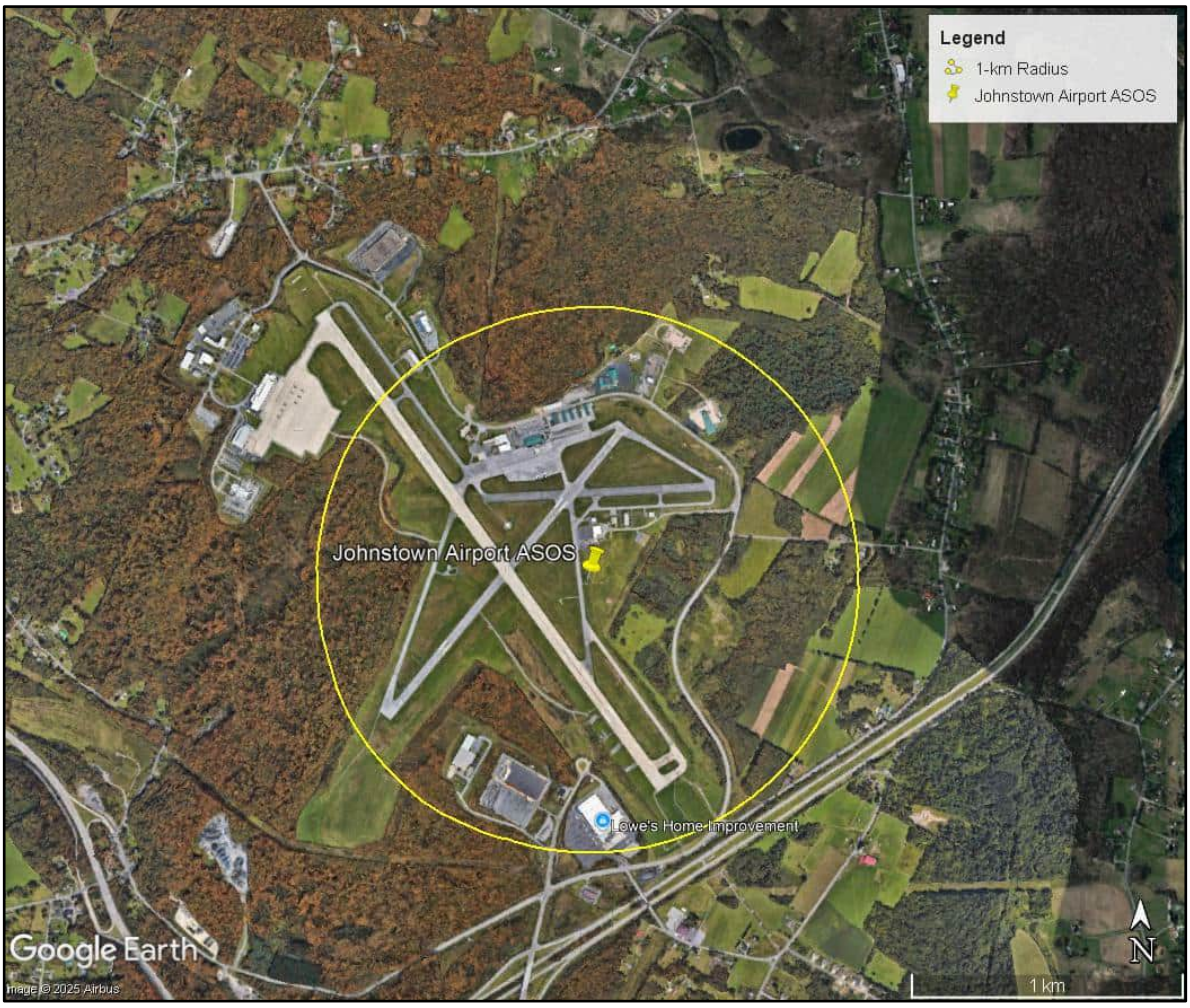
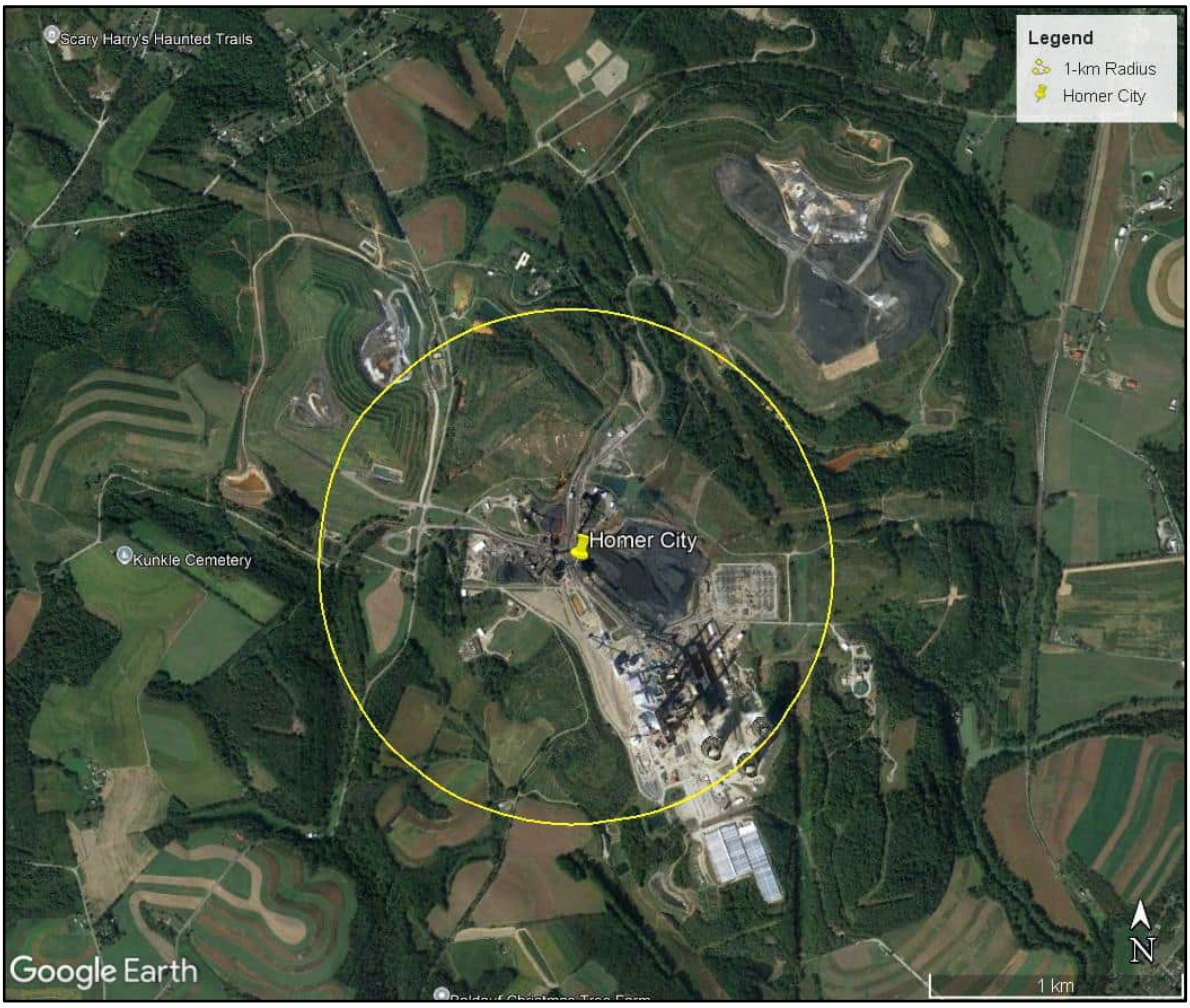


Figure 6-7. Aerial Image of Homer City



6.6.3 Evaluation of Winds at Plume Height of Modeled Sources

Another key component of evaluating the representativeness of the meteorological data for this proposed modeling demonstration is the winds at plume height. Historical modeling for Homer City has relied on the height of the 800-feet coal stacks as being sufficiently tall enough to clear regional terrain and therefore wind at that height (and higher) from Johnstown Airport would be comparable. As discussed in **Section 6.2**, the stack heights from the CCs are 190 feet, which is approximately 600 feet shorter as compared to the 800 feet coal stacks. However, with both the coal and CC stacks having good buoyancy and momentum rise, a quantified analysis to assess the plume heights of the CCs and coal stacks was performed, as opposed to focusing on just the physical stack heights.

US EPA's SCREEN3 screening model (version 13043) (US EPA, 2013) was used to estimate the plume rise and ultimately final plume height generated from the 800-foot (243.8-m) coal stacks and 190-foot (57.9-m) CC stacks. SCREEN3 was identified as the most appropriate screening model for this purpose as it provides plume heights at various distances downwind. EPA's preferred screening model, AERSCREEN, was considered, but due to limitations in not having multiple downwind distances assessed for plume height and the inability to set static meteorological conditions, SCREEN3 proved to be the most suitable for a direct plume height comparison.

An initial run of SCREEN3 was conducted for both the coal stack and CC stack. **Table 6-12** provides a summary of the input parameters used in each of these runs. The "full meteorological" option was selected to initially identify the conditions that would produce the highest concentrations. For this run, the final plume height was 1,622 m and

1,374 m for the coal stack and CC stack, respectively. This yielded approximately a 15% difference in plume rise between the two stacks. The meteorological conditions producing these results were wind speeds under 1 m/s for both stacks, which would be typical of a low wind (< 2 m/s) condition and likely maximize the potential plume height. As a result, a second SCREEN3 run was performed to evaluate a more average wind speed of 3 m/s under neutral stability conditions. As anticipated, the 3 m/s SCREEN3 run for both coal and CC stacks showed lower plume heights compared to the low wind condition, with heights of 600 m and 440 m, respectively. These heights yield an approximate 27% difference in plume height between the two stacks. These two heights will serve as the basis for comparing wind data levels in **Section 6.6.3.3**. Printouts of the SCREEN3 3 m/s output files are provided in Appendix A of the Modeling Protocol submitted to PADEP on March 10, 2025.

Table 6-12. SCREEN3 Inputs for Full Meteorology Conditions

SIMPLE TERRAIN INPUTS	Coal Stack	CC Stack
SOURCE TYPE	POINT	POINT
EMISSION RATE (G/S)	100	100
STACK HEIGHT (M)	243.8	57.9
STK INSIDE DIAM (M)	7.32	7.01
STK EXIT VELOCITY (M/S)	25.51	21.81
STK GAS EXIT TEMP (K)	351.7	351.4
AMBIENT AIR TEMP (K)	293	293
RECEPTOR HEIGHT (M)	0	0
URBAN/RURAL OPTION	RURAL	RURAL

CC = Combined-cycle combustion turbines

6.6.3.1 Surface Wind Rose Evaluation at Johnstown Airport

Prior to evaluating wind roses at plume height, an initial comparison was made between observed wind data from the Johnstown Airport and prognostic data. US EPA has been using the Weather Research and Forecasting (WRF) model to generate meteorological data for input into air quality models for several years. US EPA now routinely processed annual WRF simulations for the entire contiguous U.S., with WRF output available for recent years (2019-2021). The WRF model (Skamarock et al., 2019) (version 4.1.1) was initialized with 0.25-degree Global Forecast System (GFS) analysis data, and a 12 km WRF nest was created using analysis data from the North American Mesoscale Model (NAM). For this application, the closest WRF grid cell to the Johnstown Airport was selected, with the grid cell center (40.309N, 78.880W) located approximately 4 km to the southwest of the Johnstown Airport. To generate wind roses at specific heights above ground level, the EPA's Mesoscale Model Interface Program (MMIF) version 4.1.1 was used to extract specific vertical levels from the WRF output (US EPA, 2024d).

Figure 6-8 shows the 3-year (2019-2021) wind roses for (a) Johnstown Airport from the anemometer height of 7.9-meters and (b) the WRF at 10-m above ground level. Both wind roses capture the predominant wind direction from the west and the secondary flow pattern from the southeast. The WRF data agrees well with the Johnstown Airport in capturing the regional wind flow and direction. The overall average wind speed over the period between the WRF is only slightly lower by 0.4 m/s as compared to the Johnstown Airport ASOS, as shown in **Table 6-13**. Minor differences between the two datasets are likely attributed to localized effects that ground-based sensors are better suited at resolving.

As a means of providing a quantitative evaluation comparing the near surface Johnstown Airport and WRF wind rose, a statistical analysis was performed. **Table 6-13** provides the mean, mean bias, fractional bias (Fb), root mean square error (RMSE) and the Pearson correlation coefficient (r-squared or R^2) statistics for key meteorological parameters over the 3-year period (2019-2021).

Table 6-13. Statistical Comparison of Observed KJST ASOS to KJST WRF for Near Surface

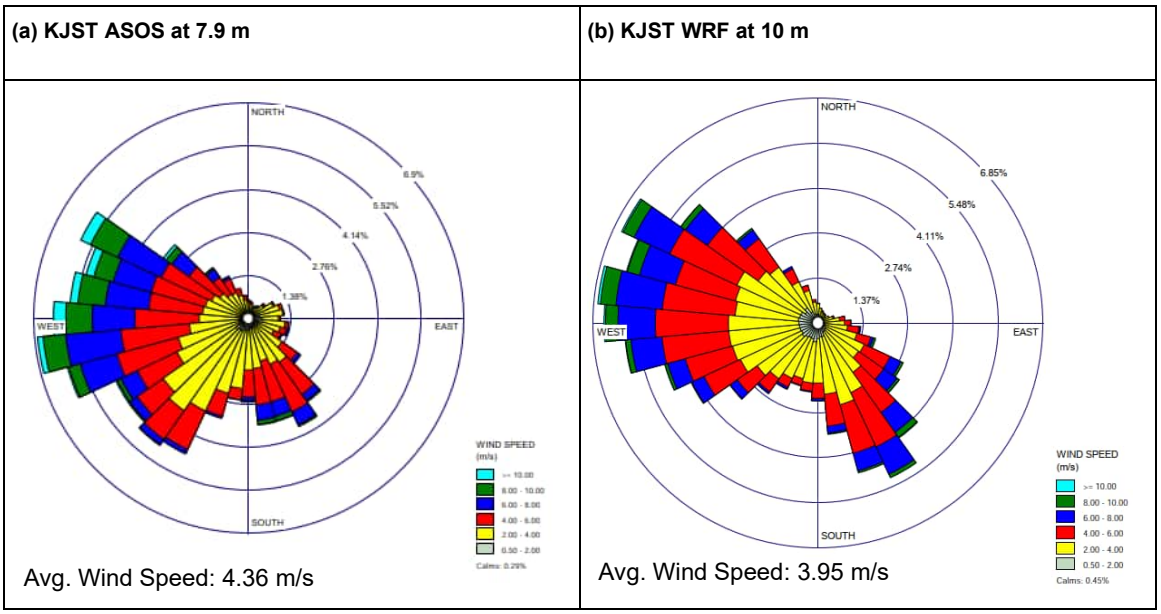
Variable	Mean of KJST ASOS	Mean of KJST WRF	Mean Bias	Fb (unitless)	RMSE	R^2 (unitless)
Wind Speed (m/s)	4.36	3.95	-0.4088	-0.0984	1.3056	0.6670
Temp (°C)	283.20	283.28	0.0838	0.0003	1.6949	0.9710
Pressure (mb)	935.91	948.38	12.4782	0.0132	12.5035	0.9822
Relative Humidity (%)	68.86	78.47	9.6124	0.1305	14.9669	0.6539
Heat Flux	14.84	28.35	13.5095	0.6257	68.5387	0.5159
Surface Friction Velocity (m/s)	0.34	0.54	0.1992	0.4498	0.2761	0.6434

Notes: ASOS = Johnstown Airport ASOS; WRF = closest node to Johnstown Airport; Fb = fractional bias; RMSE = root mean square error

The Fb serves as a good indicator in assessing the WRF's tendency to overestimate or underestimate the observed (ASOS) values. Values of the Fb range between -2.0 (extreme overprediction) and +2.0 (extreme underprediction) and are unitless. A Fb of 0 (zero) means no bias. Temperature and wind speed are the most critical variables, and both show near zero Fb, meaning minimal bias exists. The R^2 indicates the correlation of the two datasets, while the RMSE is used to evaluate the accuracy. R^2 values range from 0 to 1 and are unitless. An R^2 value closer to 1 indicates a good correlation between the two datasets. Most of the variables presented in Table 4-11 have an R^2 value around 0.65, with temperature and pressure near 1 (0.97 and 0.98, respectively). RMSE values range from zero to infinity. A low RMSE means less difference between the two datasets. For wind speed and temperature, RMSE are near 1, meaning better performance between the ASOS and WRF data. Similar seasonal-based statistical tables and wind roses are presented in Appendix A of the Modeling Protocol submitted to PADEP on March 10, 2025. These supplemental statistics show a relatively small variability between seasons, thus the annual data presented in **Table 6-13** and **Figure 6-8** serve as a good indicator for this location.

Based on this comparison, the WRF dataset should yield representative winds aloft for comparison of plume height levels at Johnstown Airport and Homer City. The results of the plume height level are presented in **Section 6.6.3.3**.

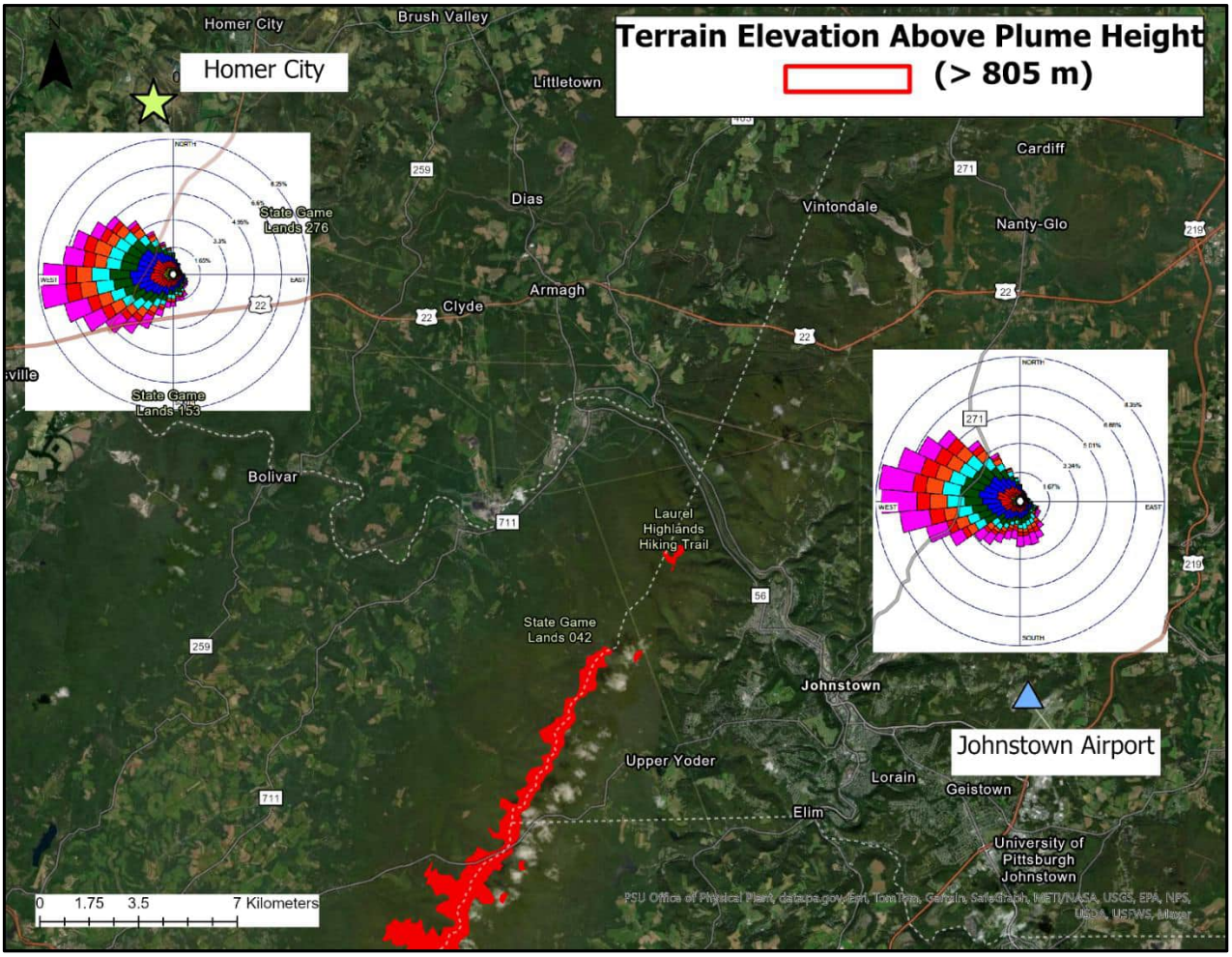
Figure 6-8. Near-Surface 3-year (2019-2021) Wind Roses for KJST ASOS vs. KJST WRF



6.6.3.2 Plume Heights Relative to Nearby Terrain

A review of terrain elevations between Homer City and Johnstown Airport was conducted to assess whether there may be significant terrain interference of wind flow and/or plume transport between these two locations. **Figure 6-9** depicts the elevated terrain in the general vicinity of Homer City and the Johnstown Airport that exceed the plume height (805 m) of the CC stacks. The areas highlighted in "red" indicate the terrain that exceeds the plume height of 805 meters, which is primarily focused to the southwest of Johnstown Airport. With the exception of a few rogue peaks along Laurel Ridge near the Laurel Highlands Hiking Trails, the rest of the surrounding terrain is below this level. This analysis further supports the predominant westerly flow at plume height is not being heavily influenced by the terrain features.

Figure 6-9. Map of Terrain Heights Above Plume Height from CC Stacks



6.6.3.3 Wind Rose Comparison at Plume Heights

Figure 6-9 illustrates the wind rose comparison using the 2019-2021 WRF data at plume heights for the coal and CC stacks at Homer City to the equivalent height levels above ground at the Johnstown Airport. The grid cell for the Johnstown Airport in this analysis is the same as the one identified in **Section 6.6.3.1**. For Homer City, the closest grid cell center (40.586N, 79.244W) is approximately 8.5 km to the northwest of the Homer City, as shown in **Figure 6-10**.

As discussed in **Section 6.6.3**, the plume heights from the SCREEN3 analysis were 600 m and 440 m above ground for the coal and CC stacks, respectively. Accounting for the base elevation at Homer City of 365 m, the wind rose heights that were evaluated at Homer City are 965 m (365 + 600) and 805 m (365 + 440) for the coal and CC stacks, respectively. The closest WRF level was selected to generate the wind rose at Homer City. These corresponded to 1,000 m and 800 m. For the wind rose heights at the Johnstown Airport, which is situated at 330 m higher than Homer City, the above ground level heights would be 635 m and 475 m. This equates to WRF heights of 600 m and 500 m that the wind roses were generated for. As shown in **Figure 6-11**, there is a predominant westerly flow signature evident in all four wind roses. The average wind speeds were calculated to be within 5-6% between the two locations for the similar plume height levels.[40]

Statistics on wind speed and temperature comparing the WRF at plume height for both the Johnstown Airport and Homer City locations are shown in **Table 6-14**. These statistics are based on the entire 3-year (2019-2021) period. The results presented in **Table 6-14** show good agreement between the WRF data at plume height between the two locations. Minor seasonal variations are noted, which are included in Appendix A of the Modeling Protocol submitted to PADEP on March 10, 2025. Based on this analysis, the Johnstown Airport the most representative dataset available for dispersion modeling at Homer City.

Table 6-14. Statistical Comparison of WRF at CC Plume Height for KJST and Homer City

Variable	Mean of KJST WRF	Mean of Homer City WRF	Mean Bias	Fb (unitless)	RMSE	R^2 (unitless)
Wind Speed (m/s)	10.48	9.87	0.6064	-0.0596	2.0768	0.8825
Temp (°C)	7.91	7.27	0.6428	-0.0847	1.2132	0.9891

Notes: ASOS = Johnstown Airport ASOS; WRF = closest node to Johnstown Airport; Fb = fractional bias; RMSE = root mean square error

[40] Average wind speed at 1,000 m level Homer City was 10.22 m/s compared to 10.68 m/s at Johnstown Airport 600 m level. Average wind speed at 800 m level Homer City was 9.87 m/s compared to 10.48 m/s at Johnstown Airport 500 m level.

Figure 6-10. Location of WRF Grid Nodes Relative to Homer City and KJST

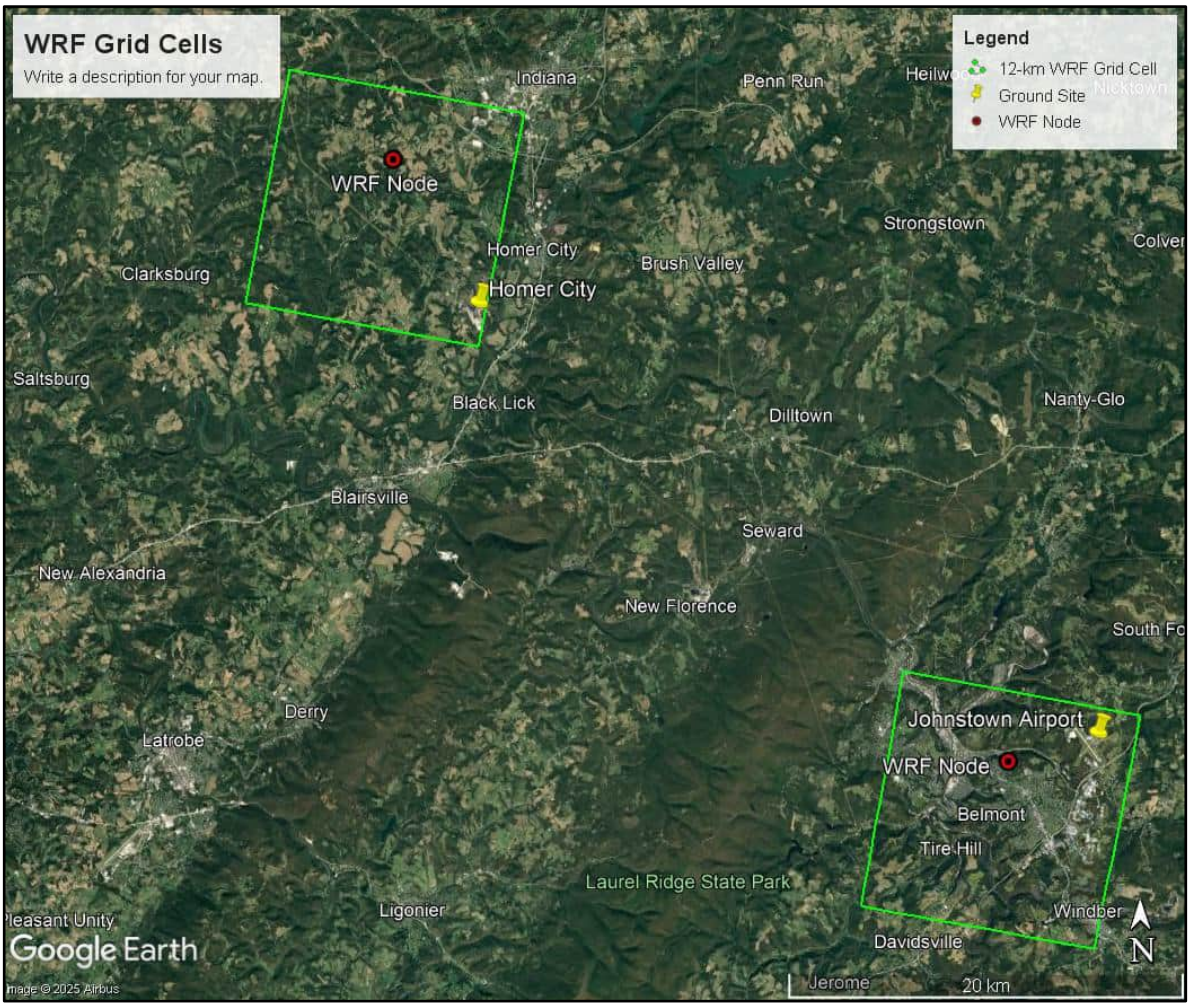
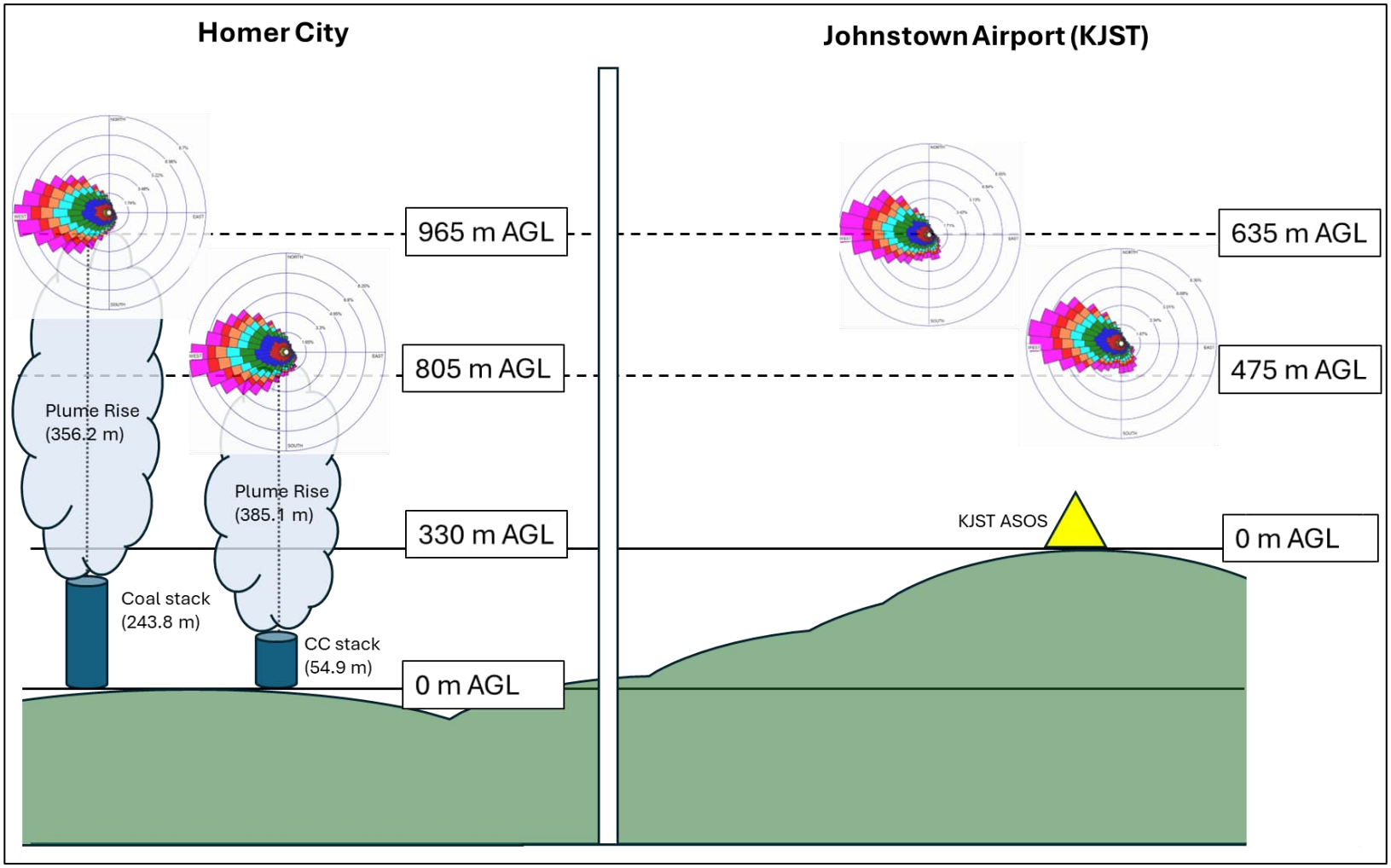


Figure 6-11: Johnstown WRF vs. Homer City WRF Schematic with Wind Roses at Plume Height



Note: Wind roses are generated based on closest WRF level (rounded to nearest 100 meters) to plume height shown. Therefore, wind roses shown for Homer City are at 1,000 m and 800 m. For Johnstown Airport, the heights of the winds depicted in the wind roses are 600 m and 500 m. Depiction of terrain is also not drawn to scale and does not account for the elevated terrain along Laurel Ridge between these two locations. Terrain relative to plume height is discussed in Section 6.6.3.2.

6.7 Receptor Processing with AERMAP

A Cartesian receptor grid extending approximately 20 km from the approximate centroid (Easting = 652529.00 m; Northing = 4486825.00 m) of the Project was used in the modeling. The receptors grid consists of the following spacing:

- 25-m spaced receptors along the ambient boundary;
- 50-m spaced receptors extending from ambient boundary to 200 m;
- 100-m spaced receptors between 200 m and 1 km from the Project centroid;
- 250-m spaced receptors between 1 km and 2.5 km from the Project centroid;
- 500-m spaced receptors between 2.5 m and 10 km from the Project centroid; and
- 1,000-m spaced receptors between 10 m and 20 km from the Project centroid.

Far-field and near-field views of the receptor grid and ambient air boundary are shown in **Figure 6-12** and **Figure 6-13**, respectively. As we be shown in Section 7, Project modeled concentrations are greater than the SILs and, as such, the controlling SIL impact for each pollutant and averaging period was not resolved with 50-m receptor spacing. Project modeled concentration for each pollutant and averaging period associated with the NAAQS and PSD increment modeling was resolved with 50-m spacing.

Figure 6-13 also shows the ambient air boundary comprising effective barriers to general public access along Homer City's property boundary. Consistent with EPA policy (US EPA, 2019b), effective barriers include physical obstacles (e.g., security fencing), active and passive deterrents (e.g., security patrols and surveillance), and natural barriers (e.g., dense vegetation, low lying water areas, ditches, creeks, and ponds) that collectively prevent reasonable access by unauthorized persons on Plant property. However, Pennsylvania State Route 3017 (Coal Road) running through the Plant property is accessible by the public. Because of this, receptors have been added to estimate concentrations along this road. Overall, the Plant is very secure and limits public access to all areas of the property.

AERMAP (version 24142), the AERMOD terrain preprocessor program, was used to calculate terrain elevations and critical hill heights for the modeled receptors (NAD83 datum and Zone 17 using USGS National Elevation Data (NED). The dataset consists of 1/3 arc second (~10 m) resolution. Consistent with the AERMAP User's Guide (US EPA, 2024e), the AERMAP domain was sufficient to ensure that all significant nodes are included such that all terrain features that exceed a 10% elevation slope from any given receptor are considered. The NED files are referenced to Datum NAD83 (note all source locations and receptors will also be referenced to NAD83 UTM Zone 17. The NED files are included in the electronic modeling archive that was submitted along with the final modeling report.

Figure 6-12. Far-field Receptor Grid

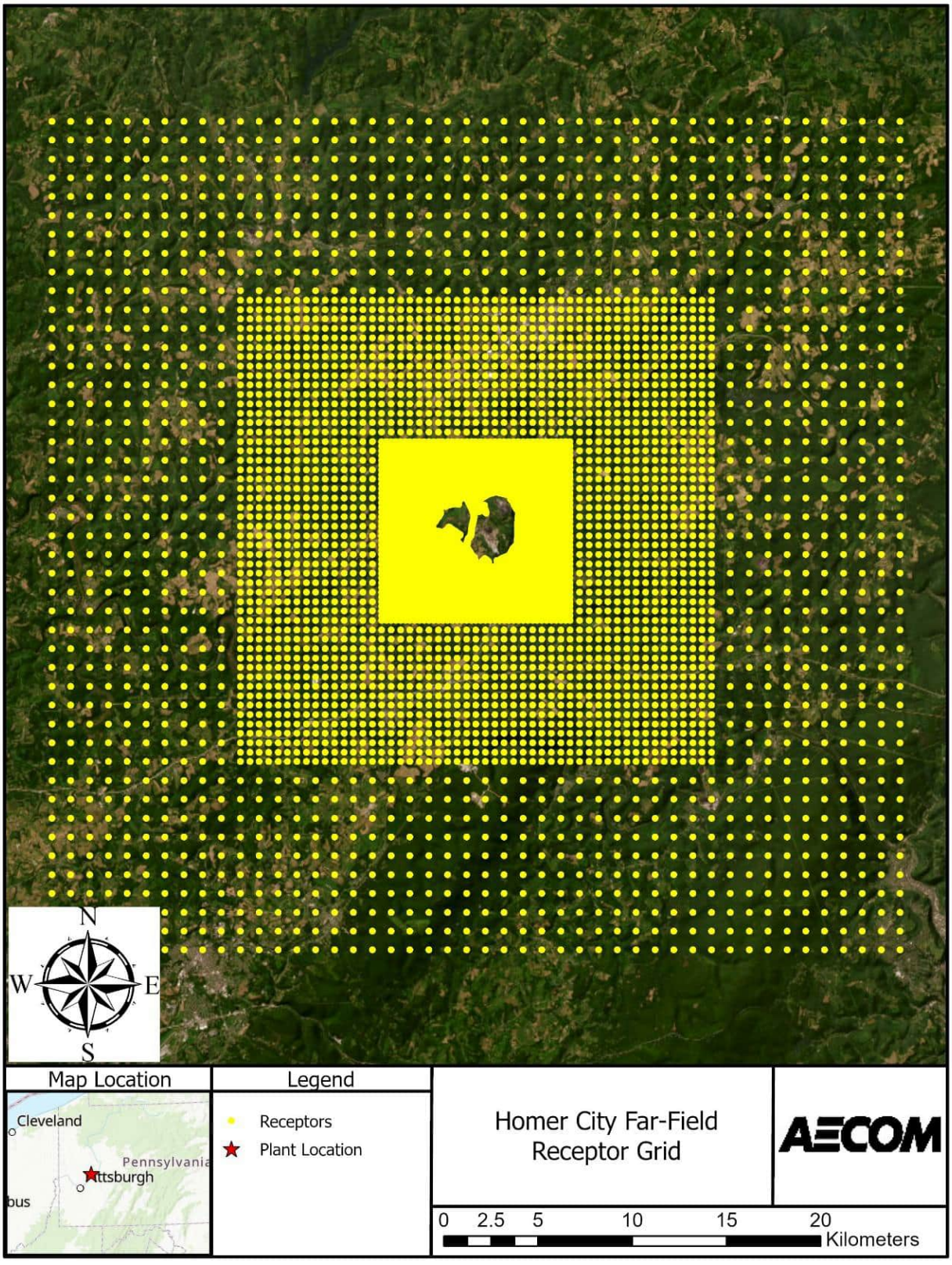


Figure 6-13. Near-field Receptor Grid and Ambient Boundary



6.8 Secondary $PM_{2.5}$

As shown in **Table 3-10**, the Project will net out of PSD review for SO_2 and NO_X ($PM_{2.5}$ precursor emissions). The change in emissions of SO_2 and NO_X will result in a decrease of over 4,000 and 875 tons of each pollutant respectively. Due to these SO_2 and NO_X reductions, the Project overall impact on secondary $PM_{2.5}$ would be a net benefit (i.e. result in reduction in secondary $PM_{2.5}$), as such, secondary $PM_{2.5}$ was not accounted for as part of the Project's SIL analysis. The NAAQS and PSD increment analysis did account for secondary $PM_{2.5}$ due to emissions associated with the Project. This is a highly conservative approach given (1) the Project will expand PSD increment in Indiana County (Co.) given the SO_2 and NO_X reductions and (2) the $PM_{2.5}$ monitor at Strongstown likely includes influence of primary and secondary $PM_{2.5}$ associated with the coal plant operations which is no longer operating.

In April 2019, US EPA released the final "Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program" (EPA-454/R-19-003) (2019 EPA MERPs Guidance) (US EPA 2019c). This guidance replaces the draft MERPs Guidance that was released in April 2016. MERP values expressed as an emission rate in the 2019 EPA MERPs Guidance represent an emission level that would result in a modeled concentration at or below specified SIL values. As such, if Project emissions were less than MERP values, the Project could be deemed to have an insignificant impact.

In February 2024, US EPA lowered the annual $PM_{2.5}$ NAAQS from 12 to 9 $\mu g/m^3$. As a result, in April 2024 US EPA issued supplemental guidance that included a new suggested SIL value for annual $PM_{2.5}$. In response to the updated SIL value for annual $PM_{2.5}$, US EPA also issued a *"Clarification on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program"* (US EPA 2024f). The purpose of this memo was to provide greater flexibility on the use of the MERPs as a direct comparison tool with critical air quality thresholds rather than direct comparison to emission rates considered equivalent to a significant air quality threshold. US EPA indicated that any MERP values presented as an emission rate published in the (2019) MERPs Guidance or through online tools should no longer be used for PSD permitting applications since the form of these values explicitly included a significant impact level that is no longer appropriate. In other words, since MERP values expressed as an emission rate in the 2019 guidance used SIL values relevant at the time the document was prepared, changes to the SIL values would essentially make any emission rate based MERP no longer valid. Therefore, US EPA has indicated that *"Any MERP values presented as an emission rate published in the MERPs Guidance or through online tools should no longer be used for PSD permitting applications since the form of these values explicitly included a significant impact level that is no longer appropriate."*

For this application, the 2019 EPA MERPs Guidance was used to develop air quality concentrations of secondary $PM_{2.5}$ for comparison to critical air quality values. Specifically, Section 4.1.3 of the 2019 US EPA MERPs Guidance illustrates how the US EPA-model data used to develop the MERPs could be used as a Tier 1 demonstration tool to estimate air quality concentrations for $PM_{2.5}$ based on Project emissions.

The methodology described in Section 4.1.3 of the 2019 US EPA MERPs Guidance was used to assess the Project impacts for secondary $PM_{2.5}$. To estimate the Project impact of secondary $PM_{2.5}$, the list of hypothetical sources that were modeled by US EPA were analyzed. The closest hypothetical site is 43 miles west of the Project site, located in Allegheny County. Two additional sites were considered but they are located further away in Tuscarawas, Ohio (120 miles west of the Project site) and Doddridge, West Virginia (115 miles southwest of the Project site).

To calculate the annual and 24-hour secondary $PM_{2.5}$ concentrations, Equation 1 provided in the April 2024 memorandum was used:

$$\textbf{Eq 1.}\quad \text{Project Air Quality Impact} = \text{Project emission rate} \times \frac{\text{Modeled air quality impact from hypothetical source}}{\text{Modeled emission rate from hypothetical source}}$$

In this case, the "Project Air Quality Impact" is the secondary $PM_{2.5}$ concentration. For secondary $PM_{2.5}$, precursor NO_x and SO_2 emissions from the hypothetical source and the modeled air quality impacts of those emissions need to be considered. The secondary $PM_{2.5}$ concentrations were added to direct $PM_{2.5}$ modeled concentrations for the Project (using AERMOD) to estimate total Project concentrations for both the SIL and NAAQS/PSD increment analyses, as applicable.

The calculated secondary $PM_{2.5}$ concentrations associated with Project emissions is shown in **Table 6-15** for each of the three nearby hypothetical MERP sites. The most conservative of the three MERP sites happens to be the closest, located in Alleghany Co.

Table 6-15. Project Estimated Secondary $PM_{2.5}$ Concentrations

	NO_X				SO_2				
Averaging Period	US EPA Precursor Emissions (TPY)	US EPA Modeled Concentration ($\mu g/m^3$)	Project Precursor Emissions (TPY)	Project Estimated Concentration ($\mu g/m^3$)	US EPA Precursor Emissions (TPY)	US EPA Modeled Concentration ($\mu g/m^3$)	Project Precursor Emissions (TPY)	Project Estimated Concentration ($\mu g/m^3$)	Project Estimated Secondary $PM_{2.5}$ Concentration ($\mu g/m^3$)
Alleghany Co. PA									
24-hour	1,000	0.080	1,142.8	0.091	1000(1)	0.251	211.8	0.053	0.1441
Annual	1,000	0.006	1,142.8	0.007	1000(1)	0.009	211.8	0.002	0.0089
Doddridge, WV									
24-hour	1,000	0.037	1,142.8	0.0425	500	0.056	211.8	0.0235	0.0660
Annual	1,000	0.001	1,142.8	0.0015	500	0.002	211.8	0.0009	0.0024
Tuscarawas, OH									
24-hour	1,000	0.080	1,142.8	0.0912	500	0.084	211.8	0.0355	0.1267
Annual	1,000	0.003	1,142.8	0.0039	500	0.004	211.8	0.0017	0.0057

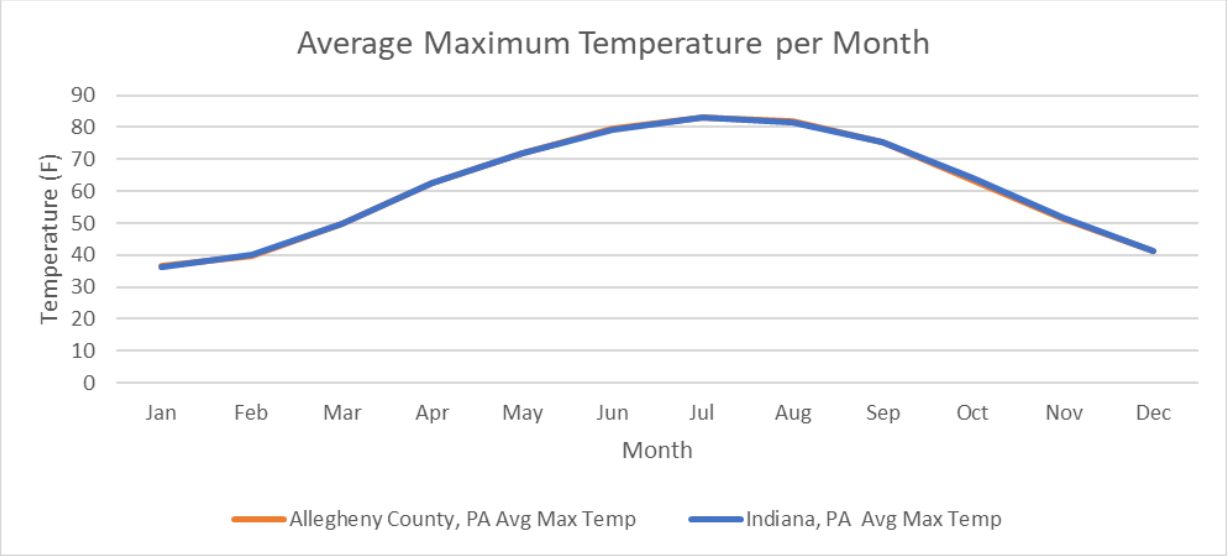
(1) A 500 TPY hypothetical NOx source is not available in the MERPs data for this location. Therefore, the 1000 TPY was used.

Due to its proximity and the fact it is the most conservative of the three nearby hypothetical MERP sites, the Alleghany Co. site was the primary site considered, as it best represents the airshed of the Project. Climate summaries from the National Oceanic and Atmospheric Administration's (NOAA's) Online Weather products for Alleghany Co. indicate very similar 30-year climate normals when compared to the location of the Project site. The weather station chosen to represent the Project site is located in Indiana, PA since it was the closest in proximity to the Project. A comparison of 30-year (1993-2023) average maximum and average minimum, temperatures and total precipitation for the Project site and the Alleghany Co. hypothetical source is provided in **Figure 6-14**, **Figure 6-15.**, and **Figure 6-16**. Data presented in these figures show a very similar annual average high temperatures in the low 60s°F, and low temperatures around 40°F. In addition, mid-summer high temperatures were in the range of 71 – 82°F for both the Project and Allegheny Co. locations. Precipitation averages are also close with approximately 40 inches of rain per year for Allegheny Co. and 48 inches of rain per year for the Project site. In addition, the MERP data for the 90-meter stack will be used for this assessment as opposed to the 10-meter stack MERP data. The 90-meter stack data is more representative of a tall stack with buoyancy and momentum rise like the main emission sources for the Project. **Section 6.6.3** references a plume height of 1,237 meters for the GE 7HA.02 stacks, this supports the use of the 90-meter MERP data.

There are some hills to the southeast of the Project site whereas the Allegheny Co. hypothetical source does not. However, the difference in terrain features would not create a substantial difference in climate regimes between the Project site and hypothetical source in Allegheny Co. Both have similar elevations: 1272 ft for Allegheny Co. and 1200 ft for the Project site. The Allegheny Co. hypothetical source also exhibits similar land use to the Project site. The Project area is primarily rural while the Alleghany Co. site is somewhat more suburban, primarily residential.

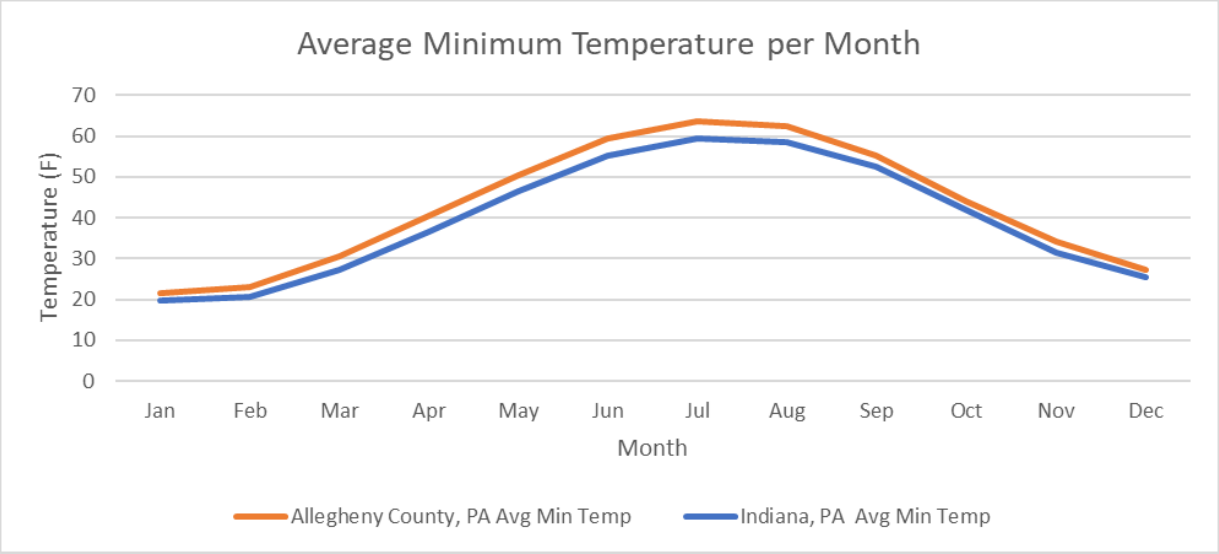
Based on the similarities in land use, climate, and terrain, the data associated with US EPA's hypothetical source in Allegheny Co., PA was used for assessing the Project impact on secondary $PM_{2.5}$. The Allegheny Co. site also has the highest concentration of secondary $PM_{2.5}$ of the three sites examined.

Figure 6-14. 30-Year Average Maximum Temperature of Allegheny County and Plant per Month



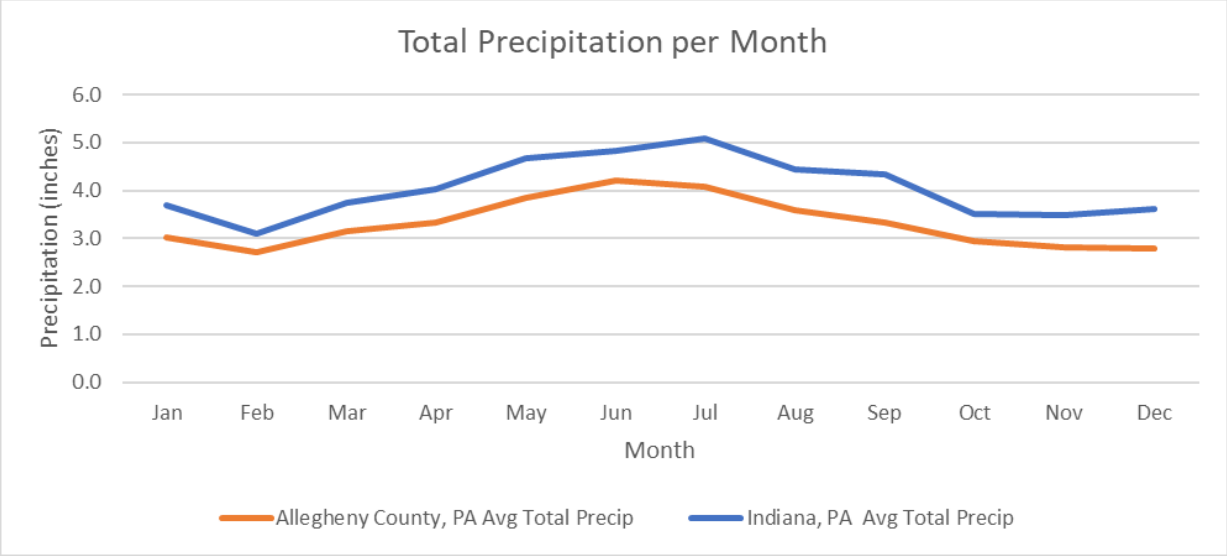
Note: Average maximum temperature at both sites are nearly identical, thus the plot shows Indiana on top of Allegheny.
Source: Data from NOAA Online Weather Data, https://weather.gov

Figure 6-15. 30-Year Average Minimum Temperature of Allegheny County and Plant per Month



Source: Data from NOAA Online Weather Data, https://weather.gov

Figure 6-16. 30-Year Average Total Precipitation for Allegheny County and Plant per Month



Source: Data from NOAA Online Weather Data, https://weather.gov

6.9 Background Air Quality and Pre-Construction Monitoring

Ambient air quality data are used to represent the contribution to total ambient air pollutant concentrations from non-modeled sources. In accordance with 40 CFR 52.21(m), an application for a PSD permit must contain an analysis of ambient air quality in the vicinity of the Project for each pollutant subject to PSD review. The objective of reviewing these data is to develop representative background concentrations which, when added to modeled impacts, are used in the NAAQS compliance analysis. This section summarizes the ambient background concentrations proposed to be used in the NAAQS analysis. The monitored concentrations presented in this section were obtained from values provided by US EPA design value spreadsheets.[41]

6.9.1 $PM_{2.5}$ Background Monitor Selection

Using the EPA Air Quality Design Values interactive map, there are four (4) $PM_{2.5}$ monitor that were considered; Strongstown (AQS Site ID: 42-063-0004), Johnstown (AQS Site ID: 42-021-0011), Kittanning (AQS Site ID: 42-005-0001), and DOT Maintenance Building in Greensburg (AQS Site ID: 42-124-0008) (see **Figure 6-17**). Factors considered when determining the most representative monitor include proximity to the Project, prevailing winds, and emission levels / population density near the monitor vs the source.

The Strongstown monitor is the closest monitor to the Project site and is in the same county. As such the county population density (see **Figure 6-17**) and emission totals are the same between the Strongstown monitor location and Project location. The wind rose shown in **Figure 6-8** also indicates that the Strongstown monitor is located in a downwind direction of the Project. The other monitors are located further away, have a higher population density or are not in a similar prevailing wind direction. Based on these factors the Strongstown monitor provides a good representation of background $PM_{2.5}$ concentration in the vicinity of the Project and is likely conservative for the following reasons:

- The monitor is likely Influenced by Homer City primary and secondary $PM_{2.5}$ emissions from coal operations that have since ceased operations (July 2023). **Figure 6-18** show the relative comparison of SO_2, NO_X and

[41] https://www.epa.gov/air-trends/air-quality-design-values

PM emissions from Homer City and other major sources in Indiana County from the 2020 NEI. Removing the Homer City emissions alone will result in a downward trend in emissions within since 2020.

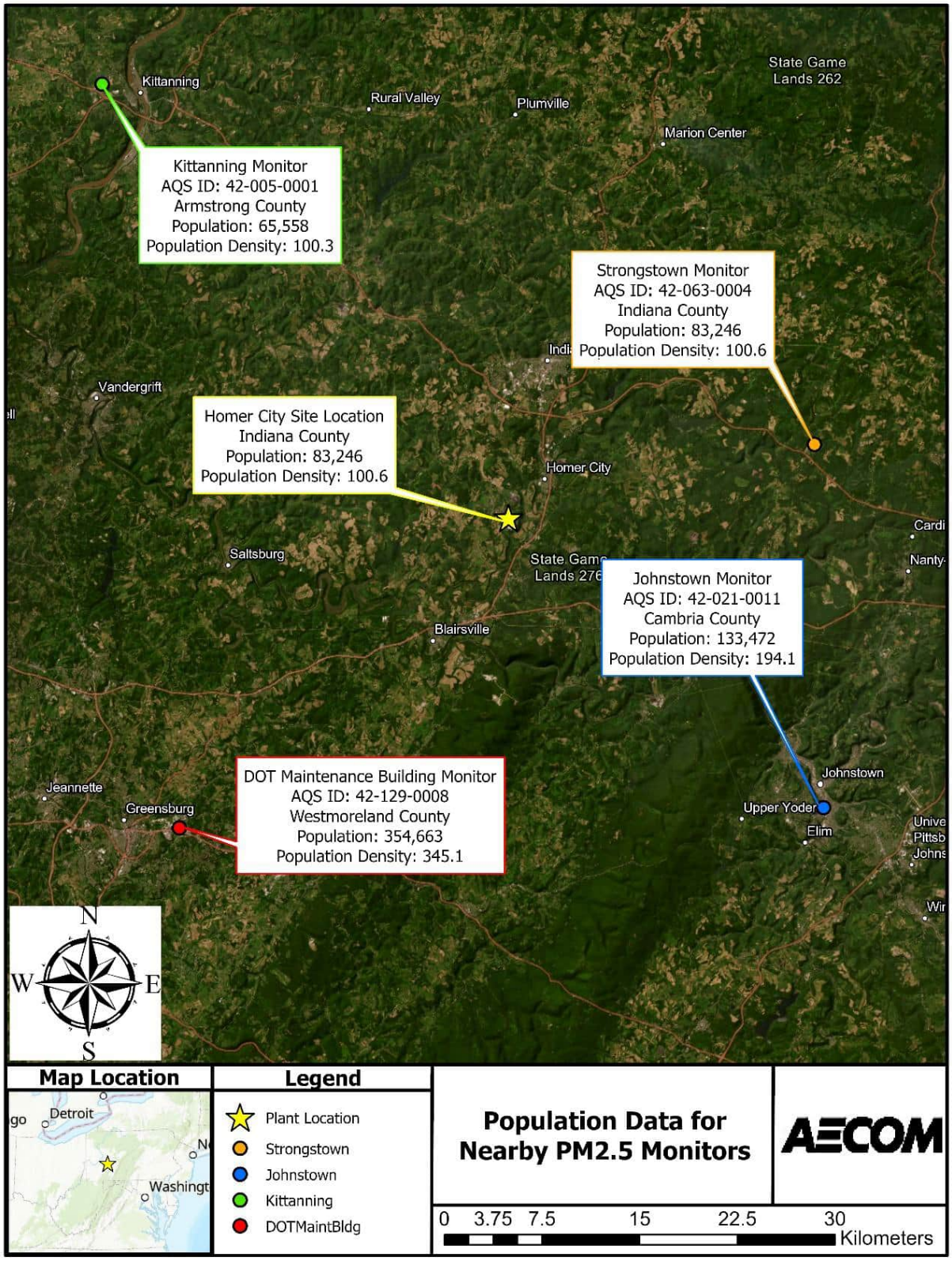
- **Table 6-16** shows the 2022-2024 $PM_{2.5}$ design concentrations which were clearly influenced by the Canadian Wildfires from 2023.

Table 6-16. $PM_{2.5}$ Ambient Background Concentrations

Pollutant	Averaging Period	AQS Site ID	Local Site Name	2021-2023 Design Value (µg/m³)	2022 Concentration (µg/m³)	2023 Concentration (µg/m³)	2024 Concentration (µg/m³)
$PM_{2.5}$	24-hour(1)	420630004	Strongstown	19	13.5	29.2	14.2
	Annual			6.8	6.4	8.1	6.1

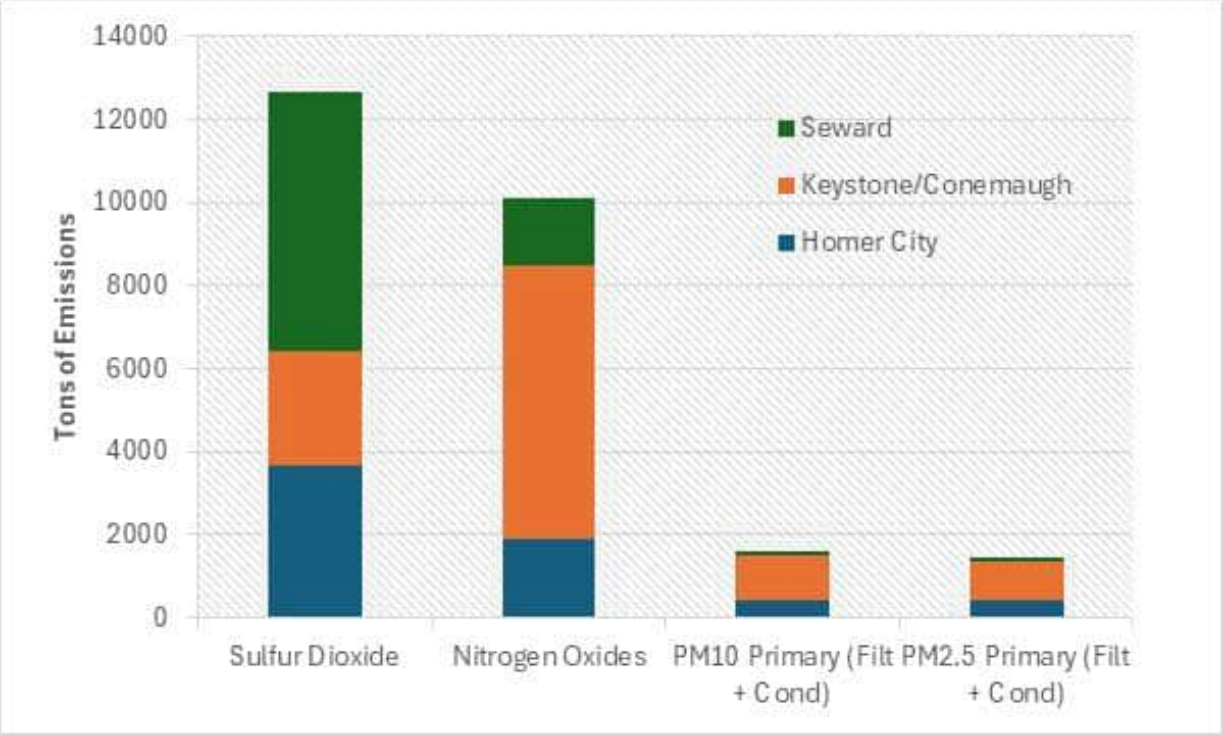
(1) Concentrations reflect the 98th percentile value.

Figure 6-17. Location of Nearby $PM_{2.5}$ Monitors



Source: US 2020 Census data from https:census.gov/quickfact

Figure 6-18. 2020 NEI Emission Data from Indiana County



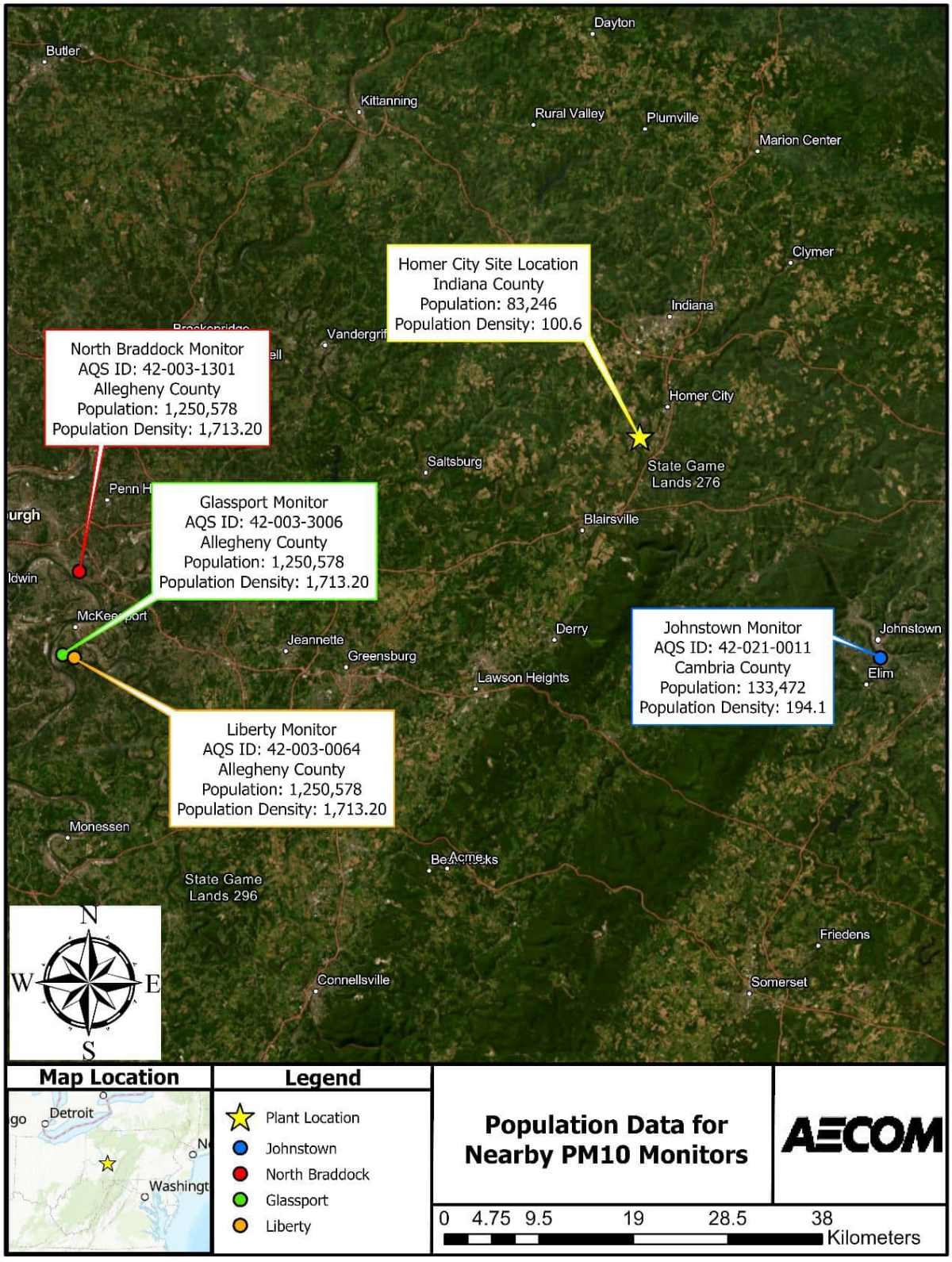
6.9.2 PM_{10} Background Monitor Selection

The monitors for PM_{10} background concentrations in western Pennsylvania near the Plant are as follows: Johnstown (AQS ID: 42-021-0011), North Braddock (AQS ID: 42-003-1201), Glassport (AQS ID: 42-003-3006), and Liberty (AQS ID: 42-003-0064). As discussed for $PM_{2.5}$, Factors considered when determining the most representative monitor include proximity to the Project, prevailing winds, and emission levels / population density near the monitor vs the source.

The Johnstown monitor is located 20 miles to the southeast of the Project site, however, is not in an ideal of a prevailing wind direction. The next closest monitors to the Project are North Braddock, Liberty, and Glassport which are 35, 37, and 39 miles west of the Plant, respectively, just outside of Pittsburgh and likely influenced by the Pittsburg urban area. Given the urban influence on these monitors near Pittsburg, the more comparable population density (see **Figure 6-19**), and comparable emissions between Cambria County and Indiana County (**Figure 6-20**), the Johnstown PM_{10} monitor provides the best representation of background PM_{10} concentrations in the vicinity of the Project.

The top ten (10) PM_{10} background concentrations are provided in **Table 6-17**. The form of the PM_{10} NAAQS is not to be exceeded more than once per year on average over 3 years. PADEP typically suggests using the highest 24-hour concentration over the latest complete 3-year period for PM_{10} background concentrations in NAAQS analysis to represent non-modeled sources. For Johnstown the highest 24-hour concentration over the 2021-2023 period was 120 μ/m^3. This value was measured on a date where wildfire smoke was impacting the State along with the next two highest 24-hour concentrations from the 2021-2023 dataset. PADEP has identified these days (June 28-July 1, 2023) as part of the $PM_{2.5}$ exceptional event analyses due to impacts from wildfire smoke. The exceptional event document can be found here (https://www.ahs.dep.pa.gov/eComment/). Based on the data presented, 54 μ/m^3 (the third highest value over the last three years) was used as the PM_{10} background concentration as part of the NAAQS assessment. This is still conservative in the sense that this day was also impacted by wildfire smoke. Data from 2024 was also evaluated but did not result in any higher values than the top three concentrations in 2023.

Figure 6-19. Population Data for Nearby PM_{10} Background Monitors

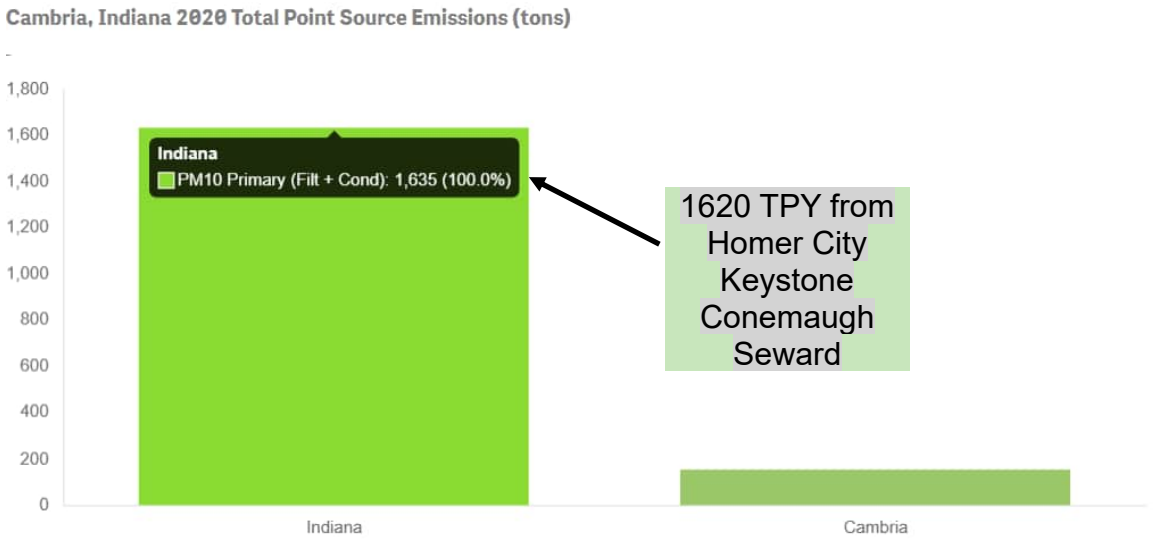


Source: US 2020 Census data from https:census.gov/quickfact

Table 6-17. PM_{10} Ambient Background Concentrations

Pollutant	Averaging Period	AQS Site ID	Local Site Name	Date	Concentration ($\mu g/m^3$)
PM_{10}	24-hour	420210011	Johnstown	6/29/2023	120
				6/28/2023	84
				6/30/2023	54
				7/20/2021	52
				6/16/2022	43
				3/9/2021	42
				12/22/2023	38
				6/6/2023	37
				7/17/2023	36
				12/21/2023	35

Figure 6-20. 2020 NEI PM_{10} Emission Data



6.9.3 Air Quality Review and Pre-construction Monitoring

According to 40 CFR §52.21(m), an analysis of ambient air quality in the vicinity of the Project for each pollutant subject to PSD review must be conducted. Air quality data are obtained from pre-construction monitoring or, under certain conditions, from existing monitoring data. Existing air quality monitoring data may be used in lieu of pre-constructing monitoring if:

- The data are representative of the proposed facility's impact areas;
- The data are of similar quality as would be obtained if the applicant monitored according to the PSD requirements; and
- The data are current; that is, the data have been collected during the two-year period preceding the permit application, provided the data are still representative of current conditions.

Existing ambient monitoring data from PADEP's monitoring network was used to satisfy the requirement for pre-construction monitoring, as described in previous sections.

7. Class II Area Significant Impact Level Analysis Results

7.1 Operating Scenario Analysis

Prior to performing the Class II Area SIL analysis, an analysis of various operating scenarios for the seven (7) GE 7HA.02 and ten (10) FT8s was performed to determine the worst-case operating scenario in terms of modeled ground-level concentrations. The analysis was conducted with emission rates and flue gas exhaust characteristics (flow rate and temperature) expected to represent the worst-case parameters among the range of possible values considered for the Project. Since emission rates and flue gas characteristics for a given operating load vary as a function of ambient temperature, data was derived for select ambient temperatures and operating scenarios for each turbine, as previously discussed in **Section 6.1**. The modeling analysis was performed using the data in **Table 6-3** and **Table 6-4**, with AERMOD and the associated databases/methodologies described in **Section 6**. Model results were estimated for both the 24-hour and annual averaging periods for PM_{10} and $PM_{2.5}$.

For the 24-hour averaging period it was assumed that two (2) GE 7HA.02 and two (2) FT8s would start up with the same hourly emission profile for every hour of the day. To determine which two (2) GE 7HA.02 and two (2) FT8s turbines should start simultaneously, modeling was conducted using individual source groups for each turbine using the same startup emission and stack characteristics. Regardless of the Project start sequence, the two (2) GE 7HA.02 and two (2) FT8s with the highest modeled concentrations were used to determine the combined impact of startup, (see **Table 7-1**).

Annual modeling of the startup scenarios was not conducted as it is not feasible to startup and shutdown these units every hour over the course of a year and annual emissions under normal operations represents a higher emission profile compared to an emission profile that includes startup and shutdown.

The results of the worst-case scenario analysis are shown in **Table 7-2**.

Table 7-2 shows the worst-case turbine operating scenario for the GE 7HA.02 is seven (7) units at 100% load with duct burner for the 24-hour averaging period. For the FT8s, the worst-case turbine operating scenario occurs with ten (10) at MECL (50% load) operations for the 24-hour averaging period.

Based on these results, two (2) scenarios were then carried out for the SIL modeling analyses presented in **Section 7.2**. These included a “Base Case” and “Worst Case” for the 24-hour averaging period. These two scenarios include the following:

- Base Case: seven (7) GE 7HA.02 at 100% load + Duct Burner and ten (10) FT8s at 100% load
- Worst Case: seven (7) GE 7HA.02 at 100% load + Duct Burner and ten (10) FT8s at 50% load

Only the Base Case was modeled for the annual averaging period as this results in the highest annual emission profile for the Project.

Table 7-1. GE 7HA.02 and FT8 Startup Analysis Results

Turbine	Maximum Modeled Concentration (µg/m^3)	
	24-hr $PM_{2.5}$	24-hr PM_{10}
CC No. 1 (GE)	**0.73**	**0.73**
CC No. 2 (GE)	**0.71**	**0.71**
CC No. 3 (GE)	0.69	0.69
CC No. 4 (GE)	0.68	0.68
CC No. 5 (GE)	0.61	0.61
CC No. 6 (GE)	0.59	0.59
CC No. 7 (GE)	0.57	0.57
FT8 No. 1	**0.55**	**0.55**
FT8 No. 2	**0.54**	**0.54**
FT8 No. 3	0.53	0.53
FT8 No. 4	0.51	0.51
FT8 No. 5	0.50	0.50
FT8 No. 6	0.51	0.51
FT8 No. 7	0.52	0.52
FT8 No. 8	0.52	0.52
FT8 No. 9	0.52	0.52
FT8 No. 10	0.51	0.51
CC Startup (2 units only) [1]	1.44	1.44
FT8 Startup (2 units only) [1]	1.09	1.09

1) Sum of the two (2) GE 7HA.02 turbines resulting in the highest modeled concentration for this startup scenario.
2) Sum of the two (2) FT8s turbines resulting in the highest modeled concentration for this startup scenario.
Bold type indicates the units resulting in the top-2 highest modeled concentrations by turbine type.

Table 7-2. Operating Scenario Analysis Results

Turbine Scenario	Maximum Modeled Concentration (µg/m³)			
	24-hr $PM_{2.5}$	Annual $PM_{2.5}$	24-hr PM_{10}	Annual PM_{10}
GE 7HA.02 Scenarios				
100% + Duct Burner	**5.49**	**0.28**	**5.49**	**0.28**
100%	4.26	0.22	4.26	0.22
75%	3.56	0.20	3.56	0.20
MECL	3.28	0.19	3.28	0.19
Startup (2 units only) [1]	1.44	--	1.44	--
Worst-Case Startup Scenario [2]	5.36	--	5.36	--
FT8 Scenarios				
100%	2.09	0.086	2.09	0.086
75%	2.30	0.093	2.30	0.093
MECL	**2.88**	**0.110**	**2.88**	**0.110**
Startup (2 units only) [3]	1.09	--	1.09	--
Worst-Case Startup Scenario [4]	2.76	--	2.76	--

(1) Sum of the two (2) GE 7HA.02 turbines resulting in the highest concentration for the startup scenario as shown in **Table 7-1**.
(2) Worst-case startup scenario includes two (2) GE 7HA.02 units at startup plus the remaining five (5) GE 7HA.02 units at 100% + Duct Burner load (3.71 µg/m³ + (5.49 µg/m³ x 5/7)).
(3) Sum of the two (2) FT8s turbines resulting in the highest concentration for the startup scenario as shown in **Table 7-1**.
(4) Bold type indicates the worst-case operating load by pollutant and averaging period
(5) Worst-case startup scenario includes two (2) FT8 units at startup plus the remaining eight (8) FT8 units at 50% load (1.09 µg/m³ + (2.09 µg/m³ x 8/10)).

7.2 SIL Analysis

The Class II Area SIL analysis was conducted using AERMOD for the base case and worst-case operating scenario as determined in **Section 7.1** for 24-hour PM_{10} and $PM_{2.5}$. For the annual averaging period, only the base case is evaluated for the SIL analysis as it results in the highest annual emission profile for the Project. In addition to the worst case and base case operating scenarios for the turbines, the SIL analysis also includes the emergency generators, auxiliary boilers, heaters, fire water pump, and cooling towers, as described in **Section 6.2.3**.

The SIL modeling analysis was used as a tool in evaluating whether the emissions of PM_{10} and $PM_{2.5}$ from the Project may cause or contribute to a NAAQS or increment exceedance. The evaluation was made using the highest 24-hour and annual modeled concentrations over the five years of meteorological data modeled. For 24-hour and annual $PM_{2.5}$, modeled concentrations were determined based on the highest 5-year averaged concentrations. For PM_{10} (24-hour and annual), the modeled concentrations were based on the highest concentration of each individual year of meteorological data.

For those pollutants and averaging periods with modeled concentrations that exceed the relevant SIL, a Class II Area cumulative impact analysis was performed to evaluate whether the Project may cause or contribute to an exceedance of the NAAQS or PSD increments. As discussed in **Section 6.8**, the net decrease in emissions of SO_2 and NOx will result in a net overall decrease in secondary $PM_{2.5}$. As a result, secondary $PM_{2.5}$ is not accounted for as part of the SIL analysis but will be conservatively added as part of the cumulative NAAQS and PSD increment analyses.

A comparison of the overall maximum modeled concentrations with the SILs is presented in **Table 7-3** for the worst-case operating scenario. As is depicted in **Table 7-3**, the annual PM_{10} modeled concentration is below its respective

SIL. As such, no further analyses were performed for annual PM_{10}. Modeled concentrations of 24-hour PM_{10}, 24-hour $PM_{2.5}$, and annual $PM_{2.5}$ are greater than their respective SILs. Note that 24-hour and annual $PM_{2.5}$ were evaluated based on maximum per meteorological year (for PSD increment) and maximum averaged over the 5-years of meteorological data (for NAAQS). As a result, a Class II Area cumulative impact analysis for 24-hour PM_{10} and $PM_{2.5}$, and annual $PM_{2.5}$ was conducted, as documented in **Section 8.0**.

The isopleths for 24-hour PM_{10}, 24-hour $PM_{2.5}$, and Annual $PM_{2.5}$ SIL results are plotted in **Figure 7-1**, **Figure 7-2**, and **Figure 7-3** respectively. In **Figure 7-1**, the maximum concentration is located on Coal Road along the Project boundary for 24-hour PM_{10}. However, there is a secondary maximum 7.5 km to the east of the Project which has increased the significant impact area for this pollutant and averaging period. The significant impacts are more widespread for 24-hour and Annual $PM_{2.5}$ (due to the lower SIL values) as seen in **Figure 7-2** and **Figure 7-3**. The maximum concentration for 24-hour $PM_{2.5}$ is also located on Coal Road along the Project boundary whereas the annual $PM_{2.5}$ maximum concentration is located on the eastern side of the Project boundary.

Table 7-3. Summary of Maximum AERMOD Concentrations to Significant Impact Levels

Pollutant	Averaging Period	Maximum Modeled Concentration (µg/m^3)	US EPA SIL (µg/m^3)	Exceeds SIL? (Yes or No)	Significant Impact Area Distance (km)
PM_{10}	24-hour (Base Case)[1]	6.43[(3)]	5.0	Yes	7.5
	24-hour (Worst Case)[2]	6.84[(3)]	5.0	Yes	7.5
	Annual[1]	0.39[(4)]	1.0	No	--
$PM_{2.5}$	24-hour (Base Case)[1]	6.38[(3)]	1.2	Yes	25.8
	24-hour (Worst Case)[2]	6.79[(3)]	1.2	Yes	25.8
	Annual[1]	0.39[(4)]	0.13	Yes	19.0
$PM_{2.5}$	24-hour (Base Case)[1]	4.95[(5)]	1.2	Yes	23.5
	24-hour (Worst Case)[2]	5.00[(5)]	1.2	Yes	19.3
	Annual[1]	0.37[(6)]	0.13	Yes	16.1

(1) Base Case: seven (7) GE 7HA.02 at 100% load + Duct Burner and ten (10) FT8s at 100% load
(2) Worst Case: seven (7) GE 7HA.02 at 100% load + Duct Burner and ten (10) FT8s at 50% load
(3) Highest 24-hour average modeled concentration per year taken over five (5) years.
(4) Highest annual average modeled concentration per year taken over five (5) years.
(5) Highest 24-hour average modeled concentration averaged over five (5) years.
(6) Highest annual average modeled concentration averaged over five (5) years.

Figure 7-1: 24-hour PM_{10} SIL Isopleth (Worst Case Scenario)

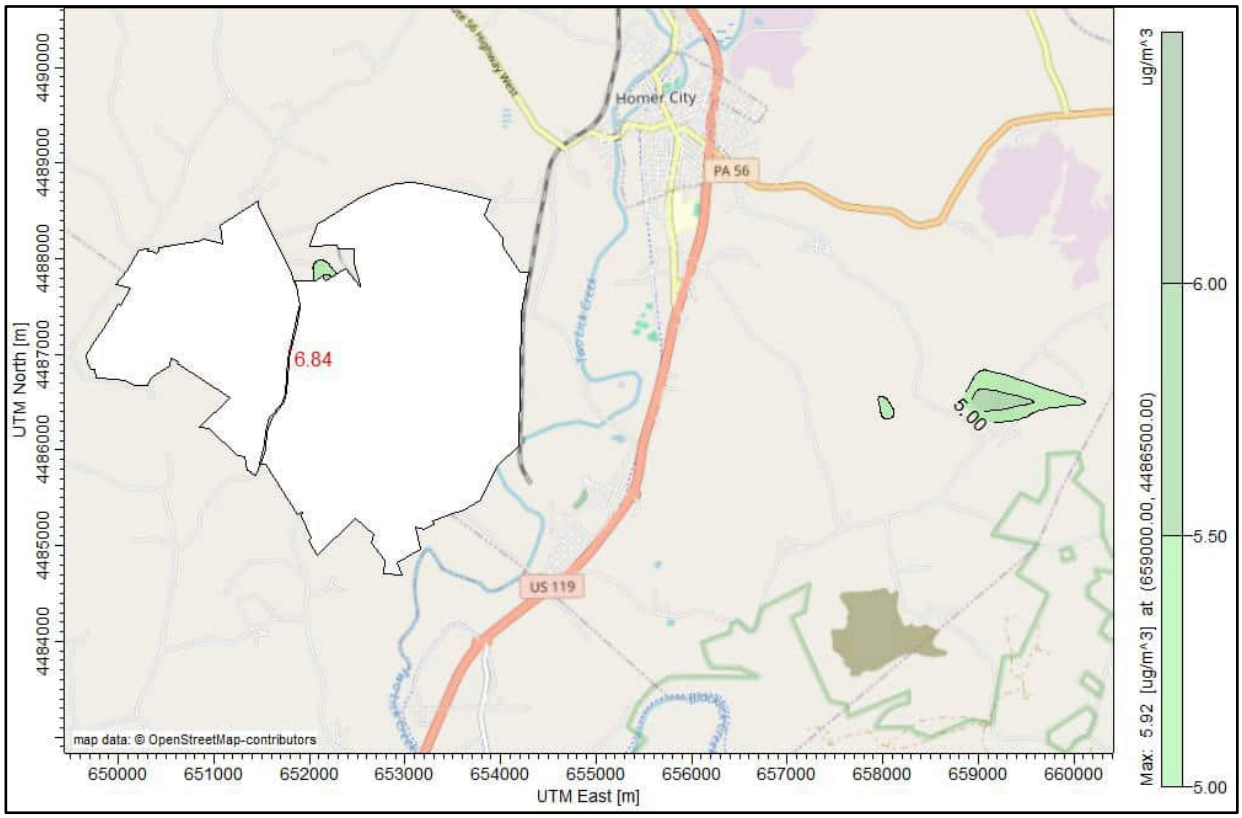


Figure 7-2: 24-hour $PM_{2.5}$ SIL Isopleth (Worst Case Scenario)

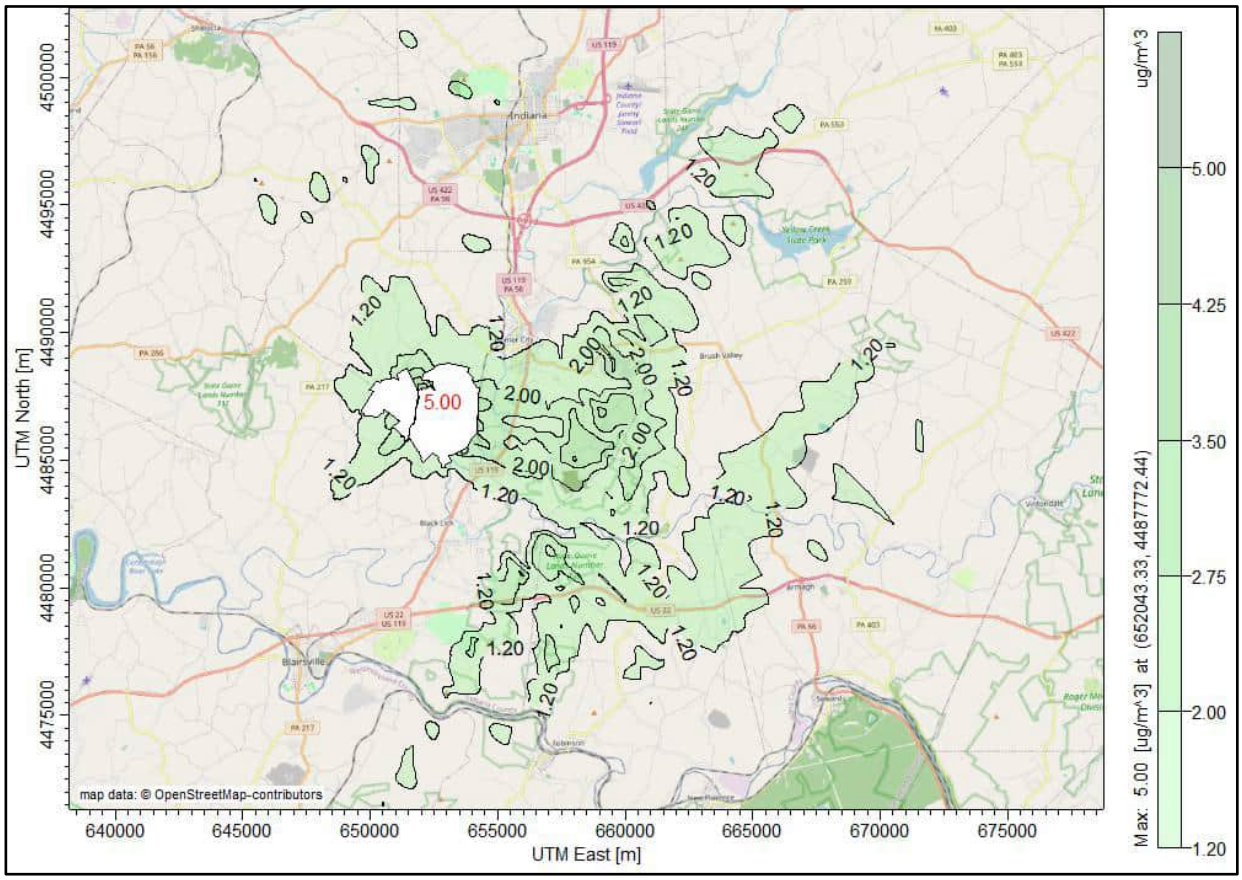
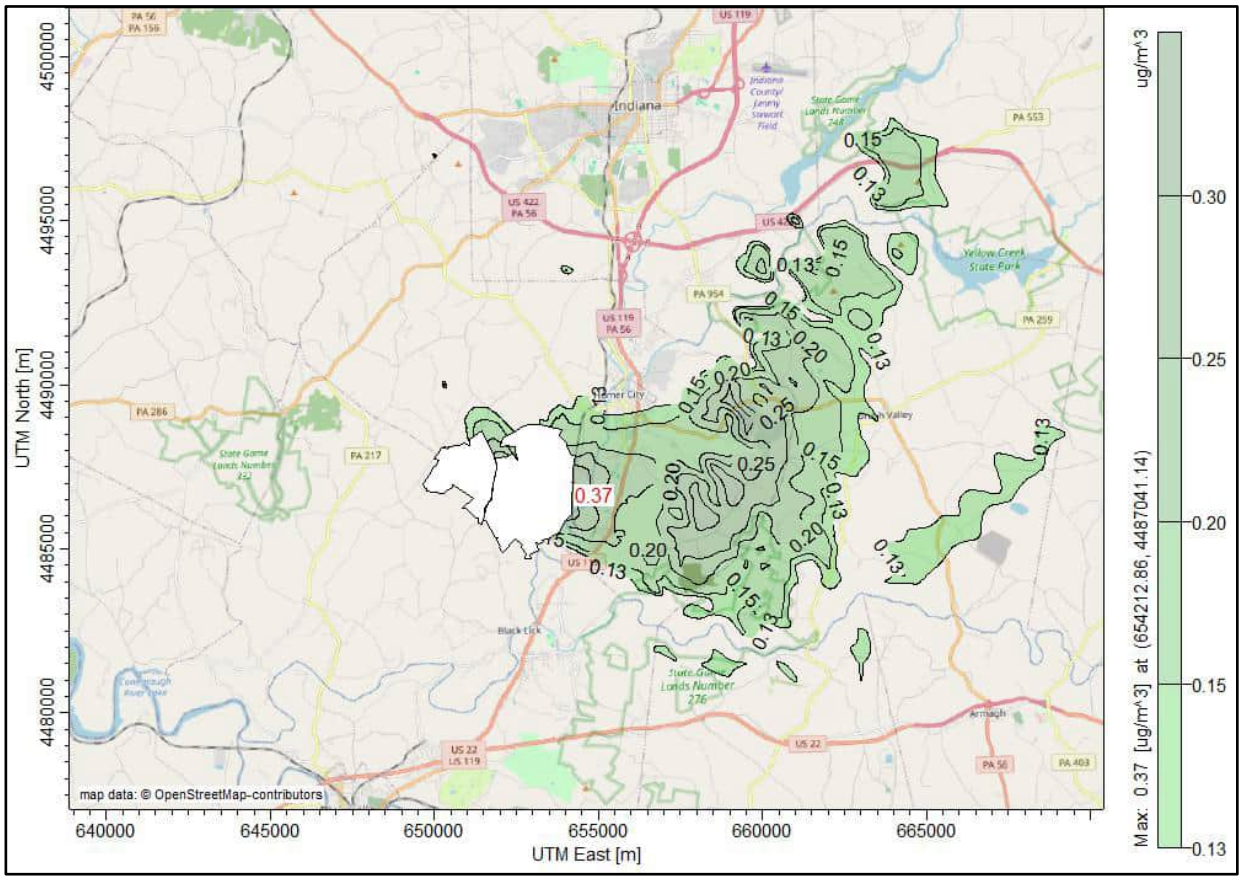


Figure 7-3: Annual $PM_{2.5}$ SIL Isopleth



8. Class II Area Cumulative Impact Analysis Results

8.1 Class II Area Air Quality Standards and PSD Increments

The discussion below applies only to those pollutants and averaging periods for which a modeled impact is predicted with AERMOD to exceed the relevant SIL. The cumulative impact analyses were conducted using methods and data described in **Sections 6** with the exception that the receptors were limited to those at which the Project has a significant modeled concentration.

The evaluation of whether the Project may cause or contribute to an exceedance of the PSD increments and NAAQS is based on the sum of the following:

- Modeled concentrations attributable to the Project;
- Modeled concentrations from "nearby" sources; and
- Representative ambient background concentration (NAAQS only).

Modeled concentrations attributable to the Project and "nearby" sources were estimated using AERMOD. An inventory of sources was developed based on information obtained from PADEP to assess cumulative impacts. The modeled design 24-hour and annual concentrations from the Project, as well as influencing nearby emission sources, were compared with the NAAQS and PSD increments. Note that primary plus secondary $PM_{2.5}$ impacts were accounted for from the Project using the secondary $PM_{2.5}$ concentrations estimated in **Section 6.8**. For the NAAQS analysis, a conservative background concentration (see **Section 6.9**) was added to modeled design concentrations.

8.2 Nearby Source Inventory

For PSD permitting, a cumulative impact analysis needs to appropriately characterize the spatial nature of air quality near a new or modified source to identify the potential for NAAQS or PSD increment exceedances. Characterization of local air quality around a new or modifying source for each pollutant and averaging period necessitates a full and comprehensive accounting for all source contributions. A cumulative impact analysis should account for the combined impacts of all direct and precursor emissions of a pollutant from:

- the new or modifying source,
- direct emissions from nearby sources, and
- monitored background concentrations accounting for primary and/or secondary impacts from regional background sources and nearby sources not explicitly modeled.

Appropriately accounting for all source contributions is an inherently discretionary exercise with use of best professional judgment in determining a representative background concentration and identifying nearby sources that need to be explicitly modeled. The development of the background source inventory for the Project relied on US EPA's *Guidance on Developing Background Concentrations for Use in Modeling Demonstrations* (Background Concentration Guidance), which was finalized November 20,2024 (US EPA, 2024g).

The regional source inventory development includes ambient background concentrations (see **Section 6.9**) to account for non-modeled sources and the modeling of direct source emissions which are not adequately represented by the background monitors. The regional source inventory development considered the extent of the Project's significant impact area (SIA) when determining the relevant sources to directly model. Based on US EPA Guidance, the hypothetical example in Appendix C of the Background Concentration Guidance, generally sources with less than 25 tons per year of actual PM_{10}/$PM_{2.5}$ emissions are likely represented in the selected regional monitors and therefore

would be excluded from explicitly modeling those sources. Larger sources may be included if they are not adequately represented by the monitor.

As discussed in **Section 7.2**, the Project identified having modeled concentrations exceeding the SIL for both PM_{10} and $PM_{2.5}$. Based on the SIAs (as shown in **Table 7-3**), a list of nearby sources within approximately 8-km (for PM_{10}) and 23-25 km (for $PM_{2.5}$) of the Project was obtained from PADEP. These lists included sources in Indiana, Armstrong, and Westmoreland counties. Of the sources provided, only four (4) sources were identified to include in the cumulative modeling: Keystone Generating Station (Armstrong County), Conemaugh Generating Station (Indiana County), Seward Generating Station (Indiana County), and Armstrong Power (Armstrong County). Additional details on the process of selecting nearby sources to model versus those captured in the background data are provided in **Appendix F**.

8.3 NAAQS Analysis Results

A summary of the NAAQS analysis is presented below in **Table 8-1**. The modeled concentrations presented represent the Project (including the secondary $PM_{2.5}$ estimated in **Section 6.8**) and nearby background sources. The modeled concentrations were added to representative ambient background concentrations to estimate the total concentrations that were then compared to the NAAQS. As shown, the total concentrations for 24-hour PM_{10}, 24-hour and annual $PM_{2.5}$ are less than the NAAQS. The results of the cumulative modeling analysis indicate that the Project will not cause or contribute to a violation of the 24-hour PM_{10}, 24-hour $PM_{2.5}$ and annual $PM_{2.5}$ NAAQS.

Table 8-1. Summary of NAAQS Analysis

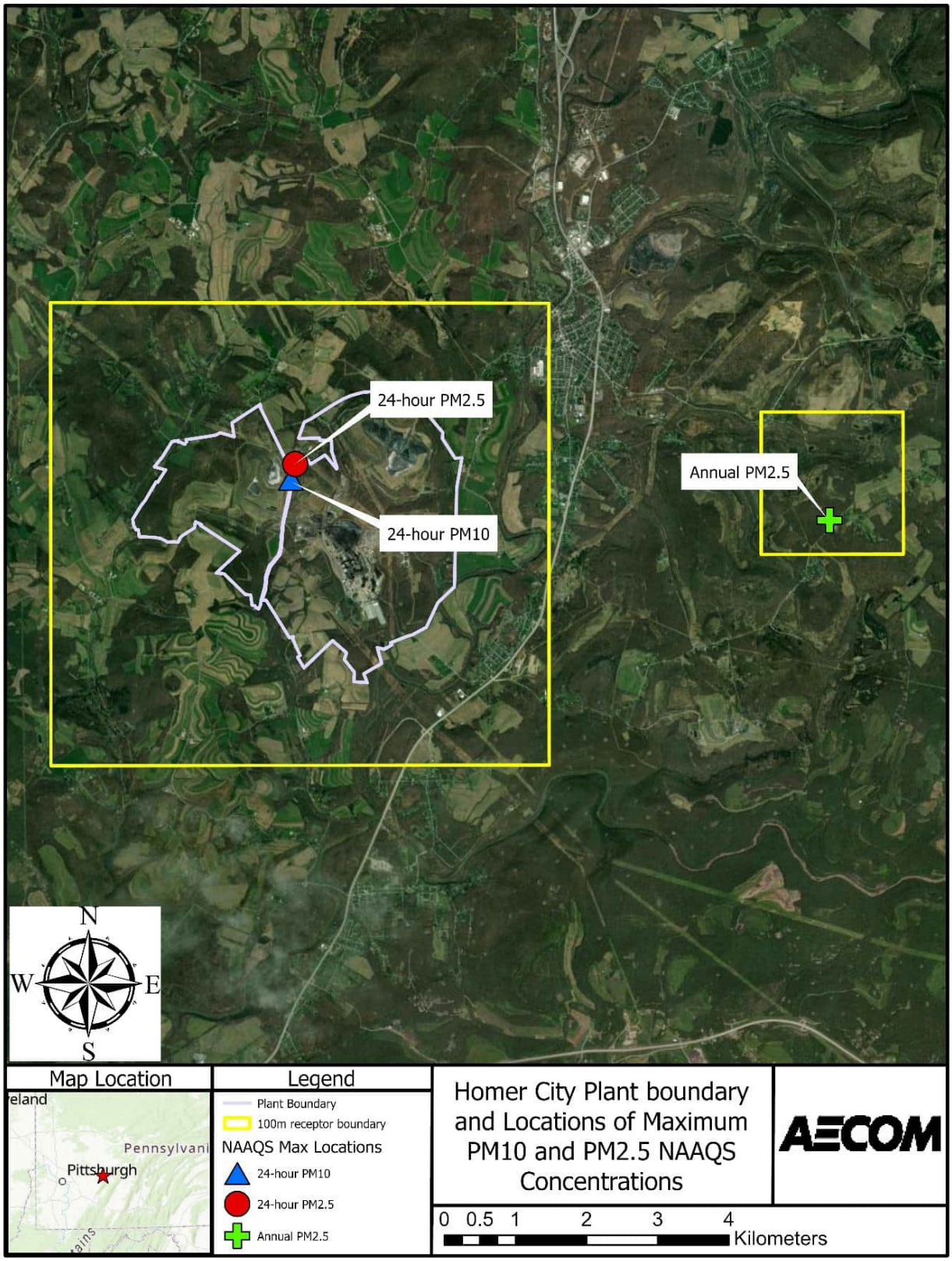
Pollutant	Averaging Period	Rank	Scenario	Modeled Concentration (µg/m³)	Secondary $PM_{2.5}$ (4) (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration(3) (µg/m³)	NAAQS (µg/m³)	Exceeds NAAQS?
PM_{10}	24-hour	6th	Base Case	6.48	--	54.0(1)	60.48	150	No
			Worst Case	6.53	--	54.0(1)	60.53	150	No
$PM_{2.5}$	24-hour	8th	Base Case	4.38	0.144	19.0(2)	23.52	35	No
			Worst Case	4.41	0.144	19.0(2)	23.55	35	No
	Annual	1st	--	0.85	0.009	6.8(2)	7.66	9	No

(1) Ambient background concentrations from the Johnstown, PA monitor, see **Table 6-17**.
(2) Ambient background concentrations from the Strongstown, PA monitor, see **Table 6-16**.
(3) Total concentration includes Project, nearby sources, and monitored background concentrations.
(4) Secondary $PM_{2.5}$ concentrations for 24-hour and annual averaging periods, see **Table 6-15**.

Figure 8-1 shows the locations of the maximum cumulative NAAQS impacts for the PM_{10} and $PM_{2.5}$ results presented in **Table 8-1**. For 24-hour PM_{10}, both the base case and worst case maximum modeled location is at the ambient boundary along Coal Road, approximately 680 m to the northwest of the Project sources. For 24-hour $PM_{2.5}$, the location of the maximum modeled concentration for the base and worst-case scenarios was also along the ambient boundary, just east of Coal Road and south of Quality Center Road. In relation to the Project sources, the maximum modeled 24-hour $PM_{2.5}$ impact for both base and worst-case scenarios was about 780 m to the northwest.

As shown in **Figure 8-1**, the maximum modeled cumulative impact for annual $PM_{2.5}$ is approximately 7 km to the east of the Project sources. A refined, 100-m spaced, receptor grid was added to resolve the maximum impact for annual $PM_{2.5}$ as it was located beyond the 100-m spaced receptors in the original grid. The results presented in **Table 8-1** account for the maximum concentration resolved using this refined 100-m spaced grid.

Figure 8-1. Location of Maximum Cumulative NAAQS Impacts for PM_{10} and $PM_{2.5}$



8.4 PSD Increment Analysis Results

A summary of the PSD increment analysis is presented in **Table 8-2** for 24-hour PM_{10}, 24-hour $PM_{2.5}$, and annual $PM_{2.5}$. The modeled concentrations presented in **Table 8-2** represent the Project (including the secondary $PM_{2.5}$ estimated in **Section 6.8**), and nearby background PSD increment-consuming sources. The results of the cumulative modeling analysis indicate that the Project will not cause or contribute to an exceedance of the 24-hour PM_{10}, 24-hour $PM_{2.5}$ and annual $PM_{2.5}$ PSD increments.

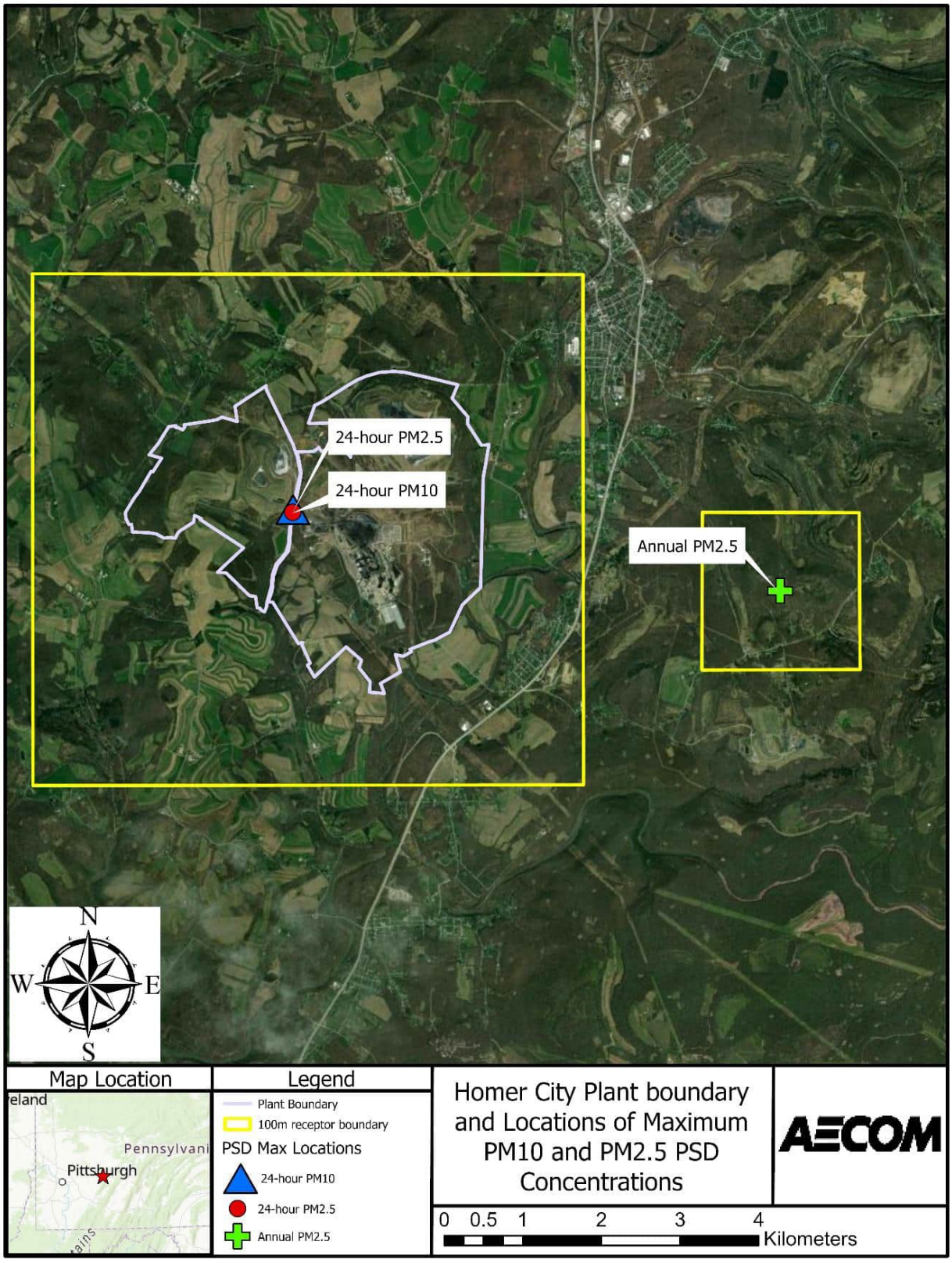
As shown in **Figure 8-2**, all maximum 24-hour averaging period concentrations (PM_{10} and $PM_{2.5}$) reside along either the western or northwestern ambient boundary (along Coal Road). For annual $PM_{2.5}$, the maximum PSD increment modeled receptor is approximately 7.2 km from the Project source, which is beyond the 100-m spaced domain. As a result, a refined 100-m spaced receptor grid was added to resolve the maximum impact based on a 100-m spaced receptor grid. The results presented in **Table 8-2** account for the maximum concentration resolved using this refined 100-m spaced grid.

Table 8-2. Summary of PSD Increment Analysis

Pollutant	Averaging Period	Rank	Scenario	Modeled Concentration ($\mu g/m^3$)	Secondary $PM_{2.5}$[1] ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)	Exceeds PSD Increment?
PM_{10}	24-hour	2nd	Base Case	6.60	--	6.60	30	No
			Worst Case	6.67	--	6.67	30	No
$PM_{2.5}$	24-hour	2nd	Base Case	6.30	0.144	6.44	9	No
			Worst Case	6.70	0.144	6.84	9	No
	Annual	1st	--	0.43	0.009	0.44	4	No

1) Secondary $PM_{2.5}$ concentrations for 24-hour and annual averaging periods, see Table **6-15**.

Figure 8-2. Location of Maximum PSD Increment Impacts for PM_{10} and $PM_{2.5}$



9. Other PSD Requirements

9.1 Class I Area Impact Analysis

PSD Class I areas are areas of special national or regional value from a natural, scenic, recreational, or historical perspective. The PSD program provides special protection for such areas. According to 40 CFR §52.21(p), sources located within 300 km of a Class I area may be required to demonstrate that the Project will not cause or contribute to an exceedance of the PSD Class I increments or adversely affect certain air quality-related values. The three (3) PSD Class I areas located within 300 km of the Project site are pictured in **Figure 9-1** and their approximate distances are:

- Dolly Sods Wilderness: 165 km
- Otter Creek Wilderness: 166 km
- Shenandoah National Park: 197 km

9.1.1 Air Quality Related Values

The Federal Land Managers' Air Quality Related Values Work Group Phase 1 Report (Revised 2010) (FLAG 2010) guidance document contains a screening approach that is designed to screen out projects with small impacts from the need to conduct an air quality related values (AQRVs) analysis for nearby Class I areas. The FLAG 2010 guidance states that a proposed source with a Q/D ratio less than 10 will likely not have an adverse impact on air quality related values, where 'Q' is the annual steady-state equivalent emission rate based on the sum of NO_X, SO_2, filterable PM_{10}, and H_2SO_4 emissions (expressed in tons per year, based on maximum 24-hour emissions) and 'D' is the distance (km) to the closest Class I area. Since the proposed Project only triggers PSD review for $PM_{10}/PM_{2.5}$ and H_2SO_4, only those pollutants were considered in the Q/D calculation.

For the proposed GE 7HA.02 CCs, Project, 'Q' is 867.7 tons per year based on the following calculation: 23.7 lb/hr ($PM_{10}/PM_{2.5}$) + 4.6 lb/hr (H_2SO_4) = 28.3 lbs/hr/CT x 7 GE 7HA.02 CCs = 198.1 lbs/hr x 8,760 hrs/yr ÷ 2000 lbs/ton = 867.7 tons/year. For the proposed FT8 CTs, Project, 'Q' is 192.7 tons per year based on the following calculation: 3.0 lb/hr ($PM_{10}/PM_{2.5}$) + 0.64 lb/hr (H_2SO_4) = 3.64 lbs/hr/CT x 10 FT8 CTs = 36.4 lbs/hr x 8,760 hrs/yr ÷ 2000 lbs/ton = 159.4 tons/year. The combined Q for the GE 7HA.02 and FT8 units is 1,027.1 tons/year. Relative to the Dolly Sods Wilderness Area (closest Class I area to the Project), Q = 1,027.1 tons/year, d=165, and Q/d ratio = 6.2. The Q/D ratio for each Class I area is shown in **Table 9-1**.

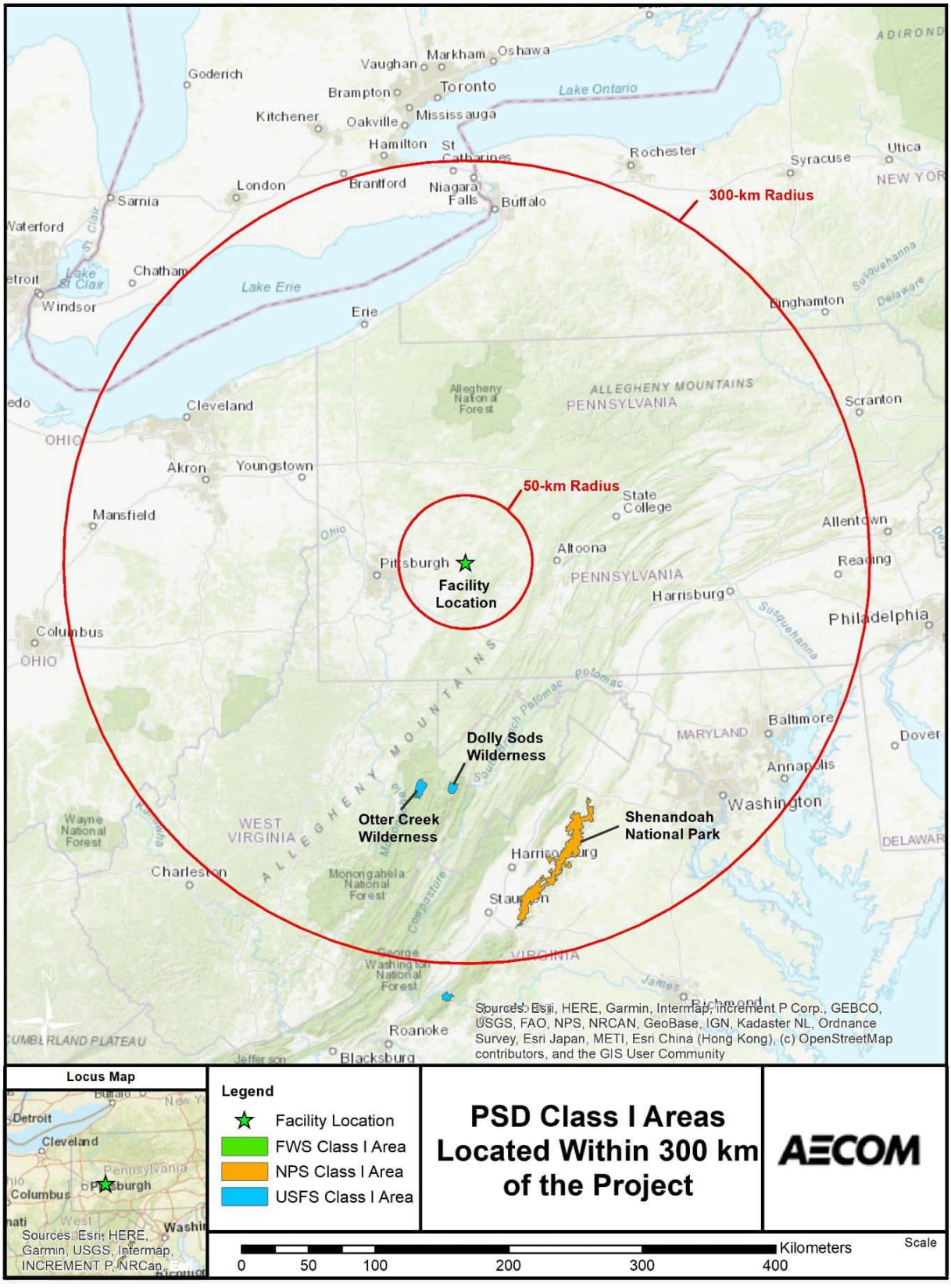
The net change in Project emissions of SO_2 and NO_X when accounting for the coal plant shutdown is -4,258 and -1,294 tons/year, respectively. If the net changes for these pollutants were factored into the Q calculation, the resultant Q would be less than zero resulting in a Q/D ratio less than zero.

Based on the Q/D, Homer City prepared a Request for Applicability of Class I Area Modeling Analysis (February 20, 2025) which was submitted to the United States Forest Service (USFS) and the National Park Service (NPS) for review to confirm that an assessment of AQRVs was not required. On February 27, 2025 and March 6. 2025, the FLMs from the NPS and USFS responded, respectively, providing a waiver from the need to perform an AQRV analysis based on the submittal. The FLM correspondence is included as an attachment in **Appendix G**.

Table 9-1. Class I Areas Q/D Calculations

Class I Area	Distance from Project (km)[(2)]	Emissions (tpy)	Q/D
Dolly Sods Wilderness	165	1027.1	6.2
Otter Creek Wilderness	166	1027.1	6.2
Shenandoah National Park	197	1027.1	5.2

Figure 9-1. PSD Class I Areas Within 300km of the Project



9.1.2 Class I Increment and SIL Analysis

In accordance with Appendix W (Section 4.2.c.i), because AERMOD is proposed for the Project's nearfield assessment (within 50 km), it can be utilized in a screening-level analysis to estimate the Project's potential for a significant modeled impact at the PSD Class I areas listed above. As such, initially AERMOD was used to assess the Class I PSD increments for PM_{10} and $PM_{2.5}$. AERMOD was applied with an arc of receptors placed 1 degree apart at 50-km, the maximum distance at which AERMOD is considered to be valid. Receptors were limited to directions in which the plume could be transported from the source to the Class I areas (see **Figure 9-2**). At these receptors, the maximum concentrations associated with the Project was modeled for comparison to the Class I PSD SILs (see **Table 4-2)**. As shown in **The results** of the Project's impact on soil and vegetation are shown in **Table 9-5.** As shown in **Table 9-5,** modeled concentrations are all well below applicable screening thresholds.

, the maximum modeled Project concentrations are greater than the Class I area SILs for 24-hour PM_{10} and 24-hour $PM_{2.5}$.

Table 9-2. Class I Area – SIL Modeling Results

Pollutant	Averaging Period	Maximum Modeled Concentration (µg/m³)	Class I SILs (µg/m³)	Exceeds Class I Area SIL?
PM_{10}	24-hour (Base Case)[1]	0.64	0.3	Yes
	24-hour (Worst Case)[2]	0.63	0.3	Yes
	Annual	0.01	0.2	No
$PM_{2.5}$	24-hour (Base Case)[1]	0.65	0.27	Yes
	24-hour (Worst Case)[2]	0.63	0.27	Yes
	Annual	0.01	0.03	No

(1) Base Case: seven (7) GE 7HA.02 at 100% load + Duct Burner and ten (10) FT8s at 100% load
(2) Worst Case: seven (7) GE 7HA.02 at 100% load + Duct Burner and ten (10) FT8s at 50% load

Since the AERMOD concentrations at 50-km are greater than the SIL for 24-hour PM_{10} and 24-hour $PM_{2.5}$, the AERMOD modeling results were extrapolated out to the Class I area distances. To create an equation to extrapolate the concentrations at 50-km out to the distance of the Class I areas, more receptors were needed. Additional receptors were arranged in arcs spaced 1 degree apart within the sector in which the emissions from the plant could be transported to the Class I areas. The arcs were placed in 1-km increments from the center of the Project out to 50-km (see **Figure 9-2**).

The AERMOD results at each downwind arc were then used to formulate an equation to approximate the modeled concentrations beyond 50-km using the change in concentration as a function of distance from the Project. The maximum AERMOD concentration for each downwind arc was summarized and plotted as shown in **Figure 9-3** and **Figure 9-4** respectively for the 24-hour PM_{10} and 24-hour $PM_{2.5}$.

Based on the plots, Excel was used to generate a best-fit exponential equation to then calculate the concentration of 24-hour PM_{10} and 24-hour $PM_{2.5}$ at the distance of the Class I areas for the Base Case as it represented a slightly higher 24-hour average concentration at 50 kilometers. The equations used to extrapolate the modeled concentration beyond 24-hour PM_{10} and 24-hour $PM_{2.5}$ concentrations out to the Class I area distances is as follows.

24-hour PM_{10} equation $\rightarrow Y = 2.8945e^{-0.032X}$

24-hour $PM_{2.5}$ equation $\rightarrow Y = 2.8884e^{-0.031X}$

Y is the calculated concentration in $\mu g/m^3$ and X is the distance in kilometers.

Applying the equations results in modeled concentrations less than the SILs for 24-hour PM_{10} and 24-hour $PM_{2.5}$ (see **Table 9-3**).

Table 9-3. Extrapolated PM_{10} and $PM_{2.5}$ 24-hour Modeled Concentrations at the Class I Area Distances

Pollutant	Averaging Period	Class I Area	Distance (km)	Concentration (µg/m^3)	Class I SILs (µg/m^3)	Exceeds Class I Area SIL?
PM_{10}	24-hour (Base Case)	Dolly Sods Wilderness Area	165	0.014	0.3	No
	24-hour (Base Case)	Otter Creek Wilderness Area	166	0.015	0.3	No
	24-hour (Base Case)	Shenandoah National Park	197	0.0053	0.3	No
$PM_{2.5}$	24-hour (Base Case)	Dolly Sods Wilderness Area	165	0.017	0.27	No
	24-hour (Base Case)	Otter Creek Wilderness Area	166	0.017	0.27	No
	24-hour (Base Case)	Shenandoah National Park	197	0.0064	0.27	No

Figure 9-2. 50-km arc of Receptors Used for Class I Modeling

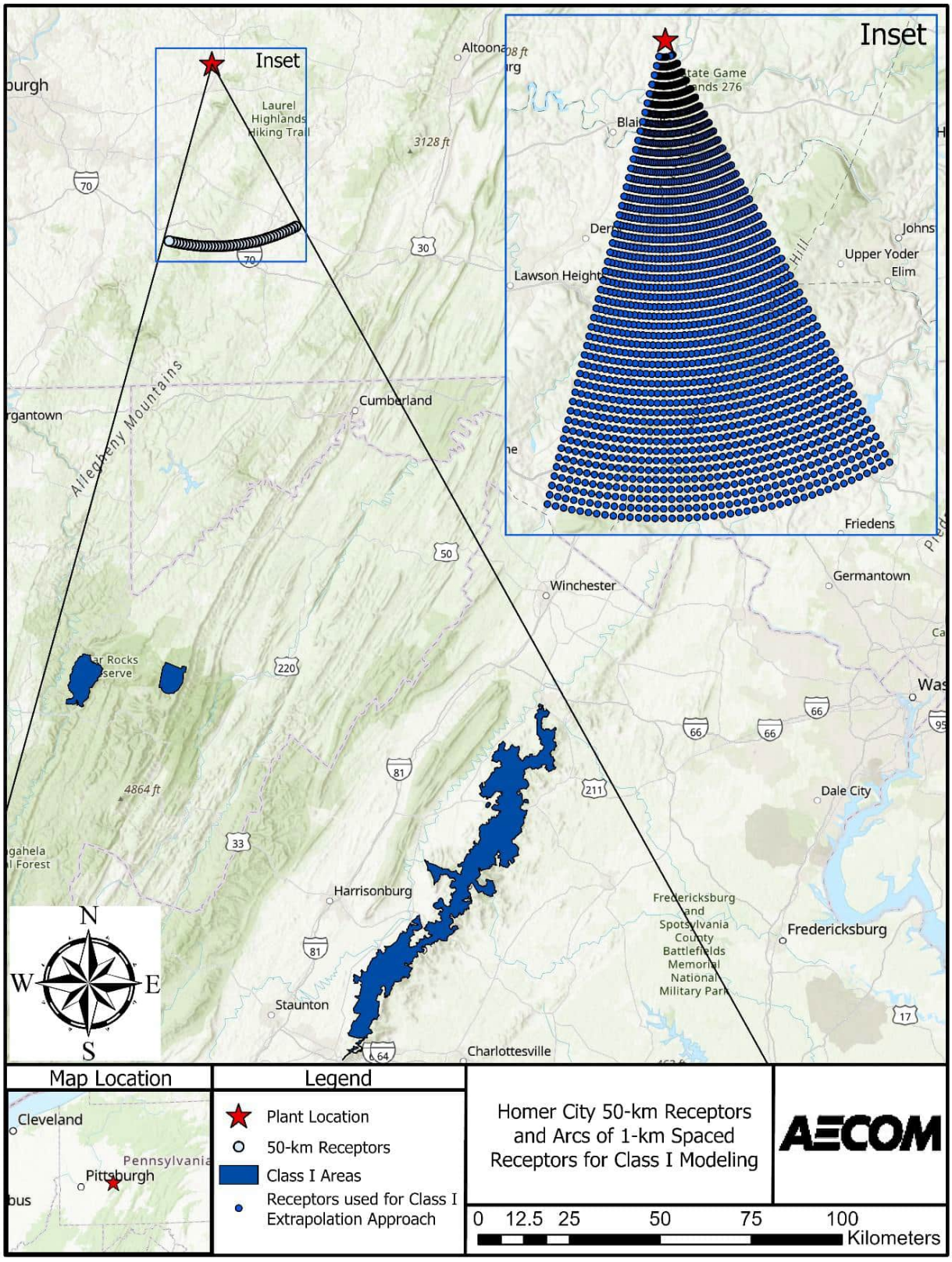


Figure 9-3. Arc-Maximum Concentration of 24-hour PM_{10} by Distance from Project (Base Case)

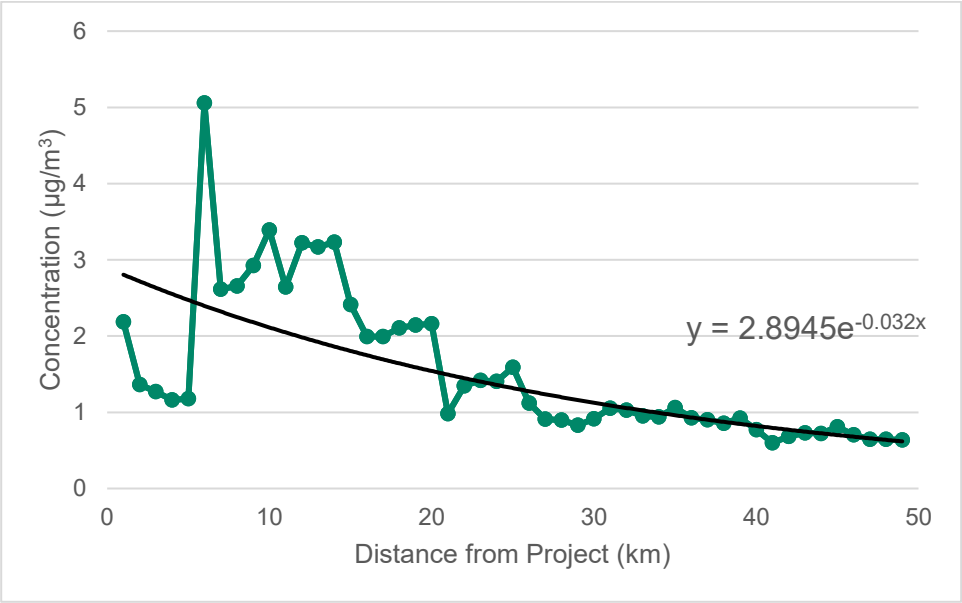
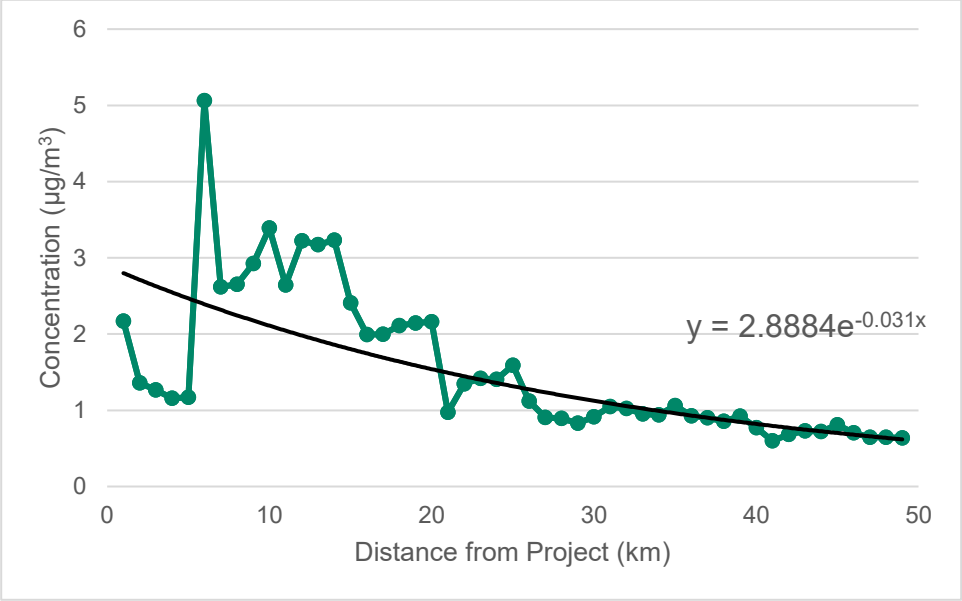


Figure 9-4. Arc-Maximum Concentration of 24-hour $PM_{2.5}$ by Distance from Project (Base Case)



9.2 Soils and Vegetation

The PSD regulations require an evaluation of the impact of Project emissions on soils and vegetation.

An analysis of the Project's potential impact on soils and vegetation in the vicinity of the facility was performed by comparing the maximum modeled impacts from the Project to the screening concentrations provided in US EPA's "A Screening Procedure for the impacts of Air Pollution Sources on Plants, Soils, and Animals" (December 12, 1980) as well as secondary NAAQS. Secondary NAAQS have been designed by US EPA to better protect public welfare against adverse effects caused by criteria air pollutants – including ecological effects such as damage to aquatic and terrestrial ecosystems. In addition, a comparison of Project modeled concentrations associated with non-criteria

pollutants for which there are Project emissions and ambient air screening concentrations in Table 5-3 of US EPA 1980 guidance, was performed. Specifically, Project modeled concentrations of beryllium and lead were estimated with AERMOD using the same methodologies described in **Section 6**. The highest modeled concentrations were compared to the AQRV screening concentrations summarized in **Table 9-4**.

The US EPA screening guidance does not include any values for PM_{10} or $PM_{2.5}$. As such, the highest modeled concentration from the Project used in the SIL analysis were compared to the secondary NAAQS, which are summarized in **Table 9-4**, to demonstrate the Project will not have an adverse impact on soils and vegetation.

Additional since the Project does not trigger PSD review for SO_2 and NO_X and has a net Project decrease of those pollutants, a soil buffering capacity associated with acid deposition was not performed.

The results of the Project's impact on soil and vegetation are shown in **Table 9-5**. As shown in **Table 9-5**, modeled concentrations are all well below applicable screening thresholds.

Table 9-4. Secondary NAAQS Values and 1980 AQRV Screening Concentration

Pollutants	Secondary NAAQS (µg/m^3)
PM_{10}	150 (24 hour)
$PM_{2.5}$	35 (24-hour) and 15 (annual)
Pollutants	**AQRV Screening Concentration (µg/m^3)**
Beryllium	0.01 (month)
Lead	1.5 (3-month)

Table 9-5. Comparison of Modeled to Secondary NAAQS and 1980 AQRV Screening Concentration

Pollutant	Averaging Period	Maximum Modeled Concentration (µg/m^3)	Secondary NAAQS (µg/m^3)	Exceeds Secondary NAAQA? (Yes or No)
PM_{10}	24-hour	6.84	150	No
$PM_{2.5}$	24-hour	5.00	35	No
	Annual	0.37	15	No
Pollutant	**Averaging Period**	**Maximum Modeled Concentration (µg/m^3)**	**AQRV Screening Concentration (µg/m^3)**	**Exceeds AQRV Screen Concentration (µg/m^3)**
Beryllium[1]	1 Month	1.8E-06	0.01	No
Lead[1]	3-Month	0.00015[2]	1.5	No

(1) Base case stack parameters were used for modeling
(2) Conservatively modeled lead concentration using 1 month averaging period since AERMOD does not have a 3-month averaging period option

9.3 Growth-Related Impacts

A growth analysis examines the potential emissions from secondary sources associated with the Project. While these activities are not directly involved in Project operation, the emissions involve those that can reasonably be expected to occur; for instance, industrial, commercial, and residential growth that will occur in the Project area due to the Project itself.

Secondary emissions are those emissions which, although associated with a source, are not emitted from the source itself. Secondary emissions occur from any facility that is not a part of the source being reviewed, but which would not be constructed or increase its emissions except as a result of the construction or operation of the major stationary source or major modification. *However, they would not include sources that do not impact the same general area as the source under review, and they should not include the effects of projects separate in time or place because mere foreseeability or but-for causation is insufficient to establish a reasonable causal chain.* Secondary emissions do not include any emissions from any off-site facility which would be constructed or increase its emissions for some reason other than the construction or operation of the major stationary source or major modification. Secondary emissions, also, do not include any emissions which come directly from a mobile source, such as emissions from the tailpipe of any on-road motor vehicle or the propulsion of a train (US EPA 1990). They also do not include sources that do not impact the same general area as the source under review.

The work force expected for the Project will be mostly made up of individuals that already live in the region. For any new personnel moving to the area, no new housing requirements are expected. Further, due to the small number of new individuals expected to move into the area to support the Project and existence of some commercial activity in the area, new commercial construction will not be necessary to support the Project's permanent. workforce.

Although secondary emissions are excluded from the potential emission estimates used for applicability determinations, they must be considered in PSD analyses if PSD review is required. In order to be considered, however, secondary emissions must be specific, well-defined, quantifiable, and impact the same general area as the stationary source or modification undergoing review.

There is the potential for additional emissions in the area as the Project will provide some power to new data centers in the region. However, these projects have not been identified/developed relative to their (1) technology (which would impact potential emission profiles) nor (2) location (which would determine if the potential emissions could impact the same area).

Since these projects are not well-defined nor quantifiable, growth expectations are unknown.

9.4 Visibility Impairment

The PSD regulations require an evaluation of the impact of the Project emissions on visibility. The primary pollutants responsible for visibility impairment are particulates, SO_2, and NO_x; however, since NO_x emissions from the Project are net negative, this analysis focuses primarily on SO_2 and PM. A visibility analysis was conducted with US EPA's VISCREEN model for Yellow Creek State Park in Pennsylvania, approximately 13.67 km to the northeast of the Project site and the nearest state park to the Project site.

The analysis was conducted in accordance with US EPA's Workbook for Plume Visual Impacts Screening and Analysis (Revised) ("Workbook"; US EPA, 1992). The VISCREEN model was applied to estimate two visual impact parameters, plume perceptibility (ΔE) and plume contrast (C_p). Screening-level guidance indicates that values above 2.0 for ΔE and +/- 0.05 for C_p are considered perceptible.

The VISCREEN model Workbook offers two levels of analysis. Level 1 screening analysis is the most simplified and conservative approach, employing worst-case default meteorological data without accounting for any site-specific conditions. The Level 2 analysis allows refinement of meteorological conditions as well as site-specific conditions such as complex terrain. Initially, the Level 1 analysis was conducted and indicated ΔE and C_p values were above the screening thresholds. Therefore, a Level 2 analysis was conducted.

The Level 2 analysis was conducted with five years of surface observations from John Murtha Johnstown-Cambria County Airport (KJST) and upper air data from Pittsburgh International Airport (KPIT).

The source data required by VISCREEN are PM_{10} emissions (842.23 – 165.73 = 676.50 lb/hr), and primary H_2SO_4 (165.73 lb/hr) for the Project (refer to **Table 3-7** for total Project emissions for PM_{10} and H_2SO_4). Note the PM_{10}

emission have been adjusted as to not double the H_2SO_4 as condensable particulate and primary sulfuric acid emissions. These emissions represent worst case emission rates.

The wind direction sector that would transport emissions from the Project site toward Yellow Creek State Park, along with the closest distance from the park to the Project site, are shown in **Table 9-6**. The wind direction sector is consistent with Workbook guidance that is +/- 11.25° to the left and right of the centerline of view from Project to state park. The location of Yellow Creek State Park relative to the Project site is shown in **Figure 9-5**.

Table 9-6. VISCREEN Level 2 Input Data

22.5º Wind Sector	Closest Distance to the Source (km)	Furthest Distance from the Source (km)	Level 2 Worst Case Stability Class	Level 2 Worst Case Wind Speed (m/s)
52.75 – 75.25	13.71 km	18.30	D	3

Based on this information, and the five years of meteorological data, a table of joint frequency of occurrence of wind speed, wind direction, and stability class was developed as outlined in the Workbook. The dispersion conditions, defined by wind speed and stability class, were ranked by evaluating the product of σ_y, σ_z, and u, where σ_y and σ_z are the Pasquill-Gifford horizontal and vertical diffusion coefficients for the given stability class and downwind distance and u is the wind speed. The dispersion conditions were then ranked in ascending order according to the value of $\sigma_y\sigma_z u$ as shown in **Table 9-7**.

According to the Workbook, VISCREEN is to be applied with the worst-case meteorological conditions that have a $\sigma_y\sigma_z u$ product with a cumulative probability of one percent. That is, the dispersion condition is selected such that the sum of all frequencies of occurrence of conditions worse than this condition totals one percent. Note that as recommended by the Workbook, dispersion conditions that result in greater than 12 hours of plume transport time are discounted from the analysis, since it is unlikely that steady-state plume conditions would persist for more than 12 hours.

Table 9-7. Dispersion Condition Frequency Analysis

Dispersion Condition		$\sigma_y\sigma_z u$	Transport Time	Frequency by Time of Day (%)				Cumulative Frequency by Time of Day (%)			
Stability Class	Wind Speed (m/s)	(m^3/s)	(hours)	0-6	6-12	12-18	18-24	0-6	6-12	12-18	18-24
F	1	18892	8	0.018	0.000	0.000	0.009	0.018	0.000	0.000	0.009
F	2	37784	3	0.758	0.082	0.073	0.666	0.776	0.082	0.073	0.675
E	1	49164	8	0.000	0.000	0.000	0.000	0.776	0.082	0.073	0.675
F	3	56675	2	0.000	0.000	0.000	0.000	0.776	0.082	0.073	0.675
E	2	98327	3	0.173	0.018	0.018	0.228	0.949	0.100	0.091	0.904
D	1	115544	8	0.000	0.000	0.000	0.000	0.949	0.100	0.091	0.904
E	3	147491	2	3.112	0.319	0.137	2.601	4.062	0.420	0.228	3.505
E	4	196654	1	2.127	0.283	0.246	1.789	6.188	0.703	0.475	5.294
D	2	231087	3	0.000	0.018	0.009	0.009	6.188	0.721	0.484	5.303
E	5	245818	1	0.000	0.000	0.000	0.000	6.188	0.721	0.484	5.303
D	**3**	**346631**	**2**	**0.000**	**0.475**	**0.146**	**0.055**	**6.188**	**1.196**	**0.630**	**5.358**
D	4	462174	1	0.520	0.812	0.493	0.484	6.709	2.008	1.123	5.842
D	5	577718	1	1.698	1.287	1.223	1.689	8.406	3.295	2.346	7.530
D	6	693262	1	1.305	1.442	1.433	0.922	9.712	4.737	3.779	8.452

D	7	808805	1	1.041	1.050	1.524	1.041	10.752	5.787	5.303	9.493
D	8	924349	1	0.639	1.114	0.977	0.593	11.391	6.900	6.280	10.086

Notes: Bold denotes row when cumulative frequency exceeds 1.0 for daytime hours (6am – 6pm).

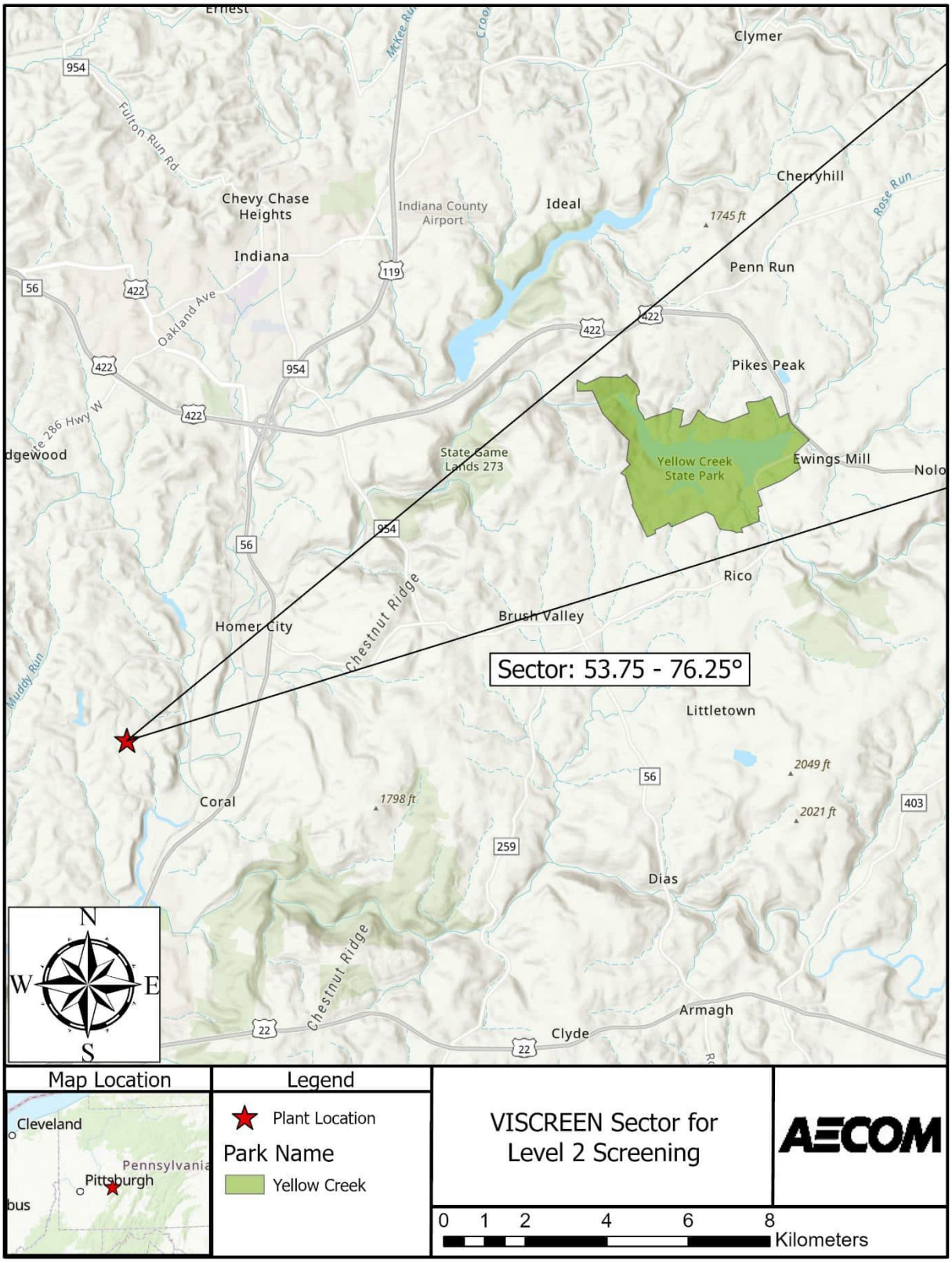
According to **Table 9-7**, the worst-case daylight (6 am – 6 pm) dispersion conditions with cumulative frequency of 1 percent are D stability, 3 m/sec. Therefore, VISCREEN was applied with D stability and a wind speed of 3 m/sec. As recommended by the Workbook, a visual range of 25 kilometers was used (see Figure 9 of the Workbook). The VISCREEN results are summarized in **Table 9-8** using maximum emissions during normal operations. VISCREEN provides results of ΔE and C_p for both sky and terrain backgrounds. The results are below the significance criteria for both sky and terrain above background for both ΔE and Cρ) for all view angles. Therefore, the plume is expected to be imperceptible against background sky and terrain.

Table 9-8. VISCREEN Results Inside Class I Area

Background	Theta[1]	Azimuth	Distance	Alpha	ΔE		Contrast (Cρ)	
					Criteria	**Plume**	Criteria	**Plume**
SKY	10	140	18.3	29	2.00	0.783	0.05	0.012
SKY	140	140	18.3	29	2.00	0.156	0.05	-0.008[2]
TERRAIN	10	84	13.7	84	2.00	1.794	0.05	0.019
TERRAIN	140	84	13.7	84	2.00	0.327	0.05	0.011

1. VISCREEN results are provided for the two VISCREEN default worst-case theta angles. The two theta angles represent the sun being in front of the observer (theta = 10 degrees) and behind the observer (theta = 140 degrees).
2. A negative C_p means the plume has a darker contrast than the background sky.

Figure 9-5. VISCREEN Level II Analysis Wind Sector



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Appendix A : Application Forms

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
CENTER FOR ENVIRONMENTAL EXCELLENCE

GENERAL INFORMATION FORM – AUTHORIZATION APPLICATION

Before completing this General Information Form (GIF), read the step-by-step instructions provided in this application package. This form is used by the Department of Environmental Protection (DEP) to inform our programs regarding what other DEP permits or authorizations may be needed for the proposed project or activity. This version of the General Information Form (GIF) must be completed and returned with any program-specific application being submitted to the DEP.

Related ID#s (If Known)				DEP USE ONLY
Client ID#	298406	**APS ID#**		Date Received & General Notes
Site ID#	236714	**Auth ID#**		
Facility ID#	262713			

CLIENT INFORMATION

DEP Client ID#	Client Type/Code	Dun & Bradstreet ID#
298406	Partnership-Limited	

Legal Organization Name or Registered Fictitious Name	Employer ID# (EIN)	Is the EIN a SSN?
Homer City Generation, L.P.	80-0833693	☐ Yes ☒ No

State of Incorporation or Registration of Fictious Name

☐ Corporation ☒ LLC ☐ Partnership ☐ LLP ☐ LP
☐ Sole Proprietorship ☐ Association/Organization
☐ Estate/Trust ☐ Other

Individual Last Name	First Name	MI	Suffix
Levesque	Michael		

Additional Individual Last Name	First Name	MI	Suffix

Mailing Address Line 1	Mailing Address Line 2
1750 Power Plant Rd	

Address Last Line – City	State	ZIP+4	Country
Homer City	PA	15748-8009	USA

Client Contact Last Name	First Name	MI	Suffix
Wroten	Mark		

Client Contact Title	Phone	Ext	Cell Phone
Deputy Chief Operating Officer	870-559-6000		

Email Address	FAX
mwroten@homercityredevelopment.com	

SITE INFORMATION

DEP Site ID#	Site Name
236714	Homer City Generation, L.P.

EPA ID# **Estimated Number of Employees to be Present at Site**

Description of Site

Tax Parcel ID(s):

County Name(s)	Municipality(ies)	City	Boro	Twp	State
Indiana	Center	☐	☐	☒	PA
		☐	☐	☐	
		☐	☐	☐	

☐	☐	☐

Site Location Line 1	Site Location Line 2
1750 Power Plant Rd	

Site Location Last Line – City	State	ZIP+4
Homer City	PA	15748-8009

Detailed Written Directions to Site

From Pittsburgh, head east on I-376 and US-22. Turn right on Villa Rd. and left onto Old US Hwy 22. Merge onto US-119 N and follow for 4.6 miles. Turn left onto Power Plant Rd.

Site Contact Last Name	First Name	MI	Suffix
Wroten	Mark		

Site Contact Title	Site Contact Firm
Deputy Chief Operating Officer	

Mailing Address Line 1	Mailing Address Line 2
1750 Power Plant Road	

Mailing Address Last Line – City	State	ZIP+4
Homer City	PA	15748-8009

Phone	Ext	FAX	Email Address
870-559-6000			mwroten@homercityredevelopment.com

NAICS Codes (Two- & Three-Digit Codes – List All That Apply)	6-Digit Code (Optional)
22	221112

Client to Site Relationship

Deputy Chief Operating Officer

FACILITY INFORMATION

Modification of Existing Facility	Yes	No
1. Will this project modify an existing facility, system, or activity?	☒	☐
2. Will this project involve an addition to an existing facility, system, or activity?	☐	☒

If "Yes", check all relevant facility types and provide DEP facility identification numbers below.

	Facility Type	DEP Fac ID#		Facility Type	DEP Fac ID#
☐	Air Emission Plant		☐	Industrial Minerals Mining Operation	
☐	Beneficial Use (water)		☐	Laboratory Location	
☐	Blasting Operation		☐	Land Recycling Cleanup Location	
☐	Captive Hazardous Waste Operation		☐	Mine Drainage Treatment / Land Recycling Project Location	
☐	Coal Ash Beneficial Use Operation		☐	Municipal Waste Operation	
☐	Coal Mining Operation		☐	Oil & Gas Encroachment Location	
☐	Coal Pillar Location		☐	Oil & Gas Location	
☐	Commercial Hazardous Waste Operation		☐	Oil & Gas Water Poll Control Facility	
☐	Dam Location		☐	Public Water Supply System	
☐	Deep Mine Safety Operation -Anthracite		☐	Radiation Facility	
☐	Deep Mine Safety Operation -Bituminous		☐	Residual Waste Operation	
☐	Deep Mine Safety Operation -Ind Minerals		☐	Storage Tank Location	
☐	Encroachment Location (water, wetland)		☐	Water Pollution Control Facility	
☐	Erosion & Sediment Control Facility		☐	Water Resource	
☐	Explosive Storage Location		☐	Other:	

Latitude/Longitude Point of Origin	Latitude			Longitude		
	Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
0/0	40	31	25	-79	11	**47**

Horizontal Accuracy Measure	Feet	*--or--*	Meters	
Horizontal Reference Datum Code	☐	North American Datum of 1927		
	☒	North American Datum of 1983		
	☐	World Geodetic System of 1984		
Horizontal Collection Method Code				
Reference Point Code				
Altitude	Feet	*--or--*	Meters	
Altitude Datum Name	☐	The National Geodetic Vertical Datum of 1929		
	☐	The North American Vertical Datum of 1988 (NAVD88)		
Altitude (Vertical) Location Datum Collection Method Code				
Geometric Type Code				
Data Collection Date				
Source Map Scale Number		Inch(es)	=	Feet
	--or--	Centimeter(s)	=	Meters

PROJECT INFORMATION

Project Name

Homer City Generation

Project Description

Redevelopment of the former Homer City Generating Station. See, Application narrative.

Project Consultant Last Name	First Name	MI	Suffix
Connors	Jeff		

Project Consultant Title	Consulting Firm
Supervisor, Air Quality Services (East)	AECOM Technical Services, Inc.

Mailing Address Line 1	Mailing Address Line 2
250 Apollo Drive	

Address Last Line – City	State	ZIP+4
Chelmsford	MA	01824-3627

Phone	Ext	FAX	Email Address
978-905-2166			jeffrey.connors@aecom.com

Time Schedules	Project Milestone (Optional)
After Plan Approval issuance	Start of Construction
Third quarter 2029	Anticipated conclusion of construction activities
Fourth quarter 2029	Anticipated startup of all project sources

1. Is the project located in or within a 0.5-**mile radius of an Environmental Justice community as defined by DEP?** ☒ Yes ☐ No

To determine if the project is located in or within a 0.5-mile radius of an environmental justice community, please use the online PennEnviroScreen tool. To see specific EJ areas, select the appropriate year of your submittal from the themes box on the right.

2. Have you informed the surrounding community prior to submitting the application to the Department? ☒ Yes ☐ No

Method of notification: Local meetings and press release

3. **Have you addressed community concerns that were identified?** ☐ Yes ☐ No ☒ N/A

If no, please briefly describe the community concerns that have been expressed and not addressed.

4. **Is your project funded by state or federal grants?** ☐ Yes ☒ No

Note: If "Yes", specify what aspect of the project is related to the grant and provide the grant source, contact person and grant expiration date.

Aspect of Project Related to Grant

Grant Source: _____

Grant Contact Person: _____

Grant Expiration Date: _____

5. **Is this application for an authorization on Appendix A of the Land Use Policy? (For referenced list, see Appendix A of the Land Use Policy attached to GIF instructions)** ☒ Yes ☐ No

Note: If "No" to Question 5, the application is not subject to the Land Use Policy.

If "Yes" to Question 5, the application is subject to this policy and the Applicant should answer the additional questions in the **Land Use Information** section.

LAND USE INFORMATION

Note: Applicants should submit copies of local land use approvals or other evidence of compliance with local comprehensive plans and zoning ordinances.

1. **Is there an adopted county or multi-county comprehensive plan?** ☒ Yes ☐ No

2. **Is there a county stormwater management plan?** ☒ Yes ☐ No

3. **Is there an adopted municipal or multi-municipal comprehensive plan?** ☒ Yes ☐ No

4. **Is there an adopted county-wide zoning ordinance, municipal zoning ordinance or joint municipal zoning ordinance?** ☒ Yes ☐ No

Note: If the Applicant answers "No" to either Questions 1, 3 or 4, the provisions of the PA MPC are not applicable, and the Applicant does not need to respond to questions 5 and 6 below.

If the Applicant answers "Yes" to questions 1, 3 and 4, the Applicant should respond to questions 5 and 6 below.

5. **Does the proposed project meet the provisions of the zoning ordinance or does the proposed project have zoning approval?** If zoning approval has been received, attach documentation. ☒ Yes ☐ No

6. **Have you attached Municipal and County Land Use Letters for the project?** ☒ Yes ☐ No

COORDINATION INFORMATION

Note: The PA Historical and Museum Commission must be notified of proposed projects in accordance with DEP Technical Guidance Document 012-0700-001 at PHMC's online portal, PA-SHARE.

If the activity will be a mining project (i.e., mining of coal or industrial minerals, coal refuse disposal and/or the operation of a coal or industrial minerals preparation/processing facility), respond to questions 1.0 through 2.5 below.

If the activity will not be a mining project, skip questions 1.0 through 2.5 and begin with question 3.0.

1.0	**Is this a coal mining project?** If "Yes", respond to 1.1-1.6. If "No", skip to Question 2.0.	☐	Yes	☒	No
1.1	**Will this coal mining project involve coal preparation/ processing activities in which the total amount of coal prepared/processed will be equal to or greater than 200 tons/day?**	☐	Yes	☐	No
1.2	**Will this coal mining project involve coal preparation/ processing activities in which the total amount of coal prepared/processed will be greater than 50,000 tons/year?**	☐	Yes	☐	No
1.3	**Will this coal mining project involve coal preparation/ processing activities in which thermal coal dryers or pneumatic coal cleaners will be used?**	☐	Yes	☐	No
1.4	**For this coal mining project, will sewage treatment facilities be constructed and treated waste water discharged to surface waters?**	☐	Yes	☐	No
1.5	**Will this coal mining project involve the construction of a permanent impoundment meeting one or more of the following criteria: (1) a contributory drainage area exceeding 100 acres; (2) a depth of water measured by the upstream toe of the dam at maximum storage elevation exceeding 15 feet; (3) an impounding capacity at maximum storage elevation exceeding 50 acre-feet?**	☐	Yes	☐	No
1.6	**Will this coal mining project involve underground coal mining to be conducted within 500 feet of an oil or gas well?**	☐	Yes	☐	No
2.0	**Is this a non-coal (industrial minerals) mining project?** If "Yes", respond to 2.1-2.6. If "No", skip to Question 3.0.	☐	Yes	☒	No
2.1	**Will this non-coal (industrial minerals) mining project involve the crushing and screening of non-coal minerals other than sand and gravel?**	☐	Yes	☐	No
2.2	**Will this non-coal (industrial minerals) mining project involve the crushing and/or screening of sand and gravel with the exception of wet sand and gravel operations (screening only) and dry sand and gravel operations with a capacity of less than 150 tons/hour of unconsolidated materials?**	☐	Yes	☐	No
2.3	**Will this non-coal (industrial minerals) mining project involve the construction, operation and/or modification of a portable non-metallic (i.e., non-coal) minerals processing plant under the authority of the General Permit for Portable Non-metallic Mineral Processing Plants (i.e., BAQ-PGPA/GP-3)?**	☐	Yes	☐	No
2.4	**For this non-coal (industrial minerals) mining project, will sewage treatment facilities be constructed and treated waste water discharged to surface waters?**	☐	Yes	☐	No

2.5	**Will this non-coal (industrial minerals) mining project involve the construction of a permanent impoundment meeting one or more of the following criteria: (1) a contributory drainage area exceeding 100 acres; (2) a depth of water measured by the upstream toe of the dam at maximum storage elevation exceeding 15 feet; (3) an impounding capacity at maximum storage elevation exceeding 50 acre-feet?**	☐ Yes	☐ No
3.0	**Will your project, activity, or authorization have anything to do with a well related to oil or gas production, have construction within 200 feet of, affect an oil or gas well, involve the waste from such a well, or string power lines above an oil or gas well?** If "Yes", respond to 3.1-3.3. If "No", skip to Question 4.0.	☐ Yes	☒ No
3.1	**Does the oil- or gas-related project involve any of the following: placement of fill, excavation within or placement of a structure, located in, along, across or projecting into a watercourse, floodway or body of water (including wetlands)?**	☐ Yes	☐ No
3.2	**Will the oil- or gas-related project involve discharge of industrial wastewater or stormwater to a dry swale, surface water, ground water or an existing sanitary sewer system or storm water system?** If "Yes", discuss in *Project Description*.	☐ Yes	☐ No
3.3	**Will the oil- or gas-related project involve the construction and operation of industrial waste treatment facilities?**	☐ Yes	☐ No
4.0	**Will the project involve a construction activity that results in earth disturbance?** If "Yes", specify the total disturbed acreage.	☒ Yes	☐ No
	4.0.1 Total Disturbed Acreage +1 acre TBD		
	4.0.2 Will the project discharge or drain to a special protection water (EV or HQ) or an EV wetland?	☐ Yes	☒ No
	4.0.3 Will the project involve a construction activity that results in earth disturbance in the area of the earth disturbance that are contaminated at levels exceeding residential or non-residential medium-specific concentrations (MSCs) in 25 Pa. Code Chapter 250 at residential or non-residential construction sites, respectively?	☐ Yes	☐ No
5.0	**Does the project involve any of the following: water obstruction and/or encroachment, wetland impacts, or floodplain project by the Commonwealth/political subdivision or public utility?** If "Yes", respond to 5.1-5.7. If "No", skip to Question 6.0.	☐ Yes	☒ No
5.1	**Water Obstruction and Encroachment Projects – Does the project involve any of the following: placement of fill, excavation within or placement of a structure, located in, along, across or projecting into a watercourse, floodway or body of water?**	☐ Yes	☐ No
5.2	**Wetland Impacts – Does the project involve any of the following: placement of fill, excavation within or placement of a structure, located in, along, across or projecting into a wetland?**	☐ Yes	☐ No

5.3	**Floodplain Projects by the Commonwealth, a Political Subdivision of the Commonwealth or a Public Utility – Does the project involve any of the following: placement of fill, excavation within or placement of a structure, located in, along, across or projecting into a floodplain?**	☐ Yes	☐ No
5.4	**Is your project an interstate transmission natural gas pipeline?**	☐ Yes	☒ No
5.5	**Does your project consist of linear construction activities which result in earth disturbance in two or more DEP regions AND three or more counties?**	☐ Yes	☒ No
5.6	**Does your project utilize Floodplain Restoration as a best management practice for Post Construction Stormwater Management?**	☐ Yes	☐ No
5.7	**Does your project utilize Class V Gravity / Injection Wells as a best management practice for Post Construction Stormwater Management?**	☐ Yes	☐ No
6.0	**Will the project involve discharge of construction related stormwater to a dry swale, surface water, ground water or separate storm water system?**	☒ Yes	☐ No
6.1	**Will the project involve discharge of industrial waste stormwater or wastewater from an industrial activity or sewage to a dry swale, surface water, ground water or an existing sanitary sewer system or separate storm water system?**	☐ Yes	☒ No
7.0	**Will the project involve the construction and operation of industrial waste treatment facilities?**	☐ Yes	☒ No
8.0	**Will the project involve construction of sewage treatment facilities, sanitary sewers, or sewage pumping stations?** If "Yes", indicate estimated proposed flow (gal/day). Also, discuss the sanitary sewer pipe sizes and the number of pumping stations/treatment facilities/name of downstream sewage facilities in the *Project Description*, where applicable.	☐ Yes	☒ No
	8.0.1 Estimated Proposed Flow (gal/day)		
9.0	**Will the project involve the subdivision of land, or the generation of 800 gpd or more of sewage on an existing parcel of land or the generation of an additional 400 gpd of sewage on an already-developed parcel, or the generation of 800 gpd or more of industrial wastewater that would be discharged to an existing sanitary sewer system?**	☐ Yes	☒ No
	9.0.1 Was Act 537 sewage facilities planning submitted and approved by DEP? If "Yes" attach the approval letter. Approval required prior to 105/NPDES approval.	☐ Yes	☐ No
10.0	**Is this project for the beneficial use of biosolids for land application within Pennsylvania?** If "Yes" indicate how much (i.e. gallons or dry tons per year).	☐ Yes	☒ No
	10.0.1 Gallons Per Year (residential septage)		
	10.0.2 Dry Tons Per Year (biosolids)		

11.0	**Does the project involve construction, modification or removal of a dam?** If "Yes", identify the dam.	☒ Yes	☐ No
11.0.1	**Dam Name** Lake Bruce		
12.0	**Will the project interfere with the flow from, or otherwise impact, a dam?** If "Yes", identify the dam.	☐ Yes	☒ No
12.0.1	**Dam Name**		
13.0	**Will the project involve operations (excluding during the construction period) that produce air emissions (i.e., NOX, VOC, etc.)?**	☒ Yes	☐ No
13.0.1	If "Yes", is the operation subject to the agricultural exemption in 35 P.S. § 4004.1?	☐ Yes	☒ No
13.0.2	If the answer to 13.0.1 is "No", identify each type of emission followed by the estimated amount of that emission.		
	Enter all types & amounts of emissions; separate each set with semicolons. See Emissions Calculations in Appendix C		
14.0	**Does the project include the construction or modification of a drinking water supply to serve 15 or more connections or 25 or more people, at least 60 days out of the year?** If "Yes," check all proposed sub-facilities.	☐ Yes	☒ No
14.0.1	**Number of Persons Served**		
14.0.2	**Number of Employee/Guests**		
14.0.3	**Number of Connections**		
14.0.4	**Sub-Fac: Distribution System**	☐ Yes	☐ No
14.0.5	**Sub-Fac: Water Treatment Plant**	☐ Yes	☐ No
14.0.6	**Sub-Fac: Source**	☐ Yes	☐ No
14.0.7	**Sub-Fac: Pump Station**	☐ Yes	☐ No
14.0.8	**Sub-Fac: Transmission Main**	☐ Yes	☐ No
14.0.9	**Sub-Fac: Storage Facility**	☐ Yes	☐ No
15.0	**Will your project include infiltration of storm water or waste water to ground water within one-half mile of a public water supply well, spring or infiltration gallery?**	☐ Yes	☒ No
16.0	**Is your project to be served by an existing public water supply?** If "Yes", indicate name of supplier and attach letter from supplier stating that it will serve the project.	☒ Yes	☐ No
16.0.1	**Supplier's Name** Homer City Water Authority		
16.0.2	**Letter of Approval from Supplier is Attached**	☐ Yes	☒ No
17.0	**Will this project be served by on-lot drinking water wells?**	☐ Yes	☒ No
18.0	**Will this project involve a new or increased drinking water withdrawal from a river, stream, spring, lake, well or other water bod(ies)?** If "Yes," reference Safe Drinking Water Program.	☐ Yes	☒ No
18.0.1	**Source Name**		

19.0	**Will the construction or operation of this project involve treatment, storage, reuse, or disposal of waste?** If "Yes," indicate what type (i.e., hazardous, municipal (including infectious & chemotherapeutic), residual) and the amount to be treated, stored, re-used or disposed. **19.0.1 Type & Amount**	☐ Yes	☒ No
20.0	**Will your project involve the removal of coal, minerals, contaminated media, or solid waste as part of any earth disturbance activities?**	☐ Yes	☒ No
21.0	**Does your project involve installation of a field constructed underground storage tank?** If "Yes," list each Substance & its Capacity. **Note:** Applicant may need a Storage Tank Site Specific Installation Permit. **21.0.1 Enter all substances & capacity of each; separate each set with semicolons.**	☐ Yes	☒ No
22.0	**Does your project involve installation of an aboveground storage tank greater than 21,000 gallons capacity at an existing facility?** If "Yes," list each Substance & its Capacity. **Note:** Applicant may need a Storage Tank Site Specific Installation Permit. **22.0.1 Enter all substances & capacity of each; separate each set with semicolons.** 19% aqueous ammonia, 9 tanks 35,000 gallons each	☒ Yes	☐ No
23.0	**Does your project involve installation of a tank greater than 1,100 gallons which will contain a highly hazardous substance as defined in DEP's Regulated Substances List, 2570-BK-DEP2724?** If "Yes," list each Substance & its Capacity. **Note:** Applicant may need a Storage Tank Site Specific Installation Permit. **23.0.1 Enter all substances & capacity of each; separate each set with semicolons.**	☐ Yes	☒ No
24.0	**Does your project involve installation of a storage tank at a new facility with a total AST capacity greater than 21,000 gallons?** If "Yes", list each Substance & its Capacity. **Note:** Applicant may need a Storage Tank Site Specific Installation Permit. **24.0.1 Enter all substances & capacity of each; separate each set with semicolons.**	☐ Yes	☒ No
	NOTE: If the project includes the installation of a regulated storage tank system, including diesel emergency generator systems, the project may require the use of a Department Certified Tank Handler. For a full list of regulated storage tanks and substances, please go to www.dep.pa.gov search term storage tanks		
25.0	**Will the intended activity involve the use of a radiation source?**	☐ Yes	☒ No

CERTIFICATION

I certify that I have the authority to submit this application on behalf of the applicant named herein and that the information provided in this application is true and correct to the best of my knowledge and information.

For applicants supplying an EIN number: I am applying for a permit or authorization from the Pennsylvania Department of Environmental Protection (DEP). As part of this application, I will provide DEP with an accurate EIN number for the applicant entity. By filing this application with DEP, I hereby authorize DEP to confirm the accuracy of the EIN number provided with the Pennsylvania Department of Revenue. As applicant, I further consent to the Department of Revenue discussing the same with DEP prior to issuance of the Commonwealth permit or authorization.

Type or Print Name	Michael J. Levesque	
Michael Levesque	Chief Operating Officer	4/1/25
Signature	**Title**	**Date**

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
CENTER FOR ENVIRONMENTAL EXCELLENCE

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

AIR QUALITY FEES FOR NEW PLAN APPROVAL

Company Information	
Federal Tax ID: 80-0833693	Firm Name: Homer City Generating, L.P.
Permit # (If any):	Facility Name: Homer City Generating
Municipality: Center Township	County: Indiana
Contact Person Name: Mark Wroten	Telephone Number: 870.559.6000
E-mail: mwroten@homercityredevelopment.com	

New Plan Approval (The following fees are cumulative.)

Line #	Check the appropriate boxes below	Type of review requested	Fee 2021 - 2025	Total Fees
1	Base Fee	Subchapter B	$2,500	$2,500
2	☒	New Source Review, Subchapter E	$7,500	7,500
3	☒	NSPS/NESHAP /MACT standard A. # of NSPS: 5 B. # of NESHAP/MACT: 4 C. Add lines A and B: 9 D. Maximum applicable standards: 3 E. Enter smaller of line C or line D: 3 Multiply line E by $2,500 and enter the amount in the "Total Fees" column.	$2,500	7,500
4	☐	Case-by-Case MACT	$9,500	
5	☒	Prevention of Significant Deterioration (PSD) requirements. Subchapter D	$32,500	32,500
6	☐	Plantwide Applicability Limit (PAL) for NSR regulated pollutants or PAL for PSD regulated pollutants or both	$7,500	
7	☐	Risk Assessment Analysis – Inhalation only	$10,000	
8	☐	Risk Assessment Analysis – Multi-pathway	$25,000	
Add Lines 1 thru 8 of Total Fees column and write it here. →				50,000

2700-PM-AQ0021 Rev. 6/2004

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Submit in Triplicate

COMBUSTION UNIT

Application for Plan Approval to Construct, Modify or Reactivate an Air Contamination Source and/or Install an Air Cleaning Device

This application and the General Information Form (GIF) must be included in the submittal

Before completing this form, read the instructions provided with this form.

Section A - Facility Name, Checklist And Certification

Organization Name or Registered Fictitious Name/Facility Name: Homer CIty Generation, L.P.

DEP Client ID# (If Known): _____

Type of Review required and Fees:

Source which is not subject to NSPS, NESHAPs, MACT, NSR and PSD: ..... $_____
Source requiring approval under NSPS or NESHAPS or both: ..... $ 7,500
Source requiring approval under NSR: ..... $ 7,500
Source requiring the establishment of a MACT limitation: ..... $_____
Source requiring approval under PSD: ..... $ 32,500

Applicant's Checklist

Check the following list to make sure that all the required documents are included.

- X **General Information Form (GIF)**
- X **Combustion Unit Plan Approval Application**
- X **Compliance Review Form** or provide reference of most recently submitted compliance review form for facilities submitting on a periodic basis: Submitted with February 11, 2025 Title V Modification
- X **Proof of County and Municipal Notifications**
- X **Permit Fees**
- X **Addendum A:** Source Applicable Requirements (only applicable to existing Title V facility)

Certification of Truth, Accuracy and Completeness by a Responsible Official

I, **Michael J. Levesque**, certify under penalty of law in 18 Pa. C. S. A. §4904, and 35 P.S. §4009(b) (2) that based on information and belief formed after reasonable inquiry, the statements and information in this application are true, accurate and complete.

(Signature): Michael Levesque Date: 4/1/25

Name (Print): Michael J. Levesque Title: Chief Operating Officer

OFFICIAL USE ONLY

Application No. _____ Unit ID _____ Site ID _____
DEP Client ID #: _____ APS. ID _____ AUTH. ID _____
Date Received _____ Date Assigned _____ Reviewed By _____
Date of 1st Technical Deficiency _____ Date of 2nd Technical Deficiency _____
Comments: _____

Section D - Additional Information

Will the construction, modification, etc. of the sources covered by this application increase emissions from other sources at the facility? If so, describe and quantify.
The construction of the Project will involve only new sources.

If this project is subject to any one of the following, attach a demonstration to show compliance with applicable standards

a. Prevention of Significant Deterioration permit (PSD), 40 CFR Part 52? ☒ YES ☐ NO

b. New Source Review, 25 Pa. Code Chapter 127, Subchapter E? ☒ YES ☐ NO

c. New Source Performance Standards, 40 CFR Part 60? ☒ YES ☐ NO
(If Yes, which subpart) KKKK, IIII, TTTTa, Dc

d. National Emissions Standards for Hazardous Air Pollutants (NESHAPS), 40 CFR Part 61? ☐ YES ☒ NO
If Yes, which subpart) _____

e. Maximum Achievable Control Technology (MACT), 40 CFR Part 63? ☒ YES ☐ NO
(If Yes, which subpart) YYYY, ZZZZ, DDDDD

Attach a demonstration showing that the emissions from any new source will be the minimum attainable through the use of best available technology (BAT).

See, Application Narrative Section 5.

Provide emission increases and decreases in allowable (or potential) and actual emissions within the last 5 years for applicable PSD pollutant(s) if the facility is an existing major facility (for PSD purposes)

See Application narrative Section 3.2 and 3.3

Section D - Additional Information (Continued)

Indicate emission increases and decreases in tons per year (tpy), for volatile organic compounds (VOCs) and nitrogen oxides (NOx) for NSR applicability since January 1, 1991 or other applicable dates (See other applicable date in instructions). The emissions increases include all emissions including stack, fugitive, material transfer, other emission generating activities, quantifiable emissions from the exempted source(s), etc.

Permit number (if applicable)	Date issued	Indicate ***Yes*** or ***No*** if emission increases and decreases were used previously for netting	Source I.D. or Name	**VOC**s		**NOx**	
				Emission increases in potential to emit (tpy)	Creditable emission decreases in actual emissions (tpy)	Emission increases in potential to emit (tpy)	Creditable emission decreases in actual emissions (tpy)
32-00055	TBD	No	Boiler No. 1, No 2, No 3		11.3		2,031.8

If the source is subject to 25 Pa. Code Chapter 127, Subchapter E, New Source Review requirements,

a. Identify Emission Reduction Credits (ERCs) for emission offsets or demonstrate ability to obtain suitable ERCs for emission offsets. Homer City is currently in the process of identifying and contacting owners of sufficient ERCs for the project

b. Provide a demonstration that the lowest achievable emission rate (LAER) control techniques will be implemented (if applicable). See application text Section 5.

c. Provide an analysis of alternate sites, sizes, production processes and environmental control techniques demonstrating that the benefits of the proposed source outweigh the environmental and social costs (if applicable). See application text Section 4.5.6.2.

Attach calculations and any additional information necessary to thoroughly evaluate compliance with all the applicable requirements of 25 Pa. Code Article III and applicable requirements of the Clean Air Act and regulations adopted there under. The Department may request additional information to evaluate the application such as a stand by plan, a plan for air pollution emergencies, air quality modeling, etc.

See Appendix C for emissions calculations.

Section G - Attachments

Number and list all attachments submitted with this application below:

Application Narrative

Section 1. Introduction
Section 2. Process Description
Section 3. PSD/NNSR Applicability Determination and Emissions Summary
Section 4. Applicable Regulations
Section 5. Control Technology Review
Section 6. Class II Area Air Quality Modeling Analysis Procedures
Section 7. Class II Area Significant Impact Level Analysis Results
Section 8. Class II Area Cumulative Impact Analysis Results
Section 9. Other PSD Requirements
Section 10. References

Appendices

Appendix A Application Forms
Appendix B Plot Plan
Appendix C Emission Calculations
Appendix D Search Results from EPA's RACT/BACT/LAER Clearinghouse
Appendix F Nearby Source Inventory
Appendix G FLM AQRV Waiver
Appendix H Acid Rain Forms
Appendix I Modeling Protocol
Appendix J Vendor Data

AECOM
250 Apollo Drive
Chelmsford, MA 01824
aecom.com

April 1, 2025

Ms. Sarah Smith
Township Secretary
Center Township Municipal Building
1212 Neal Road
Homer City, PA 15748

Subject: Homer City Generating Station Air Plan Approval Application

Dear Ms. Smith,

On behalf of Homer City Generation, LP (Homer City), AECOM is hereby providing notice that Homer City will be submitting an air plan approval application to construct and operate up to seven (7) combined-cycle combustion turbines (CCs) and up to ten (10) simple cycle aeroderivative gas turbines (ADGTs) at the former Homer City Generating Station, located in Indiana County, Pennsylvania. Construction and operation of the new CCs and ADGTs will also include new ancillary equipment such as auxiliary boiler(s), emergency generator(s), emergency fire water pump engine(s), cooling towers, and fuel gas heater(s). This application is being submitted to gain approvals to construct and operate the new project.

Pursuant to Section 1905-A of the Administrative Code of 1929 (71 P.S. §510-5) and 25 Pa. Code §127.413, Homer City is required to provide municipalities with formal notice of this application. The PADEP allows for a 30-day comment period from the date of receipt of this letter. This application may be reviewed at the PADEP's Northwest Regional Office located at 230 Chestnut Street, Meadville, PA 16335. Comments on this application should be submitted to the PADEP's Air Quality Program Manager at that address.

Yours sincerely,

Ian Miller
Senior Air Quality Engineer
AECOM
T: 978-905-2326
E: ian.miller@aecom.com

Jeff Connors
Supervisor, Air Quality Services (East)
AECOM
T: 978-605-2166
E: jeffrey.connors@aecom.com

April 02, 2025

Dear Customer,

The following is the proof-of-delivery for tracking number: 880232813311

Delivery Information:

Status:	Delivered	**Delivered To:**	Shipping/Receiving
Signed for by:	S.Smi	**Delivery Location:**	
Service type:	FedEx Standard Overnight		
Special Handling:	Deliver Weekday		HOMER CITY, PA,
		Delivery date:	Apr 2, 2025 13:16

Shipping Information:

Tracking number:	880232813311	**Ship Date:**	Apr 1, 2025
		Weight:	0.5 LB/0.23 KG

Recipient:	**Shipper:**
HOMER CITY, PA, US,	CHELMSFORD, MA, US,

Reference	60734544
Department Number	07/Ian Miller

Proof-of-delivery details appear below; however, no signature is available for this FedEx Express shipment because a signature was not required.

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AECOM
250 Apollo Drive
Chelmsford, MA 01824
aecom.com

April 1, 2025

Mr. R. Michael Keith, Chairman
Indiana County Board of Commissioners
825 Philadelphia St.
Indiana, PA 15701

Subject: Homer City Generating Station Air Plan Approval Application

Dear Mr. Keith,

On behalf of Homer City Generation, LP (Homer City), AECOM is hereby providing notice that Homer City will be submitting an air plan approval application to construct and operate up to seven (7) combined-cycle combustion turbines (CCs) and up to ten (10) simple cycle aeroderivative gas turbines (ADGTs) at the former Homer City Generating Station, located in Indiana County, Pennsylvania. Construction and operation of the new CCs and ADGTs will also include new ancillary equipment such as auxiliary boiler(s), emergency generator(s), emergency fire water pump engine(s), cooling towers, and fuel gas heater(s). This application is being submitted to gain approvals to construct and operate the new project.

Pursuant to Section 1905-A of the Administrative Code of 1929 (71 P.S. §510-5) and 25 Pa. Code §127.413, Homer City is required to provide municipalities with formal notice of this application. The PADEP allows for a 30-day comment period from the date of receipt of this letter. This application may be reviewed at the PADEP's Northwest Regional Office located at 230 Chestnut Street, Meadville, PA 16335. Comments on this application should be submitted to the PADEP's Air Quality Program Manager at that address.

Yours sincerely,

Ian Miller
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April 02, 2025

Dear Customer,

The following is the proof-of-delivery for tracking number: 880232650160

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1. Combined Cycle Combustion Turbines

- Combustion Unit Form Section B – Combustion Unit Information
- Combustion Unit Form Section C – Air Cleaning Device
- Combustion Unit Form Section F – Flue and Air Contaminant Emission
- Addendum A: Source Applicable Requirements
- Addendum 1: Method of Compliance Worksheets

Section B - Combustion Unit Information

1. Combustion Units: ☐ Coal ☐ Oil ☒ Natural Gas Other: _____

Description: The combined-cycle electric generating unit consists of seven (7) natural gas-fired combustion turbines (CTs) equipped with natural gas-fired duct burners (DBs). This form includes information for the CTs only (DBs are addressed separately).

Manufacturer	Model No.	Number of units
GE Vernova	7HA.02 1x1 MS	7

Maximum heat input (Btu/hr)	Rated heat input (Btu/hr)	Typical heat input (Btu/hr)	Furnace Volume
3,515 MMBtu/hr, each turbine, 1,034.4 MMBtu/hr each DB	3,515 MMBtu/hr, each turbine, 1,034.4 MMBtu/hr each DB	3,434 MMBtu/hr, each turbine, 936.9 MMBtu/hr each DB	

Grate Area (if applicable)	Method of firing
N/A	Premix burners

Indicate how combustion air is supplied to boiler
N/A

Indicate the Steam Usage: N/A

Mark and describe soot Cleaning Method:

i. Air Blown
ii. Steam Blown
iii. Brushed and Vacuumed
iv. Other N/A
v. Frequency of Cleaning _____

Maximum Operating schedule

Hours/Day	Days/Week	Days/Year	Hours/Year
24 (each)	7 (each)	365 (each)	8,760 (each)

Operational restrictions taken or requested, if any (e.g., bottlenecks or voluntary restrictions to limit potential to emit)

Capacity (specify units)

Per hour	Per day	Per week	Per year
4,509 MMBtu (turbine + DB)	108,215 MMBt (turbine + DB)	757,512 MMBtu (turbine + DB)	38,289,960 MMBtu (turbine + DB)

Typical Operating schedule

Hours/Day	Days/Week	Days/Year	Hours/Year
24 (each)	7 (each)	365 (each)	8,760 (each)

Seasonal variations (Months): If variations exist, describe them.

Operating using primary fuel: _____ From _____ to _____
Operating using secondary fuel: _____ Form _____ to _____
Non-operating: From _____ to _____

2. Specify the primary, secondary and startup fuel. Furnish the details in item 3.
Natural gas will be the primary fuel.

Section B - Combustion Unit Information (Continued)

3. Fuel

Type	Quantity Hourly	Annually	Sulfur	% Ash (Weight)	BTU Content
Oil Number	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Oil Number	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Oil Number	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Natural Gas	~4,419,900 SCFH	37,530 X 10^6 SCF	0.5 gr/100 SCF	0	1,020 Btu/SCF
Gas (other)	SCFH	X 10^6 Gal	gr/100 SCF		Btu/SCF
Coal					
Other*					

***** Note: Describe and furnish information separately for other fuels in Addendum B.

4. Burner

Manufacturer	Model Number	Type of Atomization (Steam, air, press, mech., rotary cup)
GE Vernova	7HA.02	N/A

Number of Burners	Maximum fuel firing rate (all burners)	Normal fuel firing rate
N/A	4,509 MMBtu/hr per turbine + duct burner	4,370 MMBtu/hr per turbine + duct burner

If oil, temperature and viscosity.
N/A

Maximum theoretical air requirement
N/A

Percent excess air 100% rating
N/A

Turndown ratio
N/A

Combustion modulation control (on/off, low-high fire, full automatic, manual). Describe.
N/A

Main burner flame ignition method (electric spark, auto gas pilot, hand-held torch, other). Describe.
N/A

5. Nitrogen Oxides (NO_x) control Options

Mark and describe the NO_x control options adopted

	Low excess air (LEA)		Flue gas recirculation	Other._____	
	Over fire air (OFA)		Burner out of service		
X	Low-NO_x burner		Reburning		
	Low NO_x burners with over fire air	**X**	Flue gas treatment (SCR / SNCR)		

Section B - Combustion Unit Information (Continued)

6. Miscellaneous Information

Describe fly ash reinjection operation
N/A

Describe, in detail, the equipment provided to monitor and to record the source(s) operating conditions, which may affect emissions of air contaminants. Show that they are reasonable and adequate.

See, Addendum A Forms

Describe each proposed modification to an existing source.

N/A

Describe how emissions will be minimized especially during start up, shut down, combustion upsets and/or disruptions. Provide emission estimates for start up, shut down and upset conditions. Provide duration of start up and shut down.

Emissions during startup/shutdown will be minimized by limiting the time that the unit is in startup or shutdown mode. Startup and shutdown are defined in Section 5 of the narrative. The emissions from startup and shutdown shall be included in the 12-month rolling sum. Turbines will not have the ability to duct fire during periods of startup or shutdown. Refer to Appendix C for startup and shutdown emission calculations.

Describe in detail with a schematic diagram of the control options adopted for SO_2 (if applicable).
N/A

Anticipated milestones:

Expected commencement date of construction/reconstruction: Upon permit issuance
Expected completion date of construction/reconstruction: Anticpated third quarter 2029
Anticipated date(s) of start-up: Anticpated fourth quarter 2029

Section C - Air Cleaning Device

1. Precontrol Emissions*

Emission Rate

Pollutant	Maximum Emission Rate				Calculation/ Estimation Method
	Specify Units	Pounds/Hour	Hours/Year	Tons/Year	
PM					
PM_{10}					
SOx					
CO					
NO_x					
VOC					
Others: (e.g., HAPs)	-----	-----	-----		-----

* These emissions must be calculated based on the requested operating schedule and/or process rate, e.g., operating schedule for maximum limits or restricted hours of operation and/or restricted throughput. Describe how the emission values were determined. Attach calculations.

2. Gas Conditioning

Water quenching ☐ YES ☐ NO Water injection rate _____GPM

Radiation and convection cooling ☐ YES ☐ NO

Air dilution ☐ YES ☐ NO
If YES, _____ CFM

Forced draft ☐ YES ☐ NO

Water cooled duct work ☐ YES ☐ NO

Other _____

Inlet volume
_____ ACFM@ _____ °F

Outlet volume
_____ ACFM@ _____ °F _____ % Moisture

Describe the system in detail.

Section C - Air Cleaning Device (Continued)

8. ☒ **SELECTIVE CATALYTIC REDUCTION (SCR)**

☐ **SELECTIVE NON-CATALYTIC REDUCTION (SNCR)**

☐ **NON-SELECTIVE CATALYTIC REDUCTION (NSCR)**

Equipment specifications

Manufacturer	Type	Model No
TBD	TBD	TBD

Design inlet volume (SCFM)	Design operating temperature (°F)

Is the system equipped with process controls for proper mixing/control of the reducing agent in gas stream? If yes, give details.

Attach efficiency and other pertinent information (e.g., Ammonia, urea slip).

Operating parameters

Volume of gases handled (ACFM) _____ @ _____ (°F)

Operating temperature range for the SCR/SNCR/NSCR system (°F) From To

Reducing agent used, if any.	Oxidation catalyst used, if any.
19% aqueous ammonia	Type of oxidation catalyst TBD

State expected range of usage rate and concentration.

Service life of catalyst	Ammonia slip (ppm)
	5 ppmvd @ 15% O2

Describe fully with a sketch giving locations of equipment, controls system, important parameters and method of operation.
This information can be provided upon final design

Describe the warning/alarm system that protects against operation when unit is not meeting design requirements.

Emissions data

Pollutant	Inlet	Outlet	Removal Efficiency (%)
NO_X		2 ppmdv @ 15% O_2	

Section C - Air Cleaning Device (Continued)

9. Other Control Equipment: Oxidation Catalyst

Equipment specifications

Manufacturer	Type	Model No
TBD	TBD	TBD

Design inlet volume (SCFM)	Capacity

Describe pH monitoring and pH adjustment, if any.

Indicate the liquid flow rate and describe equipment provided to measure pressure drop and flow rate, if any.

Attach efficiency curve and/ or other efficiency information.

Attach any additional data including auxiliary equipment and operation details to thoroughly evaluate the control equipment.

Operating parameters

Volume of gas handled

_____ @ _____ °F _____ % Moisture

Describe, in detail, important parameters and method of operation.

The oxidation catalyst will be located prior to the HRSG to remove carbon monoxide (CO) and volatile organic compounds (VOC) from the turbine exhaust gas stream.

Describe the warning/alarm system that protects against operation when unit is not meeting design requirements.

Maintaining a 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer.

Emissions data

Pollutant	Inlet	Outlet	Removal Efficiency (%)
CO		2 ppmdv @ 15% O_2	
VOC		1 ppmdv @ 15% O_2 without duct burners 2 ppmdv @ 15% O_2 with duct burners	

Section C - Air Cleaning Device (Continued)

10. Costs

Indicate cost associated with air cleaning device and its operating cost (attach documentation if necessary)

Device	Direct Cost	Indirect Cost	Total Cost	Operating Cost
Selective Catalytic Reduction (SCR)	TBD	TBD	TBD	TBD
Oxidation Catalyst	TBD	TBD	TBD	TBD

11 MISCELLANEOUS

Describe in detail the removal, handling and disposal of dust, effluent, etc. from the air cleaning device including proposed methods of controlling fugitive emissions.

N/A

Attach manufacturer's performance guarantees and/or warranties for each of the major components of the control system (or complete system).

See, Appendix C

Attach the maintenance schedule for the control equipment and any part of the process equipment that, if in disrepair, would increase air contaminant emissions.

Homer City will develop a formal maintenance plan and will perform maintenance and monitoring in accordance with 40 CFR Part 60, Subpart KKKK.

Section F - Flue and Air Contaminant Emission

1. Estimated Maximum Emissions*

Pollutant	Maximum emission rate			Calculation/ Estimation Method
	specify units	lbs/hr	tons/yr.	
PM	0.0054 lb/MMBtu	24.1	705.18	Vendor data
PM_{10}	0.0054 lb/MMBtu	24.1	705.18	Vendor data
SO_2	0.0014 lb/MMBtu	6.5	193.16	Vendor data
CO	2 ppmdv @ 15% O_2	20.2	774.40	Vendor data
NO_x	2 ppmdv @ 15% O_2	33.2	987.25	Vendor data
VOC	1 ppmdv @ 15% O_2 without duct burners 2 ppmdv @ 15% O_2 with duct burners	8.7	275.41	Vendor data
Others: (e.g., HAPs)	-----	-----	-----	-----
Max single HAP (formaldehyde)	91 ppbdv @ 15% O_2	6.91	29.32	Vendor data
Total HAP		12.08	51.29	AP-42

* These emissions must be calculated based on the requested operating schedule and/or process rate e.g., operating schedule for maximum limits or restricted hours of operation and /or restricted throughput. Describe how the emission values were determined. Attach calculations.

2. Stack and Exhauster

Stack Designation/Number

List Source(s) or source ID exhausted to this stack:
Unit 1-7

% of flow exhausted to stack: 100

Stack height above grade (ft.) 190
Grade elevation (ft.) 1200

Stack diameter (ft) or Outlet duct area (sq. ft.)
23

Weather Cap
☐ YES ☒ NO

Distance of discharge to nearest property line (ft.). Locate on topographic map.

See, Point Source Locations Table and Appendix E

Does stack height meet Good Engineering Practice (GEP)?
No

If modeling (estimating) of ambient air quality impacts is needed, attach a site plan with buildings and their dimensions and other obstructions. See, Application Narrative Section 6

Location of Stack** Latitude/Longitude Point of Origin	Latitude			Longitude		
	Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
See Point Source Locations Table						

Stack Exhaust – **Based on 59ºF @ 100% Load with DB**

Volume 1,682,300 ACFM Temperature 171.6 °F Moisture 11.88 %

Exhauster (attach fan curves) _____ in. of water _____ HP @ _____RPM.

** If the datum and collection method information and codes differ from those provided on the General Information Form - Authorization Application, provide the additional required by that form on a separate sheet.

Point Source Locations Table: Combined Cycle Turbines

	Latitude	Longitude	Distance to Property Boundary
Combined Cycle Unit 1	40° 31' 15.56"" N	079° 12' 0.36"" W	1,850 ft
Combined Cycle Unit 2	40° 31' 11.41"" N	079° 12' 0.37"" W	2,134 ft
Combined Cycle Unit 3	40° 31' 7.27"" N	079° 12' 0.36"" W	2,241 ft
Combined Cycle Unit 4	40° 31' 3.11"" N	079° 12' 0.37"" W	2,312 ft
Combined Cycle Unit 5	40° 31' 7.28"" N	079° 11' 51.03"" W	2,712 ft
Combined Cycle Unit 6	40° 31' 3.12"" N	079° 11' 51.03"" W	3,030 ft
Combined Cycle Unit 7	40° 30' 58.97"" N	079° 11' 51.02"" W	3,070 ft

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Addendum A: Source Applicable Requirements

Describe and cite all applicable requirements pertaining to this source.
Note: A Method of Compliance Worksheet (Addendum 1) must be completed for each requirement listed.

Citation Number	Citation Limitation	Limitation Used
25 Pa. Code Chapter 127.12(a)(5) – State Best Available Technology (BAT)	(Normal Operation) Combustion turbines (CTs) and heat recovery steam generators (HRSGs) with duct burners firing natural gas: 1.5 ppmvd volatile organic compounds (VOC) @15% O2 (LAER/State BAT) (average of 3-run stack test using EPA Reference Method 25A) (Normal Operation) CTs and HRSGs without duct burners firing natural gas: 1.0 ppmvd VOC @15% O2 (LAER/State BAT) (average of 3-run stack test using EPA Reference Method 25A) (Startup/Shutdown Periods) Refer to Addendum 1 for emission limits during periods of startup and shutdown.	Compliance with Nonattainment New Source Review (NNSR) lowest achievable emission rate (LAER) emissions requirements for VOC will assure compliance with State BAT requirements.
25 Pa. Code Chapter 127.205 – LAER	(Normal Operation) CTs and HRSGs with duct burners firing natural gas: 1.5 ppmvd VOC @15% O2 (LAER/State BAT) (average of 3-run stack test using EPA Reference Method 25A) (Normal Operation) CTs and HRSGs without duct burners firing natural gas: 1.0 ppmvd VOC @15% O2 (LAER/State BAT) (average of 3-run stack test using EPA Reference Method 25A) (Startup/Shutdown Periods) Refer to Addendum 1 for emission limits during periods of startup and shutdown.	See citation limitation
40 CFR Part 60, Subpart KKKK, §60.4320 – Standards of Performance for New Stationary Sources	(Normal Operation) CTs and HRSGs with duct burners firing natural gas: 15 ppmvd NOx at 15% O2 (State BAT) (1-hour block average) (Normal Operation) CTs and HRSGs without duct burners firing natural gas: 15 ppmvd NOx at 15% O2 (/State BAT) (1-hour block average) (Startup/Shutdown Periods) Refer to Addendum 1 for emission limits during periods of startup and shutdown.	Compliance with State BAT emissions requirements for NOx will assure compliance with Subpart KKKK emission limits.

25 Pa. Code §123.51 – Standards for Contaminants (Monitoring Requirements)	NOx CEMS	Compliance with Title 25, Chapter 139, Subchapter C Requirements
25 Pa. Code Chapter 127.12(a)(5) – State BAT	(Normal Operation) CTs and HRSGs with duct burners firing natural gas: 2.0 ppmvd NOx at 15% O2 (LAER/State BAT) (1-hour block average) (Normal Operation) CTs and HRSGs without duct burners firing natural gas: 2.0 ppmvd NOx at 15% O2 (LAER/State BAT) (1-hour block average) (Startup/Shutdown Periods) Refer to Addendum 1 for emission limits during periods of startup and shutdown.	Compliance with NNSR LAER emissions requirements for NOx will assure compliance with State BAT requirements.
40 CFR Part 52 – Prevention of Significant Deterioration – BACT	(Normal Operation) CTs and HRSGs with duct burners firing natural gas: 0.001 lb sulfuric acid mist (H2SO4)/hr (30 operating day rolling average) (BACT/State BAT) (Normal Operation) CTs and HRSGs without duct burners firing natural gas: 0.001 lb H2SO4/hr (30 operating day rolling average) (BACT/State BAT)	See citation limitation
25 Pa. Code Chapter 127.12(a)(5) – State BAT	(Normal Operation) CTs and HRSGs with duct burners firing natural gas: 0.001 lb H2SO4/hr (30 day rolling average) (BACT/State BAT) (Normal Operation) CTs and HRSGs without duct burners firing natural gas: 0.001 lb H2SO4/hr (30 ay rolling average) (BACT/State BAT)	Compliance with PSD BACT requirements for H2SO4 will ensure compliance with State BAT requirements.
25 Pa. Code Chapter 127.12(a)(5) – State BAT	(Normal Operation) CTs and HRSGs with duct burners firing natural gas: 1.5 ppmvd CO @15% O2 (1-hour block average)(BACT/State BAT) (Normal Operation) CTs and HRSGs without duct burners firing natural gas: 0.9 ppmvd CO @15% O2 (1-hour block average) (BACT/State BAT) (Startup/Shutdown Periods): Refer to Addendum 1 for emission limits during periods of startup and shutdown.	See citation limitation

40 CFR Part 52 – Prevention of Significant Deterioration – BACT	(Normal Operation) Each CT and HRSG with duct burner firing natural gas: 0.0054 lb particulate matter (PM)/MMBtu (average of three (3) stack test runs) (Normal Operation) Each CT and HRSG at baseload without duct burner firing natural gas: 0.0054 lb PM/MMBtu (average of three (3) stack test runs) Particulate matter comprises total particulate matter (PM), particulate matter with a diameter of less than 10 microns (PM10) including condensables, and particulate matter with a diameter of less than 2.5 microns (PM2.5) including condensables.	See citation limitation
25 Pa. Code §123.11(a)(3) – Standards for Contaminants (Combustion Units)	0.1 lb PM/MMBtu	Compliance with PSD BACT requirements for PM will ensure compliance with 25 Pa. Code §123.11 requirements.
25 Pa. Code Chapter 127.12(a)(5) – State BAT	(Normal Operation) Each CT and HRSG with duct burner firing natural gas: 0.0054 lb PM/MMBtu (average of three (3) stack test runs) (Normal Operation) Each CT and HRSG without duct burner firing natural gas: 0.0054 lb PM/MMBtu (average of three (3) stack test runs) Particulate matter comprises total particulate matter (PM), particulate matter with a diameter of less than 10 microns (PM10) including condensables, and particulate matter with a diameter of less than 2.5 microns (PM2.5) including condensables.	Compliance with PSD BACT requirements for PM/PM10/PM2.5 will ensure compliance with State BAT requirements.
40 CFR Part 52 – Prevention of Significant Deterioration – BACT	802 lb CO2e/MW-hr (gross) or 822 lb CO2e/MW-hr (net); 12-month rolling average	Compliance with NSPS Subpart TTTTa requirements will ensure compliance with BACT.
25 Pa. Code Chapter 127.12(a)(5) – State BAT	802 lb CO2e/MW-hr (gross) or 822 lb CO2e/MW-hr (net); 12-month rolling average	Compliance with NSPS Subpart TTTTa requirements will ensure compliance with State BAT.
25 Pa. Code §123.22 – Standards for Contaminants (Combustion Units)	4 lb sulfur dioxide (SO2)/MMBtu and fuel oil with no more than 500 ppmvd (0.05%) by weight	Compliance with NSPS KKKK requirements for SO2 will ensure compliance with 25 Pa. Code §123.22 requirements.

25 Pa. Code Chapter 127.12 (a)(5) – State BAT	Firing Natural Gas: 0.0014 lb SO2/MMBtu, 0.5 grains per 100 scf	See citation limitation
40 CFR Part 60, Subpart KKKK, §60.4330 – Standards of Performance for New Stationary Sources	0.90 lb SO2/MWh gross output, or 0.060 lb SO2/MMBtu heat input	Compliance with State BAT for SO2 will assure compliance with Subpart KKKK.
40 CFR 63 Subpart YYYY (§63.6095(c))	Limit the concentration of formaldehyde to 91 ppbvd or less at 15% O2.	See citation limitation
25 Pa. Code §123.41 – Standards for Contaminants (Limitations)	Limit visible emissions to 20% for a period or periods aggregating more than three (3) minutes in any one (1) hour, and 60% at any time	Compliance with PSD BACT requirements for visible emissions will ensure compliance with 25 Pa. Code §123.41 requirements.
25 Pa. Code §127.531 and 40 CFR Parts 72-73, 75, and 77 – Acid Rain Permit	Submit a complete Acid Rain permit application to the permitting authority at least 24 months before the date on which the unit commences operation.	Same requirement
40 CFR Part 97; CSAPR NOx and SO2 Allowance Trading Programs	Comply with all applicable provisions of 40 CFR, Part 97, Subparts AAAAA and EEEEE (relating to CSAPR NOx annual trading program; and CSAPR NOx ozone season Group 2 trading program) and 40 CFR Part 97, Subpart CCCCC (as relates to CSAPR SO2 Group 1 Trading Program)	Same requirement
40 CFR Part 60, Subpart TTTTa, Table 1	For base load combustion turbines: 800 lb CO2/MWh of gross energy output; or 820 lb CO2/MWh of net energy output as determined by the procedures in 60.5525a. Based on 12-month rolling average.	See citation limitation

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Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id: 80-0833693 **Firm Name:** Homer City Generation, L.P.

Plant Code: **Plant Name:** Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Seven (7) new CTs, seven (7) new HRSGs with fired duct burners

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: VOC: 25 Pa. Code Chapter 127.12(a)(5) – State BAT and 25 Pa. Code Chapter 127.205 – LAER

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☐ **Monitoring** ☒ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):**
2. **Monitoring device location:**

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

3. **How will data be reported:**

Section 3: Testing

1. Reference Test Method Description:	Stack testing following U.S. EPA Reference Method 18, 25A, or equivalent.
2. Reference Test Method Citation:	U.S. EPA Reference Method 18, 25A, or equivalent

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City will retain a copy of initial stack test results. Electronic storage includes the type of fuel being fired, the amount of fuel being fired, whether duct firing is occurring, and if startup or shutdown is occurring.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Results of initial stack test within 60 days of stack test completion.

1. Reporting start date:	Within 60 days of completion of initial stack test.

Section 6: Work Practice Standard

Describe any work practice standards:

Homer City Generation will ensure this equipment is operated according to manufacturer's specifications in order to meet the following emission limits:

VOC emissions will not exceed the following during normal operation:

(Normal Operation) CTs and HRSGs with duct burners firing natural gas:
1.5 ppmvd VOC @15% O2 (LAER/State BAT) (average of three (3) stack test runs)

(Normal Operation) CTs firing natural gas and HRSGs without duct burners:
0.7 ppmvd VOC @15% O2 (LAER/State BAT) (average of three (3) stack test runs)

Emissions during startup and shutdown shall be limited as follows:
105 lbs VOC/cold startup, where a hot startup is defined as occurring more than 72 hours or more after shutdown, not to exceed 70 minutes in duration;
105 lbs VOC/warm startup, where a warm startup is defined as occurring between 8 to 72 hours after shutdown, not to exceed 60 minutes in duration;
66 lbs VOC/hot startup, where a hot startup is defined as occurring less than 8 hours after shutdown, not to exceed 30 minutes in duration;
55 lbs VOC/shutdown, defined as the time that the combustion turbine drops below MECL during shutdown to termination of fuel flow to the combustion turbine, not to exceed 12 minutes in duration.

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Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Seven (7) new CTs, seven (7) new HRSGs with fired duct burners

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: NOx: Limitations for 40 CFR Part 60, Subpart KKKK, §60.4320 – Standards of Performance for New Stationary Sources, 25 Pa. Code Chapter 127.12(a)(5) – State BAT, 25 Pa. Code §123.51 – Standards for Contaminants (Monitoring Requirements)

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☒ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):** NOx CEM
2. **Monitoring device location:** After duct burner and add-on SCR control.

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

Per 40 CFR §60.4345,

1. Each NOx diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in 40 CFR Part 60, Appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in 40 CFR Part 60, Appendix F is not required. Alternatively, a NOx diluent CEMS that is installed and certified according to Appendix A of Part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

2. As specified in 40 CFR §60.13(e)(2), during each full unit operating hour, both the NOx monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one (1) valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two (2) valid data points (one (1) in each of two (2) quadrants) are required for each monitor to validate the NOX emission rate for the hour.

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

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

5. Homer City Generation shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, Homer City Generation may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in Section 1 of Appendix B to Part 75 of this chapter.

3. How will data be reported:	Deviations will be reported quarterly.

Section 3: Testing

1. Reference Test Method Description:	Per 40 CFR §60.4405, complete initial performance test for NOx using CEMS RATA runs.
2. Reference Test Method Citation:	U.S. EPA Reference Method 7E, or equivalent

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Per 40 CFR §60.7(b), Homer City Generation shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

Per 40 CFR §60.7(f), Homer City Generation shall retain a file of all information required for at least two (2) years following the date of the record.

Per 40 CFR §60.4345(e), Homer City Generation shall develop and keep on-site a QA plan for the NOx CEMS

monitoring equipment.

Electronic storage includes CEM NOx minute data, the type of fuel being fired, the amount of fuel being fired, whether duct firing is occurring, and if startup or shutdown is occurring.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Per 40 CFR §60.7, Homer City Generation shall submit notification of the date of construction or reconstruction and actual start-up.

Per 40 CFR §60.4375(a), for each affected unit required to continuously monitor parameters or emissions, Homer City Generation must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

1. Reporting start date:	Per 40 CFR §60.7, notification of construction commencement must be postmarked no later than 30 days after such date and notification of actual start-up is due must be post marked within 15 days of that date. Quarterly CEMS reporting to U.S. EPA and PADEP..

Section 6: Work Practice Standard

Describe any work practice standards:

Homer City Generation will ensure this equipment is operated according to manufacturer's specifications in order to meet the following emission limits:

NOX emissions will not exceed the following during normal operation:

(Normal Operation) CTs and HRSGs with duct burners firing natural gas:
2.0 ppmvd NOx at 15% O2 (State BAT) (1-hour block average)

(Normal Operation) CTs and HRSGs without duct burners firing natural gas:
2.0 ppmvd NOx at 15% O2 (State BAT) (1-hour block average)

Emissions during startup and shutdown shall be limited as follows:
200 lbs NOx/cold startup, where a hot startup is defined as occurring more than 72 hours or more after shutdown, not to exceed 70 minutes in duration;
200 lbs NOx/warm startup, where a warm startup is defined as occurring between 8 to 72 hours after shutdown, not to exceed 60 minutes in duration;
110 lbs NOx/hot startup, where a hot startup is defined as occurring less than 8 hours after shutdown, not to exceed 30 minutes in duration;
16 lbs NOx/shutdown, defined as the time that the combustion turbine drops below MECL during shutdown to termination of fuel flow to the combustion turbine, not to exceed 12 minutes in duration.

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BUREAU OF AIR QUALITY

Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Seven (7) new CTs, seven (7) new HRSGs with fired duct burners

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: H2SO4: 40 CFR Part 52 – Prevention of Significant Deterioration and 25 Pa. Code Chapter 127.12(a)(5) – State BAT

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☒ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. Monitoring device type (stack test, CEM, etc.): Testing of fuels for sulfur content or obtaining certified fuel sulfur content using test results from the fuel supplier.

2. Monitoring device location: N/A

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

Monthly sampling of natural gas for sulfur content will be conducted or facility owner/operator will obtain fuel supplier-testing results.

3. How will data be reported:	N/A

Section 3: Testing

1. Reference Test Method Description:	Initial stack testing to determine emission factors.
2. Reference Test Method Citation:	U.S. EPA Reference Method 8, or equivalent

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation shall retain copies of initial and/or most recent stack test results. A correlation emissions factor will be developed from fuel sampling results at the time of stack testing.

Records of monthly sulfur content samples of natural gas will be recorded for use in determining monthly H2SO4 emissions.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Results of initial stack test within 60 days of stack test completion.

1. Reporting start date:	Within 60 days of completion of initial stack test.

Section 6: Work Practice Standard

Describe any work practice standards:

Homer City Generation will ensure this equipment is operated according to manufacturer's specifications in order to meet the
following emission limits:

(Normal Operation) CTs and HRSGs with duct burners firing natural gas:
0.001 lb H2SO4/MMBtu (Average of three (3) test runs) (BACT/State BAT)

(Normal Operation) CTs and HRSGs without duct burners firing natural gas:
0.001 lb H2SO4/MMBtu (Average of three (3) test runs) (BACT/State BAT)

The monthly sulfur sampling will be used to determine the 30 day rolling averages based on multiplying the most recent stack test result by the ratio of the monthly monitored sulfur content and the sulfur content during the most recent testing.

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SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Seven (7) new CTs, seven (7) new HRSGs with fired duct burners

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: CO: 25 Pa. Code Chapter 127.12(a)(5) – State BAT

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☒ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):** CO CEM
2. **Monitoring device location:** After duct burner and oxidation catalyst.

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

CO will be monitored continuously.

3. **How will data be reported:** Deviations will be reported quarterly.

Section 3: Testing

1. Reference Test Method Description:	Initial performance test for CO using CEMS RATA runs.
2. Reference Test Method Citation:	U.S. EPA Reference Method 10, or equivalent

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation shall retain copies of initial stack test results.

The CO CEM will record one (1) minute averages for use in determining one (1) hour block CO emission values. Electronic storage includes CEM CO minute data, the type of fuel being fired, the amount of fuel being fired, whether duct firing is occurring, and if startup or shutdown is occurring.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Results of initial stack test within 60 days of stack test completion.

Submission of Quarterly CEMS data to PADEP.

1. Reporting start date:	Within 60 days of completion of initial stack test.

Section 6: Work Practice Standard

Describe any work practice standards:

Homer City Generation will ensure this equipment is operated according to manufacturer's specifications in order to meet the following emission limits:

CO emissions will not exceed the following during normal operation:

(Normal Operation) CTs and HRSGs with duct burners firing natural gas:
1.5 ppmvd CO @15% O2 (1-hour block average)(State BAT)

(Normal Operation) CTs and HRSGs without duct burners firing natural gas:
0.9 ppmvd CO @15% O2 (1-hour block average) (State BAT)

Emissions during startup and shutdown shall be limited as follows:
830 lbs CO/cold startup, where a hot startup is defined as occurring more than 72 hours or more after shutdown, not to exceed 70 minutes in duration;
830 lbs CO/warm startup, where a warm startup is defined as occurring between 8 to 72 hours after shutdown, not to exceed 60 minutes in duration;
215 lbs CO/hot startup, where a hot startup is defined as occurring less than 8 hours after shutdown, not to exceed 30 minutes in duration;
185 lbs CO/shutdown, defined as the time that the combustion turbine drops below MECL during shutdown to termination of fuel flow to the combustion turbine, not to exceed 12 minutes in duration.

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SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Seven (7) new CTs, seven (7) new HRSGs with duct burners

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: PM/PM10/PM2.5: 40 CFR Part 52 – Prevention of Significant Deterioration, 25 Pa. Code §123.11(a)(3) – Standards for Contaminants (Combustion Units) and 25 Pa. Code Chapter 127.12(a)(5) – State BAT

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☐ **Monitoring** ☒ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. Monitoring device type (stack test, CEM, etc.):

2. Monitoring device location:

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

3. How will data be reported:

Section 3: Testing

1. Reference Test Method Description:	Initial stack testing to determine filterable and condensable PM/PM10/PM2.5 emissions factors.
2. Reference Test Method Citation:	U.S. EPA Reference Methods 201/201A or equivalent and Method 202.

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation shall retain copies of initial stack test results and record the amount and type of fuel being fired.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Results of initial stack test within 60 days of stack test completion.

1. Reporting start date:	Within 60 days of completion of initial stack test.

Section 6: Work Practice Standard

Describe any work practice standards:

Homer City Generation will ensure this equipment is operated according to manufacturer's specifications in order to meet the following emission limits:

PM/PM10/PM2.5 (filterable and condensable) emissions will not exceed the following during normal operation:

(Normal Operation) Each CT and HRSG with or without duct burner firing natural gas:
0.0054 lb PM/PM10/PM2.5 /MMBtu (average of three (3) test runs)

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SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Seven (7) new CTs, seven (7) new HRSGs with fired duct burners

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: CO2e: 40 CFR Part 52 – Prevention of Significant Deterioration and 25 Pa. Code Chapter 127.12(a)(5) – State BAT

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☐ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. Monitoring device type (stack test, CEM, etc.): Monitoring of fuel usage and heat input per 40 CFR Part 75

2. Monitoring device location: Fuel monitoring will be where fuel is fed into the turbine and duct burner

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

Fuel use will be monitored on a continuous basis.

3. How will data be reported: Data will be reported through EPA's ECMPS program

Section 3: Testing

1. Reference Test Method Description:

2. Reference Test Method Citation:

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation shall record the type and amount of fuel being fired, the higher heating value of the fuel, and whether duct firing is occurring.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Reporting will consist of monthly fuel usage, higher heating value of the fuel, emission factors used for CO2,

CH4 and N2O, and electrical generation.

1. Reporting start date:

Section 6: Work Practice Standard

Describe any work practice standards:

Homer City Generation will ensure this equipment is operated according to manufacturer's specifications in order to meet the following emission and efficiency limits:

802 lb CO2e/MW-hr (gross) or 822 lb CO2e/MW-hr (net); based on a 12-month rolling average

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Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Seven (7) new CTs, seven (7) new HRSGs with fired duct burners

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: SO2: 25 Pa. Code §123.22 – Standards for Contaminants (Combustion Units), 25 Pa. Code Chapter 127.12(a)(5) – State BAT, and 40 CFR Part 60, Subpart KKKK, §60.4330 – Standards of Performance for New Stationary Sources

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☐ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):** Sulfur in fuel monitoring.
2. **Monitoring device location:** From fuel supplier or on-site sampling TBD.

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

Per 40 CFR §60.4360 and §60.4365, Homer City Generation will demonstrate that the fuel it fires in the turbines does not exceed potential sulfur emissions of 0.060 lb SO2/MMBtu heat input by using one (1) of the following sources of information to make the required demonstration:

1. The fuel quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract for the fuel, specifying that the total sulfur content for natural gas use is 20 grains of sulfur or less per 100 standard cubic feet, and has potential sulfur emissions of less than less than 0.060 lb SO2/MMBtu; or

2. Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 0.060 lb SO2/MMBtu heat input.

Monthly sampling of natural gas for sulfur content will be conducted.

3. How will data be reported: Deviations will be reported semi-annually.

Section 3: Testing

1. Reference Test Method Description: N/A

2. Reference Test Method Citation: N/A

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Records of monthly sulfur content samples of the natural gas will be recorded for use in determining monthly SO2 emissions.

Per 40 CFR §60.7(f) and 25 Pa. Code §123.22(g)(4)(i), Homer City Generation shall retain a file of all information required for at least two (2) years following the date of the record.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Per 40 CFR §60.7, Homer City Generation shall submit notification of the date of construction or reconstruction and actual start-
up.

Per 40 CFR §60.4375(a), for each affected unit required to periodically determine the fuel sulfur content under this subpart, Homer City Generation must submit reports of excess emissions and monitor downtime, in accordance with 40 CFR
§60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

Per 40 CFR §60.4375(b), for each affected unit that performs annual performance tests in accordance with §60.4340(a), Homer City Generation must submit a written report of the results of each performance test before the close of
business on the 60th day following the completion of the performance test.

1. Reporting start date:	Per 40 CFR §60.7, notification of construction commencement must be postmarked no later than 30 days after such date and notification of actual start-up is due must be post marked within 15 days of that date.

Section 6: Work Practice Standard

Describe any work practice standards:

Homer City Generation will monitor the sulfur content of the fuel fired at the facility in order to meet the following emission limits:
Firing Natural Gas: 0.0014 lb SO2/MMBtu and 0.5 grains per 100 scf.

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SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Seven (7) new CTs, seven (7) new HRSGs with fired duct burners

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: 40 CFR Part 63 Subpart YYYY – National Emissions Standards for Hazardous Air Pollutants

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☒ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☐ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):** Oxidation catalyst inlet temperature.
2. **Monitoring device location:** Inlet ductwork to oxidation catalyst.

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

Oxidation catalyst inlet temperature will be monitored on a 4-hour rolling average basis. Measurements will be taken at least once every fifteen minutes.

3. **How will data be reported:** Data will be reported through data historian.

Section 3: Testing

1. Reference Test Method Description:	The formaldehyde concentration must be corrected to 15% O2, on a dry basis. Results of this one (1) time performance test shall consist of the average of three 1-hour runs. Test must be conducted within 10 percent of 100% load.
2. Reference Test Method Citation:	Test Method 320 of 40 CFR Part 63, Appendix A; ASTM D6348-12e1 provided that the test plan preparation and implementation provisions of Annexes A1 through A8 are followed and the %R as determined in Annex A5 is equal or greater than 70% and less than or equal to 130%; or other methods approved by the Administrator.

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Maintain source test report for a period of five (5) years.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Results of stack testing within 60 days of stack test completion and will be submitted through EPA's CDX and CEDRI online reporting systems per 40 CFR §60.6150.

Reporting of catalyst inlet temperature will be submitted semi-annually per 40 CFR §60.6150.

1. Reporting start date:	Report of stack testing within 60 days of completion of the source testing. Reports of deviations will be submitted by the first semi-annual compliance date (either January 31 or July 31).

Section 6: Work Practice Standard

Describe any work practice standards:

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SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Seven (7) new CTs, seven (7) new HRSGs with fired duct burners

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: Visible Emissions: 25 Pa. Code §123.41 – Standards for Contaminants (Limitations)

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☐ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):** Visual monitoring U.S. EPA Reference Method 9, or equivalent
2. **Monitoring device location:** N/A

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

Opacity, weekly visual monitoring

3. **How will data be reported:** Deviations will be reported semi-annually.

Section 3: Testing

1. Reference Test Method Description:	Visible Emissions
2. Reference Test Method Citation:	U.S. EPA Reference Method 9, or equivalent

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation will retain copies of weekly inspection results.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Semi-annual reporting of monitoring deviations for visible emissions monitoring.

1. Reporting start date:	First compliance certification submittal.

Section 6: Work Practice Standard

Describe any work practice standards:

Homer City Generation will ensure this equipment is operated according to manufacturer's specifications in order to not exceed
the following visible emissions limitation:
20% for a period or periods aggregating more than three (3) minutes in any one (1) hour, and 60% at any time.

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SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id: 80-0833693 **Firm Name:** Homer City Redevelopment, LLC

Plant Code: **Plant Name:** Homer City Generation LP

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Seven (7) new CTs, seven (7) new HRSGs with fired duct burners

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: 25 Pa. Code §127.531 and 40 CFR Parts 72-73, 75, and 77 – Acid Rain Permit

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☐ **Monitoring** ☐ **Testing** ☒ **Reporting**

☐ **Record Keeping** ☐ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):**
2. **Monitoring device location:**

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

3. **How will data be reported:**

Section 3: Testing

1. Reference Test Method Description:

2. Reference Test Method Citation:

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Submit a complete Acid Rain permit application to the permitting authority.

1. Reporting start date: An initial Acid Rain Permit application must be submitted at least 24 months before the date on which the unit commences operation.

Section 6: Work Practice Standard

Describe any work practice standards:

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SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Seven (7) new CTs, seven (7) new HRSGs with fired duct burners

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: 40 CFR Part 97 –CSAPR NOx (Annual and Ozone Season Group 3) and SO2 (Annual Group 1) Allowance Trading Programs

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☐ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. Monitoring device type (stack test, CEM, etc.):
1. 40 CFR Part 75 Certified NOx CEM
2. Fuel sulfur content

2. Monitoring device location:
1. After duct burner and add-on SCR control
2. Fuel

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

1. NOx CEM (operated in accordance with 25 Pa. Code §139 40 CFR Part 75)

2. Sulfur and BTU content of fuel

3. How will data be reported: Deviations will be reported quarterly.

Section 3: Testing

1. Reference Test Method Description:

2. Reference Test Method Citation:

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation will retain records of NOx CEMS one minute emissions data for five (5) years.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Quarterly NOx and SO2 emissions reporting to U.S. EPA and PADEP.

1. Reporting start date: Following first quarter of operation.

Section 6: Work Practice Standard

Describe any work practice standards:

Homer City Generation will comply with the allowance provisions of 40 CFR Part 97 Subparts AAAAA, CCCCC, and EEEEE as required.

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SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Seven (7) new CTs, seven (7) new HRSGs with fired duct burners

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: GHG – 40 CFR Part 60, Subpart TTTTa

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☐ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):** Fuel use meter for monitoring natural gas consumption and watt meter for measuring electrical generation.

2. **Monitoring device location:** Fuel meter will be located between the natural gas pipeline and the turbine and duct burner fuel inlets. Watter meters will be located at the terminals of the combustion turbine and steam turbine.

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

Natural gas fuel consumption and electrical generation will each be monitored on a continuous basis.

3. How will data be reported:	Data will be reported through EPA's ECMPS reporting system per 40 CFR §60.5555a(b). Reports will be submitted quarterly in accordance with 40 CFR §60.5555a(a).

Section 3: Testing

1. Reference Test Method Description:	
2. Reference Test Method Citation:	

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Per 40 CFR §60.5560a, Homer City Generation will maintain records as required by Subpart F of Part 75, calculations of 12-month rolling averages, calculations used for compliance, and records of electric sales.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Homer City Generation will meet all applicable reporting requirements and submit reports as required per 40 §60.5555a, including Subpart G of Part 75.

1. Reporting start date:	Per §60.5555a(c)(3)(i), reports described in §60.5555a(c)(1) are to begin with data recorded on and after the earlier of: The date of provisional certification, as defined in §75.20(a)(3), or 180 days after the date the CTs commences commercial operation.

Section 6: Work Practice Standard

Describe any work practice standards:

Homer City Generation will ensure this equipment is operated according to manufacturer's specifications in order to meet the following emission and efficiency limits:

800 lb CO2/MW-hr (gross) or 820 lb CO2/MW-hr (net);

2. Simple Cycle Combustion Turbines

- Section B – Combustion Unit Information
- Section C – Air Cleaning Device
- Section F – Flue and Air Contaminant Emission
- Addendum A: Source Applicable Requirements
- Addendum 1: Method of Compliance Worksheets

Section B - Combustion Unit Information

1. Combustion Units: ☐ Coal ☐ Oil ☒ Natural Gas Other: _____

Description: The group of simple-cycle electric generating units consists of ten (10) natural gas-fired combustion turbines (CTs).

Manufacturer	Model No.	Number of units	
Mitsubishi Power	FT8 Mobilepac	10	
Maximum heat input (Btu/hr)	**Rated heat input (Btu/hr)**	**Typical heat input (Btu/hr)**	**Furnace Volume**
301 MMBtu/hr (each)	301 MMBtu/hr (each)	297 MMBtu/hr (each)	N/A
Grate Area (if applicable)		**Method of firing**	
N/A		Premix burners	

Indicate how combustion air is supplied to boiler
N/A

Indicate the Steam Usage: N/A

Mark and describe soot Cleaning Method:

i. Air Blown
ii. Steam Blown
iii. Brushed and Vacuumed
iv. Other N/A
v. Frequency of Cleaning _____

Maximum Operating schedule

Hours/Day	Days/Week	Days/Year	Hours/Year
24 (each)	7 (each)	365 (each)	8760 (each)

Operational restrictions taken or requested, if any (e.g., bottlenecks or voluntary restrictions to limit potential to emit)

Capacity (specify units)

Per hour	Per day	Per week	Per year
301 MMBtu (each)	7,224 MMBtu (each)	50,568 MMBtu (each)	2,601,720 MMBtu (each)

Typical Operating schedule

Hours/Day	Days/Week	Days/Year	Hours/Year
24(each)	7 (each)	365 (each)	8,760 (each)

Seasonal variations (Months): If variations exist, describe them.

Operating using primary fuel: _____ From _____ to _____
Operating using secondary fuel: _____ Form _____ to _____
Non-operating: From _____ to _____

2. Specify the primary, secondary and startup fuel. Furnish the details in item 3.
Natural gas will be the primary fuel.

Section B - Combustion Unit Information (Continued)

3. Fuel

Type	Quantity Hourly	Annually	Sulfur	% Ash (Weight)	BTU Content
Oil Number	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Oil Number	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Oil Number	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Natural Gas	~295,100 SCFH	2,551 MMscf/yr X 10^6 SCF	0.5 gr/100 SCF	0	1,020 Btu/SCF
Gas (other)	SCFH	X 10^6 Gal	gr/100 SCF		Btu/SCF
Coal					
Other*					

***** Note: Describe and furnish information separately for other fuels in Addendum B.

4. Burner

Manufacturer	Model Number	Type of Atomization (Steam, air, press, mech., rotary cup)
Mitsubishi	TBD	N/A

Number of Burners	Maximum fuel firing rate (all burners)	Normal fuel firing rate
TBD	301 MMBtu/hr	297 MMBtu/hr

If oil, temperature and viscosity.
NA

Maximum theoretical air requirement
TBD

Percent excess air 100% rating
TBD

Turndown ratio
TBD

Combustion modulation control (on/off, low-high fire, full automatic, manual). Describe.

Main burner flame ignition method (electric spark, auto gas pilot, hand-held torch, other). Describe.

5. Nitrogen Oxides (NO_x) control Options

Mark and describe the NO_x control options adopted

	Low excess air (LEA)		Flue gas recirculation	Other._____	
	Over fire air (OFA)		Burner out of service		
X	Low-NO_x burner		Reburning		
	Low NO_x burners with over fire air	**X**	Flue gas treatment (SCR / SNCR)		

Section B - Combustion Unit Information (Continued)

6. Miscellaneous Information

Describe fly ash reinjection operation
N/A

Describe, in detail, the equipment provided to monitor and to record the source(s) operating conditions, which may affect emissions of air contaminants. Show that they are reasonable and adequate.

See, Addendim A Forms

Describe each proposed modification to an existing source.

N/A

Describe how emissions will be minimized especially during start up, shut down, combustion upsets and/or disruptions. Provide emission estimates for start up, shut down and upset conditions. Provide duration of start up and shut down.

Emissions during startup/shutdown will be minimized by limiting the time that the unit is in startup or shutdown mode. Startup and shutdown are defined in Section 5 of the narrative. The emissions from startup and shutdown shall be included in the 12-month rolling sum. Refer to Appendix C for startup and shutdown emission calculations.

Describe in detail with a schematic diagram of the control options adopted for SO_2 (if applicable).
N/A

Anticipated milestones:

Expected commencement date of construction/reconstruction:	Upon permit issuance
Expected completion date of construction/reconstruction:	Anticpated third quarter 2029
Anticipated date(s) of start-up:	Anticpated fourth quarter 2029

Section C - Air Cleaning Device

1. Precontrol Emissions*

Emission Rate

Pollutant	Maximum Emission Rate				Calculation/ Estimation Method
	Specify Units	Pounds/Hour	Hours/Year	Tons/Year	
PM					
PM_{10}					
SOx					
CO					
NO_x					
VOC					
Others: (e.g., HAPs)	-----	-----	-----		-----
Total HAPs					

* These emissions must be calculated based on the requested operating schedule and/or process rate, e.g., operating schedule for maximum limits or restricted hours of operation and/or restricted throughput. Describe how the emission values were determined. Attach calculations. See Appendix C for emission calculations.

2. Gas Conditioning

Water quenching ☒ YES ☐ NO Water injection rate 26.8 GPM

Radiation and convection cooling ☐ YES ☒ NO

Air dilution ☐ YES ☒ NO

If YES, _____ CFM

Forced draft ☐ YES ☒ NO

Water cooled duct work ☐ YES ☒ NO

Other _____

Inlet volume

_____ ACFM@ _____ °F

Outlet volume

_____ ACFM@ _____ °F _____ % Moisture

Describe the system in detail.

Section C - Air Cleaning Device (Continued)

8. ☒ SELECTIVE CATALYTIC REDUCTION (SCR)

☐ **SELECTIVE NON-CATALYTIC REDUCTION (SNCR)**

☐ **NON-SELECTIVE CATALYTIC REDUCTION (NSCR)**

Equipment specifications

Manufacturer	Type	Model No
TBD	TBD	TBD

Design inlet volume (SCFM)	Design operating temperature (°F)
273,030 - 435,990 ACFM (each CT)	699-850 F - Turbine Exhaust Temperature

Is the system equipped with process controls for proper mixing/control of the reducing agent in gas stream? If yes, give details.

Attach efficiency and other pertinent information (e.g., Ammonia, urea slip).
Refer to Appendix TBD

Operating parameters

Volume of gases handled (ACFM) 273,030 - 435,990 @ 699 - 850 (°F)

Operating temperature range for the SCR/SNCR/NSCR system (°F)	From	To
	699 F	850 F

Reducing agent used, if any.	Oxidation catalyst used, if any.
Aqueous Ammonia (19%)	Type of Catalyst TBD

State expected range of usage rate and concentration.
Usage rate and concentration TBD.

Service life of catalyst	Ammonia slip (ppm)
N/A	Up to 5 ppmvd @ 15 % O2 (3 x 1-hr tests)

Describe fully with a sketch giving locations of equipment, controls system, important parameters and method of operation.
This information can be provided upon request

Describe the warning/alarm system that protects against operation when unit is not meeting design requirements.
TBD

Emissions data

Pollutant	Inlet	Outlet	Removal Efficiency (%)
NOx		2.79 lbs/hr	

Section C - Air Cleaning Device (Continued)

9. Other Control Equipment: Oxidation Catalyst

Equipment specifications

Manufacturer	Type	Model No
TBD	TBD	TBD

Design inlet volume (SCFM)	Capacity
273,030 - 435,990 ACFM (each CT)	TBD

Describe pH monitoring and pH adjustment, if any.
N/A

Indicate the liquid flow rate and describe equipment provided to measure pressure drop and flow rate, if any.
N/A

Attach efficiency curve and/ or other efficiency information.

Attach any additional data including auxiliary equipment and operation details to thoroughly evaluate the control equipment.
Refer to application narrative and Appendix TBD.

Operating parameters

Volume of gas handled

_____ @ _____ °F N/A _____ % Moisture

Describe, in detail, important parameters and method of operation.

Oxidation catalyst will be located upstream from the HRSG to remove carbon monoxide (CO) and volatile organic compounds (VOC) from the turbine exhuast gas stream.

Describe the warning/alarm system that protects against operation when unit is not meeting design requirements.

TBD

Emissions data

Pollutant	Inlet	Outlet	Removal Efficiency (%)
CO		9.35 lbs/hr	
VOC		3.12 lbs/hr	

Section C - Air Cleaning Device (Continued)

10. Costs

Indicate cost associated with air cleaning device and its operating cost (attach documentation if necessary)

Device	Direct Cost	Indirect Cost	Total Cost	Operating Cost
Selective Catalytic Reduction (SCR)				
Oxidation Catalyst				

11 MISCELLANEOUS

Describe in detail the removal, handling and disposal of dust, effluent, etc. from the air cleaning device including proposed methods of controlling fugitive emissions.

N/A

Attach manufacturer's performance guarantees and/or warranties for each of the major components of the control system (or complete system).

See Appendix C

Attach the maintenance schedule for the control equipment and any part of the process equipment that, if in disrepair, would increase air contaminant emissions.

Homer City Generation will develop a formal maintenance plan and will perform maintenance and monitoring in accordance with 40 CFR Part 60, Subpart KKKK.

Section F - Flue and Air Contaminant Emission

1. Estimated Maximum Emissions*

Pollutant	Maximum emission rate			Calculation/ Estimation Method
	specify units	lbs/hr	tons/yr.	
PM		3.00	132.45	Vendor data
$PM_{10/2.5}$		3.00	132.45	Vendor data
SO_2		0.42	17.96	Vendor data
CO		9.35	257.45	Vendor data
NO_x	2.5 ppmdv @ 15% O_2	2.79	132.00	Vendor data
VOC		3.12	51.13	Vendor data
Others: (e.g., HAPs)	-----	-----	-----	-----
Max single HAP (formaldehyde)	91 ppbdv @ 15% O_2	0.66	2.85	Vendor data
Total HAPs		1.15	4.98	AP-42

* These emissions must be calculated based on the requested operating schedule and/or process rate e.g., operating schedule for maximum limits or restricted hours of operation and /or restricted throughput. Describe how the emission values were determined. Attach calculations.

2. Stack and Exhauster

Stack Designation/Number FT8_01 through FT8_10

List Source(s) or source ID exhausted to this stack:	% of flow exhausted to stack:
FT-8 Units 1-10	

Stack height above grade (ft.) 90 Grade elevation (ft.) 1200	Stack diameter (ft) or Outlet duct area (sq. ft.) 13 ft	Weather Cap ☐ YES ☒ NO

Distance of discharge to nearest property line (ft.). Locate on topographic map.

See, Point Source Locations Table and Appendix E

Does stack height meet Good Engineering Practice (GEP)?

No

If modeling (estimating) of ambient air quality impacts is needed, attach a site plan with buildings and their dimensions and other obstructions. See, Application Narrative Section 6

Location of Stack** Latitude/Longitude Point of Origin	Latitude			Longitude		
	Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
See, Point Source Locations Table						

Stack Exhaust – **Based on 59ºF @ 100% Load**

Volume 401,922 ACFM Temperature 800 °F Moisture 8.88 %

Exhauster (attach fan curves) _____ in. of water _____ HP @ _____RPM.

** If the datum and collection method information and codes differ from those provided on the General Information Form - Authorization Application, provide the additional required by that form on a separate sheet.

Point Source Locations Table: Simple Cycle Turbines

	Latitude	Longitude	Distance to Property Boundary
Simple Cycle Unit 1	40° 31' 6.11"" N	079° 12' 13.77"" W	1,252 ft
Simple Cycle Unit 2	40° 31' 5.84"" N	079° 12' 12.37"" W	1,363 ft
Simple Cycle Unit 3	40° 31' 5.58"" N	079° 12' 10.96"" W	1,474 ft
Simple Cycle Unit 4	40° 31' 5.31"" N	079° 12' 9.55"" W	1,585 ft
Simple Cycle Unit 5	40° 31' 5.05"" N	079° 12' 8.14"" W	1,696 ft
Simple Cycle Unit 6	40° 31' 3.9"" N	079° 12' 16.17"" W	1,089 ft
Simple Cycle Unit 7	40° 31' 3.64"" N	079° 12' 14.76"" W	1,201 ft
Simple Cycle Unit 8	40° 31' 3.38"" N	079° 12' 13.34"" W	1,311 ft
Simple Cycle Unit 9	40° 31' 3.11"" N	079° 12' 11.94"" W	1,422 ft
Simple Cycle Unit 10	40° 31' 2.84"" N	079° 12' 10.54"" W	1,533 ft

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Addendum A: Source Applicable Requirements

Describe and cite all applicable requirements pertaining to this source.
Note: A Method of Compliance Worksheet (Addendum 1) must be completed for each requirement listed.

Citation Number	Citation Limitation	Limitation Used
25 Pa. Code Chapter 127.12(a)(5) – State Best Available Technology (BAT)	(Normal Operation) Combustion turbines (CTs) firing natural gas less than 3.75 lbs/hr of volatile organic compounds (VOC) @15% O2 (LAER/State BAT) (average of 3-run stack test using EPA Reference Method 25A) (Startup/Shutdown Periods) Refer to Addendum 1 for emission limits during periods of startup and shutdown.	Compliance with Nonattainment New Source Review (NNSR) lowest achievable emission rate (LAER) emissions requirements for VOC will assure compliance with State BAT requirements.
25 Pa. Code Chapter 127.205 – LAER	(Normal Operation) CTs firing natural gas less than 3.75 lbs/hr of VOC @15% O2 (LAER/State BAT)(average of 3-run stack test using EPA Referene Method 25A) (Startup/Shutdown Periods) Refer to Addendum 1 for emission limits during periods of startup and shutdown.	See citation limitation
25 Pa. Code Chapter 127.12(a)(5) – State Best Available Technology (BAT)	(Normal Operation) CTs firing natural gas: 2.5 ppmvd nitrogen oxides (NOx) at 15% O2 (State BAT) (4-hour rolling average) (Startup/Shutdown Periods) Refer to Addendum 1 for emission limits during periods of startup and shutdown.	See citation limitation
40 CFR Part 60, Subpart KKKK, §60.4320 – Standards of Performance for New Stationary Sources	(Normal Operation) New CT firing natural gas greater than 50 MMBtu/hr and less than or equal to 850 MMBtu/hr. NOx emission standard: 25 ppm at 15% O2. (Startup/Shutdown Periods) Refer to Addendum 1 for emission limits during periods of startup and shutdown.	Compliance with BAT emission limits for NOx will assure compliance with Subpart KKKK emission limits.
25 Pa. Code §123.51 – Standards for Contaminants (Monitoring Requirements)	NOx CEMS	Compliance with Title 25, Chapter 139, Subchapter C Requirements
40 CFR Part 52 – Prevention of	(Normal Operation) CTs firing natural gas: 0.0022 lb sulfuric acid mist (H2SO4)/MMBtu	See citation limitation

Significant Deterioration – BACT	(Average of three (3) test runs) (BACT/State BAT). Fuel sulfur content less than 0.5 gr/100scf.	
25 Pa. Code Chapter 127.12(a)(5) – State BAT	(Normal Operation) CTs firing natural gas: 0.0022 lb H2SO4/MMBtu (Average of three (3) test runs) (BACT/State BAT) Fuel sulfur content less than 0.5 gr/100scf.	Compliance with PSD BACT requirements for H2SO4 will ensure compliance with State BAT requirements.
25 Pa. Code Chapter 127.12(a)(5) – State BAT	(Normal Operation) CTs firing natural gas with less than 9.35 lbs/hr of CO @15% O2 (4-hour rolling average)(State BAT) (Startup/Shutdown Periods): Refer to Addendum 1 for emission limits during periods of startup and shutdown.	See citation limitation
40 CFR Part 52 – Prevention of Significant Deterioration – BACT	(Normal Operation) Each CT firing natural gas: 0.011 lb PM/MMBtu (average of three (3) stack test runs) Particulate matter comprises total particulate matter (PM), particulate matter with a diameter of less than 10 microns (PM10) including condensables, and particulate matter with a diameter of less than 2.5 microns (PM2.5) including condensables.	See citation limitation
25 Pa. Code §123.11(a)(3) – Standards for Contaminants (Combustion Units)	0.147 lbs PM/MMBtu	Compliance with PSD BACT requirements for PM will ensure compliance with 25 Pa. Code §123.11 requirements.
25 Pa. Code Chapter 127.12(a)(5) – State BAT	(Normal Operation) Each CT firing natural gas: 0.011 lb PM/MMBtu (average of three (3) stack test runs) Particulate matter comprises total particulate matter (PM), particulate matter with a diameter of less than 10 microns (PM10) including condensables, and particulate matter with a diameter of less than 2.5 microns (PM2.5) including condensables.	Compliance with PSD BACT requirements for PM will ensure compliance with State BAT requirements.
40 CFR Part 52 – Prevention of Significant Deterioration – BACT	1,450 lb CO2e/MW-hr (natural gas)	See citation limitation
25 Pa. Code Chapter 127.12(a)(5) – State BAT	1,450 lb CO2e/MW-hr (gross)	Compliance with PSD BACT requirements for CO2e will ensure compliance with State BAT requirements.
25 Pa. Code §123.22 –	4 lbs sulfur dioxide (SO2)/MMBtu (over a 1-hr	Compliance with NSPS KKKK requirements for SO2 will ensure compliance with 25 Pa. Code

Standards for Contaminants (Combustion Units)	period)	§123.22 requirements.
25 Pa. Code Chapter 127.12 (a)(5) – State BAT	Firing Natural Gas: 0.0014 lb SO2/MMBtu	See citation limitation
40 CFR Part 60, Subpart KKKK, §60.4330 – Standards of Performance for New Stationary Sources	0.90 lb SO2/MWh gross output, or 0.060 lb SO2/MMBtu heat input	Compliance with State BAT for SO2 will assure compliance with Subpart KKKK.
40 CFR 63 Subpart YYYY (§63.6095(c))	Limit the concentration of formaldehyde to 91 ppbvd or less at 15% O2.	See citation limitation
25 Pa. Code §123.41 – Standards for Contaminants (Limitations)	Limit visible emissions to 20% for a period or periods aggregating more than three (3) minutes in any one (1) hour, and 60% at any time	Compliance with PSD BACT requirements for PM emissions will ensure compliance with 25 Pa. Code §123.41 requirements.
25 Pa. Code §127.531 and 40 CFR Parts 72-73, 75, and 77 – Acid Rain Permit	Submit an Acid Rain new unit exemption application to the permitting authority	See citation limitation

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Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id: 80-0833693 **Firm Name:** Homer City Generation, L.P.

Plant Code: **Plant Name:** Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Ten (10) new simple cycle CTs

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: VOC: 25 Pa. Code Chapter 127.12(a)(5) – State BAT and 25 Pa. Code Chapter 127.205 – LAER

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☐ **Monitoring** ☒ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):**
2. **Monitoring device location:**

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

3. **How will data be reported:**

Section 3: Testing

1. Reference Test Method Description:	Stack testing following U.S. EPA Reference Method 18, 25A, or equivalent.
2. Reference Test Method Citation:	U.S. EPA Reference Method 18, 25A, or equivalent

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation will retain a copy of initial stack test results. Electronic storage includes the type of fuel being fired, the amount of fuel being fired, and if startup or shutdown is occurring.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Results of initial stack test within 60 days of stack test completion.

1. Reporting start date:	Within 60 days of completion of initial stack test.

Section 6: Work Practice Standard

Describe any work practice standards:

Homer City Generation will ensure this equipment is operated according to manufacturer's specifications in order to meet the
following emission limits:

VOC emissions will not exceed the following during normal operation:

(Normal Operation) CTs firing natural gas:
3.75 lbs/hr VOC @15% O2 (LAER/State BAT)(average of 3-run stack test using EPA Reference Method 25A)

Emissions during startup and shutdown shall be limited as follows:
1.3 lbs VOC/startup, where startup is defined as from initiation of unit start until full load emissions compliance, not to exceed 30 minutes in duration;
0.5 lbs VOC/shutdown, defined as the time that the combustion turbine drops below MECL during shutdown to termination of fuel flow to the combustion turbine, not to exceed 9 minutes in duration.

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Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Ten (10) new simple cycle CTs

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: NOX: Limitations for 40 CFR Part 60, Subpart KKKK, §60.4320 – Standards of Performance for New Stationary Sources, 25 Pa. Code Chapter 127.12(a)(5) – State BAT, 25 Pa. Code §123.51 – Standards for Contaminants (Monitoring Requirements)

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☒ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):** NOx CEM
2. **Monitoring device location:** After add-on SCR control.

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

Per 40 CFR §60.4345,

1. Each NOX diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in 40 CFR Part 60, Appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in 40 CFR Part 60, Appendix F is not required. Alternatively, a NOx diluent CEMS that is installed and certified according to Appendix A of Part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

2. As specified in 40 CFR §60.13(e)(2), during each full unit operating hour, both the NOX monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one (1) valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two (2) valid data points (one (1) in each of two (2) quadrants) are required for each monitor to validate the NOx emission rate for the hour.

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

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

5. Homer City Generation shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, Homer City Generation may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in Section 1 of Appendix B to Part 75 of this chapter.

3. How will data be reported:	Deviations will be reported quarterly.

Section 3: Testing

1. Reference Test Method Description:	Per 40 CFR §60.4405, complete initial performance test for NOx using CEMS RATA runs.
2. Reference Test Method Citation:	U.S. EPA Reference Method 7E, or equivalent

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Per 40 CFR §60.7(b), Homer City Generation shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

Per 40 CFR §60.7(f), Homer City Generation shall retain a file of all information required for at least two (2) years following the date of the record.

Per 40 CFR §60.4345(e), Homer City Generation shall develop and keep on-site a QA plan for the NOX CEMS monitoring equipment.

Electronic storage includes CEM NOx minute data, the type of fuel being fired, the amount of fuel being fired, whether duct firing is occurring, and if startup or shutdown is occurring.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Per 40 CFR §60.7, Homer City Generation shall submit notification of the date of construction or reconstruction and actual start-up.

Per 40 CFR §60.4375(a), for each affected unit required to continuously monitor parameters or emissions, Homer City Generation must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

Per 40 CFR §60.4375(b), for each affected unit that performs annual performance tests in accordance with §60.4340(a), Homer City Generation must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

1. Reporting start date:	Per 40 CFR §60.7, notification of construction commencement must be postmarked no later than 30 days after such date and notification of actual start-up is due must be post marked within 15 days of that date. Quarterly CEMS reporting to U.S. EPA and PADEP.

Section 6: Work Practice Standard

Describe any work practice standards:

Homer City Generation will ensure this equipment is operated according to manufacturer's specifications in order to meet the
following emission limits:

NOx emissions will not exceed the following during normal operation:

(Normal Operation) CTs firing natural gas:
2.5 ppmvd NOx at 15% O2 (State BAT) (4-hour rolling average)

Emissions during startup and shutdown shall be limited as follows:
14.4 lbs NOx/startup, where startup is defined as from initiation of unit start until full load emissions compliance, not to exceed 30 minutes in duration;
2.8 lbs NOx/shutdown, defined as the time that the combustion turbine drops below MECL during shutdown to termination of fuel flow to the combustion turbine, not to exceed 9 minutes in duration.

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DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Addendum 1
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SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Ten (10) new simple cycle CTs

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: H2SO4: 40 CFR Part 52 – Prevention of Significant Deterioration and 25 Pa. Code Chapter 127.12(a)(5) – State BAT

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☒ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. Monitoring device type (stack test, CEM, etc.): Testing of fuels for sulfur content or obtaining certified fuel sulfur content using test results from the fuel supplier.

2. Monitoring device location: Fuel

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

Monthly sampling of natural gas for sulfur content will be conducted or facility owner/operator will obtain fuel supplier-testing results.

3. How will data be reported: N/A

Section 3: Testing

1. Reference Test Method Description:	Initial stack testing to determine emission factors.
2. Reference Test Method Citation:	U.S. EPA Reference Method 8, or equivalent

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation shall retain copies of initial stack test results. A correlation emissions factor will be developed from fuel sampling results at the time of stack testing.

Records of monthly sulfur content samples of natural gas will be recorded for use in determining monthly H2SO4 emissions.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Results of initial stack test within 60 days of stack test completion.

1. Reporting start date:	Within 60 days of completion of initial stack test.

Section 6: Work Practice Standard

Describe any work practice standards:

Homer City Generation will ensure this equipment is operated according to manufacturer's specifications in order to meet the
following emission limits:

(Normal Operation) CTs firing natural gas:
0.0022 lb H2SO4/MMBtu (Average of three (3) test runs) (BACT/State BAT)

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SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Ten (10) new simple cycle CTs

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: 25 Pa. Code Chapter 127.12(a)(5) – State BAT

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☒ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):** CO CEM
2. **Monitoring device location:** After oxidation catalyst.

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

CO will be monitored continuously, one measurement at least every 15 minutes

3. **How will data be reported:** Deviations will be reported quarterly.

Section 3: Testing

1. Reference Test Method Description:	Initial performance test for CO using CEMS RATA runs.
2. Reference Test Method Citation:	U.S. EPA Reference Method 10, or equivalent

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation shall retain copies of initial stack test results.

The CO CEM will record one (1) minute averages for use in determining 4-hr rolling average CO emission values.

Electronic storage includes CEM CO minute data, the type of fuel being fired, the amount of fuel being fired, whether duct firing is occurring, and if startup or shutdown is occurring.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Results of initial stack test within 60 days of stack test completion.

Submission of Quarterly CEMS data to PADEP.

1. Reporting start date:	Within 60 days of completion of initial stack test.

Section 6: Work Practice Standard

Describe any work practice standards:

Homer City Generation will ensure this equipment is operated according to manufacturer's specifications in order to meet the
following emission limits:

CO emissions will not exceed the following during normal operation:

(Normal Operation) CTs firing natural gas:
9.35 lbs/hr CO @15% O2 (4-hour rolling average)(State BAT)

Emissions during startup and shutdown shall be limited as follows:
27.7 lbs CO/startup, where startup is defined as from initiation of unit start until full load emissions compliance, not to exceed 30 minutes in duration;
6.7 lbs CO/shutdown, defined as the time that the combustion turbine drops below MECL during shutdown to termination of fuel flow to the combustion turbine, not to exceed 9 minutes in duration.

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SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id: 80-0833693 **Firm Name:** Homer City Generation, L.P.

Plant Code: **Plant Name:** Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Ten (10) new simple cycle CTs

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: PM/PM10/PM2.5: 40 CFR Part 52 – Prevention of Significant Deterioration, 25 Pa. Code §123.11(a)(3) – Standards for Contaminants (Combustion Units) and 25 Pa. Code Chapter 127.12(a)(5) – State BAT

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☐ **Monitoring** ☒ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. Monitoring device type (stack test, CEM, etc.):

2. Monitoring device location:

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

3. How will data be reported:

Section 3: Testing

1. Reference Test Method Description:	Initial stack testing to determine filterable and condensable PM/PM10/PM2.5 emissions factors.
2. Reference Test Method Citation:	U.S. EPA Reference Methods 201/201A or equivalent and Method 202.

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation shall retain copies of initial stack test results and record the amount and type of fuel being fired.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Results of initial stack test within 60 days of stack test completion.

1. Reporting start date:	Within 60 days of completion of initial stack test.

Section 6: Work Practice Standard

Describe any work practice standards:

Homer City Generation will ensure this equipment is operated according to manufacturer's specifications in order to meet the
following emission limits:

PM/PM10/PM2.5 emissions will not exceed the following during normal operation:

(Normal Operation) Each CT firing natural gas:
0.011 lb PM/MMBtu (average of three (3) stack test runs)

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Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Ten (10) new simple cycle CTs

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: CO2e: 40 CFR Part 52 – Prevention of Significant Deterioration and 25 Pa. Code Chapter 127.12(a)(5) – State BAT

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☐ **Monitoring** ☒ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):**
2. **Monitoring device location:**

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

3. **How will data be reported:**

Section 3: Testing

1. Reference Test Method Description:	Initial stack testing to determine emission factors.
2. Reference Test Method Citation:	U.S. EPA Reference Method 3A, or equivalent.

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation shall retain copies of initial stack test results. Homer City Generation shall record the type and amount of fuel being fired,
and whether duct firing is occurring.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Results of initial stack test within 60 days of stack test completion.

1. Reporting start date:	Within 60 days of completion of initial stack test.

Section 6: Work Practice Standard

Describe any work practice standards:

Homer City Generation will ensure this equipment is operated according to manufacturer's specifications in order to meet the
following emission and efficiency limits:

1,425 lb CO2e/MWh (gross)

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Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Ten (10) new simple cycle CTs

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: SO2: 25 Pa. Code §123.22 – Standards for Contaminants (Combustion Units), 25 Pa. Code Chapter 127.12(a)(5) – State BAT, and 40 CFR Part 60, Subpart KKKK, §60.4330 – Standards of Performance for New Stationary Sources

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☐ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):** Sulfur in fuel monitoring.
2. **Monitoring device location:** Prior to combustion.

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

Per 40 CFR §60.4360 and §60.4365, Homer City Generation will demonstrate that the fuel it fires in the turbines does not exceed potential sulfur emissions of 0.060 lb SO2/MMBtu heat input by using one (1) of the following sources of information to make the required demonstration:

1. The fuel quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract for the fuel, specifying that the total sulfur content for natural gas use is 20 grains of sulfur or less per 100 standard cubic feet, and has potential sulfur emissions of less than less than 0.060 lb SO2/MMBtu; or

2. Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 0.060 lb SO2/MMBtu heat input.

Monthly sampling of natural gas for sulfur content will be conducted.

3. How will data be reported:	Deviations will be reported semi-annually.

Section 3: Testing

1. Reference Test Method Description:	N/A
2. Reference Test Method Citation:	N/A

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Records of monthly sulfur content samples of the natural gas will be recorded for use in determining monthly SO2 emissions.

Per 40 CFR §60.7(f) and 25 Pa. Code §123.22(g)(4)(i), Homer City Generation shall retain a file of all information required for at least two (2) years following the date of the record.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Per 40 CFR §60.7, Homer City Generation shall submit notification of the date of construction or reconstruction and actual start-up.

Per 40 CFR §60.4375(a), for each affected unit required to periodically determine the fuel sulfur content under this subpart, Homer City Generation must submit reports of excess emissions and monitor downtime, in accordance with 40 CFR §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

Per 40 CFR §60.4375(b), for each affected unit that performs annual performance tests in accordance with §60.4340(a), Homer City Generation must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

1. Reporting start date:	Per 40 CFR §60.7, notification of construction commencement must be postmarked no later than 30 days after such date and notification of actual start-up is due must be post marked within 15 days of that date.

Section 6: Work Practice Standard

Describe any work practice standards:

Homer City Generation will monitor the sulfur content of the fuel fired at the facility in order to meet the following emission limits:
Firing Natural Gas: 0.0014 lb SO2/MMBtu

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Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Ten (10) new simple cycle CTs

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: *Although the proposed project is not subject to 40 CFR Part 63 Subpart YYYY, Homer City Generation proposes to comply with the formaldehyde emission limitation in Table 1 of this Subpart for State BAT.

Limit the concentration of formaldehyde to 91 ppbvd or less at 15% O2.

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☒ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☐ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):** Oxidation catalyst inlet temperature.
2. **Monitoring device location:** Inlet ductwork to oxidation catalyst.

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

Oxidation catalyst inlet temperature will be monitored on a 4-hour rolling average basis. Measurements will be taken at least once every fifteen minutes.

3. **How will data be reported:** Data will be reported through data historian.

Section 3: Testing

1. Reference Test Method Description:	The formaldehyde concentration must be corrected to 15% O2, on a dry basis. Results of this one (1) time performance test shall consist of the average of three 1-hour runs. Test must be conducted within 10 percent of 100% load.
2. Reference Test Method Citation:	Test Method 320 of 40 CFR Part 63, Appendix A; ASTM D6348-12e1 provided that the test plan preparation and implementation provisions of Annexes A1 through A8 are followed and the %R as determined in Annex A5 is equal or greater than 70% and less than or equal to 130%; or other methods approved by the Administrator

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Maintain source test report for a period of five (5) years.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Results of stack testing within 60 days of stack test completion and will be submitted through EPA's CDX and CEDRI online reporting systems per 40 CFR §60.6150.

Reporting of catalyst inlet temperature will be submitted semi-annually per 40 CFR §60.6150.

1. Reporting start date:	Report of stack testing within 60 days of completion of the source testing. Reports of deviations will be submitted by the first semi-annual compliance date (either January 31 or July 31).

Section 6: Work Practice Standard

Describe any work practice standards:

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Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Ten (10) new simple cycle CTs

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: Visible Emissions: 25 Pa. Code §123.41 – Standards for Contaminants (Limitations)

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☐ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):** Visual monitoring U.S. EPA Reference Method 9, or equivalent
2. **Monitoring device location:** N/A

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

Opacity, weekly visual monitoring

3. **How will data be reported:** Deviations will be reported semi-annually.

Section 3: Testing

1. Reference Test Method Description:	Visible Emissions
2. Reference Test Method Citation:	U.S. EPA Reference Method 9, or equivalent

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation will retain copies of weekly inspection results.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Semi-annual reporting of monitoring deviations for visible emissions monitoring.

1. Reporting start date:	First compliance certification submittal.

Section 6: Work Practice Standard

Describe any work practice standards:

Homer City Generation will ensure this equipment is operated according to manufacturer's specifications in order to not exceed
the following visible emissions limitation:
20% for a period or periods aggregating more than three (3) minutes in any one (1) hour, and 60% at any time.

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SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id: 80-0833693 **Firm Name:** Homer City Generation, L.P.

Plant Code: **Plant Name:** Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Ten (10) new simple cycle CTs

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: 25 Pa. Code §127.531 and 40 CFR Parts 72-73, 75, and 77 – Acid Rain Permit

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☐ **Monitoring** ☐ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☐ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):**
2. **Monitoring device location:**

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

3. **How will data be reported:**

Section 3: Testing

1. Reference Test Method Description:

2. Reference Test Method Citation:

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Maintain records that the nameplate capacity of each generator is not more than 25 MWe and the sulfur content of the gaseous fuel burned is less than 0.05 percent by weight.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Submit an Acid Rain new unit exemption application to the permitting authority.

1. Reporting start date: An Acid Rain new unit exemption application must be submitted before the date on which the unit commences operation.

Section 6: Work Practice Standard

Describe any work practice standards:

3. Fuel Gas Heaters

- Section B – Combustion Unit Information
- Section F – Flue and Air Contaminant Emission
- Addendum A: Source Applicable Requirements
- Addendum 1: Method of Compliance Worksheets

Section B - Combustion Unit Information

2. Combustion Units: ☐ Coal ☐ Oil ☒ Natural Gas Other: _____

Description: Fuel gas heaters

Manufacturer	Model No.	Number of units
TBD	TBD	7

Maximum heat input (Btu/hr)	Rated heat input (Btu/hr)	Typical heat input (Btu/hr)	Furnace Volume
10.8 MMBtu/hr, each	10.8 MMBtu/hr, each	10.8 MMBtu/hr, total	

Grate Area (if applicable)	Method of firing
N/A	

Indicate how combustion air is supplied to boiler
N/A

Indicate the Steam Usage: N/A

Mark and describe soot Cleaning Method:

i. Air Blown
ii. Steam Blown
iii. Brushed and Vacuumed
iv. Other N/A
v. Frequency of Cleaning _____

Maximum Operating schedule

Hours/Day	Days/Week	Days/Year	Hours/Year
24 (each)	7 (each)	365 (each)	8,760 (each)

Operational restrictions taken or requested, if any (e.g., bottlenecks or voluntary restrictions to limit potential to emit)

Capacity (specify units)

Per hour	Per day	Per week	Per year
10.8 MMBtu (each)	259.2 MMBtu	1,814.4 MMBtu	94,608 MMBtu

Typical Operating schedule

Hours/Day	Days/Week	Days/Year	Hours/Year
24 (each)	7 (each)	365 (each)	8,760 (each)

Seasonal variations (Months): If variations exist, describe them.

Operating using primary fuel: _____ From _____ to _____
Operating using secondary fuel: _____ Form _____ to _____
Non-operating: From _____ to _____

3. Specify the primary, secondary and startup fuel. Furnish the details in item 3.
Natural gas will be the primary fuel.

Section B - Combustion Unit Information (Continued)

5. Fuel

Type	Quantity Hourly	Annually	Sulfur	% Ash (Weight)	BTU Content
Oil Number	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Oil Number	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Oil Number	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Natural Gas	0.0106 SCFH	92.59 X 10^6 SCF	0.5 gr/100 SCF	0	1,020 Btu/SCF
Gas (other)	SCFH	X 10^6 Gal	gr/100 SCF		Btu/SCF
Coal					
Other*					

***** Note: Describe and furnish information separately for other fuels in Addendum B.

6. Burner

Manufacturer	Model Number	Type of Atomization (Steam, air, press, mech., rotary cup)
TBD	TBD	N/A

Number of Burners	Maximum fuel firing rate (all burners)	Normal fuel firing rate
TBD	10.8 MMBtu/hr	10.8 MMBtu/hr

If oil, temperature and viscosity.

Maximum theoretical air requirement

Percent excess air 100% rating

Turndown ratio

Combustion modulation control (on/off, low-high fire, full automatic, manual). Describe.

Main burner flame ignition method (electric spark, auto gas pilot, hand-held torch, other). Describe.

5. Nitrogen Oxides (NO_x) control Options

Mark and describe the NO_x control options adopted

	Low excess air (LEA)	Flue gas recirculation	Other._____
	Over fire air (OFA)	Burner out of service	
X	Low-NO_x burner	Reburning	
	Low NO_x burners with over fire air	Flue gas treatment (SCR / SNCR)	

Section B - Combustion Unit Information (Continued)

6. Miscellaneous Information

Describe fly ash reinjection operation
N/A

Describe, in detail, the equipment provided to monitor and to record the source(s) operating conditions, which may affect emissions of air contaminants. Show that they are reasonable and adequate.

See, Addendum A Forms

Describe each proposed modification to an existing source.

N/A

Describe how emissions will be minimized especially during start up, shut down, combustion upsets and/or disruptions. Provide emission estimates for start up, shut down and upset conditions. Provide duration of start up and shut down.

The fuel gas heaters are designed to operate with minimal startups and shutdowns. Emissions during

startup/shutdown will be minimized by limiting the time that the units are in startup or shutdown mode.

Describe in detail with a schematic diagram of the control options adopted for SO_2 (if applicable).
N/A

Anticipated milestones:

Expected commencement date of construction/reconstruction: Upon permit issuance
Expected completion date of construction/reconstruction: Anticpated third quarter 2029
Anticipated date(s) of start-up: Anticpated fourth quarter 2029

Section F - Flue and Air Contaminant Emission

1. Estimated Maximum Emissions*

Pollutant	Maximum emission rate			Calculation/ Estimation Method
	specify units	lbs/hr	tons/yr.	
PM		0.05	1.59	Vendor data
$PM_{10/2.5}$		0.05	1.59	Vendor data
SO_x		0.02	0.46	Mass balance
CO		0.40	12.2	Vendor data
NO_x		0.32	9.92	Vendor data
VOC		0.05	1.65	Vendor data
Others: (e.g., HAPs)	-----	-----	-----	-----
Max single HAP	(hexane)	1.33E-01	5.83E-01	AP-42
Total HAP		1.40E-01	6.12E-01	AP-42

* These emissions must be calculated based on the requested operating schedule and/or process rate e.g., operating schedule for maximum limits or restricted hours of operation and /or restricted throughput. Describe how the emission values were determined. Attach calculations.

2. Stack and Exhauster

Stack Designation/Number HTR_1 through HTR_7

List Source(s) or source ID exhausted to this stack:	% of flow exhausted to stack: 100
Fuel Gas Heaters 1-7	

Stack height above grade (ft.) 15 Grade elevation (ft.) 1200	Stack diameter (ft) or Outlet duct area (sq. ft.) 2.5	Weather Cap ☐ YES ☒ NO

Distance of discharge to nearest property line (ft.). Locate on topographic map.

See, Point Source Locations Table and Appendix E

Does stack height meet Good Engineering Practice (GEP)?

No

If modeling (estimating) of ambient air quality impacts is needed, attach a site plan with buildings and their dimensions and other obstructions. See, Application Narrative Section 6

Location of Stack**	Latitude			Longitude		
Latitude/Longitude Point of Origin	Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
See, Point Source Locations Table						

Stack Exhaust

Volume 3,434 ACFM Temperature 670 °F Moisture _____ %

Exhauster (attach fan curves) _____ in. of water _____ HP @ _____ RPM.

** If the datum and collection method information and codes differ from those provided on the General Information Form - Authorization Application, provide the additional required by that form on a separate sheet.

Point Source Locations Table: Fuel Gas Heaters

	Latitude	Longitude	Distance to Property Boundary
Fuel Gas Heater 1	40° 31' 16.25"" N	079° 12' 2.01"" W	1,803 ft
Fuel Gas Heater 2	40° 31' 12.09"" N	079° 12' 2.01"" W	1,994 ft
Fuel Gas Heater 3	40° 31' 7.9"" N	079° 12' 2.01"" W	2,101 ft
Fuel Gas Heater 4	40° 31' 3.73"" N	079° 12' 2.01"" W	2,180 ft
Fuel Gas Heater 5	40° 31' 7.91"" N	079° 11' 52.67"" W	2,629 ft
Fuel Gas Heater 6	40° 31' 3.74"" N	079° 11' 52.66"" W	2,898 ft
Fuel Gas Heater 7	40° 30' 59.58"" N	079° 11' 52.67"" W	2,938 ft

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Addendum A: Source Applicable Requirements

Describe and cite all applicable requirements pertaining to this source.
Note: A Method of Compliance Worksheet (Addendum 1) must be completed for each requirement listed.

Citation Number	Citation Limitation	Limitation Used
25 Pa. Code Chapter 123 – Standards for Contaminants	PM limit: 0.4 lb/MMBtu; Visible emissions: 20% for a period or periods aggregating more than three (3) minutes in any one (1) hour, and 60% at any time	PM Limit: Compliance with PSD-BACT, and/or State BAT requirements will assure compliance with Chapter 123 PM emission requirements. Visible Emissions: Method 9.
40 CFR Part 52 – PSD 25 Pa. Code Chapter 127.12(a)(5) – State BAT 25 Pa. Code Chapter 127.205 – LAER	Compliance with State BAT, NNSR LAER and Federal PSD Air Pollution Control Technology Requirements as applicable.	PM/PM10/PM2.5 – 0.0048 lb/MMBtu (BACT/State BAT) NOX – 0.03 lb/MMBtu (BACT/State BAT/LAER) CO – 0.04 lb/MMBtu (BACT/State BAT) VOC – 0.005 lb/MMBtu (State BAT/LAER) SO2 – 0.0014 lb/MMBtu (State BAT) H2SO4 – 2.14E-5 lb/MMBtu (State BAT/BACT) GHGs – good combustion practices, clean fuels and energy efficiency utilization BACT/State BAT)
40 CFR 63 Subpart DDDDD	Performance of tune-ups, either annually or every 5 years	Record and maintain records of the tune-ups. Provide initial notification.

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id: 80-0833693 **Firm Name:** Homer City Generation, L.P.

Plant Code: **Plant Name:** Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Seven (7) Fuel Gas Heaters

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: 25 Pa. Code Chapter 123 – Standards for Contaminants (PM, Visible Emissions)

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☐ **Monitoring** ☒ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):** N/A
2. **Monitoring device location:** N/A

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

N/A

3. **How will data be reported:** N/A

Section 3: Testing

1. Reference Test Method Description:	Visible Emissions Observation
2. Reference Test Method Citation:	U.S. EPA Reference Method 9, or equivalent

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation will keep copies of each vendor guarantees for emissions and retain a record of visible emissions observations.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Annual compliance

certification.

1. Reporting start date:	Within one (1) year of startup.

Section 6: Work Practice Standard

Describe any work practice standards:

Good combustion practices, clean fuels, and energy efficiency will be utilized in order to meet the following emission limits:

PM emissions shall not exceed 0.4 lb/MMBtu;

Visible emissions shall not exceed 20% for a period or periods aggregating more than three (3) minutes in any one (1) hour, and 60% at any time.

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DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id: 80-0833693 **Firm Name:** Homer City Generation, L.P.

Plant Code: **Plant Name:** Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Seven (7) Fuel Gas Heaters

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: 40 CFR Part 52 – PSD, 25 Pa. Code Chapter 127.12(a)(5) – State BAT, and 25 Pa. Code Chapter 127.205 – LAER

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☐ **Monitoring** ☐ **Testing** ☐ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):** N/A
2. **Monitoring device location:** N/A

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

N/A

3. **How will data be reported:** N/A

Section 3: Testing

1. Reference Test Method Description:	N/A
2. Reference Test Method Citation:	N/A

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation will keep copies of each vendor guarantees for emissions.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Annual compliance certification.

1. Reporting start date:	Within one (1) year of startup.

Section 6: Work Practice Standard

Describe any work practice standards:

Good combustion practices, clean fuels, and energy efficiency will be utilized in order to meet the following emission limits:

PM/PM10/PM2.5 – 0.0048 lb/MMBtu (BACT/State BAT)

NOX – 0.03 lb/MMBtu (State BAT)

CO – 0.04 lb/MMBtu (State BAT)

VOC – 0.005 lb/MMBtu (State BAT/LAER)

SO2 – 0.0014 lb/MMBtu (State BAT)

H2SO4 – 2.14E-5 lb/MMBtu (State BAT/BACT)

GHGs – good combustion practices, clean fuels and energy efficiency utilization (BACT/State BAT)

4. Auxiliary Boilers

- Section B – Combustion Unit Information
- Section C – Air Cleaning Device
- Section F – Flue and Air Contaminant Emission
- Addendum A: Source Applicable Requirements
- Addendum 1: Method of Compliance Worksheets

Section B - Combustion Unit Information

1. Combustion Units: ☐ Coal ☐ Oil ☒ Natural Gas Other: _____

Description: Three (3) natural gas-fired auxiliary boilers.

Manufacturer	Model No.	Number of units	
Superior Boiler or equivalent	TBD	3	
Maximum heat input (Btu/hr)	**Rated heat input (Btu/hr)**	**Typical heat input (Btu/hr)**	**Furnace Volume**
67.0 MMBtu/hr (each)	67.0 MMBtu/hr (each)	67.0 MMBtu/hr (each)	TBD
Grate Area (if applicable)		**Method of firing**	
N/A		TBD	

Indicate how combustion air is supplied to boiler
N/A

Indicate the Steam Usage: Steam from the auxiliary boiler is used to preheat components of the HRSG and steam turbine.

Mark and describe soot Cleaning Method:

i. Air Blown
ii. Steam Blown
iii. Brushed and Vacuumed
iv. Other N/A
v. Frequency of Cleaning _____

Maximum Operating schedule

Hours/Day	Days/Week	Days/Year	Hours/Year
24 (each)	7 (each)	365 (each)	438 (each)

Operational restrictions taken or requested, if any (e.g., bottlenecks or voluntary restrictions to limit potential to emit)

Capacity (specify units)

Per hour	Per day	Per week	Per year
67.0 MMBtu (each)	1,608 MMBtu (each)	11,256 MMBtu (each)	29,346 MMBtu (each)

Typical Operating schedule

Hours/Day	Days/Week	Days/Year	Hours/Year
24(each)	7 (each)	365 (each)	438 (each)

Seasonal variations (Months): If variations exist, describe them.

Operating using primary fuel: _____ From _____ to _____
Operating using secondary fuel: _____ Form _____ to _____
Non-operating: From _____ to _____

2. Specify the primary, secondary and startup fuel. Furnish the details in item 3.
Natural gas only.

Section B - Combustion Unit Information (Continued)

3. Fuel

Type	Quantity Hourly	Annually	Sulfur	% Ash (Weight)	BTU Content
Oil Number	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Oil Number	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Oil Number	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Natural Gas	65,700 SCFH	28.78 MMscf/yr X 10^6 Gal	0.5 gr/100 SCF	0	1,020 Btu/SCF
Gas (other)	SCFH	X 10^6 Gal	gr/100 SCF		Btu/SCF
Coal					
Other*					

* Note: Describe and furnish information separately for other fuels in Addendum B.

4. Burner

Manufacturer	Model Number	Type of Atomization (Steam, air, press, mech., rotary cup)
Superior Boiler or equivalent	TBD	N/A

Number of Burners	Maximum fuel firing rate (all burners)	Normal fuel firing rate
1	0.0657 MMscf/hr (each boiler)	0.0657 MMscf/hr (each boiler)

If oil, temperature and viscosity.
N/A

Maximum theoretical air requirement
N/A

Percent excess air 100% rating
N/A

Turndown ratio
N/A

Combustion modulation control (on/off, low-high fire, full automatic, manual). Describe.
N/A

Main burner flame ignition method (electric spark, auto gas pilot, hand-held torch, other). Describe.
N/A

5. Nitrogen Oxides (NO_x) control Options

Mark and describe the NO_x control options adopted

	Low excess air (LEA)	Flue gas recirculation	Other._____
	Over fire air (OFA)	Burner out of service	
X	Low-NO_x burner	Reburning	
	Low NO_x burners with over fire air	Flue gas treatment (SCR / SNCR)	

Section B - Combustion Unit Information (Continued)

6. Miscellaneous Information

Describe fly ash reinjection operation
N/A

Describe, in detail, the equipment provided to monitor and to record the source(s) operating conditions, which may affect emissions of air contaminants. Show that they are reasonable and adequate.

See, Addendim A Forms

Describe each proposed modification to an existing source.

N/A

Describe how emissions will be minimized especially during start up, shut down, combustion upsets and/or disruptions. Provide emission estimates for start up, shut down and upset conditions. Provide duration of start up and shut down.

N/A

Describe in detail with a schematic diagram of the control options adopted for SO_2 (if applicable).
N/A

Anticipated milestones:

Expected commencement date of construction/reconstruction:	Upon permit issuance
Expected completion date of construction/reconstruction:	Anticpated third quarter 2029
Anticipated date(s) of start-up:	Anticpated fourth quarter 2029

Section C - Air Cleaning Device (Continued)

10. Costs – N/A

Indicate cost associated with air cleaning device and its operating cost (attach documentation if necessary)

Device	Direct Cost	Indirect Cost	Total Cost	Operating Cost

11 MISCELLANEOUS

Describe in detail the removal, handling and disposal of dust, effluent, etc. from the air cleaning device including proposed methods of controlling fugitive emissions.

N/A

Attach manufacturer's performance guarantees and/or warranties for each of the major components of the control system (or complete system).

The manufacturer's emissions information is attached.

Attach the maintenance schedule for the control equipment and any part of the process equipment that, if in disrepair, would increase air contaminant emissions.

The auxiliary boilers and all of its emission-related equipment will be maintained as per the manufacturer's maintenance schedule.

Section F - Flue and Air Contaminant Emission

1. Estimated Maximum Emissions*

Pollutant	Maximum emission rate			Calculation/ Estimation Method
	specify units	lbs/hr	tons/yr.	
PM		1.50	0.33	AP-42
$PM_{10/2.5}$		1.50	0.33	AP-42
SO_x		0.28	0.06	AP-42
CO		16.55	3.36	AP-42
NO_x		9.85	2.16	AP-42
VOC		1.08	0.24	AP-42
Others: (e.g., HAPs)	-----	-----	-----	-----
Max single HAP	(hexane)	0.36	7.77E-02	AP-42
Total HAPs		0.37	0.08	AP-42

* These emissions must be calculated based on the requested operating schedule and/or process rate e.g., operating schedule for maximum limits or restricted hours of operation and /or restricted throughput. Describe how the emission values were determined. Attach calculations.

2. Stack and Exhauster

Stack Designation/Number AUX_2, AUX_4, AUX_6

List Source(s) or source ID exhausted to this stack:	% of flow exhausted to stack: 100
Three Auxiliary Boilers	

Stack height above grade (ft.) 55 Grade elevation (ft.) 1200	Stack diameter (ft) or Outlet duct area (sq. ft.) 4 ft	Weather Cap ☐ YES ☒ NO

Distance of discharge to nearest property line (ft.). Locate on topographic map.

See, Point Source Locations Table and Appendix E

Does stack height meet Good Engineering Practice (GEP)?

No

If modeling (estimating) of ambient air quality impacts is needed, attach a site plan with buildings and their dimensions and other obstructions. See, Application Narrative Section 6

Location of Stack**	Latitude			Longitude		
Latitude/Longitude Point of Origin	Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
See, Point Source Locations Table						

Stack Exhaust

Volume 21,242 ACFM Temperature 344.0 °F Moisture _____ %

Exhauster (attach fan curves) _____ in. of water _____ HP @ _____ RPM.

** If the datum and collection method information and codes differ from those provided on the General Information Form - Authorization Application, provide the additional required by that form on a separate sheet.

Point Source Locations Table: Auxiliary Boilers

	Latitude	Longitude	Distance to Property Boundary
Aux Boiler 2	40° 31' 9.92"" N	079° 11' 59.19"" W	2,260 ft
Aux Boiler 4	40° 31' 1.62"" N	079° 11' 59.19"" W	2,417 ft
Aux Boiler 6	40° 31' 1.62"" N	079° 11' 49.88"" W	3,133 ft

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Addendum A: Source Applicable Requirements

Describe and cite all applicable requirements pertaining to this source.
Note: A Method of Compliance Worksheet (Addendum 1) must be completed for each requirement listed.

Citation Number	Citation Limitation	Limitation Used
40 CFR 60 Subpart Dc	Recordkeeping and Notification Only	Record and maintain records of the amount of natural gas combusted during each calendar month. Provide initial notification.
25 Pa. Code Chapter 123: Standards for Contaminants	1. PM limit: 2.85E-01 lb/MMBtu; 2. SO2 limit: 4 lb/MMBTU 3. Visible emissions: 20% for a period or periods aggregating more than three (3) minutes in any one (1) hour, and 60% at any time	PM and SO2 Limit: Compliance with PSD-BACT, and/or State BAT requirements will assure compliance with Chapter 123 PM and SO2 emission requirements. Visible Emissions: Method 9.
40 CFR Part 52 – PSD 25 Pa. Code Chapter 127.12(a)(5) – State BAT 25 Pa. Code Chapter 127.205 – LAER	Compliance with State BAT, NNSR LAER and Federal PSD Air Pollution Control Technology Requirements as applicable.	PM/PM10/PM2.5 – 0.007 lb/MMBtu (BACT/ State BAT) NOx – 0.011 lb/MMBtu (State BAT) CO – 0.037 lb/MMBtu (State BAT) VOC – 0.004 lb/MMBtu (State BAT/LAER) SO2 – 0.009 lb/MMBtu (State BAT) H2SO4 – 0.0011 lb/MMBtu (BACT/State BAT) GHGs – good combustion practices, clean fuels and energy efficient utilization (BACT/State BAT)
40 CFR 63 Subpart DDDDD	Performance of tune-ups, either annually or every 5 years	Record and maintain records of the tune-ups. Provide initial notification.

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Three (3) new natural gas-fired auxiliary boilers

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: 40 CFR 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (NSPS)

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☐ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☐ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):** Fuel flow meter
2. **Monitoring device location:** Prior to burner

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

Fuel flow will be monitored continuously.

3. **How will data be reported:** N/A

Section 3: Testing

1. Reference Test Method Description:	
2. Reference Test Method Citation:	

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Per 40 CFR §60.48c (g)(2), Homer City Generation will record and maintain records of the amount of each fuel combusted during each calendar month.

Per 40 CFR §40.48c (i), Homer City Generation will maintain all records for a period of two (2) years following the date of such record.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Per 40 CFR §60.48c (a), Homer City Generation will submit notification of the date of construction or reconstruction and actual startup, as provided by 40 CFR §60.7.

1. Reporting start date:	Per 40 CFR §60.7, notification of construction commencement must be postmarked no later than 30 days after such date and notification of actual start-up is due must be post marked within 15 days of that date.

Section 6: Work Practice Standard

Describe any work practice standards:

COMMONWEALTH OF PENNSYLVANIA
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BUREAU OF AIR QUALITY

Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id: 80-0833693 **Firm Name:** Homer City Generation, L.P.

Plant Code: **Plant Name:** Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Three (3) new natural gas-fired auxiliary boilers

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: 25 Pa. Code Chapter 123 – Standards for Contaminants (PM, SO2, Visible Emissions)

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☐ **Monitoring** ☒ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

4. Monitoring device type (stack test, CEM, etc.):

5. Monitoring device location:

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

6. How will data be reported:

Section 3: Testing

3. Reference Test Method Description:	Visible emissions observation, PM and sulfur in fuel
4. Reference Test Method Citation:	U.S. EPA Reference Method 9, or equivalent, Method 5 and a total sulfur analyzer meeting ASTM D4468

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

To demonstrate compliance with the emission limits, Homer City Generation will keep copies of each vendor guarantees for
emissions, source test and fuel sulfur analyzer results. Homer City Generation will keep log of visible emissions observations.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Annual compliance certification.

1. Reporting start date:	Within one (1) year of startup.

Section 6: Work Practice Standard

Describe any work practice standards:

Good combustion practices, clean fuels, and energy efficiency will be utilized in order to meet the following emission limits:

PM emissions shall not exceed 2.85E-01 lb/MMBtu;

SO2 emissions shall not exceed 4 lb/MMBtu;

Visible emissions shall not exceed 20% for a period or periods aggregating more than three (3) minutes in any one (1) hour, and 60% at any time.

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DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id: 80-0833693 **Firm Name:** Homer City Generation, L.P.

Plant Code: **Plant Name:** Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Three (3) new natural gas-fired auxiliary boilers

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: 40 CFR Part 52 – PSD, 25 Pa. Code Chapter 127.12(a)(5) – State BAT, and 25 Pa. Code Chapter 127.205 – LAER

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☐ **Monitoring** ☐ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

7. Monitoring device type (stack test, CEM, etc.):

8. Monitoring device location:

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

9. How will data be reported:

Section 3: Testing

5. Reference Test Method Description:

6. Reference Test Method Citation:

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation will retain copies of initial stack test results. Homer City Generation will calculate Project-wide GHG emissions on a 12-month rolling average.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Results of annual stack tests within 60 days of stack test completion.

2. Reporting start date: N/A

Section 6: Work Practice Standard

Describe any work practice standards:

Good combustion practices, clean fuels, and energy efficiency will be utilized in order to meet the following emission limits:
PM/PM10/PM2.5 – 0.0075 lb/MMBtu (BACT/ State BAT)
NOX – 0.05 lb/MMBtu (State BAT)
CO – 0.08 lb/MMBtu (State BAT)
VOC – 0.00539 lb/MMBtu (State BAT/LAER)
SO2 – 0.0014 lb/MMBtu (State BAT)
H2SO4 – 0.00002 lb/MMBtu (BACT/State BAT)
GHGs – good combustion practices, clean fuels and energy efficiency utilization (BACT/State BAT)

5. Emergency Generators (1.0 MW each)

- Section B – Combustion Unit Information
- Section C – Air Cleaning Device
- Section F – Flue and Air Contaminant Emission
- Addendum A: Source Applicable Requirements
- Addendum 1: Method of Compliance Worksheets

Section B - Combustion Unit Information

1. Combustion Units: ☐ Coal ☒ Oil ☐ Natural Gas Other: _____

Description: Two (2) 1.0 MW (each 1,483 bhp) diesel fuel-fired emergency generators.

Manufacturer	Model No.	Number of units	
Caterpillar (or equivalent)	C32 or equivalent	2	
Maximum heat input (Btu/hr)	**Rated heat input (Btu/hr)**	**Typical heat input (Btu/hr)**	**Furnace Volume**
10.38 MMBtu/hr (each)	10.38 MMBtu/hr (each)	10.38 MMBtu/hr (each)	TBD
Grate Area (if applicable)		**Method of firing**	
N/A		TBD	

Indicate how combustion air is supplied to boiler
N/A

Indicate the Steam Usage:

Mark and describe soot Cleaning Method:

i. Air Blown
ii. Steam Blown
iii. Brushed and Vacuumed
iv. Other N/A
v. Frequency of Cleaning _____

Maximum Operating schedule

Hours/Day	Days/Week	Days/Year	Hours/Year
24 (each)	7 (each)	365 (each)	500 (each)

Operational restrictions taken or requested, if any (e.g., bottlenecks or voluntary restrictions to limit potential to emit)

Capacity (specify units)

Per hour	Per day	Per week	Per year
10.38 MMBtu (each)	249.14 MMBtu (each)	1,744.01 MMBtu (each)	5,190.5 MMBtu (each)

Typical Operating schedule

Hours/Day	Days/Week	Days/Year	Hours/Year
24(each)	7 (each)	365 (each)	500 (each)

Seasonal variations (Months): If variations exist, describe them.

Operating using primary fuel: _____ From _____ to _____
Operating using secondary fuel: _____ Form _____ to _____
Non-operating: From _____ to _____

2. Specify the primary, secondary and startup fuel. Furnish the details in item 3.
15 ppmw ULSD

Section B - Combustion Unit Information (Continued)

3. Fuel

Type	Quantity Hourly	Annually	Sulfur	% Ash (Weight)	BTU Content
Oil Number 2	each 75.8 GPH @ 60°F	each 37.9 X 10^3 Gal	0.0015% by wt	<0.001	each 137,000Btu/Gal. & Lbs./Gal. @ 60 °F
Oil Number	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Oil Number	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Natural Gas	SCFH	X 10^6 Gal	gr/100 SCF		Btu/SCF
Gas (other)	SCFH	X 10^6 Gal	gr/100 SCF		Btu/SCF
Coal					
Other*					

* Note: Describe and furnish information separately for other fuels in Addendum B.

4. Burner

Manufacturer	Model Number	Type of Atomization (Steam, air, press, mech., rotary cup)
N/A	N/A	N/A

Number of Burners	Maximum fuel firing rate (all burners)	Normal fuel firing rate
N/A	N/A	

If oil, temperature and viscosity.
N/A

Maximum theoretical air requirement
N/A

Percent excess air 100% rating
N/A

Turndown ratio
N/A

Combustion modulation control (on/off, low-high fire, full automatic, manual). Describe.
N/A

Main burner flame ignition method (electric spark, auto gas pilot, hand-held torch, other). Describe.
N/A

5. Nitrogen Oxides (NO_x) control Options

Mark and describe the NO_x control options adopted

Low excess air (LEA)	Flue gas recirculation	Other. TBD
Over fire air (OFA)	Burner out of service	
Low-NO_x burner	Reburning	
Low NO_x burners with over fire air	Flue gas treatment (SCR / SNCR)	

Section B - Combustion Unit Information (Continued)

6. Miscellaneous Information

Describe fly ash reinjection operation
N/A

Describe, in detail, the equipment provided to monitor and to record the source(s) operating conditions, which may affect emissions of air contaminants. Show that they are reasonable and adequate.

See, Addendim A Forms

Describe each proposed modification to an existing source.

N/A

Describe how emissions will be minimized especially during start up, shut down, combustion upsets and/or disruptions. Provide emission estimates for start up, shut down and upset conditions. Provide duration of start up and shut down.

Emissions during startup/shutdown will be minimized by limiting the time that the units are in startup or shutdown mode.

Describe in detail with a schematic diagram of the control options adopted for SO_2 (if applicable).
N/A

Anticipated milestones:

Expected commencement date of construction/reconstruction: Upon permit issuance
Expected completion date of construction/reconstruction: Anticpated third quarter 2029
Anticipated date(s) of start-up: Anticpated fourth quarter 2029

Section C - Air Cleaning Device (Continued)

10. Costs – N/A

Indicate cost associated with air cleaning device and its operating cost (attach documentation if necessary)

Device	Direct Cost	Indirect Cost	Total Cost	Operating Cost

11 MISCELLANEOUS

Describe in detail the removal, handling and disposal of dust, effluent, etc. from the air cleaning device including proposed methods of controlling fugitive emissions.

N/A

Attach manufacturer's performance guarantees and/or warranties for each of the major components of the control system (or complete system).

The manufacturer will have to certify to meet EPA Tier 4 standards for diesel generators.
This will be provided when a manufacturer is chosen.

Attach the maintenance schedule for the control equipment and any part of the process equipment that, if in disrepair, would increase air contaminant emissions.

The engines' emissions control systems will be maintained as per the manufacturer's maintenance specifications.

Section F - Flue and Air Contaminant Emission

1. Estimated Maximum Emissions*

Pollutant	Maximum emission rate			Calculation/ Estimation Method
	specify units	lbs/hr	tons/yr.	
PM		0.15	0.04	NSPS IIII
$PM_{10/2.5}$		0.14	0.03	NSPS IIII, AP-42 speciation
SO_x		0.04	9.00E-03	AP-42
CO		17.07	4.27	NSPS IIII
NO_x		3.27	0.82	NSPS IIII
TOC		0.93	0.23	NSPS IIII
Others: (e.g., HAPs)	-----	-----	-----	-----
Max single HAP	(benzene)	1.61E-02	4.03E-03	AP-42
Total HAP		3.27E-02	8.17E-03	AP-42

* These emissions must be calculated based on the requested operating schedule and/or process rate e.g., operating schedule for maximum limits or restricted hours of operation and /or restricted throughput. Describe how the emission values were determined. Attach calculations.

2. Stack and Exhauster

Stack Designation/Number S031 & S032

List Source(s) or source ID exhausted to this stack:
Emergency Generators 11 and 12

% of flow exhausted to stack: 100

Stack height above grade (ft.) 20
Grade elevation (ft.)

Stack diameter (ft) or Outlet duct area (sq. ft.)
1.2 ft

Weather Cap
☐ YES ☒ NO

Distance of discharge to nearest property line (ft.). Locate on topographic map.

See, Point Source Locations Table and Appendix E

Does stack height meet Good Engineering Practice (GEP)?
No

If modeling (estimating) of ambient air quality impacts is needed, attach a site plan with buildings and their dimensions and other obstructions. See, Application Narrative Section 6

Location of Stack** Latitude/Longitude Point of Origin	Latitude			Longitude		
	Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
See, Point Source Locations Table						

Stack Exhaust

Volume 8,065 ACFM Temperature 889.5 °F Moisture _____%

Exhauster (attach fan curves) _____ in. of water _____ HP @ _____RPM.

** If the datum and collection method information and codes differ from those provided on the General Information Form - Authorization Application, provide the additional required by that form on a separate sheet.

Point Source Locations Table: Emergency Generator Engines (1.0 MW)

	Latitude	Longitude	Distance to Property Boundary
EG-1MW-01	40° 31' 4.67"" N	079° 12' 11.84"" W	1,415 ft
EG-1MW-02	40° 31' 4.34"" N	079° 12' 12.8"" W	1,344 ft

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DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Addendum A: Source Applicable Requirements

Describe and cite all applicable requirements pertaining to this source.
Note: A Method of Compliance Worksheet (Addendum 1) must be completed for each requirement listed.

Citation Number	Citation Limitation	Limitation Used
25 Pa. Code Chapter 123 – Standards for Contaminants	25 Pa. Code §127.12(a)(5): Emissions from these sources will be the minimum attainable through the use of BAT. 25 Pa. Code §123.13(c)(1)(i): PM limit of 0.38 lb/MMBtu	Compliance with BAT will assure compliance with 25 Pa. Code §123.13(c)(1)(i).
25 Pa. Code Chapter 123 – Standards for Contaminants	25 Pa. Code §123.41 (Visible emissions): 20% for a period or periods aggregating more than three (3) minutes in any one (1) hour, and 60% at any time	Compliance with Subpart IIII requirements will assure compliance with BAT and 25 Pa. Code §123.41.
40 CFR 60 Subpart IIII (§§60.4202 and 60.4209)	NMHC: 0.19 g/kW-hr; NOx: 0.67 g/kW-hr; PM: 0.03 g/kW-hr; and CO: 3.5 g/kW-hr. A non-resettable hour meter must be installed prior to startup of each engine.	Manufacturer certification to EPA Tier 4 standards.
40 CFR 60 Subpart IIII (§60.4207)	Sulfur content – diesel fuel that meets the requirements of 40 CFR §80.510(b) – 15 ppm	Use of ULSD as fuel, which has less than or equal to 15 ppm sulfur.
40 CFR Part 52 – PSD 25 Pa. Code Chapter 127 – BAT	H2SO4: 0.0004 lb/MMBtu; CO: 2.61 g/hp-hr; PM/PM10/PM2.5: 0.022 g/hp-hr; VOC: 0.142 g/hp-hr; and NOx: 0.5 g/hp-hr.	Compliance with Subpart IIII emissions requirements will assure compliance with BACT/State BAT requirements.
25 Pa. Code Chapter 127.205 – LAER	VOC: 0.142 g/hp-hr;	Same limits used.
40 CFR 63 Subpart ZZZZ	No limitations are applicable for emergency engines > 500 bhp at major source of HAP emissions.	Only required to submit initial notification.

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DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Ten (10) Emergency Generators (2.5 MW), Two (2) Emergency Generators (1.0 MW)

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: 40 CFR Part 52 – PSD, 25 Pa. Code Chapter §127.12 – BAT, Chapter §123.13 – Standards for Contaminants (PM), and 25 Pa. Code Chapter §127.205 – LAER

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☐ **Monitoring** ☐ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

10. Monitoring device type (stack test, CEM, etc.): N/A

11. Monitoring device location:

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

12. How will data be reported:

Section 3: Testing

7. Reference Test Method Description: N/A

8. Reference Test Method Citation:

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation will retain records and 12-month rolling average fuel usage rates by fuel type.

Homer City Generation will retain records of supporting calculations used to determine compliance with the emissions limits based on manufacturer guarantees.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Report emissions to PADEP annually to demonstrate compliance with permitted emissions limits and for the annual air emissions inventory.

3. Reporting start date: One (1) year after start-up

Section 6: Work Practice Standard

Describe any work practice standards:

(1) Operate and maintain the stationary CI internal combustion engines and control devices according to the manufacturer's emissions-related written instructions;

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

(3) Meet the requirements of 40 CFR Parts 89, and/or 1068, as they apply.

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BUREAU OF AIR QUALITY

Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Ten (10) Emergency Generators (2.5 MW), Two (2) Emergency Generators (1.0 MW)

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: 40 CFR Part 52 – PSD, 25 Pa. Code Chapter §127.12 – BAT, Chapter §123.13 – Standards for Contaminants (PM), and 25 Pa. Code Chapter §127.205 – LAER

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☐ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☐ **Work Practice Standard**

Section 2: Monitoring

13. Monitoring device type (stack test, CEM, etc.): Methods 9 and 22

14. Monitoring device location: N/A

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

Periodic monitoring of emergency generator stacks for presence of visible emissions while operating.

15. How will data be reported: Deviations will be reported semi-annually.

Section 3: Testing

9. Reference Test Method Description: N/A

10. Reference Test Method Citation:

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation will retain records of visible emissions readings conducted on a weekly basis.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Six (6)-month and annual compliance reporting.

Annual air emissions reporting.

4. Reporting start date: 6-month period after start-up

Section 6: Work Practice Standard

Describe any work practice standards: N/A

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id: 80-0833693 **Firm Name:** Homer City Generation, L.P.

Plant Code: **Plant Name:** Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Ten (10) Emergency Generators (2.5 MW), Two (2) Emergency Generators (1.0 MW)

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: 40 CFR Part 60, Subpart IIII (§60.4202)

Demonstrate that the emergency engine meets the applicable emissions standards and has not been operated for more than 100 hours per calendar year for non-emergency operation.

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☐ **Testing** ☐ **Reporting**

☒ **Record Keeping** ☐ **Work Practice Standard**

Section 2: Monitoring

16. Monitoring device type (stack test, CEM, etc.): Non-resettable hour meter.

17. Monitoring device location: N/A

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

N/A

18. How will data be reported: N/A

Section 3: Testing

11. Reference Test Method Description: N/A

12. Reference Test Method Citation:

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation will retain records of the operation of the engines in emergency and non-emergency service that are
recorded through the non-resettable hour meter. These records will include descriptions of non-emergency operations (i.e., maintenance check, readiness testing, etc.).

Section 5: Reporting

Describe what is to be reported and the frequency of reporting: N/A

5. Reporting start date:

Section 6: Work Practice Standard

Describe any work practice standards:

The manufacturer has certified that the emergency generators meet the following standards:

NMHC: 0.19 g/kW-hr;

NOx: 0.67 g/kW-hr;

PM: 0.03 g/kW-hr; and

CO: 3.5 g/kW-hr.

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DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Ten (10) Emergency Generators (2.5 MW), Two (2) Emergency Generators (1.0 MW)

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: 40 CFR Part 60, Subpart IIII (§60.4207) – Diesel fuel with a sulfur content of less than or equal to 15 ppm by weight.

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☐ **Monitoring** ☐ **Testing** ☐ **Reporting**

☒ **Record Keeping** ☐ **Work Practice Standard**

Section 2: Monitoring

19. Monitoring device type (stack test, CEM, etc.): N/A

20. Monitoring device location:

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

21. How will data be reported:

Section 3: Testing

13. Reference Test Method Description: N/A

14. Reference Test Method Citation:

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation will retain records of the ULSD fuel specifications from the supplier as deliveries arrive on-site.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting: N/A

6. Reporting start date:

Section 6: Work Practice Standard

Describe any work practice standards: N/A

6. Emergency Generators (2.5 MW each)

- Section B – Combustion Unit Information
- Section C – Air Cleaning Device
- Section F – Flue and Air Contaminant Emission
- *See 1MW Units for Addendum A: Source Applicable Requirements*
- *See 1MW Units for Addendum 1: Method of Compliance Worksheets*

Section B - Combustion Unit Information

1. Combustion Units: ☐ Coal ☒ Oil ☐ Natural Gas Other: _____

Description: Ten (10) 2.5 MW (each 3,633 bhp) ultra low sulfur diesel fuel-fired emergency generators.

Manufacturer	Model No.	Number of units	
TBD	TBD	10	
Maximum heat input (Btu/hr)	Rated heat input (Btu/hr)	Typical heat input (Btu/hr)	Furnace Volume
25.43 MMBtu/hr (approximate, each)	25.43 MMBtu/hr (approximate, each)	25.43 MMBtu/hr (approximate, each)	TBD
Grate Area (if applicable)		Method of firing	
N/A		TBD	

Indicate how combustion air is supplied to boiler
N/A

Indicate the Steam Usage: N/A

Mark and describe soot Cleaning Method:

i. Air Blown
ii. Steam Blown
iii. Brushed and Vacuumed
iv. Other N/A
v. Frequency of Cleaning _____

Maximum Operating schedule

Hours/Day	Days/Week	Days/Year	Hours/Year
24 (each)	7 (each)	365 (each)	500 (each)

Operational restrictions taken or requested, if any (e.g., bottlenecks or voluntary restrictions to limit potential to emit)

Capacity (specify units)

Per hour	Per day	Per week	Per year
25.43 MMBtu	610.34 MMBtu	4,272.41 MMBtu	12,715.50 MMBtu

Typical Operating schedule

Hours/Day	Days/Week	Days/Year	Hours/Year
24(each)	7 (each)	365 (each)	500 (each)

Seasonal variations (Months): If variations exist, describe them.

Operating using primary fuel: _____ From _____ to _____
Operating using secondary fuel: _____ Form _____ to _____
Non-operating: From _____ to _____

2. Specify the primary, secondary and startup fuel. Furnish the details in item 3.
15 ppmw Ultra-low sulfur diesel

Section B - Combustion Unit Information (Continued)

3. Fuel

Type	Quantity Hourly	Annually	Sulfur	% Ash (Weight)	BTU Content
Oil Number 2	each 185.63 GPH @ 60°F	each 92.8 X 10^3 Gal	0.0015% by wt	<0.001	each 137,000Btu/Gal. & Lbs./Gal. @ 60 °F
Oil Number	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Oil Number	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Natural Gas	SCFH	X 10^6 Gal	gr/100 SCF		Btu/SCF
Gas (other)	SCFH	X 10^6 Gal	gr/100 SCF		Btu/SCF
Coal					
Other*					

* Note: Describe and furnish information separately for other fuels in Addendum B.

4. Burner

Manufacturer	Model Number	Type of Atomization (Steam, air, press, mech., rotary cup)

Number of Burners	Maximum fuel firing rate (all burners)	Normal fuel firing rate

If oil, temperature and viscosity.
N/A

Maximum theoretical air requirement
N/A

Percent excess air 100% rating
N/A

Turndown ratio
N/A

Combustion modulation control (on/off, low-high fire, full automatic, manual). Describe.
N/A

Main burner flame ignition method (electric spark, auto gas pilot, hand-held torch, other). Describe.
N/A

5. Nitrogen Oxides (NO_x) control Options

Mark and describe the NO_x control options adopted

Low excess air (LEA)	Flue gas recirculation	Other._____
Over fire air (OFA)	Burner out of service	
Low-NO_x burner	Reburning	
Low NO_x burners with over fire air	Flue gas treatment (SCR / SNCR)	

Section B - Combustion Unit Information (Continued)

6. Miscellaneous Information

Describe fly ash reinjection operation
N/A

Describe, in detail, the equipment provided to monitor and to record the source(s) operating conditions, which may affect emissions of air contaminants. Show that they are reasonable and adequate.

See, Addendim A Forms

Describe each proposed modification to an existing source.

N/A

Describe how emissions will be minimized especially during start up, shut down, combustion upsets and/or disruptions. Provide emission estimates for start up, shut down and upset conditions. Provide duration of start up and shut down.

Emissions during startup/shutdown will be minimized by limiting the time that the units are in startup or shutdown mode.

Describe in detail with a schematic diagram of the control options adopted for SO_2 (if applicable).
N/A

Anticipated milestones:

Expected commencement date of construction/reconstruction: Upon permit issuance
Expected completion date of construction/reconstruction: Anticpated third quarter 2029
Anticipated date(s) of start-up: Anticpated fourth quarter 2029

Section C - Air Cleaning Device (Continued)

10. Costs – N/A

Indicate cost associated with air cleaning device and its operating cost (attach documentation if necessary)

Device	Direct Cost	Indirect Cost	Total Cost	Operating Cost

11 MISCELLANEOUS

Describe in detail the removal, handling and disposal of dust, effluent, etc. from the air cleaning device including proposed methods of controlling fugitive emissions.

N/A

Attach manufacturer's performance guarantees and/or warranties for each of the major components of the control system (or complete system).

The manufacturer will have to certify to meet EPA Tier 4 standards for diesel generators.
This will be provided when a manufacturer is chosen.

Attach the maintenance schedule for the control equipment and any part of the process equipment that, if in disrepair, would increase air contaminant emissions.

The engines' emissions control systems will be maintained as per the manufacturer's maintenance specifications.

Section F - Flue and Air Contaminant Emission

1. Estimated Maximum Emissions*

Pollutant	Maximum emission rate			Calculation/ Estimation Method
	specify units	lbs/hr	tons/yr.	
PM		1.79	0.45	NSPS IIII
$PM_{10/2.5}$		1.66	0.41	NSPS IIII, AP-42 speciation
SO_x		0.44	0.11	AP-42
CO		209.04	52.26	NSPS IIII
NO_x		40.02	10.00	NSPS IIII
TOC		11.35	2.84	NSPS IIII
Others: (e.g., HAPs)	-----	-----	-----	-----
Max single HAP	()	0.20	0.05	AP-42
Total HAP		0.40	0.10	AP-42

* These emissions must be calculated based on the requested operating schedule and/or process rate e.g., operating schedule for maximum limits or restricted hours of operation and /or restricted throughput. Describe how the emission values were determined. Attach calculations.

2. Stack and Exhauster

Stack Designation/Number G01_25MW through G10_25MW

List Source(s) or source ID exhausted to this stack:	% of flow exhausted to stack: 100
Emergency Generators 1-10	

Stack height above grade (ft.) 20 Grade elevation (ft.) 1,200	Stack diameter (ft) or Outlet duct area (sq. ft.) 1.2 ft	Weather Cap ☐ YES ☒ NO

Distance of discharge to nearest property line (ft.). Locate on topographic map.

See, Point Source Locations Table and Appendix E

Does stack height meet Good Engineering Practice (GEP)?

No

If modeling (estimating) of ambient air quality impacts is needed, attach a site plan with buildings and their dimensions and other obstructions. See, Application Narrative Section 6

Location of Stack**	Latitude			Longitude		
Latitude/Longitude Point of Origin	Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
See, Point Source Locations Table						

Stack Exhaust

Volume 4,524 ACFM Temperature 964.0 °F Moisture _____%

Exhauster (attach fan curves) _____ in. of water _____ HP @ _____RPM.

** If the datum and collection method information and codes differ from those provided on the General Information Form - Authorization Application, provide the additional required by that form on a separate sheet.

Point Source Locations Table: Emergency Generator Engines (2.5 MW)

	Latitude	Longitude	Distance to Property Boundary
G01_25MW	40° 31' 15.09"" N	79° 11' 54.73"" W	1,889 ft
G02_25MW	40° 31' 10.94"" N	79° 11' 54.74"" W	2,308 ft
G03_25MW	40° 31' 6.74"" N	79° 11' 54.73"" W	2,675 ft
G04_25MW	40° 31' 2.58"" N	79° 11' 54.73"" W	2,750 ft
G05_25MW	40° 31' 6.74"" N	79° 11' 45.38"" W	2,871 ft
G06_25MW	40° 31' 2.60"" N	79° 11' 45.38"" W	3,272 ft
G07_25MW	40° 30' 58.43"" N	79° 11' 45.38"" W	3,509 ft
G08_25MW	40° 30' 59.02"" N	79° 11' 54.26"" W	2,820 ft
G09_25MW	40° 30' 44.37"" N	79° 11' 35.83"" W	3,119 ft
G10_25MW	40° 30' 58.34"" N	79° 11' 24.27"" W	2,867 ft

7. Fire Water Pump

- Section B – Combustion Unit Information
- Section C – Air Cleaning Device
- Section F – Flue and Air Contaminant Emission
- Addendum A: Source Applicable Requirements
- Addendum 1: Method of Compliance Worksheets

Section B – Combustion Unit Information

1. Combustion Units: ☐ Coal ☒ Oil ☐ Natural Gas Other: _____

Description: One - 399 bhp - diesel fuel-fired emergency fire pump engine.

Manufacturer	Model No.	Number of units	
TBD	TBD	1	
Maximum heat input (Btu/hr)	Rated heat input (Btu/hr)	Typical heat input (Btu/hr)	Furnace Volume
2.793 MMBtu/hr	2.793 MMBtu/hr	2.793 MMBtu/hr	TBD
Grate Area (if applicable)		Method of firing	
N/A		TBD	

Indicate how combustion air is supplied to boiler
N/A

Indicate the Steam Usage:

Mark and describe soot Cleaning Method:

i. Air Blown
ii. Steam Blown
iii. Brushed and Vacuumed
iv. Other N/A
v. Frequency of Cleaning _____

Maximum Operating schedule

Hours/Day	Days/Week	Days/Year	Hours/Year
24	7	365	500

Operational restrictions taken or requested, if any (e.g., bottlenecks or voluntary restrictions to limit potential to emit)

Capacity (specify units)

Per hour	Per day	Per week	Per year
2.793 MMBtu	67.032 MMBtu	469.22 MMBtu	1,396.5 MMBtu

Typical Operating schedule

Hours/Day	Days/Week	Days/Year	Hours/Year
24	7	365	500

Seasonal variations (Months): If variations exist, describe them.

Operating using primary fuel: _____ From _____ to _____
Operating using secondary fuel: _____ Form _____ to _____
Non-operating: From _____ to _____

2. Specify the primary, secondary and startup fuel. Furnish the details in item 3.
ULSD

Section B – Combustion Unit Information (Continued)

3. Fuel

Type	Quantity Hourly	Annually	Sulfur	% Ash (Weight)	BTU Content
Oil Number 2	20.39 GPH @ 60°F	10.19 X 10^3 Gal	0.0015% by wt	<0.001	each 137,000Btu/Gal. & Lbs./Gal. @ 60 °F
Oil Number	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Oil Number	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Natural Gas	SCFH	X 10^6 Gal	gr/100 SCF		Btu/SCF
Gas (other)	SCFH	X 10^6 Gal	gr/100 SCF		Btu/SCF
Coal					
Other*					

* Note: Describe and furnish information separately for other fuels in Addendum B.

4. Burner

Manufacturer	Model Number	Type of Atomization (Steam, air, press, mech., rotary cup)
N/A	N/A	N/A

Number of Burners	Maximum fuel firing rate (all burners)	Normal fuel firing rate
N/A	N/A	

If oil, temperature and viscosity.
N/A

Maximum theoretical air requirement
N/A

Percent excess air 100% rating
N/A

Turndown ratio
N/A

Combustion modulation control (on/off, low-high fire, full automatic, manual). Describe.
N/A

Main burner flame ignition method (electric spark, auto gas pilot, hand-held torch, other). Describe.
N/A

5. Nitrogen Oxides (NO_x) control Options

Mark and describe the NO_x control options adopted

Low excess air (LEA)	Flue gas recirculation	Other._____
Over fire air (OFA)	Burner out of service	
Low-NO_x burner	Reburning	
Low NO_x burners with over fire air	Flue gas treatment (SCR / SNCR)	

Section B – Combustion Unit Information (Continued)

6. Miscellaneous Information

Describe fly ash reinjection operation
N/A

Describe, in detail, the equipment provided to monitor and to record the source(s) operating conditions, which may affect emissions of air contaminants. Show that they are reasonable and adequate.

See, Addendim A Forms

Describe each proposed modification to an existing source.

N/A

Describe how emissions will be minimized especially during start up, shut down, combustion upsets and/or disruptions. Provide emission estimates for start up, shut down and upset conditions. Provide duration of start up and shut down.

Emissions during startup/shutdown will be minimized by limiting the time that the units are in startup or shutdown mode.

Describe in detail with a schematic diagram of the control options adopted for SO_2 (if applicable).
N/A

Anticipated milestones:

Expected commencement date of construction/reconstruction: Upon permit issuance
Expected completion date of construction/reconstruction: Anticpated third quarter 2029
Anticipated date(s) of start-up: Anticpated fourth quarter 2029

Section C – Air Cleaning Device (Continued)

10. Costs – N/A

Indicate cost associated with air cleaning device and its operating cost (attach documentation if necessary)

Device	Direct Cost	Indirect Cost	Total Cost	Operating Cost

11 MISCELLANEOUS

Describe in detail the removal, handling and disposal of dust, effluent, etc. from the air cleaning device including proposed methods of controlling fugitive emissions.

N/A

Attach manufacturer's performance guarantees and/or warranties for each of the major components of the control system (or complete system).

TBD

Attach the maintenance schedule for the control equipment and any part of the process equipment that, if in disrepair, would increase air contaminant emissions.

The engines' emissions control systems will be maintained as per the manufacturer's maintenance specifications.

Section F – Flue and Air Contaminant Emission

1. Estimated Maximum Emissions*

Pollutant	Maximum emission rate			Calculation/ Estimation Method
	specify units	lbs/hr	tons/yr.	
PM		0.13	0.03	NSPS IIII
$PM_{10/2.5}$		0.12	0.03	NSPS IIII, AP-42 speciation
SO_X		4.84E-03	1.21E-03	AP-42
CO		2.29	0.57	NSPS IIII
NO_x		2.64	0.66	NSPS IIII
TOC		2.64	0.66	NSPS IIII
Others: (e.g., HAPs)	-----	-----	-----	-----
Max single HAP	(formaldehyde)	3.30E-03	8.24E-04	AP-42
Total HAP		1.08E-02	2.70E-03	AP-42

* These emissions must be calculated based on the requested operating schedule and/or process rate e.g., operating schedule for maximum limits or restricted hours of operation and /or restricted throughput. Describe how the emission values were determined. Attach calculations.

2. Stack and Exhauster

Stack Designation/Number FWP_1

List Source(s) or source ID exhausted to this stack:
Emergency Fire Pump Engine

% of flow exhausted to stack: 100

Stack height above grade (ft.) 12
Grade elevation (ft.) 1,200

Stack diameter (ft) or Outlet duct area (sq. ft.)
0.5 ft

Weather Cap
☐ YES ☒ NO

Distance of discharge to nearest property line (ft.). Locate on topographic map.

2,475 ft

Does stack height meet Good Engineering Practice (GEP)?
No

If modeling (estimating) of ambient air quality impacts is needed, attach a site plan with buildings and their dimensions and other obstructions. See, Application Narrative Section 6

Location of Stack** Latitude/Longitude Point of Origin	Latitude			Longitude		
	Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
See, Point Source Locations Table	40	31	9.38	-79	11	53.07

Stack Exhaust

Volume 2,214 ACFM Temperature 826.0 °F Moisture _____%

Exhauster (attach fan curves) _____ in. of water _____ HP @ _____RPM.

** If the datum and collection method information and codes differ from those provided on the General Information Form – Authorization Application, provide the additional required by that form on a separate sheet.

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Addendum A: Source Applicable Requirements

Describe and cite all applicable requirements pertaining to this source.
Note: A Method of Compliance Worksheet (Addendum 1) must be completed for each requirement listed.

Citation Number	Citation Limitation	Limitation Used
25 Pa. Code Chapter 123 – Standards for Contaminants	25 Pa. Code §127.12(a)(5): Emissions from these sources will be the minimum attainable through the use of BAT. 25 Pa. Code §123.13(c)(1)(i): PM limit of 0.4 lb/MMBtu	Compliance with BAT will assure compliance with 25 Pa. Code §123.13(c)(1)(i).
25 Pa. Code Chapter 123 – Standards for Contaminants	25 Pa. Code §123.41 (Visible emissions): 20% for a period or periods aggregating more than three (3) minutes in any one (1) hour, and 60% at any time	Compliance with Subpart IIII requirements will assure compliance with BAT and 25 Pa. Code §123.41.
40 CFR 60 Subpart IIII (§§60.4202 and 60.4209)	NMHC + NO_X: 3.0 g/bhp-hr; PM: 0.15 g/bhp-hr; and CO: 3.5 g/bhp-hr. A non-resettable hour meter must be installed prior to startup of each engine.	Manufacturer certification to applicable standards.
40 CFR 60 Subpart IIII (§60.4207)	Sulfur content – diesel fuel that meets the requirements of 40 CFR §80.510(b) – 15 ppm	Use of ULSD as fuel, which has less than or equal to 15 ppm sulfur.
40 CFR Part 52 – PSD 25 Pa. Code Chapter 127 – BAT	H2SO4: 0.0002 lb/MMBtu; CO: 2.6 g/hp-hr; PM/PM10/PM2.5: 0.15 g/hp-hr; NO_X+VOC: 3.0 g/hp-hr.	Same limits used.
25 Pa. Code Chapter 127.205 – LAER	NO_X+VOC: 3.0 g/hp-hr.	Same limits used.

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id: 80-0833693 **Firm Name:** Homer City Generation, L.P.

Naming.Plant **Plant Name:** Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☐ **A group of sources, Group ID:**

☒ **A single source, Unit ID:** Fire Water Pump

☐ **Alternative Scenario, Scenario Name:**

Citation #: 25 Pa. Code §127.12(a)(5) – BAT and 25 Pa. Code §123.13(c)(1)(i) – Standards for Contaminants (PM)

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☐ **Monitoring** ☐ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):** N/A
2. **Monitoring device location:**

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

3. **How will data be reported:**

Section 3: Testing

1. Reference Test Method Description: N/A

2. Reference Test Method Citation:

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation will retain records and 12-month rolling average fuel usage rates by fuel type.

Homer City Generation will retain records of supporting calculations used to determine compliance with the emissions limits based on manufacturer emissions guarantees.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Report emissions to PADEP annually to demonstrate compliance with emissions limits and for the annual air emissions inventory.

1. Reporting start date: One (1) year after start-up.

Section 6: Work Practice Standard

Describe any work practice standards:

(1) Operate and maintain the stationary CI internal combustion engines and control devices according to the manufacturer's emissions-related written instructions;

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

(3) Meet the requirements of 40 CFR Parts 89, and/or 1068, and they apply.

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id: 80-0833693 **Firm Name:** Homer City Generation, L.P.

Plant Code: **Plant Name:** Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☐ **A group of sources, Group ID:**

☒ **A single source, Unit ID:** Fire Water Pump

☐ **Alternative Scenario, Scenario Name:**

Citation #: 25 Pa. Code §127.12(a)(5) – BAT and Chapter 123.41 – Standards for Contaminants – Visible Emissions

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☐ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☐ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):** Methods 9 and 22
2. **Monitoring device location:** N/A

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

N/A

3. **How will data be reported:** Deviations will be reported semi-annually.

Section 3: Testing

1. Reference Test Method Description: N/A

2. Reference Test Method Citation:

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation will retain records of visible emissions readings when operating.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Six (6)-month and annual compliance reporting.

Annual air emissions reporting.

2. Reporting start date: Six (6)-month period after start-up.

Section 6: Work Practice Standard

Describe any work practice standards: N/A

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☐ **A group of sources, Group ID:**

☒ **A single source, Unit ID:** Fire Water Pump

☐ **Alternative Scenario, Scenario Name:**

Citation #: 40 CFR Part 60, Subpart IIII (§60.4202)

Citation #: 40 CFR Part 60, Subpart IIII (§60.4202)

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☐ **Testing** ☐ **Reporting**

☒ **Record Keeping** ☐ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):** Non-resettable hour meter
2. **Monitoring device location:** N/A

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

Demonstrate that the emergency engine has not been operated for more than 100 hours per calendar year for non-emergency operation.

3. How will data be reported: N/A

Section 3: Testing

1. Reference Test Method Description: N/A

2. Reference Test Method Citation:

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation will retain records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. These records will include descriptions of non-emergency operations (i.e., maintenance check, readiness testing, etc.).

Section 5: Reporting

Describe what is to be reported and the frequency of reporting: N/A

1. Reporting start date:

Section 6: Work Practice Standard

Describe any work practice standards: N/A

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id: 80-0833693 **Firm Name:** Homer City Generation, L.P.

Plant Code: **Plant Name:** Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☐ **A group of sources, Group ID:**

☒ **A single source, Unit ID:** Fire Water Pump

☐ **Alternative Scenario, Scenario Name:**

Citation #: 40 CFR Part 60, Subpart IIII (§60. 4207) – Diesel fuel with a sulfur content of less than or equal to 15 ppm by weight.

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☐ **Testing** ☐ **Reporting**

☒ **Record Keeping** ☐ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):** N/A

2. **Monitoring device location:** N/A

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

Fuel Sulfur content will be provided by fuel provider

3. **How will data be reported:** N/A

Section 3: Testing

1. Reference Test Method Description: N/A

2. Reference Test Method Citation:

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation will retain records of the ULSD fuel specifications from the supplier as deliveries arrive on-site.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting: N/A

1. Reporting start date:

Section 6: Work Practice Standard

Describe any work practice standards:

The manufacturer has certified that the emergency generators meet the following standards:

NMHC + NOX: 4.0 g/kW-hr / 3.0 g/bhp-hr;

PM: 0.2 g/kW-hr / 0.15 g/bhp-hr; and

CO: 3.5 g/kW-hr / 2.6 g/bhp-hr.

8. Cooling Towers

- Section B – Combustion Unit Information
- Section F – Flue and Air Contaminant Emission
- Addendum A: Source Applicable Requirements
- Addendum 1: Method of Compliance Worksheets

Section B - Processes Information

1. Source Information

Source Description (give type, use, raw materials, product, etc). Attach additional sheets as necessary.
Seven (7) Cooling towers, each consisting of 8-Cells each, 56 cells total

Manufacturer	Model No.	Number of Sources
TBD	TBD	7
Source Designation	**Maximum Capacity**	**Rated Capacity**
CT01-CT07	95,007 gpm, total	95,007 gpm, total

Type of Material Processed
cooling water

Maximum Operating Schedule

Hours/Day	Days/Week	Days/Year	Hours/Year
24	7	365	8,760

Operational restrictions existing or requested, if any (e.g., bottlenecks or voluntary restrictions to limit PTE)

Capacity (specify units)

Per Hour	Per Day	Per Week	Per Year
5,700,420 gal/hr, total for all 7 cooling towers	136,810,080 gal/day, total for all 7 cooling towers	957,670,560 gal/wk, total for all 7 cooling towers	49,936 MMgal/yr, total for all 7 cooling towers

Operating Schedule

Hours/Day	Days/Week	Days/Year	Hours/Year
24	7	365	8,760

Seasonal variations (Months) From to

If variations exist, describe them
N/A

2. Fuel

Type	Quantity Hourly	Annually	Sulfur	% Ash (Weight)	BTU Content
Oil Number _____	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Oil Number _____	GPH @ 60°F	X 10^3 Gal	% by wt		Btu/Gal. & Lbs./Gal. @ 60 °F
Natural Gas	SCFH	X 10^6 SCF	grain/100 SCF		Btu/SCF
Gas (other) _____	SCFH	X 10^6 SCF	grain/100 SCF		Btu/SCF
Coal _____	TPH	Tons	% by wt		Btu/lb
Other * _____					
_____					
_____					

*Note: Describe and furnish information separately for other fuels in Addendum B.

Section B - Processes Information (Continued)

3. Burner

Manufacturer	Type and Model No.	Number of Burners
N/A	N/A	N/A

Description:
N/A

Rated Capacity	Maximum Capacity
N/A	N/A

4. Process Storage Vessels

A. For Liquids:

Name of material stored
N/A

Tank I.D. No.	Manufacturer	Date Installed
N/A	N/A	N/A

Maximum Pressure	Capacity (gallons/Meter^3)
N/A	N/A

Type of relief device (pressure set vent/conservation vent/emergency vent/open vent)
N/A

Relief valve/vent set pressure (psig)	Vapor press. of liquid at storage temp. (psia/kPa)
N/A	N/A

Type of Roof: Describe:
N/A

Total Throughput Per Year	
N/A	Number of fills per day (fill/day): N/A Filling Rate (gal./min.): N/A Duration of fill hr./fill): N/A

B. For Solids

Type: ☐ Silo ☐ Storage Bin ☐Other, Describe	Name of Material Stored
	N/A

Silo/Storage Bin I.D. No.	Manufacturer	Date Installed
N/A	N/A	N/A

State whether the material will be stored in loose or bags in silos	Capacity (Tons)
N/A	N/A
Turn over per year in tons	Turn over per day in tons
N/A	N/A

Describe fugitive dust control system for loading and handling operations
N/A

Describe material handling system
N/A

5. Request for Confidentiality

Do you request any information on this application to be treated as "Confidential"? ☐ Yes ☒ No
If yes, include justification for confidentiality. Place such information on separate pages marked **"confidential"**.

Section B - Processes Information (Continued)

6. Miscellaneous Information

Attach flow diagram of process giving all (gaseous, liquid and solid) flow rates. Also, list all raw materials charged to process equipment, and the amounts charged (tons/hour, etc.) at rated capacity (give maximum, minimum and average charges describing fully expected variations in production rates). Indicate (on diagram) all points where contaminants are controlled (location of water sprays, collection hoods, or other pickup points, etc.). Describe collection hoods location, design, airflow and capture efficiency. Describe any restriction requested and how it will be monitored.
See, Appendix C.

Describe fully the facilities provided to monitor and to record process operating conditions, which may affect the emission of air contaminants. Show that they are reasonable and adequate.
Refer to Addendum A1 forms.

Describe each proposed modification to an existing source.
N/A

Identify and describe all fugitive emission points, all relief and emergency valves and any by-pass stacks.
N/A

Describe how emissions will be minimized especially during start up, shut down, process upsets and/or disruptions.
Drift eliminators with an efficiency of 0.0005% will be incorporated into the cooling tower design to decrease the amount and size of cooling tower water droplets that are carried out with the exhaust from the cooling tower system. Because there is no U.S. EPA methodology for source testing the cooling tower for emissions, the efficiency of the drift eliminator for the towers is certified by the tower manufacturer from test data on the drift eliminator design in a controlled test cell.

Anticipated Milestones:

i. Expected commencement date of construction/reconstruction/installation: Upon permit issuance
ii. Expected completion date of construction/reconstruction/installation: Anticpated third quarter 2029
iii. Anticipated date of start-up: Anticpated fourth quarter 2029

Section F - Flue and Air Contaminant Emission

1. Estimated Atmospheric Emissions*

Pollutant	Maximum emission rate			Calculation/ Estimation Method
	specify units	lbs/hr	tons/yr.	
PM		0.71	3.13	AP-42 & New Mexico Guidance document
PM_{10}		0.50	2.20	AP-42 & New Mexico Guidance document
SO_x				
CO				
NO_x				
VOC				
Others: (e.g., HAPs)	-----	-----	-----	-----

* These emissions must be calculated based on the requested operating schedule and/or process rate e.g., operating schedule for maximum limits or restricted hours of operation and /or restricted throughput. Describe how the emission values were determined. Attach calculations.

2. Stack and Exhauster

Stack Designation/Number

List Source(s) or source ID exhausted to this stack:
CT01-CT07

% of flow exhausted to stack: 100

Stack height above grade (ft.) 55
Grade elevation (ft.) 1,200

Stack diameter (ft) or Outlet duct area (sq. ft.)
34 ft, per cooling tower cell

f. Weather Cap
☐ YES ☒ NO

Distance of discharge to nearest property line (ft.). Locate on topographic map.

See, Point Source Locations Table

Does stack height meet Good Engineering Practice (GEP)?
No

If modeling (estimating) of ambient air quality impacts is needed, attach a site plan with buildings and their dimensions and other obstructions. See, Application Narrative Section 6.

Location of stack** Latitude/Longitude Point of Origin	Latitude			Longitude		
	Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
See, Point Source Locations Table						

Stack exhaust
Volume 1,328,300 ACFM (per cell) Temperature 110 °F Moisture _____ %

Indicate on an attached sheet the location of sampling ports with respect to exhaust fan, breeching, etc. Give all necessary dimensions.

Exhauster (attach fan curves) _____ in. of water _____ HP @ _____RPM.

** If the data and collection method codes differ from those provided on the General Information Form-Authorization Application, provide the additional detail required by that form on a separate form.

Point Source Locations Table: Cooling Tower Cells (7 cooling towers, 8 cells each)

	Latitude	Longitude	Distance to Property Boundary			Latitude	Longitude	Distance to Property Boundary
CT1_1	40° 31' 13.42"" N	079° 12' 2.43"" W	1,929 ft		CT4_5	40° 31' 0.4"" N	079° 12' 2.44"" W	2,178 ft
CT1_2	40° 31' 13.43"" N	079° 12' 1.75"" W	1,980 ft		CT4_6	40° 31' 0.39"" N	079° 12' 1.76"" W	2,231 ft
CT1_3	40° 31' 13.43"" N	079° 12' 1.08"" W	2,030 ft		CT4_7	40° 31' 0.4"" N	079° 12' 1.08"" W	2,283 ft
CT1_4	40° 31' 13.43"" N	079° 12' 0.39"" W	2,064 ft		CT4_8	40° 31' 0.41"" N	079° 12' 0.4"" W	2,335 ft
CT1_5	40° 31' 12.94"" N	079° 12' 2.43"" W	1,942 ft		CT5_1	40° 31' 5.05"" N	079° 11' 53.08"" W	2,842 ft
CT1_6	40° 31' 12.94"" N	079° 12' 1.75"" W	1,993 ft		CT5_2	40° 31' 5.06"" N	079° 11' 52.4"" W	2,892 ft
CT1_7	40° 31' 12.95"" N	079° 12' 1.06"" W	2,043 ft		CT5_3	40° 31' 5.07"" N	079° 11' 51.73"" W	2,924 ft
CT1_8	40° 31' 12.95"" N	079° 12' 0.39"" W	2,094 ft		CT5_4	40° 31' 5.07"" N	079° 11' 51.04"" W	2,932 ft
CT2_1	40° 31' 9.24"" N	079° 12' 2.46"" W	2,034 ft		CT5_5	40° 31' 4.57"" N	079° 11' 53.08"" W	2,854 ft
CT2_2	40° 31' 9.24"" N	079° 12' 1.77"" W	2,085 ft		CT5_6	40° 31' 4.57"" N	079° 11' 52.4"" W	2,905 ft
CT2_3	40° 31' 9.25"" N	079° 12' 1.1"" W	2,135 ft		CT5_7	40° 31' 4.58"" N	079° 11' 51.71"" W	2,956 ft
CT2_4	40° 31' 9.25"" N	079° 12' 0.41"" W	2,186 ft		CT5_8	40° 31' 4.58"" N	079° 11' 51.04"" W	2,980 ft
CT2_5	40° 31' 8.76"" N	079° 12' 2.45"" W	2,047 ft		CT6_1	40° 31' 0.89"" N	079° 11' 53.08"" W	2,893 ft
CT2_6	40° 31' 8.75"" N	079° 12' 1.77"" W	2,098 ft		CT6_2	40° 31' 0.9"" N	079° 11' 52.4"" W	2,945 ft
CT2_7	40° 31' 8.76"" N	079° 12' 1.09"" W	2,148 ft		CT6_3	40° 31' 0.91"" N	079° 11' 51.73"" W	2,997 ft
CT2_8	40° 31' 8.77"" N	079° 12' 0.41"" W	2,199 ft		CT6_4	40° 31' 0.91"" N	079° 11' 51.04"" W	3,050 ft
CT3_1	40° 31' 5.04"" N	079° 12' 2.45"" W	2,133 ft		CT6_5	40° 31' 0.41"" N	079° 11' 53.08"" W	2,898 ft
CT3_2	40° 31' 5.05"" N	079° 12' 1.77"" W	2,186 ft		CT6_6	40° 31' 0.41"" N	079° 11' 52.4"" W	2,950 ft
CT3_3	40° 31' 5.05"" N	079° 12' 1.09"" W	2,237 ft		CT6_7	40° 31' 0.42"" N	079° 11' 51.72"" W	3,003 ft
CT3_4	40° 31' 5.05"" N	079° 12' 0.41"" W	2,290 ft		CT6_8	40° 31' 0.42"" N	079° 11' 51.04"" W	3,055 ft
CT3_5	40° 31' 4.56"" N	079° 12' 2.45"" W	2,138 ft		CT7_1	40° 30' 56.76"" N	079° 11' 53.12"" W	2,930 ft
CT3_6	40° 31' 4.56"" N	079° 12' 1.76"" W	2,190 ft		CT7_2	40° 30' 56.77"" N	079° 11' 52.43"" W	2,982 ft
CT3_7	40° 31' 4.56"" N	079° 12' 1.08"" W	2,243 ft		CT7_3	40° 30' 56.78"" N	079° 11' 51.76"" W	3,034 ft
CT3_8	40° 31' 4.57"" N	079° 12' 0.4"" W	2,295 ft		CT7_4	40° 30' 56.78"" N	079° 11' 51.07"" W	3,087 ft
CT4_1	40° 31' 0.88"" N	079° 12' 2.45"" W	2,173 ft		CT7_5	40° 30' 56.28"" N	079° 11' 53.11"" W	2,935 ft
CT4_2	40° 31' 0.88"" N	079° 12' 1.76"" W	2,226 ft		CT7_6	40° 30' 56.28"" N	079° 11' 52.43"" W	2,987 ft
CT4_3	40° 31' 0.89"" N	079° 12' 1.09"" W	2,277 ft		CT7_7	40° 30' 56.29"" N	079° 11' 51.75"" W	3,040 ft
CT4_4	40° 31' 0.89"" N	079° 12' 0.4"" W	2,330 ft		CT7_8	40° 30' 56.29"" N	079° 11' 51.07"" W	3,092 ft

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DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Addendum A: Source Applicable Requirements

Describe and cite all applicable requirements pertaining to this source.
Note: A Method of Compliance Worksheet (Addendum 1) must be completed for each requirement listed.

Citation Number	Citation Limitation	Limitation Used
25 Pa. Code Chapter 123 – Standards for Contaminants	25 Pa. Code §123.13(c)(1)(iii): PM limit of 0.02 gr/dscf	Compliance with BAT will assure compliance with 25 Pa. Code §123.13(c)(1)(i).
25 Pa. Code Chapter 123 – Standards for Contaminants	25 Pa. Code §123.41 (Visible emissions): 20% for a period or periods aggregating more than three (3) minutes in any one (1) hour, and 60% at any time	No visible emissions, except for uncombined water vapor. Compliance with BAT will assure compliance with 25 Pa. Code §123.41.
40 CFR Part 52 – PSD BACT	PM, PM10, and PM2.5 BACT for the cooling tower will consist of limiting the drift rate to 0.0005%. Emissions will be limited to 0.71 pounds per hour for PM, 0.50 pounds per hour for PM10, and 1.61e-3 pounds per hour for PM2.5, based on a maximum total dissolved solid (TDS) of 3,000 parts per million (ppm).	PM, PM10, and PM2.5 BACT for the cooling tower will consist of limiting the drift rate to 0.0005%. Emissions will be limited to 0.71 pounds per hour for PM, 0.50 pounds per hour for PM10, and 1.61e-3 pounds per hour for PM2.5, based on a maximum total dissolved solid (TDS) of 3,000 parts per million (ppm).
25 Pa. Code Chapter 127.12(a)(5) – BAT	PM, PM10, and PM2.5 BACT for the cooling tower will consist of limiting the drift rate to 0.0005%. Emissions will be limited to 0.71 pounds per hour for PM, 0.50 pounds per hour for PM10, and 1.61e-3 pounds per hour for PM2.5, based on a maximum total dissolved solid (TDS) of 3,000 parts per million (ppm).	Compliance with Federal PSD BACT Air Pollution Control Technology Requirements will assure compliance with State BAT as applicable.

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id:	80-0833693	**Firm Name:**	Homer City Generation, L.P.
Plant Code:		**Plant Name:**	Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Cooling Towers

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: 25 Pa. Code §123.13(c)(1)(iii) – Standards for Contaminants (PM) and 25 Pa. Code Chapter 127.12(a)(5) – State BAT

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☒ **Monitoring** ☒ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. Monitoring device type (stack test, CEM, etc.): Sample of cooling tower blowdown water for total dissolved solids (TDS). Volume of circulating cooling water and number of concentration cycles.

2. Monitoring device location: Sampling of the cooling tower blowdown water discharge (twice monthly).

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

Sampling of cooling tower blowdown water will occur twice monthly, monitoring of cooling tower circulating water flow rate will be continuous.

3. How will data be reported:	Sampling results will be used to determine monthly and 12-month rolling TDS and PM/PM10/PM2.5 emissions calculations.

Section 3: Testing

1. Reference Test Method Description:	TDS method approved under facility NPDES water quality permit.
2. Reference Test Method Citation:	N/A

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation will retain records of the control efficiency of the drift eliminators that will be installed.

Homer City Generation will retain records of all TDS sampling results and monthly water flow rates and the number of concentration cycles being used.

Homer City Generation will record monthly and 12-month rolling average TDS results.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Six (6)-month and annual compliance reporting.

Annual air emissions reporting.

1. Reporting start date:	N/A

Section 6: Work Practice Standard

Describe any work practice standards:

Homer City Generation will install, operate, and maintain drift eliminators to ensure compliance with this standard.

TDS in cooling water tower blowdown shall not exceed 3,000 ppmw (12-month rolling average)

PM emissions shall not exceed 0.71 lb/hr (12-month rolling average); PM10 emissions shall not exceed 0.5 lb/hr (12-month rolling average); PM2.5 emissions shall not exceed 0.00161 lb/hr (12-month rolling average).

No substances containing zinc or chromium shall be used in the water treatment chemicals for the cooling towers.

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

Addendum 1
Method Of Compliance Worksheet

SECTION 1. APPLICABLE REQUIREMENT

Federal Tax Id: 80-0833693 **Firm Name:** Homer City Generation, L.P.

Plant Code: **Plant Name:** Homer City Generation

Applicable Requirement for: (please check only one box below)

☐ **The entire site**

☒ **A group of sources, Group ID:** Cooling Towers

☐ **A single source, Unit ID:**

☐ **Alternative Scenario, Scenario Name:**

Citation #: 25 Pa. Code Chapter 127.12(a)(5) – State BAT and 25 Pa. Code §123.41: Standards for Contaminants – Visible Emissions

Compliance Method based upon: ☒ **Applicable Requirement** ☐ **Gap Filling Requirement**

Method of Compliance Type: (Check all that applies and complete all appropriate sections below)

☐ **Monitoring** ☒ **Testing** ☒ **Reporting**

☒ **Record Keeping** ☒ **Work Practice Standard**

Section 2: Monitoring

1. **Monitoring device type (stack test, CEM, etc.):** N/A
2. **Monitoring device location:**

Describe all parameters being monitored along with the frequency and duration of monitoring each parameter:

3. **How will data be reported:**

Section 3: Testing

3. Reference Test Method Description:	U.S. EPA Reference Method 22 and/or Reference Method 9.
4. Reference Test Method Citation:	N/A

Section 4: Record Keeping

Describe what parameters will be recorded and the frequency of recording:

Homer City Generation will retain records of visible emissions readings conducted on a monthly basis.

Section 5: Reporting

Describe what is to be reported and the frequency of reporting:

Six (6)-month and annual compliance reporting.

Annual air emissions reporting.

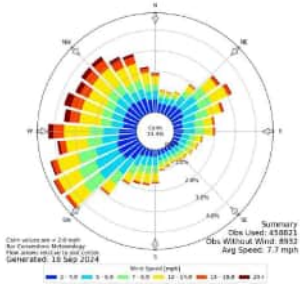
1. Reporting start date:	N/A

Section 6: Work Practice Standard

Describe any work practice standards:

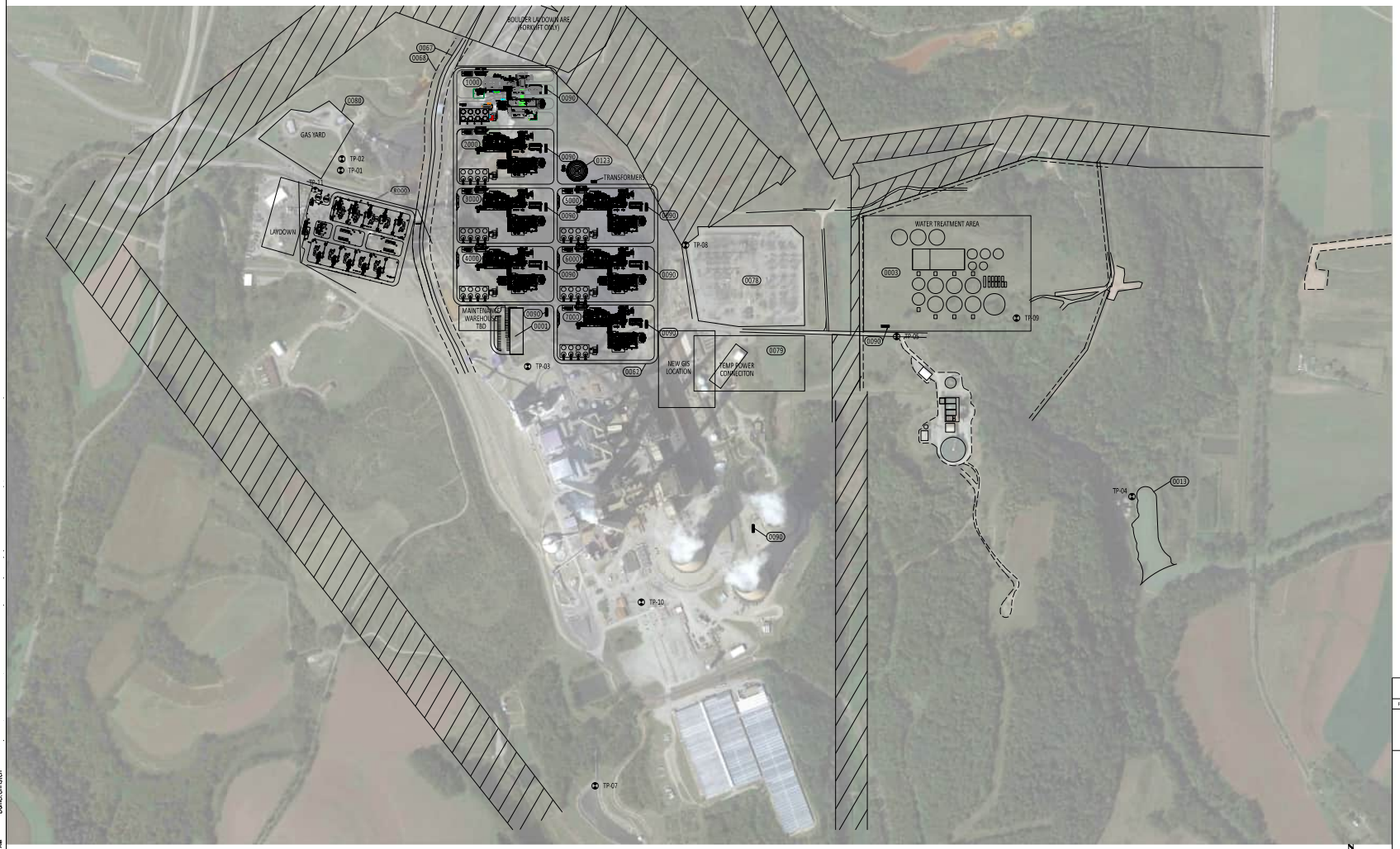
Cooling towers will be operated according to manufacturer specifications so that there are no visible emissions, except for uncombined water vapor.

Appendix B : Plot Plan



LEGEND

0000 ADMINISTRATION BUILDING
0001 WATER TREATMENT AREA
0013 RAW WATER INLET
0062 ROADWAY
0067 EXISTING RAILWAY
0068 RAILWAY SAFETY CLEARANCE (SETT OFFSET NO AROUND)
0078 EXISTING SWITCHYARD
0079 TEMP POWER
0080 CRH FUEL GAS YARD
0090 EMERGENCY DIESEL GENERATOR
0123 FIRE / SERVICE WATER STORAGE TANK
1000 UNIT 1
2000 UNIT 2
3000 UNIT 3
4000 UNIT 4
5000 UNIT 5
6000 UNIT 6
7000 UNIT 7
8000 FTB COMBUSTION TURBINES - SCOPE BY OTHER



	TIE-IN LOCATIONS
TP-01	HIGH PRESSURE FUEL GAS SUPPLY
TP-02	LOW PRESSURE FUEL GAS SUPPLY
TP-03	POTABLE WATER (CITY WATER SUPPLY)
TP-04	RAW WATER SUPPLY (INTAKE)
TP-05	WASTE WATER DISCHARGE
TP-06	COOLING TOWER BLOWDOWN
TP-07	STORM / SURFACE WATER RUNOFF
TP-08	EXISTING SWITCHYARD CONNECTION
TP-09	DATA CENTER COOLING WATER SUPPLY
TP-10	SANITARY DISCHARGE
TP-11	HIGH PRESSURE FG SUPPLY TO FTB (W)

HIGH VOLTAGE RIGHT OF WAY

- PRELIMINARY -
NOT FOR CONSTRUCTION

REV	DESIGN BY	CHECKED BY	DATE
A	ISSUED FOR REVIEW		
	D. METZGER	P. STEWART	OPEN

HOMER CITY REDEVELOPMENT
(7) 1X1 COMBINED CYCLE

Kiewit

SITE PLAN

SCALE: 1" = 300'

PLANT NORTH

ENGINEER/DESIGN ORIGINATOR	D. METZGER
LEAD ENG	R. BAGGA
ENG MGR	J. GILES
PROJ MGR	C. BREMER

DRAWING NUMBER
20058605-SP-001

6:45:29 AM Daniel.Christen
6/3/2025

Appendix C :
Emission Calculations

Table C-1

Summary of PSD/NNSR Applicability Assessment

	TSP	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2e
GE 7HA.02 (7 units total)	705.18	705.18	705.18	987.25	774.40	275.41	193.16	137.97	6.57E-02	15,942,537
FT8 MOBILEPAC (10 units total)	132.45	132.45	132.45	132.00	257.45	51.13	17.96	27.75	6.35E-03	1,547,728
Auxiliary Boilers (3 units total)	0.33	0.33	0.33	2.16	3.63	0.24	0.062	0.0009	2.16E-05	5,237
Fuel Gas Heaters (7 units total)	1.59	1.59	1.59	9.92	12.23	1.65	0.46	0.0071	1.62E-04	39,329
Emergency Generators-2.5 MW (10 units total)	0.45	0.41	0.40	10.00	52.26	2.84	0.11	0.0084	--	10,401
Emergency Generators-1 MW (2 units total)	0.037	0.034	0.034	0.82	4.27	0.23	0.0090	0.00069	--	849
Fire Pump Engine	0.033	0.030	0.030	0.66	0.57	0.66	0.0012	0.000093	--	114
Cooling Towers	3.13	2.20	0.0071	--	--	--	--	--	--	--
GIS Equipment	--	--	--	--	--	--	--	--	--	4,054
Fugitive Leaks	--	--	--	--	--	--	--	--	--	1,205
Facility Total	**843.19**	**842.23**	**840.02**	**1142.80**	**1104.80**	**332.16**	**211.76**	**165.73**	**7.22E-02**	**17,551,454**
PSD Significance Level (ton/yr)	25	15	10		100			7	6.00E-01	75,000
PSD Review Potentially Triggered?	Yes	Yes	Yes		Yes			Yes	No	Yes
Emissions Reduction Credits/Netting	220.2	220.2	220.2		4096.5			28.4	1.85E-01	3,973,771
Facility Total Less ERCs/Netting	**623.0**	**622.0**	**619.8**		**-2991.7**			**137.3**	**-1.13E-01**	**13,577,683**
PSD Significance Level (ton/yr)	25	15	10		100			7	6.00E-01	75,000
PSD Review Triggered?	Yes	Yes	Yes		No			Yes	No	Yes
NNSR Significance Level (ton/yr)				40		40	40			
NNSR LAER Review Potentially Triggered?				Yes		Yes	Yes			
Emissions Reduction Credits/Netting				2,031.8		11.3	4,460.6			
Facility Total Less ERCs/Netting				-889.0		320.9	-4,248.8			
NNSR significance Level (ton/yr)				40		40	40			
NNSR LAER Review Triggered?				No		Yes	No			

Table C-2
Facility-Wide Summary of Air Toxics
Annual Emission Estimate (tons/yr)

Compounds	GE 7HA.02 (7 Units)	FT8 MOBILEPACs (10 Units)	Auxiliary Boilers (3 Units)	Gas Heaters (7 Units)	Cooling Towers	Fire Pump Engine (1 unit)	2.5 MW Emergency Generators (10 Units)	1.0 MW Emergency Generators (2 Units)	Facility-Wide
Metal HAP Compounds:									
Arsenic	2.63E-02	2.55E-03	8.63E-06	6.48E-05	-	-	-	-	**2.89E-02**
Beryllium	1.58E-03	1.53E-04	5.18E-07	3.89E-06	-	-	-	-	**1.73E-03**
Cadmium	1.44E-01	1.40E-02	4.75E-05	3.56E-04	-	-	-	-	**1.59E-01**
Chromium (Cr III)	1.77E-01	1.71E-02	5.80E-05	4.36E-04	-	-	-	-	**1.94E-01**
Chromium (Cr VI)	7.36E-03	7.14E-04	2.42E-06	1.81E-05	-	-	-	-	**8.09E-03**
Cobalt	1.10E-02	1.07E-03	3.63E-06	2.72E-05	-	-	-	-	**1.21E-02**
Lead	6.57E-02	6.38E-03	2.16E-05	1.62E-04	-	-	-	-	**7.22E-02**
Manganese	4.99E-02	4.85E-03	1.64E-05	1.23E-04	-	-	-	-	**5.49E-02**
Mercury	3.42E-02	3.32E-03	1.12E-05	8.43E-05	-	-	-	-	**3.76E-02**
Nickel	2.76E-01	2.68E-02	9.06E-05	6.81E-04	-	-	-	-	**3.03E-01**
Selenium	3.15E-03	3.06E-04	1.04E-06	7.78E-06	-	-	-	-	**3.47E-03**
Metal non-HAP Compounds:									
Barium	5.78E-01	3.93E-02	1.90E-04	1.43E-03	-	-	-	-	**6.19E-01**
Copper	1.12E-01	7.59E-03	3.67E-05	2.75E-04	-	-	-	-	**1.20E-01**
Molybdenum	1.44E-01	9.82E-03	4.75E-05	3.56E-04	-	-	-	-	**1.55E-01**
Vanadium	3.02E-01	2.05E-02	9.93E-05	7.45E-04	-	-	-	-	**3.23E-01**
Zinc	3.81E+00	2.59E-01	1.25E-03	9.40E-03	-	-	-	-	**4.08E+00**
Organic HAP Compounds:									
1,3-Butadiene	2.88E-02	2.80E-03	-	-	-	2.73E-05	-	-	**3.16E-02**
Acetaldehyde	2.68E+00	2.60E-01	-	-	-	5.36E-04	1.60E-03	1.31E-04	**2.94E+00**
Acrolein	4.29E-01	4.16E-02	-	-	-	6.46E-05	5.01E-04	4.09E-05	**4.71E-01**
Benzene	8.04E-01	7.81E-02	9.06E-05	6.81E-04	-	6.51E-04	4.93E-02	4.03E-03	**9.37E-01**
Dichlorobenzene	-	-	5.18E-05	3.89E-04	-	-	-	-	**4.41E-04**
Ethylbenzene	2.14E+00	2.08E-01	-	-	-	-	-	-	**2.35E+00**
Formaldehyde	2.93E+01	2.85E+00	3.24E-03	2.43E-02	-	8.24E-04	5.02E-03	4.10E-04	**3.22E+01**
Hexane	-	-	7.77E-02	5.83E-01	-	-	-	-	**6.61E-01**
Propylene Oxide	1.94E+00	1.89E-01	-	-	-	-	-	-	**2.13E+00**
Toluene	8.71E+00	8.46E-01	1.47E-04	1.10E-03	-	2.86E-04	1.79E-02	1.46E-03	**9.58E+00**
Xylene	4.29E+00	4.16E-01	-	-	-	1.99E-04	1.23E-02	1.00E-03	**4.72E+00**
Organic non-HAP Compounds:									
Butane	-	-	9.06E-02	6.81E-01	-	-	-	-	**7.71E-01**
Ethane	-	-	1.34E-01	1.00E+00	-	-	-	-	**1.14E+00**
Pentane	-	-	1.12E-01	8.43E-01	-	-	-	-	**9.55E-01**
Propane	-	-	6.90E-02	5.19E-01	-	-	-	-	**5.88E-01**
Propylene	-	-	-	-	-	1.80E-03	1.77E-01	1.45E-02	**1.94E-01**
Polycyclic Organic Matter:									
Total POM	**1.47E-01**	**1.43E-02**	**3.01E-05**	**2.26E-04**	**0.00E+00**	**1.17E-04**	**1.34E-02**	**1.10E-03**	**1.77E-01**
3-Methylchloranthrene	-	-	7.77E-08	5.83E-07	-	-	-	-	**6.61E-07**
Total PAHs	*1.47E-01*	*1.43E-02*	*3.01E-05*	*2.26E-04*	*0.00E+00*	*1.17E-04*	*1.34E-02*	*1.10E-03*	***1.77E-01***
2-Methylnaphthalene	-	-	1.04E-06	7.78E-06	-	-	-	-	**8.81E-06**
7,12-Dimethylbenz(a)anthrac	-	-	6.90E-07	5.19E-06	-	-	-	-	**5.88E-06**
Acenaphthene	-	-	*7.77E-08*	*5.83E-07*	-	*9.92E-07*	*2.98E-04*	*2.43E-05*	***3.23E-04***
Acenaphthylene	-	-	*7.77E-08*	*5.83E-07*	-	*3.53E-06*	*5.87E-04*	*4.79E-05*	***6.39E-04***
Anthracene	-	-	*1.04E-07*	*7.78E-07*	-	*1.31E-06*	*7.82E-05*	*6.38E-06*	***8.68E-05***
Benz(a)anthracene	-	-	*7.77E-08*	*5.83E-07*	-	*1.17E-06*	*3.95E-05*	*3.23E-06*	***4.46E-05***
Benzo(a)pyrene	-	-	*5.18E-08*	*3.89E-07*	-	*1.31E-07*	*1.63E-05*	*1.33E-06*	***1.82E-05***
Benzo(b)fluoranthene	-	-	*7.77E-08*	*5.83E-07*	-	*6.92E-08*	*7.06E-05*	*5.76E-06*	***7.71E-05***
Benzo(g,h,i)perylene	-	-	*5.18E-08*	*3.89E-07*	-	*3.41E-07*	*3.53E-05*	*2.89E-06*	***3.90E-05***
Benzo(k)fluoranthene	-	-	*7.77E-08*	*5.83E-07*	-	*1.08E-07*	*1.39E-05*	*1.13E-06*	***1.58E-05***
Chrysene	-	-	*7.77E-08*	*5.83E-07*	-	*2.46E-07*	*9.73E-05*	*7.94E-06*	***1.06E-04***
Dibenzo(a,h)anthracene	-	-	*5.18E-08*	*3.89E-07*	-	*4.07E-07*	*2.20E-05*	*1.80E-06*	***2.46E-05***
Fluoranthene	-	-	*1.29E-07*	*9.72E-07*	-	*5.31E-06*	*2.56E-04*	*2.09E-05*	***2.84E-04***
Fluorene	-	-	*1.21E-07*	*9.07E-07*	-	*2.04E-05*	*8.14E-04*	*6.64E-05*	***9.02E-04***
Indeno(1,2,3-cd)pyrene	-	-	*7.77E-08*	*5.83E-07*	-	*2.62E-07*	*2.63E-05*	*2.15E-06*	***2.94E-05***
Naphthalene	*8.71E-02*	*8.46E-03*	*2.63E-05*	*1.98E-04*	-	*5.92E-05*	*8.27E-03*	*6.75E-04*	***1.05E-01***
Phenanathrene	-	-	*7.34E-07*	*5.51E-06*	-	*2.05E-05*	*2.59E-03*	*2.12E-04*	***2.83E-03***
Pyrene	-	-	*2.16E-07*	*1.62E-06*	-	*3.34E-06*	*2.36E-04*	*1.93E-05*	***2.60E-04***
Ammonia:									
Ammonia	9.14E+02	8.87E+01	-	-	-	-	-	-	**1.00E+03**

Total POM is the sum of the three individual POM compounds and the total PAHs.
POM as a class of substances and naphthalene are listed as HAP compounds.

Table C-2A
Facility-Wide Summary of Air Toxics
Annual Emission Estimate (tons/yr/unit)

Compounds	Combustion Turbines[1]	FT8 MOBILEPACs[2]	Auxiliary Boilers[3]	Gas Heaters[4]	Cooling Towers	Fire Pump Engine[5]	2.5 MW Emergency Generators[6]	1.0 MW Emergency Generators[7]
Metal HAP Compounds:								
Arsenic	3.75E-03	2.55E-04	2.88E-06	9.26E-06	-	-	-	-
Beryllium	2.25E-04	1.53E-05	1.73E-07	5.56E-07	-	-	-	-
Cadmium	2.06E-02	1.40E-03	1.58E-05	5.09E-05	-	-	-	-
Chromium (Cr III)	2.52E-02	1.71E-03	1.93E-05	6.22E-05	-	-	-	-
Chromium (Cr VI)	1.05E-03	7.14E-05	8.06E-07	2.59E-06	-	-	-	-
Cobalt	1.58E-03	1.07E-04	1.21E-06	3.89E-06	-	-	-	-
Lead	9.38E-03	6.38E-04	7.19E-06	2.31E-05	-	-	-	-
Manganese	7.13E-03	4.85E-04	5.47E-06	1.76E-05	-	-	-	-
Mercury	4.88E-03	3.32E-04	3.74E-06	1.20E-05	-	-	-	-
Nickel	3.94E-02	2.68E-03	3.02E-05	9.72E-05	-	-	-	-
Selenium	4.50E-04	3.06E-05	3.45E-07	1.11E-06	-	-	-	-
Metal non-HAP Compounds:								
Barium	8.26E-02	5.61E-03	6.33E-05	2.04E-04	-	-	-	-
Copper	1.59E-02	1.08E-03	1.22E-05	3.94E-05	-	-	-	-
Molybdenum	2.06E-02	1.40E-03	1.58E-05	5.09E-05	-	-	-	-
Vanadium	4.32E-02	2.93E-03	3.31E-05	1.06E-04	-	-	-	-
Zinc	5.44E-01	3.70E-02	4.17E-04	1.34E-03	-	-	-	-
Organic HAP Compounds:								
1,3-Butadiene	4.12E-03	2.80E-04	-	-	-	2.73E-05	-	-
Acetaldehyde	3.83E-01	2.60E-02	-	-	-	5.36E-04	1.60E-04	6.54E-05
Acrolein	6.13E-02	4.16E-03	-	-	-	6.46E-05	5.01E-05	2.05E-05
Benzene	1.15E-01	7.81E-03	3.02E-05	9.72E-05	-	6.51E-04	4.93E-03	2.01E-03
Dichlorobenzene	-	-	1.73E-05	5.56E-05	-	-	-	-
Ethylbenzene	3.06E-01	2.08E-02	-	-	-	-	-	-
Formaldehyde	4.19E+00	2.85E-01	1.08E-03	3.47E-03	-	8.24E-04	5.02E-04	2.05E-04
Hexane	-	-	2.59E-02	8.33E-02	-	-	-	-
Propylene Oxide	2.78E-01	1.89E-02	-	-	-	-	-	-
Toluene	1.24E+00	8.46E-02	4.89E-05	1.57E-04	-	2.86E-04	1.79E-03	7.29E-04
Xylene	6.13E-01	4.16E-02	-	-	-	1.99E-04	1.23E-03	5.01E-04
Organic non-HAP Compounds:								
Butane	-	-	3.02E-02	9.72E-02	-	-	-	-
Ethane	-	-	4.46E-02	1.44E-01	-	-	-	-
Pentane	-	-	3.74E-02	1.20E-01	-	-	-	-
Propane	-	-	2.30E-02	7.41E-02	-	-	-	-
Propylene	-	-	-	-	-	1.80E-03	1.77E-02	7.24E-03
Polycyclic Organic Matter:								
Total POM	**2.11E-02**	**1.43E-03**	**1.00E-05**	**3.23E-05**	**0.00E+00**	**1.17E-04**	**1.34E-03**	**5.49E-04**
3-Methylchloranthrene	-	-	2.59E-08	8.33E-08	-	-	-	-
Total PAHs	*2.11E-02*	*1.43E-03*	*1.00E-05*	*3.22E-05*	*0.00E+00*	*1.17E-04*	*1.34E-03*	*5.49E-04*
2-Methylnaphthalene	-	-	3.45E-07	1.11E-06	-	-	-	-
7,12-Dimethylbenz(a)anthrac	-	-	2.30E-07	7.41E-07	-	-	-	-
Acenaphthene	-	-	*2.59E-08*	*8.33E-08*	-	*9.92E-07*	*2.98E-05*	*1.21E-05*
Acenaphthylene	-	-	*2.59E-08*	*8.33E-08*	-	*3.53E-06*	*5.87E-05*	*2.40E-05*
Anthracene	-	-	*3.45E-08*	*1.11E-07*	-	*1.31E-06*	*7.82E-06*	*3.19E-06*
Benz(a)anthracene	-	-	*2.59E-08*	*8.33E-08*	-	*1.17E-06*	*3.95E-06*	*1.61E-06*
Benzo(a)pyrene	-	-	*1.73E-08*	*5.56E-08*	-	*1.31E-07*	*1.63E-06*	*6.67E-07*
Benzo(b)fluoranthene	-	-	*2.59E-08*	*8.33E-08*	-	*6.92E-08*	*7.06E-06*	*2.88E-06*
Benzo(g,h,i)perylene	-	-	*1.73E-08*	*5.56E-08*	-	*3.41E-07*	*3.53E-06*	*1.44E-06*
Benzo(k)fluoranthene	-	-	*2.59E-08*	*8.33E-08*	-	*1.08E-07*	*1.39E-06*	*5.66E-07*
Chrysene	-	-	*2.59E-08*	*8.33E-08*	-	*2.46E-07*	*9.73E-06*	*3.97E-06*
Dibenzo(a,h)anthracene	-	-	*1.73E-08*	*5.56E-08*	-	*4.07E-07*	*2.20E-06*	*8.98E-07*
Fluoranthene	-	-	*4.32E-08*	*1.39E-07*	-	*5.31E-06*	*2.56E-05*	*1.05E-05*
Fluorene	-	-	*4.03E-08*	*1.30E-07*	-	*2.04E-05*	*8.14E-05*	*3.32E-05*
Indeno(1,2,3-cd)pyrene	-	-	*2.59E-08*	*8.33E-08*	-	*2.62E-07*	*2.63E-06*	*1.07E-06*
Naphthalene	*1.24E-02*	*8.46E-04*	*8.78E-06*	*2.82E-05*	-	*5.92E-05*	*8.27E-04*	*3.37E-04*
Phenanathrene	-	-	*2.45E-07*	*7.87E-07*	-	*2.05E-05*	*2.59E-04*	*1.06E-04*
Pyrene	-	-	*7.19E-08*	*2.31E-07*	-	*3.34E-06*	*2.36E-05*	*9.63E-06*
Ammonia	1.31E+02	8.87E+00	-	-	-	-	-	-

Notes:
Total POM is the sum of the three individual POM compounds and the total PAHs.
POM as a class of substances and naphthalene are listed as HAP compounds.

Table C-2B
Facility-Wide Summary of Air Toxics
Short-Term Emission Estimate (lb/hr/unit)

Compounds	Combustion Turbines[1]	FT8 MOBILEPACs[2]	Auxiliary Boilers[3]	Gas Heaters[4]	Cooling Towers	Fire Pump Engine[5]	2.5 MW Emergency Generators[6]	1.0 MW Emergency Generators[7]
Metal HAP Compounds:								
Arsenic	8.84E-04	5.90E-05	1.31E-05	2.11E-06	-	-	-	-
Beryllium	5.30E-05	3.54E-06	7.88E-07	1.27E-07	-	-	-	-
Cadmium	4.86E-03	3.25E-04	7.23E-05	1.16E-05	-	-	-	-
Chromium (Cr III)	5.94E-03	3.97E-04	8.83E-05	1.42E-05	-	-	-	-
Chromium (Cr VI)	2.48E-04	1.65E-05	3.68E-06	5.92E-07	-	-	-	-
Cobalt	3.71E-04	2.48E-05	5.52E-06	8.88E-07	-	-	-	-
Lead	2.21E-03	1.48E-04	3.28E-05	5.29E-06	-	-	-	-
Manganese	1.68E-03	1.12E-04	2.50E-05	4.02E-06	-	-	-	-
Mercury	1.15E-03	7.67E-05	1.71E-05	2.75E-06	-	-	-	-
Nickel	9.28E-03	6.20E-04	1.38E-04	2.22E-05	-	-	-	-
Selenium	1.06E-04	7.08E-06	1.58E-06	2.54E-07	-	-	-	-
Metal non-HAP Compounds:								
Barium	1.94E-02	1.30E-03	2.89E-04	4.65E-05	-	-	-	-
Copper	3.76E-03	2.51E-04	5.58E-05	8.98E-06	-	-	-	-
Molybdenum	4.86E-03	3.25E-04	7.23E-05	1.16E-05	-	-	-	-
Vanadium	1.02E-02	6.79E-04	1.51E-04	2.43E-05	-	-	-	-
Zinc	1.28E-01	8.56E-03	1.90E-03	3.07E-04	-	-	-	-
Organic HAP Compounds:								
1,3-Butadiene	9.69E-04	6.47E-05	-	-	-	1.09E-04	-	-
Acetaldehyde	9.02E-02	6.02E-03	-	-	-	2.14E-03	6.41E-04	2.62E-04
Acrolein	1.44E-02	9.63E-04	-	-	-	2.58E-04	2.00E-04	8.18E-05
Benzene	2.71E-02	1.81E-03	1.38E-04	2.22E-05	-	2.61E-03	1.97E-02	8.06E-03
Dichlorobenzene	-	-	7.88E-05	1.27E-05	-	-	-	-
Ethylbenzene	7.21E-02	4.82E-03	-	-	-	-	-	-
Formaldehyde	9.87E-01	6.59E-02	4.93E-03	7.93E-04	-	3.30E-03	2.01E-03	8.19E-04
Hexane	-	-	1.18E-01	1.90E-02	-	-	-	-
Propylene Oxide	6.54E-02	4.36E-03	-	-	-	-	-	-
Toluene	2.93E-01	1.96E-02	2.23E-04	3.59E-05	-	1.14E-03	7.15E-03	2.92E-03
Xylene	1.44E-01	9.63E-03	-	-	-	7.96E-04	4.91E-03	2.00E-03
Organic non-HAP Compounds:								
Butane	-	-	1.38E-01	2.22E-02	-	-	-	-
Ethane	-	-	2.04E-01	3.28E-02	-	-	-	-
Pentane	-	-	1.71E-01	2.75E-02	-	-	-	-
Propane	-	-	1.05E-01	1.69E-02	-	-	-	-
Propylene	-	-	-	-	-	7.21E-03	7.10E-02	2.90E-02
Polycyclic Organic Matter:								
Total POM	**4.96E-03**	**3.31E-04**	**4.59E-05**	**7.38E-06**	**0.00E+00**	**4.69E-04**	**5.38E-03**	**2.20E-03**
3-Methylchloranthrene	-	-	1.18E-07	1.90E-08	-	-	-	-
Total PAHs	*4.96E-03*	*3.31E-04*	*4.57E-05*	*7.36E-06*	*0.00E+00*	*4.69E-04*	*5.38E-03*	*2.20E-03*
2-Methylnaphthalene	-	-	1.58E-06	2.54E-07	-	-	-	-
7,12-Dimethylbenz(a)anthrac	-	-	1.05E-06	1.69E-07	-	-	-	-
Acenaphthene	-	-	*1.18E-07*	*1.90E-08*	-	*3.97E-06*	*1.19E-04*	*4.86E-05*
Acenaphthylene	-	-	*1.18E-07*	*1.90E-08*	-	*1.41E-05*	*2.35E-04*	*9.58E-05*
Anthracene	-	-	*1.58E-07*	*2.54E-08*	-	*5.22E-06*	*3.13E-05*	*1.28E-05*
Benz(a)anthracene	-	-	*1.18E-07*	*1.90E-08*	-	*4.69E-06*	*1.58E-05*	*6.46E-06*
Benzo(a)pyrene	-	-	*7.88E-08*	*1.27E-08*	-	*5.25E-07*	*6.54E-06*	*2.67E-06*
Benzo(b)fluoranthene	-	-	*1.18E-07*	*1.90E-08*	-	*2.77E-07*	*2.82E-05*	*1.15E-05*
Benzo(g,h,i)perylene	-	-	*7.88E-08*	*1.27E-08*	-	*1.37E-06*	*1.41E-05*	*5.77E-06*
Benzo(k)fluoranthene	-	-	*1.18E-07*	*1.90E-08*	-	*4.33E-07*	*5.54E-06*	*2.26E-06*
Chrysene	-	-	*1.18E-07*	*1.90E-08*	-	*9.86E-07*	*3.89E-05*	*1.59E-05*
Dibenzo(a,h)anthracene	-	-	*7.88E-08*	*1.27E-08*	-	*1.63E-06*	*8.80E-06*	*3.59E-06*
Fluoranthene	-	-	*1.97E-07*	*3.17E-08*	-	*2.13E-05*	*1.02E-04*	*4.18E-05*
Fluorene	-	-	*1.84E-07*	*2.96E-08*	-	*8.16E-05*	*3.26E-04*	*1.33E-04*
Indeno(1,2,3-cd)pyrene	-	-	*1.18E-07*	*1.90E-08*	-	*1.05E-06*	*1.05E-05*	*4.30E-06*
Naphthalene	*2.93E-03*	*1.96E-04*	*4.01E-05*	*6.45E-06*	-	*2.37E-04*	*3.31E-03*	*1.35E-03*
Phenanathrene	-	-	*1.12E-06*	*1.80E-07*	-	*8.21E-05*	*1.04E-03*	*4.24E-04*
Pyrene	-	-	*3.28E-07*	*5.29E-08*	-	*1.34E-05*	*9.43E-05*	*3.85E-05*
Ammonia	3.07E+01	2.05E+00	-	-	-	-	-	-

Notes:
Total POM is the sum of the three individual POM compounds and the total PAHs.
POM as a class of substances and naphthalene are listed as HAP compounds.

Table C-3
GE 7HA.02 Criteria Pollutant Emissions
Annual and Maximum Hourly Emission Estimate

Maximum Heat Input (HHV) 4,509 MMBtu/hr
Annual Average Heat Input (HHV) 4,370 MMBtu/hr

	TSP[4/5]	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2	CH_4	N_2O	CO_2e
	Summary of Short Term Emission Rates (lb/hr/unit)												
Maximum hourly operating emission rates [1/2]	24.10	24.10	24.10	33.20	20.20	8.70	6.50	4.70	2.21E-03	535,915	9.94	0.99	536,457
Annual average hourly operating emission rates [2/3]	23.00	23.00	23.00	32.20	19.60	8.40	6.30	4.50	0.0021	519,453	9.64	0.96	519,978
	Summary of Annual Emission Rates, Normal Operations (tpy/unit)												
Full Load Operation @ Permit Capacity Factor	100.74	100.74	100.74	141.04	85.85	36.79	27.59	19.71	9.38E-03	2,275,205	42.20	4.22	2,277,505

	TSP	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2	CH_4	N_2O	CO_2e
	Summary of GE 7HA.02 Combustion Turbine Worst-Case Annual Emission Totals (all GE turbines tons/yr)												
Worst-Case Annual Emissions [6]	705.18	705.18	705.18	987.25	774.40	275.41	193.16	137.97	6.57E-02	15,926,437	295.41	29.54	15,942,537

	TSP	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2	CH_4	N_2O	CO_2e
	Assessment of GE 7HA.02 combustion turbine worst-case annual emission totals (all GE turbines ton/yr)												
1. Full Load Operation @ Permit Capacity Factor	705.18	705.18	705.18	987.25	600.94	257.54	193.16	137.97	6.57E-02	15,926,437	295.41	29.54	15,942,537
2. Accounting for SU/SD hours [7]	Annual hours breakdown per unit: cold start: 1,024.33; warm start: 1,960.00; hot start: 100.00; shutdown: 50.80; operating: 5,624.87												
a. Cold Startup Emissions	0.70	0.70	0.70	9.80	40.67	5.15	0.14	0.09	4.98E-05	12,071	0.22	0.02	12,083
b. Warm Startup Emissions	1.71	1.71	1.71	22.40	32.90	9.80	0.34	0.23	1.25E-04	30,246	0.56	0.06	30,277
c. Hot Startup Emissions	4.27	4.27	4.27	77.00	150.50	46.20	0.81	0.55	2.95E-04	71,466	1.33	0.13	71,538
d. Shutdown Emissions	2.13	2.13	2.13	14.22	164.47	48.90	0.27	0.18	9.66E-05	23,422	0.43	0.04	23,446
e. Operating Emissions [7]	452.80	452.80	452.80	633.92	385.87	165.37	124.03	88.59	4.22E-02	10,226,494	189.69	18.97	10,236,831
Total Emissions	**461.61**	**461.61**	**461.61**	**757.35**	**774.40**	**275.41**	**125.59**	**89.64**	**4.27E-02**	**10,363,699**	**192.23**	**19.22**	**10,374,176**

Notes:

1/ Maximum short term PM, NOx, CO, VOC, and CO_2 emission rates are from the 100% load at 20ºF ambient temperature case.

2/ Emission rates for lead, CH_4 and N_2O are calculated using emission factors from AP-42 Table 1.4-2 (Pb), 40 CFR Part 75, Appendix G, Sec. 2.3 (CO_2) and 40 CFR Part 98 Table C-2 (CH_4 and N_2O).

3/ Annual average PM, NOx, CO and VOC emission rates are from the 100% load at 59ºF ambient temperature case.

4/ $PM_{2.5}$ = PM_{10} = TPM

5/ Short term and annual average particulate emission rates are estimated at the expected maximum gas sulfur content of 15.9 ppm for gas fuel.

6/ Worst-case emissions determined during normal operation for permited capacity factor hours per year or operations with expected startup/shutdown times.

7/ No SU/SD emissions data available for SO_2, H_2SO_4, lead, or greenhouse gas pollutants. Operating emissions for these pollutants assume 8,760 hours of operation.

Table C-4
GE 7HA.02 Emissions Estimates

Case Description		-20°F, Gas fuel, 1 GT @ 100% load, DB 0%	-20°F, Gas fuel, 1 GT @ 100% load, DB 100%	-20°F, Gas fuel, 1 GT @ 75% load, DB 0%	-20°F, Gas fuel, 1 GT @ 45% load, DB 0%	20°F, Gas fuel, 1 GT @ 100% load, DB 0%	20°F, Gas fuel, 1 GT @ 100% load, DB 96.102%	20°F, Gas fuel, 1 GT @ 75% load, DB 0%	20°F, Gas fuel, 1 GT @ 30% load, DB 0%	52°F, Gas fuel, 1 GT @ 100% load, DB 0%	52°F, Gas fuel, 1 GT @ 100% load, DB 92.145%	52°F, Gas fuel, 1 GT @ 75% load, DB 0%	52°F, Gas fuel, 1 GT @ 30% load, DB 0%	59°F, Gas fuel, 1 GT @ 100% load, DB 0%	59°F, Gas fuel, 1 GT @ 100% load, DB 90.58%	59°F, Gas fuel, 1 GT @ 75% load, DB 0%	59°F, Gas fuel, 1 GT @ 30% load, DB 0%	70°F, Gas fuel, 1 GT @ 100% load, DB 0%	70°F, Gas fuel, 1 GT @ 100% load, DB 90.05%	70°F, Gas fuel, 1 GT @ 100% load, EC on, DB 90.4%	70°F, Gas fuel, 1 GT @ 100% load, EC on, DB 0%
Ambient Conditions																					
Ambient Temperature	°F	-20.0	-20.0	-20.0	-20.0	20.0	20.0	20.0	20.0	52.0	52.0	52.0	52.0	59.0	59.0	59.0	59.0	70.0	70.0	70.0	70.0
Ambient Pressure	psia	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085
Ambient Relative Humidity	%	80	80	80	80	60	60	60	60	80	80	80	80	60	60	60	60	77	77	77	77
Gas Turbine																					
GT Fuel Type		Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas
Number of Gas Turbines operating per Block		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
GT load fraction	-	100%	100%	75%	45%	100%	100%	75%	30%	100%	100%	75%	30%	100%	100%	75%	30%	100%	100%	100%	100%
Evap Cooler status		off	off	off	off	off	off	off	off	off	off	off	off	off	off	off	off	off	off	On	On
Gas turbine water injection flow rate	klb/h	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Abatement Status																					
CO Catalyst Operating status		Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating
SCR Operating status		Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating
GT Fuel																					
Gas Turbine fuel LHV	Btu/lb	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210
Gas Turbine fuel HHV	Btu/lb	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508
Gas Turbine gas fuel molecular weight	lb/lbmole	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72
Gas Turbine sulfur ppm (by mass)	ppm	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9
Duct Burner																					
Duct Burner fuel LHV	Btu/lb	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210
Duct Burner fuel HHV	Btu/lb	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508
Duct Burner fuel molecular weight	lb/lbmole	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72
Duct Burner fuel sulfur content (by mass)	ppm	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9
Duct Burner status		Off	Operating	Off	Off	Off	Operating	Off	Off	Off	Operating	Off	Off	Off	Operating	Off	Off	Off	Operating	Operating	Off
Duct Burner gas fuel flow	lb/h	0.0	44000.1	0.0	0.0	0.0	42284.8	0.0	0.0	0.0	40544.0	0.0	0.0	0.0	39855.1	0.0	0.0	0.0	39622.2	39775.9	0.0
Duct Burner load fraction	%	0.0	100.0	0.0	0.0	0.0	96.1	0.0	0.0	0.0	92.1	0.0	0.0	0.0	90.6	0.0	0.0	0.0	90.1	90.4	0.0
Heat Consumption for permitting (per unit)																					
GT Heat Cons (HHV), with permitting margin		3454.3	3449.2	2752.9	1991.4	3518.1	3514.9	2757.9	1569.9	3469.6	3465.4	2716.4	1531.2	3437.7	3433.5	2694.8	1513.6	3405.4	3401.0	3424.1	3428.6
DB Heat Cons (HHV)		0.0	1034.4	0.0	0.0	0.0	994.0	0.0	0.0	0.0	953.1	0.0	0.0	0.0	936.9	0.0	0.0	0.0	931.4	935.1	0.0
Total	MMBtu/h	3454.3	4483.6	2752.9	1991.4	3518.1	4508.9	2757.9	1569.9	3469.6	4418.5	2716.4	1531.2	3437.7	4370.4	2694.8	1513.6	3405.4	4332.4	4359.2	3428.6
HRSG Exit Exhaust gas (per unit)																					
Stack N_2 mole fraction	-	0.74760	0.73780	0.74790	0.74950	0.74600	0.73670	0.74640	0.75060	0.73920	0.73020	0.73960	0.74430	0.73950	0.73050	0.73980	0.74470	0.73270	0.72380	0.72250	0.73140
Stack O_2 mole fraction	-	0.11550	0.08765	0.11620	0.12070	0.11430	0.08783	0.11540	0.12730	0.11170	0.08582	0.11290	0.12630	0.11180	0.08602	0.11290	0.12670	0.11060	0.08492	0.08408	0.10980
Stack AR mole fraction	-	0.00890	0.00879	0.00891	0.00892	0.00888	0.00877	0.00889	0.00894	0.00880	0.00869	0.00881	0.00886	0.00881	0.00870	0.00881	0.00887	0.00873	0.00862	0.00860	0.00871
Stack H_2O mole fraction	-	0.08457	0.10950	0.08390	0.07991	0.08699	0.11070	0.08603	0.07537	0.09608	0.11920	0.09504	0.08311	0.09579	0.11880	0.09480	0.08242	0.10410	0.12690	0.12890	0.10610
Stack CO_2 mole fraction	-	0.04336	0.05609	0.04301	0.04097	0.04371	0.05584	0.04322	0.03776	0.04408	0.05597	0.04355	0.03742	0.04411	0.05591	0.04360	0.03724	0.04381	0.05557	0.05581	0.04403
Stack Molecular Weight	lb/lbmole	28.43	28.27	28.43	28.46	28.40	28.25	28.41	28.48	28.31	28.16	28.31	28.39	28.31	28.16	28.32	28.39	28.22	28.07	28.05	28.20
Stack Temperature	°F	172.9	169.9	169.2	163.8	171.8	170.5	168.2	162.8	174.8	172.0	168.7	162.3	174.6	171.6	168.5	162.6	177.1	172.2	172.4	177.2
Stack Mass flow, including Permitting Margin, per stack	lb/h	6025400	6071400	4841600	3681000	6082000	6126300	4823100	3152700	5926100	5968500	4698200	3093800	5868900	5910600	4655300	3073900	5834700	5876100	5882400	5840800
Margined exhaust vol flow (incl. permitting margin)	Mft3/h	102.17	103.03	81.599	61.454	103.03	104.12	81.214	52.51	101.21	102.01	79.445	51.647	100.18	100.94	78.686	51.324	100.33	100.77	100.99	100.52
HRSG Exit Emissions (per unit)																					
NOx Volume fraction, dry, at 15 % O_2	ppm	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
NOx mass flow rate (as NO_2, calculated using EPA Method 19)	lb/h	25.5	33.0	20.3	14.7	25.9	33.2	20.3	11.6	25.6	32.6	20.0	11.3	25.3	32.2	19.9	11.2	25.1	31.9	32.1	25.3
CO Volume fraction, dry, at 15 % O_2	ppm	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CO mass flow rate (calculated using EPA Method 19)	lb/h	15.5	20.1	12.3	8.9	15.8	20.2	12.4	7.0	15.6	19.8	12.2	6.9	15.4	19.6	12.1	6.8	15.3	19.4	19.6	15.4
VOC Volume fraction, dry, at 15 % O_2 (as methane)	ppm	1	1.5	1	1	1	1.5	1	1	1	1.5	1	1	1	1.5	1	1	1	1.5	1.5	1
VOC mass flow rate (as CH_4, calculated using EPA Method 19)	lb/h	4.4	8.6	3.5	2.6	4.5	8.7	3.5	2.0	4.5	8.5	3.5	2.0	4.4	8.4	3.5	1.9	4.4	8.3	8.4	4.4
VOC Volume fraction, dry, at 15 % O_2 (as propane)	ppm	0.333	0.500	0.333	0.333	0.333	0.500	0.333	0.333	0.333	0.500	0.333	0.333	0.333	0.500	0.333	0.333	0.333	0.500	0.500	0.333
VOC mass flow rate (as $C3H_8$, calculated using EPA Method 19)	lb/h	4.1	7.9	3.2	2.3	4.1	8.0	3.2	1.8	4.1	7.8	3.2	1.8	4.0	7.7	3.2	1.8	4.0	7.6	7.7	4.0
NH_3 Volume fraction, dry, at 15 % O_2	ppm	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
NH_3 mass flow rate	lb/h	23.2	30.5	18.5	13.4	23.6	30.7	18.5	10.5	23.3	30.1	18.3	10.3	23.1	29.7	18.1	10.2	22.9	29.5	29.7	23.0
SOx mass flow rate (as SO_2, See notes 1, 2, and 3)	lb/h	4.9	6.4	3.9	2.8	5.0	6.5	3.9	2.2	4.9	6.3	3.9	2.2	4.9	6.3	3.8	2.1	4.8	6.2	6.3	4.9
SOx mass flow rate (calculated, See notes 1, 2, and 3)	lb/MMBtu	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014
Total Particulates (see notes 6, 7 , 8, and 11)	lb/h	18.7	24.1	14.9	10.8	19.0	23.7	14.9	8.5	18.7	23.2	14.7	8.3	18.6	23	14.6	8.2	18.4	22.9	22.9	18.5
Total Particulates (Calculated, see notes 6, 7, 8, and 11)	lb/MMBtu	0.0054	0.0054	0.0054	0.0054	0.0054	0.0053	0.0054	0.0054	0.0054	0.0053	0.0054	0.0054	0.0054	0.0053	0.0054	0.0054	0.0054	0.0053	0.0053	0.0054
Sulfur Mist as H_2SO_4 (See notes 2 and 3)	lb/h	3.3	4.7	2.6	1.9	3.4	4.6	2.6	1.5	3.3	4.6	2.6	1.5	3.3	4.5	2.6	1.5	3.3	4.5	4.5	3.3
H_2SO_4 (calculated)	lb/MMBtu	0.0010	0.0010	0.0009	0.0010	0.0010	0.0010	0.0009	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010
Stack CO_2 (calcualted, based on Part 75, see note 10)	lb/h	410,568	532,908	327,202	236,692	418,151	535,915	327,796	186,594	412,387	525,170	322,864	181,994	408,595	519,453	320,296	179,902	404,756	514,937	518,122	407,514
Stack CH_4 (calculated)	lb/h	7.62	9.88	6.07	4.39	7.76	9.94	6.08	3.46	7.65	9.74	5.99	3.38	7.58	9.64	5.94	3.34	7.51	9.55	9.61	7.56
Stack N_2O (calculated)	lb/h	0.76	0.99	0.61	0.44	0.78	0.99	0.61	0.35	0.76	0.97	0.60	0.34	0.76	0.96	0.59	0.33	0.75	0.96	0.96	0.76
Stack CO_2e (calculated)	lb/h	410,983	533,447	327,533	236,931	418,574	536,457	328,127	186,782	412,804	525,701	323,190	182,178	409,008	519,978	320,620	180,084	405,165	515,457	518,646	407,926
Stack CO_2 rate (calculated, per Gross CC Power per stack)	lb/MWh	789	829	803	867	772	811	783	905	763	804	776	895	763	803	777	894	766	807	807	767
Stack CO_2 rate (calculated per Net Plant CC Power per stack)	lb/MWh	803	848	820	889	787	829	800	937	778	822	794	932	778	821	795	931	781	825	825	782

Notes:
(1) SO_2 emission values have been estimated by assuming that all the sulfur in the fuel is converted to SO_2.
(2) SO_2 and sulfur mist emission values are based on maximum sulfur content of 15.9 ppm for gas.
(3) SO_2 and sulfur mist values are margined by 5% to account for variation in fuel sulfur content and measurement error.
(4) The CO_2 estimates are margined 0 % to account for equipment variation and site operating conditions. If CO_2 compliance is to be demonstrated using actual CO_2 measurement from the HRSG stack, GE recommends an additional 10% margin to the estimated values.
(5) Sulfur mist emission calculations conservatively assume that all SO_3 combines with water to form sulfur mist. In actuality, some SO_3 may form other chemical species. This would include ammonium sulfates in the presence of NH_3. The maximum sulfur mist is reported to be conservative.
(6) Particulate Matter estimates over the entire emissions compliance region of GT operation are based on field data obtained at base load for the GT. In reality, particulate matter emissions measured in lb/h are expected to decrease at part load operation and the lb/MMBTU values at part load operation are expected not to exceed the lb/MMBTU value for PM at baseload.
(7) PM_{10} and $PM_{2.5}$ are estimated at the same rate as Total Particulates.
(8) PM estimates are based on maximum S content in the fuel of 15.9 ppm for gas fuel.
(9) Average conditions are based on 59°F at max load and 90.58% duct burner load.
(10) Calculated CO_2 based on Part 74, Appendix G, Equation G-4.
(11) Particulate values for baseload and part load conditions set to use 0.0054 lb/MMBtu based on highest lb/hr value.

Table C-4
GE 7HA.02 Emissions Estimates

Case Description		70°F, Gas fuel, 1 GT @ 75% load, DB 0%	70°F, Gas fuel, 1 GT @ 30% load, DB 0%	90°F, Gas fuel, 1 GT @ 100% load, DB 0%	90°F, Gas fuel, 1 GT @ 100% load, DB 86.005%	90°F, Gas fuel, 1 GT @ 100% load, EC on, DB 89.668%	90°F, Gas fuel, 1 GT @ 100% load, EC on, DB 0%	90°F, Gas fuel, 1 GT @ 75% load, DB 0%	90°F, Gas fuel, 1 GT @ 30% load, DB 0%	105°F, Gas fuel, 1 GT @ 100% load, DB 0%	105°F, Gas fuel, 1 GT @ 100% load, DB 78.679%	105°F, Gas fuel, 1 GT @ 100% load, EC on, DB 89.735%	105°F, Gas fuel, 1 GT @ 100% load, EC on, DB 0%	105°F, Gas fuel, 1 GT @ 75% load, DB 0%	105°F, Gas fuel, 1 GT @ 35% load, DB 0%	Average[9]	Maximum
Ambient Conditions																	
Ambient Temperature	°F	70.0	70.0	90.0	90.0	90.0	90.0	90.0	90.0	105.0	105.0	105.0	105.0	105.0	105.0	59	20
Ambient Pressure	psia	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085	14.085
Ambient Relative Humidity	%	77	77	45	45	45	45	45	45	25	25	25	25	25	25	60	60
Gas Turbine																	
GT Fuel Type		Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas
Number of Gas Turbines operating per Block		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
GT load fraction	-	75%	30%	100%	100%	100%	100%	75%	30%	100%	100%	100%	100%	75%	35%	100%	100%
Evap Cooler status		off	off	off	off	On	On	off	off	off	off	On	On	off	off	off	off
Gas turbine water injection flow rate	klb/h	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0
Abatement Status																	
CO Catalyst Operating status		Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating
SCR Operating status		Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating
GT Fuel																	
Gas Turbine fuel LHV	Btu/lb	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210
Gas Turbine fuel HHV	Btu/lb	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508
Gas Turbine gas fuel molecular weight	lb/lbmole	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72
Gas Turbine sulfur ppm (by mass)	ppm	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9
Duct Burner																	
Duct Burner fuel LHV	Btu/lb	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210	21210
Duct Burner fuel HHV	Btu/lb	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508	23508
Duct Burner fuel molecular weight	lb/lbmole	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72	16.72
Duct Burner fuel sulfur content (by mass)	ppm	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9
Duct Burner status		Off	Off	Off	Operating	Operating	Off	Off	Off	Off	Operating	Operating	Off	Off	Off	Operating	Operating
Duct Burner gas fuel flow	lb/h	0.0	0.0	0.0	37842.2	39454.1	0.0	0.0	0.0	0.0	34618.7	39483.5	0.0	0.0	0.0	39855	42284.8
Duct Burner load fraction	%	0.0	0.0	0.0	86.0	89.7	0.0	0.0	0.0	0.0	78.7	89.7	0.0	0.0	0.0	90.6	96.1
Heat Consumption for permitting (per unit)																	
GT Heat Cons (HHV), with permitting margin		2662.4	1493.4	3247.1	3242.9	3388.9	3393.3	2543.6	1448.1	3018.4	3014.7	3382.6	3387.0	2381.7	1487.0	*3433.5*	*3514.9*
DB Heat Cons (HHV)		0.0	0.0	0.0	889.6	927.5	0.0	0.0	0.0	0.0	813.8	928.2	0.0	0.0	0.0	*936.9*	*994*
Total	MMBtu/h	2662.4	1493.4	3247.1	4132.5	4316.4	3393.3	2543.6	1448.1	3018.4	3828.5	4310.8	3387.0	2381.7	1487.0	4370.4	4508.9
HRSG Exit Exhaust gas (per unit)																	
Stack N_2 mole fraction	-	0.73310	0.73790	0.73130	0.72250	0.71820	0.72690	0.73200	0.73670	0.73350	0.72490	0.71730	0.72610	0.73480	0.73870	0.73050	0.73670
Stack O_2 mole fraction	-	0.11160	0.12550	0.11130	0.08594	0.08353	0.10910	0.11330	0.12700	0.11220	0.08734	0.08356	0.10910	0.11620	0.12720	0.08602	0.08783
Stack AR mole fraction	-	0.00873	0.00879	0.00871	0.00860	0.00855	0.00866	0.00872	0.00877	0.00873	0.00863	0.00854	0.00865	0.00875	0.00880	0.00870	0.00877
Stack H_2O mole fraction	-	0.10320	0.09083	0.10540	0.12790	0.13410	0.11150	0.10360	0.09142	0.10240	0.12450	0.13510	0.11240	0.09891	0.08906	0.11880	0.11070
Stack CO_2 mole fraction	-	0.04333	0.03695	0.04324	0.05487	0.05549	0.04375	0.04233	0.03602	0.04307	0.05448	0.05537	0.04363	0.04126	0.03618	0.05591	0.05584
Stack Molecular Weight	lb/lbmole	28.22	28.30	28.20	28.05	27.99	28.14	28.21	28.28	28.23	28.09	27.98	28.12	28.25	28.31	28.16	28.25
Stack Temperature	°F	170.9	164.9	177.6	170.1	172.2	179.6	172.5	166.7	175.3	166.5	172.3	180.4	172.4	167.3	171.6	170.5
Stack Mass flow, including Permitting Margin, per stack	lb/h	4613500	3046400	5633100	5672800	5845200	5803900	4509700	3028900	5262700	5299000	5848800	5807500	4339500	3100100		
Margined exhaust vol flow (incl. permitting margin)	Mft3/h	78.543	51.229	97.005	97.03	100.54	100.47	77.006	51.103	90.194	90.016	100.65	100.71	73.979	52.309	100.94000	104.12000
HRSG Exit Emissions (per unit)																	
NOx Volume fraction, dry, at 15 % O_2	ppm	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
NOx mass flow rate (as NO_2, calculated using EPA Method 19)	lb/h	19.6	11.0	23.9	30.4	31.8	25.0	18.7	10.7	22.2	28.2	31.8	25.0	17.5	11.0	32.2	33.2
CO Volume fraction, dry, at 15 % O_2	ppm	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CO mass flow rate (calculated using EPA Method 19)	lb/h	11.9	6.7	14.6	18.5	19.4	15.2	11.4	6.5	13.5	17.2	19.3	15.2	10.7	6.7	19.6	20.2
VOC Volume fraction, dry, at 15 % O_2 (as methane)	ppm	1	1	1	1.5	1.5	1	1	1	1	1.5	1.5	1	1	1	1.5	1.5
VOC mass flow rate (as CH_4, calculated using EPA Method 19)	lb/h	3.4	1.9	4.2	8.0	8.3	4.4	3.3	1.9	3.9	7.4	8.3	4.4	3.1	1.9	8.4	8.7
VOC Volume fraction, dry, at 15 % O_2 (as propane)	ppm	0.333	0.333	0.333	0.500	0.500	0.333	0.333	0.333	0.333	0.500	0.500	0.333	0.333	0.333		
VOC mass flow rate (as $C3H_8$, calculated using EPA Method 19)	lb/h	3.1	1.8	3.8	7.3	7.6	4.0	3.0	1.7	3.6	6.8	7.6	4.0	2.8	1.8		
NH_3 Volume fraction, dry, at 15 % O_2	ppm	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
NH_3 mass flow rate	lb/h	17.9	10.0	21.8	28.1	29.4	22.8	17.1	9.7	20.3	26.0	29.3	22.8	16.0	10.0	29.7	30.7
SOx mass flow rate (as SO_2, See notes 1, 2, and 3)	lb/h	3.8	2.1	4.6	5.9	6.2	4.8	3.6	2.1	4.3	5.5	6.2	4.8	3.4	2.1	6.3	6.5
SOx mass flow rate (calculated, See notes 1, 2, and 3)	lb/MMBtu	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0015	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014
Total Particulates (see notes 6, 7 , 8, and 11)	lb/h	14.4	8.1	17.5	22.2	22.8	18.3	13.7	7.8	16.3	21.1	22.8	18.3	12.9	8.0	23	24.1
Total Particulates (Calculated, see notes 6, 7, 8, and 11)	lb/MMBtu	0.0054	0.0054	0.0054	0.0054	0.0053	0.0054	0.0054	0.0054	0.0054	0.0055	0.0053	0.0054	0.0054	0.0054	0.0053	0.0054
Sulfur Mist as H_2SO_4 (See notes 2 and 3)	lb/h	2.6	1.4	3.1	4.3	4.4	3.3	2.4	1.4	2.9	3.9	4.4	3.2	2.3	1.4	4.5	4.7
H_2SO_4 (calculated)	lb/MMBtu	0.0010	0.0009	0.0010	0.0010	0.0010	0.0010	0.0009	0.0010	0.0010	0.0010	0.0010	0.0009	0.0010	0.0009	0.0010	0.0010
Stack CO_2 (calcualted, based on Part 75, see note 10)	lb/h	316,445	177,501	385,941	491,177	513,035	403,318	302,325	172,117	358,758	455,045	512,369	402,569	283,082	176,741	519,453	535,915
Stack CH_4 (calculated)	lb/h	5.87	3.29	7.16	9.11	9.52	7.48	5.61	3.19	6.65	8.44	9.50	7.47	5.25	3.28		
Stack N_2O (calculated)	lb/h	0.59	0.33	0.72	0.91	0.95	0.75	0.56	0.32	0.67	0.84	0.95	0.75	0.53	0.33		
Stack CO_2e (calculated)	lb/h	316,765	177,681	386,331	491,674	513,554	403,726	302,631	172,291	359,121	455,505	512,887	402,976	283,368	176,919		
Stack CO_2 rate (calculated, per Gross CC Power per stack)	lb/MWh	779	900	770	811	811	771	785	911	772	812	813	772	790	897	803	811
Stack CO_2 rate (calculated per Net Plant CC Power per stack)	lb/MWh	798	939	786	830	830	786	804	951	789	831	831	788	811	935	821	829

Notes:
(1) SO_2 emission values have been estimated by assuming that all the sulfur in the fuel is c
(2) SO_2 and sulfur mist emission values are based on maximum sulfur content of 15.9 ppm
(3) SO_2 and sulfur mist values are margined by 5% to account for variation in fuel sulfur co
(4) The CO_2 estimates are margined 0 % to account for equipment variation and site opera
(5) Sulfur mist emission calculations conservatively assume that all SO_3 combines with wa
(6) Particulate Matter estimates over the entire emissions compliance region of GT operatic
(7) PM_{10} and $PM_{2.5}$ are estimated at the same rate as Total Particulates.
(8) PM estimates are based on maximum S content in the fuel of 15.9 ppm for gas fuel.
(9) Average conditions are based on 59°F at max load and 90.58% duct burner load.
(10) Calculated CO_2 based on Part 74, Appendix G, Equation G-4.
(11) Particulate values for baseload and part load conditions set to use 0.0054 lb/MMBtu b

Table C-5
GE 7HA.02 Startup/Shutdown Emissions Estimates

Startup/Shutdown Type Events	Emissions per Startup/Shutdown Event (lbs/event/CC)				Event Duration (min)	Power Generated (MWh)	Heat Consumption, LHV (MMBtu)
	NOx	CO	VOC as Methane	Total PM			
Cold Start, No HP drum Warming[1]	200	830	105	14.2	70	186	1,870
Warm Start (48 hrs median)[2]	160	235	70	12.2	60	159	1,640
Hot Start [1]	110	215	66	6.1	30	68	775
Shutdown	16	185	55	2.4	12	9	200

Table Notes:

(1) Hot starts are defined as taking place within 8 hours of the previous shutdown. Cold starts are preceded by over 72 hours of shutdown. Cold Start and Hot Start values can be used for both typical estimates and not-to-exceed permit limits.
(2) Warm Start cool down duration ranges from >8 to <72 hours after shutdown. The Warm Start emissions will vary depending on duration of the cool down period ranging between the Hot Start and Cold Start values. Warm Start values are based on a 48 hours cool down period as a median point. Warm Starts with

Basis

1. The table above represents the emissions during startup and shutdown events.
2. Emissions assume no contribution from pollutants present in the GT inlet air.
3. Emissions assume methane as the fuel and gas only combustors.
4. Particulates emissions account for sulfates resulting from 15.9 ppmw total fuel sulfur content (Natural gas, MW=16.94). Higher fuel sulfur content will increase particulate emissions.
5. The information is based on a GE designed and supplied extended scope power plant. Design, manufacture, construction, and commissioning of equipment outside of this scope of supply such as auxiliary boiler must meet GE functional requirements.
6. Event duration: Startup is from the time a non-zero value is measured at the HRSG stack (of a pollutant which is guaranteed) to the time of compliance. Emission compliance is verified by 10 subsequent consecutive compliant CEMS readings however this is only a verification measurement and not counted as part of startup emission mass or duration. Shutdown is from the time that the HRSG stack is out of emissions compliance until the time that the GT fuel valve has closed.
7. Ammonia is injected during startup. To vaporize this ammonia, electric air heaters may be required.
8. NOx and CO Emissions are per HRSG stack and measured at the HRSG stack using CEMS, following the CEMs calibration and commissioning. Emissions concentration (ppm) signal from the HRSG stack CEMS at 15-second or smaller sampling intervals will be converted to emissions mass flow (lb/hr) using the GT control exhaust flow signal and integrated over the event or hour.
9. The plant is started using GE's Rapid Response Lite auto-start sequence. Prior to start, the plant is in a ready-to-start condition, i.e. all plant equipment which is needed to be operating during startup is in a no-fault condition, operational and/or in automatic mode. Water levels and pressures in drums, hotwell and other vessels are within range and/or not in an alarmed condition. GT and HRSG Purge credit are available.
10. The plant is previously shut down from steady state operation at base load using normal shutdown sequence in accordance with General Electric's recommendations. The duration of the shutdown/non-operational/standby period for the purpose of defining the start begins at termination of fuel flow to the GT during the plant shutdown. During the standby period, the plant is maintained as per GE-recommended procedures.
11. The GT is kept at MECL load level until stack compliance is achieved.
12. HRSG drum steam is not bled off for auxiliary services, steam seals, etc during shutdown.
13. HRSG stack damper remains closed during the shutdown period.

Table C-6
GE 7HA.02 Hazardous Air Pollutant Emissions
Annual and Maximum Hourly Emission Estimate

Compounds	CC Emission Factor			Oxidation Catalyst Control	HAP Emissions from CCs			
					CC Gas Emissions			
					Emission Rate, 1 Turbine		Emission Rate, All CCs	
	(lb/10^{6}scf)	(lb/MMBtu)[1]	Rating		Max Hourly (lb/hr)	Annual (tpy)	Max Hourly (lb/hr)	Annual (tpy)
Metal HAP Compounds[2]:								
Arsenic	2.00E-04	1.96E-07	E	0%	8.84E-04	3.75E-03	6.19E-03	2.63E-02
Beryllium	1.20E-05	1.18E-08	E	0%	5.30E-05	2.25E-04	3.71E-04	1.58E-03
Cadmium	1.10E-03	1.08E-06	D	0%	4.86E-03	2.06E-02	3.40E-02	1.44E-01
Chromium (Cr III)	1.34E-03	1.32E-06	D[6]	0%	5.94E-03	2.52E-02	4.16E-02	1.77E-01
Chromium (Cr VI)	5.60E-05	5.49E-08	D[6]	0%	2.48E-04	1.05E-03	1.73E-03	7.36E-03
Cobalt	8.40E-05	8.23E-08	D	0%	3.71E-04	1.58E-03	2.60E-03	1.10E-02
Lead	5.00E-04	4.90E-07	D	0%	2.21E-03	9.38E-03	1.55E-02	6.57E-02
Manganese	3.80E-04	3.72E-07	D	0%	1.68E-03	7.13E-03	1.18E-02	4.99E-02
Mercury	2.60E-04	2.55E-07	D	0%	1.15E-03	4.88E-03	8.04E-03	3.42E-02
Nickel	2.10E-03	2.06E-06	C	0%	9.28E-03	3.94E-02	6.50E-02	2.76E-01
Selenium	2.40E-05	2.35E-08	E	0%	1.06E-04	4.50E-04	7.43E-04	3.15E-03
Metal non-HAP Compounds[2]:								
Barium	4.40E-03	4.31E-06	D	0%	1.94E-02	8.26E-02	1.36E-01	5.78E-01
Copper	8.50E-04	8.33E-07	D	0%	3.76E-03	1.59E-02	2.63E-02	1.12E-01
Molybdenum	1.10E-03	1.08E-06	D	0%	4.86E-03	2.06E-02	3.40E-02	1.44E-01
Vanadium	2.30E-03	2.25E-06	C	0%	1.02E-02	4.32E-02	7.12E-02	3.02E-01
Zinc	2.90E-02	2.84E-05	E	0%	1.28E-01	5.44E-01	8.97E-01	3.81E+00
Organic Compounds[3]:								
1,3-Butadiene		4.30E-07	D	50%	9.69E-04	4.12E-03	6.79E-03	2.88E-02
Acetaldehyde		4.00E-05	C	50%	9.02E-02	3.83E-01	6.31E-01	2.68E+00
Acrolein		6.40E-06	C	50%	1.44E-02	6.13E-02	1.01E-01	4.29E-01
Benzene		1.20E-05	A	50%	2.71E-02	1.15E-01	1.89E-01	8.04E-01
Ethylbenzene		3.20E-05	C	50%	7.21E-02	3.06E-01	5.05E-01	2.14E+00
Formaldehyde		2.19E-04		included[4]	9.87E-01	4.19E+00	6.91E+00	2.93E+01
Naphthalene		1.30E-06	C[5]	50%	2.93E-03	1.24E-02	2.05E-02	8.71E-02
Total PAHs		2.20E-06	C[5]	50%	4.96E-03	2.11E-02	3.47E-02	1.47E-01
Propylene Oxide		2.90E-05	D	50%	6.54E-02	2.78E-01	4.58E-01	1.94E+00
Toluene		1.30E-04	C	50%	2.93E-01	1.24E+00	2.05E+00	8.71E+00
Xylene		6.40E-05	C	50%	1.44E-01	6.13E-01	1.01E+00	4.29E+00
Ammonia[7]								
Ammonia		6.82E-03			3.07E+01	1.31E+02	2.15E+02	9.14E+02

Combustion Turbine Total HAPs (ton/yr)[5] **5.13E+01**

Max Hourly Heat Input per Turbine(MMBtu/hr):	**4,509**
Average Hourly Heat Input per Turbine(MMBtu/hr):	**4,370**
Annual Heat Input per Turbine(MMBtu/yr):	**38,284,704**
Natural Gas Heating Value, HHV (Btu/scf):	**1,020**

Notes:

1/ Emission factor (lb/MMBtu) = (Emission factor, lb/10^6 scf) / (Volumetric Heat Content, Btu/scf) if lb/10^6 scf is given.

2/ Emission factors for metal compounds from AP-42, Section 1.4.

3/ Emission factors for organic compounds from AP-42, Section 3.1-3.

4/ Formaldehyde based on MACT Subpart YYYY limit of 91 ppbv @ 15% O2. Converted to lb/MMBtu using Method 19 methodology.

5/ Naphthalene is included in total PAHs and is not double counted as part of total HAPs

6/ Speciated chrome based on total chromium from AP-42 Table 1.4-4 and 96% Cr III / 4% Cr VI from EPA NEI Supporting Data - natural gas combustion turbines
https://gaftp.epa.gov/air/nei/2020/doc/supporting_data/Chromium_speciation_nonNAICS_28jan2023.zip

7/ Ammonia based on 5 ppmdv @ 15% O_2. Converted to lb/MMBtu using Method 19 methodology.

Table C-7
FT8 MOBILEPAC Criteria Pollutant Emissions
Annual and Maximum Hourly Emission Estimate

Maximum Heat Input (HHV) 301 MMBtu/hr
Annual Average Heat Input (HHV) 297 MMBtu/hr

	TSP[4/5]	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2	CH_4	N_2O	CO_2e
	Summary of Short Term Emission Rates (lb/hr/unit)												
Maximum hourly operating emission rates [1/2]	3.00	3.00	3.00	2.79	9.35	3.12	0.42	0.64	1.47E-04	35,776	0.66	0.07	35,812
Annual average hourly operating emission rates [2/3]	3.00	3.00	3.00	2.75	5.35	1.15	0.41	0.63	1.45E-04	35,301	0.65	0.07	35,336
	Summary of Annual Emission Rates, Normal Operations (tpy/unit)												
Full Load Operation @ Permit Capacity Factor	13.14	13.14	13.14	12.05	23.43	5.04	1.80	2.77	6.35E-04	154,617	2.87	0.29	154,773

	TSP	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2	CH_4	N_2O	CO_2e
	Summary of FT8 Combustion Turbine Worst-Case Annual Emission Totals (all FT8 turbines tons/yr)												
Worst-Case Annual Emissions [6]	132.45	132.45	132.45	132.00	257.45	51.13	17.96	27.75	6.35E-03	1,546,165	28.68	2.87	1,547,728

	TSP	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2	CH_4	N_2O	CO_2e
	Assessment of FT8 combustion turbine worst-case annual emission totals (all FT8 turbines ton/yr)												
1. Full Load Operation @ Permit Capacity Factor	131.40	131.40	131.40	120.45	234.33	50.37	17.96	27.75	6.35E-03	1,546,165	28.68	2.87	1,547,728
2. Accounting for SU/SD hours [7]	Annual hours breakdown per unit: starts: 75.00 shutdown: 23.50 operating: 8,661.50												
a. Startup Emissions	1.84	1.84	1.84	10.80	20.75	0.97	0.09	0.06	3.31E-05	8,015	0.15	0.01	8,023
b. Shutdown Emissions	0.69	0.69	0.69	2.10	5.00	0.36	0.01	0.01	4.86E-06	1,179	0.02	0.00	1,180
c. Operating Emissions [7]	129.92	129.92	129.92	119.10	231.70	49.80	17.76	27.44	6.28E-03	1,528,779	28.36	2.84	1,530,325
Total Emissions	**132.45**	**132.45**	**132.45**	**132.00**	**257.45**	**51.13**	**17.86**	**27.51**	**6.32E-03**	**1,537,973**	**28.53**	**2.85**	**1,539,528**

Notes:

1/ Maximum short term PM, NOx, CO and VOC emission rates are from the 100% load at 40ºF ambient temperature case.

2/ Emission rates for lead, CO_2, CH_4 and N_2O are calculated using emission factors from AP-42 Table 1.4-2 (Pb), 40 CFR Part 75, Appendix G, Sec. 2.3 (CO_2) and 40 CFR Part 98 Table C-2 (CH_4 and N_2O).

3/ Annual average PM, NOx, CO and VOC emission rates are from the 100% load at 59ºF ambient temperature case.

4/ $PM_{2.5} = PM_{10} = TPM$

5/ Short term and annual average particulate emission rates are estimated at the expected maximum gas sulfur content of 1 gr/100 scf for gas fuel.

6/ Worst-case emissions determined during normal operation for permited capacity factor hours per year.

7/ No SU/SD emissions data available for SO_2, H_2SO_4, lead, or greenhouse gas pollutants. Operating emissions for these pollutants assume 8,760 hours of operation.

Table C-8
FT8 MOBILEPAC Emissions Estimates
New Engine Emissions

Performance Data

Fuel Type		Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas
Percent of Unit Rating	%	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	75	65	100	75	50	100	75	50
Ambient Relative Humidity	%	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Ambient Temperature	Deg F	-18.4	-10.0	4.0	10.0	20.0		40.0	48.0	**59.0**	64.4	70.0	80.0	90.0	100.0	107.0	120.0	30.0	30.0	30.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0
Ambient Pressure	Psia	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696
Burner Water Injection In-Service	Yes / No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Inlet Loss	Inch H_2O	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Exhaust Loss	Inch H_2O	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
Fuel LHV	Btu/lb	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142
Ratio of HHV to LHV		1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110
Gross Power Output per MP, ref Gen Term	MWe	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	24.28	22.90	25.00	18.75	16.25	25.00	18.75	12.50	25.00	18.75	12.50	
Gross Heat Rate, LHV, ref Gen Term	Btu/kWhr	9,514	9,557	9,631	9,663	9,719	9,777	9,835	9,884	9,953	9,987	10,023	10,089	10,158	10,202	10,278	10,498	9,777	10,384	10,768	9,953	10,552	12,198	10,158	10,759	12,432	
Power Isle Aux Load, per MP	kW	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	
SCR Load	kW	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	
Net Power Output, per MP	MWe	24.678	24.678	24.678	24.678	24.678	24.678	24.678	24.678	24.678	24.678	24.678	24.678	24.678	24.678	23.958	22.582	24.678	18.424	15.923	24.678	18.429	12.179	24.678	18.428	12.178	
Net Heat Rate, LHV	Btu/kWhr	9,638	9,682	9,756	9,790	9,846	9,904	9,964	10,013	10,083	10,117	10,154	10,221	10,291	10,335	10,416	10,647	9,904	10,565	10,986	10,083	10,736	12,520	10,291	10,947	12,761	
Fuel Flow, per GT	lbs/hr	11,250	11,301	11,388	11,427	11,493	11,561	11,630	11,688	11,769	11,810	11,852	11,930	12,012	12,064	11,803	11,373	11,561	9,207	8,274	11,769	9,359	7,213	12,012	9,542	7,350	
Gaseous Fuel Flow, per GT	SCF/hr	257,682	258,862	260,852	261,741	263,256	264,810	266,395	267,705	269,582	270,503	271,477	273,263	275,149	276,335	270,360	260,492	264,810	210,892	189,518	269,582	214,360	165,208	275,149	218,570	168,364	
Calc Heat Input, HHV, per GT	MMBtu/hr	264	265	267	268	270	271	273	274	276	277	278	280	282	283	277	267	271	216	194	276	220	169	282	224	173	
Burner Water Injection Flow, per GT	gal/min	19.7	20.3	21.0	21.4	21.9	22.5	23.1	23.5	24.2	24.5	24.8	25.4	26.0	26.6	26.2	25.3	22.5	16.5	14.2	24.2	17.8	12.8	26.0	19.1	13.8	

Emissions & Exhaust Conditions at GT Exit, Secondary (Enclosure) Cooling Air Separately Exhausted *

NOx	ppmvd	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
NOx, as NO_2, per GT	lbs/hr	25.8	25.8	26.0	26.1	26.3	26.4	26.6	26.7	26.9	27.0	27.1	27.3	27.5	27.7	27.2	26.2	26.4	21.0	19.1	26.9	21.4	16.5	27.5	21.8	16.8	
CO	ppmvd	187	183	177	173	167	155	135	119	100	100	100	92	75	75	75	75	155.3	182.8	208.7	100.0	168.5	185.0	75.0	124.6	171.9	
CO, per GT	lbs/hr	116.9	115.0	111.9	110.3	106.6	99.9	87.6	77.7	65.5	65.8	66.0	61.3	50.2	50.6	49.6	47.8	99.9	93.6	96.0	65.5	87.7	74.1	50.2	66.2	70.2	
VOC as C1	ppmvd	17.5	16.8	15.7	15.1	14.0	12.4	9.7	7.9	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	12.4	16.8	24.2	6.0	14.3	17.2	6.0	8.4	14.9	
VOC as C1, per GT	lbs/hr	6.25	6.04	5.68	5.50	5.12	4.54	3.61	2.92	2.25	2.25	2.26	2.28	2.29	2.31	2.27	2.19	4.54	4.90	6.36	2.25	4.25	3.93	2.29	2.54	3.47	
SO_2, per GT (calculated, based on 0.5 gr/100 scf)	lbs/hr	0.37	0.37	0.37	0.37	0.38	0.38	0.38	0.38	0.38	0.39	0.39	0.39	0.39	0.39	0.39	0.37	0.38	0.30	0.27	0.38	0.31	0.24	0.39	0.31	0.24	
SO_2, per GT (calculated)	lb/MMBtu	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	

Treated Exhaust Characteristics (Post SCR & CO Converter and Addition of SCR Tempering Air) *

NOx	ppmvd	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
NOx, as NO_2, per GT	lbs/hr	2.58	2.58	2.60	2.61	2.63	2.64	2.66	2.67	2.69	2.70	2.71	2.73	2.75	2.77	2.72	2.62	2.64	2.10	1.91	2.69	2.14	1.65	2.75	2.18	1.68	
CO	ppmvd	14.9	14.6	14.1	13.9	13.3	12.4	10.8	9.6	8.0	8.0	8.0	7.4	6.0	6.0	6.0	6.0	12.4	14.6	16.7	8.0	13.5	14.8	6.0	10.0	13.8	
CO, per GT	lbs/hr	9.35	9.20	8.95	8.82	8.53	7.99	7.01	6.22	5.24	5.26	5.28	4.90	4.02	4.05	3.97	3.83	7.99	7.49	7.68	5.24	7.02	5.93	4.02	5.29	5.62	
VOC as C1	ppmvd	8.7	8.4	7.8	7.6	7.0	6.2	4.9	3.9	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	6.2	8.4	12.1	3.0	7.2	8.6	3.0	4.2	7.4	
VOC as C1, per GT	lbs/hr	3.12	3.02	2.84	2.75	2.56	2.27	1.80	1.46	1.12	1.13	1.13	1.14	1.15	1.16	1.13	1.09	2.27	2.45	3.18	1.12	2.13	1.96	1.15	1.27	1.74	
TSP/PM_{10}, Filterable and Cond, per GT	lbs/hr	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	
TSP/PM_{10}, Filterable and Cond, per GT (calculated)	lb/MMBtu	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.014	0.015	0.011	0.014	0.018	0.011	0.013	0.017	
Ammonia Slip, NH_3	ppmvd	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	
CO2, per GT (calcaulted, based on Part 75)	lb/hr	31,384	31,527	31,770	31,878	32,062	32,252	32,445	32,604	32,833	32,945	33,064	33,281	33,511	33,655	32,928	31,726	32,252	25,685	23,082	32,833	26,107	20,121	33,511	26,620	20,505	
CH4, per GT (calcaulted)	lb/hr	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.4	0.6	0.5	0.4	0.6	0.5	0.4	
N2O, per GT (calcaulted)	lb/hr	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0	
CO2e, per GT (calculated)	lb/hr	31,415	31,559	31,802	31,910	32,095	32,284	32,477	32,637	32,866	32,978	33,097	33,315	33,545	33,689	32,961	31,758	32,284	25,711	23,105	32,866	26,134	20,141	33,545	26,647	20,526	
CO2e rate (based on gross power output)	lb/MWh	1,257	1,263	1,273	1,277	1,284	1,292	1,300	1,306	1,315	1,320	1,324	1,333	1,342	1,348	1,358	1,387	1,292	1,372	1,423	1,315	1,394	1,612	1,342	1,422	1,643	
CO2e rate (based on net power output)	lb/MWh	1,273	1,279	1,289	1,294	1,301	1,309	1,317	1,323	1,332	1,337	1,342	1,350	1,360	1,366	1,376	1,407	1,309	1,396	1,452	1,332	1,419	1,654	1,360	1,446	1,686	
SCR Tempering Air Flow (at ambient T), per GT	lbs/sec	0.0	0.0	0.0	0.0	0.0	2.6	8.8	13.8	20.7	24.1	27.5	33.8	39.9	46.1	48.1	51.5	2.6	0.0	0.0	20.7	7.2	0.0	39.9	23.4	12.2	
Stack Exit Gas Flow Rate, per GT **	lbs/sec	205.4	203.0	199.0	197.3	194.7	194.6	198.3	201.4	205.6	207.7	209.9	213.7	217.6	221.4	219.5	215.4	194.6	170.2	160.6	205.6	170.8	143.8	217.6	180.4	150.1	
Stack Exit Gas Temperature **	Deg F	699	718	750	764	787	800	800	800	800	800	800	800	800	800	800	800	800	767	750	800	800	793	800	800	800	
Stack Gas Molecular Weight, Wet	lbs/lbmol	28.40	28.39	28.36	28.34	28.32	28.30	28.28	28.27	28.24	28.22	28.20	28.15	28.10	28.02	27.96	27.82	28.30	28.37	28.41	28.24	28.28	28.34	28.10	28.13	28.17	
Stack Gas Vol Flow Rate, per GT **	ACFS	6119.2	6148.9	6198.9	6220.4	6256.2	6327.6	6451.6	6553.7	6698.7	6770.4	6845.8	6982.6	7123.0	7266.5	7221.1	7121.9	6327.6	5369.7	4990.3	6698.7	5555.8	4640.7	7123.0	5899.8	4900.3	
H_2O	% Vol wet	7.29	7.47	7.78	7.93	8.20	8.41	8.51	8.63	8.88	9.05	9.26	9.76	10.43	11.34	12.09	13.95	8.41	7.53	7.11	8.88	8.37	7.63	10.43	9.95	9.30	
O_2	% Vol wet	14.77	14.66	14.47	14.38	14.23	14.16	14.21	14.24	14.26	14.26	14.25	14.21	14.13	14.01	13.91	13.64	14.16	14.78	15.08	14.26	14.57	15.10	14.13	14.42	14.88	
CO_2	% Vol wet	2.64	2.68	2.75	2.78	2.84	2.85	2.81	2.78	2.74	2.72	2.70	2.66	2.63	2.59	2.56	2.49	2.85	2.61	2.49	2.74	2.63	2.42	2.63	2.52	2.34	
A	% Vol wet	0.89	0.88	0.88	0.88	0.88	0.88	0.88	0.87	0.87	0.87	0.87	0.86	0.86	0.85	0.84	0.82	0.88	0.88	0.89	0.87	0.88	0.88	0.86	0.86	0.86	
N_2	% Vol wet	74.40	74.29	74.10	74.01	73.83	73.68	73.58	73.46	73.24	73.09	72.91	72.50	71.94	71.21	70.59	69.09	73.68	74.18	74.42	73.24	73.55	73.96	71.94	72.24	72.60	

* All concentrations corrected to 15% O_2

** After addition of SCR tempering air

Table C-9
FT8 MOBILEPAC Emissions Estimates
Refurbished Engine Emissions

Performance Data

Fuel Type		Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas
Percent of Unit Rating	%	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	75	65	100	75	50	100	75	50
Ambient Relative Humidity	%	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Ambient Temperature	Deg F	-18.4	-10.0	4.0	10.0	20.0	30.0	40.0	48.0	**59.0**	64.4	70.0	83.0	90.0	100.0	107.0	120.0	30.0	30.0	30.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0
Ambient Pressure	Psia	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696
Burner Water Injection In-Service	Yes / No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Inlet Loss	Inch H_2O	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Exhaust Loss	Inch H_2O	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
Fuel LHV	Btu/lb	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142	21,142
Ratio of HHV to LHV		1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110
Gross Power Output per MP, ref Gen Term	MWe	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	24.95	24.31	23.34	22.58	21.30	25.00	18.75	16.25	25.00	18.75	12.50	24.31	18.23	12.15	
Gross Heat Rate, LHV, ref Gen Term	Btu/kWhr	10,220	10,268	10,349	10,385	10,447	10,512	10,577	10,632	10,707	10,744	10,783	10,882	10,984	11,147	11,280	11,536	10,512	11,167	11,590	10,707	11,361	12,729	10,984	11,674	13,530	
Power Isle Aux Load, per MP	kW	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	
SCR Load	kW	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	
Net Power Output, per MP	MWe	24.679	24.678	24.678	24.678	24.678	24.678	24.678	24.678	24.678	24.678	24.678	24.628	23.986	23.021	22.259	20.979	24.678	18.430	15.930	24.678	18.429	12.179	23.986	17.909	11.832	
Net Heat Rate, LHV	Btu/kWhr	10,354	10,402	10,484	10,521	10,584	10,649	10,716	10,770	10,846	10,884	10,924	11,024	11,132	11,303	11,443	11,713	10,649	11,362	11,824	10,846	11,559	13,066	11,132	11,883	13,898	
Fuel Flow, per GT	lbs/hr	12,086	12,141	12,237	12,280	12,354	12,430	12,508	12,572	12,661	12,705	12,751	12,842	12,630	12,308	12,048	11,623	12,430	9,905	8,910	12,661	10,076	7,527	12,630	10,067	7,779	
Gaseous Fuel Flow, per GT	SCF/hr	276,836	278,100	280,302	281,284	282,974	284,710	286,498	287,964	289,999	291,005	292,070	294,157	289,286	281,924	275,960	266,230	284,710	226,877	204,077	289,999	230,794	172,401	289,286	230,578	178,168	
Calc Heat Input, HHV, per GT	MMBtu/hr	284	285	287	288	290	292	294	295	297	298	299	301	296	289	283	273	292	232	209	297	236	177	296	236	183	
Burner Water Injection Flow, per GT	gal/min	20.8	21.2	22.0	22.4	23.0	23.6	24.2	24.7	25.4	25.7	26.0	26.8	26.4	25.9	25.4	24.6	23.6	17.3	15.0	25.4	18.7	12.7	26.4	19.6	14.2	

Emissions & Exhaust Conditions at GT Exit, Secondary (Enclosure) Cooling Air Separately Exhausted *

NOx	ppmvd	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
NOx, as NO_2, per GT	lbs/hr	26.2	26.3	26.5	26.6	26.8	27.0	27.1	27.3	27.5	27.6	27.7	27.9	27.4	26.7	26.2	25.2	27.0	21.5	19.3	27.5	21.8	16.3	27.4	21.8	16.8	
CO	ppmvd	181	177	168	164	147	127	106	100	100	92	79	75	75	75	75	75	127	177	184	100	152	185	75	101	164	
CO, per GT	lbs/hr	115.3	113.4	108.8	106.5	96.1	83.2	70.1	66.4	66.9	61.6	53.6	50.9	50.1	48.8	47.8	46.1	83.2	92.3	86.6	66.9	80.7	73.4	50.1	53.8	67.4	
VOC as C1	ppmvd	16.4	15.8	14.3	13.6	11.3	8.6	6.6	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	8.6	15.7	17.1	6.0	11.9	17.2	6.0	6.1	13.6	
VOC as C1, per GT	lbs/hr	5.99	5.76	5.27	5.04	4.22	3.24	2.49	2.28	2.29	2.30	2.31	2.33	2.29	2.23	2.18	2.11	3.24	4.69	4.58	2.29	3.61	3.89	2.29	1.86	3.18	
SO_2, per GT (calculated)	lbs/hr	0.40	0.40	0.40	0.40	0.40	0.41	0.41	0.41	0.41	0.42	0.42	0.42	0.41	0.40	0.39	0.38	0.41	0.32	0.29	0.41	0.33	0.25	0.41	0.33	0.25	
SO_2, per GT (calculated)	lb/MMBtu	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	

Treated Exhaust Characteristics (Post SCR & CO Converter and Addition of SCR Tempering Air) *

NOx	ppmvd	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
NOx, as NO_2, per GT	lbs/hr	2.62	2.63	2.65	2.66	2.68	2.70	2.71	2.73	2.75	2.76	2.77	2.79	2.74	2.67	2.62	2.52	2.70	2.15	1.93	2.75	2.18	1.63	2.74	2.18	1.68	
CO	ppmvd	14.5	14.2	13.5	13.1	11.8	10.1	8.5	8.0	8.0	7.3	6.4	6.0	6.0	6.0	6.0	6.0	10.1	14.1	14.8	8.0	12.1	14.8	6.0	8.1	13.1	
CO, per GT	lbs/hr	9.23	9.07	8.70	8.52	7.69	6.66	5.61	5.31	5.35	4.93	4.29	4.07	4.01	3.90	3.82	3.69	6.66	7.39	6.93	5.35	6.46	5.87	4.01	4.30	5.39	
VOC as C1	ppmvd	8.2	7.9	7.1	6.8	5.7	4.3	3.3	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	4.3	7.9	8.5	3.0	5.9	8.6	3.0	3.1	6.8	
VOC as C1, per GT	lbs/hr	2.99	2.88	2.64	2.52	2.11	1.62	1.24	1.14	1.15	1.15	1.15	1.16	1.14	1.12	1.09	1.05	1.62	2.34	2.29	1.15	1.81	1.95	1.14	0.93	1.59	
TSP/PM_{10}, Filterable and Cond, per GT	lbs/hr	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	
TSP/PM_{10}, Filterable and Cond, per GT (calculated)	lb/MMBtu	0.011	0.011	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.011	0.011	0.010	0.013	0.014	0.010	0.013	0.017	0.010	0.013	0.016	
Ammonia Slip, NH_3	ppmvd	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	
CO2, per GT (calcaulted, based on Part 75)	lb/hr	33,716	33,870	34,138	34,258	34,464	34,675	34,893	35,072	35,319	35,442	35,572	35,826	35,233	34,336	33,610	32,425	34,675	27,632	24,855	35,319	28,109	20,997	35,233	28,082	21,699	
CH4, per GT (calcaulted)	lb/hr	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.6	0.6	0.6	0.5	0.5	0.7	0.5	0.4	0.7	0.5	0.4	
N2O, per GT (calcaulted)	lb/hr	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.0	0.1	0.1	0.0	
CO2e, per GT (calculated)	lb/hr	33,750	33,904	34,173	34,293	34,499	34,710	34,928	35,107	35,355	35,478	35,608	35,862	35,268	34,371	33,644	32,457	34,710	27,660	24,880	35,355	28,137	21,018	35,268	28,111	21,721	
CO2e rate (based on gross power output)	lb/MWh	1,350	1,357	1,367	1,372	1,380	1,389	1,398	1,405	1,415	1,420	1,425	1,438	1,451	1,473	1,490	1,524	1,389	1,476	1,531	1,415	1,501	1,682	1,451	1,542	1,788	
CO2e rate (based on net power output)	lb/MWh	1,368	1,374	1,385	1,390	1,398	1,407	1,416	1,423	1,433	1,438	1,443	1,457	1,471	1,494	1,512	1,548	1,407	1,501	1,562	1,433	1,527	1,726	1,471	1,570	1,836	
SCR Tempering Air Flow (at ambient T), per GT	lbs/sec	0.0	0.0	0.0	0.0	5.1	11.4	17.8	22.9	29.8	33.2	36.7	44.7	47.1	50.2	52.0	55.3	11.4	0.0	0.0	29.8	15.1	3.5	47.1	30.4	18.0	
Stack Exit Gas Flow Rate, per GT **	lbs/sec	201.9	199.5	195.7	194.1	196.6	200.4	204.2	207.4	211.7	213.9	216.1	221.0	219.8	217.6	215.3	211.5	200.4	167.3	157.8	211.7	176.0	140.2	219.8	182.9	152.4	
Stack Exit Gas Temperature **	Deg F	729.9	749.5	782.0	795.9	800.3	800.3	800.3	800.3	800.3	800.3	800.3	800.3	800.3	800.3	800.3	800.3	800.3	798.5	781.5	800.3	800.3	800.3	800.3	800.3	800.3	
Stack Gas Molecular Weight, Wet	lbs/lbmol	28.37	28.36	28.33	28.31	28.30	28.29	28.28	28.26	28.24	28.22	28.20	28.14	28.11	28.04	27.98	27.84	28.29	28.34	28.38	28.24	28.28	28.34	28.11	28.14	28.18	
Stack Gas Vol Flow Rate, per GT **	ACFS	6180	6210	6261	6283	6389	6514	6644	6750	6898	6972	7050	7223	7193	7139	7080	6990	6514	5421	5038	6898	5725	4551	7193	5980	4975	
H_2O	% Vol wet	7.62	7.80	8.12	8.28	8.35	8.41	8.51	8.63	8.88	9.05	9.26	9.93	10.38	11.22	11.97	13.84	8.41	7.86	7.44	8.88	8.37	7.73	10.38	9.90	9.27	
O_2	% Vol wet	14.54	14.42	14.23	14.14	14.16	14.21	14.26	14.29	14.31	14.30	14.30	14.24	14.20	14.12	14.02	13.74	14.21	14.55	14.85	14.31	14.61	15.02	14.20	14.49	14.93	
CO_2	% Vol wet	2.73	2.78	2.85	2.88	2.86	2.82	2.79	2.76	2.72	2.70	2.68	2.63	2.60	2.55	2.51	2.45	2.82	2.70	2.58	2.72	2.61	2.45	2.60	2.49	2.32	
A	% Vol wet	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.87	0.87	0.87	0.87	0.86	0.86	0.85	0.84	0.82	0.88	0.88	0.88	0.87	0.87	0.88	0.86	0.86	0.86	
N_2	% Vol wet	74.21	74.10	73.91	73.81	73.74	73.67	73.56	73.45	73.22	73.07	72.89	72.33	71.96	71.26	70.65	69.14	73.67	74.00	74.23	73.22	73.53	73.91	71.96	72.25	72.60	

* All concentrations corrected to 15% O_2

** After addition of SCR tempering air

Table C-10

FT8 MOBILEPAC Emissions Average and Maximum/Worst Cases for New or Refurbished Engines

Performance Data		Annual Average Case	Full Load Maximum/Extreme Case
Fuel LHV	Btu/lb	21,142	21,142
Ratio of HHV to LHV		1.110	1.110
Gaseous Fuel Flow, per CT	SCF/hr	289,999	294,157
Calculated Heat Input, HHV, per CT	MMBtu/hr	297	301

Treated Exhaust Characteristics (Post SCR & CO Converter and Addition of SCR Tempering Air)[a]		Annual Average Case[c]	Full Load Maximum/Extreme Case
NOx, as NO_2, per CT	lbs/hr	2.75	2.79
CO, per CT	lbs/hr	5.35	9.35
VOC as C1, per CT	lbs/hr	1.15	3.12
TSP/PM_{10}, Filterable and Cond, per CT	lbs/hr	3.00	3.00
SO_2, per CT	lbs/hr	0.41	0.42
Ammonia Slip, NH_3	ppmvd	5.0	5.0
Stack Exit Gas Temperature[b]	Deg F	800.3	699
Stack Gas Vol Flow Rate, per CT[b]	ACFS	6,698.7	6119.2

[a] All concentrations corrected to 15% O_2

[b] After addition of SCR tempering air

[c] Annual average case based on 100% load at 59°F

Table C-11
FT8 MOBILEPAC Startup/Shutdown Emissions Estimates

		Natural Gas Quantities per ADGT	
Pollutants		**Startup**	**Shutdown**
NOx as NO_2	lbs/event	14.4	2.8
CO	lbs/event	27.7	6.7
VOC	lbs/event	1.3	0.5
TSP	lbs/event	2.5	0.9
Parameters			
Heat Input, HHV	MMBtu	89.9	13.2
Heat Input, LHV	MMBtu	81.0	11.9
Duration	min/event	30	9
Load/Unload Rate	MW/min	15	7.5

Notes:

(1) Total emissions produced during the startup period are impacted by loading/unloading rates, ambient conditions, water injection introduction & other operational variables. Some margin applied.

(2) Startup emissions estimates assume: 30 minutes from initiating unit start command to emissions compliance including - 5 min purge prior to light-off; 7 min from light-off to full load; 18 additional min at full load to emissions compliance. These times are estimated and may change based on loading rates, ambient conditions, and other operational variables.

(3) Shutdown emissions estimates assume: 9 minutes from initiating unit stop command to fuel chop.

(4) Estimates are calculated by integrating the emission rates for various operating conditions during startup and shutdown, such as purge timer duration, accel to GG idle, accel to sync idle, synchronization and breaker closure, 25% to 100% of rated output.

(5) During Startup the SCR/CO efficiency is assumed to be zero.

(6) Data is valid for cold, warm and hot starts.

Table C-12
FT8 MOBILEPAC Hazardous Air Pollutant Emissions
Annual and Maximum Hourly Emissions Estimates

Compounds	CT Emission Factor			Oxidation Catalyst Control	HAP Emissions from CTs			
					CT Gas Emissions			
					Emission Rate, 1 CT		Emission Rate, All CTs	
	(lb/10^6scf)	(lb/MMBtu)[1]	Rating		Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)
Metal HAP Compounds[2]:								
Arsenic	2.00E-04	1.96E-07	D	0%	5.90E-05	2.55E-04	5.90E-04	2.55E-03
Beryllium	1.20E-05	1.18E-08	E	0%	3.54E-06	1.53E-05	3.54E-05	1.53E-04
Cadmium	1.10E-03	1.08E-06	D	0%	3.25E-04	1.40E-03	3.25E-03	1.40E-02
Chromium (Cr III)	1.34E-03	1.32E-06	D[6]	0%	3.97E-04	1.71E-03	3.97E-03	1.71E-02
Chromium (Cr VI)	5.60E-05	5.49E-08	D[6]	0%	1.65E-05	7.14E-05	1.65E-04	7.14E-04
Cobalt	8.40E-05	8.23E-08	D	0%	2.48E-05	1.07E-04	2.48E-04	1.07E-03
Lead	5.00E-04	4.90E-07	D	0%	1.48E-04	6.38E-04	1.48E-03	6.38E-03
Manganese	3.80E-04	3.72E-07	D	0%	1.12E-04	4.85E-04	1.12E-03	4.85E-03
Mercury	2.60E-04	2.55E-07	D	0%	7.67E-05	3.32E-04	7.67E-04	3.32E-03
Nickel	2.10E-03	2.06E-06	C	0%	6.20E-04	2.68E-03	6.20E-03	2.68E-02
Selenium	2.40E-05	2.35E-08	E	0%	7.08E-06	3.06E-05	7.08E-05	3.06E-04
Metal non-HAP Compounds[2]:								
Barium	4.40E-03	4.31E-06	D	0%	1.30E-03	5.61E-03	9.09E-03	3.93E-02
Copper	8.50E-04	8.33E-07	D	0%	2.51E-04	1.08E-03	1.76E-03	7.59E-03
Molybdenum	1.10E-03	1.08E-06	D	0%	3.25E-04	1.40E-03	2.27E-03	9.82E-03
Vanadium	2.30E-03	2.25E-06	C	0%	6.79E-04	2.93E-03	4.75E-03	2.05E-02
Zinc	2.90E-02	2.84E-05	E	0%	8.56E-03	3.70E-02	5.99E-02	2.59E-01
Organic HAP Compounds[3]:								
1,3-Butadiene		4.30E-07	D	50%	6.47E-05	2.80E-04	6.47E-04	2.80E-03
Acetaldehyde		4.00E-05	C	50%	6.02E-03	2.60E-02	6.02E-02	2.60E-01
Acrolein		6.40E-06	C	50%	9.63E-04	4.16E-03	9.63E-03	4.16E-02
Benzene		1.20E-05	A	50%	1.81E-03	7.81E-03	1.81E-02	7.81E-02
Ethylbenzene		3.20E-05	C	50%	4.82E-03	2.08E-02	4.82E-02	2.08E-01
Formaldehyde		2.19E-04		included[4]	6.59E-02	2.85E-01	6.59E-01	2.85E+00
Naphthalene		1.30E-06	C[5]	50%	1.96E-04	8.46E-04	1.96E-03	8.46E-03
Total PAHs		2.20E-06	C[5]	50%	3.31E-04	1.43E-03	3.31E-03	1.43E-02
Propylene Oxide		2.90E-05	D	50%	4.36E-03	1.89E-02	4.36E-02	1.89E-01
Toluene		1.30E-04	C	50%	1.96E-02	8.46E-02	1.96E-01	8.46E-01
Xylene		6.40E-05	C	50%	9.63E-03	4.16E-02	9.63E-02	4.16E-01
Ammonia[7]								
Ammonia		6.82E-03			2.05E+00	8.87E+00	2.05E+01	8.87E+01

Combustion Turbine Total HAPs (ton/yr)[5] 4.98E+00

Max Heat Input per Turbine(MMBtu/hr):	**301**
Average Heat Input per Turbine(MMBtu/hr):	**297**
Total Heat Input per Turbine(MMBtu/yr):	**2,601,720**
Natural Gas Heating Value, HHV (Btu/scf):	**1,020**

Notes:

1/ Emission factor (lb/MMBtu) = (Emission factor, lb/10^6 scf) / (Volumetric Heat Content, Btu/scf) if lb/10^6 scf is given.

2/ Emission factors for metal compounds from AP-42, Section 1.4.

3/ Emission factors for organic compounds from AP-42, Section 3.1-3.

4/ Formaldehyde based on MACT Subpart YYYY limit of 91 ppbv @ 15% O_2. Converted to lb/MMBtu using Method 19 methodology.

5/ Naphthalene is included in total PAHs and is not double counted as part of total HAPs

6/ Speciated chrome based on total chromium from AP-42 Table 1.4-4 and 96% Cr III / 4% Cr VI from EPA NEI Supporting Data - natural gas combustion turbines
https://gaftp.epa.gov/air/nei/2020/doc/supporting_data/Chromium_speciation_nonNAICS_28jan2023.zip

7/ Ammonia based on 5 ppmdv @ 15% O_2. Converted to lb/MMBtu using Method 19 methodology.

Table C-13
Auxiliary Boiler Criteria Pollutant Emissions
Annual and Maximum Hourly Emissions Estimates

Emission Source	Auxiliary Boilers	
Source Type	Natural Gas-Fired Boiler	
Number of Units	3	
Heat Input (MMBtu/hr/boiler)	67.0	29,346.0
Maximum Fuel Usage (MMcf/hr/boiler)	0.0657	
Natural Gas Heating Value (Btu/scf)	1,020	
Sulfur Content of Natural Gas (gr /100 scf)	0.50	
Annual Capacity Factor (%)	5%	438 hours per year

	Note	Emission Factor	Emission Rates		
			Hourly[8]	Annual[9]	Annual
		(lb/MMBtu)	(lbs/hr)	(tons/year/boiler)	(tons/year)
TSP	1	0.0075	0.50	0.11	0.33
PM_{10}	1,2	0.0075	0.50	0.11	0.33
$PM_{2.5}$	1,2	0.0075	0.50	0.11	0.33
Nitrogen Oxides	1,3	0.05	3.28	0.72	2.16
Carbon Monoxide	1	0.08	5.52	1.21	3.63
VOC	1	5.39E-03	0.36	0.08	0.24
Sulfur Oxides	4	0.0014	0.09	0.02	0.06
H_2SO_4	5	2.14E-05	1.44E-03	3.15E-04	9.44E-04
Lead	1	4.90E-07	3.28E-05	7.19E-06	2.16E-05
CO_2	6	119	7,963	1,744	5,232
CH_4	6	2.20E-03	0.15	0.03	0.10
N_2O	6	2.20E-04	0.01	3.23E-03	9.70E-03
CO_2e	7	--	7,971	1,746	5,237

Notes:

1/ Emission factor is from USEPA AP-42, Section 1.4, Table 1.4-2, dated July 1998.

2/ Assumes PM = PM_{10} = $PM_{2.5}$.

3/ NOx emission factor assumes use of Low NOx burner.

4/ SO_2 emission factor assumes 100% conversion of sulfur in gas to SO_2.

5/ H_2SO_4 emissions assume 1% conversion of SO_2 to SO_3 (Basis: EPRI "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (3002012398)"; 2018 Update, Table 4-1).

6/ Emission factors for CO_2, CH_4 and N_2O are from 40 CFR Part 98 "Mandatory Greenhouse Gas Reporting ", Tables C-1 and C-2.

7/ Global Warming Potentials for GHGs are from Federal Register Vol. 89, Issue 81, April 25, 2024; (89 FR 31802).

8/ Hourly Emission Rate (lb/hr) = Heat Input (MMBtu/hr) * Emission Factor (lb/MMBtu).

9/ Annual Emission Rate (ton/yr) = Hourly Emission Rate (lb/hr) * Annual Operating Hours (hr/yr) / (2,000 lb/ton). Assumes 438 annual operating hours.

Stack Parameters (Per Boiler)

Stack Height	55.0	ft
Stack Diameter	4.0	ft
Stack Exit Velocity	28	ft/sec
Exhaust Temp	344	F
Exhaust Flow	21,242	ACFM

Table C-14
Auxiliary Boiler Hazardous Air Pollutant Emissions
Annual and Maximum Hourly Emissions Estimates

Compounds	Emission Factor		Emission Est. Method	Emission Rate - Per Unit		Emission Rate - Total	
	(lb/10^6scf)	(lb/MMBtu)[a]		Max Hourly (lb/hr)	Annual (tpy)	Max Hourly (lb/hr)	Annual (tpy)
Organic HAP Compounds:							
Benzene	2.10E-03	2.06E-06	1	1.38E-04	3.02E-05	4.14E-04	9.06E-05
Dichlorobenzene	1.20E-03	1.18E-06	1	7.88E-05	1.73E-05	2.36E-04	5.18E-05
Formaldehyde	7.50E-02	7.35E-05	1	4.93E-03	1.08E-03	1.48E-02	3.24E-03
Hexane	1.80E+00	1.76E-03	1	1.18E-01	2.59E-02	3.55E-01	7.77E-02
Toluene	3.40E-03	3.33E-06	1	2.23E-04	4.89E-05	6.70E-04	1.47E-04
Organic non-HAP Compounds:							
Butane	2.10E+00	2.06E-03	2	1.38E-01	3.02E-02	4.14E-01	9.06E-02
Ethane	3.10E+00	3.04E-03	2	2.04E-01	4.46E-02	6.11E-01	1.34E-01
Pentane	2.60E+00	2.55E-03	2	1.71E-01	3.74E-02	5.12E-01	1.12E-01
Propane	1.60E+00	1.57E-03	2	1.05E-01	2.30E-02	3.15E-01	6.90E-02
Polycyclic Organic Matter:							
2-Methylnaphthalene	2.40E-05	2.35E-08	1	1.58E-06	3.45E-07	4.73E-06	1.04E-06
3-Methylchloranthrene	1.80E-06	1.76E-09	1	1.18E-07	2.59E-08	3.55E-07	7.77E-08
7,12-Dimethylbenz(a)anthracene	1.60E-05	1.57E-08	1	1.05E-06	2.30E-07	3.15E-06	6.90E-07
Acenaphthene	1.80E-06	1.76E-09	1	1.18E-07	2.59E-08	3.55E-07	7.77E-08
Acenaphthylene	1.80E-06	1.76E-09	1	1.18E-07	2.59E-08	3.55E-07	7.77E-08
Anthracene	2.40E-06	2.35E-09	1	1.58E-07	3.45E-08	4.73E-07	1.04E-07
Benz(a)anthracene	1.80E-06	1.76E-09	1	1.18E-07	2.59E-08	3.55E-07	7.77E-08
Benzo(a)pyrene	1.20E-06	1.18E-09	1	7.88E-08	1.73E-08	2.36E-07	5.18E-08
Benzo(b)fluoranthene	1.80E-06	1.76E-09	1	1.18E-07	2.59E-08	3.55E-07	7.77E-08
Benzo(g,h,i)perylene	1.20E-06	1.18E-09	1	7.88E-08	1.73E-08	2.36E-07	5.18E-08
Benzo(k)fluoranthene	1.80E-06	1.76E-09	1	1.18E-07	2.59E-08	3.55E-07	7.77E-08
Chrysene	1.80E-06	1.76E-09	1	1.18E-07	2.59E-08	3.55E-07	7.77E-08
Dibenzo(a,h)anthracene	1.20E-06	1.18E-09	1	7.88E-08	1.73E-08	2.36E-07	5.18E-08
Fluoranthene	3.00E-06	2.94E-09	1	1.97E-07	4.32E-08	5.91E-07	1.29E-07
Fluorene	2.80E-06	2.75E-09	1	1.84E-07	4.03E-08	5.52E-07	1.21E-07
Indeno(1,2,3-cd)pyrene	1.80E-06	1.76E-09	1	1.18E-07	2.59E-08	3.55E-07	7.77E-08
Naphthalene	6.10E-04	5.98E-07	1	4.01E-05	8.78E-06	1.20E-04	2.63E-05
Phenanathrene	1.70E-05	1.67E-08	1	1.12E-06	2.45E-07	3.35E-06	7.34E-07
Pyrene	5.00E-06	4.90E-09	1	3.28E-07	7.19E-08	9.85E-07	2.16E-07
Metal non-HAP Compounds:							
Barium	4.40E-03	4.31E-06	2	2.89E-04	6.33E-05	8.67E-04	1.90E-04
Copper	8.50E-04	8.33E-07	2	5.58E-05	1.22E-05	1.68E-04	3.67E-05
Molybdenum	1.10E-03	1.08E-06	2	7.23E-05	1.58E-05	2.17E-04	4.75E-05
Vanadium	2.30E-03	2.25E-06	2	1.51E-04	3.31E-05	4.53E-04	9.93E-05
Zinc	2.90E-02	2.84E-05	2	1.90E-03	4.17E-04	5.71E-03	1.25E-03
Metal HAP Compounds:							
Arsenic	2.00E-04	1.96E-07	2	1.31E-05	2.88E-06	3.94E-05	8.63E-06
Beryllium	1.20E-05	1.18E-08	2	7.88E-07	1.73E-07	2.36E-06	5.18E-07
Cadmium	1.10E-03	1.08E-06	2	7.23E-05	1.58E-05	2.17E-04	4.75E-05
Chromium (Cr III)	1.34E-03	1.32E-06	2 [4]	8.83E-05	1.93E-05	2.65E-04	5.80E-05
Chromium (Cr VI)	5.60E-05	5.49E-08	2 [4]	3.68E-06	8.06E-07	1.10E-05	2.42E-06
Cobalt	8.40E-05	8.24E-08	2	5.52E-06	1.21E-06	1.66E-05	3.63E-06
Lead	5.00E-04	4.90E-07	3	3.28E-05	7.19E-06	9.85E-05	2.16E-05
Manganese	3.80E-04	3.73E-07	2	2.50E-05	5.47E-06	7.49E-05	1.64E-05
Mercury	2.60E-04	2.55E-07	2	1.71E-05	3.74E-06	5.12E-05	1.12E-05
Nickel	2.10E-03	2.06E-06	2	1.38E-04	3.02E-05	4.14E-04	9.06E-05
Selenium	2.40E-05	2.35E-08	2	1.58E-06	3.45E-07	4.73E-06	1.04E-06
						Total HAPs	**8.15E-02**

Fuel	Natural Gas
Number of Units	3
Total Heat Input (MMBtu/hr/boile	67
Max Operating hours per year	438
Annual Heat Input (MMBtu/yr)	29,346
Gas Heating Value (BTU/scf)	1,020

Notes:

1/ AP-42 Section 1.4 07/98 - Boilers - Natural Gas Combustion Table 1.4-3
2/ AP-42 Section 1.4 07/98 - Boilers - Natural Gas Combustion Table 1.4-4
3/ AP-42 Section 1.4 07/98 - Boilers - Natural Gas Combustion Table 1.4-2
4/ Speciated chrome based on total chromium from AP-42 Table 1.4-4 and 96% Cr III / 4% Cr VI from EPA NEI Supporting Data - natural gas boilers
https://gaftp.epa.gov/air/nei/2020/doc/supporting_data/Chromium_speciation_nonNAICS_28jan2023.zip

Table C-15
2.5 MW Emergency Diesel Generator Emissions
Annual and Maximum Hourly Emissions Estimates

Emission Source:	Emergency Generators				
Source Type:	Diesel Generator				
Engine Power	bhp:	3,633 (approximate)	kWm:	2,710	
			kWe:	2,500	
Heat Input (MMBtu/hr/engine)		25.431			
Fuel consumption (Btu/hp-hr)[1]		7,000			
Number of Units:		10			
Fuel Oil Heating Value (Btu/gal)[2]		137,000			
Sulfur Content of Fuel (wt. %)[3]		0.0015			
Operating Hours per Year[4]		500			

Compound	Note	Emission Factors		Emission Rates		
				Hourly[11] (lbs/hr/engine)	Annual[12] (tons/year/engine)	Annual (tons/year)
Nitrogen Oxides	5	0.50	g/hp-hr	4.00	1.00	10.0
Carbon Monoxide	5	2.6	g/hp-hr	20.9	5.23	52.3
TOC	5	0.14	g/hp-hr	1.13	0.28	2.84
Sulfur Oxides	6	0.0055	g/hp-hr	0.04	0.01	0.11
H_2SO_4	7	0.0004	g/hp-hr	3.38E-03	8.44E-04	8.44E-03
TSP	5	0.022	g/hp-hr	0.18	0.04	0.45
PM_{10}	8	0.021	g/hp-hr	0.17	0.04	0.41
$PM_{2.5}$	8	0.020	g/hp-hr	0.16	0.04	0.40
CO_2	9	163	lb/MMBtu	4,147	1,037	10,367
CH_4	9	6.61E-03	lb/MMBtu	0.17	0.04	0.42
N_2O	9	1.32E-03	lb/MMBtu	0.03	8.41E-03	0.08
CO_2e	10	--		4,160	1,040	10,401

Notes:

1/ USEPA AP-42, Section 3.3, Table 3.3-1, footnote a, dated October 1996.

2/ USEPA AP-42, Appendix A, Typical Parameters of Various Fuels, dated September 1985.

3/ Assumes ultra-low sulfur diesel per the standards at 40 CFR §1090.305.

4/ USEPA Title V Operating Permit Policy and Guidance Document, Calculating Potential to Emit (PTE) for Emergency Generators, Seitz, John, September 1995.

5/ Emission factors (g/hp-hr) are the Tier 4 NSPS Subpart IIII limits for Stationary Compression Ignition 2014 model year and later engines in generator sets.

6/ SO_2 emission factor from USEPA AP-42, Section 3.4, Table 3.4-1, dated October 1996, 100% conversion of fuel sulfur to SO_2.

7/ Assumes 5% conversion of SO_2 to SO_3 (per AP-42 Section 1.3.3.2, September 1998).

8/ Emission factors for PM_{10} and $PM_{2.5}$ are based on speciation in AP-42 Table 3.4-2, adjusted based on Tier 4 TSP limit.

9/ Emission factors for CO_2, CH_4 and N_2O are from 40 CFR Part 98 "Mandatory Greenhouse Gas Reporting ", Tables C-1 and C-2.

10/ Global Warming Potentials for GHGs are from Federal Register Vol. 89, Issue 81, April 25, 2024; (89 FR 31802).

11/ Hourly Emission Rate (Lbs/Hr) = (Emission Factor, g/hp-hr) * (Engine Power, hp) * (1 lb / 453.6 g)

12/ Annual Emission Rate (Tons/Yr) = (Hourly Emission Rate, Lbs/Hr) * (Hour of Operation Per Year, Hr/Yr) / (2,000 Lbs/Ton)

Stack Parameters (Per Engine)

Stack Height	20.0	ft
Stack Diameter	1.2	ft
Stack Exit Velocity	67	ft/sec
Exhaust Temp	964	F
Exhaust Flow	4,524	ACFM

Table C-16
2.5 MW Emergency Generator Hazardous Air Pollutant Emissions
Annual and Maximum Hourly Emissions Estimates

Compounds	Emission Factor		Emission Est. Method	Emission Rate - Per Unit		Emission Rate - Total	
	Value	Units		Max Hourly (lb/hr)	Annual (tpy)	Max Hourly (lb/hr)	Annual (tpy)
Organic HAP Compounds:							
Acetaldehyde	2.52E-05	lb/MMBtu	1	6.41E-04	1.60E-04	6.41E-03	1.60E-03
Acrolein	7.88E-06	lb/MMBtu	1	2.00E-04	5.01E-05	2.00E-03	5.01E-04
Benzene	7.76E-04	lb/MMBtu	1	1.97E-02	4.93E-03	1.97E-01	4.93E-02
Formaldehyde	7.89E-05	lb/MMBtu	1	2.01E-03	5.02E-04	2.01E-02	5.02E-03
Toluene	2.81E-04	lb/MMBtu	1	7.15E-03	1.79E-03	7.15E-02	1.79E-02
Xylene	1.93E-04	lb/MMBtu	1	4.91E-03	1.23E-03	4.91E-02	1.23E-02
Organic non-HAP Compounds:							
Propylene	2.79E-03	lb/MMBtu	1	7.10E-02	1.77E-02	7.10E-01	1.77E-01
Polycyclic Organic Matter:							
Acenaphthene	4.68E-06	lb/MMBtu	2	1.19E-04	2.98E-05	1.19E-03	2.98E-04
Acenaphthylene	9.23E-06	lb/MMBtu	2	2.35E-04	5.87E-05	2.35E-03	5.87E-04
Anthracene	1.23E-06	lb/MMBtu	2	3.13E-05	7.82E-06	3.13E-04	7.82E-05
Benz(a)anthracene	6.22E-07	lb/MMBtu	2	1.58E-05	3.95E-06	1.58E-04	3.95E-05
Benzo(b)fluoranthene	1.11E-06	lb/MMBtu	2	2.82E-05	7.06E-06	2.82E-04	7.06E-05
Benzo(k)fluoranthene	2.18E-07	lb/MMBtu	2	5.54E-06	1.39E-06	5.54E-05	1.39E-05
Benzo(g,h,i)perylene	5.56E-07	lb/MMBtu	2	1.41E-05	3.53E-06	1.41E-04	3.53E-05
Benzo(a)pyrene	2.57E-07	lb/MMBtu	2	6.54E-06	1.63E-06	6.54E-05	1.63E-05
Chrysene	1.53E-06	lb/MMBtu	2	3.89E-05	9.73E-06	3.89E-04	9.73E-05
Dibenzo(a,h)anthracene	3.46E-07	lb/MMBtu	2	8.80E-06	2.20E-06	8.80E-05	2.20E-05
Fluoranthene	4.03E-06	lb/MMBtu	2	1.02E-04	2.56E-05	1.02E-03	2.56E-04
Fluorene	1.28E-05	lb/MMBtu	2	3.26E-04	8.14E-05	3.26E-03	8.14E-04
Indeno(1,2,3-cd)pyrene	4.14E-07	lb/MMBtu	2	1.05E-05	2.63E-06	1.05E-04	2.63E-05
Naphthalene	1.30E-04	lb/MMBtu	2	3.31E-03	8.27E-04	3.31E-02	8.27E-03
Phenanathrene	4.08E-05	lb/MMBtu	2	1.04E-03	2.59E-04	1.04E-02	2.59E-03
Pyrene	3.71E-06	lb/MMBtu	2	9.43E-05	2.36E-05	9.43E-04	2.36E-04
						Total HAPs	**1.00E-01**

Fuel	Diesel
Horsepower (hp)	4023
Max Heat Input (MMBtu/hr/engine)	25.43
Max Operating hours per year	500
Total Heat Input (MMBtu/yr)	12,716
Fuel Oil Heating Value (BTU/gal)	137,000

Notes:

1/ AP-42 Table 3.4-3 (10/96) Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines

2/ AP-42 Table 3.4-4 (10/96) PAH Emission Factors for Large Uncontrolled Stationary Diesel Engines

Table C-17
1.0 MW Emergency Diesel Generator Emissions
Annual and Maximum Hourly Emissions Estimates

Emission Source:	Emergency Generators			
Source Type:	Diesel Generator			
Engine Power	bhp:	1,483	kWm:	1,106
			kWe:	1000
Heat Input (MMBtu/hr)		10.381		
Fuel consumption (Btu/hp-hr)[1]		7,000		
Number of Units:		2		
Fuel Oil Heating Value (Btu/gal)[2]		137,000		
Sulfur Content of Fuel (wt. %)[3]		0.0015		
Operating Hours per Year[4]		500		

Compound	Note	Emission Factors		Emission Rates		
				Hourly[11] (lbs/hr)	Annual[12] (tons/year/generator)	Annual (tons/year)
Nitrogen Oxides	5	0.50	g/hp-hr	1.63	0.41	0.82
Carbon Monoxide	5	2.6	g/hp-hr	8.53	2.13	4.27
TOC	5	0.14	g/hp-hr	0.46	0.12	0.23
Sulfur Oxides	6	0.0055	g/hp-hr	0.02	4.50E-03	9.00E-03
H_2SO_4	7	0.0004	g/hp-hr	1.38E-03	3.44E-04	6.89E-04
TSP	5	0.022	g/hp-hr	0.07	0.02	0.04
PM_{10}	8	0.021	g/hp-hr	0.07	0.02	0.03
$PM_{2.5}$	8	0.020	g/hp-hr	0.07	0.02	0.03
CO_2	9	163	lb/MMBtu	1,693	423	846
CH_4	9	6.61E-03	lb/MMBtu	0.07	0.02	0.03
N_2O	9	1.32E-03	lb/MMBtu	0.01	3.43E-03	6.87E-03
CO_2e	10	--		1,698	425	849

Notes:

1/ USEPA AP-42, Section 3.3, Table 3.3-1, footnote a, dated October 1996.

2/ USEPA AP-42, Appendix A, Typical Parameters of Various Fuels, dated September 1985.

3/ Assumes ultra-low sulfur diesel per the standards at 40 CFR §1090.305.

4/ USEPA Title V Operating Permit Policy and Guidance Document, Calculating Potential to Emit (PTE) for Emergency Generators, Seitz, John, September 1995.

5/ Emission factors (g/hp-hr) are the Tier 4 NSPS Subpart IIII limits for Stationary Compression Ignition 2014 model year and later engines in generator sets.

6/ SO_2 emission factor from USEPA AP-42, Section 3.4, Table 3.4-1, dated October 1996, 100% conversion of fuel sulfur to SO_2.

7/ Assumes 5% conversion of SO_2 to SO_3 (per AP-42 Section 1.3.3.2, September 1998).

8/ Emission factors for PM_{10} and $PM_{2.5}$ are based on speciation in AP-42 Table 3.4-2, adjusted based on Tier 4 TSP limit.

9/ Emission factors for CO_2, CH_4 and N_2O are from 40 CFR Part 98 "Mandatory Greenhouse Gas Reporting ", Tables C-1 and C-2.

10/ Global Warming Potentials for GHGs are from Federal Register Vol. 89, Issue 81, April 25, 2024; (89 FR 31802).

11/ Hourly Emission Rate (Lbs/Hr) = (Emission Factor, g/hp-hr) * (Engine Power, hp) * (1 lb / 453.6 g)

12/ Annual Emission Rate (Tons/Yr) = (Hourly Emission Rate, Lbs/Hr) * (Hour of Operation Per Year, Hr/Yr) / (2,000 Lbs/Ton)

Stack Parameters (Per Engine)

Stack Height	20.0	ft
Stack Diameter	1.2	ft
Stack Exit Velocity	119	ft/sec
Exhaust Temp	889.5	F
Exhaust Flow	8,065	ACFM

Table C-18
1.0 MW Emergency Generator Hazardous Air Pollutant Emissions
Annual and Maximum Hourly Emissions Estimates

Compounds	Emission Factor		Emission Est. Method	Emission Rate - Per Unit		Emission Rate - Total	
	Value	Units		Max Hourly (lb/hr)	Annual (tpy)	Max Hourly (lb/hr)	Annual (tpy)
Organic HAP Compounds:							
Acetaldehyde	2.52E-05	lb/MMBtu	1	2.62E-04	6.54E-05	5.23E-04	1.31E-04
Acrolein	7.88E-06	lb/MMBtu	1	8.18E-05	2.05E-05	1.64E-04	4.09E-05
Benzene	7.76E-04	lb/MMBtu	1	8.06E-03	2.01E-03	1.61E-02	4.03E-03
Formaldehyde	7.89E-05	lb/MMBtu	1	8.19E-04	2.05E-04	1.64E-03	4.10E-04
Toluene	2.81E-04	lb/MMBtu	1	2.92E-03	7.29E-04	5.83E-03	1.46E-03
Xylene	1.93E-04	lb/MMBtu	1	2.00E-03	5.01E-04	4.01E-03	1.00E-03
Organic non-HAP Compounds:							
Propylene	2.79E-03	lb/MMBtu	1	2.90E-02	7.24E-03	5.79E-02	1.45E-02
Polycyclic Organic Matter:							
Acenaphthene	4.68E-06	lb/MMBtu	2	4.86E-05	1.21E-05	9.72E-05	2.43E-05
Acenaphthylene	9.23E-06	lb/MMBtu	2	9.58E-05	2.40E-05	1.92E-04	4.79E-05
Anthracene	1.23E-06	lb/MMBtu	2	1.28E-05	3.19E-06	2.55E-05	6.38E-06
Benz(a)anthracene	6.22E-07	lb/MMBtu	2	6.46E-06	1.61E-06	1.29E-05	3.23E-06
Benzo(b)fluoranthene	1.11E-06	lb/MMBtu	2	1.15E-05	2.88E-06	2.30E-05	5.76E-06
Benzo(k)fluoranthene	2.18E-07	lb/MMBtu	2	2.26E-06	5.66E-07	4.53E-06	1.13E-06
Benzo(g,h,i)perylene	5.56E-07	lb/MMBtu	2	5.77E-06	1.44E-06	1.15E-05	2.89E-06
Benzo(a)pyrene	2.57E-07	lb/MMBtu	2	2.67E-06	6.67E-07	5.34E-06	1.33E-06
Chrysene	1.53E-06	lb/MMBtu	2	1.59E-05	3.97E-06	3.18E-05	7.94E-06
Dibenzo(a,h)anthracene	3.46E-07	lb/MMBtu	2	3.59E-06	8.98E-07	7.18E-06	1.80E-06
Fluoranthene	4.03E-06	lb/MMBtu	2	4.18E-05	1.05E-05	8.37E-05	2.09E-05
Fluorene	1.28E-05	lb/MMBtu	2	1.33E-04	3.32E-05	2.66E-04	6.64E-05
Indeno(1,2,3-cd)pyrene	4.14E-07	lb/MMBtu	2	4.30E-06	1.07E-06	8.60E-06	2.15E-06
Naphthalene	1.30E-04	lb/MMBtu	2	1.35E-03	3.37E-04	2.70E-03	6.75E-04
Phenanathrene	4.08E-05	lb/MMBtu	2	4.24E-04	1.06E-04	8.47E-04	2.12E-04
Pyrene	3.71E-06	lb/MMBtu	2	3.85E-05	9.63E-06	7.70E-05	1.93E-05
						Total HAPs	**8.17E-03**

Fuel	Diesel
Horsepower (hp)	4023
Max Heat Input (MMBtu/hr)	10.38
Max Operating hours per year	500
Total Heat Input (MMBtu/yr)	5,191
Fuel Oil Heating Value (BTU/gal)	137,000

Notes:

1/ AP-42 Table 3.4-3 (10/96) Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines

2/ AP-42 Table 3.4-4 (10/96) PAH Emission Factors for Large Uncontrolled Stationary Diesel Engines

Table C-19
Diesel Fire Pump Engine Emissions
Annual and Maximum Hourly Emissions Estimates

Emission Source:	Emergency Fire Pump Engine	
Source Type:	Diesel Fueled IC Reciprocating Engines	
Engine Power	bhp:	399
	kw:	298
Heat Input (MMBtu/hr)		2.793
Fuel consumption (Btu/hp-hr)[1]		7,000
Number of Units:		1
Fuel Oil Heating Value (Btu/gal)[2]		137,000
Sulfur Content of Fuel (wt. %)[3]		0.0015
Operating Hours per Year[4]		500

Compound	Note	Emission Factors		Emission Rates	
				Hourly[11] (lbs/hr)	Annual[12] (tons/year)
Nitrogen Oxides	5	3.0	g/hp-hr	2.64	0.66
Carbon Monoxide	5	2.6	g/hp-hr	2.29	0.57
TOC	5	3.0	g/hp-hr	2.64	0.66
Sulfur Oxides	6	0.0055	g/hp-hr	4.84E-03	1.21E-03
H_2SO_4	7	0.0004	g/hp-hr	3.71E-04	9.27E-05
TSP	5	0.15	g/hp-hr	0.13	0.03
PM_{10}	8	0.14	g/hp-hr	0.12	0.03
$PM_{2.5}$	8	0.13	g/hp-hr	0.12	0.03
CO_2	9	163	lb/MMBtu	455	114
CH_4	9	6.61E-03	lb/MMBtu	0.02	4.62E-03
N_2O	9	1.32E-03	lb/MMBtu	3.69E-03	9.24E-04
CO_2e	10	--		457	114

Notes:

1/ USEPA AP-42, Section 3.3, Table 3.3-1, footnote a, dated October 1996.

2/ USEPA AP-42, Appendix A, Typical Parameters of Various Fuels, dated September 1985.

3/ Assumes ultra-low sulfur diesel per the standards at 40 CFR §1090.305.

4/ USEPA Title V Operating Permit Policy and Guidance Document, Calculating Potential to Emit (PTE) for Emergency Generators, Seitz, John, September 1995.

5/ Emission factors (g/hp-hr) are the NSPS Subpart IIII limits for Stationary Compression Ignition Fire Pump Engines, 300<HP<600, 2009+.

6/ SO_2 emission factor from USEPA AP-42, Section 3.4, Table 3.4-1, dated October 1996, 100% conversion of fuel sulfur to SO_2.

7/ Assumes 5% conversion of SO_2 to SO_3 (per AP-42 Section 1.3.3.2, September 1998).

8/ Emission factors for PM_{10} and $PM_{2.5}$ are based on speciation in AP-42 Table 3.4-2, adjusted based on 40 CFR 60 Subpart IIII TSP limit.

9/ Emission factors for CO_2, CH_4 and N_2O are from 40 CFR Part 98 "Mandatory Greenhouse Gas Reporting ", Tables C-1 and C-2.

10/ Global Warming Potentials for GHGs are from Federal Register Vol. 89, Issue 81, April 25, 2024; (89 FR 31802).

11/ Hourly Emission Rate (Lbs/Hr) = (Emission Factor, g/hp-hr) * (Engine Power, hp) * (1 lb / 453.6 g)

12/ Annual Emission Rate (Tons/Yr) = (Hourly Emission Rate, Lbs/Hr) * (Hour of Operation Per Year, Hr/Yr) / (2,000 Lbs/Ton)

Stack Parameters (Per Engine)

Stack Height	12.0	ft
Stack Diameter	0.5	ft
Stack Exit Velocity	188	ft/sec
Exhaust Temp	826	F
Exhaust Flow	2,214	ACFM

Table C-20
Diesel Fire Pump Hazardous Air Pollutant Emissions
Annual and Maximum Hourly Emissions Estimates

Compounds	Emission Factor		Emission Est. Method	Emission Rate	
	Value	Units		Max Hourly (lb/hr)	Annual (tpy)
Organic HAP Compounds:					
Acetaldehyde	7.67E-04	lb/MMBtu	1	2.14E-03	5.36E-04
Acrolein	9.25E-05	lb/MMBtu	1	2.58E-04	6.46E-05
Benzene	9.33E-04	lb/MMBtu	1	2.61E-03	6.51E-04
1,3-Butadiene	3.91E-05	lb/MMBtu	1	1.09E-04	2.73E-05
Formaldehyde	1.18E-03	lb/MMBtu	1	3.30E-03	8.24E-04
Toluene	4.09E-04	lb/MMBtu	1	1.14E-03	2.86E-04
Xylene	2.85E-04	lb/MMBtu	1	7.96E-04	1.99E-04
Organic non-HAP Compounds:					
Propylene	2.58E-03	lb/MMBtu	1	7.21E-03	1.80E-03
Polycyclic Organic Matter:					
Acenaphthene	1.42E-06	lb/MMBtu	1	3.97E-06	9.92E-07
Acenaphthylene	5.06E-06	lb/MMBtu	1	1.41E-05	3.53E-06
Anthracene	1.87E-06	lb/MMBtu	1	5.22E-06	1.31E-06
Benz(a)anthracene	1.68E-06	lb/MMBtu	1	4.69E-06	1.17E-06
Benzo(b)fluoranthene	9.91E-08	lb/MMBtu	1	2.77E-07	6.92E-08
Benzo(k)fluoranthene	1.55E-07	lb/MMBtu	1	4.33E-07	1.08E-07
Benzo(g,h,i)perylene	4.89E-07	lb/MMBtu	1	1.37E-06	3.41E-07
Benzo(a)pyrene	1.88E-07	lb/MMBtu	1	5.25E-07	1.31E-07
Chrysene	3.53E-07	lb/MMBtu	1	9.86E-07	2.46E-07
Dibenzo(a,h)anthracene	5.83E-07	lb/MMBtu	1	1.63E-06	4.07E-07
Fluoranthene	7.61E-06	lb/MMBtu	1	2.13E-05	5.31E-06
Fluorene	2.92E-05	lb/MMBtu	1	8.16E-05	2.04E-05
Indeno(1,2,3-cd)pyrene	3.75E-07	lb/MMBtu	1	1.05E-06	2.62E-07
Naphthalene	8.48E-05	lb/MMBtu	1	2.37E-04	5.92E-05
Phenanathrene	2.94E-05	lb/MMBtu	1	8.21E-05	2.05E-05
Pyrene	4.78E-06	lb/MMBtu	1	1.34E-05	3.34E-06
				Total HAPs	**2.70E-03**

Fuel	Diesel
Horsepower (hp)	399
Max Heat Input (MMBtu/hr)	2.79
Max Operating hours per year	500
Total Heat Input (MMBtu/yr)	1,397
Fuel Oil Heating Value (Btu/gal)	137,000

Notes:

1/ AP-42 Table 3.3-2 (10/96) Speciated Organic Compound Emission Factors for Uncontrolled Diesel Engines

Table C-21
Gas Heater Criteria Pollutant Emissions
Annual and Maximum Hourly Emissions Estimates

Emission Source		Gas Heaters			
Source Type		Natural Gas-Fired Heaters			
Number of Units		7			
Total Heat Input (MMBtu/hr)		10.8			
Maximum Fuel Usage (MMcf/hr)		0.0106			
Natural Gas Heating Value (Btu/scf)		1,020			
Sulfur Content of Natural Gas (gr /100 scf)		0.50			
Annual Capacity Factor (%)		100%		8,760	hours per year
Compound	**Note**	**Emission Factor**	**Emission Rates**		
			Hourly[8]	**Annual[9]**	**Annual**
		(lb/MMBtu)	**(lbs/hr)**	**(tons/year/heater)**	**(tons/year)**
TSP	10	4.80E-03	0.05	0.23	1.59
PM_{10}	10	4.80E-03	0.05	0.23	1.59
$PM_{2.5}$	10	4.80E-03	0.05	0.23	1.59
Nitrogen Oxides	10	0.03	0.32	1.42	9.92
Carbon Monoxide	10	0.04	0.40	1.75	12.2
VOC	10	5.00E-03	0.05	0.24	1.65
Sulfur Oxides	4	1.40E-03	0.02	0.07	0.46
H_2SO_4	5	2.14E-05	2.31E-04	1.01E-03	7.09E-03
Lead	1	4.90E-07	5.29E-06	2.31E-05	1.62E-04
CO_2	6	119	1,281	5,613	39,289
CH_4	6	2.20E-03	0.02	0.10	0.73
N_2O	6	2.20E-04	2.38E-03	0.01	0.07
CO_2e	7	--	1,283	5,618	39,329

Notes:

1/ Emission factor is from USEPA AP-42, Section 1.4, Table 1.4-2, dated July 1998.

2/ Assumes PM = PM_{10} = $PM_{2.5}$.

3/ NOx emission factor assumes use of uncontrolled burners.

4/ SO_2 emission factor assumes 100% conversion of sulfur in gas to SO_2.

5/ H_2SO_4 emissions assume 1% conversion of SO_2 to SO_3 (Basis: EPRI "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (3002012398)"; 2018 Update, Table 4-1).

6/ Emission factors for CO_2, CH_4 and N_2O are from 40 CFR Part 98 "Mandatory Greenhouse Gas Reporting ", Tables C-1 and C-2.

7/ Global Warming Potentials for GHGs are from Federal Register Vol. 89, Issue 81, April 25, 2024; (89 FR 31802).

8/ Hourly Emission Rate (lb/hr) = Heat Input (MMBtu/hr) * Emission Factor (lb/MMBtu).

9/ Annual Emission Rate (ton/yr) = Hourly Emission Rate (lb/hr) * Annual Operating Hours (hr/yr) / (2,000 lb/ton). Assumes 8,760 annual operating hours.

10/ Based on prospective vendor information.

Stack Parameters (Per Heater)

Stack Height	15.0	ft
Stack Diameter	2.5	ft
Stack Exit Velocity	11	ft/sec
Exhaust Temp	670	F
Exhaust Flow	3,112	ACFM

Table C-22
Gas Heater Hazardous Air Pollutant Emissions
Annual and Maximum Hourly Emissions Estimates

Compounds	Emission Factor ($lb/10^6 scf$)	Emission Est. Method	Emission Rate - Per Unit		Emission Rate - Total	
			Max Hourly (lb/hr)	Annual (tpy)	Max Hourly (lb/hr)	Annual (tpy)
Organic HAP Compounds:						
Benzene	2.10E-03	1	2.22E-05	9.72E-05	1.55E-04	6.81E-04
Dichlorobenzene	1.20E-03	1	1.27E-05	5.56E-05	8.88E-05	3.89E-04
Formaldehyde	7.50E-02	1	7.93E-04	3.47E-03	5.55E-03	2.43E-02
Hexane	1.80E+00	1	1.90E-02	8.33E-02	1.33E-01	5.83E-01
Toluene	3.40E-03	1	3.59E-05	1.57E-04	2.52E-04	1.10E-03
Organic non-HAP Compounds:						
Butane	2.10E+00	1	2.22E-02	9.72E-02	1.55E-01	6.81E-01
Ethane	3.10E+00	1	3.28E-02	1.44E-01	2.29E-01	1.00E+00
Pentane	2.60E+00	1	2.75E-02	1.20E-01	1.92E-01	8.43E-01
Propane	1.60E+00	1	1.69E-02	7.41E-02	1.18E-01	5.19E-01
Polycyclic Organic Matter:						
2-Methylnaphthalene	2.40E-05	1	2.54E-07	1.11E-06	1.78E-06	7.78E-06
3-Methylchloranthrene	1.80E-06	1	1.90E-08	8.33E-08	1.33E-07	5.83E-07
7,12-Dimethylbenz(a)anthracene	1.60E-05	1	1.69E-07	7.41E-07	1.18E-06	5.19E-06
Acenaphthene	1.80E-06	1	1.90E-08	8.33E-08	1.33E-07	5.83E-07
Acenaphthylene	1.80E-06	1	1.90E-08	8.33E-08	1.33E-07	5.83E-07
Anthracene	2.40E-06	1	2.54E-08	1.11E-07	1.78E-07	7.78E-07
Benz(a)anthracene	1.80E-06	1	1.90E-08	8.33E-08	1.33E-07	5.83E-07
Benzo(a)pyrene	1.20E-06	1	1.27E-08	5.56E-08	8.88E-08	3.89E-07
Benzo(b)fluoranthene	1.80E-06	1	1.90E-08	8.33E-08	1.33E-07	5.83E-07
Benzo(g,h,i)perylene	1.20E-06	1	1.27E-08	5.56E-08	8.88E-08	3.89E-07
Benzo(k)fluoranthene	1.80E-06	1	1.90E-08	8.33E-08	1.33E-07	5.83E-07
Chrysene	1.80E-06	1	1.90E-08	8.33E-08	1.33E-07	5.83E-07
Dibenzo(a,h)anthracene	1.20E-06	1	1.27E-08	5.56E-08	8.88E-08	3.89E-07
Fluoranthene	3.00E-06	1	3.17E-08	1.39E-07	2.22E-07	9.72E-07
Fluorene	2.80E-06	1	2.96E-08	1.30E-07	2.07E-07	9.07E-07
Indeno(1,2,3-cd)pyrene	1.80E-06	1	1.90E-08	8.33E-08	1.33E-07	5.83E-07
Naphthalene	6.10E-04	1	6.45E-06	2.82E-05	4.51E-05	1.98E-04
Phenanathrene	1.70E-05	1	1.80E-07	7.87E-07	1.26E-06	5.51E-06
Pyrene	5.00E-06	1	5.29E-08	2.31E-07	3.70E-07	1.62E-06
Metal non-HAP Compounds:						
Barium	4.40E-03	2	4.65E-05	2.04E-04	3.26E-04	1.43E-03
Copper	8.50E-04	2	8.98E-06	3.94E-05	6.29E-05	2.75E-04
Molybdenum	1.10E-03	2	1.16E-05	5.09E-05	8.14E-05	3.56E-04
Vanadium	2.30E-03	2	2.43E-05	1.06E-04	1.70E-04	7.45E-04
Zinc	2.90E-02	2	3.07E-04	1.34E-03	2.15E-03	9.40E-03
Metal HAP Compounds:						
Arsenic	2.00E-04	2	2.11E-06	9.26E-06	1.48E-05	6.48E-05
Beryllium	1.20E-05	2	1.27E-07	5.56E-07	8.88E-07	3.89E-06
Cadmium	1.10E-03	2	1.16E-05	5.09E-05	8.14E-05	3.56E-04
Chromium (Cr III)	1.34E-03	2 [4]	1.42E-05	6.22E-05	9.94E-05	4.36E-04
Chromium (Cr VI)	5.60E-05	2 [4]	5.92E-07	2.59E-06	4.14E-06	1.81E-05
Cobalt	8.40E-05	2	8.88E-07	3.89E-06	6.22E-06	2.72E-05
Lead	5.00E-04	3	5.29E-06	2.31E-05	3.70E-05	1.62E-04
Manganese	3.80E-04	2	4.02E-06	1.76E-05	2.81E-05	1.23E-04
Mercury	2.60E-04	2	2.75E-06	1.20E-05	1.92E-05	8.43E-05
Nickel	2.10E-03	2	2.22E-05	9.72E-05	1.55E-04	6.81E-04
Selenium	2.40E-05	2	2.54E-07	1.11E-06	1.78E-06	7.78E-06
					Total HAPs	**6.12E-01**

Fuel	Natural Gas
Number of Units	7
Total Fuel Input (scf/hr)	10,570
Max Operating hours per year	8,760
Annual Fuel Input (MMscf/yr)	92,593,200

Notes:

1/ AP-42 Section 1.4 07/98 - Boilers - Natural Gas Combustion Table 1.4-3

2/ AP-42 Section 1.4 07/98 - Boilers - Natural Gas Combustion Table 1.4-4

3/ AP-42 Section 1.4 07/98 - Boilers - Natural Gas Combustion Table 1.4-2

4/ Speciated chrome based on total chromium from AP-42 Table 1.4-4 and 96% Cr III / 4% Cr VI from EPA NEI Supporting Data - natural gas boilers
https://gaftp.epa.gov/air/nei/2020/doc/supporting_data/Chromium_speciation_nonNAICS_28jan2023.zip

Table C-23
Cooling Tower Emissions
Annual and Maximum Hourly Emissions Estimates

Operating Water Circulation Rate (all cells)	(GPM)	95,007
Design Water Circulation Rate (a) all cells	(GPM)	95,007
No of Cells		56.0
Total Liquid Drift (b)	(%)	0.0005
Expected TDS/TSS of Circulated Water (c)	(ppmw)	3,000
Weight % PM_{10} in Particulate Emissions (e)		70.51%
Weight % $PM_{2.5}$ in Particulate Emissions (e)		0.23%
Emission Rate - Total Cooling Tower		
Total Suspended Particulate (d)	(Lbs/Hr)	0.71
	(Tons/Yr)	3.13
PM_{10} (e)	(Lbs/Hr)	0.50
	(Tons/Yr)	2.20
$PM_{2.5}$ (e)	(Lbs/Hr)	1.61E-03
	(Tons/Yr)	7.06E-03
Emission Rate - Per Cell		
Total Suspended Particulate	(Lbs/Hr)	0.01
	(Tons/Yr)	0.06
PM_{10}	(Lbs/Hr)	8.98E-03
	(Tons/Yr)	0.04
$PM_{2.5}$	(Lbs/Hr)	2.88E-05
	(Tons/Yr)	1.26E-04

Notes:

(a) Design Water Circulation Rate, Gallons/Minute (GPM)

(b) Design Total Liquid Drift, Percent (%) [vendor guarantee]

(c) Estimated 3000 ppmw TDS in circulating water. Based on 500 ppmw TDS * 6 cycles of concentration.

(d) Based on USEPA AP-42 Section 13.4 Wet Cooling Towers,
Table 13.4-1 dated 1/95. Modified to Cooling Tower Design
Lbs/Hr = (Water Circulation Rate,GPM)*60*(Drift,%) / 100 *
(8.3453 Lbs/Gal) * (TDS, Lbs PM/1,000,000 Lbs Water)
Tons/Yr = (Lbs/Hr) * (8,760 Hrs/Yr) / (2,000 Lbs/Ton)

(e) Droplet size distribution from "Calculating TSP, PM-10, and PM-2.5 from Cooling Towers",
New Mexico Environment Department Air Quality Bureau, September 2013.

Table C-24
Circuit Breaker Emissions
Annual Emissions Estimates

Annual SF_6 Usage[1]	lbs SF_6/bay	3,000
Number of bays		23
Total SF_6 for GIS	lbs SF_6	69,000
Leak Rate[2]	(%)	0.5%
Total SF_6 Emissions	lbs/year	345
	tons/year	0.173
Total GHG Emissions[3]	tons CO_2e/year	4,054

Notes:

1/ Based on prospective vendor information.

2/ Assumed leak rate based on guidance document from IEC, International Electrotechnical Commission Standard 62271-1, 2004.

3/ SF_6 global warming potential (GWP) from 40 CFR 98, Subpart A, Table A-1.

SF_6 GWP: 23,500

Table C-25
Fugitive Leak Emissions
Annual Emissions Estimates

	Component Counts	lb/hr/component	lb/hr	lbs/yr	tons CH4/yr	tons CO2e/yr
Valves	847	9.92E-03	8.40	73,609	36.80	1,030.5
Flanges	525	8.60E-04	0.45	3,954	1.98	55.4
Relief Valves	39	1.94E-02	0.76	6,628	3.31	92.8
Sampling Connections	7	4.41E-04	0.00	27	0.01	0.4
Orifice Meters	11	1.94E-02	0.21	1,869	0.93	26.2
Total					43	1,205

Notes:
1/ Number of components taken from Fairview application, Table 3-14, and scaled up based on the number of combined cycle CTs (7/2)
2/ Emission factors (converted from kg/hr/component) taken from Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017); Table 2-4, for gas service. Category "others' used for relief valves and orifice meters.
3/ Global Warming Potentials for CH4 is from Federal Register Vol. 89, Issue 81, April 25, 2024; (89 FR 31802).

Appendix D :
Search Results from EPA's RACT/BACT/LAER Clearinghouse

TABLE D-1

NATURAL GAS-FIRED COMBINED CYCLE TURBINES >25 MW, PERMIT DATES 1/1/2014 THROUGH 11/12/2024

LISTINGS FOR NO_X

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*IN-0371	WABASH VALLEY RESOURCES, LLC	1/11/2024	Integrated Gasification Combined Cycle Combustion Turbine	2292	MMBtu/hr	Steam Injection/SCR and Good Combustion Practices	2	PPMV
*IN-0365	MAPLE CREEK ENERGY LLC	6/19/2023	Combined Cycle Turbine CTGB	4200	MMBtu per hour	Selective Catalytic Reduction system and dry-low-NOx combustors.	2	PPMVD
*IN-0365	MAPLE CREEK ENERGY LLC	6/19/2023	Combined Cycle Turbine CTGA	3800	MMBtu per hour	Selective catalytic reduction system and dry-low-NOx combustors	0.0085	POUND PER MMBTU
MI-0455	MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP	2/1/2023	EUCTGHRSG1	4197.6	MMBTU/H	Selective catalytic regeneration	2	PPM
MI-0454	LBWL-ERICKSON STATION	12/20/2022	EUCTGHRSG1	667	MMBTU/H	Dry low NOx burners and selective catalytic reduction for NOx control for each CTG/HRSG unit.	3	PPM
MI-0454	LBWL-ERICKSON STATION	12/20/2022	EUCTGHRSG2	667	MMBTU/H	Dry low NOx burners and selective catalytic reduction for NOx control for each CTG/HRSG unit.	3	PPM
IL-0133	LINCOLN LAND ENERGY CENTER	7/29/2022	Combined-Cycle Combustion Turbines	3647	mmBtu/hour	Dry low-NOx combustion with ultra-low NOx combustors; low-NOx duct burners; and selective catalytic reduction (SCR)	2	PPMV @ 15% O2
AK-0088	LIQUEFACTION PLANT	7/7/2022	Four Combined Cycle Gas-Fired Turbines	384	MMBtu/hr	SCR, DLN combustors, and good combustion practices	2	PPMV @ 15% O2
MI-0452	MEC SOUTH, LLC	6/23/2022	EUCTGHRSG (South Plant): A combined-cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	3064	MMBTU/H	SCR with DLNB [Selective Catalytic Reduction with Dry Low NOx Burners]	2	PPM
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	6/3/2022	Combined Cycle Gas Turbine w/ Duct Burners and HRSG	5081	mm BTU/h	Dry low-NOx combustor design, selective catalytic reduction (SCR), and good combustion practices.	2	PPMVD
*WV-0033	MAIDSVILLE	1/5/2022	Combustion Turbine & Duct Burner (CT-01/HRSG1 & CT-02/HRSG2)	1275	mw	Dry Low NOx Combustion w/ SCR	2	PPMDV @ 15% O2
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	6/7/2021	GE 7HA.02 Combustion Turbine and HRSG with Duct Firing	3622.1	MMBtu/hour	Dry low-NOX combustors and Selective Catalytic Reduction (SCR)	2	PPMVD AT 15% O2
PA-0334	RENOVO ENERGY CENTER LLC/RENOVO PLT	4/29/2021	COMBUSTION TURBINE w DUCT BURNER #2 (Natural Gas)	4546	MMBtu/Hr	SCR, CATALYTIC OXIDIZER	2	PPMVD
PA-0334	RENOVO ENERGY CENTER LLC/RENOVO PLT	4/29/2021	COMBUSTION TURBINE w DUCT BURNER #1 (Natural Gas)	4546	MMBtu/Hr	SCR, Catalytic Oxidizer	2	PPMVD
*VA-0335	PANDA STONEWALL LLC	12/18/2020	Combustion Turbines, Two (2) and HRSG Duct Burners	2.55	MMBTU/H	Selective Catalytic Reduction (SCR), with ammonia injection and dry low NOx combustion.	2	PPMVD @ 15% O2
VA-0334	DOMINION ENERGY - BRUNSWICK	12/1/2020	COMBUSTION TURBINE GENERATORS, (3) with Alternate Operating Scenario - Turbine Tuning	3442	MMBTU/H	Dry, low NOx burners and selective catalytic reduction (SCR) with a NOx performance of 2.0 ppmvd at 15% O2.	604	LBS
VA-0334	DOMINION ENERGY - BRUNSWICK	12/1/2020	COMBUSTION TURBINE GENERATORS, (3) with Alternate Operating Scenario - Turbine Blade Water Washing	3442	MMBTU/H	Dry, low NOx burners and selective catalytic reduction (SCR) with a NOx performance of 2.0 ppmvd at 15% O2.	604	LBS
AL-0328	PLANT BARRY	11/9/2020	Two 744 MW Combined Cycle Units	744	MW	SCR	2	PPM

TABLE D-2
NATURAL GAS-FIRED COMBINED CYCLE TURBINES >25 MW, PERMIT DATES 1/1/2014 THROUGH 11/12/2024
LISTINGS FOR CO

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
CT-0161	KILLINGLY ENERGY CENTER	6/30/2017	Natural Gas w/o Duct Firing	2969	MMBtu/hr	Oxidation Catalyst	0.9	PPMVD @15% O2
CT-0157	CPV TOWANTIC, LLC	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/12 months	Oxidation Catalyst	0.9	PPMVD @15% O2
CT-0158	CPV TOWANTIC, LLC	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/yr	Oxidation Catalyst	0.9	PPMVD @15% O2
NJ-0082	WEST DEPTFORD ENERGY STATION	7/18/2014	Combined Cycle Combustion Turbine without Duct Burner	20282	MMCF/YR	Oxidation Catalyst and Use of Natural gas a clean burning fuel	0.9	PPMVD@15%O2
VA-0332	CHICKAHOMINY POWER LLC	6/24/2019	Three (3) Mitsubishi Hitachi Power Systems Combustion	35000	MMCF/YR	Oxidation catalyst and good combustion practices	214	LB/TURBINE/DAY
VA-0332	CHICKAHOMINY POWER LLC	6/24/2019	Three (3) Mitsubishi Hitachi Power Systems combustion turbine generators	35000	MMCF/YR	Controlled by an oxidation catalyst and good combustion practices (e.g. controlled fuel/air mixing, adequate temperature, and gas residence time).	1	PPMVD @ 15% O2
VA-0328	C4GT, LLC	4/26/2018	GE Combustion Turbine - Tuning & Water Washing	34000	MMCF/YR	Oxidation catalyst and good combustion practices	194	LB/TURBINE/DAY
VA-0328	C4GT, LLC	4/26/2018	GE Combustion Turbine - Option 1 - Normal Operation	34000	MMCF/YR	Oxidation catalyst and good combustion practices	1	PPMVD@ 15% O2
VA-0328	C4GT, LLC	4/26/2018	Siemens Combustion Turbine - Tuning & Water Washing	35000	MMCF/YR	Oxidation catalyst and good combustion practices	309	LB/TURBINE/DAY
IL-0133	LINCOLN LAND ENERGY CENTER	7/29/2022	Combined-Cycle Combustion Turbines	3647	mmBtu/hour	Oxidation catalyst and good combustion practices	1.5	PPMV @ 15% O2
PA-0334	RENOVO ENERGY CENTER LLC/RENOVO PLT	4/29/2021	COMBUSTION TURBINE w DUCT BURNER #2 (Natural Gas)	4546	MMBtu/Hr	SCR, CATALYTIC OXIDIZER	1.5	PPMVD
PA-0334	RENOVO ENERGY CENTER LLC/RENOVO PLT	4/29/2021	COMBUSTION TURBINE w DUCT BURNER #1 (Natural Gas)	4546	MMBtu/Hr	SCR, Catalytic Oxidizer	1.5	PPMVD
WI-0300	NEMADJI TRAIL ENERGY CENTER	9/1/2020	Natural-Gas-Fired Combined-Cycle Turbine (P01)	4671	MMBTU/H	Oxidation Catalyst and good combustion controls	1.5	PPM AT 15% O2
PA-0333	ESC TIOGA COUNTY POWER LLC/ELEC PWR GEN FAC	8/20/2019	COMBUSTION TURBINE/DUCT BURNER	4469	MMBtu/Hr	SCR, Catalytic Oxidizer	1.5	PPMVD
CA-1251	PALMDALE ENERGY PROJECT	4/25/2018	Combustion Turbines (GEN1 and GEN2)	2217	MMBTU/H	Oxidation Catalyst	1.5	PPM @ 15% O2
NJ-0082	WEST DEPTFORD ENERGY STATION	7/18/2014	Combined Cycle Combustion Turbine with Duct Burner	20282	MMCF/YR	Oxidation catalyst and use of natural gas a clean burning fuel	1.5	PPMVD@15%O2
MD-0042	WILDCAT POINT GENERATION FACILITY	4/8/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITHOUT DUCT FIRING	270	MW	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS, USE OF AN OXIDATION CATALYST AND EFFICIENT CT DESIGN	1.5	PPMVD @ 15% O2
VA-0325	GREENSVILLE POWER STATION	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)	3227	MMBTU/HR	Oxidation Catalyst	1.6	PPMVD
VA-0328	C4GT, LLC	4/26/2018	Siemens Combusion Turbine - Option 2 - Normal Operation	35000	MMCF/YR	Oxidation catalyst & good combustion practice	1.8	PPMVD @ 15% O2
OH-0365	ROLLING HILLS GENERATING, LLC	5/20/2015	Combustion Turbines, Scenario 1 (4, identical) (P001, P002, P004, P005)	2022	MMBTU/H	Oxidation catalyst	10.4	LB/H
PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	2/12/2016	Large combustion turbine			Oxidation Catalyst and good combustion practice	15.9	LB/HR
OH-0365	ROLLING HILLS GENERATING, LLC	5/20/2015	Combustion Turbines, Scenario 2 (4, identical) (P001, P002, P004, P005)	2144	MMBTU/H	Oxidation catalyst	12	LB/H
*WV-0032	BROOKE COUNTY POWER PLANT	9/18/2018	GE 7HA.01 Turbine	2737.7	mmBtu/hr	Oxidation Catalyst, Good Combustion Practices	14.1	LB/HR

TABLE D-3
NATURAL GAS-FIRED COMBINED CYCLE TURBINES >25 MW, PERMIT DATES 1/1/2014 THROUGH 11/12/2024
LISTINGS FOR VOC

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
VA-0332	CHICKAHOMINY POWER LLC	6/24/2019	Three (3) Mitsubishi Hitachi Power Systems combustion turbine generators	35000	MMCF/YR	Controlled by an oxidation catalyst and good combustion practices (e.g. controlled fuel/air mixing, adequate temperature, and gas residence time)	0.7	PPMVD @ 15% O2
*PA-0316	RENOVO ENERGY CENTER, LLC	1/26/2018	Combustion Turbine Firing NG				0.7	PPMVD @ 15% O2
CT-0161	KILLINGLY ENERGY CENTER	6/30/2017	Natural Gas w/o Duct Firing	2969	MMBtu/hr	Oxidation Catalyst	0.7	PPMVD @15% O2
NJ-0082	WEST DEPTFORD ENERGY STATION	7/18/2014	Combined Cycle Combustion Turbine without Duct Burner	20282	MMCF/YR	Oxidation catalysts and use of Natural gas a clean burning fuel	0.7	PPMVD215%O2
*IN-0365	MAPLE CREEK ENERGY LLC	6/19/2023	Combined Cycle Turbine CTGB	4200	MMBtu per hour	catalytic oxidation	0.0013	POUNDS PER MMBTU
IL-0133	LINCOLN LAND ENERGY CENTER	7/29/2022	Combined-Cycle Combustion Turbines	3647	mmBtu/hour	Oxidation catalyst and good combustion practices.	1	PPMV, ADJ. TO 15% O
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	6/3/2022	Combined Cycle Gas Turbine w/ Duct Burners and HRSG	5081	mm BTU/h	Catalytic oxidation and good combustion practices.	1	PPMVD
*WV-0033	MAIDSVILLE	1/5/2022	Combustion Turbine & Duct Burner (CT-01/HRSG1 & CT-02/HRSG2)	1275	mw	good combustion practices and oxidation catalyst	1	PPMDV @ 15% O2
*WV-0033	MAIDSVILLE	1/5/2022	Combustion Turbine & Duct Burner (CT-01/HRSG1 & CT-02/HRSG2)	1275	mw	good combustion practices and oxidation catalyst	1	PPMDV @ 15% O2
TX-0915	UNIT 5	3/17/2021	COMBINED CYCLE TURBINE			OXIDATION CATALYST	1	PPMVD
NJ-0088	COGEN TECH LINDEN VENTURE LP	7/30/2019	250 MW COMBINED CYCLE COMBUSTION TURBINE FIRING NATURAL GAS	21042	MMCubic ft/yr	Add on Oxidation Catalyst and use of Natural Gas as primary fuel for pollution prevention	3.2	LB/H
*PA-0319	RENAISSANCE ENERGY CENTER	8/27/2018	COMBUSTION TURBINE UNIT w/o DUCT BURNERS UNIT	2665.9	MMBtu/hr	Oxidation Catalyst	1	PPMDV
MI-0432	NEW COVERT GENERATING FACILITY	7/30/2018	FG-TURB/DB1-3 (3 combined cycle combustion turbine and heat recovery steam generator trains)	1230	MW	An oxidation catalyst and good combustion practices.	1	PPMVD
VA-0328	C4GT, LLC	4/26/2018	Siemens Combusion Turbine - Option 2 - Normal Operation	35000	MMCF/YR	Oxidation catalyst and good combustion practice	1	PPMVD @ 15% O2
FL-0364	SEMINOLE GENERATING STATION	3/21/2018	2-on-1 natural gas combined-cycle unit (GE 7HA.02)	3514	MMBtu/hr	Oxidation catalyst	1	PPMVD@15% O2
FL-0363	DANIA BEACH ENERGY CENTER	12/4/2017	2-on-1 combined cycle unit (GE 7HA)	4000	MMBtu/hr	Clean fuels	1	PPMVD@15% O2
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	11/7/2017	General Electric Combustion Turbine (P004)	3544	MMBTU/H	Oxidation catalyst and good combustion practices as recommended by the manufacturer.	4.54	LB/H
*PA-0315	HILLTOP ENERGY CENTER, LLC	4/12/2017	Combustion Turbine without Duct Burner	3509	MMBtu/hr		1	PPMDV
TX-0817	CHOCOLATE BAYOU STEAM GENERATING (CBSG) STATION	2/17/2017	Combined Cycle Cogeneration	50	MW	OXIDATION CATALYST	1	PPMDV
PA-0310	CPV FAIRVIEW ENERGY CENTER	9/2/2016	Combustion turbine and HRSG without duct burner NG only				1	PPMDV @ 15% O2
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas without Duct Burner	8040	H/YR	Oxidation catalyst and good combustion practices	1	PPMVD@15%O2
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	3/9/2016	Combined-cycle electric generating unit	3096	MMBtu/hr per turbine	Complete combustion minimizes VOC	1	PPMVD@15%O2
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	12/23/2015	Combustion turbine without duct burner			Oxidation catalyst, combustion controls, exclusive natural gas	1	PPNDV @ 15% O2
CT-0157	CPV TOWANTIC, LLC	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/12 months	Oxidation Catalyst	1	PPMVD @15% O2
CT-0158	CPV TOWANTIC, LLC	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/yr	Oxidation Catalyst	1	PPMVD @15% O2
MD-0045	MATTAWOMAN ENERGY CENTER	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES	286	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1	PPMVD @ 15% O2

TABLE D-4
NATURAL GAS-FIRED COMBINED CYCLE TURBINES >25 MW, PERMIT DATES 1/1/2014 THROUGH 11/12/2024
LISTINGS FOR TPM

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*IN-0365	MAPLE CREEK ENERGY LLC	6/19/2023	Combined Cycle Turbine CTGA	3800	MMBtu per hour		0.0049	POUND PER MMBTU
*IN-0365	MAPLE CREEK ENERGY LLC	6/19/2023	Combined Cycle Turbine CTGB	4200	MMBtu per hour		0.0074	POUND PER MMBTU
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	3/13/2023	TURBINE MSS	0		On-line turbine washing, turbine filter changeouts,	0	
TX-0878	LNG EXPORT TERMINAL	9/15/2022	Refrigeration Compression Turbines	26.92	MMTON/Y	Dry low NOx burners and good combustion practices.	11.0	LB/HR
AK-0088	LIQUEFACTION PLANT	7/7/2022	Four Combined Cycle Gas-Fired Turbines	384	MMBtu/hr	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU
*WV-0033	MAIDSVILLE	1/5/2022	Combustion Turbine & Duct Burner (CT-01/HRSG1 & CT-02/HRSG2)	1275	mw	Good Combustion Practice and Clean Fuel	23.36	LB/HR
*WV-0033	MAIDSVILLE	1/5/2022	Combustion Turbine & Duct Burner (CT-01/HRSG1 & CT-02/HRSG2)	1275	mw	Clean Fuels and Good Combustion Practice	25.32	LB/HR
PA-0334	RENOVO ENERGY CENTER LLC/RENOVO PLT	4/29/2021	COMBUSTION TURBINE w DUCT BURNER #2 (Natural Gas)	4546	MMBtu/Hr	SCR, CATALYTIC OXIDIZER	22.5	LB/HR
PA-0334	RENOVO ENERGY CENTER LLC/RENOVO PLT	4/29/2021	COMBUSTION TURBINE w DUCT BURNER #1 (Natural Gas)	4546	MMBtu/Hr	SCR, Catalytic Oxidizer	22.5	LB/HR
WI-0300	NEMADJI TRAIL ENERGY CENTER	9/1/2020	Natural-Gas-Fired Combined-Cycle Turbine (P01)	4671	MMBTU/H	Only combust pipeline quality natural gas and diesel fuel oil and use good combustion control according to the	36.3	LB/H
AK-0085	GAS TREATMENT PLANT	8/13/2020	Six (6) Cogeneration Gas-Fired Turbines (Treated Gas Compressor Turbines)	576	MMBtu/hr	Good Combustion Practices and burning clean fuels (NG)	0.0063	LB/MMBTU
AK-0085	GAS TREATMENT PLANT	8/13/2020	Six (6) Cogeneration Gas-Fired Turbines (CO2 Compressor Turbines))	431	MMBtu/hr	Good Combustion Practices and burning clean fuels (NG)	0.0063	LB/MMBTU
*WV-0032	BROOKE COUNTY POWER PLANT	9/18/2018	GE 7HA.01 Turbine	2737.7	mmBtu/hr	Air Filter, Use of Natural Gas, Good Combustion Practices	16.9	LB/HR
*PA-0319	RENAISSANCE ENERGY CENTER	8/27/2018	COMBUSTION TURBINE UNIT w/o DUCT BURNERS UNIT	2665.9	MMBtu/hr		0.0043	LB/MMBTU
OH-0377	HARRISON POWER	4/19/2018	Mitsubishi Hitachi Power Systems (MHPS) Combustion Turbines (P007 & P008)	3231	MMBTU/H	Good combustion practices and pipeline quality natural gas	17.7	LB/H
OH-0377	HARRISON POWER	4/19/2018	General Electric (GE) Combustion Turbines (P005 & P006)	3459.6	MMBTU/H	Good combustion practices and pipeline quality natural	18.4	LB/H
TX-0834	MONTGOMERY COUNTY POWER STATIOIN	3/30/2018	Combined Cycle Turbine	2635	MMBTU/HR/UNI	PIPELINE NATURAL GAS, GOOD COMBUSTION	125.7	TON/YR
*WV-0029	HARRISON COUNTY POWER PLANT	3/27/2018	GE 7HA.02 Turbine	3496.2	mmBtu/hr	Air Filter, Use of Natural Gas, Good Combustion Practices	18.2	LB/HR
OH-0374	GUERNSEY POWER STATION LLC	10/23/2017	Combined Cycle Combustion Turbines (3, identical) (P001 to P003)	3516	MMBTU/H	pipeline quality natural gas	23.3	LB/H
TX-0819	GAINES COUNTY POWER PLANT	4/28/2017	Combined Cycle Turbine with Heat Recovery Steam Generator, fired Duct Burners, and Steam Turbine Generator	426	MW	Pipeline quality natural gas; good combustion practices	0	
*PA-0315	HILLTOP ENERGY CENTER, LLC	4/12/2017	Combustion Turbine without Duct Burner	3509	MMBtu/hr		0.0072	LB
TX-0817	CHOCOLATE BAYOU STEAM GENERATING (CBSG) STATION	2/17/2017	Combined Cycle Cogeneration	50	MW		6.98	LB/H

TABLE D-5

NATURAL GAS-FIRED COMBINED CYCLE TURBINES >25 MW, PERMIT DATES 1/1/2014 THROUGH 11/12/2024

LISTINGS FOR PM_{10}

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0432	NEW COVERT GENERATING FACILITY	7/30/2018	FG-TURB/DB1-3 (3 combined cycle combustion turbine and heat recovery steam generator trains)	1230	MW	Use clean fuel (natural gas) and good combustion practices.	10.7	LB/H
MI-0423	INDECK NILES, LLC	1/4/2017	FGCTGHRSG (2 Combined Cycle CTGs with HRSGs)	8322	MMBTU/H	Good combustion practices, inlet air conditioning, and the use of pipeline quality natural gas.	19.8	LB/H
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas without Duct Burner	8040	H/YR	USE OF NATURAL GAS A CLEAN BURNING FUEL	11.7	LB/H
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITHOUT DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Use of Natural Gas as a clean burning fuel	12.7	LB/H
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	3/7/2014	Combined Cycle Combustion Turbine -Siemens turbine without Duct Burner	33691	MMCF/YR	USE OF NATURAL GAS A CLEAN BURNING FUEL	13	LB/H
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - SIEMENS	33691	MMCF/YR	Use of natural gas a clean burning fuel	14	LB/H
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)	0		Good combustion practices, inlet air conditioning, and the use of pipeline quality natural gas.	16	LB/H
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	11/7/2017	General Electric Combustion Turbine (P004)	3544	MMBTU/H	natural gas or a natural gas and ethane mixture only	12.1	LB/H
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Use of natural gas only as a clean burning fuel	14.6	LB/H
VA-0325	GREENSVILLE POWER STATION	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)	3227	MMBTU/HR	Low sulfur/carbon fuel and good combustion pratices	0.0039	LB/MMBTU
PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	2/12/2016	Large combustion turbine	0		Good combustion practices with the use of low ash/sulfer fuels	11.8	LB/HR
AL-0328	PLANT BARRY	11/9/2020	Two 744 MW Combined Cycle Units	744	MW		0.004	LB/MMBTU
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	11/7/2017	Mitsubishi Combustion Turbine (P005)	3320	MMBTU/H	natural gas or a natural gas and ethane mixture only	12.6	LB/H
IL-0133	LINCOLN LAND ENERGY CENTER	7/29/2022	Combined-Cycle Combustion Turbines	3647	mmBtu/hour	Good combustion practices.	0.0041	POUNDS/MMBTU
*PA-0319	RENAISSANCE ENERGY CENTER	8/27/2018	COMBUSTION TURBINE UNIT w/o DUCT BURNERS UNIT	2665.9	MMBtu/hr		0.0043	LB/MMBTU
CT-0161	KILLINGLY ENERGY CENTER	6/30/2017	Natural Gas w/o Duct Firing	2969	MMBtu/hr	Good Combustion	0.0044	LB/MMBTU
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas with Duct Burner	4000	h/yr	COMPLIANCE BY STACK TESTING	18.3	LB/H
OH-0370	TRUMBULL ENERGY CENTER	9/7/2017	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3025	MMBTU/H	Good combustion controls and low sulfur fuel	15.2	LB/H
OH-0372	OREGON ENERGY CENTER	9/27/2017	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3055	MMBTU/H	good combustion practices and pipeline quality natural gas	15.4	LB/H
NJ-0088	COGEN TECH LINDEN VENTURE LP	7/30/2019	250 MW COMBINED CYCLE COMBUSTION TURBINE FIRING NATURAL GAS	21042	MMCubic ft/yr	USE OF NATURAL GAS AND ULSD; BOTH CLEAN BURNING FUELS	11.58	LB/H
*MI-0445	INDECK NILES, LLC	11/26/2019	FGCTGHRSG	3421	MMBTU/H	Good combustion practices, inlet air conditioning, and the use of pipeline quality natural gas.	19.8	LB/H

TABLE D-6

NATURAL GAS-FIRED COMBINED CYCLE TURBINES >25 MW, PERMIT DATES 1/1/2014 THROUGH 11/12/2024

LISTINGS FOR $PM_{2.5}$

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0432	NEW COVERT GENERATING FACILITY	7/30/2018	FG-TURB/DB1-3 (3 combined cycle combustion turbine and heat recovery steam generator trains)	1230	MW	Use clean fuel (natural gas) and good combustion practices.	10.7	LB/H
MI-0423	INDECK NILES, LLC	1/4/2017	FGCTGHRSG (2 Combined Cycle CTGs with HRSGs)	8322	MMBTU/H	Good Combustion Practices, inlet air conditioning, and the use of pipeline quality natural gas.	19.8	LB/H
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Use of Natural Gas a clean burning fuel	9.8	LB/H
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas without Duct Burner	8040	H/YR	USE OF NATURAL GAS A CLEAN BURNING FUEL	11.7	LB/H
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITHOUT DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Use of natural gas as a clean burning fuel	12.7	LB/H
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	3/7/2014	Combined Cycle Combustion Turbine -Siemens turbine without Duct Burner	33691	MMCF/YR	USE OF NATURAL GAS A CLEAN BURNING FUEL	13	LB/H
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - SIEMENS	33691	MMCF/YR	Use of natural gas a clean burning fuel	14	LB/H
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)			Good combustion practices, inlet air conditioning and the use of pipeline quality natural gas.	16	LB/H
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	11/7/2017	General Electric Combustion Turbine (P004)	3544	MMBTU/H	natural gas or a natural gas and ethane mixture only	0.0036	LB/MMBTU
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	11/21/2014	Combined Cycle Turbine/Duct Burner	2419.61	mmBtu/Hr	Good Combustion Practices, Inlet Air Filtration, & use of Natural Gas	8.9	LB/H
*VA-0335	PANDA STONEWALL LLC	12/18/2020	Combustion Turbines, Two (2) and HRSG Duct Burners	2.55	MMBTU/H	Good combustion practices and use of low-sulfur fuels	0.0037	LB/MMBTU
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Use of natural gas only as a clean burning fuel	14.6	LB/H
VA-0325	GREENSVILLE POWER STATION	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)	3227	MMBTU/HR	Pipeline Quality Natural Gas	0.0039	LB/MMBTU
PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	2/12/2016	Large combustion turbine			Good combustion practices	0.0039	LB/MMBTU
AL-0328	PLANT BARRY	11/9/2020	Two 744 MW Combined Cycle Units	744	MW		0.004	LB/MMBTU
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	11/7/2017	Mitsubishi Combustion Turbine (P005)	3320	MMBTU/H	natural gas or a natural gas and ethane mixture only	0.004	LB/MMBTU
CT-0157	CPV TOWANTIC, LLC	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/12 months		9.73	LB/H
CT-0158	CPV TOWANTIC, LLC	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/yr		9.73	LB/H
NJ-0082	WEST DEPTFORD ENERGY STATION	7/18/2014	Combined Cycle Combustion Turbine without Duct Burner	20282	MMCF/YR	Use of natural gas a clean burning fuel	10	LB/H
*PA-0319	RENAISSANCE ENERGY CENTER	8/27/2018	COMBUSTION TURBINE UNIT w/o DUCT BURNERS UNIT	2665.9	MMBtu/hr		0.0043	LB/MMBTU
CT-0161	KILLINGLY ENERGY CENTER	6/30/2017	Natural Gas w/o Duct Firing	2969	MMBtu/hr	Good Combustion	0.0044	LB/MMBTU
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas with Duct Burner	4000	h/yr	COMPLIANCE BY STACK TESTING	18.3	LB/H

TABLE D-7

NATURAL GAS-FIRED COMBINED CYCLE TURBINES >25 MW, PERMIT DATES 1/1/2014 THROUGH 11/12/2024

LISTINGS FOR SO_2

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0364	FG LA COMPLEX	1/6/2020	Cogeneration Units	2222	mm btu/h	Use of pipeline quality natural gas or fuel gas.	1.24	LB/H
VA-0332	CHICKAHOMINY POWER LLC	6/24/2019	Three (3) Mitsubishi Hitachi Power Systems combustion turbine generators	35000	MMCF/YR	Controlled by the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 standard cubic feet (scf), on a 12-month rolling average.	0.0011	LB/MMBTU
VA-0328	C4GT, LLC	4/26/2018	GE Combustion Turbine - Option 1 - Normal Operation	34000	MMCF/YR	use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12-month rolling average.	0.0011	LB/MMBTU
VA-0328	C4GT, LLC	4/26/2018	Siemens Combusion Turbine - Option 2 - Normal Operation	35000	MMCF/YR	use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	0.0011	LB/MMBTU
VA-0325	GREENSVILLE POWER STATION	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)	3227	MMBTU/HR	Low Sulfur fuel	0.0011	LB/MMBTU
*WV-0033	MAIDSVILLE	1/5/2022	Combustion Turbine & Duct Burner (CT-01/HRSG1 & CT-02/HRSG2)	1275	mw	Low Sulfur Fuel	0.4	GR-S/100 SCF
*WV-0033	MAIDSVILLE	1/5/2022	Combustion Turbine & Duct Burner (CT-01/HRSG1 & CT-02/HRSG2)	1275	mw	Low Sulfur Fuel	0.4	GR-S/100 SCF
MD-0042	WILDCAT POINT GENERATION FACILITY	4/8/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	1000	MW	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS AND EFFICIENT TURBINE DESIGN	8.2	LB/H
PA-0334	RENOVO ENERGY CENTER LLC/RENOVO PLT	4/29/2021	COMBUSTION TURBINE w DUCT BURNER #2 (Natural Gas)	4546	MMBtu/Hr	SCR, CATALYTIC OXIDIZER	0.0012	LB/MMBTU
PA-0334	RENOVO ENERGY CENTER LLC/RENOVO PLT	4/29/2021	COMBUSTION TURBINE w DUCT BURNER #1 (Natural Gas)	4546	MMBtu/Hr	SCR, Catalytic Oxidizer	0.0012	LB/MMBTU
NJ-0088	COGEN TECH LINDEN VENTURE LP	7/30/2019	250 MW COMBINED CYCLE COMBUSTION TURBINE FIRING NATURAL GAS	21042	MMCubic ft/yr	USE OF NATURAL GAS AND ULSD; BOTH CLEAN BURNING FUELS	3.45	LB/H
MI-0423	INDECK NILES, LLC	1/4/2017	FGCTGHRSG (2 Combined Cycle CTGs with HRSGs)	8322	MMBTU/H	Good Combustion Practices and the use of pipeline quality natural gas.	11.7	LB/H
OH-0367	SOUTH FIELD ENERGY LLC	9/23/2016	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3131	MMBTU/H	Low sulfur fuels	5.64	LB/H
IL-0133	LINCOLN LAND ENERGY CENTER	7/29/2022	Combined-Cycle Combustion Turbines	3647	mmBtu/hour	Good combustion practices and use of natural gas with a sulfur content of no more than 0.5 grains (gr)/100 standard cubic feet (scf).	5.5	POUNDS/HOUR
OH-0374	GUERNSEY POWER STATION LLC	10/23/2017	Combined Cycle Combustion Turbines (3, identical) (P001 to P003)	3516	MMBTU/H	pipeline quality natural gas with a maximum sulfur content not exceed 0.50 grain/100 scf	0.0015	LB/MMBTU
CT-0161	KILLINGLY ENERGY CENTER	6/30/2017	Natural Gas w/Duct Firing	2639	MMBtu/hr	Low Sulfur Fuel	0.0015	LB/MMBTU
CT-0161	KILLINGLY ENERGY CENTER	6/30/2017	Natural Gas w/o Duct Firing	2969	MMBtu/hr	Low Sulfur fuel	0.0015	LB/MMBTU
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	1/30/2014	Combustion Turbine with Duct Burner	2449	MMBTU/H		0.3	PPMVD@15% O2
OH-0372	OREGON ENERGY CENTER	9/27/2017	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3055	MMBTU/H	low sulfur fuel	5.1	LB/H
OH-0370	TRUMBULL ENERGY CENTER	9/7/2017	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3025	MMBTU/H	Low sulfur fuel	5.1	LB/H

TABLE D-8

NATURAL GAS-FIRED COMBINED CYCLE TURBINES >25 MW, PERMIT DATES 1/1/2014 THROUGH 11/12/2024

LISTINGS FOR H_2SO_4

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
CT-0161	KILLINGLY ENERGY CENTER	6/30/2017	Natural Gas w/Duct Firing	2639	MMBtu/hr	Low Sulfur Fuels	0	LB/MMBTU
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	6/3/2022	Combined Cycle Gas Turbine w/ Duct Burners and HRSG	5081	mm BTU/h	Use of gaseous fuel (pipeline-quality natural gas) and good combustion practices.	0.0062	GR/DSCF
MI-0432	NEW COVERT GENERATING FACILITY	7/30/2018	FG-TURB/DB1-3 (3 combined cycle combustion turbine and heat recovery steam generator trains)	1230	MW	Use of clean fuel (natural gas) with a fuel sulfur limit of 0.8 grains per 100 standard cubic feet of natural gas.	1	LB/H
OH-0365	ROLLING HILLS GENERATING, LLC	5/20/2015	Combustion Turbines, Scenario 1 (4, identical) (P001, P002, P004, P005)	2022	MMBTU/H	good combustion practices along with clean fuels. Firing only natural gas with a sulfur content of 0.25 grains per 100 standard cubic feet (gr/100 scf)	2	T/YR
OH-0365	ROLLING HILLS GENERATING, LLC	5/20/2015	Combustion Turbines, Scenario 2 (4, identical) (P001, P002, P004, P005)	2144	MMBTU/H	good combustion practices along with clean fuels. Firing only natural gas with a sulfur content of 0.25 grains per 100 standard cubic feet (gr/100 scf)	2.1	T/YR
NJ-0082	WEST DEPTFORD ENERGY STATION	7/18/2014	Combined Cycle Combustion Turbine with Duct Burner	20282	MMCF/YR	Use of natural gas a clean burning fuel	0.98	LB/H
NJ-0082	WEST DEPTFORD ENERGY STATION	7/18/2014	Combined Cycle Combustion Turbine without Duct Burner	20282	MMCF/YR	Use of natural gas a clean burning fuel	0.74	LB/H
LA-0313	ST. CHARLES POWER STATION	8/31/2016	SCPS Combined Cycle Unit 1A	3625	MMBTU/hr	Use of low sulfur fuel	1.21	LB/H
LA-0313	ST. CHARLES POWER STATION	8/31/2016	SCPS Combined Cycle Unit 1B	3625	MMBTU/hr	Use of low sulfur fuels	1.21	LB/H
*IN-0365	MAPLE CREEK ENERGY LLC	6/19/2023	Combined Cycle Turbine CTGA	3800	MMBtu per hour		0.0004	POUND PER MMBTU
MD-0041	CPV ST. CHARLES	4/23/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	725	MEGAWATT	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS	2.2	LB/H
CT-0161	KILLINGLY ENERGY CENTER	6/30/2017	Natural Gas w/o Duct Firing	2969	MMBtu/hr	Low Sulfur content fuel	0.0005	LB/MMBTU
*PA-0319	RENAISSANCE ENERGY CENTER	8/27/2018	COMBUSTION TURBINE UNIT w/o DUCT BURNERS UNIT	2665.9	MMBtu/hr		5.98	TPY
VA-0328	C4GT, LLC	4/26/2018	Siemens Combusion Turbine - Option 2 - Normal Operation	35000	MMCF/YR	use of natural gas with a sulfur content of no more than 0.4 gr/100scf, 12 mo rolling av.	2.2	LB/H
MI-0423	INDECK NILES, LLC	1/4/2017	FGCTGHRSG (2 Combined Cycle CTGs with HRSGs)	8322	MMBTU/H	Good Combustion Practices and the use of pipeline quality natural gas.	4.6	LB/H
VA-0325	GREENSVILLE POWER STATION	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)	3227	MMBTU/HR	Low Sulfur fuel	0.0006	LB/MMBTU
PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	2/12/2016	Large combustion turbine			Low sulfur fuel and good combustion practices	0.0006	LB/MMBTU
VA-0328	C4GT, LLC	4/26/2018	GE Combustion Turbine - Option 1 - Normal Operation	34000	MMCF/YR	use of natural gas with a sulfur content of no more than 0.4 gr/100scf, 12-mo rolling av	2.5	LB/H
MI-0451	MEC NORTH, LLC	6/23/2022	EUCTGHRSG (North Plant): A combined cycle natural gas fired combustion turbine generator with heat recovery steam generator	3064	MMBTU/H	Good combustion practices and the use of pipeline quality natural gas.	2.6	LB/H
MI-0452	MEC SOUTH, LLC	6/23/2022	EUCTGHRSG (South Plant): A combined-cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	3064	MMBTU/H	Good Combustion Practices and the use of pipeline quality natural gas	2.6	LB/H

TABLE D-9

NATURAL GAS-FIRED COMBINED CYCLE TURBINES >25 MW, PERMIT DATES 1/1/2014 THROUGH 11/12/2024

LISTINGS FOR CO_2e

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*IN-0371	WABASH VALLEY RESOURCES, LLC	1/11/2024	Integrated Gasification Combined Cycle Combustion Turbine	2292	MMBtu/hr	Good Combustion Practices	110	LB/MMBTU
*IN-0365	MAPLE CREEK ENERGY LLC	6/19/2023	Combined Cycle Turbine CTGA	3800	MMBtu per hour		726	LB/MW-HR (GROSS)
*IN-0365	MAPLE CREEK ENERGY LLC	6/19/2023	Combined Cycle Turbine CTGB	4200	MMBtu per hour		826	LB/MW-HR (GROSS)
MI-0455	MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP	2/1/2023	EUCTGHRSG1	4197.6	MMBTU/H	Low carbon fuel, good combustion practices, energy efficiency measures.	2375313	T/YR
MI-0454	LBWL-ERICKSON STATION	12/20/2022	EUCTGHRSG1	667	MMBTU/H	low carbon fuel (pipeline quality natural gas), good combustion practices, and energy efficiency measures.	430349	T/YR
MI-0454	LBWL-ERICKSON STATION	12/20/2022	EUCTGHRSG2	667	MMBTU/H	Low carbon fuel (pipeline quality natural gas), good combustion practices, and energy efficiency measures.	430349	T/YR
TX-0878	LNG EXPORT TERMINAL	9/15/2022	Refrigeration Compression Turbines	26.92	MMTON/Y	Equipment specifications & work practices - Good combustion practices and use of low carbon fuel	504000	TON/Y
IL-0133	LINCOLN LAND ENERGY CENTER	7/29/2022	Combined-Cycle Combustion Turbines	3647	mmBtu/hour	Inherently lower-polluting design, good combustion practices and operational energy efficiency	850	LB/MW-HR (GROSS)
AK-0088	LIQUEFACTION PLANT	7/7/2022	Four Combined Cycle Gas-Fired Turbines	384	MMBtu/hr	Good combustion practices and burning clean fuels (natural gas)	117.1	LB/MMBTU
MI-0451	MEC NORTH, LLC	6/23/2022	EUCTGHRSG (North Plant): A combined cycle natural gas fired combustion turbine generator with heat recovery steam generator	3064	MMBTU/H	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas)	2001019	T/YR
MI-0452	MEC SOUTH, LLC	6/23/2022	EUCTGHRSG (South Plant): A combined-cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	3064	MMBTU/H	Energy Efficiency Measures and the use of a low carbon fuel (pipeline quality natural gas)	2001019	T/YR
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	6/3/2022	Combined Cycle Gas Turbine w/ Duct Burners and HRSG	5081	mm BTU/h	Use of gaseous fuel (pipeline-quality natural gas), thermally efficient turbines, and good combustion practices.	875	LB/MW-H
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	6/7/2021	GE 7HA.02 Combustion Turbine and HRSG with Duct Firing	3622.1	MMBtu/hour	Low-emitting fuel	875	LB/MWH
MI-0447	LBWL--ERICKSON STATION	1/7/2021	EUCTGHRSG1	667	MMBTU/H	Low carbon fuel (pipeline quality natural gas), good combustion practices, and energy efficiency measures.	430349	T/YR
MI-0447	LBWL--ERICKSON STATION	1/7/2021	EUCTGHRSG2	667	MMBTU/H	Low carbon fuel (pipeline quality natural gas), good combustion practices, and energy efficiency measures.	430349	T/YR

TABLE D-10

NATURAL GAS-FIRED COMBINED CYCLE TURBINES >25 MW, PERMIT DATES 1/1/2014 THROUGH 11/12/2024

LISTINGS FOR NH_3

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
CT-0161	KILLINGLY ENERGY CENTER	6/30/2017	Natural Gas w/Duct Firing	2639	MMBtu/hr	Optimization of SCR	2	PPMVD @15% O2
CT-0161	KILLINGLY ENERGY CENTER	6/30/2017	Natural Gas w/o Duct Firing	2969	MMBtu/hr	Good Combustion, Optimization of SCR	2	PPMVD @15% O2
CT-0157	CPV TOWANTIC, LLC	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/12 months		2	PPMVD @15% O2
CT-0158	CPV TOWANTIC, LLC	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/yr		2	PPMVD @15% O2
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	1/30/2014	Combustion Turbine with Duct Burner	2449	MMBTU/H		2	PPMVD@15% O2
*IN-0365	MAPLE CREEK ENERGY LLC	6/19/2023	Combined Cycle Turbine CTGB	4200	MMBtu per hour		5	PPMVD
*IN-0365	MAPLE CREEK ENERGY LLC	6/19/2023	Combined Cycle Turbine CTGA	3800	MMBtu per hour		5	PPMVDC
PA-0334	RENOVO ENERGY CENTER LLC/RENOVO PLT	4/29/2021	COMBUSTION TURBINE w DUCT BURNER #2 (Natural Gas)	4546	MMBtu/Hr	SCR, oxidation catalyst	5	PPMVD
PA-0334	RENOVO ENERGY CENTER LLC/RENOVO PLT	4/29/2021	COMBUSTION TURBINE w DUCT BURNER #1 (Natural Gas)	4546	MMBtu/Hr	SCR, Catalytic Oxidizer	5	PPMVD
*PA-0319	RENAISSANCE ENERGY CENTER	8/27/2018	COMBUSTION TURBINE UNIT w/o DUCT BURNERS UNIT	2665.9	MMBtu/hr		5	PPMDV
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas with Duct Burner	4000	h/yr	USE OF NATURAL GAS A CLEAN BURNING FUEL	27.4	LB/H
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas without Duct Burner	8040	H/YR	USE OF NATURAL GAS A CLEAN BURNING FUEL	5	PPMVD@15%O2
MD-0045	MATTAWOMAN ENERGY CENTER	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES	286	MW	INITIAL STACK TEST USING EPA METHOD CTM-027 OR EQUIVALENT METHOD APPROVED BY MDE-ARMA	5	PPMVD @ 15% O2
MD-0046	KEYS ENERGY CENTER	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	235	MW	INITIAL STACK TEST USING EPA METHOD CTM-027 OR EQUIVALENT METHOD APPROVED BY MDE-ARMA	5	PPMVD @ 15% O2
*PA-0298	FUTURE POWER PA/GOOD SPRINGS NGCC FACIL	3/4/2014	Turbine, COMBINED CYCLE UNIT (Siemens 5000)	2267	MMBTU/H		72.5	TPY
TX-0660	FGE TEXAS POWER I AND FGE TEXAS POWER II	3/24/2014	Alstom Turbine	230.7	MW	AVO, good combustion practices	7	PPMVD

TABLE D-11
NATURAL-GAS FIRED SIMPLE CYCLE TURBINES, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024 LISTINGS FOR NO_X

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
CA-1238	PUENTE POWER	10/13/2016	Gas turbine	262	MW		2.5	PPMVD
NJ-0086	BAYONNNE ENERGY CENTER	8/26/2016	Simple Cycle Stationary Turbines firing Natural gas	2143980	MMBTU/YR	Selective Catalytic Reduction, water injection, use of natural gas a low NOx emitting fuel	2.5	PPMVD
MD-0043	PERRYMAN GENERATING STATION	7/1/2014	(2) 60-MW SIMPLE CYCLE COMBUSTION TURBINES, FIRING NATURAL GAS	120	MW	USE OF NATURAL GAS, WATER/STEAM INJECTION, AND A SELECTIVE CATAYTIC REDUCTION (SCR) SYSTEM	2.5	PPMVD
TN-0187	TENNESSEE VALLEY AUTHORITY - JOHNSONVILLE COMBUSTION TURBINE	8/31/2022	Ten Simple Cycle NG Turbines	465.8	MMBtu/hr	dry low-NOx burners selective catalytic reduction	5	PPMVD
ND-0030	LONESOME CREEK GENERATING STATION	9/16/2013	Natural Gas Fired Simple Cycle Turbines	412	MMBTU/H	SCR	5	PPMVD
ND-0029	PIONEER GENERATING STATION	5/14/2013	Natural gas-fired turbines	451	MMBTU/H	Water injection plus SCR	5	PPMVD
CO-0076	PUEBLO AIRPORT GENERATING STATION	12/11/2014	Turbines - two simple cycle gas	799.7	MMBTU/H each	SCR and dry low NOx burners	7.8	PPMVD
NY-0106	GREENIDGE STATION	9/7/2016	Turbine - natural gas	107	MW	Advanced low NOx burners, closed-coupled and staged over-fire air, Selective Non-Catalytic Reduction, and Selective Catalytic Reduction.	8.1	PPMVD
IL-0121	INVENERGY NELSON EXPANSION LLC	9/27/2016	Two Simple Cycle Combustion Turbines	190	MW	Dry low-NOx combustion technology	9.0	PPMVD
TX-0975	FREESTONE PEAKERS PLANT	6/13/2024	Simple Cycle Gas Turbines	221	MW	Dry low-NOx burners (DLNB) and good combustion practices.	9	PPMVD
AL-0329	COLBERT COMBUSTION TURBINE PLANT	9/21/2021	Three 229 MW Simple Cycle Combustion Turbines	229	MW		9	PPMVD
TX-0900	ECTOR COUNTY ENERGY CENTER	8/17/2020	Simple Cycle Turbines	0		Equipped with dry-low NOx burners with best management practices and good combustion practices. Minimize the duration of startup and shutdown events to less than 60 minutes per event. Limit MSS by 140 lb/hr maximum allowable emission rate for each turbine.	9.0	PPMVD
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	2201	MM BTU/hr	Pipeline quality natural gas & dry-low-NOX burners	9	PPMVD
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	2201	MM BTU/hr	Pipeline quality natural gas & dry-low-NOX burners	9	PPMVD
TX-0833	JACKSON COUNTY GENERATORS	1/26/2018	Combustion Turbines	920	MW	Dry low NOx burners	9	PPMVD
TX-0826	MUSTANG STATION	8/16/2017	Simple Cycle Turbine	162.8	MW	Dry low-NOx burners	9	PPMVD
WV-0026	WAVERLY FACILITY	1/23/2017	GE Model 7FA Turbine	1571	mmbtu/hr	Dry Low-NOx Combustion System (DLNB), Water Injection	9	PPMVD
VA-0326	DOSWELL ENERGY CENTER	10/4/2016	Two (2) GE 7FA simple cycle combustion turbines	1961	MMBTU/HR	Low NOx Burners/Combustion Technology	9	PPMVD

TABLE D-12

NATURAL-GAS FIRED SIMPLE CYCLE TURBINES, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024

LISTINGS FOR CO

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
VA-0326	DOSWELL ENERGY CENTER	10/4/2016	Two (2) GE 7FA simple cycle combustion turbines	1961	MMBTU/HR	Pipeline Quality Natural Gas	3.2	PPMV
FL-0354	LAUDERDALE PLANT	8/25/2015	Five 200-MW combustion turbines	2100	MMBtu/hr (approx)	Good combustion minimizes CO formation	4	PPMV
TX-0694	INDECK WHARTON ENERGY CENTER	2/2/2015	(3) combustion turbines	220	MW	DLN combustors	4	PPMV
TN-0187	TENNESSEE VALLEY AUTHORITY - JOHNSONVILLE COMBUSTION TURBINE	8/31/2022	Ten Simple Cycle NG Turbines	465.8	MMBtu/hr	oxidation catalyst	5	PPMV
NJ-0086	BAYONNNE ENERGY CENTER	8/26/2016	Simple Cycle Stationary Turbines firing Natural gas	2143980	MMBTU/YR	Add-on control is CO Oxidation Catalyst, and use of natural gas as fuel for pollution prevention	5	PPMV
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas	6	PPMV
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas	6	PPMV
ND-0030	LONESOME CREEK GENERATING STATION	9/16/2013	Natural Gas Fired Simple Cycle Turbines	412	MMBTU/H	Oxidation Catalyst	6	PPMV
ND-0029	PIONEER GENERATING STATION	5/14/2013	Natural gas-fired turbines	451	MMBTU/H	Catalytic oxidation system	6	PPMV
TX-0701	ECTOR COUNTY ENERGY CENTER	5/13/2013	Simple Cycle Combustion Turbines	180	MW	Good combustion practices	6	PPMV
AL-0329	COLBERT COMBUSTION TURBINE PLANT	9/21/2021	Three 229 MW Simple Cycle Combustion Turbines	229	MW		9	PPMV
WV-0028	WAVERLY POWER PLANT	3/13/2018	GE 7FA.004 Turbine	167.8	MW	Combustion Controls	9	PPMV
TX-0833	JACKSON COUNTY GENERATORS	1/26/2018	Combustion Turbines	920	MW	Dry low NOx burners	9	PPMV
WV-0026	WAVERLY FACILITY	1/23/2017	GE Model 7FA Turbine	1571	mmbtu/hr	Good Combustion Practices	9	PPMV
TX-0794	HILL COUNTY GENERATING FACILITY	4/7/2016	Simple cycle turbine	171	MW	Premixing of fuel and air enhances combustion efficiency and minimizes emissions.	9	PPMV
TX-0788	NECHES STATION	3/24/2016	Large Combustion Turbines >25 MW	232	MW	good combustion practices	9	PPMV
TX-0777	UNION VALLEY ENERGY CENTER	12/9/2015	Simple Cycle Turbine	183	MW	dry low NOx burners and good combustion practices	9	PPMV
TX-0769	VAN ALSTYNE ENERGY CENTER (VAEC)	10/27/2015	Simple Cycle Turbine	183	MW	DLN burners and good combustion practices	9	PPMV
TX-0764	NACOGDOCHES POWER ELECTRIC GENERATING PLANT	10/14/2015	Natural Gas Simple Cycle Turbine (>25 MW)	232	MW	dry low NOx burners, good combustion practices, limited operation	9	PPMV
TX-0768	SHAWNEE ENERGY CENTER	10/9/2015	Simple cycle turbines greater than 25 megawatts (MW)	230	MW	dry low NOx burners and lmiited operation, clean fuel	9	PPMV
TX-0733	ANTELOPE ELK ENERGY CENTER	5/12/2015	Simple Cycle Turbine & Generator	202	MW	Good combustion practices; limited operating hours	9	PPMV
TX-0734	CLEAR SPRINGS ENERGY CENTER (CSEC)	5/8/2015	Simple Cycle Turbine	183	MW	DLN burners and good combustion practices	9	PPMV

TABLE D-13

NATURAL-GAS FIRED SIMPLE CYCLE TURBINES, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024 LISTINGS FOR VOC

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0768	SHAWNEE ENERGY CENTER	10/9/2015	Simple cycle turbines greater than 25 megawatts (MW)	230	MW	Pipeline quality natural gas; limited hours; good combustion practices.	1.4	PPMV
TX-0696	ROAN'S PRAIRIE GENERATING STATION	9/22/2014	(2) simple cycle turbines	600	MW	good combustion	1.4	PPMV
KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	3/18/2013	GE 7FA Simple Cycle Combustion Turbine	1780	MMBTU/HR	will utilize efficient combustion/design technology	1.4	PPMV
TX-0788	NECHES STATION	3/24/2016	Large Combustion Turbines >25 MW	232	MW	good combustion practices	2.0	PPMVD
TX-0975	FREESTONE PEAKERS PLANT	6/13/2024	Simple Cycle Gas Turbines	221	MW	Good combustion practices	2	PPMVD
TX-0833	JACKSON COUNTY GENERATORS	1/26/2018	Combustion Turbines	920	MW	Good combustion practices	2	PPMVD
CA-1238	PUENTE POWER	10/13/2016	Gas turbine	262	MW		2	PPMV
NJ-0086	BAYONNNE ENERGY CENTER	8/26/2016	Simple Cycle Stationary Turbines firing Natural gas	2143980	MMBTU/YR	Add-on VOC control is Oxidation Catalyst, and use of natural gas as fuel for pollution prevention	2	PPMV
TX-0764	NACOGDOCHES POWER ELECTRIC GENERATING PLANT	10/14/2015	Natural Gas Simple Cycle Turbine (>25 MW)	232	MW	Pipeline quality natural gas; limited hours; good combustion practices.	2	PPMV
TX-0733	ANTELOPE ELK ENERGY CENTER	5/12/2015	Simple Cycle Turbine & Generator	202	MW	Good combustion practices	2	PPMV
KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	3/18/2013	GE LM6000PC SPRINT Simple cycle combustion turbine	405.3	MMBTU/hr	utilize efficient combustion/design technology	11.2	PPMV
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG01 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas		
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG02 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas		
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG01 SUSD - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0019]	2201	MM BTU/hR	Good combustion practices & use of pipeline quality natural gas		
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG02 SUSD - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0020]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas		
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas		
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas		
TX-0833	JACKSON COUNTY GENERATORS	1/26/2018	Combustion Turbines MSS	0		Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices.		
IN-0261	VERMILLION GENERATING STATION	2/28/2017	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	80	MW	GOOD COMBUSTION PRACTICES		
TX-0794	HILL COUNTY GENERATING FACILITY	4/7/2016	Simple cycle turbine	171	MW	Premixing of fuel and air enhances combustion efficiency and minimizes emissions.		

TABLE D-14

NATURAL-GAS FIRED SIMPLE CYCLE TURBINES, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024 LISTINGS FOR TPM

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0764	NACOGDOCHES POWER ELECTRIC GENERATING PLANT	10/14/2015	Natural Gas Simple Cycle Turbine (>25 MW)	232	MW	Pipeline quality natural gas; limited hours; good combustion practices.	0.006	lb/MMBtu
TN-0187	TENNESSEE VALLEY AUTHORITY - JOHNSONVILLE COMBUSTION TURBINE	8/31/2022	Ten Simple Cycle NG Turbines	465.8	MMBtu/hr	good combustion design and operating practices and the use of low sulfur fuel	0.008	lb/MMBtu
KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	3/18/2013	GE 7FA Simple Cycle Combustion Turbine	1780	MMBTU/HR	will fire only pipeline quality natural gas	0.010	lb/MMBtu
KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	3/18/2013	GE LM6000PC SPRINT Simple cycle combustion turbine	405.3	MMBTU/hr	fire only pipeline quality natural gas	0.015	lb/MMBtu
TX-0975	FREESTONE PEAKERS PLANT	6/13/2024	Simple Cycle Gas Turbines	221	MW	Good combustion practices		
TX-0833	JACKSON COUNTY GENERATORS	1/26/2018	Combustion Turbines MSS	0		Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices.		
FL-0355	FORT MYERS PLANT	9/10/2015	Combustion Turbines	2262.4	MMBtu/hr gas	Use of clean fuels, and annual VE test		
FL-0354	LAUDERDALE PLANT	8/25/2015	Five 200-MW combustion turbines	2100	MMBtu/hr (approx)	Clean fuel prevents PM formation		
TX-0733	ANTELOPE ELK ENERGY CENTER	5/12/2015	Simple Cycle Turbine & Generator	202	MW	Pipeline quality natural gas; limited hours; good combustion practices.		

TABLE D-15
NATURAL-GAS FIRED SIMPLE CYCLE TURBINES, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024 LISTINGS FOR TPM_{10}

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG01 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	2201	MM BTU/hr	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG02 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	2201	MM BTU/hr	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG01 SUSD - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0019]	2201	MM BTU/hR	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG02 SUSD - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0020]	2201	MM BTU/hr	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	2201	MM BTU/hr	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	2201	MM BTU/hr	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
IL-0121	INVENERGY NELSON EXPANSION LLC	9/27/2016	Two Simple Cycle Combustion Turbines	190	MW	turbine design and good combustion practices	0.005	lb/MMBtu
TX-0777	UNION VALLEY ENERGY CENTER	12/9/2015	Simple Cycle Turbine	183	MW	pipeline quality natural gas, good combustion practices	0.005	lb/MMBtu
TX-0769	VAN ALSTYNE ENERGY CENTER (VAEC)	10/27/2015	Simple Cycle Turbine	183	MW	Pipeline Quality Natural Gas	0.005	lb/MMBtu
TX-0764	NACOGDOCHES POWER ELECTRIC GENERATING PLANT	10/14/2015	Natural Gas Simple Cycle Turbine (>25 MW)	232	MW	Pipeline quality natural gas; limited hours; good combustion practices.	0.006	lb/MMBtu
TX-0788	NECHES STATION	3/24/2016	Large Combustion Turbines >25 MW	232	MW	good combustion practices, low sulfur fuel	0.007	lb/MMBtu
ND-0028	R.M. HESKETT STATION	2/22/2013	Combustion Turbine	986	MMBTU/H	Good Combustion Practices	0.007	lb/MMBtu
NJ-0086	BAYONNNE ENERGY CENTER	8/26/2016	Simple Cycle Stationary Turbines firing Natural gas	643	MMBTU/hr	Use of Natural gas a clean burning fuel	0.008	lb/MMBtu
MD-0043	PERRYMAN GENERATING STATION	7/1/2014	(2) 60-MW SIMPLE CYCLE COMBUSTION TURBINES, FIRING NATURAL GAS	120	MW	GOOD COMBUSTION PRACTICES AND USE OF NATURAL GAS	0.008	lb/MMBtu
AL-0329	COLBERT COMBUSTION TURBINE PLANT	9/21/2021	Three 229 MW Simple Cycle Combustion Turbines	229	MW		0.008	lb/MMBtu
TX-0794	HILL COUNTY GENERATING FACILITY	4/7/2016	Simple cycle turbine	171	MW	Premixing of fuel and air enhances combustion efficiency and minimizes emissions.	0.010	lb/MMBtu
KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	3/18/2013	GE 7FA Simple Cycle Combustion Turbine	1780	MMBTU/HR	will fire only pipeline quality natural gas	0.010	lb/MMBtu
CO-0075	PUEBLO AIRPORT GENERATING STATION	5/30/2014	Turbine - simple cycle gas	375	MMBTU/H	Firing of pipeline quality natural gas as defined in 40 CFR Part 72. Specifically, the owner or the operator shall demonstrate that the natural gas burned has total sulfur content less than 0.5 grains/100 SCF.	0.013	lb/MMBtu
KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	3/18/2013	GE LM6000PC SPRINT Simple cycle combustion turbine	405.3	MMBTU/hr	fire only pipeline quality natural gas	0.015	lb/MMBtu
TX-0768	SHAWNEE ENERGY CENTER	10/9/2015	Simple cycle turbines greater than 25 megawatts (MW)	230	MW	Pipeline quality natural gas; limited hours; good combustion practices.	0.043	lb/MMBtu
TX-0975	FREESTONE PEAKERS PLANT	6/13/2024	Simple Cycle Gas Turbines	221	MW	Good combustion practices		

TABLE D-16
NATURAL-GAS FIRED SIMPLE CYCLE TURBINES, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024 LISTINGS FOR $TPM_{2.5}$

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
IN-0264	MONTPELIER GENERATING STATION	1/6/2017	PRATT & TWIN-PAC SIMPLE CYCLE TURBINES	270.9	MMBTU/H	NATURAL GAS PRIMARY FUEL; GOOD COMBUSTION PRACTICES	0.007	lb/MMBtu
AL-0329	COLBERT COMBUSTION TURBINE PLANT	9/21/2021	Three 229 MW Simple Cycle Combustion Turbines	229	MW		0.008	lb/MMBtu
CO-0075	PUEBLO AIRPORT GENERATING STATION	5/30/2014	Turbine - simple cycle gas	375	MMBTU/H	Firing of pipeline quality natural gas as defined in 40 CFR Part 72. Specifically, the owner or the operator shall demonstrate that the natural gas burned has total sulfur content less than 0.5 grains/100 SCF.	0.013	lb/MMBtu
IN-0261	VERMILLION GENERATING STATION	2/28/2017	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	80	MW	GOOD COMBUSTION PRACTICES	0.007	lb/MMBtu
NJ-0086	BAYONNNE ENERGY CENTER	8/26/2016	Simple Cycle Stationary Turbines firing Natural gas	643	MMBTU/HR	Use of natural gas a clean burning fuel	0.008	lb/MMBtu
ND-0030	LONESOME CREEK GENERATING STATION	9/16/2013	Natural Gas Fired Simple Cycle Turbines	412	MMBTU/H		0.012	lb/MMBtu
ND-0029	PIONEER GENERATING STATION	5/14/2013	Natural gas-fired turbines	451	MMBTU/H		0.012	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG01 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	2201	MM BTU/hr	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG02 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	2201	MM BTU/hr	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG01 SUSD - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0019]	2201	MM BTU/hR	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG02 SUSD - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0020]	2201	MM BTU/hr	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	2201	MM BTU/hr	Good combustion practices & use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	2201	MM BTU/hr	Good combustion practices & use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
ND-0028	R.M. HESKETT STATION	2/22/2013	Combustion Turbine	986	MMBTU/H	Good combustion practices.	0.007	lb/MMBtu
TX-0769	VAN ALSTYNE ENERGY CENTER (VAEC)	10/27/2015	Simple Cycle Turbine	183	MW	Pipeline Quality Natural Gas	0.005	lb/MMBtu
VA-0326	DOSWELL ENERGY CENTER	10/4/2016	Two (2) GE 7FA simple cycle combustion turbines	1961	MMBTU/HR	Good combustion, operation and maintenance practices and use of pipeline quality natural gas	0.006	lb/MMBtu
TX-0764	NACOGDOCHES POWER ELECTRIC GENERATING PLANT	10/14/2015	Natural Gas Simple Cycle Turbine (>25 MW)	232	MW	Pipeline quality natural gas; limited hours; good combustion practices.	0.006	lb/MMBtu
TX-0788	NECHES STATION	3/24/2016	Large Combustion Turbines >25 MW	232	MW	good combustion practices, low sulfur fuel	0.007	lb/MMBtu
TX-0794	HILL COUNTY GENERATING FACILITY	4/7/2016	Simple cycle turbine	171	MW	Premixing of fuel and air enhances combustion efficiency and minimizes emissions.	0.010	lb/MMBtu
TX-0777	UNION VALLEY ENERGY CENTER	12/9/2015	Simple Cycle Turbine	183	MW	pipeline quality natural gas, good combustion practices	0.009	lb/MMBtu
WV-0026	WAVERLY FACILITY	1/23/2017	GE Model 7FA Turbine	1571	mmbtu/hr	Inlet Air Filtration, Use of Natural Gas, Ultra-Low Sulfur Diesel	0.010	lb/MMBtu

TABLE D-17
NATURAL-GAS FIRED SIMPLE CYCLE TURBINES, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024 LISTINGS FOR SO_2

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
IN-0261	VERMILLION GENERATING STATION	2/28/2017	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	80	MW	GOOD COMBUSTION PRACTICES	0.6	LB/H
IN-0261	VERMILLION GENERATING STATION	2/28/2017	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	80	MW	GOOD COMBUSTION PRACTICES	0.6	LB/H
NJ-0086	BAYONNNE ENERGY CENTER	8/26/2016	Simple Cycle Stationary Turbines firing Natural gas	2143980	MMBTU/YR	Use of natural gas a low sulfur fuel	0.77	LB/H
NJ-0086	BAYONNNE ENERGY CENTER	8/26/2016	Simple Cycle Stationary Turbines firing Ultra Low Sulfur Distillate Oil	720	H/YR	Use of ULSD a very low sulfur fuel	0.8	LB/H
KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	3/18/2013	GE LM6000PC SPRINT Simple cycle combustion turbine	405.3	MMBTU/hr	fire only pipeline quality natural gas	10.1	LB/H
KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	3/18/2013	GE 7FA Simple Cycle Combustion Turbine	1780	MMBTU/HR	fire only pipeline quality natural gas	44.3	LB/H
FL-0355	FORT MYERS PLANT	9/10/2015	Combustion Turbines	2262.4	MMBtu/hr gas	Use of clean fuels	56.3	LB/H
TX-0788	NECHES STATION	3/24/2016	Large Combustion Turbines >25 MW	232	MW	good combustion practices, low sulfur fuel		
FL-0354	LAUDERDALE PLANT	8/25/2015	Five 200-MW combustion turbines	2100	MMBtu/hr (approx)	Limitation on S in fuel		
TX-0695	ECTOR COUNTY ENERGY CENTER	8/1/2014	(2) combustion turbines	180	MW			
TX-0701	ECTOR COUNTY ENERGY CENTER	5/13/2013	Simple Cycle Combustion Turbines	180	MW	Firing pipeline quality natural gas and good combustion practices.		

TABLE D-18

NATURAL-GAS FIRED SIMPLE CYCLE TURBINES, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024 LISTINGS FOR SULFURIC ACID

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0788	NECHES STATION	3/24/2016	Large Combustion Turbines >25 MW	232	MW	good combustion practices, low sulfur fuel	1	GR/100 SCF
FL-0354	LAUDERDALE PLANT	8/25/2015	Five 200-MW combustion turbines	2100	MMBtu/hr (approx)	Limitation on S in fuel	2	GRS/100 SCF
KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	3/18/2013	GE LM6000PC SPRINT Simple cycle combustion turbine	405.3	MMBTU/hr	fire only pipeline quality natural gas	2	GRS/100 SCF
KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	3/18/2013	GE 7FA Simple Cycle Combustion Turbine	1780	MMBTU/HR	dry low NOx burners and fire only pipeline natural gas	2	GRS/100 SCF

TABLE D-19
NATURAL-GAS FIRED SIMPLE CYCLE TURBINES, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024 LISTINGS FOR CO_2e AND CO_2

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0975	FREESTONE PEAKERS PLANT	6/13/2024	Simple Cycle Gas Turbines	221	MW	Good combustion practices	800	LB/MWHR
IN-0264	MONTPELIER GENERATING STATION	1/6/2017	PRATT & TWIN-PAC SIMPLE CYCLE TURBINES	270.9	MMBTU/H	NATURAL GAS AS PRIMARY FUEL; GOOD COMBUSTION PRACTICES	1121	LB/MWHR
TN-0187	TENNESSEE VALLEY AUTHORITY - JOHNSONVILLE COMBUSTION TURBINE	8/31/2022	Ten Simple Cycle NG Turbines	465.8	MMBtu/hr	Efficient turbine operation and good combustion practices	1140	LB/MWHR
AL-0329	COLBERT COMBUSTION TURBINE PLANT	9/21/2021	Three 229 MW Simple Cycle Combustion Turbines	229	MW		1140	LB/MWHR
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	2201	MM BTU/hr	Facility-wide energy efficiency measures, such as improved combustion measures, and use of pipeline quality natural gas.	1140	LB/MWHR
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	2201	MM BTU/hr	Facility-wide energy efficiency measures, such as improved combustion measures, and use of pipeline quality natural gas.	1140	LB/MWHR
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG01 SUSD - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0019]	2201	MM BTU/hR	Facility-wide energy efficiency measures, such as improved combustion measures, and use of pipeline quality natural gas.	1140	LB/MWHR
LA-0327	WASHINGTON PARISH ENERGY CENTER	5/23/2018	CTG02 SUSD - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0020]	2201	MM BTU/hr	Facility-wide energy efficiency measures, such as improved combustion measures, and use of pipeline quality natural gas.	1140	LB/MWHR
TX-0826	MUSTANG STATION	8/16/2017	Simple Cycle Turbine	162.8	MW	Pipeline quality natural gas and good combustion practices	1140	LB/MWHR
NY-0106	GREENIDGE STATION	9/7/2016	Turbine - natural gas	107	MW		1236.615	LB/MWHR
TX-0757	INDECK WHARTON ENERGY CENTER	5/12/2014	Simple Cycle Combustion Turbine, GE 7FA.05	0			1276	LB/MWHR
TX-0753	GUADALUPE GENERATING STATION	12/2/2014	Simple Cycle Combustion Turbine Generator	10673	Btu/kWh		1293.3	LB/MWHR
WV-0028	WAVERLY POWER PLANT	3/13/2018	GE 7FA.004 Turbine	167.8	MW	Use of natural gas & use of GE 7FA.004	1300	LB/MWHR
WV-0026	WAVERLY FACILITY	1/23/2017	GE Model 7FA Turbine	1571	mmbtu/hr	Use of Natural Gas, Selection of GE7FA	1300	LB/MWHR
NY-0113	EDGEWOOD ENERGY LLC	7/9/2013	Turbines - NG	0			1300	LB/MWHR
TX-0735	ANTELOPE ELK ENERGY CENTER	5/20/2015	Simple Cycle Turbine & Generator	202	MW	Energy efficiency, good design & combustion practices	1304	LB/MWHR
TX-0824	JACKSON COUNTY GENERATING FACILITY	6/30/2017	Simple Cycle Turbines	920	MW	energy efficiency designs, practices, and procedures, CT inlet air cooling, periodic CT burner maintenance and tuning, reduction in heat loss, i.e., insulation of the CT, instrumentation and controls	1316	LB/MWHR
TX-0757	INDECK WHARTON ENERGY CENTER	5/12/2014	Simple Cycle Combustion Turbine, SGT-5000F(5)	0			1337	LB/MWHR
TX-0788	NECHES STATION	3/24/2016	Large Combustion Turbines >25 MW	232	MW	good combustion practices	1341	LB/MWHR
FL-0354	LAUDERDALE PLANT	8/25/2015	Five 200-MW combustion turbines	2100	MMBtu/hr (approx)	Use of natural gas with restricted use of ULSD as backup fuel	1372	LB/MWHR
FL-0355	FORT MYERS PLANT	9/10/2015	Combustion Turbines	2262.4	MMBtu/hr gas	Use of low-emitting fuel and efficient turbine	1374	LB/MWHR

TABLE D-20

BOILERS (<100 MMBTU/HR), PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024

LISTINGS FOR NO_X

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
WV-0029	HARRISON COUNTY POWER PLANT	3/27/2018	Auxiliary Boiler	77.8	mmBtu/hr	LNB, FGR, Good Combustion Practices	0.0011	LB/MMBTU
PA-0311	MOXIE FREEDOM GENERATION PLANT	9/1/2015	Auxilary Boiler	55.4	MMBtu/hr		0.006	LB/MMBTU
NY-0103	CRICKET VALLEY ENERGY CENTER	2/3/2016	Auxiliary boiler	60	MMBTU/H	flue gas recirculation with low NOx burners	0.0085	LB/MMBTU
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	6/15/2015	Auxilary Boiler	62.04	MCF/hr	Good combustion practices, Ultra-Low NOx burners, FGR	0.0086	LB/MMBTU
IL-0133	LINCOLN LAND ENERGY CENTER	7/29/2022	Auxiliary Boiler	80	mmBtu/hour	Ultra low-NOx burners and flue gas recirculation, air preheater, automated combustion management system, with an oxygen trim system and an automated water blowdown system.	0.01	LB/MMBTU
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	6/3/2022	Auxiliary Boiler	80	mm BTU/h	Ultra-low NOx burners and good combustion practices.	0.01	LB/MMBTU
IL-0130	JACKSON ENERGY CENTER	12/31/2018	Auxiliary Boiler	96	mmBtu/hr	Ultra low-NOx burners and flue gas recirculation air preheater, automated combustion management systems, automated water blowdown, good combustion practices	0.01	LB/MMBTU
MD-0045	MATTAWOMAN ENERGY CENTER	11/13/2015	AUXILIARY BOILER	42	MMBTU/H	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS, ULTRA LOW-NOX BURNERS, AND GOOD COMBUSTION PRACTICES	0.01	LB/MMBTU
MD-0046	KEYS ENERGY CENTER	10/31/2014	AUXILIARY BOILER	93	MMBTU/H	EFFICIENT BOILER DESIGN WITH ULTRA LOW NOX BURNER, EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS, AND APPLICATION OF GOOD COMBUSTION PRACTICES	0.01	LB/MMBTU
MD-0042	WILDCAT POINT GENERATION FACILITY	4/8/2014	AUXILLARY BOILER	45	MMBTU/H	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.01	LB/MMBTU
WI-0283	AFE, INC. ""LCM PLANT	4/24/2018	B01-B12, Boilers	28	mmBTU/hr	Ultra-low NOx Burners, Flue Gas Recirculation and Good Combustion Practices	0.0105	LB/MMBTU
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	4/24/2018	B13-B24 & B25-B36 Natural Gas-Fired Boilers	28	mmBTU	Ultra-Low NOx Burners, Flue Gas Recirculation, and Good Combustion Practices.	0.0105	LB/MMBTU
OH-0387	INTEL OHIO SITE	9/20/2022	29.4 MMBtu/hr Natural Gas-Fired Boilers: B001 through B028	29.4	MMBTU/H	Ultra-low NOX burners, good combustion practices, and the use of natural gas	0.011	LB/MMBTU
AL-0328	PLANT BARRY	11/9/2020	90.5 MMBtu/hr Aux Boiler	90.5	MMBtu/hr		0.011	LB/MMBTU
IL-0129	CPV THREE RIVERS ENERGY CENTER	7/30/2018	Auxiliary Boiler	96	mmBtu/hr	Ultra-low NOx burners and flue gas recirculation, air preheater, automated combustion management system with O2 trim system and automated water blowdown, and good combustion practices.	0.011	LB/MMBTU
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	11/7/2017	Auxiliary Boiler (B001)	26.8	MMBTU/H	Flue gas recirculation and low NOX burner	0.011	LB/MMBTU
PA-0310	CPV FAIRVIEW ENERGY CENTER	9/2/2016	Auxilary boiler	92.4	MMBtu/hr	Ultra low NOx burners, FGR, good combustion practices	0.011	LB/MMBTU

TABLE D-21
BOILERS (<100 MMBTU/HR), PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024
LISTINGS FOR CO

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	1/30/2014	Auxiliary Boiler	80	MMBTU/H	Oxidation catalyst	0.0035	LB/MMBTU
OK-0168	SEMINOLE GNRTNG STA	5/5/2015	NATURAL GAS-FIRED BOILER (<100MMBTUH)	40.4	MMBTUH	NO CONTROLS FEASIBLE;GOOD COMBUSTION PRACTICES	0.0075	LB/MMBTU
IA-0107	MARSHALLTOWN GENERATING STATION	4/14/2014	auxiliary boiler	60.1	mmBtu/hr	CO catalytic oxidizer	0.0164	LB/MMBTU
WI-0283	AFE, INC. LCM PLANT	4/24/2018	B01-B12, Boilers	28	mmBTU/hr	Ultra-low NOx Burners, Flue Gas Recirculation and Good Combustion Practices	0.018571429	LB/MMBTU
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	4/24/2018	B13-B24 & B25-B36 Natural Gas-Fired Boilers	28	mmBTU	Ultra-Low NOx Burners, Flue Gas Recirculation, and Good Combustion Practices.	0.018571429	LB/MMBTU
MD-0041	CPV ST. CHARLES	4/23/2014	AUXILLARY BOILER	93	MMBTU/H	GOOD COMBUSTION PRACTICES	0.02	LB/MMBTU
OH-0377	HARRISON POWER	4/19/2018	Auxiliary Boiler (B002)	80	MMBTU/H	Good combustion practices	0.031	LB/MMBTU
MD-0042	WILDCAT POINT GENERATION FACILITY	4/8/2014	AUXILLARY BOILER	45	MMBTU/H	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.036	LB/MMBTU
MI-0406	RENAISSANCE POWER LLC	11/1/2013	FG-AUXBOILER1-2; Two (2) natural gas-fired auxiliary boilers.	40	MMBTU/H	Good combustion practices	0.036	LB/MMBTU
IN-0317	RIVERVIEW ENERGY CORPORATION	6/11/2019	Boiler EU-6000	68.5	MMBTU/H	Unit shall burn only natural gas and process fuel gas. Unit shall use good combustion practices including an oxygen trim system.	0.0365	LB/MMBTU
MI-0454	LBWL-ERICKSON STATION	12/20/2022	EUAUXBOILER--natural-gas fired auxiliary boiler, rated at less than or equal to 99 MMBTU/H	50	MMBTU/H	Good combustion practices.	0.036994213	LB/MMBTU
MI-0447	LBWL--ERICKSON STATION	1/7/2021	EUAUXBOILER--nat gas fired auxiliary boiler	50	MMBTU/H	Good combustion practices.	0.036994213	LB/MMBTU
MI-0441	LBWL--ERICKSON STATION	12/21/2018	EUAUXBOILER--natural gas fired auxiliary boiler rated at <= 99MMBTU/H	99	MMBTU/H	Good combustion practices	0.036994213	LB/MMBTU
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	40	MMBTU/H	Good combustion practice to ensure complete combustion.	0.036994213	LB/MMBTU
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	95.7	MMBTU/H	Good combustion practice to ensure complete combustion.	0.036994213	LB/MMBTU
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	13.2	MMBTU/H	Good combustion practice to ensure complete combustion.	0.036994213	LB/MMBTU
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	6/18/2015	Commercial/Institutional Size Boilers (<100 MMBtu) "" natural gas	73.3	MMBTU/H	Good combustion practices	0.036994213	LB/MMBTU
*IN-0365	MAPLE CREEK ENERGY LLC	6/19/2023	Auxiliary Boiler	96	MMBtu per hour	CO emissions shall be controlled through the use of good combustion practices.	0.037	LB/MMBTU

TABLE D-22

BOILERS (<100 MMBTU/HR), PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024

LISTINGS FOR VOC

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
IL-0133	LINCOLN LAND ENERGY CENTER	7/29/2022	Auxiliary Boiler	80	mmBtu/hour	Good burner design and good combustion practices	1.50E-03	LB/MMBTU
NY-0103	CRICKET VALLEY ENERGY CENTER	2/3/2016	Auxiliary boiler	60	MMBTU/H	good combustion practice	1.50E-03	LB/MMBTU
WY-0075	CHEYENNE PRAIRIE GENERATING STATION	7/16/2014	Auxiliary Boiler	25.06	MMBtu/h	good combustion practices	1.70E-03	LB/MMBTU
MD-0041	CPV ST. CHARLES	4/23/2014	AUXILLARY BOILER	93	MMBTU/H	EXCLUSIVE USE OF NATURAL GAS, AND GOOD COMBUSTION PRACTICES	2.00E-03	LB/MMBTU
MD-0046	KEYS ENERGY CENTER	10/31/2014	AUXILIARY BOILER	93	MMBTU/H	EFFICIENT BOILER DESIGN, EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS, THE USE OF ULTRA-LOW NOX BURNERS, AND GOOD COMBUSTION PRACTICES	2.00E-03	LB/MMBTU
AR-0171	NUCOR STEEL ARKANSAS	2/14/2019	SN-142 Vacuum Degasser Boiler	50.4	MMBTU/hr	Good combustion practices	2.60E-03	LB/MMBTU
MD-0045	MATTAWOMAN ENERGY CENTER	11/13/2015	AUXILIARY BOILER	42	MMBTU/H	EXCLUSIVE USE OF NATURAL GAS, AND GOOD COMBUSTION PRACTICES	3.00E-03	LB/MMBTU
OH-0377	HARRISON POWER	4/19/2018	Auxiliary Boiler (B002)	80	MMBTU/H	Good combustion practices	3.10E-03	LB/MMBTU
MD-0042	WILDCAT POINT GENERATION FACILITY	4/8/2014	AUXILLARY BOILER	45	MMBTU/H	THE EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS, LIMITED HOURS OF OPERATION, AND GOOD COMBUSTION PRACTICES	3.30E-03	LB/MMBTU
OH-0377	HARRISON POWER	4/19/2018	Auxiliary Boiler (B001)	44.55	MMBTU/H	Good combustion practices	3.60E-03	LB/MMBTU
WI-0283	AFE, INC. ""LCM PLANT	4/24/2018	B01-B12, Boilers	28	mmBTU/hr	Ultra-low NOx Burners, Flue Gas Recirculation and Good Combustion Practices	3.60E-03	LB/MMBTU
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	4/24/2018	B13-B24 & B25-B36 Natural Gas-Fired Boilers	28	mmBTU	Ultra-Low NOx Burners, Flue Gas Recirculation, and Good Combustion Practices.	3.60E-03	LB/MMBTU
AL-0328	PLANT BARRY	11/9/2020	90.5 MMBtu/hr Aux Boiler	90.5	MMBtu/hr		4.00E-03	LB/MMBTU
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	6/29/2018	EUAUXBOILER (North Plant): Auxiliary Boilder	61.5	MMBTU/H	Good combustion practices.	4.00E-03	LB/MMBTU
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	6/29/2018	EUAUXBOILER (South Plant): Auxiliary Boiler	61.5	MMBTU/h	Good combustion practices.	4.00E-03	LB/MMBTU
MI-0451	MEC NORTH, LLC	6/23/2022	EUAUXBOILER (North Plant): Auxiliary Boiler	61.5	MMBTU/H	Good combustion practices	4.00E-03	LB/MMBTU
MI-0452	MEC SOUTH, LLC	6/23/2022	EUAUXBOILER (South Plant): Auxiliary Boiler	61.5	MMBTU/H	Good combustion practices	4.00E-03	LB/MMBTU
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	6/15/2015	Auxilary Boiler	62.04	MCF/hr	Good combustion practices and FGR	4.00E-03	LB/MMBTU
IA-0107	MARSHALLTOWN GENERATING STATION	4/14/2014	auxiliary boiler	60.1	mmBtu/hr		5.00E-03	LB/MMBTU
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	1/30/2014	Auxiliary Boiler	80	MMBTU/H	oxidation catalyst	5.00E-03	LB/MMBTU
MI-0406	RENAISSANCE POWER LLC	11/1/2013	FG-AUXBOILER1-2; Two (2) natural gas-fired auxiliary boilers.	40	MMBTU/H	Good combustion practices.	5.00E-03	LB/MMBTU

TABLE D-23

BOILERS (<100 MMBTU/HR), PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024

LISTINGS FOR TPM

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
IN-0361	C-PLANT (SPECIALTY SOYBEAN EXTRACTION)	5/12/2023	SPC Boiler #1 PS37 & SPC Boiler #2 PS38	73.6	MMBtu/hr (each)	Good Combustion Practices	0.001862745	LB/MMBTU
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	8/21/2019	FGAUXBOILER	80	MMBTU/H	Low sulfur fuel (natural gas) and good combustion practices (efficient combustion).	0.001862745	LB/MMBTU
IL-0133	LINCOLN LAND ENERGY CENTER	7/29/2022	Auxiliary Boiler	80	mmBtu/hour	Good combustion practices.	0.0019	LB/MMBTU
IA-0117	SHELL ROCK SOY PROCESSING	3/17/2021	Natural Gas Boiler A	82	MMBtu/hr	Low NOx Burner and Flue Gas Recirculation	0.003170732	LB/MMBTU
IA-0117	SHELL ROCK SOY PROCESSING	3/17/2021	Natural Gas Boiler B	82	MMBtu/hr	Low NOx Burner and Flue Gas Recirculation	0.003170732	LB/MMBTU
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	7/14/2015	Auxiliary boiler	18.6	MMBTU/HR		0.005	LB/MMBTU
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	6/15/2015	Auxilary Boiler	62.04	MCF/hr	Good combustion practices and low sulfur fuels	0.005	LB/MMBTU
IN-0202	IPL EAGLE VALLEY GENERATING STATION	10/11/2013	AUXILLARY BOILER EU-3	79.3	MMBTU/HOUR	Good combustion practices	0.005	LB/MMBTU
OH-0377	HARRISON POWER	4/19/2018	Auxiliary Boiler (B002)	80	MMBTU/H	Pipeline quality natural gas	0.006	LB/MMBTU
PA-0311	MOXIE FREEDOM GENERATION PLANT	9/1/2015	Auxilary Boiler	55.4	MMBtu/hr		0.007	LB/MMBTU
AK-0083	KENAI NITROGEN OPERATIONS	1/6/2015	Five (5) Waste Heat Boilers	50	MMBTU/H		0.0074	LB/MMBTU
SC-0193	MERCEDES BENZ VANS, LLC	4/15/2016	Energy Center Boilers	14.27	MMBTU/hr	Annual tune ups per 40 CFR 63.7540(a)(10) are required.	0.00745098	LB/MMBTU
IL-0129	CPV THREE RIVERS ENERGY CENTER	7/30/2018	Auxiliary Boiler	96	mmBtu/hr	Good combustion practices	0.0075	LB/MMBTU
IL-0130	JACKSON ENERGY CENTER	12/31/2018	Auxiliary Boiler	96	mmBtu/hr	Good combustion practice	0.0075	LB/MMBTU
IN-0365	MAPLE CREEK ENERGY LLC	6/19/2023	Auxiliary Boiler	96	MMBtu per hour	pipeline-quality natural gas and good combustion practices	0.0075	LB/MMBTU
OH-0377	HARRISON POWER	4/19/2018	Auxiliary Boiler (B001)	44.55	MMBTU/H	Pipeline quality natural gas	0.0075	LB/MMBTU
WI-0283	AFE, INC. ""LCM PLANT	4/24/2018	B01-B12, Boilers	28	mmBTU/hr	Good Combustion Practices and use of pipeline quality natural gas	0.0075	LB/MMBTU
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	4/24/2018	B13-B24 & B25-B36 Natural Gas-Fired Boilers	28	mmBTU	Good Combustion Practices and The Use of Pipeline Quality Natural Gas	0.0075	LB/MMBTU
IA-0107	MARSHALLTOWN GENERATING STATION	4/14/2014	auxiliary boiler	60.1	mmBtu/hr		0.008	LB/MMBTU
WI-0306	WPL- RIVERSIDE ENERGY CENTER	2/28/2020	Temporary Boiler (B98A)	14.67	MMBTU/H	Combust only pipeline quality natural gas, can be operated for no more than 500 hours.	0.008	LB/MMBTU
WV-0029	HARRISON COUNTY POWER PLANT	3/27/2018	Auxiliary Boiler	77.8	mmBtu/hr	Use of Natural Gas, Good Combustion Practices	0.008	LB/MMBTU

TABLE D-24

BOILERS (<100 MMBTU/HR), PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024

LISTINGS FOR TPM_{10}

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
OH-0387	INTEL OHIO SITE	9/20/2022	29.4 MMBtu/hr Natural Gas-Fired Boilers: B001 through B028	29.4	MMBTU/H	Good combustion practices and the use of natural gas	0.0005	LB/MMBTU
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	3/24/2017	FGAUXBOILERS (6 auxiliary boilers EUAUXBOIL2A, EUAUXBOIL3A, EUAUXBOIL2B, EUAUXBOIL3B, EUAUXBOIL2C, EUAUXBOIL3C)	3	MMBTU/H	Good combustion practices and low sulfur fuel (pipeline quality natural gas).	0.0005	LB/MMBTU
AR-0140	BIG RIVER STEEL LLC	9/18/2013	BOILER, PICKLE LINE	67	MMBTU/H	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0005	LB/MMBTU
AR-0140	BIG RIVER STEEL LLC	9/18/2013	BOILERS SN-26 AND 27, GALVANIZING LINE	24.5	MMBTU/H	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0005	LB/MMBTU
AR-0155	BIG RIVER STEEL LLC	11/7/2018	BOILER SN-26, GALVANIZING LINE	53.7	MMBTU/HR	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0007	LB/MMBTU
AR-0159	BIG RIVER STEEL LLC	4/5/2019	BOILERS SN-26 AND SN-27, GALVANIZING LINE	0		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0007	LB/MMBTU
AR-0173	BIG RIVER STEEL LLC	1/31/2022	Galvanizing Line Boilers #1 and #2	53.7	MMBtu/hr	Combustion of Natural gas and Good Combustion Practice	0.0007	LB/MMBTU
IN-0359	NUCOR STEEL	3/30/2023	Boiler (CC-BOIL)	50	MMBtu/hr	good combustion practices and only pipeline quality natural gas fuel shall be combusted	0.0007	LB/MMBTU
AR-0172	NUCOR STEEL ARKANSAS	9/1/2021	SN-202, 203, 204 Pickle Line Boilers	0		Good Combustion Practice	0.0011	LB/MMBTU
AR-0173	BIG RIVER STEEL LLC	1/31/2022	Pickle Galvanizing Line Boiler	53.7	MMBtu/hr	Combustion of Natural gas and Good Combustion Practice	0.0012	LB/MMBTU
AR-0155	BIG RIVER STEEL LLC	11/7/2018	BOILER, PICKLE LINE	53.7	MMBTU/HR	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0019	LB/MMBTU
AR-0159	BIG RIVER STEEL LLC	4/5/2019	BOILER, PICKLE LINE	0		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0019	LB/MMBTU
AR-0159	BIG RIVER STEEL LLC	4/5/2019	BOILER, ANNEALING PICKLE LINE	0		Combustion of Natural gas and Good Combustion Practice	0.0019	LB/MMBTU
AR-0173	BIG RIVER STEEL LLC	1/31/2022	Pickle Line Boiler	53.7	MMBtu/hr	Combustion of Natural gas and Good Combustion Practice	0.0019	LB/MMBTU
FL-0363	DANIA BEACH ENERGY CENTER	12/4/2017	99.8 MMBtu/hr auxiliary boiler	99.8	MMBtu/hr	Clean fuels	0.0028	LB/MMBTU
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	7/27/2018	60 MMBtu/hour Auxiliary Boiler	60	MMBtu/hour	Clean fuels	0.0028	LB/MMBTU
NE-0064	NORFOLK CRUSH, LLC	11/21/2022	Boiler A	84	MMBtu/hr		0.0031	LB/MMBTU
NE-0064	NORFOLK CRUSH, LLC	11/21/2022	Boiler B	84	MMBtu/hr		0.0031	LB/MMBTU
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	7/14/2015	Auxiliary boiler	18.6	MMBTU/HR		0.0050	LB/MMBTU
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	1/30/2014	Auxiliary Boiler	80	MMBTU/H		0.0050	LB/MMBTU

TABLE D-25

BOILERS (<100 MMBTU/HR), PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024

LISTINGS FOR $TPM_{2.5}$

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
OH-0387	INTEL OHIO SITE	9/20/2022	29.4 MMBtu/hr Natural Gas-Fired Boilers: B001 through B028	29.4	MMBTU/H	Good combustion practices and the use of natural gas	0.0004	LB/MMBTU
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	3/24/2017	FGAUXBOILERS (6 auxiliary boilers EUAUXBOIL2A, EUAUXBOIL3A, EUAUXBOIL2B, EUAUXBOIL3B, EUAUXBOIL2C, EUAUXBOIL3C)	3	MMBTU/H	Good combustion practices and low sulfur fuel (pipeline quality natural gas).	0.0005	LB/MMBTU
AR-0140	BIG RIVER STEEL LLC	9/18/2013	BOILER, PICKLE LINE	67	MMBTU/H	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0005	LB/MMBTU
AR-0140	BIG RIVER STEEL LLC	9/18/2013	BOILERS SN-26 AND 27, GALVANIZING LINE	24.5	MMBTU/H	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0005	LB/MMBTU
AR-0155	BIG RIVER STEEL LLC	11/7/2018	BOILER SN-26, GALVANIZING LINE	53.7	MMBTU/HR	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0007	LB/MMBTU
AR-0159	BIG RIVER STEEL LLC	4/5/2019	BOILERS SN-26 AND SN-27, GALVANIZING LINE	0		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0007	LB/MMBTU
AR-0173	BIG RIVER STEEL LLC	1/31/2022	Galvanizing Line Boilers #1 and #2	53.7	MMBtu/hr	Combustion of Natural gas and Good Combustion Practice	0.0007	LB/MMBTU
IN-0359	NUCOR STEEL	3/30/2023	Boiler (CC-BOIL)	50	MMBtu/hr	good combustion practices and only pipeline quality natural gas fuel shall be combusted	0.0007	LB/MMBTU
AR-0172	NUCOR STEEL ARKANSAS	9/1/2021	SN-202, 203, 204 Pickle Line Boilers	0		Good Combustion Practice	0.0011	LB/MMBTU
AR-0173	BIG RIVER STEEL LLC	1/31/2022	Pickle Galvanizing Line Boiler	53.7	MMBtu/hr	Combustion of Natural gas and Good Combustion Practice	0.0012	LB/MMBTU
AR-0155	BIG RIVER STEEL LLC	11/7/2018	BOILER, PICKLE LINE	53.7	MMBTU/HR	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0019	LB/MMBTU
AR-0159	BIG RIVER STEEL LLC	4/5/2019	BOILER, PICKLE LINE	0		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.0019	LB/MMBTU
AR-0159	BIG RIVER STEEL LLC	4/5/2019	BOILER, ANNEALING PICKLE LINE	0		Combustion of Natural gas and Good Combustion Practice	0.0019	LB/MMBTU
AR-0173	BIG RIVER STEEL LLC	1/31/2022	Pickle Line Boiler	53.7	MMBtu/hr	Combustion of Natural gas and Good Combustion Practice	0.0019	LB/MMBTU
FL-0363	DANIA BEACH ENERGY CENTER	12/4/2017	99.8 MMBtu/hr auxiliary boiler	99.8	MMBtu/hr	Clean fuels	0.0028	LB/MMBTU
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	7/14/2015	Auxiliary boiler	18.6	MMBTU/HR		0.0050	LB/MMBTU
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	1/30/2014	Auxiliary Boiler	80	MMBTU/H		0.0050	LB/MMBTU
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	6/15/2015	Auxilary Boiler	62.04	MCF/hr	Good combustion practices and low sulfur fuels	0.0050	LB/MMBTU
IN-0202	IPL EAGLE VALLEY GENERATING STATION	10/11/2013	AUXILLARY BOILER EU-3	79.3	MMBTU/HOUR		0.0050	LB/MMBTU

TABLE D-26

BOILERS (<100 MMBTU/HR), PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024

LISTINGS FOR SO_2

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
OH-0377	HARRISON POWER	4/19/2018	Auxiliary Boiler (B001)	44.55	MMBTU/H	Pipeline quality natural gas	5.00E-04	LB/MMBTU
AR-0140	BIG RIVER STEEL LLC	9/18/2013	BOILER, PICKLE LINE	67	MMBTU/H	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	5.88E-04	LB/MMBTU
AR-0140	BIG RIVER STEEL LLC	9/18/2013	BOILERS SN-26 AND 27, GALVANIZING LINE	24.5	MMBTU/H	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	5.88E-04	LB/MMBTU
KY-0115	NUCOR STEEL GALLATIN, LLC	4/19/2021	Vacuum Degasser Boiler (EP 20-13)	50.4	MMBtu/hr	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	5.88E-04	LB/MMBTU
KY-0115	NUCOR STEEL GALLATIN, LLC	4/19/2021	Pickle Line #2 ""‘ Boiler #1 & #2 (EP 21-04 & EP 21-05)	18	MMBtu/hr, each	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	5.88E-04	LB/MMBTU
AR-0159	BIG RIVER STEEL LLC	4/5/2019	BOILER, PICKLE LINE	0		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	6.00E-04	LB/MMBTU
AR-0159	BIG RIVER STEEL LLC	4/5/2019	BOILER, ANNEALING PICKLE LINE	0		Combustion of Natural gas and Good Combustion Practice	6.00E-04	LB/MMBTU
AR-0159	BIG RIVER STEEL LLC	4/5/2019	BOILERS SN-26 AND SN-27, GALVANIZING LINE	0		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	6.00E-04	LB/MMBTU
AR-0171	NUCOR STEEL ARKANSAS	2/14/2019	SN-142 Vacuum Degasser Boiler	50.4	MMBTU/hr	Good combustion practices	6.00E-04	LB/MMBTU
AR-0171	NUCOR STEEL ARKANSAS	2/14/2019	SN-233 Galvanizing Line Boilers	15	MMBTU/hr each	Good combustion practices	6.00E-04	LB/MMBTU
AR-0172	NUCOR STEEL ARKANSAS	9/1/2021	SN-202, 203, 204 Pickle Line Boilers	0		Low Sulfur fuels	6.00E-04	LB/MMBTU
AR-0173	BIG RIVER STEEL LLC	1/31/2022	Pickle Line Boiler	53.7	MMBtu/hr	Combustion of Natural gas and Good Combustion Practice	6.00E-04	LB/MMBTU
AR-0173	BIG RIVER STEEL LLC	1/31/2022	Galvanizing Line Boilers #1 and #2	53.7	MMBtu/hr	Combustion of Natural gas and Good Combustion Practice	6.00E-04	LB/MMBTU
AR-0173	BIG RIVER STEEL LLC	1/31/2022	Pickle Galvanizing Line Boiler	53.7	MMBtu/hr	Combustion of Natural gas and Good Combustion Practice	6.00E-04	LB/MMBTU
IN-0359	NUCOR STEEL	3/30/2023	Boiler (CC-BOIL)	50	MMBtu/hr	good combustion practices and only pipeline quality natural gas fuel shall be combusted	6.00E-04	LB/MMBTU
MD-0042	WILDCAT POINT GENERATION FACILITY	4/8/2014	AUXILLARY BOILER	45	MMBTU/H	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS	6.00E-04	LB/MMBTU
WI-0283	AFE, INC. ""‘LCM PLANT	4/24/2018	B01-B12, Boilers	28	mmBTU/hr	Good Combustion Practices and the Use of Pipeline Quality Natural Gas	6.00E-04	LB/MMBTU
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	4/24/2018	B13-B24 & B25-B36 Natural Gas-Fired Boilers	28	mmBTU	Good Combustion Practices and The Use of Pipeline Quality Natural Gas	6.00E-04	LB/MMBTU
IL-0133	LINCOLN LAND ENERGY CENTER	7/29/2022	Auxiliary Boiler	80	mmBtu/hour	Use of only natural gas with a sulfur content of no greater than 0.5 grains (gr)/100 standard cubic feet (scf).	1.40E-03	LB/MMBTU
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	1/30/2014	Auxiliary Boiler	80	MMBTU/H		1.50E-03	LB/MMBTU
OH-0370	TRUMBULL ENERGY CENTER	9/7/2017	Auxiliary Boiler (B001)	37.8	MMBTU/H	Low sulfur fuel	1.50E-03	LB/MMBTU

TABLE D-27
BOILERS (<100 MMBTU/HR), PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024
LISTINGS FOR SULFURIC ACID MIST

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	6/15/2015	Auxilary Boiler	62.04	MCF/hr	Good combustion practices and low sulfur fuels	4.60E-05	LB/MMBTU
OH-0377	HARRISON POWER	4/19/2018	Auxiliary Boiler (B001)	44.55	MMBTU/H	Pipeline quality natural gas	8.00E-05	LB/MMBTU
IA-0107	MARSHALLTOWN GENERATING STATION	4/14/2014	auxiliary boiler	60.1	mmBtu/hr		9.15E-05	LB/MMBTU
IN-0365	MAPLE CREEK ENERGY LLC	6/19/2023	Auxiliary Boiler	96	MMBtu per hour	H2SO4 emissions shall be controlled through the use of only pipeline quality natural gas.	1.00E-04	LB/MMBTU
PA-0311	MOXIE FREEDOM GENERATION PLANT	9/1/2015	Auxilary Boiler	55.4	MMBtu/hr		1.00E-04	LB/MMBTU
NY-0103	CRICKET VALLEY ENERGY CENTER	2/3/2016	Auxiliary boiler	60	MMBTU/H	natural gas with maximum sulfur content 0.4 grains/100 dscf	1.10E-04	LB/MMBTU
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	8/25/2015	Auxiliary Boiler (B001)	34	MMBTU/H	Low sulfur fuel	1.10E-04	LB/MMBTU
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	11/7/2017	Auxiliary Boiler (B001)	26.8	MMBTU/H	Low sulfur fuel	1.10E-04	LB/MMBTU
OH-0372	OREGON ENERGY CENTER	9/27/2017	Auxiliary Boiler (B001)	37.8	MMBTU/H	low sulfur fuel	1.15E-04	LB/MMBTU
WV-0029	HARRISON COUNTY POWER PLANT	3/27/2018	Auxiliary Boiler	77.8	mmBtu/hr	Use of Natural Gas	2.00E-04	LB/MMBTU
OH-0360	CARROLL COUNTY ENERGY	11/5/2013	Auxiliary Boiler (B001)	99	MMBtu/H	only burning natural gas	2.20E-04	LB/MMBTU
OH-0377	HARRISON POWER	4/19/2018	Auxiliary Boiler (B002)	80	MMBTU/H	Pipeline quality natural gas	2.20E-04	LB/MMBTU
OH-0370	TRUMBULL ENERGY CENTER	9/7/2017	Auxiliary Boiler (B001)	37.8	MMBTU/H	Low sulfur fuel	2.30E-04	LB/MMBTU
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	1/30/2014	Auxiliary Boiler	80	MMBTU/H		9.00E-04	LB/MMBTU
IL-0129	CPV THREE RIVERS ENERGY CENTER	7/30/2018	Auxiliary Boiler	96	mmBtu/hr	Good combustion practice	1.04E-03	LB/MMBTU
IL-0130	JACKSON ENERGY CENTER	12/31/2018	Auxiliary Boiler	96	mmBtu/hr	Good combustion practice	1.04E-03	LB/MMBTU
MD-0042	WILDCAT POINT GENERATION FACILITY	4/8/2014	AUXILLARY BOILER	45	MMBTU/H	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS	4.00E-03	LB/MMBTU
MD-0045	MATTAWOMAN ENERGY CENTER	11/13/2015	AUXILIARY BOILER	42	MMBTU/H	EXCLUSIVE USE OF NATURAL GAS, AND GOOD COMBUSTION PRACTICES	4.00E-03	LB/MMBTU
IL-0133	LINCOLN LAND ENERGY CENTER	7/29/2022	Auxiliary Boiler	80	mmBtu/hour	Use of only natural gas with a sulfur content of no greater than 0.5 grains (gr)/100 standard cubic feet (scf).	2.00E-02	LB/MMBTU
FL-0363	DANIA BEACH ENERGY CENTER	12/4/2017	99.8 MMBtu/hr auxiliary boiler	99.8	MMBtu/hr	Clean fuels. May only fire natural gas with sulfur content less than 2 grains per 100 scf.		
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	7/27/2018	60 MMBtu/hour Auxiliary Boiler	60	MMBtu/hour	Clean fuels. May only fire natural gas with sulfur content less than 2 grains per 100 scf.		
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	6/7/2021	60 MMBtu/hour Auxiliary Boiler	60	MMBtu/hour	Limited sulfur content in fuel. May only fire natural gas with sulfur content less than 1.4 grains per 100 scf.		
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUAUXBOILER: Auxiliary Boiler	99.9	MMBTU/H	Good combustion practices, low sulfur fuel		
OR-0050	TROUTDALE ENERGY CENTER, LLC	3/5/2014	Auxiliary boiler	39.8	MMBTU/H	Good combustion practices; Utilize only natural gas.		

TABLE D-28

BOILERS (<100 MMBTU/HR), PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024

LISTINGS FOR GREENHOUSE GASES (AS CO_2e)

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
OH-0377	HARRISON POWER	4/19/2018	Auxiliary Boiler (B001)	44.55	MMBTU/H	Good combustion practices and pipeline quality natural gas	2817.6	TPY
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	8/25/2015	Auxiliary Boiler (B001)	34	MMBTU/H	Good combustion controls/natural gas combustion	4008	TPY
OH-0370	TRUMBULL ENERGY CENTER	9/7/2017	Auxiliary Boiler (B001)	37.8	MMBTU/H	Good combustion controls/natural gas combustion	4456	TPY
WV-0031	MOCKINGBIRD HILL COMPRESSOR STATION	6/14/2018	WH-1 - Boiler	8.72	mmBtu/hr	Limited to natural gas; and tune-up the boiler once every five years.	4468	TPY
OH-0372	OREGON ENERGY CENTER	9/27/2017	Auxiliary Boiler (B001)	37.8	MMBTU/H	use of natural gas, good combustion controls	4502	TPY
OH-0377	HARRISON POWER	4/19/2018	Auxiliary Boiler (B002)	80	MMBTU/H	Good combustion practices and pipeline quality natural gas	5009.1	TPY
IL-0133	LINCOLN LAND ENERGY CENTER	7/29/2022	Auxiliary Boiler	80	mmBtu/hour	Good combustion practices.	5059	TPY
MI-0420	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	6/3/2016	FGAUXBOILERS	6	MMBTU/H	Use of pipeline quality natural gas and energy efficiency measures.	6155	TPY
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	13.2	MMBTU/H	Good combustion practice to ensure complete combustion.	6850	TPY
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	3/24/2017	FGAUXBOILERS (6 auxiliary boilers EUAUXBOIL2A, EUAUXBOIL3A, EUAUXBOIL2B, EUAUXBOIL3B, EUAUXBOIL2C, EUAUXBOIL3C)	3	MMBTU/H	Use of pipeline quality natural gas and energy efficiency measures.	7324	TPY
OH-0379	PETMIN USA INCORPORATED	2/6/2019	Startup boiler (B001)	15.17	MMBTU/H	Good combustion practices and the use of natural gas	7814	TPY
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	11/7/2017	Auxiliary Boiler (B001)	26.8	MMBTU/H	Natural gas as the sole fuel	7845	TPY
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	7/14/2015	Auxiliary boiler	18.6	MMBTU/HR	Compliance with the CO2e BACT limit shall be demonstrated with an oxygen (O2) concentration monitor in accordance with CO2 calculations provided in 40 CFR Part 75. Calculations shall consist of CO2 emissions only, which account for 99.9% of total CO2e emissions.	9521.5	TPY
IN-0365	MAPLE CREEK ENERGY LLC	6/19/2023	Auxiliary Boiler	96	MMBtu per hour	CO2e emissions from the Auxiliary Boiler shall be controlled through the use of good combustion practices.	11244	TPY
IL-0130	JACKSON ENERGY CENTER	12/31/2018	Auxiliary Boiler	96	mmBtu/hr	Good combustion practice	11250	TPY
MI-0406	RENAISSANCE POWER LLC	11/1/2013	FG-AUXBOILER1-2; Two (2) natural gas-fired auxiliary boilers.	40	MMBTU/H	Good combustion practices.	11503.7	TPY
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	12/17/2013	Auxiliary Boiler	40	MMBTU/H		12346	TPY

TABLE D-29

EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024

LISTINGS FOR NOx

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	4/1/2015	Emergency Diesel Generator	1500	hp	Minimized hours of operations Tier II engine	0.0218	g/hp-hr
OH-0368	PALLAS NITROGEN LLC	4/19/2017	Emergency Fire Pump Diesel Engine (P008)	460	HP	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII	0.30	g/hp-hr
TX-0846	MOTOR VEHICLE ASSEMBLY PLANT	9/23/2018	FIRE PUMP DIESEL ENGINE	214	kW	Meets EPA Tier 4 requirements	0.30	g/hp-hr
OH-0368	PALLAS NITROGEN LLC	4/19/2017	Emergency Generator (P009)	5000	HP	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII	0.50	g/hp-hr
OH-0379	PETMIN USA INCORPORATED	2/6/2019	Emergency Generators (P005 and P006)	3131	HP	Tier IV engine Tier IV NSPS standards certified by engine manufacturer.	0.5	g/hp-hr
IL-0114	CRONUS CHEMICALS, LLC	9/5/2014	Emergency Generator	3755	HP	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	0.5	g/hp-hr
IL-0114	CRONUS CHEMICALS, LLC	9/5/2014	Emergency Generator	3755	HP	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	0.50	g/hp-hr
PA-0291	HICKORY RUN ENERGY STATION	4/23/2013	EMERGENCY FIREWATER PUMP-450 bhp	3.25	MMBTU/H		0.66	g/hp-hr
MI-0425	GRAYLING PARTICLEBOARD	5/9/2017	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	500	H/YR	Certified engines, limited operating hours	0.99	g/hp-hr
PA-0291	HICKORY RUN ENERGY STATION	4/23/2013	EMERGENCY GENERATOR	7.8	MMBTU/H		1.46	g/hp-hr
LA-0346	GULF COAST METHANOL COMPLEX	1/4/2018	emergency generators (4 units)	13410	hp each	Comply with standards of 40 CFR 60 Subpart JJJJ	2	g/hp-hr
NY-0103	CRICKET VALLEY ENERGY CENTER	2/3/2016	Black start generator	3000	KW	Generator equipped with selective catalytic reduction. Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	2.11	g/hp-hr
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	3/10/2016	Emergency Diesel Fire Pump -360 bhp	360	bhp	use of ULSD a clean burning fuel, and limited hours of operation	2.14	g/hp-hr
LA-0308	MORGAN CITY POWER PLANT	9/26/2013	380 HP Diesel Fired Pump Engine	2.3	MMBTU/hr	Good combustion and maintenance practices, and compliance with NSPS 40 CFR 60 Subpart IIII	2.2	g/hp-hr
OH-0352	OREGON CLEAN ENERGY CENTER	6/18/2013	Emergency fire pump engine	300	HP	Purchased certified to the standards in NSPS Subpart IIII	2.57	g/hp-hr
NY-0103	CRICKET VALLEY ENERGY CENTER	2/3/2016	Emergency fire pump	460	hp	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	2.6	g/hp-hr
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	1/31/2013	Fire Pump Engine	460	bhp		2.6	g/hp-hr
OH-0360	CARROLL COUNTY ENERGY	11/5/2013	Emergency fire pump engine (P004)	400	HP	Purchased certified to the standards in NSPS Subpart IIII	2.61	g/hp-hr
OH-0367	SOUTH FIELD ENERGY LLC	9/23/2016	Emergency fire pump engine (P004)	311	HP	State-of-the-art combustion design	2.61	g/hp-hr

TABLE D-30
EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024
LISTINGS FOR CO

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
OH-0387	INTEL OHIO SITE	9/20/2022	5,051 bhp (3,768 kWm) Diesel-Fired Emergency Generators: P001 through P046	5051	HP	Certified to meet Tier 2 standards and good combustion practices	0.07	g/hp-hr
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	4/1/2015	Emergency Diesel Generator	1500	hp	Minimized hours of operations Tier II engine	0.13	g/hp-hr
AK-0084	DONLIN GOLD PROJECT	6/30/2017	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	143.5	MMBtu/hr	Oxidation Catalyst and Maintain Good Combustion Practices	0.13	g/hp-hr
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	8/21/2019	FGEMENGINE	1100	KW		0.15	g/hp-hr
LA-0312	ST. JAMES METHANOL PLANT	6/30/2017	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	1474	horsepower	Compliance with NSPS Subpart IIII	0.16	g/hp-hr
PA-0311	MOXIE FREEDOM GENERATION PLANT	9/1/2015	Emergency Generator	0			0.26	g/hp-hr
WV-0033	MAIDSVILLE	1/5/2022	Emergency Generator	2100	hp	Good Combustion Practices w/ OxCat. Applicant did not justify why an oxcat is infeasible for an emergency engine	0.42	g/hp-hr
TX-0872	CONDENSATE SPLITTER FACILITY	10/31/2019	Emergency Generators	0		Limiting duration and frequency of generator use to 100 hr/yr. Good combustion practices will be used to reduce VOC including maintaining proper air-to-fuel ratio.	0.45	g/hp-hr
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	4/24/2018	Diesel-Fired Emergency Generators	0		Good Combustion Practices	0.45	g/hp-hr
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	4/24/2018	P42 -Diesel Fired Emergency Generator	0		Good Combustion Practices	0.45	g/hp-hr
NY-0104	CPV VALLEY ENERGY CENTER	8/1/2013	Emergency generator	0		Good combustion practice.	0.45	g/hp-hr
LA-0401	KOCH METHANOL (KME) FACILITY	12/20/2023	E. GEN 01 - Generac SD 2000	2923	horsepower	Compliance with the requirements of 40 CFR 60 Subpart IIII	0.45	g/hp-hr
LA-0401	KOCH METHANOL (KME) FACILITY	12/20/2023	E. GEN 02 - Generac SD 2000	2923	horsepower	Compliance with the requirements of 40 CFR 60 Subpart IIII	0.45	g/hp-hr
PA-0326	SHELL POLYMERS MONACA SITE	2/18/2021	Emergency Generator Parking Garage	0		The use of certified engines, design of engines to include turbocharger and an intercooler/aftercooler, good combustion practices and proper operation and maintenance including certification to applicable federal emission standards	0.50	g/hp-hr
PA-0326	SHELL POLYMERS MONACA SITE	2/18/2021	Emergency GeneratorTelecom Hut & Tower	0		The use of certified engines, design of engines to include turbocharger and an intercooler/aftercooler, good combustion practices and proper operation and maintenance including certification to applicable federal emission standards	0.50	g/hp-hr
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	12/23/2015	Fire pump engine	15	gal/hr		0.50	g/hp-hr
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	1/31/2013	Fire Pump Engine - 460 BHP	0			0.50	g/hp-hr

TABLE D-31

EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024

LISTINGS FOR VOC

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0312	ST. JAMES METHANOL PLANT	6/30/2017	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	1474	horsepower	Compliance with NSPS Subpart IIII	0.01	g/hp-hr
IN-0234	GRAIN PROCESSING CORPORATION	12/8/2015	EMERGENCY FIRE PUMP ENGINE	0		GOOD COMBUSTION PRACTICES & shall not exceed 1,128 gallons per twelve (12) consecutive month period, with compliance determined at the end of each month.	0.05	g/hp-hr
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	5/23/2014	Firewater Pump Nos. 1-3 (EQTs 997, 998, & 999)	500	HP	Compliance with 40 CFR 60 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage	0.09	g/hp-hr
NY-0103	CRICKET VALLEY ENERGY CENTER	2/3/2016	Emergency fire pump	460	hp	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	0.10	g/hp-hr
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	1/31/2013	Fire Pump Engine - 460 BHP	0			0.10	g/hp-hr
NY-0103	CRICKET VALLEY ENERGY CENTER	2/3/2016	Black start generator	3000	KW	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	0.11	g/hp-hr
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	12/23/2015	Fire pump engine	15	gal/hr		0.12	g/hp-hr
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	7/19/2016	EMERGENCY GENERATOR DIESEL	0	100 H/YR	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation	0.13	g/hp-hr
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	3/10/2016	Emergency Diesel Fire Pump	100	H/YR	use of ULSD a clean burning fuel, and limited hours of operation	0.13	g/hp-hr
OH-0368	PALLAS NITROGEN LLC	4/19/2017	Emergency Fire Pump Diesel Engine (P008)	460	HP	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII	0.14	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	6/4/2014	FIRE PUMP	500	HP	GOOD COMBUSTION PRACTICES	0.14	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	6/4/2014	FIRE PUMP	500	HP	GOOD COMBUSTION PRACTICES	0.14	g/hp-hr
IN-0179	OHIO VALLEY RESOURCES, LLC	9/25/2013	DIESEL-FIRED EMERGENCY WATER PUMP	481	BHP	GOOD COMBUSTION PRACTICES	0.14	g/hp-hr
TX-0846	MOTOR VEHICLE ASSEMBLY PLANT	9/23/2018	FIRE PUMP DIESEL ENGINE	214	kW	Meets EPA Tier 4 requirements	0.14	g/hp-hr
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	5/23/2014	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)	2682	HP	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	0.14	g/hp-hr
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	5/23/2014	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	2682	HP	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.	0.14	g/hp-hr

TABLE D-32

EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024

LISTINGS FOR TPM

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	8/21/2019	FGEMENGINE	1100	KW	Good combustion practices and ultra low sulfur diesel	0.04	g/hp-hr
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	4/24/2018	P42 -Diesel Fired Emergency Generator	2346	bhp	Good Combustion Practices and The Use of Ultra-low Sulfur Fuel	0.13	g/hp-hr
AK-0084	DONLIN GOLD PROJECT	6/30/2017	Fire Pump Diesel Internal Combustion Engines	252	hp	Clean Fuel and Good Combustion Practices	0.14	g/hp-hr
OH-0387	INTEL OHIO SITE	9/20/2022	5,051 bhp (3,768 kWm) Diesel-Fired Emergency Generators: P001 through P046	5051	HP	Certified to meet Tier 2 standards and good combustion practices	0.15	g/hp-hr
OH-0387	INTEL OHIO SITE	9/20/2022	275 hp (205 kW) Diesel-Fired Emergency Fire Pump Engine	275	HP	Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices	0.15	g/hp-hr
IL-0133	LINCOLN LAND ENERGY CENTER	7/29/2022	Emergency Engines	1250	kW		0.15	g/hp-hr
IL-0133	LINCOLN LAND ENERGY CENTER	7/29/2022	Fire Water Pump Engine	320	horsepower		0.15	g/hp-hr
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	6/7/2021	1,500 kW Emergency Diesel Generator	14.82	MMBtu/hour		0.15	g/hp-hr
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	6/7/2021	Emergency Fire Pump Engine (347 HP)	2.46	MMBtu/hour		0.15	g/hp-hr
IN-0317	RIVERVIEW ENERGY CORPORATION	6/11/2019	Emergency generator EU-6006	2800	HP	Tier II diesel engine	0.15	g/hp-hr
IL-0130	JACKSON ENERGY CENTER	12/31/2018	Firewater Pump Engine	420	horsepower		0.15	g/hp-hr
IL-0130	JACKSON ENERGY CENTER	12/31/2018	Emergency Engine	1500	kW		0.15	g/hp-hr
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	3/9/2016	Three 3300-kW ULSD emergency generators	0		Use of clean fuel	0.15	g/hp-hr
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	3/9/2016	One 422-hp emergency fire pump engine	0		Use of clean fuel	0.15	g/hp-hr
FL-0354	LAUDERDALE PLANT	8/25/2015	Emergency fire pump engine, 300 HP	29	MMBTU/H	Low-emitting fuel and certified engine	0.15	g/hp-hr
IN-0365	MAPLE CREEK ENERGY LLC	6/19/2023	Emergency generator	2012	hp		0.15	g/hp-hr
IN-0359	NUCOR STEEL	3/30/2023	Emergency Generator (CC-GEN1)	3000	Horsepower	certified engine	0.15	g/hp-hr
IN-0359	NUCOR STEEL	3/30/2023	Emergency Generator (CC-GEN2)	500	Horsepower	certified engine	0.15	g/hp-hr
WV-0033	MAIDSVILLE	1/5/2022	Emergency Generator	2100	hp	Clean Fuels and Good Combustion Practices.	0.15	g/hp-hr
WI-0300	NEMADJI TRAIL ENERGY CENTER	9/1/2020	Emergency Diesel Fire Pump (P06)	282	HP	Operation limited to 500 hours/year, sulfur content of diesel fuel oil fired may not exceed 15 ppm, and shall be operated and maintained according to the manufacturer's recommendations.	0.15	g/hp-hr
WI-0300	NEMADJI TRAIL ENERGY CENTER	9/1/2020	Emergency Diesel Generator (P07)	1490	HP	Limited to operate 500 hours/year, sulfur content of the diesel fuel oil fired may not exceed 15 ppm, and operate and maintain according to the manufacturer's recommendations.	0.15	g/hp-hr

TABLE D-33
EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024
LISTINGS FOR SO2

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
AR-0180	HYBAR LLC	4/28/2023	Emergency Generators	0		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.0015	%S fuel
AR-0180	HYBAR LLC	4/28/2023	Emergency Water Pumps	0		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.0015	%S fuel
IN-0359	NUCOR STEEL	3/30/2023	Emergency Generator (CC-GEN1)	3000	Horsepower	ultra-low sulfur diesel fuel (0.0015%S)	0.0015	%S fuel
IN-0359	NUCOR STEEL	3/30/2023	Emergency Generator (CC-GEN2)	500	Horsepower	ultra-low sulfur diesel fuel (0.0015%S)	0.0015	%S fuel
AR-0177	NUCOR STEEL ARKANSAS	11/21/2022	SN-230 Galvanizing Line No, 2 Emergency Generator	3634	Horsepower	Fuel Specification	0.0015	%S fuel
IL-0133	LINCOLN LAND ENERGY CENTER	7/29/2022	Emergency Engines	1250	kW	Use of ultra-low sulfur diesel, with a sulfur content < 15 ppm sulfur.	0.0015	%S fuel
IL-0133	LINCOLN LAND ENERGY CENTER	7/29/2022	Fire Water Pump Engine	320	horsepower	Use of ultra-low sulfur diesel, with a sulfur content < 15 ppm sulfur.	0.0015	%S fuel
AK-0088	LIQUEFACTION PLANT	7/7/2022	Diesel Fire Pump Engine	27.9	Gal/hr	Good Combustion Practices; ULSD; Limited Operation;	0.0015	%S fuel
MI-0451	MEC NORTH, LLC	6/23/2022	EUFPENGINE (North Plant): Fire Pump Engine	300	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	0.0015	%S fuel
MI-0451	MEC NORTH, LLC	6/23/2022	EUEMENGINE (North Plant): Emergency engine	1341	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	0.0015	%S fuel
MI-0452	MEC SOUTH, LLC	6/23/2022	EUEMENGINE (South Plant): Emergency engine	1341	HP	Good Combustion Practices and meeting NSPS Subpart IIII requirements	0.0015	%S fuel
MI-0452	MEC SOUTH, LLC	6/23/2022	EUFPENGINE (South Plant): Fire pump engine	300	HP	Good Combustion Practices and meeting NSPS Subpart IIII requirements	0.0015	%S fuel
AR-0173	BIG RIVER STEEL LLC	1/31/2022	Emergency Engines	0		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.0015	%S fuel
AR-0173	BIG RIVER STEEL LLC	1/31/2022	Emergency Water Pumps	0		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.0015	%S fuel
TX-0933	NACERO PENWELL FACILITY	11/17/2021	Emergency Generators	0		limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR Â§ 1039.101) exhaust emission standards	0.0015	%S fuel
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	6/7/2021	1,500 kW Emergency Diesel Generator	14.82	MMBtu/hour		0.0015	%S fuel
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	6/7/2021	Emergency Fire Pump Engine (347 HP)	2.46	MMBtu/hour		0.0015	%S fuel
AR-0168	BIG RIVER STEEL LLC	3/17/2021	Emergency Engines	0		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.0015	%S fuel
AL-0328	PLANT BARRY	11/9/2020	Diesel Emergency Engines	0			0.0015	%S fuel
AK-0085	GAS TREATMENT PLANT	8/13/2020	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	19.4	gph	Good combustion practices, ULSD, and limit operation to 500 hours per year.	0.0015	%S fuel
TX-0888	ORANGE POLYETHYLENE PLANT	4/23/2020	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	0		ultra-low sulfur diesel (15 ppmw sulfur content).	0.0015	%S fuel
WI-0302	WPL- RIVERSIDE ENERGY CENTER	2/28/2020	Diesel-Fired Fire Pump Engine (P04)	290	HP	Only use diesel fuel oil with a sulfur content of no greater than 0.0015% by weight.	0.0015	%S fuel

TABLE D-34

EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024

LISTINGS FOR SULFURIC ACID MIST

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
IL-0133	LINCOLN LAND ENERGY CENTER	7/29/2022	Emergency Engines	1250	kW	Use of ultra-low sulfur diesel, with a sulfur content < 15 ppm sulfur.		
IL-0133	LINCOLN LAND ENERGY CENTER	7/29/2022	Fire Water Pump Engine	320	horsepower	Use of ultra-low sulfur diesel, with a sulfur content < 15 ppm sulfur.		
IL-0133	LINCOLN LAND ENERGY CENTER	7/29/2022	Emergency Engines	1250	kW	Use of ultra-low sulfur diesel, with a sulfur content < 15 ppm sulfur.		
WI-0300	NEMADJI TRAIL ENERGY CENTER	9/1/2020	Emergency Diesel Fire Pump (P06)	282	HP	Operation limited to 500 hours/year, operate and maintain according to the manufacturer's recommendations, and sulfur content of the diesel fuel oil fired may not exceed 15 ppm.		
WI-0300	NEMADJI TRAIL ENERGY CENTER	9/1/2020	Emergency Diesel Generator (P07)	1490	HP	Operation limited to 500 hours/year, sulfur content of the diesel fuel oil fired may not exceed 15 ppm, and permittee shall operate and maintain generator according to the manufacturer's recommendations.		
WI-0300	NEMADJI TRAIL ENERGY CENTER	9/1/2020	Emergency Diesel Generator (P07)	1490	HP	Operation limited to 500 hours/year, sulfur content of the diesel fuel oil fired may not exceed 15 ppm, and permittee shall operate and maintain generator according to the manufacturer's recommendations.		
WI-0302	WPL- RIVERSIDE ENERGY CENTER	2/28/2020	Diesel-Fired Fire Pump Engine (P04)	290	HP	Only use diesel fuel oil with a sulfur content of no greater than 0.015% by weight		
VA-0332	CHICKAHOMINY POWER LLC	6/24/2019	Emergency Diesel Generator - 300 kW	500	H/YR	good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	0.0001	LB/MMBTU
VA-0332	CHICKAHOMINY POWER LLC	6/24/2019	Emegency Fire Water Pump	500	HR/YR	good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	0.0001	LB/MMBTU
VA-0332	CHICKAHOMINY POWER LLC	6/24/2019	Emergency Diesel Generator - 300 kW	500	H/YR	good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	0.0001	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUEMENGINE: Emergency engine	2	MW	Good combustion practices, low sulfur fuel.	15	PPM
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUFPENGINE: Fire pump engine	399	BHP	Good combustion practices, low sulfur fuel.	15	PPM
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUEMENGINE: Emergency engine	2	MW	Good combustion practices, low sulfur fuel.	15	PPM
VA-0328	C4GT, LLC	4/26/2018	Emergency Diesel GEN	500	H/YR	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.		
VA-0328	C4GT, LLC	4/26/2018	Emergency Fire Water Pump	500	HR/YR	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.		

TABLE D-35
EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	12/4/2013	Emergency Engine --Diesel Fire Pump (EUFPENGINE)	165	HP	Good combustion practices	0.29	ton/yr
LA-0370	WASHINGTON PARISH ENERGY CENTER	4/27/2020	Emergency Fire Pump Engine (EQT0021, ENG-1)	157	hp	Good combustion practices in order to comply with 40 CFR 60 Subpart IIII	9	ton/yr
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	5/23/2014	Firewater Pump Nos. 1-3 (EQTs 997, 998, & 999)	500	HP	Compliance with 40 CFR 60 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage	10	ton/yr
MI-0445	INDECK NILES, LLC	11/26/2019	EUFPENGINE (Emergency engine-diesel fire pump	266	bhp	Good combustion practices	13.58	ton/yr
MI-0423	INDECK NILES, LLC	1/4/2017	EUFPENGINE (Emergency engine--diesel fire pump)	260	bhp	Good combustion practices	13.58	ton/yr
OK-0164	MIDWEST CITY AIR DEPOT	1/8/2015	Diesel-Fueled Fire Pump Engines	300	HP	1. Good Combustion Practices. 2. Efficient Design.	14.7	ton/yr
MI-0410	THETFORD GENERATING STATION	7/25/2013	EU-FPENGINE: Diesel fuel fired emergency backup fire pump	315	hp nameplate	Proper combustion design and ultra low sulfur diesel fuel.	15.6	ton/yr
OH-0377	HARRISON POWER	4/19/2018	Emergency Fire Pump (P004)	320	HP	Efficient design and proper maintenance and operation	18.67	ton/yr
MI-0447	LBWL--ERICKSON STATION	1/7/2021	EUFPRICE--A 315 HP diesel fueled emergency engine	315	HP	Low carbon fuel (pipeline quality natural gas), good combustion practices and energy efficiency measures.	20	ton/yr
MI-0441	LBWL--ERICKSON STATION	12/21/2018	EUFPRICE--A 315 HP diesel fueled emergency engine	315	HP	Good combustion practices and energy efficiency measures.	20	ton/yr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Firewater Pumps (P005 and P006)	402	HP	good operating practices (proper maintenance and operation)	23	ton/yr
IL-0134	CRONUS CHEMICALS	12/21/2023	Firewater Pump Engine	369	hp		25	ton/yr
LA-0328	PLAQUEMINES PLANT 1	5/2/2018	Emergency Diesel Engine Pump P-39A	375	HP	Good Combustion Practices	28	ton/yr
LA-0328	PLAQUEMINES PLANT 1	5/2/2018	Emergency Diesel Engine Pump P-39B	300	HP	Good Combustion Practices	28	ton/yr
OH-0374	GUERNSEY POWER STATION LLC	10/23/2017	Emergency Fire Pump (P006)	410	HP	good operating practices (proper maintenance and operation)	29	ton/yr
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	8/25/2015	Emergency fire pump engine (P004)	140	HP	Efficient design	41	ton/yr
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	12/5/2016	EUFPENGINE (Emergency engine--diesel fire pump)	165	hp	Good combustion practices.	55.6	ton/yr
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	5/23/2014	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)	2682	HP	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	56	ton/yr

TABLE D-36
FUEL HEATERS AT POWER STATIONS, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024
LISTINGS FOR NO_X

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
PA-0316	RENOVO ENERGY CENTER, LLC	1/26/2018	Water Bath Heater	15	MMBtu/hr		0.010	LB/MMBTU
AL-0329	COLBERT COMBUSTION TURBINE PLANT	9/21/2021	Three Gas Heaters	10	MMBtu/hr		0.011	LB/MMBTU
VA-0332	CHICKAHOMINY POWER LLC	6/24/2019	Three (3) Fuel Gas Heaters	103	MMCF/YR	Low NOx burners	0.011	LB/MMBTU
IL-0130	JACKSON ENERGY CENTER	12/31/2018	Fuel Heater	13	mmBtu/hour	Low-NOx combustion technology	0.011	LB/MMBTU
IL-0129	CPV THREE RIVERS ENERGY CENTER	7/30/2018	Fuel Heater	12.8	mmBtu/hr	Low-NOx burners	0.011	LB/MMBTU
PA-0310	CPV FAIRVIEW ENERGY CENTER	9/2/2016	Dew point heater 13.8	0			0.011	LB/MMBTU
VA-0325	GREENSVILLE POWER STATION	6/17/2016	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	185	MMBTU/HR	ultra low-NOx burners	0.011	LB/MMBTU
PA-0311	MOXIE FREEDOM GENERATION PLANT	9/1/2015	Fuel Gas Heater	0			0.011	LB/MMBTU
IA-0107	MARSHALLTOWN GENERATING STATION	4/14/2014	dew point heater	13.32	mmBtu/hr		0.013	LB/MMBTU
OH-0374	GUERNSEY POWER STATION LLC	10/23/2017	Fuel Gas Heaters (2 identical, P007 and P008)	15	MMBTU/H	Low-NOx gas burner	0.020	LB/MMBTU
TX-0908	NEWMAN POWER STATION	8/27/2021	LINE HEATER			Low NOx burner, pipeline natural gas and goo combustion practices.	0.030	LB/MMBTU
IL-0121	INVENERGY NELSON EXPANSION LLC	9/27/2016	Fuel Heater	15	mmbtu/hr		0.033	LB/MMBTU
PA-0310	CPV FAIRVIEW ENERGY CENTER	9/2/2016	Dew point heater 3.2	3.2	MMBtu/hr		0.035	LB/MMBTU
MD-0041	CPV ST. CHARLES	4/23/2014	FUEL GAS HEATER	9.5	MMBTU/H	USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	12/17/2013	Fuel Preheater	8.5	MMBTU/H		0.035	LB/MMBTU
TX-0693	ANTELOPE ELK ENERGY CENTER	4/22/2014	heater	5.5	MMBTU/H		0.036	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUFUELHTR1: Natural gas fired fuel heater	20.8	MMBTU/H	Low NOx burner	0.036	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUFUELHTR2: Natural gas fired fuel heater	3.8	MMBTU/H	Low NOx burner	0.037	LB/MMBTU
MI-0445	INDECK NILES, LLC	11/26/2019	FGFUELHTR (2 fuel pre-heaters)	27	MMBTU/H	Good combustion practices	0.049	LB/MMBTU
WI-0300	NEMADJI TRAIL ENERGY CENTER	9/1/2020	Natural Gas-Fired Heater (P04)	10	MMBTU/H	Low-NOx burners, only use pipeline quality natural gas, maintain and operate according to manufacturer's recommendations.	0.049	LB/MMBTU
WI-0300	NEMADJI TRAIL ENERGY CENTER	9/1/2020	Natural Gas-Fired Heater (P05)	10	MMBTU/H	Low-NOx burners, only combust pipeline quality natural gas, and operate and maintain the heater according to the manufacturer's recommendations.	0.049	LB/MMBTU
MD-0042	WILDCAT POINT GENERATION FACILITY	4/8/2014	DEW POINT HEATER	5	MMBTU/H	USE OF EFFICIENT DESIGN OF THE HEATER, EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS ONLY, AND APPLICATION OF GOOD COMBUSTION PRACTICES	0.049	LB/MMBTU
IN-0371	WABASH VALLEY RESOURCES, LLC	1/11/2024	Dewpoint Heater	1.44	MMBtu/hr	Low NOx burners and good combustion practices	0.049	LB/MMBTU

TABLE D-37
FUEL HEATERS AT POWER STATIONS, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024
LISTINGS FOR CO

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
VA-0328	C4GT, LLC	4/26/2018	Dew Point Heater	140	MMCF/YR	good combustion practices	0.036	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUFUELHTR2: Natural gas fired fuel heater	3.8	MMBTU/H	Good combustion controls	0.037	LB/MMBTU
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	3/13/2023	Water Bath Heater	16.8	MMBtu/hr	Good combustion practices	0.037	LB/MMBTU
TX-0908	NEWMAN POWER STATION	8/27/2021	LINE HEATER			Good combustions practices and pipeline natural gas	0.037	LB/MMBTU
VA-0332	CHICKAHOMINY POWER LLC	6/24/2019	Three (3) Fuel Gas Heaters	103	MMCF/YR	good combustion practices, operator training, and proper emissions unit design, construction and maintenance.	0.037	LB/MMBTU
VA-0325	GREENSVILLE POWER STATION	6/17/2016	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	7.8	MMBTU/HR	Clean fuel and good combustion practices	0.037	LB/MMBTU
PA-0311	MOXIE FREEDOM GENERATION PLANT	9/1/2015	Fuel Gas Heater	0			0.037	LB/MMBTU
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	4/1/2013	DEW POINT HEATER	15	MMBTU/H		0.037	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUFUELHTR1: Natural gas fired fuel heater	20.8	MMBTU/H	Good combustion controls.	0.037	LB/MMBTU
TX-0694	INDECK WHARTON ENERGY CENTER	2/2/2015	heater	3	MMBTU/H		0.040	LB/MMBTU
IA-0107	MARSHALLTOWN GENERATING STATION	4/14/2014	dew point heater	13.32	mmBtu/hr		0.041	LB/MMBTU
MI-0445	INDECK NILES, LLC	11/26/2019	FGFUELHTR (2 fuel pre-heaters)	27	MMBTU/H	Good combustion practices	0.041	LB/MMBTU
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	12/17/2013	Fuel Preheater	8.5	MMBTU/H		0.050	LB/MMBTU
TX-0691	PH ROBINSON ELECTRIC GENERATING STATION	5/20/2014	fuel gas heater	18	MMBTU/H		0.054	LB/MMBTU
OH-0374	GUERNSEY POWER STATION LLC	10/23/2017	Fuel Gas Heaters (2 identical, P007 and P008)	15	MMBTU/H	Combustion control	0.055	LB/MMBTU
AL-0329	COLBERT COMBUSTION TURBINE PLANT	9/21/2021	Three Gas Heaters	10	MMBtu/hr		0.080	LB/MMBTU
WI-0300	NEMADJI TRAIL ENERGY CENTER	9/1/2020	Natural Gas-Fired Heater (P04)	10	MMBTU/H	Only combust pipeline quality natural gas and operate and maintain the process according to manufacturer's recommendations.	0.080	LB/MMBTU
WI-0300	NEMADJI TRAIL ENERGY CENTER	9/1/2020	Natural Gas-Fired Heater (P05)	10	MMBTU/H	Only combust pipeline quality natural gas and operate and maintain heater according to the manufacturer's recommendations.	0.080	LB/MMBTU
IL-0130	JACKSON ENERGY CENTER	12/31/2018	Fuel Heater	13	mmBtu/hour	Good combustion practice	0.080	LB/MMBTU
IL-0129	CPV THREE RIVERS ENERGY CENTER	7/30/2018	Fuel Heater	12.8	mmBtu/hr	Good combustion practice	0.080	LB/MMBTU
PA-0310	CPV FAIRVIEW ENERGY CENTER	9/2/2016	Dew point heater 13.8	0			0.080	LB/MMBTU
PA-0310	CPV FAIRVIEW ENERGY CENTER	9/2/2016	Dew point heater 3.2	3.2	MMBtu/hr		0.080	LB/MMBTU

TABLE D-38
FUEL HEATERS AT POWER STATIONS, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024
LISTINGS FOR VOC

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	3/13/2023	Water Bath Heater	16.8	MMBTU/HR	Good combustion practices	0.0050	LB/MMBTU
WI-0300	NEMADJI TRAIL ENERGY CENTER	9/1/2020	Natural Gas-Fired Heater (P04)	10	MMBTU/H	Only combust pipeline quality natural gas, operate and maintain process according to manufacturer's recommendations.	0.0050	LB/MMBTU
WI-0300	NEMADJI TRAIL ENERGY CENTER	9/1/2020	Natural Gas-Fired Heater (P05)	10	MMBTU/H	Only combust pipeline quality natural gas and operate and maintain according to manufacturer's recommendations.	0.0050	LB/MMBTU
FL-0364	SEMINOLE GENERATING STATION	3/21/2018	Two natural gas heaters (<10 MMBtu/hr each)	9.9	MMBtu/hr		0.0050	LB/MMBTU
PA-0316	RENOVO ENERGY CENTER, LLC	1/26/2018	Water Bath Heater	15	MMBtu/hr		0.0050	LB/MMBTU
OH-0374	GUERNSEY POWER STATION LLC	10/23/2017	Fuel Gas Heaters (2 identical, P007 and P008)	15	MMBTU/H	Combustion control	0.0050	LB/MMBTU
PA-0311	MOXIE FREEDOM GENERATION PLANT	9/1/2015	Fuel Gas Heater	0			0.0050	LB/MMBTU
MD-0041	CPV ST. CHARLES	4/23/2014	FUEL GAS HEATER	9.5	MMBTU/H	EXCLUSIVE USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0050	LB/MMBTU
MD-0042	WILDCAT POINT GENERATION FACILITY	4/8/2014	DEW POINT HEATER	5	MMBTU/H	USE OF EFFICIENT DESIGN OF THE HEATER, EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS ONLY, AND APPLICATION OF GOOD COMBUSTION PRACTICES	0.0050	LB/MMBTU
MI-0445	INDECK NILES, LLC	11/26/2019	FGFUELHTR (2 fuel pre-heaters)	13.5	MMBTU/H	Good combustion practices	0.0052	LB/MMBTU
VA-0325	GREENSVILLE POWER STATION	6/17/2016	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	185	MMBTU/HR	Good combustion pratices	0.0053	LB/MMBTU
WI-0299	WPL- RIVERSIDE ENERGY CENTER	8/20/2020	Natural Gas-Fired Space and Unit Heater (P30)	15.5	MMBTU/H	Only combust natural gas in each heater.	0.0054	LB/MMBTU
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	3/31/2016	Indirect fuel-gas heater	2	mmBTU/hr		0.0055	LB/MMBTU
MI-0423	INDECK NILES, LLC	1/4/2017	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	27	MMBTU/H	Good combustion practices.	0.0056	LB/MMBTU
VA-0332	CHICKAHOMINY POWER LLC	6/24/2019	Three (3) Fuel Gas Heaters	103	MMCF/YR	good combustion practices, operator training, and proper emissions unit design, construction and maintenance.	0.0057	LB/MMBTU
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	4/1/2013	DEW POINT HEATER	15	MMBTU/H		0.0060	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUFUELHTR2: Natural gas fired fuel heater	3.8	MMBTU/H	Good combustion controls.	0.0079	LB/MMBTU
MI-0410	THETFORD GENERATING STATION	7/25/2013	FG-FUELHTRS: 2 natural gas fuel heaters, 12 MMBTU/H each	12	MMBTU/H heat input each fuel heater	Efficient combustion; natural gas fuel.	0.0080	LB/MMBTU
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	12/5/2016	EUFUELHTR (Fuel pre-heater)	3.7	MMBTU/H	Good combustion practices.	0.0081	LB/MMBTU

TABLE D-39

FUEL HEATERS AT POWER STATIONS, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024

LISTINGS FOR TPM

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
OH-0374	GUERNSEY POWER STATION LLC	10/23/2017	Fuel Gas Heaters (2 identical, P007 and P008)	15	MMBTU/H	Combustion control	0.005	LB/MMBTU
PA-0311	MOXIE FREEDOM GENERATION PLANT	9/1/2015	Fuel Gas Heater	0			0.007	LB/MMBTU
WI-0299	WPL- RIVERSIDE ENERGY CENTER	8/20/2020	Natural Gas-Fired Space and Unit Heater (P30)	15.5	MMBTU/H	Only combust natural gas in each heater.	0.0075	LB/MMBTU
IL-0130	JACKSON ENERGY CENTER	12/31/2018	Fuel Heater	13	mmBtu/hour	Good combustion practice	0.0075	LB/MMBTU
IL-0129	CPV THREE RIVERS ENERGY CENTER	7/30/2018	Fuel Heater	12.8	mmBtu/hr	Good combustion practice	0.0075	LB/MMBTU
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	3/31/2016	Indirect fuel-gas heater	2	mmBTU/hr		0.0075	LB/MMBTU
WI-0264	WPSC - WEST MARINETTE	2/15/2016	Natural gas-fired pipeline heater (process P14)	3.5	mmBtu/hr	Good combustion practices and only fire pipeline quality natural gas	0.008	LB/MMBTU
IA-0107	MARSHALLTOWN GENERATING STATION	4/14/2014	dew point heater	13.32	mmBtu/hr		0.008	LB/MMBTU
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	4/1/2013	DEW POINT HEATER	15	MMBTU/H		0.008	LB/MMBTU
WI-0300	NEMADJI TRAIL ENERGY CENTER	9/1/2020	Natural Gas-Fired Heater (P04)	10	MMBTU/H	Operate and maintain heaters according to manufacturer's recommendations. Only combust pipeline quality natural gas.	0.01	LB/MMBTU
WI-0300	NEMADJI TRAIL ENERGY CENTER	9/1/2020	Natural Gas-Fired Heater (P05)	10	MMBTU/H	Operate and maintain heater according to the manufacturer's recommendations and only combust pipeline quality natural gas.	0.01	LB/MMBTU

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FUEL HEATERS AT POWER STATIONS, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024

LISTINGS FOR TPM_{10}

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0445	INDECK NILES, LLC	11/26/2019	FGFUELHTR (2 fuel pre-heaters)	27	MMBTU/H	Good combustion practices	0.0037	LB/MMBTU
OH-0374	GUERNSEY POWER STATION LLC	10/23/2017	Fuel Gas Heaters (2 identical, P007 and P008)	15	MMBTU/H	Combustion control	0.0050	LB/MMBTU
IL-0121	INVENERGY NELSON EXPANSION LLC	9/27/2016	Fuel Heater	15	mmbtu/hr		0.0070	LB/MMBTU
VA-0325	GREENSVILLE POWER STATION	6/17/2016	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	185	MMBTU/HR	Low sulfur/carbon fuel and good combustion practices	0.0070	LB/MMBTU
PA-0311	MOXIE FREEDOM GENERATION PLANT	9/1/2015	Fuel Gas Heater	0			0.0070	LB/MMBTU
MD-0041	CPV ST. CHARLES	4/23/2014	FUEL GAS HEATER	9.5	MMBTU/H	USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0070	LB/MMBTU
MI-0410	THETFORD GENERATING STATION	7/25/2013	FG-FUELHTRS: 2 natural gas fuel heaters, 12 MMBTU/H each	12	MMBTU/H heat input each fuel heater	Efficient combustion; natural gas fuel.	0.0070	LB/MMBTU
VA-0328	C4GT, LLC	4/26/2018	Dew Point Heater	140	MMCF/YR	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	0.0070	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUFUELHTR1: Natural gas fired fuel heater	20.8	MMBTU/H	Low sulfur fuel	0.0072	LB/MMBTU
MI-0423	INDECK NILES, LLC	1/4/2017	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	27	MMBTU/H	Good combustion practices.	0.0074	LB/MMBTU
WI-0299	WPL- RIVERSIDE ENERGY CENTER	8/20/2020	Natural Gas-Fired Space and Unit Heater (P30)	15.5	MMBTU/H	Only combust natural gas in each heater.	0.0075	LB/MMBTU
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	12/5/2016	EUFUELHTR (Fuel pre-heater)	3.7	MMBTU/H	Good combustion practices.	0.0075	LB/MMBTU
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	3/31/2016	Indirect fuel-gas heater	2	mmBTU/hr		0.0075	LB/MMBTU
MD-0042	WILDCAT POINT GENERATION FACILITY	4/8/2014	DEW POINT HEATER	5	MMBTU/H	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0075	LB/MMBTU
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	12/4/2013	Fuel pre-heater (EUFUELHTR)	3.7	MMBTU/H	Good combustion practices	0.0075	LB/MMBTU
VA-0332	CHICKAHOMINY POWER LLC	6/24/2019	Three (3) Fuel Gas Heaters	103	MMCF/YR	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12-month rolling average.	0.0076	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUFUELHTR2: Natural gas fired fuel heater	3.8	MMBTU/H	Low sulfur fuel	0.0079	LB/MMBTU
WI-0264	WPSC - WEST MARINETTE	2/15/2016	Natural gas-fired pipeline heater (process P14)	3.5	mmBtu/hr	Good combustion practices and use pipeline quality natural gas	0.0080	LB/MMBTU
MI-0406	RENAISSANCE POWER LLC	11/1/2013	EU-HEATERSC: Natural gas-fired fuel heater used for heating natural gas prior to combustion in the CTGs. Misc. boilers, furnaces, and heaters	20	MMBTU/H	Good combustion practices	0.0090	LB/MMBTU

TABLE D-41
FUEL HEATERS AT POWER STATIONS, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024
LISTINGS FOR $TPM_{2.5}$

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0445	INDECK NILES, LLC	11/26/2019	FGFUELHTR (2 fuel pre-heaters)	27	MMBTU/H	Good combustion practices	0.0037	LB/MMBTU
OH-0374	GUERNSEY POWER STATION LLC	10/23/2017	Fuel Gas Heaters (2 identical, P007 and P008)	15	MMBTU/H	Combustion control	0.0050	LB/MMBTU
IL-0121	INVENERGY NELSON EXPANSION LLC	9/27/2016	Fuel Heater	15	mmbtu/hr		0.0070	LB/MMBTU
PA-0311	MOXIE FREEDOM GENERATION PLANT	9/1/2015	Fuel Gas Heater	0			0.0070	LB/MMBTU
MI-0410	THETFORD GENERATING STATION	7/25/2013	FG-FUELHTRS: 2 natural gas fuel heaters, 12 MMBTU/H each	12	MMBTU/H heat input each fuel heater	Efficient combustion; natural gas fuel.	0.0070	LB/MMBTU
VA-0328	C4GT, LLC	4/26/2018	Dew Point Heater	140	MMCF/YR	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	0.0070	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUFUELHTR1: Natural gas fired fuel heater	20.8	MMBTU/H	Low sulfur fuel	0.0072	LB/MMBTU
MI-0423	INDECK NILES, LLC	1/4/2017	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	27	MMBTU/H	Good combustion practices.	0.0074	LB/MMBTU
WI-0299	WPL- RIVERSIDE ENERGY CENTER	8/20/2020	Natural Gas-Fired Space and Unit Heater (P30)	15.5	MMBTU/H	Only combust natural gas in each heater.	0.0075	LB/MMBTU
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	12/5/2016	EUFUELHTR (Fuel pre-heater)	3.7	MMBTU/H	Good combustion practices.	0.0075	LB/MMBTU
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	3/31/2016	Indirect fuel-gas heater	2	mmBTU/hr		0.0075	LB/MMBTU
MD-0042	WILDCAT POINT GENERATION FACILITY	4/8/2014	DEW POINT HEATER	5	MMBTU/H	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0075	LB/MMBTU
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	12/4/2013	Fuel pre-heater (EUFUELHTR)	3.7	MMBTU/H	Good combustion pracitces.	0.0075	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUFUELHTR2: Natural gas fired fuel heater	3.8	MMBTU/H	Low sulfur fuel	0.0079	LB/MMBTU
WI-0264	WPSC - WEST MARINETTE	2/15/2016	Natural gas-fired pipeline heater (process P14)	3.5	mmBtu/hr	Good combustion practices, only fire pipeline quality natural gas	0.0080	LB/MMBTU
MI-0406	RENAISSANCE POWER LLC	11/1/2013	EU-HEATERSC: Natural gas-fired fuel heater used for heating natural gas prior to combustion in the CTGs. Misc. boilers, furnaces, and heaters	20	MMBTU/H	Good combustion practices	0.0090	LB/MMBTU
VA-0332	CHICKAHOMINY POWER LLC	6/24/2019	Three (3) Fuel Gas Heaters	103	MMCF/YR	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12-month rolling average.	0.0095	LB/MMBTU
WI-0300	NEMADJI TRAIL ENERGY CENTER	9/1/2020	Natural Gas-Fired Heater (P04)	10	MMBTU/H	Operate and maintain heater according to manufacturer's recommendations. Only combust pipeline quality natural gas.	0.0100	LB/MMBTU

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FUEL HEATERS AT POWER STATIONS, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024

LISTINGS FOR SO_2

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0445	INDECK NILES, LLC	11/26/2019	FGFUELHTR (2 fuel pre-heaters)	27	MMBTU/H	Good combustion practices and the use of pipeline quality natural gas.	0.00028	LB/MMBTU
MI-0423	INDECK NILES, LLC	1/4/2017	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	27	MMBTU/H	Good combustion practices and the use of pipeline quality natural gas.	0.00028	LB/MMBTU
VA-0332	CHICKAHOMINY POWER LLC	6/24/2019	Three (3) Fuel Gas Heaters	103	MMCF/YR		0.00056	LB/MMBTU
VA-0328	C4GT, LLC	4/26/2018	Dew Point Heater	140	MMCF/YR		0.00056	LB/MMBTU
MD-0042	WILDCAT POINT GENERATION FACILITY	4/8/2014	DEW POINT HEATER	5	MMBTU/H	USE OF EFFICIENT DESIGN OF THE HEATER, EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS ONLY, AND APPLICATION OF GOOD COMBUSTION PRACTICES	0.00060	LB/MMBTU
VA-0325	GREENSVILLE POWER STATION	6/17/2016	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	185	MMBTU/HR	Low sulfur fuel	0.00110	LB/MMBTU
OH-0374	GUERNSEY POWER STATION LLC	10/23/2017	Fuel Gas Heaters (2 identical, P007 and P008)	15	MMBTU/H	Pipeline natural gas fuel	0.00150	LB/MMBTU
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	12/17/2013	Fuel Preheater	8.5	MMBTU/H		0.00200	LB/MMBTU
NY-0104	CPV VALLEY ENERGY CENTER	8/1/2013	Gas heater	0		Natural gas.	0.00220	LB/MMBTU
FL-0363	DANIA BEACH ENERGY CENTER	12/4/2017	Two natural gas heaters	9.9	MMBtu/hr	Clean fuel	0.00280	LB/MMBTU
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	3/9/2016	Two natural gas heaters	10	MMBtu/hr	Use of low-sulfur fuel	0.00280	LB/MMBTU
TX-0908	NEWMAN POWER STATION	8/27/2021	LINE HEATER	0		Good combustions practices and pipeline natural gas. Fuel to contain less than 5 grains of sulfur per dscf	0.00700	LB/MMBTU
WI-0264	WPSC - WEST MARINETTE	2/15/2016	Natural gas-fired pipeline heater (process P14)	3.5	mmBtu/hr	Use pipeline quality natural gas		LB/MMBTU

TABLE D-43
FUEL HEATERS AT POWER STATIONS, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024
LISTINGS FOR SULFURIC ACID MIST

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
WI-0300	NEMADJI TRAIL ENERGY CENTER	9/1/2020	Natural Gas-Fired Heater (P04)	10	MMBTU/H	Only combust pipeline quality natural gas and maintain heater according to manufacturer's recommendations.		
WI-0300	NEMADJI TRAIL ENERGY CENTER	9/1/2020	Natural Gas-Fired Heater (P05)	10	MMBTU/H	Only combust pipeline quality natural gas and operate and maintain heater according to manufacturer's recommendations.		
WI-0299	WPL- RIVERSIDE ENERGY CENTER	8/20/2020	Natural Gas-Fired Space and Unit Heater (P30)	15.5	MMBTU/H	Only combust pipeline quality natural gas in each heater.		
VA-0332	CHICKAHOMINY POWER LLC	6/24/2019	Three (3) Fuel Gas Heaters	103	MMCF/YR	Pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf		
IL-0130	JACKSON ENERGY CENTER	12/31/2018	Fuel Heater	13	mmBtu/hour	Good combustion practice		
IL-0129	CPV THREE RIVERS ENERGY CENTER	7/30/2018	Fuel Heater	12.8	mmBtu/hr	Good combustion practice		
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUFUELHTR1: Natural gas fired fuel heater	20.8	MMBTU/H	Low sulfur fuel		
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUFUELHTR2: Natural gas fired fuel heater	3.8	MMBTU/H	Low sulfur fuel		
VA-0328	C4GT, LLC	4/26/2018	Dew Point Heater	140	MMCF/YR	Pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf		
OH-0374	GUERNSEY POWER STATION LLC	10/23/2017	Fuel Gas Heaters (2 identical, P007 and P008)	15	MMBTU/H	Pipeline natural gas fuel		
VA-0325	GREENSVILLE POWER STATION	6/17/2016	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	185	MMBTU/HR	Pipeline quality natural gas		
MD-0045	MATTAWOMAN ENERGY CENTER	11/13/2015	FUEL GAS HEATER	13.8	MMBTU/H	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES		
PA-0311	MOXIE FREEDOM GENERATION PLANT	9/1/2015	Fuel Gas Heater	0				
MD-0042	WILDCAT POINT GENERATION FACILITY	4/8/2014	DEW POINT HEATER	5	MMBTU/H	USE OF EFFICIENT DESIGN OF THE HEATER, EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS ONLY, AND APPLICATION OF GOOD COMBUSTION PRACTICES		
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	12/17/2013	Fuel Preheater	8.5	MMBTU/H			
NY-0104	CPV VALLEY ENERGY CENTER	8/1/2013	Gas heater	0		Natural gas.		

TABLE D-44

FUEL HEATERS AT POWER STATIONS, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024

LISTINGS FOR GREENHOUSE GASES (AS CO_2e)

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0757	INDECK WHARTON ENERGY CENTER	5/12/2014	Pipeline Heater	3	MMBtu/hr (HHV)		624.78	TPY
IN-0371	WABASH VALLEY RESOURCES, LLC	1/11/2024	Dewpoint Heater	1.44	MMBtu/hr	Good Combustion Practices	737.9424	TPY
TX-0749	GOLDEN SPREAD ELECTRIC COOPERATIVE, ANTELOPE STATION	6/2/2014	Fuel Gas Heater	5.5	MMBtu/hr (HHV)		1488	TPY
IL-0121	INVENERGY NELSON EXPANSION LLC	9/27/2016	Fuel Heater	15	mmbtu/hr		1836	TPY
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	12/5/2016	EUFUELHTR (Fuel pre-heater)	3.7	MMBTU/H	Good combustion practices.	1934	TPY
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	12/4/2013	Fuel pre-heater (EUFUELHTR)	3.7	MMBTU/H	Good combustion practices	1934	TPY
TX-0758	ECTOR COUNTY ENERGY CENTER	8/1/2014	Dew-Point Heater	9	MMBTU/H		2631	TPY
TX-0824	JACKSON COUNTY GENERATING FACILITY	6/30/2017	Natural-Gas-Fired Fuel Gas Heaters	15.9	MMBTU/HR	natural gas as a low carbon fuel, good operating and maintenance practices, efficient design, and low annual capacity	2818.74	TPY
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	12/17/2013	Fuel Preheater	8.5	MMBTU/H		4996.3	TPY
AL-0329	COLBERT COMBUSTION TURBINE PLANT	9/21/2021	Three Gas Heaters	10	MMBtu/hr		5128.98	TPY
MI-0410	THETFORD GENERATING STATION	7/25/2013	FG-FUELHTRS: 2 natural gas fuel heaters, 12 MMBTU/H each	12	MMBTU/H heat input each fuel heater	Efficient combustion; energy efficiency.	6156	TPY
VA-0332	CHICKAHOMINY POWER LLC	6/24/2019	Three (3) Fuel Gas Heaters	103	MMCF/YR	use of natural gas and high efficiency design and operation	6261	TPY
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUFUELHTR1: Natural gas fired fuel heater	20.8	MMBTU/H	Natural gas fuel	6310	TPY
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUFUELHTR2: Natural gas fired fuel heater	3.8	MMBTU/H	Natural gas fuel	6310	TPY
IL-0129	CPV THREE RIVERS ENERGY CENTER	7/30/2018	Fuel Heater	12.8	mmBtu/hr	Good combustion practice	6600	TPY
IL-0130	JACKSON ENERGY CENTER	12/31/2018	Fuel Heater	13	mmBtu/hour	Good combustion practice	6700	TPY
IA-0107	MARSHALLTOWN GENERATING STATION	4/14/2014	dew point heater	13.32	mmBtu/hr		6860	TPY
OH-0374	GUERNSEY POWER STATION LLC	10/23/2017	Fuel Gas Heaters (2 identical, P007 and P008)	15	MMBTU/H	Natural gas, low-emitting fuel	7695	TPY
PA-0311	MOXIE FREEDOM GENERATION PLANT	9/1/2015	Fuel Gas Heater	0			7845	TPY
VA-0328	C4GT, LLC	4/26/2018	Dew Point Heater	140	MMCF/YR	use of natural gas and high efficiency design and operation	8208	TPY
MI-0406	RENAISSANCE POWER LLC	11/1/2013	EU-HEATERSC: Natural gas-fired fuel heater used for heating natural gas prior to combustion in the CTGs. Misc. boilers, furnaces, and heaters	20	MMBTU/H	Good combustion practices	10943	TPY

TABLE D-45
COOLING TOWERS, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024
LISTINGS FOR TPM

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0967	QUAIL RUN CARBON CAPTURE PLANT	2/5/2024	COOLING TOWERS	142,700	GPM	drift eliminators 0.0005%	0.0005	% DRIFT
OH-0391	VALENCIA PROJECT LLC	10/27/2023	Cooling Towers (P023, P024, P025)			A drift eliminator achieving “drift loss”□equal to or less than 0.0005 percent	0.0005	% DRIFT
NE-0068	AG PROCESSING INC - DAVID CITY	6/27/2023	Cooling Tower 1	12,660	GPM	There is a drift loss design specification with the mist eliminator (CE-8000) and a TDS concentration limit.	0.0005	% DRIFT
NE-0068	AG PROCESSING INC - DAVID CITY	6/27/2023	Cooling Tower 2	5,064	GPM	There is a drift loss design specification with the mist eliminator (CE-8001) and a TDS concentration limit.	0.0005	% DRIFT
NE-0064	NORFOLK CRUSH, LLC	11/21/2022	Cooling Tower	8,001	GPM	There is a drift loss design specification and a TDS concentration limit; controlled by a mist eliminator.	0.0005	% DRIFT
OH-0387	INTEL OHIO SITE	9/20/2022	Cooling Towers: P054 through P178			Drift eliminator	0.0005	% DRIFT
TX-0922	HOUSTON PLANT - 46307	6/13/2022	COOLING TOWER			Drift eliminators with 0.0005% drift	0.0005	% DRIFT
WV-0034	WEST VIRGINIA STEEL MILL	5/5/2022	Cooling Towers	90,000	GPM	High Efficiency Drift Eliminator at 0.0005%.	0.0005	% DRIFT
TX-0930	CENTURION BROWNSVILLE	10/19/2021	Cooling Tower			Drift eliminators required. Maximum drift 0.0005 percent. TDS limit of 3,500 ppmw in the cooling water. Daily sampling for TDS required, or weekly TDS sampling is allowed if conductivity is monitored daily and a TDS to conductivity ratio is established.	0.0005	% DRIFT
TX-0915	UNIT 5	3/17/2021	COOLING TOWER			Drift eliminators ”“ 0.0005%	0.0005	% DRIFT
WI-0311	SUPERIOR REFINING COMPANY LLC	9/27/2019	Cooling Tower No.1 (P80)	10,000	GPM	Drift eliminator, cooling additive control system that results in a total dissolved solids (TDS) concentration of not more than 3,000 ppm.	0.0005	% DRIFT
IN-0317	RIVERVIEW ENERGY CORPORATION	6/11/2019	Cooling tower EU-6001	533	GPM	drift eliminator	0.0005	% DRIFT
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Cooling Tower (P011)	231,333	GPM	High efficiency drift eliminator designed to achieve a 0.0005% drift rate and maintenance of a total dissolved solids (TDS) content not to exceed 2,000 ppm in the circulating cooling water based on a rolling 12-month average.	0.0005	% DRIFT
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	11/7/2017	Wet Mechanical Draft Cooling Tower (P003)	120,000	GPM	High efficiency drift eliminator designed to achieve a 0.0005% drift rate and total dissolved solids (TDS) content not to exceed 5,000 mg/l.	0.0005	% DRIFT
IN-0263	MIDWEST FERTILIZER COMPANY LLC	3/23/2017	EIGHTEEN CELL COOLING TOWER (EU-010)			HIGH EFFICIENCY DRIFT ELIMINATORS	0.0005	% DRIFT
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	3/9/2016	Mechanical draft cooling tower	465,815	GPM	Must have certified drift rate no more than 0.0005%.	0.0005	% DRIFT
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	7/14/2015	Mechanical draft cooling tower			high efficiency drift eliminators (integral part of the design)	0.0005	% DRIFT
OH-0364	OREGON ENERGY CENTER	5/20/2015	Cooling Towers #1 & #2 (P009 & P010)	115,037	GPM	advanced drift eliminators with a drift rate of less than 0.0005 percent and maintain the total dissolved solids (TDS) content of the circulating cooling water at 5,130 mg/L or less as a 24-hour rolling average	0.0005	% DRIFT

TABLE D-46

COOLING TOWERS, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024

LISTINGS FOR TPM_{10}

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0967	QUAIL RUN CARBON CAPTURE PLANT	2/5/2024	COOLING TOWERS	142700	GPM	drift eliminators 0.0005%	0.0005	% DRIFT
IL-0134	CRONUS CHEMICALS	12/21/2023	Cooling Tower	145310	GPM	High efficiency drift eliminators	0.0005	% DRIFT
LA-0401	KOCH METHANOL (KME) FACILITY	12/20/2023	CWT - Cooling Water Tower	200000	GPM	Use of High efficiency drift eliminators	0.0005	% DRIFT
LA-0394	GEISMAR PLANT	12/12/2023	04-22 - AO-5 Cooling Water Tower, W-S5401	47410	GPM	Implementation of a heat exchange leak detection and repair program consistent with 40 CFR 63 Subpart F requirements	0.0005	% DRIFT
OH-0391	VALENCIA PROJECT LLC	10/27/2023	Cooling Towers (P023, P024, P025)			A drift eliminator achieving “drift loss”□equal to or less than 0.0005 percent	0.0005	% DRIFT
OH-0387	INTEL OHIO SITE	9/20/2022	Cooling Towers: P054 through P178			Drift eliminator	0.0005	% DRIFT
TX-0922	HOUSTON PLANT - 46307	6/13/2022	COOLING TOWER			Drift eliminators with 0.0005% drift	0.0005	% DRIFT
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	6/3/2022	Cooling Tower	8400	GPM	High-efficiency drift eliminators.	0.0005	% DRIFT
TX-0930	CENTURION BROWNSVILLE	10/19/2021	Cooling Tower			Drift eliminators required. Maximum drift 0.0005 percent. TDS limit of 3,500 ppmw in the cooling water. Daily sampling for TDS required, or weekly TDS sampling is allowed if conductivity is monitored daily and a TDS to conductivity ratio is established.	0.0005	% DRIFT
TX-0915	UNIT 5	3/17/2021	COOLING TOWER			Drift eliminators "“ 0.0005%	0.0005	% DRIFT
WI-0311	SUPERIOR REFINING COMPANY LLC	9/27/2019	Cooling Tower No.1 (P80)	10000	GPM	Drift eliminator, cooling additive control system that results in a total dissolved solids (TDS) concentration of not more than 3,000 ppm.	0.0005	% DRIFT
AR-0161	SUN BIO MATERIAL COMPANY	9/23/2019	Cooling Towers			Drift Eliminators Low TDS	0.0005	% DRIFT
IN-0317	RIVERVIEW ENERGY CORPORATION	6/11/2019	Cooling tower EU-6001	533	GPM	drift eliminator	0.0005	% DRIFT
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Cooling Tower (P011)	231333	GPM	High efficiency drift eliminator designed to achieve a 0.0005% drift rate and maintenance of a total dissolved solids (TDS) content not to exceed 2,000 ppm in the circulating cooling water based on a rolling 12-month average.	0.0005	% DRIFT
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUCOOLINGTWR: Cooling Tower			High efficiency drift/mist eliminators	0.0005	% DRIFT
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	6/29/2018	EUCOOLTOWER (North Plant): Cooling Tower	170000	GPM	High efficiency drift/mist eliminators	0.0005	% DRIFT
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	6/29/2018	EUCOOLTOWER (South Plant): Cooling Tower	170000	GPM	High efficiency drift/mist eliminators.	0.0005	% DRIFT
OH-0376	IRONUNITS LLC - TOLEDO HBI	2/9/2018	Wet Cooling Tower (P005)	24766	GPM	drift eliminator with a maximum drift rate of 0.0005% and total dissolved solids (TDS) concentration of the cooling water less than or equal to 1,100 parts per million by weight (ppmw).	0.0005	% DRIFT

TABLE D-47

COOLING TOWERS, PERMIT DATES FROM 1/01/2013 THROUGH 11/06/2024

LISTINGS FOR $TPM_{2.5}$

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0967	QUAIL RUN CARBON CAPTURE PLANT	2/5/2024	COOLING TOWERS	142700	GPM	drift eliminators 0.0005%	0.0005	% DRIFT
IL-0134	CRONUS CHEMICALS	12/21/2023	Cooling Tower	145310	GPM	High efficiency drift eliminators	0.0005	% DRIFT
LA-0401	KOCH METHANOL (KME) FACILITY	12/20/2023	CWT - Cooling Water Tower	200000	GPM	Use of high efficiency drift eliminators	0.0005	% DRIFT
LA-0394	GEISMAR PLANT	12/12/2023	04-22 - AO-5 Cooling Water Tower, W-S5401	47410	GPM	Implementation of a heat exchange leak detection and repair program consistent with 40 CFR 63 Subpart F requirements	0.0005	% DRIFT
OH-0391	VALENCIA PROJECT LLC	10/27/2023	Cooling Towers (P023, P024, P025)			A drift eliminator achieving “drift loss” equal to or less than 0.0005 percent	0.0005	% DRIFT
OH-0387	INTEL OHIO SITE	9/20/2022	Cooling Towers: P054 through P178			Drift eliminator	0.0005	% DRIFT
TX-0922	HOUSTON PLANT - 46307	6/13/2022	COOLING TOWER			Drift eliminators with 0.0005% drift	0.0005	% DRIFT
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	6/3/2022	Cooling Tower	8400	GPM	High-efficiency drift eliminators.	0.0005	% DRIFT
TX-0930	CENTURION BROWNSVILLE	10/19/2021	Cooling Tower			Drift eliminators required. Maximum drift 0.0005 percent. TDS limit of 3,500 ppmw in the cooling water. Daily sampling for TDS required, or weekly TDS sampling is allowed if conductivity is monitored daily and a TDS to conductivity ratio is established.	0.0005	% DRIFT
TX-0915	UNIT 5	3/17/2021	COOLING TOWER			Drift eliminators "“ 0.0005%	0.0005	% DRIFT
TX-0881	EXXONMOBIL BEAUMONT REFINERY	1/10/2020	COOLING TOWERS			High efficiency drift eliminators to control drift to no more than 0.005%.	0.0005	% DRIFT
WI-0311	SUPERIOR REFINING COMPANY LLC	9/27/2019	Cooling Tower No.1 (P80)	10000	GPM	Drift eliminator, cooling additive control system that results in a total dissolved solids (TDS) concentration of not more than 3,000 ppm.	0.0005	% DRIFT
AR-0161	SUN BIO MATERIAL COMPANY	9/23/2019	Cooling Towers			Drift Eliminators Low TDS	0.0005	% DRIFT
IN-0317	RIVERVIEW ENERGY CORPORATION	6/11/2019	Cooling tower EU-6001	533	GPM	drift eliminator	0.0005	% DRIFT
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Cooling Tower (P011)	231333	GPM	High efficiency drift eliminator designed to achieve a 0.0005% drift rate and maintenance of a total dissolved solids (TDS) content not to exceed 2,000 ppm in the circulating cooling water based on a rolling 12-month average.	0.0005	% DRIFT
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	7/16/2018	EUCOOLINGTWR: Cooling Tower			High efficiency drift/mist eliminators	0.0005	% DRIFT
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	6/29/2018	EUCOOLTOWER (North Plant): Cooling Tower	170000	GPM	High efficiency drift/mist eliminators	0.0005	% DRIFT
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	6/29/2018	EUCOOLTOWER (South Plant): Cooling Tower	170000	GPM	High efficiency drift/mist eliminators.	0.0005	% DRIFT

Appendix E :
Air Dispersion Modeling Archive

Modeling Files to Support Air Permit Application for Homer City Generation, L.P. Project Modeling Analysis

April, 2025

This document summarizes the content of the modeling archive folders as described below. The modeling is in support of an air permit application for Homer City Generation, L.P. Project.

AERMAP	Contains AERMAP input/output files used to process terrain data to produce the receptor elevations and critical hill heights for use within the AERMOD model.
Version	**24142**

- **Class_I –** includes the receptors used to model impacts out to 50 kms from the Project to then calculate the impacts beyond 50 kms at the Class I areas to the south of the Project.
- **LoadAnalysis_SILs –** includes the nested Cartesian receptor grid extending out 20 km from the Project's centroid (Easting = 652529.00 m; Northing = 4486825.00 m). The .ROU file was used for load analysis and SIL model runs.
- **NED_Files –** 10-meter resolution National Elevation Dataset (NED) file used to determine receptor elevations and critical hill heights. These files were downloaded on March 6th, 2025.
- **Refined_Grid –** included the .ROU files used for refined modeling as needed to resolve the maximum $PM_{2.5}$ PSD increment concentration found outside of 100-meter spaced receptors from the original grid.

AERMOD	Contains AERMOD input/output files for the modeling in support of the PSD application.
Version	**24142**

- **01 Load_Analysis –** input and output AERMOD files for the load analysis of the GE units and FT8 units independently.
- **02 SIL –** input and output AERMOD files for the SIL runs of the project sources.
    - **PM10_24hr** – Base and Worst Case SIL runs used to support SIA determination, if applicable, for both NAAQS and PSD Increment. Each meteorological year was modeled separately.
    - **PM10_Ann** – Base and Worst Case SIL runs used to support SIA determination, if applicable, for NAAQS. Each meteorological year was modeled separately.
    - **PM25_24hr_1yr** – Base and Worst Case SIL runs used to support SIA determination, if applicable, for PSD Increment. Each meteorological year was modeled separately.
    - **PM25_24hr_5yr** – Base and Worst Case SIL runs used to support SIA determination, if applicable, for NAAQS.
    - **PM25_Ann_1yr** – Base and Worst Case SIL runs used to support SIA determination, if applicable, for PSD Increment. Each meteorological year was modeled separately.
    - **PM25_Ann_5yr** – Base and Worst Case SIL runs used to support SIA determination, if applicable, for NAAQS.
- **03 NAAQS –** input and output AERMOD files for the pollutants and averaging periods that exceeded their respective SIL. The controlling (i.e. worst-case) meteorological dataset from the SIL run was used for the NAAQS modeling.
- **04 PSD –** input and output AERMOD files for the PSD modeling for 24-hr and annual $PM_{2.5}$. For the controlling year of Annual $PM_{2.5}$ (2021), a refined receptor grid was conducted since the maximum impacts were beyond the 100-m spaced receptors of the original receptor grid.

- **05 Class_I –** input and output AERMOD files for the Class I area modeling and the excel files used to calculate the impacts at the Class I area distances.
- **06 Vegetation –** input and output AERMOD files for the monthly Beryllium and 3-month Lead runs.

Background_Source_Inventory	Contains inventory of nearby sources based on SIA's for PM_{10} and $PM_{2.5}$.

- *.xlsx : Spreadsheet containing inventory provided by PADEP and permitted emission rates used in the modeling.
- *.SRC : Source file formatted for input to AERMOD cumulative runs.

BPIP	Contains BPIP input and output files. The most recent version of BPIP, version 04274, was used in this modeling.
Version	**04274**

- Homer_City_BPIPPRM.inp : BPIP input file
- Homer_City_BPIPPRM.out : BPIP output file
- Homer_City_BPIPPRM.sum : BPIP summary file
- downwash_files – .BLD files created using the .OUT file to be used in model runs.

Executables	Contains the modeling executables used to run AERMOD and its preprocessors.

Met_Data	Contains AERMOD input/output files for the modeling in support of the PSD application.
Versions	**AERMET (24124); AERSURFACE (24142)**

- **PADEP-Provided –** 5-year (2020 – 2024) AERMET input/output files for Johnstown, PA provided by PADEP. Includes the default low wind option (Adjusted-Ustar). For this modeling application, the Adjusted-Ustar dataset was used.
- **Site_LandUse –** input and output AERSURFACE files used to determine land use around the project site.

SIA_Cumulative-Receptors	Contains an excel spreadsheet to determine the SIA for pollutants and subsequent receptor files for Increment and NAAQS modeling.

- **INC –** .ROU files containing the receptors within the SIA for PSD Increment modeling.
- **NAAQS –** .ROU files containing the receptors within the SIA for NAAQS modeling.
- **SIA_Calculator.xlsx –** used to determine which receptors are above the SIL for each pollutant and averaging period to create the SIA.

VISCREEN	Contains modeling files to conduct a visible plume analysis.
Versions	**VISCREEN; VISFREQ5**

- **VISCREEN_Level-II –** input and output Level II VISCREEN files used to determine the visibility impacts of the Project.
- **VISFREQ –** input and output VISFREQ files and excel spreadsheet used to determine the controlling stability class and windspeed that was used in the VISCREEN Level II modeling.

Appendix F :
Nearby Source Inventory

Procedure to Determine Nearby Sources for Homer City Air PM_{10} and $PM_{2.5}$ Dispersion Modeling

F.1 Introduction

For cumulative modeling, the impact of the facility, nearby sources, and regional background concentrations must be considered in the compliance demonstration. Appropriately accounting for all source contributions is an inherently discretionary exercise with use of best professional judgment in determining a representative background concentration and identifying nearby sources that need to be explicitly modeled. The United States Environmental Protection Agency (US EPA) recently issued *Guidance on Developing Background Concentrations for Use in Modeling Demonstrations* (Background Concentration Guidance), which provides a framework on developing background concentrations for use in cumulative modeling demonstrations.[42] This guidance identifies three key elements of a cumulative impact analysis: (1) the new or modifying source, (2) direct emissions from nearby sources, and (3) monitored background concentrations accounting for primary and/or secondary impacts from regional background sources and nearby sources not explicitly modeled. This discussion focuses on the components related to nearby sources and monitored background concentrations. As discussed in US EPA's guidance, care should be taken to avoid over conservatism through double-counting when selecting a regional background monitor(s) and the inventory of nearby sources that will be explicitly modeled.

F.2 Regional Background Concentration

Ambient air quality data are used to represent the contribution to total ambient air pollutant concentrations from non-modeled sources. As discussed in **Section 6.9** of this PSD Application, the Strongstown monitor (AQS Site ID: 42-063-004) and the Johnstown monitor (AQS Site ID: 42-021-0011) were identified as the most representative monitors for $PM_{2.5}$ and PM_{10}, respectively. The Strongstown monitor is located downwind (to the east) of the Project location and has been influenced by the previous coal operations at Homer City that ceased in July 2023. As a result, the background design concentration from the most recent 3-year period (2021-2023) is conservative given it contains influence from sources no longer in operation. For $PM_{2.5}$, the Johnstown monitor is selected as the most representative site given the next closest monitors are all located farther away (more than 15 miles farther) and heavily influenced by urban surroundings.

F.3 Consideration of Smoke from Wildfires and Dust Events Impacting Monitored Data

Particulate matter (PM) is a primary component of smoke. Wildfires can generate an exorbitant amount of smoke which can travel across entire continents. The Hazard Mapping System (HMS), developed and maintained by the National Oceanic and Atmospheric Administration (NOAA) National Environmental Satellite, Data, and Information Service (NESDIS), tracks wildfires and smoke transport across north America.[43] In recent years, wildfires have contributed to up to 25 percent of $PM_{2.5}$ across the United States, with nearly half in some western states.[44] The US EPA has acknowledged that events that are unusual or naturally occurring that can affect air quality but are not reasonably controllable using techniques that tribal, state or local air agencies may implement may be excluded from datasets used to calculate design concentrations. These events, also known as "exception events", may include wildfires, high wind dust events, prescribed burns, stratospheric ozone intrusion, and volcanic and seismic activities. In September of 2016, US EPA finalized the Exceptional Event Rule[45] that established a procedure for identifying if

[42] https://www.epa.gov/system/files/documents/2023-10/draft-guidance-on-developing-background-concentrations-for-use-in-modeling-demonstrations.pdf
[43] Hazard Mapping System (HMS). https://www.ospo.noaa.gov/Products/land/hms.html
[44] Burke, M. et at. (2021). The Changing Risk and Burden of Wildfire in the United States. Proc Natl Acad. Sci. 118(2):e2011048118. Available at: https://www.ncbi.nlm.nih.gov/pmc/articles/PMC7812759/
[45] US EPA, 2016. Treatment of Data Influenced by Exceptional Events. https://www.epa.gov/sites/default/files/2018-10/documents/exceptional_events_rule_revisions_2060-as02_final.pdf

air quality monitoring data has been influenced by an exceptional event and how to exclude these data from air quality design concentrations. In April 2019, US EPA further provided a mechanism for modifying background concentrations that do not qualify treatment as exceptional events (i.e., exceedances or violations of the air quality standards), but are impacted by events that would otherwise qualify for removal/adjustment.[46] The 2019 procedures are important for background concentration data due to the inclusion of near exceedance level concentrations that are still influenced by external events.

In accordance with US EPA's Exceptional Event Rule, PADEP has conducted analyses, identifying exceptional events impacting PM_{10} and $PM_{2.5}$ monitoring across the state. PADEP typically suggests using the highest 24-hour concentration over the latest complete 3-year period for PM_{10} background concentrations in NAAQS analysis to represent non-modeled sources. As shown in **Table F-1**, the top three (3) 24-hour averaged concentration values all occurred on days when smoke was impacting the state. PADEP identified this 3-day stretch (June 28 – July 1, 2023) as a PM exceptional event.[47] Based on the data presented, 54 μ/m^3 (the third highest value over the last three years) will be used as the PM_{10} background concentration as part of the NAAQS assessment. This is still conservative in the sense that this day was also impacted by wildfire smoke. This value is also only 2 $\mu g/m^3$ higher than the first highest non-wildfire smoke impacted day, so it's not an extreme outlier like the first and second ranked values from the 2021-2023 period.

Table F-1. PM_{10} Ambient Background Concentrations (Top 10 Values 2021-2023)

Pollutant	Averaging Period	AQS Site ID	Local Site Name	Date	Concentration ($\mu g/m^3$)	Influenced by Wildfire Smoke (Y/N)
PM_{10}	24-hour	420210011	Johnstown	6/29/2023	120	Yes
				6/28/2023	84	Yes
				6/30/2023	54	Yes
				7/20/2021	52	No
				6/16/2022	43	No
				3/9/2021	42	No
				12/22/2023	38	No
				6/6/2023	37	Yes
				7/17/2023	36	No
				12/21/2023	35	No

F.4 Analysis of Nearby Source Inventories

Background source inventory data for PM_{10} and $PM_{2.5}$ were obtained from PADEP. The size of the inventory was based upon the extent of the Project's significant impact area (SIA). Based on the SIA, the inventory list contained sources within approximately 23-25 km for $PM_{2.5}$ and 8 km for PM_{10}. These included sources in Indiana, Armstrong, and Westmoreland counties of Pennsylvania. A listing of these background inventory sources provided by PADEP are summarized in **Table F-2** and **Table F-3**, for $PM_{2.5}$ and PM_{10}, respectively.

US EPA's Background Concentration Guidance indicates that there should be an emphasis on the emissions data for multi-source situations. Based on US EPA Guidance, the hypothetical example in Appendix C of the Background Concentration Guidance, generally sources with less than 25 tons per year of actual $PM_{10}/PM_{2.5}$ emissions are likely represented in the selected regional monitors and therefore would be excluded from modeling those source's direct emissions. Larger sources may be included if they are not adequately represented by the monitor.

[46] US EPA, 2019: Additional Methods, Determinations, and Analyses to Modify Air Quality Data Beyond Exceptional Events. https://www.epa.gov/sites/default/files/2019-04/documents/clarification_memo_on_data_modification_methods.pdf
[47] PADEP eComment website: https://www.ahs.dep.pa.gov/eComment/

For $PM_{2.5}$, the rows highlighted in light blue in **Table F-2** denote sources with actual emissions (from 2023) above 25 tons per year (TPY). Those sources include Keystone Generating Station (Armstrong County), Conemaugh Generating Station (Indiana County), Seward Generating Station (Indiana County), and Armstrong Power (Armstrong County). All four (4) of these sources were in operation prior to the major source baseline date for $PM_{2.5}$ of October 20, 2010 indicating none of them consume $PM_{2.5}$ increment. As such, these sources were only included in the $PM_{2.5}$ NAAQS modeling and not included in the $PM_{2.5}$ PSD increment modeling since they are part of the baseline.

Figure F-1 illustrates the location of the Strongstown $PM_{2.5}$ monitor relative to the Project and inventory sources within 23 km of the Project. The four (4) larger $PM_{2.5}$ sources (Keystone Station, Armstrong Power, Seward Station, and Conemaugh Station) are denoted as pink circles in **Figure F-1**. Those sources that are less than 25 TPY of $PM_{2.5}$ emissions, with the vast majority of them having less than 2 TPY in 2023, are denoted by the orange circles in **Figure F-1**. All $PM_{2.5}$ inventory sources are located to the west or southwest of the Strongstown monitor (including the Project site). The prevailing winds from the representative Johnstown Airport are from the west and southwest, as shown in **Figure F-2** (wind rose). This highlights favorable transport of $PM_{2.5}$ plumes from these 20 inventory sources to the monitor. Except for the Torrence Quarry (No. 16 in **Figure F-1**), there are no significant terrain features between the inventory sources and the Strongstown monitor. However, the Torrence Quarry is situated in a very localized valley within Chestnut Ridge and, as shown in **Table F-2**, its 2023 $PM_{2.5}$ emissions were only about 15 TPY. Based on the orientation of the valley (northwest to southeast), it is likely that any plume transport from the quarry would tend to move east or southeast and away from the SIA of the Project.

Given the upwind location of the $PM_{2.5}$ inventory sources relative to the monitor, lack of significant terrain impeding the flow between source and monitor, and the magnitude of emissions well below the threshold recommended by US EPA guidance, the sources in **Figure F-1** denoted by orange circles are considered adequately accounted for in the monitoring data. Therefore, the only sources that were added to the modeling of the Project sources for the $PM_{2.5}$ NAAQS assessment were Keystone Station, Armstrong Power, Seward Station, and Conemaugh Station.

For PM_{10}, there are only seven (7) inventory sources within the 8 km SIA. The 2023 actual PM_{10} emissions from these sources are all at least an order of magnitude lower than the 25 TPY threshold mentioned in the US EPA Background Concentration Guidance. Based on this analysis, there are no inventory sources of PM_{10} to include in the model. However, to be conservative (and consistent with the modeling of $PM_{2.5}$), the four (4) larger PM sources of Keystone Station, Armstrong Power, Seward Station, and Conemaugh Station are also included in the PM_{10} NAAQS and PSD increment cumulative modeling. These sources are included in the PM_{10} increment modeling as well given the much earlier PM_{10} major source baseline date of January 6, 1975. Ultimately, including any additional sources in the PM_{10} NAAQS and PSD increment modeling is a conservative approach given these sources are well beyond the Project's SIA for PM_{10}.

Table F-2. Background Inventory Sources for $PM_{2.5}$ within 23 km of the Project

Plant Name	Permit Type	Permit Number	County	Distance (km)	UTM Zone	UTM East (M)	UTM North (M)	$PM_{2.5}$ Emissions (Tons/Year)
Conemaugh Station	Title V	32-00059	Indiana	18.89	17	664670	4472266	250.30
Keystone Station	Title V	03-00027	Armstrong	19.92	17	640176	4502361	99.62
Seward Station	Title V	32-00040	Indiana	18.54	17	666806	4474891	68.97
Armstrong Power	Title V	03-00975	Armstrong	18.54	17	639413	4499829	24.73
Torrance Quarry	State Only	65-00143	Westmoreland	13.84	17	652566	4472931	15.13
Fka Pellegrene Site	Title V	32-00266	Indiana	6.07	17	657995	4484035	1.84
Eastern Gas Trans & Storage Inc - South Bend Comp Sta	Title V	03-00180	Armstrong	18.79	17	638971	4499739	1.76
Armagh Station	Title V	32-00230	Indiana	13.62	17	662465	4477409	0.73
Girty Station			Armstrong	18.90	17	638916	4499831	0.69
Xto Energy Homer City Pp Comp Sta/Indiana			Indiana	2.32	17	652951	4489063	0.48
Clyde Comp Station			Indiana	14.04	17	663119	4477509	0.29
Egry Station			Indiana	12.76	17	639827	4486242	0.11
Diversified Production Llc Spurlin Cs			Indiana	7.47	17	649546	4493604	0.06
Creekside Comp Station			Indiana	15.31	17	653379	4502060	0.05
Malone Cs			Indiana	17.95	17	634962	4483332	0.04
Integrated Power Services	State Only	32-00227	Indiana	7.61	17	657293	4492741	0.03
Ernest Comp Sta			Indiana	6.75	17	656498	4481284	0.02
Infinity Natural Resources South Bend Comp Station			Armstrong	18.34	17	638893	4498995	0.01
Lowry 2 Left Borehole	State Only	32-00448	Indiana	5.67	17	654106	4481312	0.01
Windy Ridge Ind Park	State Only	32-00428	Indiana	7.91	17	652159	4494675	0.01

Notes: Light blue highlighted rows denote sources with 2023 annual emissions > 25 tons per year (TPY)

Table F-3. Background Inventory Sources for PM_{10} within 8 km of the Project

Plant Name	Permit Type	Permit Number	County	Distance (km)	UTM Zone	UTM East (M)	UTM North (M)	PM_{10} Emissions (Tons/Year)
Fka Pellegrene Site	Title V	32-00266	Indiana	6.07	17	657995	4484035	1.84
Xto Energy Homer City Pp Comp Sta/Indiana			Indiana	2.32	17	652951	4489063	0.48
Diversified Production Llc Spurlin Cs			Indiana	7.47	17	649546	4493604	0.06
Integrated Power Services	State Only	32-00227	Indiana	7.61	17	657293	4492741	0.03
Ernest Comp Sta			Indiana	6.75	17	656498	4481284	0.02
Windy Ridge Ind Park	State Only	32-00428	Indiana	7.91	17	652159	4494675	0.02
Lowry 2 Left Borehole	State Only	32-00448	Indiana	5.67	17	654106	4481312	0.01

F.5 Summary of Nearby Sources for Cumulative Modeling of the Homer City Project

A qualitative analysis of background monitoring data and offsite inventory was conducted to assess what offsite inventory sources would need to be explicitly modeled or if they would be adequately captured in the regional background monitoring data.

Consistent with US EPA's Background Concentration Guidance, it was determined that only four (4) larger sources of PM_{10} and $PM_{2.5}$ would need to be added to the modeling. The remaining sources are captured by the selected background monitor and were found to have low emissions (less than 25 TPY) of PM_{10} and $PM_{2.5}$ (based upon 2023 actual data from PADEP).

Figure F-1. Location of $PM_{2.5}$ Inventory Sources Relative to Strongstown Monitor

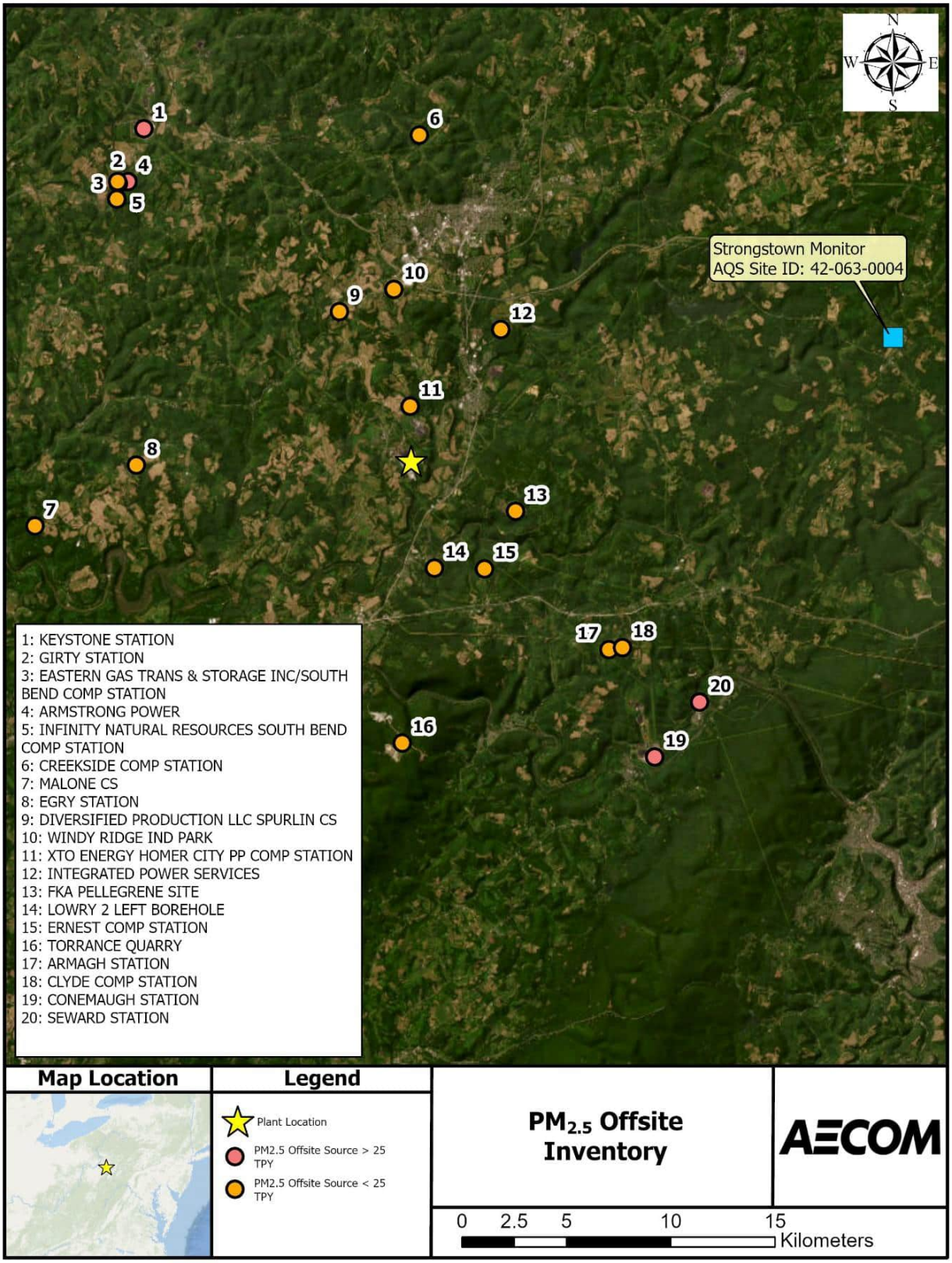
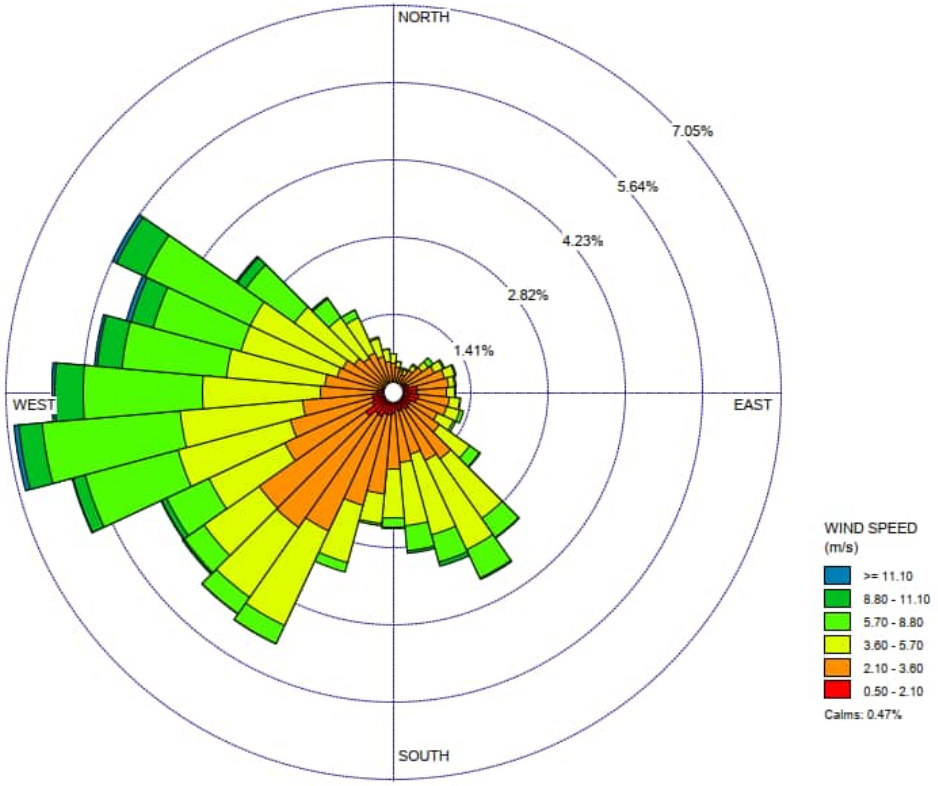


Figure F-2. Wind Rose for 2020-2024 at Johnstown Airport



Appendix G :
FLM AQRV Waiver

Connors, Jeffrey

From: Prosperi, Alexia - FS, WI <Alexia.Prosperi@usda.gov>
Sent: Thursday, March 6, 2025 3:51 PM
To: Connors, Jeffrey; Stacy, Andrea; Salazer, Holly; Childress, Evan S; Sandeno, Cynthia - FS, WV
Cc: Chemsak, Jacob; Balog, David; Fleck, Andrew; Roble, Daniel; Bonifacio, Henry; Gary R. Cline (gcline@homercityredevelopment.com); Mark Wroten; Warren, Christopher; Raphael, David J. (Dave.Raphael@klgates.com); Olson, Shawn - FS, WI; Gries, James - FS, WI; Don Shepherd (Don_Shepherd@nps.gov)
Subject: RE: AQRV Waiver Request

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Hi Jeff

Thank you for the notification. Given the information provided, the Forest Service is not requesting a Class I AQRV analysis for Dolly Sods or Otter Creek. Please reach out if you have any questions, or if any significant changes to the information provided occur.

Best,
Alexia

Alexia Prosperi
Air Resource Specialist
Forest Service
Eastern Region
p: 414-308-8669
alexia.prosperi@usda.gov
626 E. Wisconsin Ave
Milwaukee, WI 53202

From: Connors, Jeffrey <Jeffrey.Connors@aecom.com>
Sent: Thursday, February 20, 2025 4:33 PM
To: Prosperi, Alexia - FS, WI <Alexia.Prosperi@usda.gov>; Stacy, Andrea <Andrea_Stacy@nps.gov>; Salazer, Holly <Holly_Salazer@nps.gov>; Childress, Evan S <evan_childress@nps.gov>
Cc: Chemsak, Jacob <jachemsak@pa.gov>; Balog, David <dbalog@pa.gov>; Fleck, Andrew <afleck@pa.gov>; Roble, Daniel <droble@pa.gov>; Bonifacio, Henry <hbonifacio@pa.gov>; Gary R. Cline (gcline@homercityredevelopment.com) <gcline@homercityredevelopment.com>; Mark Wroten <mwroten@homercityredevelopment.com>; Warren,

Christopher <Christopher.Warren@aecom.com>; Raphael, David J. (Dave.Raphael@klgates.com) <Dave.Raphael@klgates.com>
Subject: AQRV Waiver Request

Good Afternoon Alexia and Andrea,

Homer City Generation, L.P. (Homer City) is considering a potential project to construct and operate up to seven (7) combined-cycle combustion turbines (CCs) along with up to ten (10) aeroderivative gas turbines (ADGTs) at the former Homer City Generating Station ("the Station"), located in Indiana County, Pennsylvania. Construction and operation of the new CCs and ADGTs will also include new ancillary equipment such as auxiliary boiler(s), emergency generator(s), emergency fire water pump engine(s), cooling towers, and fuel gas heater(s). The new CCs and ADGTs, in final configuration, along with all associated ancillary equipment, will be herein referred to as the "Project." The new CCs and ADGTs will be fueled only by pipeline quality natural gas. Each CC and ADGT will be equipped with a selective catalytic reduction (SCR) to minimize nitrogen oxide (NO_X) emissions and an oxidation catalyst to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions.

The former Station was an existing "major source" of criteria air pollutants, and the Project constitutes a "major modification" under Prevention of Significant Deterioration (PSD) permitting requirements. As such, Homer City will be applying to the Pennsylvania Department of Environmental Protection (PADEP) for a Plan Approval authorizing construction and operation of the Project. Homer City will use emission offsets, associated with the retirement of the coal-fired boilers, to net out of PSD review for NOx, CO, and sulfur dioxide (SO_2). Lead (Pb) emissions from the Project will not exceed the PSD Significant Emission Rate (SER) threshold. As such, the Project will be subject to PSD requirements under the New Source Review (NSR) program for emissions of particulate matter (PM), particulate matter (PM) equal to and less than 10 microns in diameter (PM_{10}), PM equal to and less than 2.5 microns in diameter ($PM_{2.5}$), VOC, sulfuric acid mist (SAM, or H_2SO_4), and greenhouse gases (GHG). Since Pennsylvania is located in the Ozone Transport Region (OTR), the Project will be subject to Non-attainment NSR (NAA-NSR) for VOC emissions.

The three (3) PSD Class I areas located within 300 km of the Project site:
Dolly Sods Wilderness: 165 km
Otter Creek Wilderness: 166 km
Shenandoah National Park: 197 km

The FLAG 2010 guidance states that a proposed source with a Q/d ratio less than 10 will likely not have an adverse impact on air quality related values (AQRVs), where 'Q' is the annual steady-state equivalent emission rate based on the sum of NO_X, SO_2, PM_{10}, and H_2SO_4 emissions (in tons per year, based on maximum 24-hour emissions) and 'd' is the distance (km) to the closest Class I area. As an initial screening tool, the Q/d ratio is used to determine whether a proposed source may affect AQRVs of Class I areas and warrants further analysis. Please note that for purposes of this Project, there are net decreases in emissions of SO_2 and NO_X, as such, the Q/d calculation for this Project only includes $PM_{10}/PM_{2.5}$ and H_2SO_4.

For the proposed GE 7HA.02 CCs, Project, 'Q' is 867.7 tons per year based on the following calculation: 23.7 lb/hr ($PM_{10}/PM_{2.5}$) + 4.6 lb/hr (H_2SO_4) = 28.3 lbs/hr/CT x 7 GE 7HA.02 CCs = 198.1 lbs/hr x 8,760 hrs/yr ÷ 2000 lbs/ton = 867.7 tons/year.
For the proposed FT8 CTs, Project, 'Q' is 192.7 tons per year based on the following calculation: 3.0 lb/hr ($PM_{10}/PM_{2.5}$) + 1.4 lb/hr (H_2SO_4) = 4.4 lbs/hr/CT x 10 FT8 CTs = 44.0 lbs/hr x 8,760 hrs/yr ÷ 2000 lbs/ton = 192.7 tons/year.

The combined Q for the GE 7HA.02 and FT8 units is 1,060.4 tons/year. Relative to the Dolly Sods Wilderness Area, Q = 1,060.4 tons/year, d=165, and Q/d ratio = 6.4.
The net change in Project emissions of SO_2 and NO_X when accounting for the coal plant shutdown is -4,263 and -1,064 tons/year, respectively.

If the net changes for these pollutants were factors into the Q calculation, the resultant Q would be less than zero resulting in a Q/D ratio less than zero.

Attached please find a completed "Request for Determination of Need for a Class I AQRV Modeling Analysis" form that provides all the relevant information to make a determination regarding this project.

It would be greatly appreciated if you could provide a response within the next two weeks so that your determination may be included in the air permit application.

Thank you for considering our request and we look forward to your response.
If you have any questions, please contact me.

Regards,
Jeff Connors
Supervisor, Air Quality Services (East)
Environment
D 978.905.2166
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Connors, Jeffrey

From: Stacy, Andrea <Andrea_Stacy@nps.gov>
Sent: Thursday, February 27, 2025 8:35 PM
To: Connors, Jeffrey; Prosperi, Alexia - FS, WI; Salazer, Holly; Childress, Evan S; Shepherd, Don
Cc: Chemsak, Jacob; Balog, David; Fleck, Andrew; Roble, Daniel; Bonifacio, Henry; Gary R. Cline (gcline@homercityredevelopment.com); Mark Wroten; Warren, Christopher; Raphael, David J. (Dave.Raphael@klgates.com)
Subject: RE: AQRV Waiver Request

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Jeffery,

Thank you for providing this notification regarding the potential combustion turbines project at the former Homer City Generating Station, located in Indiana County, Pennsylvania. Based on the proposed emission rates and distances from Shenandoah National Park, it is unlikely that modeling would show any significant impacts to Air Quality Related Values (AQRV) in this Class I area. Therefore, the National Park Service (NPS) is not requesting a Class I AQRV analysis for this park. Please note that we are only addressing the need for an AQRV analysis for Class I areas managed by the NPS, and the state agency may still require a Class I increment analysis.

Feel free to reach back out to me if you have additional questions, or if the emissions or the nature of the project changes significantly. Finally, we request that PADEP provide the NPS with a copy of the final permit application, the draft and final permits and associated staff analyses once these materials are available.

Thank you for keeping us informed and involving the National Park Service in the project review.

Regards,
Andrea

Andrea Stacy
National Park Service
Air Resources Division
Phone: 303-969-2816
Email: andrea_stacy@nps.gov

12795 W. Alameda Pkwy | P.O. Box 25287 | Denver, CO 80225

From: Connors, Jeffrey <Jeffrey.Connors@aecom.com>
Sent: Thursday, February 20, 2025 3:33 PM
To: Prosperi, Alexia - FS, WI <alexia.prosperi@usda.gov>; Stacy, Andrea <Andrea_Stacy@nps.gov>; Salazer, Holly

<Holly_Salazer@nps.gov>; Childress, Evan S <evan_childress@nps.gov>
Cc: Chemsak, Jacob <jachemsak@pa.gov>; Balog, David <dbalog@pa.gov>; Fleck, Andrew <afleck@pa.gov>; Roble, Daniel <droble@pa.gov>; Bonifacio, Henry <hbonifacio@pa.gov>; Gary R. Cline (gcline@homercityredevelopment.com) <gcline@homercityredevelopment.com>; Mark Wroten <mwroten@homercityredevelopment.com>; Warren, Christopher <Christopher.Warren@aecom.com>; Raphael, David J. (Dave.Raphael@klgates.com) <Dave.Raphael@klgates.com>
Subject: [EXTERNAL] AQRV Waiver Request

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Good Afternoon Alexia and Andrea,

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The three (3) PSD Class I areas located within 300 km of the Project site:
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Shenandoah National Park: 197 km

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purposes of this Project, there are net decreases in emissions of SO_2 and NO_X, as such, the Q/d calculation for this Project only includes $PM_{10}/PM_{2.5}$ and H_2SO_4.

For the proposed GE 7HA.02 CCs, Project, 'Q' is 867.7 tons per year based on the following calculation: 23.7 lb/hr ($PM_{10}/PM_{2.5}$) + 4.6 lb/hr (H_2SO_4) = 28.3 lbs/hr/CT x 7 GE 7HA.02 CCs = 198.1 lbs/hr x 8,760 hrs/yr ÷ 2000 lbs/ton = 867.7 tons/year.
For the proposed FT8 CTs, Project, 'Q' is 192.7 tons per year based on the following calculation: 3.0 lb/hr ($PM_{10}/PM_{2.5}$) + 1.4 lb/hr (H_2SO_4) = 4.4 lbs/hr/CT x 10 FT8 CTs = 44.0 lbs/hr x 8,760 hrs/yr ÷ 2000 lbs/ton = 192.7 tons/year.

The combined Q for the GE 7HA.02 and FT8 units is 1,060.4 tons/year. Relative to the Dolly Sods Wilderness Area, Q = 1,060.4 tons/year, d=165, and Q/d ratio = 6.4.
The net change in Project emissions of SO_2 and NO_X when accounting for the coal plant shutdown is -4,263 and -1,064 tons/year, respectively.
If the net changes for these pollutants were factors into the Q calculation, the resultant Q would be less than zero resulting in a Q/D ratio less than zero.

Attached please find a completed "Request for Determination of Need for a Class I AQRV Modeling Analysis" form that provides all the relevant information to make a determination regarding this project.

It would be greatly appreciated if you could provide a response within the next two weeks so that your determination may be included in the air permit application.

Thank you for considering our request and we look forward to your response.
If you have any questions, please contact me.

Regards,
Jeff Connors
Supervisor, Air Quality Services (East)
Environment
D 978.905.2166
M 978.660.4097
jeffrey.connors@aecom.com

AECOM
250 Apollo Drive
Chelmsford, MA 01824-3627
978-905-2100 (main)
978-905-2101 (fax)
aecom.com

LinkedIn Twitter Facebook Instagram

Appendix H :
Acid Rain Forms

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 05/31/2025

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ■ **new** ☐ **revised** ☐ **for ARP permit renewal**

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code
Homer City Generation	PA	TBD

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
CC1	Yes
CC2	Yes
CC3	Yes
CC4	Yes
CC5	Yes
CC6	Yes
CC7	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

Facility (Source) Name (from STEP 1) Homer City Generation

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
   (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
   (ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:
   (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
   (ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
   (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
   (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
   (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
   (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Facility (Source) Name (from STEP 1) Homer City Generation

STEP 3, Cont'd.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
   (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
   (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
   (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
   (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
   (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
   (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Facility (Source) Name (from STEP 1)	Homer City Generation

STEP 3, Cont'd.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a source can hold; provided, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Certification

Read the certification statement, sign, and date.

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Mark Wroten	
Signature 	Date 4.1.2025

Certificate of Representation

See instructions and 40 CFR 72.24, 97.416, 97.516, 97.616, 97.716, 97.816, and 97.916, 97.1016, or a comparable state regulation, as applicable. Note that the designated representative identified on this form is also the certifying official responsible for making related submissions for the identified unit(s), under additional programs, as indicated in the instructions.

This submission is: ☒ **New** ☐ **Revised (revised submissions must be complete; see instructions)**

STEP 1
Provide information for the plant

Plant Name: Homer City Generation	State: PA	Plant Code: TBD
County Name: Indiana		
Latitude: 40.51540	Longitude: -79.19657	

STEP 2
Enter requested information for the designated representative

Name: Mark Wroten	Title: Deputy Chief Operating Officer		
Company Name: Homer City Generation, L.P.			
Mailing Address: 1750 Power Plant Road	City: Homer City	State: PA	Zip Code: 15748-8009
Phone Number: 870-559-6000	Fax Number:		
Email Address: mwroten@homercityredevelopment.com			

STEP 3
Enter requested information for the alternate designated representative

Name: Michael Levesque	Title: Chief Operating Officer		
Company Name: Homer City Generation, L.P.			
Mailing Address: 1750 Power Plant Road	City: Homer CIty	State: PA	Zip Code: 15748-8009
Phone Number: 870-559-6000	Fax Number:		
Email Address: mlevesque@homercityredevelopment.com			

UNIT INFORMATION

STEP 4: **Complete a separate page 2 for each unit located at the plant identified in STEP 1** (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine). Do not list duct burners. Indicate each program to which the unit is subject and enter all other unit-specific information. See instructions for details.

Applicable Program(s):

- ■ Acid Rain
- ■ CSAPR NO_X Annual
- ☐ CSAPR NO_X Ozone Season Group 1
- ☐ CSAPR NO_X Ozone Season Group 2
- ■ CSAPR NOx Ozone Season Group 3
- ■ CSAPR SO_2 Group 1
- ☐ CSAPR SO_2 Group 2
- ☐ Texas SO_2

Additional Program(s):

- ■ GHG NSPS
- ☐ MATS
- ☐ NO_X SIP Call

Unit ID#	Unit Type	Source Category	Generator ID Number (Maximum 8 characters)	Acid Rain Nameplate Capacity (MWe)	CSAPR / Texas SO_2 / Other Nameplate Capacity (MWe)
CC1	CC	Electricity Generation	CC1TG	TBD	TBD
		NAICS Code: 221112	CC1ST	TBD	TBD

Enter the date the unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy):	Is this unit located in Indian country?	Has this unit ever operated at another location?
Check One: ☐ Actual Date ■ Projected Date	Check One: ☐ Yes ■ No	Check One: ☐ Yes ■ No

Company Name: Homer City Generation, L.P.	■ Owner ■ Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator

UNIT INFORMATION

STEP 4: **Complete a separate page 2 for each unit located at the plant identified in STEP 1** (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine). Do not list duct burners. Indicate each program to which the unit is subject and enter all other unit-specific information. See instructions for details.

Applicable Program(s):

- ☒ Acid Rain
- ☒ CSAPR NO_X Annual
- ☐ CSAPR NO_X Ozone Season Group 1
- ☐ CSAPR NO_X Ozone Season Group 2
- ☒ CSAPR NOx Ozone Season Group 3
- ☒ CSAPR SO_2 Group 1
- ☐ CSAPR SO_2 Group 2
- ☐ Texas SO_2

Additional Program(s):

- ☒ GHG NSPS
- ☐ MATS
- ☐ NO_X SIP Call

Unit ID#	Unit Type	Source Category	Generator ID Number (Maximum 8 characters)	Acid Rain Nameplate Capacity (MWe)	CSAPR / Texas SO_2 / Other Nameplate Capacity (MWe)
CC2	CC	Electricity Generation	CC2TG	TBD	TBD
		NAICS Code: 221112	CC2ST	TBD	TBD

Enter the date the unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy):	Is this unit located in Indian country?	Has this unit ever operated at another location?
Check One: ☐ Actual Date ☒ Projected Date	Check One: ☐ Yes ☒ No	Check One: ☐ Yes ☒ No

Company Name: Homer City Generation, L.P.	☒ Owner ☒ Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator

UNIT INFORMATION

STEP 4: **Complete a separate page 2 for each unit located at the plant identified in STEP 1** (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine). Do not list duct burners. Indicate each program to which the unit is subject and enter all other unit-specific information. See instructions for details.

Applicable Program(s):

- ☒ Acid Rain
- ☒ CSAPR NO_X Annual
- ☐ CSAPR NO_X Ozone Season Group 1
- ☐ CSAPR NO_X Ozone Season Group 2
- ☒ CSAPR NOx Ozone Season Group 3
- ☒ CSAPR SO_2 Group 1
- ☐ CSAPR SO_2 Group 2
- ☐ Texas SO_2

Additional Program(s):

- ☒ GHG NSPS
- ☐ MATS
- ☐ NO_X SIP Call

Unit ID#	Unit Type	Source Category	Generator ID Number (Maximum 8 characters)	Acid Rain Nameplate Capacity (MWe)	CSAPR / Texas SO_2 / Other Nameplate Capacity (MWe)
CC3	CC	Electricity Generation	CC3TG	TBD	TBD
		NAICS Code: 221112	CC3ST	TBD	TBD

Enter the date the unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy):	Is this unit located in Indian country?	Has this unit ever operated at another location?
Check One: ☐ Actual Date ☒ Projected Date	Check One: ☐ Yes ☒ No	Check One: ☐ Yes ☒ No

Company Name: Homer City Generation, L.P.	☒ Owner ☒ Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator

UNIT INFORMATION

STEP 4: **Complete a separate page 2 for each unit located at the plant identified in STEP 1** (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine). Do not list duct burners. Indicate each program to which the unit is subject and enter all other unit-specific information. See instructions for details.

Applicable Program(s):

- ☒ Acid Rain
- ☒ CSAPR NO_X Annual
- ☐ CSAPR NO_X Ozone Season Group 1
- ☐ CSAPR NO_X Ozone Season Group 2
- ☒ CSAPR NOx Ozone Season Group 3
- ☒ CSAPR SO_2 Group 1
- ☐ CSAPR SO_2 Group 2
- ☐ Texas SO_2

Additional Program(s):

- ☒ GHG NSPS
- ☐ MATS
- ☐ NO_X SIP Call

Unit ID#	Unit Type	Source Category	Generator ID Number (Maximum 8 characters)	Acid Rain Nameplate Capacity (MWe)	CSAPR / Texas SO_2 / Other Nameplate Capacity (MWe)
CC4	CC	Electricity Generation	CC4TG	TBD	TBD
		NAICS Code: 221112	CC4SG	TBD	TBD

Enter the date the unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy):	Is this unit located in Indian country?	Has this unit ever operated at another location?
Check One: ☐ Actual Date ☒ Projected Date	Check One: ☐ Yes ☒ No	Check One: ☐ Yes ☒ No

Company Name: Homer City Generation, L.P.	☒ Owner ☒ Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator

UNIT INFORMATION

STEP 4: **Complete a separate page 2 for each unit located at the plant identified in STEP 1** (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine). Do not list duct burners. Indicate each program to which the unit is subject and enter all other unit-specific information. See instructions for details.

Applicable Program(s):

- ☒ Acid Rain
- ☒ CSAPR NO_X Annual
- ☐ CSAPR NO_X Ozone Season Group 1
- ☐ CSAPR NO_X Ozone Season Group 2
- ☒ CSAPR NOx Ozone Season Group 3
- ☒ CSAPR SO_2 Group 1
- ☐ CSAPR SO_2 Group 2
- ☐ Texas SO_2

Additional Program(s):

- ☒ GHG NSPS
- ☐ MATS
- ☐ NO_X SIP Call

Unit ID#	Unit Type	Source Category	Generator ID Number (Maximum 8 characters)	Acid Rain Nameplate Capacity (MWe)	CSAPR / Texas SO_2 / Other Nameplate Capacity (MWe)
CC5	CC	Electricity Generation	CC5TG	TBD	TBD
		NAICS Code: 221112	CC5ST	TBD	TBD

Enter the date the unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy):	Is this unit located in Indian country?	Has this unit ever operated at another location?
Check One: ☐ Actual Date ☒ Projected Date	Check One: ☐ Yes ☒ No	Check One: ☐ Yes ☒ No

Company Name: Homer City Generation, L.P.	☒ Owner ☒ Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator

UNIT INFORMATION

STEP 4: **Complete a separate page 2 for each unit located at the plant identified in STEP 1** (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine). Do not list duct burners. Indicate each program to which the unit is subject and enter all other unit-specific information. See instructions for details.

Applicable Program(s):

- ☒ Acid Rain
- ☒ CSAPR NO_X Annual
- ☐ CSAPR NO_X Ozone Season Group 1
- ☐ CSAPR NO_X Ozone Season Group 2
- ☒ CSAPR NOx Ozone Season Group 3
- ☒ CSAPR SO_2 Group 1
- ☐ CSAPR SO_2 Group 2
- ☐ Texas SO_2

Additional Program(s):

- ☒ GHG NSPS
- ☐ MATS
- ☐ NO_X SIP Call

Unit ID#	Unit Type	Source Category	Generator ID Number (Maximum 8 characters)	Acid Rain Nameplate Capacity (MWe)	CSAPR / Texas SO_2 / Other Nameplate Capacity (MWe)
CC6	CC	Electricity Generation	CC6TG	TBD	TBD
		NAICS Code: 221112	CC6ST	TBD	TBD

Enter the date the unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy):	Is this unit located in Indian country?	Has this unit ever operated at another location?
Check One: ☒ Actual Date ☐ Projected Date	Check One: ☐ Yes ☒ No	Check One: ☐ Yes ☒ No

Company Name: Homer City Generation, L.P.	☒ Owner ☒ Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator

UNIT INFORMATION

STEP 4: **Complete a separate page 2 for each unit located at the plant identified in STEP 1** (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine). Do not list duct burners. Indicate each program to which the unit is subject and enter all other unit-specific information. See instructions for details.

Applicable Program(s):

- ☒ Acid Rain
- ☒ CSAPR NO_X Annual
- ☐ CSAPR NO_X Ozone Season Group 1
- ☐ CSAPR NO_X Ozone Season Group 2
- ☒ CSAPR NOx Ozone Season Group 3
- ☒ CSAPR SO_2 Group 1
- ☐ CSAPR SO_2 Group 2
- ☐ Texas SO_2

Additional Program(s):

- ☒ GHG NSPS
- ☐ MATS
- ☐ NO_X SIP Call

Unit ID#	Unit Type	Source Category	Generator ID Number (Maximum 8 characters)	Acid Rain Nameplate Capacity (MWe)	CSAPR / Texas SO_2 / Other Nameplate Capacity (MWe)
CC7	CC	Electricity Generation	CC7TG	TBD	TBD
		NAICS Code: 221112	CC7ST	TBD	TBD

Enter the date the unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy):	Is this unit located in Indian country?	Has this unit ever operated at another location?
Check One: ☐ Actual Date ☒ Projected Date	Check One: ☐ Yes ☒ No	Check One: ☐ Yes ☒ No

Company Name: Homer City Generation, L.P.	☒ Owner ☒ Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator

STEP 5: Read the applicable certification statements, sign, and date.

Acid Rain Program

I certify that I was selected as the 'designated representative' or 'alternate designated representative', as applicable, by an agreement binding on the owners and operators of the affected source and each affected unit at the source.

I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and each affected unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the affected source and each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the designated representative or alternate designated representative, as applicable, and of the agreement by which I was selected to each owner and operator of the affected source and each affected unit at the source and; allowances and proceeds of transactions involving allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of allowances by contract, allowances and proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

CSAPR NO_X Annual Trading Program

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CSAPR NO_X Annual unit at the source.

I certify that I have all the necessary authority to carry out my duties and responsibilities under the CSAPR NO_X Annual Trading Program on behalf of the owners and operators of the source and of each CSAPR NO_X Annual unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CSAPR NO_X Annual unit, or where a utility or industrial customer purchases power from a CSAPR NO_X Annual unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CSAPR NO_X Annual unit at the source; and CSAPR NO_X Annual allowances and; proceeds of transactions involving CSAPR NO_X Annual allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CSAPR NO_X Annual allowances by contract, CSAPR NO_X Annual allowances and proceeds of transactions involving CSAPR NO_X Annual allowances will be deemed to be held or distributed in accordance with the contract.

CSAPR NO_X Ozone Season Group 1 Trading Program

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CSAPR NO_X Ozone Season Group 1 unit at the source.

I certify that I have all the necessary authority to carry out my duties and responsibilities under the CSAPR NO_X Ozone Season Group 1 Trading Program on behalf of the owners and operators of the source and of each CSAPR NO_X Ozone Season Group 1 unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CSAPR NO_X Ozone Season Group 1 unit, or where a utility or industrial customer purchases power from a CSAPR NO_X Ozone Season Group 1 unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CSAPR NO_X Ozone Season Group 1 unit at the source; and CSAPR NO_X Ozone Season Group 1 allowances and proceeds of transactions involving CSAPR NO_X Ozone Season Group 1 allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CSAPR NO_X Ozone Season Group 1 allowances by contract, CSAPR NO_X Ozone Season Group 1 allowances and proceeds of transactions involving CSAPR NO_X Ozone Season Group 1 allowances will be deemed to be held or distributed in accordance with the contract.

CSAPR NO_X Ozone Season Group 2 Trading Program

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source.

I certify that I have all the necessary authority to carry out my duties and responsibilities under the CSAPR NO_X Ozone Season Group 2 Trading Program on behalf of the owners and operators of the source and of each CSAPR NO_X Ozone Season Group 2 unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CSAPR NO_X Ozone Season Group 2 unit, or where a utility or industrial customer purchases power from a CSAPR NO_X Ozone Season Group 2 unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CSAPR NO_X Ozone Season Group 2 unit at the source; and CSAPR NO_X Ozone Season Group 2 allowances and proceeds of transactions involving CSAPR NO_X Ozone Season Group 2 allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CSAPR NO_X Ozone Season Group 2 allowances by contract, CSAPR NO_X Ozone Season Group 2 allowances and proceeds of transactions involving CSAPR NO_X Ozone Season Group 2 allowances will be deemed to be held or distributed in accordance with the contract.

CSAPR NO_X Ozone Season Group 3 Trading Program

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CSAPR NO_X Ozone Season Group 3 unit at the source.

I certify that I have all the necessary authority to carry out my duties and responsibilities under the CSAPR NO_X Ozone Season Group 3 Trading Program on behalf of the owners and operators of the source and of each CSAPR NO_X Ozone Season Group 3 unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CSAPR NO_X Ozone Season Group 3 unit, or where a utility or industrial customer purchases power from a CSAPR NO_X Ozone Season Group 3 unit under a life of the unit, firm power contractual arrangement, I certify that:
I have given a written notice of my selection as the designated representative or alternate designated representative, as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CSAPR NO_X Ozone Season Group 3 unit at the source; and CSAPR NO_X Ozone Season Group 3 allowances and proceeds of transactions involving CSAPR NO_X Ozone Season Group 3 allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CSAPR NO_X Ozone Season Group 3 allowances by contract, CSAPR NO_X Ozone Season Group 3 allowances and proceeds of transactions involving CSAPR NO_X Ozone Season Group 3 allowances will be deemed to be held or distributed in accordance with the contract.

CSAPR SO_2 Group 1 Trading Program

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source.

I certify that I have all the necessary authority to carry out my duties and responsibilities under the CSAPR SO_2 Group 1 Trading Program on behalf of the owners and operators of the source and of each CSAPR SO_2 Group 1 unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CSAPR SO_2 Group 1 unit, or where a utility or industrial customer purchases power from a CSAPR SO_2 Group 1 unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the ‘designated representative’ or ‘alternate designated representative’, as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CSAPR SO_2 Group 1 unit at the source; and CSAPR SO_2 Group 1 allowances and proceeds of transactions involving CSAPR SO_2 Group 1 allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CSAPR SO_2 Group 1 allowances by contract, CSAPR SO_2 Group 1 allowances and proceeds of transactions involving CSAPR SO_2 Group 1 allowances will be deemed to be held or distributed in accordance with the contract.

CSAPR SO_2 Group 2 Trading Program

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CSAPR SO_2 Group 2 unit at the source.

I certify that I have all the necessary authority to carry out my duties and responsibilities under the CSAPR SO_2 Group 2 Trading Program on behalf of the owners and operators of the source and of each CSAPR SO_2 Group 2 unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CSAPR SO_2 Group 2 unit, or where a utility or industrial customer purchases power from a CSAPR SO_2 Group 2 unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CSAPR SO_2 Group 2 unit at the source; and CSAPR SO_2 Group 2 allowances and proceeds of transactions involving CSAPR SO_2 Group 2 allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CSAPR SO_2 Group 2 allowances by contract, CSAPR SO_2 Group 2 allowances and proceeds of transactions involving CSAPR SO_2 Group 2 allowances will be deemed to be held or distributed in accordance with the contract.

Texas SO_2 Trading Program

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each Texas SO_2 Trading Program unit at the source.

I certify that I have all the necessary authority to carry out my duties and responsibilities under the Texas SO_2 Trading Program on behalf of the owners and operators of the source and of each Texas SO_2 Trading Program unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a Texas SO_2 Trading Program unit, or where a utility or industrial customer purchases power from a Texas SO_2 Trading Program unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each Texas SO_2 Trading Program unit at the source; and Texas SO_2 Trading Program allowances and proceeds of transactions involving Texas SO_2 Trading Program allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of Texas SO_2 Trading Program allowances by contract, Texas SO_2 Trading Program allowances and proceeds of transactions involving Texas SO_2 Trading Program allowances will be deemed to be held or distributed in accordance with the contract.

General

I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Signature (Designated Representative)	Date: 4.1.2025
Signature (Alternate Designated Representative)	Date: 4/1/25

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 05/31/2025

New Unit Exemption

For more information, see instructions and refer to 40 CFR 72.7

This submission is: ☑ **New** ☐ **Revised**

STEP 1
Identify the new unit by plant name, State, Plant Code (ORISPL) and unit ID#.

Plant Name	State	Plant Code	Unit ID#
Homer City Generation	PA	TBD	FT801

STEP 2
List the generator ID numbers and, to one decimal place, the nameplate capacity of each generator served by the unit. Then total nameplate capacity and enter the result.

GEN ID #	GEN ID #	GEN ID #	GEN ID #	GEN ID #
ADGT1				
25.0 MWe	MWe	MWe	MWe	MWe

TOTAL
25.0 MWe

STEP 3
List all fuels currently burned or expected to be burned, by the unit and the percent sulfur content by weight of each.

Fuel (current)	Sulfur Content (current)	Fuel (expected)	Sulfur Content (expected)
Natural Gas	0.0016 %	Natural Gas	0.0016 %
Natural Gas	0.0016 %	Natural Gas	0.0016 %

STEP 4
Identify the first full calendar year in which the unit meets (or will meet) the requirements of 40 CFR 72.7(a).

January 1, 2026 .

STEP 5
Read the special provisions.

Special Provisions

(1) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 72.7 shall (i) comply with the requirements of 40 CFR 72.7(a) for all periods for which the unit is exempt under 40 CFR 72.7 and (ii) comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.
(2) For any period for which a unit is exempt under 40 CFR 72.7, the unit is not an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71 and is not eligible to be an opt-in source under 40 CFR part 74. As an unaffected unit, the unit shall continue to be subject to any other applicable requirements under 40 CFR parts 70 and 71.
(3) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 72.7 shall retain at the source that includes the unit records demonstrating that the requirements of 40 CFR 72.7(a) are met. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the Administrator or the permitting authority. Such records shall include, for each delivery of fuel to the unit or for fuel delivered to the unit continuously by pipeline, the type of fuel, the sulfur content, and the sulfur content of each sample taken. The owners and operators bear the burden of proof that the requirements of paragraph 40 CFR 72.7(a) are met.
(4) On the earliest of the following dates, a unit exempt under 40 CFR 72.7(b), (c), or (e) shall lose its exemption and become an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71: (i) the date on which the unit first serves one or more generators with total nameplate capacity in excess of 25 MWe; (ii) the date on which the unit burns any coal or coal-derived fuel except for coal-derived gaseous fuel with a total sulfur content no greater than natural gas; or (iii) January 1 of the year following the year in which the annual average sulfur content for gaseous fuel burned at the unit exceeds 0.05 percent by weight (as determined under 40 CFR 72.7(d)) or for nongaseous fuel burned at the unit

exceeds 0.05 percent by weight (as determined under 40 CFR 72.7(d)). Notwithstanding 40 CFR 72.30(b) and (c), the designated representative for a unit that loses its exemption under 40 CFR 72.7 shall submit a complete Acid Rain permit application on the later of January 1, 1998 or 60 days after the first date on which the unit is no longer exempt. For the purpose of applying monitoring requirements under 40 CFR part 75, a unit that loses its exemption under 40 CFR 72.7 shall be treated as a new unit that commenced commercial operation on the first date on which the unit is no longer exempt.

STEP 6
Read the appropriate certification and sign and date.

Certification (for designated representatives only)

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Mark Wroten	
Signature 	Date 4.1.2025

Certification (for certifying officials only)

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Mark Wroten	Title Deputy Chief Operating Officer		
Company Owner Name Homer City Generation, L.P.			
Mailing Address 1750 Power Plant Road	City Homer City	State PA	Zip Code
Phone 870-559-6000	Email Address mwroten@homercityredevelopment.com		
Signature 	Date 4.1.2025		

Certification (for additional certifying officials, if applicable)

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Title		
Company Owner Name			
Mailing Address	City	State	Zip Code
Phone	Email Address		
Signature	Date		

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 05/31/2025

New Unit Exemption

For more information, see instructions and refer to 40 CFR 72.7

This submission is: ☑ **New** ☐ **Revised**

STEP 1
Identify the new unit by plant name, State, Plant Code (ORISPL) and unit ID#.

Plant Name	State	Plant Code	Unit ID#
Homer City Generation	PA	TBD	FT802

STEP 2
List the generator ID numbers and, to one decimal place, the nameplate capacity of each generator served by the unit. Then total nameplate capacity and enter the result.

GEN ID #	GEN ID #	GEN ID #	GEN ID #	GEN ID #
ADGT2				
25.0 MWe	MWe	MWe	MWe	MWe

TOTAL
25.0 MWe

STEP 3
List all fuels currently burned or expected to be burned, by the unit and the percent sulfur content by weight of each.

Fuel (current)	Sulfur Content (current)	Fuel (expected)	Sulfur Content (expected)
Natural Gas	0.0016 %	Natural Gas	0.0016 %
Natural Gas	0.0016 %	Natural Gas	0.0016 %

STEP 4
Identify the first full calendar year in which the unit meets (or will meet) the requirements of 40 CFR 72.7(a).

January 1, 2026.

STEP 5
Read the special provisions.

Special Provisions

(1) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 72.7 shall (i) comply with the requirements of 40 CFR 72.7(a) for all periods for which the unit is exempt under 40 CFR 72.7 and (ii) comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.
(2) For any period for which a unit is exempt under 40 CFR 72.7, the unit is not an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71 and is not eligible to be an opt-in source under 40 CFR part 74. As an unaffected unit, the unit shall continue to be subject to any other applicable requirements under 40 CFR parts 70 and 71.
(3) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 72.7 shall retain at the source that includes the unit records demonstrating that the requirements of 40 CFR 72.7(a) are met. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the Administrator or the permitting authority. Such records shall include, for each delivery of fuel to the unit or for fuel delivered to the unit continuously by pipeline, the type of fuel, the sulfur content, and the sulfur content of each sample taken. The owners and operators bear the burden of proof that the requirements of paragraph 40 CFR 72.7(a) are met.
(4) On the earliest of the following dates, a unit exempt under 40 CFR 72.7(b), (c), or (e) shall lose its exemption and become an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71: (i) the date on which the unit first serves one or more generators with total nameplate capacity in excess of 25 MWe; (ii) the date on which the unit burns any coal or coal-derived fuel except for coal-derived gaseous fuel with a total sulfur content no greater than natural gas; or (iii) January 1 of the year following the year in which the annual average sulfur content for gaseous fuel burned at the unit exceeds 0.05 percent by weight (as determined under 40 CFR 72.7(d)) or for nongaseous fuel burned at the unit

exceeds 0.05 percent by weight (as determined under 40 CFR 72.7(d)). Notwithstanding 40 CFR 72.30(b) and (c), the designated representative for a unit that loses its exemption under 40 CFR 72.7 shall submit a complete Acid Rain permit application on the later of January 1, 1998 or 60 days after the first date on which the unit is no longer exempt. For the purpose of applying monitoring requirements under 40 CFR part 75, a unit that loses its exemption under 40 CFR 72.7 shall be treated as a new unit that commenced commercial operation on the first date on which the unit is no longer exempt.

STEP 6
Read the appropriate certification and sign and date.

Certification (for designated representatives only)

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Mark Wroten	
Signature 	Date 4.1.2025

Certification (for certifying officials only)

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Mark Wroten	Title Deputy Chief Operating Officer		
Company Owner Name Homer City Generation, L.P.			
Mailing Address 1750 Power Plant Road	City Homer City	State PA	Zip Code
Phone 870-559-6000	Email Address mwroten@homercityredevelopment.com		
Signature 	Date 4.1.2025		

Certification (for additional certifying officials, if applicable)

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Title		
Company Owner Name			
Mailing Address	City	State	Zip Code
Phone	Email Address		
Signature	Date		

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 05/31/2025

New Unit Exemption

For more information, see instructions and refer to 40 CFR 72.7

This submission is: ☑ **New** ☐ **Revised**

STEP 1
Identify the new unit by plant name, State, Plant Code (ORISPL) and unit ID#.

Plant Name	State	Plant Code	Unit ID#
Homer City Generation	PA	TBD	FT803

STEP 2
List the generator ID numbers and, to one decimal place, the nameplate capacity of each generator served by the unit. Then total nameplate capacity and enter the result.

GEN ID #	GEN ID #	GEN ID #	GEN ID #	GEN ID #
ADGT3				
25.0 MWe	MWe	MWe	MWe	MWe

TOTAL
25.0 MWe

STEP 3
List all fuels currently burned or expected to be burned, by the unit and the percent sulfur content by weight of each.

Fuel (current)	Sulfur Content (current)	Fuel (expected)	Sulfur Content (expected)
Natural Gas	0.0016 %	Natural Gas	0.0016 %
Natural Gas	0.0016 %	Natural Gas	0.0016 %

STEP 4
Identify the first full calendar year in which the unit meets (or will meet) the requirements of 40 CFR 72.7(a).

January 1, 2026 .

STEP 5
Read the special provisions.

Special Provisions

(1) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 72.7 shall (i) comply with the requirements of 40 CFR 72.7(a) for all periods for which the unit is exempt under 40 CFR 72.7 and (ii) comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.
(2) For any period for which a unit is exempt under 40 CFR 72.7, the unit is not an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71 and is not eligible to be an opt-in source under 40 CFR part 74. As an unaffected unit, the unit shall continue to be subject to any other applicable requirements under 40 CFR parts 70 and 71.
(3) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 72.7 shall retain at the source that includes the unit records demonstrating that the requirements of 40 CFR 72.7(a) are met. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the Administrator or the permitting authority. Such records shall include, for each delivery of fuel to the unit or for fuel delivered to the unit continuously by pipeline, the type of fuel, the sulfur content, and the sulfur content of each sample taken. The owners and operators bear the burden of proof that the requirements of paragraph 40 CFR 72.7(a) are met.
(4) On the earliest of the following dates, a unit exempt under 40 CFR 72.7(b), (c), or (e) shall lose its exemption and become an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71: (i) the date on which the unit first serves one or more generators with total nameplate capacity in excess of 25 MWe; (ii) the date on which the unit burns any coal or coal-derived fuel except for coal-derived gaseous fuel with a total sulfur content no greater than natural gas; or (iii) January 1 of the year following the year in which the annual average sulfur content for gaseous fuel burned at the unit exceeds 0.05 percent by weight (as determined under 40 CFR 72.7(d)) or for nongaseous fuel burned at the unit

exceeds 0.05 percent by weight (as determined under 40 CFR 72.7(d)). Notwithstanding 40 CFR 72.30(b) and (c), the designated representative for a unit that loses its exemption under 40 CFR 72.7 shall submit a complete Acid Rain permit application on the later of January 1, 1998 or 60 days after the first date on which the unit is no longer exempt. For the purpose of applying monitoring requirements under 40 CFR part 75, a unit that loses its exemption under 40 CFR 72.7 shall be treated as a new unit that commenced commercial operation on the first date on which the unit is no longer exempt.

STEP 6
Read the appropriate certification and sign and date.

Certification (for designated representatives only)

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Mark Wroten	
Signature 	Date 4.1.2025

Certification (for certifying officials only)

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Mark Wroten	Title Deputy Chief Operating Officer		
Company Owner Name Homer City Generation, L.P.			
Mailing Address 1750 Power Plant Road	City Homer City	State PA	Zip Code
Phone 870-559-6000	Email Address mwroten@homercityredevelopment.com		
Signature 	Date 4.1.2025		

Certification (for additional certifying officials, if applicable)

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Title		
Company Owner Name			
Mailing Address	City	State	Zip Code
Phone	Email Address		
Signature	Date		

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 05/31/2025

New Unit Exemption

For more information, see instructions and refer to 40 CFR 72.7

This submission is: ☑ **New** ☐ **Revised**

STEP 1
Identify the new unit by plant name, State, Plant Code (ORISPL) and unit ID#.

Plant Name	State	Plant Code	Unit ID#
Homer City Generation	PA	TBD	FT804

STEP 2
List the generator ID numbers and, to one decimal place, the nameplate capacity of each generator served by the unit. Then total nameplate capacity and enter the result.

GEN ID #	GEN ID #	GEN ID #	GEN ID #	GEN ID #
ADGT4				
25.0 MWe	MWe	MWe	MWe	MWe

TOTAL
25.0 MWe

STEP 3
List all fuels currently burned or expected to be burned, by the unit and the percent sulfur content by weight of each.

Fuel (current)	Sulfur Content (current)	Fuel (expected)	Sulfur Content (expected)
Natural Gas	0.0016 %	Natural Gas	0.0016 %
Natural Gas	0.0016 %	Natural Gas	0.0016 %

STEP 4
Identify the first full calendar year in which the unit meets (or will meet) the requirements of 40 CFR 72.7(a).

January 1, 2026.

STEP 5
Read the special provisions.

Special Provisions

(1) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 72.7 shall (i) comply with the requirements of 40 CFR 72.7(a) for all periods for which the unit is exempt under 40 CFR 72.7 and (ii) comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.
(2) For any period for which a unit is exempt under 40 CFR 72.7, the unit is not an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71 and is not eligible to be an opt-in source under 40 CFR part 74. As an unaffected unit, the unit shall continue to be subject to any other applicable requirements under 40 CFR parts 70 and 71.
(3) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 72.7 shall retain at the source that includes the unit records demonstrating that the requirements of 40 CFR 72.7(a) are met. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the Administrator or the permitting authority. Such records shall include, for each delivery of fuel to the unit or for fuel delivered to the unit continuously by pipeline, the type of fuel, the sulfur content, and the sulfur content of each sample taken. The owners and operators bear the burden of proof that the requirements of paragraph 40 CFR 72.7(a) are met.
(4) On the earliest of the following dates, a unit exempt under 40 CFR 72.7(b), (c), or (e) shall lose its exemption and become an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71: (i) the date on which the unit first serves one or more generators with total nameplate capacity in excess of 25 MWe; (ii) the date on which the unit burns any coal or coal-derived fuel except for coal-derived gaseous fuel with a total sulfur content no greater than natural gas; or (iii) January 1 of the year following the year in which the annual average sulfur content for gaseous fuel burned at the unit exceeds 0.05 percent by weight (as determined under 40 CFR 72.7(d)) or for nongaseous fuel burned at the unit

exceeds 0.05 percent by weight (as determined under 40 CFR 72.7(d)). Notwithstanding 40 CFR 72.30(b) and (c), the designated representative for a unit that loses its exemption under 40 CFR 72.7 shall submit a complete Acid Rain permit application on the later of January 1, 1998 or 60 days after the first date on which the unit is no longer exempt. For the purpose of applying monitoring requirements under 40 CFR part 75, a unit that loses its exemption under 40 CFR 72.7 shall be treated as a new unit that commenced commercial operation on the first date on which the unit is no longer exempt.

STEP 6
Read the appropriate certification and sign and date.

Certification (for designated representatives only)

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Mark Wroten	
Signature 	Date 4.1.2025

Certification (for certifying officials only)

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Name Mark Wroten	Title Deputy Chief Operating Officer		
Company Owner Name Homer City Generation, L.P.			
Mailing Address 1750 Power Plant Road	City Homer City	State PA	Zip Code
Phone 870-559-6000	Email Address mwroten@homercityredevelopment.com		
Signature 	Date 4.1.2025		

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Name	Title		
Company Owner Name			
Mailing Address	City	State	Zip Code
Phone	Email Address		
Signature	Date		

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 05/31/2025

New Unit Exemption

For more information, see instructions and refer to 40 CFR 72.7

This submission is: ☑ **New** ☐ **Revised**

STEP 1
Identify the new unit by plant name, State, Plant Code (ORISPL) and unit ID#.

Plant Name	State	Plant Code	Unit ID#
Homer City Generation	PA	TBD	FT805

STEP 2
List the generator ID numbers and, to one decimal place, the nameplate capacity of each generator served by the unit. Then total nameplate capacity and enter the result.

GEN ID #	GEN ID #	GEN ID #	GEN ID #	GEN ID #
ADGT5				
25.0 MWe	MWe	MWe	MWe	MWe

TOTAL
25.0 MWe

STEP 3
List all fuels currently burned or expected to be burned, by the unit and the percent sulfur content by weight of each.

Fuel (current)	Sulfur Content (current)	Fuel (expected)	Sulfur Content (expected)
Natural Gas	0.0016 %	Natural Gas	0.0016 %
Natural Gas	0.0016 %	Natural Gas	0.0016 %

STEP 4
Identify the first full calendar year in which the unit meets (or will meet) the requirements of 40 CFR 72.7(a).

January 1, 2026.

STEP 5
Read the special provisions.

Special Provisions

(1) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 72.7 shall (i) comply with the requirements of 40 CFR 72.7(a) for all periods for which the unit is exempt under 40 CFR 72.7 and (ii) comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.
(2) For any period for which a unit is exempt under 40 CFR 72.7, the unit is not an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71 and is not eligible to be an opt-in source under 40 CFR part 74. As an unaffected unit, the unit shall continue to be subject to any other applicable requirements under 40 CFR parts 70 and 71.
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(4) On the earliest of the following dates, a unit exempt under 40 CFR 72.7(b), (c), or (e) shall lose its exemption and become an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71: (i) the date on which the unit first serves one or more generators with total nameplate capacity in excess of 25 MWe; (ii) the date on which the unit burns any coal or coal-derived fuel except for coal-derived gaseous fuel with a total sulfur content no greater than natural gas; or (iii) January 1 of the year following the year in which the annual average sulfur content for gaseous fuel burned at the unit exceeds 0.05 percent by weight (as determined under 40 CFR 72.7(d)) or for nongaseous fuel burned at the unit

exceeds 0.05 percent by weight (as determined under 40 CFR 72.7(d)). Notwithstanding 40 CFR 72.30(b) and (c), the designated representative for a unit that loses its exemption under 40 CFR 72.7 shall submit a complete Acid Rain permit application on the later of January 1, 1998 or 60 days after the first date on which the unit is no longer exempt. For the purpose of applying monitoring requirements under 40 CFR part 75, a unit that loses its exemption under 40 CFR 72.7 shall be treated as a new unit that commenced commercial operation on the first date on which the unit is no longer exempt.

STEP 6
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Name Mark Wroten	
Signature 	Date 4.1.2025

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Company Owner Name Homer City Generation, L.P.			
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Name	Title		
Company Owner Name			
Mailing Address	City	State	Zip Code
Phone	Email Address		
Signature	Date		

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 05/31/2025

New Unit Exemption

For more information, see instructions and refer to 40 CFR 72.7

This submission is: ☑ **New** ☐ **Revised**

STEP 1
Identify the new unit by plant name, State, Plant Code (ORISPL) and unit ID#.

Plant Name	State	Plant Code	Unit ID#
Homer City Generation	PA	TBD	FT806

STEP 2
List the generator ID numbers and, to one decimal place, the nameplate capacity of each generator served by the unit. Then total nameplate capacity and enter the result.

GEN ID #	GEN ID #	GEN ID #	GEN ID #	GEN ID #
ADGT6				
25.0 MWe	MWe	MWe	MWe	MWe

TOTAL
25.0 MWe

STEP 3
List all fuels currently burned or expected to be burned, by the unit and the percent sulfur content by weight of each.

Fuel (current)	Sulfur Content (current)	Fuel (expected)	Sulfur Content (expected)
Natural Gas	0.0016 %	Natural Gas	0.0016 %
Natural Gas	0.0016 %	Natural Gas	0.0016 %

STEP 4
Identify the first full calendar year in which the unit meets (or will meet) the requirements of 40 CFR 72.7(a).

January 1, 2026.

STEP 5
Read the special provisions.

Special Provisions

(1) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 72.7 shall (i) comply with the requirements of 40 CFR 72.7(a) for all periods for which the unit is exempt under 40 CFR 72.7 and (ii) comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.
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(4) On the earliest of the following dates, a unit exempt under 40 CFR 72.7(b), (c), or (e) shall lose its exemption and become an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71: (i) the date on which the unit first serves one or more generators with total nameplate capacity in excess of 25 MWe; (ii) the date on which the unit burns any coal or coal-derived fuel except for coal-derived gaseous fuel with a total sulfur content no greater than natural gas; or (iii) January 1 of the year following the year in which the annual average sulfur content for gaseous fuel burned at the unit exceeds 0.05 percent by weight (as determined under 40 CFR 72.7(d)) or for nongaseous fuel burned at the unit

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STEP 6
Read the appropriate certification and sign and date.

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Name Mark Wroten	
Signature 	Date 4.1.2025

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Company Owner Name Homer City Generation, L.P.			
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Name	Title		
Company Owner Name			
Mailing Address	City	State	Zip Code
Phone	Email Address		
Signature	Date		

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 05/31/2025

New Unit Exemption

For more information, see instructions and refer to 40 CFR 72.7

This submission is: ☑ **New** ☐ **Revised**

STEP 1
Identify the new unit by plant name, State, Plant Code (ORISPL) and unit ID#.

Plant Name	State	Plant Code	Unit ID#
Homer City Generation	PA	TBD	FT807

STEP 2
List the generator ID numbers and, to one decimal place, the nameplate capacity of each generator served by the unit. Then total nameplate capacity and enter the result.

GEN ID #	GEN ID #	GEN ID #	GEN ID #	GEN ID #
ADGT7				
25.0 MWe	MWe	MWe	MWe	MWe

TOTAL
25.0 MWe

STEP 3
List all fuels currently burned or expected to be burned, by the unit and the percent sulfur content by weight of each.

Fuel (current)	Sulfur Content (current)	Fuel (expected)	Sulfur Content (expected)
Natural Gas	0.0016 %	Natural Gas	0.0016 %
Natural Gas	0.0016 %	Natural Gas	0.0016 %

STEP 4
Identify the first full calendar year in which the unit meets (or will meet) the requirements of 40 CFR 72.7(a).

January 1, 2026.

STEP 5
Read the special provisions.

Special Provisions

(1) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 72.7 shall (i) comply with the requirements of 40 CFR 72.7(a) for all periods for which the unit is exempt under 40 CFR 72.7 and (ii) comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.
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Read the appropriate certification and sign and date.

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Name Mark Wroten	
Signature 	Date 4.1.2025

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Name	Title		
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United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 05/31/2025

New Unit Exemption

For more information, see instructions and refer to 40 CFR 72.7

This submission is: ☑ **New** ☐ **Revised**

STEP 1
Identify the new unit by plant name, State, Plant Code (ORISPL) and unit ID#.

Plant Name	State	Plant Code	Unit ID#
Homer City Generation	PA	TBD	FT808

STEP 2
List the generator ID numbers and, to one decimal place, the nameplate capacity of each generator served by the unit. Then total nameplate capacity and enter the result.

GEN ID #	GEN ID #	GEN ID #	GEN ID #	GEN ID #
ADGT8				
25.0 MWe	MWe	MWe	MWe	MWe

TOTAL
25.0 MWe

STEP 3
List all fuels currently burned or expected to be burned, by the unit and the percent sulfur content by weight of each.

Fuel (current)	Sulfur Content (current)	Fuel (expected)	Sulfur Content (expected)
Natural Gas	0.0016 %	Natural Gas	0.0016 %
Natural Gas	0.0016 %	Natural Gas	0.0016 %

STEP 4
Identify the first full calendar year in which the unit meets (or will meet) the requirements of 40 CFR 72.7(a).

January 1, 2026 .

STEP 5
Read the special provisions.

Special Provisions

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Name Mark Wroten	
Signature 	Date 4.1.2025

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Company Owner Name			
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United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 05/31/2025

New Unit Exemption

For more information, see instructions and refer to 40 CFR 72.7

This submission is: ☑ **New** ☐ **Revised**

STEP 1
Identify the new unit by plant name, State, Plant Code (ORISPL) and unit ID#.

Plant Name	State	Plant Code	Unit ID#
Homer City Generation	PA	TBD	FT809

STEP 2
List the generator ID numbers and, to one decimal place, the nameplate capacity of each generator served by the unit. Then total nameplate capacity and enter the result.

GEN ID #	GEN ID #	GEN ID #	GEN ID #	GEN ID #
ADGT9				
25.0 MWe	MWe	MWe	MWe	MWe

TOTAL
25.0 MWe

STEP 3
List all fuels currently burned or expected to be burned, by the unit and the percent sulfur content by weight of each.

Fuel (current)	Sulfur Content (current)	Fuel (expected)	Sulfur Content (expected)
Natural Gas	0.0016 %	Natural Gas	0.0016 %
Natural Gas	0.0016 %	Natural Gas	0.0016 %

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Name Mark Wroten	
Signature 	Date 4.1.2025

Certification (for certifying officials only)

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Mark Wroten	Title Deputy Chief Operating Officer		
Company Owner Name Homer City Generation, L.P.			
Mailing Address 1750 Power Plant Road	City Homer City	State PA	Zip Code
Phone 870-559-6000	Email Address mwroten@homercityredevelopment.com		
Signature 	Date 4.1.2025		

Certification (for additional certifying officials, if applicable)

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Title		
Company Owner Name			
Mailing Address	City	State	Zip Code
Phone	Email Address		
Signature	Date		

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 05/31/2025

New Unit Exemption

For more information, see instructions and refer to 40 CFR 72.7

This submission is: ☑ **New** ☐ **Revised**

STEP 1
Identify the new unit by plant name, State, Plant Code (ORISPL) and unit ID#.

Plant Name	State	Plant Code	Unit ID#
Homer City Generation	PA	TBD	FT810

STEP 2
List the generator ID numbers and, to one decimal place, the nameplate capacity of each generator served by the unit. Then total nameplate capacity and enter the result.

GEN ID #	GEN ID #	GEN ID #	GEN ID #	GEN ID #
ADGT0				
25.0 MWe	MWe	MWe	MWe	MWe

TOTAL
25.0 MWe

STEP 3
List all fuels currently burned or expected to be burned, by the unit and the percent sulfur content by weight of each.

Fuel (current)	Sulfur Content (current)	Fuel (expected)	Sulfur Content (expected)
Natural Gas	0.0016 %	Natural Gas	0.0016 %
Natural Gas	0.0016 %	Natural Gas	0.0016 %

STEP 4
Identify the first full calendar year in which the unit meets (or will meet) the requirements of 40 CFR 72.7(a).

January 1, 2026.

STEP 5
Read the special provisions.

Special Provisions

(1) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 72.7 shall (i) comply with the requirements of 40 CFR 72.7(a) for all periods for which the unit is exempt under 40 CFR 72.7 and (ii) comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.
(2) For any period for which a unit is exempt under 40 CFR 72.7, the unit is not an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71 and is not eligible to be an opt-in source under 40 CFR part 74. As an unaffected unit, the unit shall continue to be subject to any other applicable requirements under 40 CFR parts 70 and 71.
(3) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 72.7 shall retain at the source that includes the unit records demonstrating that the requirements of 40 CFR 72.7(a) are met. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the Administrator or the permitting authority. Such records shall include, for each delivery of fuel to the unit or for fuel delivered to the unit continuously by pipeline, the type of fuel, the sulfur content, and the sulfur content of each sample taken. The owners and operators bear the burden of proof that the requirements of paragraph 40 CFR 72.7(a) are met.
(4) On the earliest of the following dates, a unit exempt under 40 CFR 72.7(b), (c), or (e) shall lose its exemption and become an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71: (i) the date on which the unit first serves one or more generators with total nameplate capacity in excess of 25 MWe; (ii) the date on which the unit burns any coal or coal-derived fuel except for coal-derived gaseous fuel with a total sulfur content no greater than natural gas; or (iii) January 1 of the year following the year in which the annual average sulfur content for gaseous fuel burned at the unit exceeds 0.05 percent by weight (as determined under 40 CFR 72.7(d)) or for nongaseous fuel burned at the unit

exceeds 0.05 percent by weight (as determined under 40 CFR 72.7(d)). Notwithstanding 40 CFR 72.30(b) and (c), the designated representative for a unit that loses its exemption under 40 CFR 72.7 shall submit a complete Acid Rain permit application on the later of January 1, 1998 or 60 days after the first date on which the unit is no longer exempt. For the purpose of applying monitoring requirements under 40 CFR part 75, a unit that loses its exemption under 40 CFR 72.7 shall be treated as a new unit that commenced commercial operation on the first date on which the unit is no longer exempt.

STEP 6
Read the appropriate certification and sign and date.

Certification (for designated representatives only)

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Mark Wroten	
Signature 	Date 4.1.2025

Certification (for certifying officials only)

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Mark Wroten	Title Deputy Chief Operating Officer		
Company Owner Name Homer City Generation, L.P.			
Mailing Address 1750 Power Plant Road	City Homer City	State PA	Zip Code
Phone 870-559-6000	Email Address mwroten@homercityredevelopment.com		
Signature 	Date 4.1.2025		

Certification (for additional certifying officials, if applicable)

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Title		
Company Owner Name			
Mailing Address	City	State	Zip Code
Phone	Email Address		
Signature	Date		

Appendix I :
Modeling Protocol

Pennsylvania
Department of
Environmental Protection

March 17, 2025

VIA EMAIL

Jeff Connors
AECOM
250 Apollo Drive
Chelmsford, MA 01824-3627

Re: DEP Acceptance of Air Dispersion Modeling Protocol
Air Quality Analyses for Prevention of Significant Deterioration
Homer City Generation, L.P.
Proposed Major Modification
Former Homer City Generating Station Site
Black Lick Township and Center Township, Indiana County

Dear Jeff Connors:

The Pennsylvania Department of Environmental Protection (DEP) received an air dispersion modeling protocol[1] on March 10, 2025, for Homer City Generation, L.P. (Homer City) proposed major modification at the former Homer City Generating Station site in Black Lick Township and Center Township, Indiana County.

According to the protocol, Homer City will submit a plan approval application to the DEP for a proposed project that would be a major modification to an existing major stationary source and therefore subject to the Prevention of Significant Deterioration (PSD) regulations. The federal PSD regulations are codified in 40 CFR § 52.21 and are adopted and incorporated by reference in their entirety in 25 *Pa. Code* § 127.83 and the Commonwealth's State Implementation Plan (SIP) codified in 40 CFR § 52.2020. A written modeling protocol is intended to establish a common understanding of how the required PSD air quality analyses will be conducted and helps to keep misunderstandings and resource expenditures at a minimum.

The DEP reviewed Homer City's protocol and determined that it adequately establishes modeling procedures and databases for conducting the required air quality analyses to be included with Homer City's plan approval application. The DEP reviewed Homer City's protocol to ensure that the modeling procedures and databases are consistent with the PSD requirements for air quality analyses codified in paragraphs (k) through (p) of 40 CFR § 52.21,

[1] Air Dispersion Modeling Protocol. March 4, 2025. Prepared for: Homer City Generation, L.P. Prepared by: AECOM, Chelmsford, MA.

the U.S. Environmental Protection Agency's (EPA) "Guideline on Air Quality Models" (40 CFR Part 51, Appendix W), and the EPA's relevant air quality modeling policy and guidance.

The modeling procedures and databases established in Homer City's protocol and the DEP's acceptance of Homer City's protocol are not intended to supersede or conflict with the PSD requirements, the EPA's "Guideline on Air Quality Models," or the EPA's relevant air quality modeling policy and guidance. Additionally, the protocol is not intended to be a binding, formal legal document and changes in or deviations from the protocol are often necessary as the analyses progress; therefore, the DEP reserves the right to require the modeling procedures and databases set forth in Homer City's protocol to be revised or modified in appropriate circumstances. Moreover, the DEP's acceptance of Homer City's protocol does not preclude the DEP from issuing comments resulting from the technical review of Homer City's air quality analyses.

If you have any questions relevant to conducting Homer City's air quality analyses, you may contact me (droble@pa.gov, 717.705.7689) or Andrew Fleck (afleck@pa.gov, 717.783.9243), manager of the Air Quality Modeling and Risk Assessment Section.

Sincerely,

Daniel J. Roble

Daniel J. Roble
Air Quality Program Specialist
Air Quality Modeling and Risk Assessment Section
Division of Permits

cc: Gary Cline, Homer City
Mark Wroten, Homer City
Joel Heiser, Homer City
Christopher Warren, AECOM
Lori McNabb, DEP/NWRO/Air Quality
David Balog, DEP/NWRO/Air Quality/New Source Review
Jacob Chemsak, DEP/NWRO/Air Quality/New Source Review
Nicholas Lazor, DEP/BAQ/Director
Viren Trivedi, DEP/BAQ/Permits
Sean Wenrich, DEP/BAQ/Permits/New Source Review
Andrew Fleck, DEP/BAQ/Permits/Air Quality Modeling and Risk Assessment

Air Dispersion Modeling Protocol
Homer City Generation, L.P.

Submitted to the Pennsylvania Department of Environmental Protection

Project number: 60734544

March 4, 2025

Delivering a better world

Prepared for:

Homer City Generation, L.P.

Prepared by:

AECOM
250 Apollo Drive
Chelmsford, MA 01824
aecom.com

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1. Introduction

1.1 Project Overview

Homer City Generation, L.P. (Homer City) is considering a potential project to construct and operate up to seven (7) combined-cycle combustion turbines (CCs) along with up to ten (10) aeroderivative gas turbines (ADGTs) at the former Homer City Generating Station ("the Station"), located in Indiana County, Pennsylvania. Construction and operation of the new CCs and ADGTs will also include new ancillary equipment such as auxiliary boiler(s), emergency generator(s), emergency fire water pump engine(s), cooling towers, and fuel gas heater(s). The new CCs and ADGTs, in final configuration, along with all associated ancillary equipment, will be herein referred to as the "Project." The new CCs and ADGTs will be fueled only by pipeline quality natural gas. Each CC and ADGT will be equipped with a selective catalytic reduction (SCR) to minimize nitrogen oxide (NO_X) emissions and an oxidation catalyst to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions.

The former Station was an existing "major source" of criteria air pollutants, and the Project constitutes a "major modification" under Prevention of Significant Deterioration (PSD) permitting requirements. As such, Homer City will be applying to the Pennsylvania Department of Environmental Protection (PADEP) for a Plan Approval authorizing construction and operation of the Project. Homer City will use emission offsets, associated with the retirement of the coal-fired boilers, to net out of PSD review for NOx, CO, and sulfur dioxide (SO_2). Lead (Pb) emissions from the Project will not exceed the PSD Significant Emission Rate (SER) threshold. As such, the Project will be subject to PSD requirements under the New Source Review (NSR) program for emissions of particulate matter (PM), particulate matter (PM) equal to and less than 10 microns in diameter (PM_{10}), PM equal to and less than 2.5 microns in diameter ($PM_{2.5}$), VOC, sulfuric acid mist (SAM, or H_2SO_4), and greenhouse gases (GHG). Since Pennsylvania is in the Ozone Transport Region (OTR), emissions of ozone precursors (i.e., NOx and VOC), would be subject to Non-attainment NSR (NAA-NSR) requirements and not PSD requirements.

The United States Environmental Protection Agency's (US EPA) *Revision to the Guideline on Air Quality Models* (GAQM) (US EPA, 2024a), published on November 29, 2024, acknowledges that although a modeling protocol should be agreed upon by all involved parties, it is not meant to be a binding, formal legal document. This modeling protocol is meant to establish the basic methodology for the air dispersion modeling analyses and to present preliminary details of the proposed project. The methodology and project details may change as the analyses progress. This protocol follows the methods in the GAQM and guidance received from PADEP. The modeling protocol will address the air quality impact analyses required for those pollutants subject to the permitting action, PM, PM_{10}, $PM_{2.5}$, GHGs, and VOC. Please note, there are no modeling requirements for GHGs.

1.2 Purpose of Modeling Protocol

The purpose of this document is to present the proposed methodology for conducting the air dispersion modeling analyses that will be performed in support of the air permit application for the Project. Modeling methods and assumptions, including model selection and options, meteorological data, and source parameters to be used in the modeling analyses, are presented in this document for review and approval by PADEP.

1.3 Contents of Modeling Protocol

The modeling protocol consists of the following additional sections:

- Section 2 contains the Project description, including information regarding Project equipment, location, and the expected air emissions.
- Section 3 is a discussion of applicable air regulations.
- Section 4 presents a detailed description of the modeling approach proposed to be used in evaluating air quality impacts of the proposed Project, including model selection criteria, the good engineering practice stack height determination, refined modeling analyses, and ambient air quality compliance approaches.
- Section 5 presents elements for a Class II area modeling analysis.
- Section 6 is a discussion of Class I Area Quality Relative Values, Class I PSD Increments, Class II Visibility, Air Quality Review/Pre-Construction Monitoring, Soils and Vegetation, and Growth-related impacts.
- Section 7 provides a description of the results analysis that will be submitted to PADEP in support of the Plan Approval permit application for the Project, and
- Section 8 contains References.

2. Project Description

2.1 Project Location

The former Station and Project is located in Indiana County, approximately 4 kilometers (2.5 miles) southwest of the town of Homer City, Pennsylvania. **Figure 2-1** is an aerial map showing the location of the Station and **Figure 2-2** provides a closer view of the Station. **Figure 2-3** shows an overlay of a preliminary site layout of the proposed Project. The general area of the proposed Project is situated to the northwest of the former Station coal stacks and primary structures. The approximate size of the proposed Project footprint is shown in **Figure 2-3**.

2.2 Proposed Emission Sources

As stated in **Section 1.0**, the Project consists of seven (7) CCs along with up to ten (10) ADGTs. The CCs are proposed to be General Electric (GE) 7HA.02 unit and the ADGTs are proposed to be Mitsubishi Power FT8 Gas Turbine MOBILEPAC. The CCs and ADGTs are the primary sources of air emissions associated with the proposed Project. The ancillary pieces of equipment being proposed for the Project are listed below:

- Three (3) auxiliary boiler rated at approximately 67 million British thermal units per hour (MMBtu/hr) each, operating on pipeline quality natural gas;
- Ten (10) emergency generators (reciprocating internal combustion engines [RICE]) rated at approximately 2,500 kilowatts (kW) each, operating on ultra-low sulfur diesel fuel (ULSD);
- Two (2) emergency generators rated at approximately 1,000 kilowatts (kW) each, operating on ultra-low sulfur diesel fuel (ULSD);
- One (1) emergency fire-water pump (RICE) rated at approximately 400 brake horsepower (bhp), operating on ULSD;
- Seven (7) fuel gas heaters each rated at approximately 10 MMBtu/hr operating on pipeline quality natural gas; and
- Seven (7) cooling towers, with eight (8) cells each.

2.3 Source Data

2.3.1 Criteria Pollutant Emissions

The Project is located at an existing major stationary source. As such, the Project must be evaluated to determine whether it constitutes a major modification at a major stationary source. A major modification is defined as a physical change or change in the method of operation at a major source that results in a significant emissions increase and a significant net emissions increase of a regulated NSR pollutant that is greater than the PSD significant emission rate (SER).

As stated in **Section 1**, Homer City will use emission offsets, associated with the retirement of the coal-fired boilers, to net out of PSD review for NOx, CO, and SO_2. As such, the Project will be subject to PSD requirements under the NSR program for emissions of PM, PM_{10}, $PM_{2.5}$, VOC, sulfuric acid mist (SAM, or H_2SO_4), and GHG. Since Pennsylvania is in the Ozone Transport Region (OTR), emissions of ozone precursors (i.e., NOx and VOC), would be subject to Non-attainment NSR (NAA-NSR) requirements and not PSD requirements..

Table 2-1 lists the applicable expected annual emission increases resulting from the Project. Please note, these emissions are indicative, based on preliminary lowest achievable emission rate (LAER), best available

control technology (BACT), and best available technology (BAT). **Table 2-2** shows a comparison of the Project emission increases relative to the PSD SERs. **Table 2-3** shows a comparison of the applicable Project emission increases to the NAA-NSR thresholds. As indicated in **Table 2-2**, the Project is expected to be a major modification and subject to PSD review for PM_{10}, $PM_{2.5}$, H_2SO_4, and GHG. **Table 2-3** indicates the Project triggers NAA-NSR for VOC.

Table 2-1. Preliminary Project Emission Increases

	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2e
GE 7HA.02 (7 units total)	705.18	705.18	984.19	677.9	275.4	193.2	138.0	0.066	15,942,536.8
FT8 MOBILPAC (10 units total)	132.49	132.49	147.16	214.8	67.7	10.5	29.2	0.007	1,659,247.8
Auxiliary Boilers (3 units total)	0.33	0.33	2.16	3.63	0.24	0.06	0.0009	0.00002	5,237.3
Fuel Gas Heaters (7 units total)	1.59	1.59	9.92	12.23	1.65	0.463	0.0071	0.000162	39,328.9
Emergency Generators (2,500 kW) (10 units total)	0.41	0.40	10.00	52.26	2.84	0.110	0.0084	-	10,400.6
Emergency Generators (1,000 kW) (2 units total)	0.03	0.03	0.82	4.27	0.23	0.009	0.0007	-	849.1
Fire-water Pump Engine (1 unit total)	0.03	0.03	0.66	0.57	0.66	0.0012	0.00009	--	114.2
Cooling Towers	2.20	0.01	--	--	--	--	--	--	--
Facility Total	842.26	840.05	1,154.90	965.73	348.69	204.32	167.14	0.073	17,710,208.2
Emissions Reduction Credits/Netting	220.18	220.18	2,436.38	4,096.52	11.37	4,460.55	28.44	--	--
Facility Total Less ERCs/Netting	622.08	619.87	-963.69	-3,130.79	337.33	-4,256.23	138.70	0.073	17,710,208

Table 2-2. Preliminary Project Emission Increases Compared to PSD Significant Emission Rates

	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	H_2SO_4	Lead	CO_2e
Facility Total Less ERCs/Netting	622.08	619.87	-963.69	-3,130.79	-4,256.23	138.70	0.073	17,710,208
PSD Significance Emission Rate (ton/yr)	15	10	40	100	40	7	0.6	75,000
PSD Review Triggered?	**Yes**	**Yes**	No	No	No	**Yes**	No	**Yes**

Table 2-3. Preliminary Project Emission Increases Compared to NAA-NSR Significance Emission Rate

	NO_x	VOC
Facility Total Less ERCs/Netting	-963.69	337.33
NAA-NSR Significance Emission Rate (ton/yr)	40	40
NAA-NSR LAER Review Triggered?	No	**Yes**

2.3.2 Short Term Emission Rates

Table 2-4 lists the expected maximum hourly emission rates of criteria pollutants for turbine type. The data shown below reflects the maximum hourly emissions for each individual turbine over a range of operating loads and ambient operating conditions. **Table 2-5** lists the maximum hourly emission rates of criteria pollutants from each of the ancillary sources.

Table 2-4. Preliminary Maximum Hourly Emission Rates of Criteria Pollutants from each CCs and ADGTs

	Maximum Hourly Emission Rates (lb/hr) [(1)(2)]	
Pollutant	**GE 7HA.02**	**FT8**
PM_{10}	24.1	3.0
$PM_{2.5}$	24.1	3.0

(1) Hourly emission rates are based on vendor information. Pollutant emission rates shown represent maximum operation of a single unit over the proposed operating ranges and for all ambient temperatures.
(2) Emission rates presented in this table are preliminary and are subject to change.

Table 2-5. Preliminary Maximum Hourly Emission Rates of Criteria Pollutants Ancillary Sources

	Pollutant Emission Rates for Ancillary Sources (lb/hr/unit) [(1), (4)]	
Equipment	**PM_{10}**	**$PM_{2.5}$**
Auxiliary Boiler [(2)]	0.50	0.50
Fuel Gas Heater [(2)]	0.05	0.05
Emergency Generator [(2)] (2,500 kw)	0.17	0.16
Emergency Generator [(2)] (1,00 kw)	0.02	0.02
Fire-water Pump [(2)]	0.12	0.12
Cooling Tower [(3)]	0.50	0.0016

(1) Hourly emission rates based on emission factors and vendor information.
(2) Emission rates reflect each unit if multiple units are proposed as part of the project.
(3) Emission rates reflect one 8-cell cooling tower.
(4) Emission rates presented in this table are preliminary and are subject to change.

Figure 2-1. Project Location

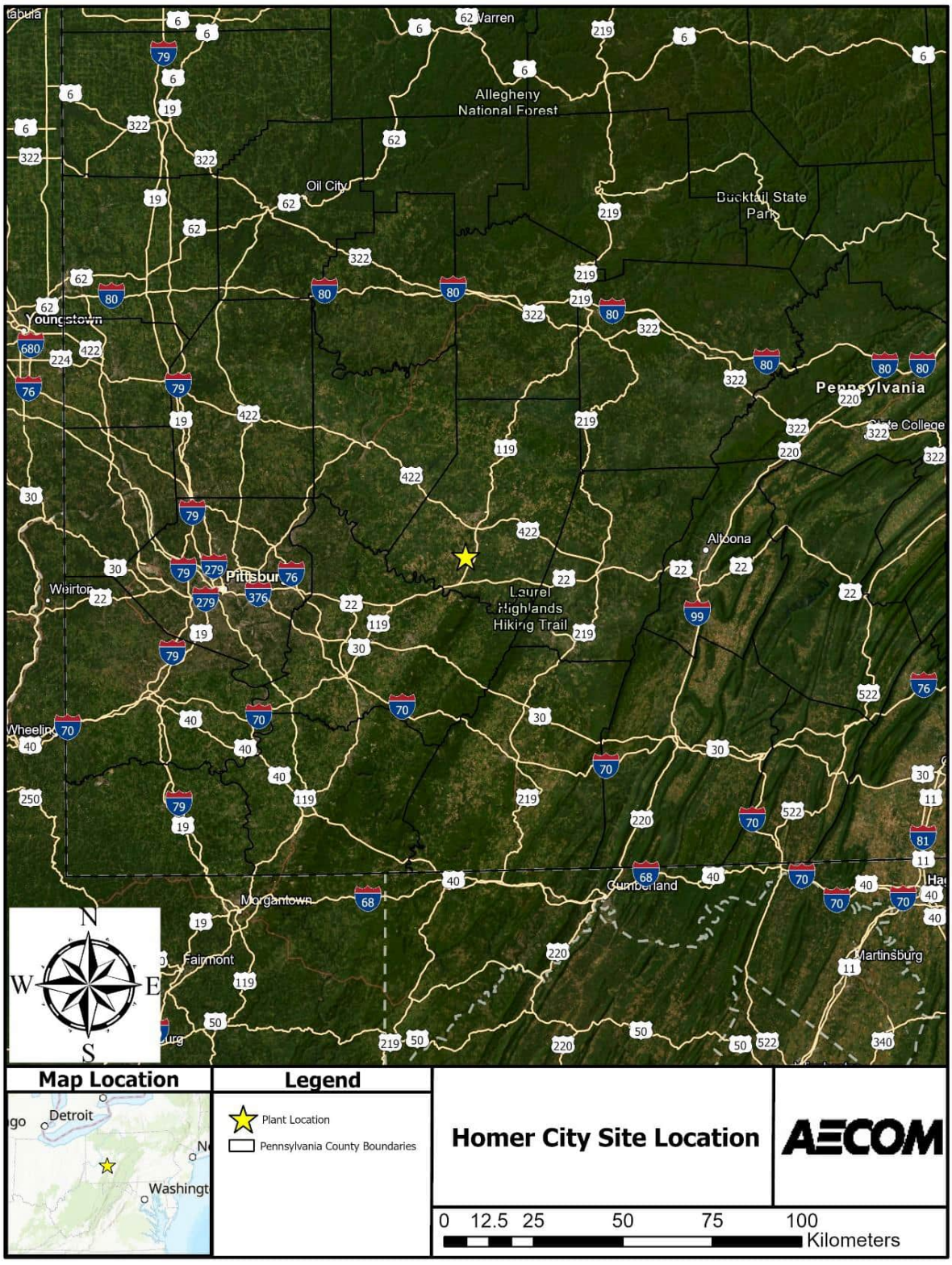


Figure 2-2. Aerial View of Project Site

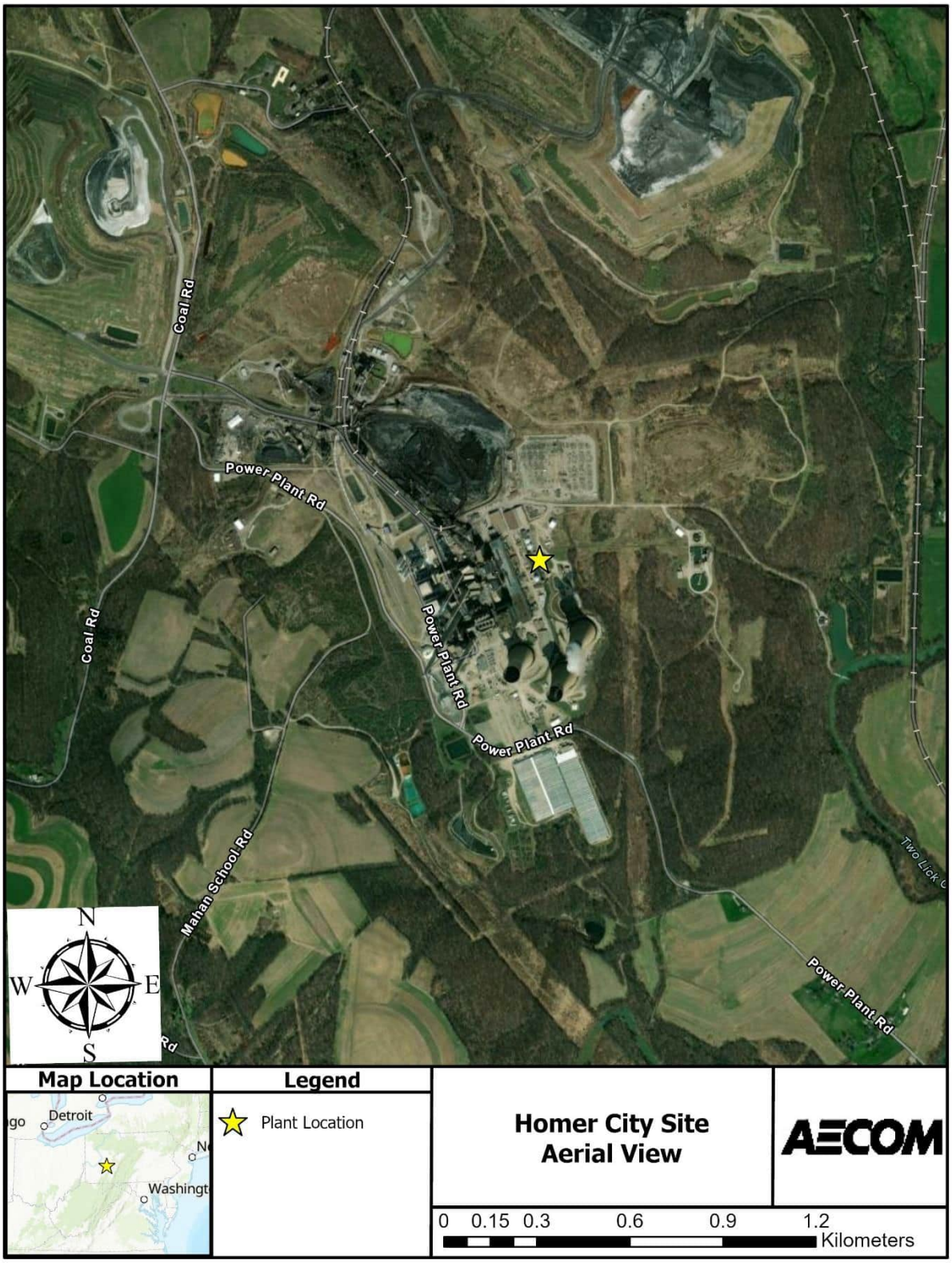
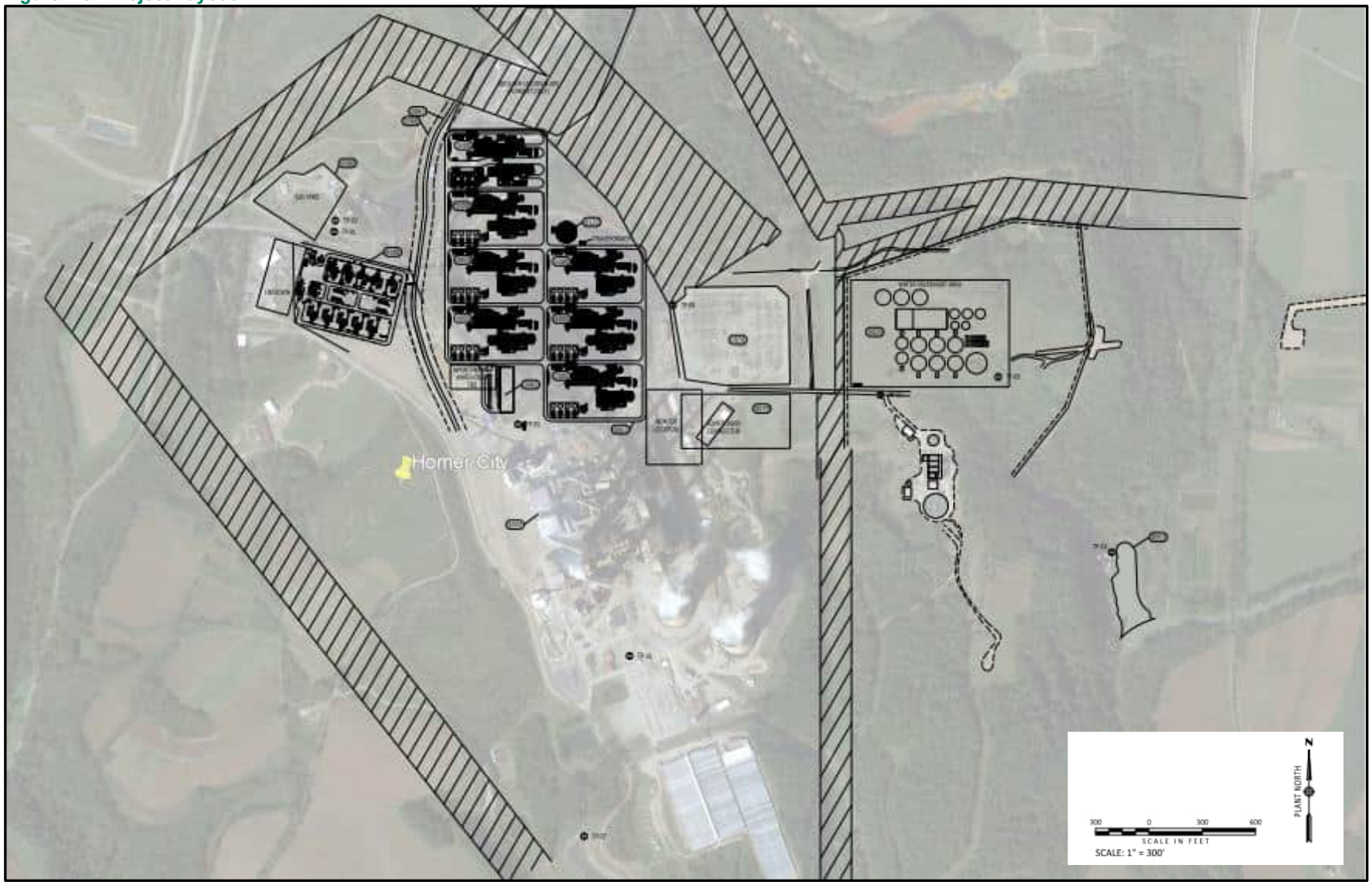


Figure 2-3. Project Layout



3. Applicable Regulations

3.1 Federal Air Quality Standards

The Clean Air Act of 1970 required the US EPA to establish ambient concentration thresholds for certain compounds based upon the identifiable effects that the compounds may have on the public health and welfare. Subsequently, the US EPA promulgated regulations that set NAAQS for several criteria compounds applicable to this Project: particulate matter (PM_{10} and $PM_{2.5}$). Two classes of ambient air quality standards have been established: (1) primary standards defining levels of air quality that the US EPA has judged as necessary to protect public health; and (2) secondary standards defining levels for protecting soils, vegetation, wildlife, and other aspects of public welfare. **Table 3-1** lists the currently applicable NAAQS for which the Project will be subject to PSD review. Pennsylvania has adopted all of the NAAQS.

Table 3-1. National Ambient Air Quality Standards

Pollutant	Averaging Period	Primary Standard ($\mu g/m^3$)	Secondary Standard ($\mu g/m^3$)
PM_{10}	24-hour(1)	150	150
$PM_{2.5}$	24-hour(2)	35	35
	Annual(3)	9	15

1. Not to be exceeded more than once per year on average over 3 years.
2. Compliance with the 24-hour standard is demonstrated when the 3-year average (5-year average in a modeling demonstration) of the 98th-percentile (8th High) 24-hour concentration is below the standard.
3. Not to be exceeded by the arithmetic average of the annual arithmetic averages from 3 successive years.

Source: EPA 40 CFR 50

Pursuant to the 1970 Clean Air Act, states were required to delineate air quality control regions (AQCRs) and to adopt State Implementation Plans (SIPs) to provide for attainment of the NAAQS as expeditiously as practical, within certain time limits. The 1977 Clean Air Act Amendments, in Section 107, required US EPA and states to identify, by category, those AQCRs (or portions thereof) meeting and not meeting the NAAQS. Areas meeting the NAAQS are termed attainment areas, and areas not meeting the NAAQS are termed non-attainment areas. Areas that have insufficient data to make a determination of attainment/non-attainment status are unclassified or are not designated but are treated as being attainment areas for permitting purposes. The designation of an area is made on a pollutant-by-pollutant basis. **Table 3-2** lists the attainment status for Indiana County for each NAAQS which the Project is subject to PSD permitting.

Table 3-2. Attainment Status of Indiana County, Pennsylvania

Compound	Attainment Status(1)
PM_{10}	Unclassifiable/Attainment
$PM_{2.5}$	Unclassifiable/Attainment

40 CFR §81.301 and US EPA information available at https://www.epa.gov/green-book

(1) Pennsylvania is part of the Ozone Transport Region and thus will be subject to NAA-NSR for VOC.

3.2 Prevention of Significant Deterioration

The PSD regulations require that an owner or operator undertaking a major modification perform the following analyses for those pollutants triggering PSD:

- Analysis of existing air quality in the vicinity of the source;
- Application of best available control technology (BACT) to the modified or proposed source (not covered by this protocol);
- Assessment of air quality impacts resulting from pollutant emissions from the source relative to PSD Increments and NAAQS;
- PSD increment consumption, visibility, and air quality related values (AQRVs) impact analyses at PSD Class I areas (generally within 300 kilometers of the facility where the project is slated to take place);
- A Class II visibility analysis;
- Assessment of the effects of emitted pollutants on soils and vegetation in the source's impact areas; and
- Assessment of impacts associated with indirect economic growth.

The PSD regulations limit the amount that ambient air quality concentrations can be increased above existing ambient levels in attainment areas. These allowable increases in concentrations, called PSD increments, have only been established for PM_{10}, $PM_{2.5}$, SO_2 and NO_2. It is assumed the proposed Project will be subject to a PSD increment consumption analysis for $PM_{2.5}$ and PM_{10}

US EPA has defined concentrations, called significant impact levels (SILs), that are used to determine whether a major new source or modification causes or contributes to a violation of a NAAQS or exceedance of a PSD increment. US EPA has also proposed SILs for PSD Class I areas (July 23, 1996, Federal Register, Section IV.C.4), but these have not yet been finalized. US EPA recently established updated Class I and II SILs for $PM_{2.5}$ (US EPA, 2024b). As detailed in **Section 5**, if modeled concentrations exceed the SILs described in **Table 3-3** below, additional cumulative modeling will be conducted using an inventory of major background sources to demonstrate compliance with the NAAQS and PSD increments. If modeled concentrations are less than or equal to the SILs, then no additional modeling will be performed, as the project would be deemed not to cause or contributes to a violation of a NAAQS or exceedance of a PSD increment. **Table 3-3** lists the applicable PSD increments and SILs which the Project is subject to PSD permitting.

Table 3-3. PSD Increments and Significant Impact Levels

		PSD Increments (µg/m^3)		Significant Impact Levels (µg/m^3)	
Pollutant	**Averaging Period**	**Class I**	**Class II**	**Class I**	**Class II**
PM_{10}	24-hour(2)	8	30	0.3	5
	Annual(1)	4	17	0.2	1
$PM_{2.5}$	24-hour(2)	2	9	0.27	1.2
	Annual(1)	1	4	0.03	0.13

1. Not to be exceeded (PSD Increment).
2. Not to be exceeded more than once per year (PSD Increment).

Source: EPA 40 CFR 50

4. Dispersion Modeling Approach

4.1 Overview

This section presents the approach to the dispersion modeling analysis that will be conducted to assess compliance with the applicable state and federal ambient air quality regulations and guidelines. The analysis will be conducted in accordance with the US EPA's GAQM, which is contained in 40 CFR Part 51, Appendix W (US EPA, 2024a).

Based on preliminary understanding of the Project emission sources, the proposed Project is expected to be subject to PSD review for PM_{10}, $PM_{2.5}$, H_2SO_4, and GHG. The project will also be subject to NAA-NSR for VOC. Therefore, associated dispersion modeling analyses will be conducted only for PM_{10} and $PM_{2.5}$. There are no modeling requirements for H_2SO_4, VOC (as NAA-NSR applies), and GHGs. The modeling analysis will address impacts associated with secondary $PM_{2.5}$ as described further in **Section 4.8**.

4.2 Modeling Source Approach and Configurations

The air dispersion modeling analysis will be conducted with emission rates and flue gas exhaust characteristics (flow rate and temperature) expected to represent the worst-case parameters among the range of possible values considered for the proposed Project. Since emission rates and flue gas characteristics for a given operating load vary as a function of ambient temperature, data was derived for the following ambient temperatures and operating scenarios for each turbine:

GE 7HA.02

- 5 operating scenarios
    1. base load (~100 load) with duct burners (DB),
    2. base load (~100 load) no DB,
    3. intermediate load (~75% load),
    4. minimum emission compliance load (MECL, ~35-45% load)
    5. Startup and shutdown
- 7 ambient temperatures (105°F, 90°F, 70°F, 59°F, 52°F, 20°F, and -20°F)

FT8

- 3 operating scenarios
    1. base load (~100 load),
    2. intermediate load (~75% load),
    3. MECL, ~50% load)
    4. Startup and shutdown
- 3 ambient temperatures (90°F, 59°F, and 30°F)

A summary of the exhaust data and emission rates for each ambient temperature and operating scenario for each GE 7HA.02 and FT8 is provided in **Table 4-1** and

Table 4-2**,** respectively. In order to conservatively calculate ground-level concentrations, a composite "worst-case" set of emission rates and exhaust parameters will be used in the modeling as an initial approach for each turbine. For each turbine operating load, the highest pollutant-specific emission rate coupled with the lowest exhaust temperature and exhaust flow rate was selected. **Table 4-3** and **Table 4-4** summarize the worst-case emission parameters for the CCs and CTs, respectively. This data will be used to perform a load analysis for the turbines without any additional Project sources to determine which load results in the highest ground-level concentrations. The worst-case load scenario for each pollutant and averaging period will be used in subsequent SIL, NAAQS, and PSD increment modeling, as applicable unless that approach is deemed too conservative in which each case may be modeled explicitly to determine the worst-case operating load. If

baseload operations is not the worst-case load, both the baseload and worst-case load will be included in the SIL any subsequent cumulative modeling.

The turbine load analysis will also include the assessment of startup and shutdown operations to the extent that those emissions and stack parameters are worst-case relative normal operations.

Table 4-1. GE 7HA.02 Stack Exhaust Parameters and Emission Rates

Load/Scenario[1]	Ambient Temp. (ºF)	Stack Height (ft)	Stack Dia. (ft)	Exit Temp. (ºF)	Exit Velocity (fps)	Maximum Hourly Emissions (lb/hr) [2]	
						PM_{10}	$PM_{2.5}$
Base Load 100% + DB	-20°F,	190.0	23.0	169.9	68.88	24.1	24.1
Base Load 100% + DB	20°F,	190.0	23.0	170.5	69.61	23.7	23.7
Base Load 100% + DB	52°F,	190.0	23.0	172.0	68.20	23.2	23.2
Base Load 100% + DB	59°F,	190.0	23.0	171.6	67.49	23.0	23.0
Base Load 100% + DB	70°F,	190.0	23.0	172.2	67.37	22.9	22.9
Base Load 100% + DB	70°F,	190.0	23.0	172.4	67.52	22.9	22.9
Base Load 100% + DB	90°F,	190.0	23.0	170.1	64.87	22.2	22.2
Base Load 100% + DB	90°F,	190.0	23.0	172.2	67.22	22.8	22.8
Base Load 100% + DB	105°F,	190.0	23.0	166.5	60.18	21.1	21.1
Base Load 100% + DB	105°F,	190.0	23.0	172.3	67.29	22.8	22.8
Base Load 100%	-20°F,	190.0	23.0	172.9	68.31	12.1	12.1
Base Load 100%	20°F,	190.0	23.0	171.8	68.88	12.2	12.2
Base Load 100%	52°F,	190.0	23.0	174.8	67.67	12.2	12.2
Base Load 100%	59°F,	190.0	23.0	174.6	66.98	12.1	12.1
Base Load 100%	70°F,	190.0	23.0	177.1	67.08	12.1	12.1
Base Load 100%	70°F,	190.0	23.0	177.2	67.21	12.1	12.1
Base Load 100%	90°F,	190.0	23.0	177.6	64.86	11.9	11.9
Base Load 100%	90°F,	190.0	23.0	179.6	67.17	12.1	12.1
Base Load 100%	105°F,	190.0	23.0	175.3	60.30	11.4	11.4
Base Load 100%	105°F,	190.0	23.0	180.4	67.33	12.1	12.1
Intermediate Load 75%	-20°F,	190.0	23.0	169.2	54.56	11.3	11.3
Intermediate Load 75%	20°F,	190.0	23.0	168.2	54.30	11.3	11.3
Intermediate Load 75%	52°F,	190.0	23.0	168.7	53.12	11.3	11.3
Intermediate Load 75%	59°F,	190.0	23.0	168.5	52.61	11.3	11.3
Intermediate Load 75%	70°F,	190.0	23.0	170.9	52.51	11.2	11.2
Intermediate Load 75%	90°F,	190.0	23.0	172.5	51.48	11.1	11.1
Intermediate Load 75%	105°F,	190.0	23.0	172.4	49.46	10.9	10.9
MECL 45%	-20°F,	190.0	23.0	163.8	41.09	10.4	10.4
MECL 35%	20°F,	190.0	23.0	162.8	35.11	9.9	9.9
MECL 30%	52°F,	190.0	23.0	162.3	34.53	9.9	9.9
MECL 30%	59°F,	190.0	23.0	162.6	34.31	9.9	9.9
MECL 30%	70°F,	190.0	23.0	164.9	34.25	9.9	9.9
MECL 30%	90°F,	190.0	23.0	166.7	34.17	9.8	9.8
MECL 30%	105°F,	190.0	23.0	167.3	34.97	9.8	9.8

Load/Scenario[1]	Ambient Temp. (ºF)	Stack Height (ft)	Stack Dia. (ft)	Exit Temp. (ºF)	Exit Velocity (fps)	Maximum Hourly Emissions (lb/hr) [2]	
						PM_{10}	$PM_{2.5}$

Note: Data are provided per emission unit unless otherwise noted and are preliminary and subject to change.
(1) Data presented are for multiple operating loads/conditions and several ambient temperatures.
(2) Hourly emissions reflect operation of a single GE 7HA.02 unit firing natural gas.

Table 4-2. FT8 Stack Exhaust Parameters and Emission Rates

Load/Scenario[1]	Ambient Temp. (ºF)	Stack Height (ft)	Stack Dia. (ft)	Exit Temp. (ºF)	Exit Velocity (fps)	Maximum Hourly Emissions (lb/hr) [2]	
						PM_{10}	$PM_{2.5}$
Base Load (100%)	30	90.0	13.0	800.0	56.57	3.0	3.0
Base Load (100%)	59	90.0	13.0	800.0	57.04	3.0	3.0
Base Load (100%)	90	90.0	13.0	800.0	55.39	3.0	3.0
Intermediate Load (75%)	30	90.0	13.0	796.0	45.37	3.0	3.0
Intermediate Load (75%)	59	90.0	13.0	800.0	46.39	3.0	3.0
Intermediate Load (75%)	90	90.0	13.0	800.0	45.70	3.0	3.0
MECL (50%)	30	90.0	13.0	744.0	36.63	3.0	3.0
MECL (50%)	59	90.0	13.0	800.0	36.31	3.0	3.0
MECL (50%)	90	90.0	13.0	800.0	36.05	3.0	3.0

Note: Data are provided per emission unit unless otherwise noted and are preliminary and subject to change.
(1) Data presented are for multiple operating loads/conditions and several ambient temperatures.
(2) Hourly emissions reflect operation of a single FT8 unit firing natural gas.

Table 4-3. GE 7HA.02 Composite Worst-Case Data[1] Modeling Inputs

Parameter		Value			
Load (%)		**Base Load (100%) + DB**	**Base Load (100%)**	**Intermediate Load (75%)**	**MECL (50%)**
Stack Height (ft)		190.0	190.0	190.0	190.0
Stack Diameter (ft)		23.0	23.0	23.0	23.0
Exit Temperature (°F)		166.5	171.8	168.2	162.3
Exit Velocity (ft/sec)		60.18	60.30	49.46	34.17
Pollutant Emissions Per Unit (lb/hr)	**PM_{10}**	24.10	12.20	11.30	10.40
	$PM_{2.5}$	24.10	12.20	11.30	10.40

Note: Data are provided per emission unit unless otherwise noted and are preliminary and subject to change.
(1) The values in the table represent the worst-case stack parameters and the emission rates for the operating loads taken from Table 4-1.

Table 4-4. FT8 Composite Worst-Case Data(1) Modeling Inputs

Parameter		Value		
Load (%)		**Base Load (100%)**	**Intermediate Load (75%)**	**MECL (50%)**
Stack Height (ft)		90.0	90.0	90.0
Stack Diameter (ft)		13.0	13.0	13.0
Exit Temperature (°F)		800.0	796.0	744.0
Exit Velocity (ft/sec)		54.05	44.28	35.18
Pollutant Emissions Per Unit (lb/hr)	**PM_{10}**	3.0	3.0	3.0
	$PM_{2.5}$	3.0	3.0	3.0

Note: Data are provided per emission unit unless otherwise noted and are preliminary and subject to change.
(1) The values in the table represent the worst-case stack parameters and the emission rates for the three operating loads taken from Table 4-2.

The Project will also consist of three (3) auxiliary boilers and seven (7) natural gas heaters, which will be modeled as vertical, unobstructed point sources. Because the performance data for the auxiliary boilers and fuel gas heaters is not expected to be affected by ambient conditions, only one set of parameters will be modeled (e.g., stack parameters and emission rates associated with 100% load). The auxiliary boilers and fuel gas heaters will be modeled assuming a conservative 100% capacity factors. **Table 4-5** includes the stack parameters and emission rates for the auxiliary boilers and fuel gas heaters.

The Project will also include ten (10) 2,500 kW emergency generators, two (2) 1,000 kW emergency generators, and one (1) emergency fire-water pump engine, which will each be modeled as point sources. The emergency generators and fire-water pump engine are considered emergency units and will be operated for no more than 100 hours per year for routine testing and maintenance (i.e. non-emergency use) in accordance with 40 CFR 60.4230 JJJJ. For annual modeling, the emission rates will reflect the annual operating hour limitations. **Table 4-5** includes the emergency generators and fire-water pump engine stack parameters and emission rates.

Finally, the Project will also consist of seven (7) new cooling towers, each with eight (8) cells. Each cooling tower cell will be modeled as a vertical, unobstructed point source, and it is assumed emissions per cell is equivalent to one-eighth of total emissions from each of the seven (7) cooling tower units. **Table 4-5** includes the cooling tower stack parameters and emission rates.

Table 4-5. Source Parameters and Criteria Pollutant Emission Rates for Ancillary Sources

Source ID	Stack Height (ft)	Stack Diameter (ft)	Exit Temp. (°F)	Exit Velocity (fps)	Hourly Emissions (lb/hr/unit)(1)	
					PM_{10}	$PM_{2.5}$
Auxiliary Boiler	55.0	4.00	344.0	28.17	0.4992	0.4992
Gas Heater	22.0	2.50	670.0	10.57	0.0469	0.0469
Emergency Generators (2,500 kW)	20.0	1.20	964.0	66.67	0.1656	0.1607
Emergency Generators (1,000 kW)	20.0	1.20	964.0	66.67	0.06765	0.0656
Fire Water Pumps	12.0	0.50	826.0	187.93	0.1219	0.1183
Cooling Towers (2)	55.0	34.00	110.0	24.38	8.98E-03	2.88E-05

Note: Data are provided per emission unit and are preliminary and subject to change.
(1) Hourly emission rates/calculations based on vendor information.
Emission rates presented in this table are preliminary and are subject to change.
(2) Emissions represent per cell emissions - 1/8 total cooling tower emissions.

4.3 Model Selection

The suitability of an air quality dispersion model for a particular application is dependent upon several factors. The following selection criteria were evaluated:

- stack height relative to nearby structures;
- dispersion environment;
- representative meteorological data; and
- local terrain.

The US EPA GAQM prescribes a set of approved models for regulatory applications for a wide range of source types and dispersion environments. AERMOD is US EPA's recommended refined dispersion model for simple and complex terrain for receptors within 50 kilometers (km) of a modeled source and is capable of handling the source geometry, terrain, and dispersion environment associated with this proposed Project. Representative meteorological data with suitable data capture for various meteorological parameters is needed to run AERMOD.

Based on a review of the factors described in the following sections of this protocol, the latest version of AERMOD (version 24142) (US EPA, 2024c) will be used to assess air quality impacts for the proposed Project. AERMOD will be used to assess air quality impacts of PM_{10}, and $PM_{2.5}$ at receptors located within 20 km of the Project site. AERMOD will be run with default model options in the CONTROL pathway, unless otherwise noted or discussed with PADEP. AERMOD will also be applied without using any urban source options as discussed in **Section 4.5**.

4.4 Building Downwash and GEP Height Analysis

US EPA modeling guidelines require the evaluation of the potential for physical structures to affect the dispersion of emissions from stack emission points. The exhaust from stacks that are located within specified distances of buildings, and whose physical heights are below specified levels, may be subject to "aerodynamic building downwash" under certain meteorological conditions. If this is the case, a model capable of simulating this effect must be employed.

The analysis used to evaluate the potential for building downwash is referred to as a physical "Good Engineering Practice" ("GEP") stack height analysis. Stacks with heights below physical GEP are considered to

be subject to building downwash. In the absence of influencing structures, a "default" GEP stack height is creditable up to 65 meters (213 feet) per the *Guideline for Determination of Good Engineering Practice Stack Height* (US EPA, 1985). Any portion of a stack above the maximum of the physical or default GEP height cannot be used in the dispersion modeling analysis for purposes of comparison to US EPA's ambient impact criteria.

A GEP stack height analysis will be performed for all point sources included in the modeling in accordance with US EPA's guidelines (US EPA, 1985). Per the guidelines, the physical GEP height ("H_{GEP}") is determined from the dimensions of all buildings that are within the region of influence using the following equation:

$$H_{GEP} = H + 1.5L$$

where:

H = height of the structure within 5L of the stack which maximizes H_{GEP}, and
L = lesser dimension (height or projected width) of the structure.

For a squat structure (*i.e.,* height less than projected width), the formula reduces to:

$$H_{GEP} = 2.5H$$

Both the height and width of the structure are determined from the frontal area of the structure projected onto a plane perpendicular to the direction of the wind. In all instances, the GEP stack height is based on the plane projections of any nearby building which result in the greatest justifiable height. For purposes of the GEP analysis, nearby refers to the "sphere of influence," defined as five times the height or width of the building, whichever is less, downwind from the trailing edge of the structure.

The current Project design has all modeled stacks less than 65 meters. As such, all Project stacks will be modeled using their actual stack height. In addition, the EPA's Building Profile Input Program (BPIP-Version 04274) version that is appropriate for use with PRIME algorithms in AERMOD will be used to incorporate wind-direction-specific building dimensions for input to AERMOD. Building coordinates and stack locations will be developed using site plan drawings, aerial photographs, and GIS software. All relevant building structures will be included in the BPIP modeling for both new and existing stacks at the Plant, as applicable.

4.5 Dispersion Environment

4.5.1 Land Use Analysis

The application of AERMOD requires characterization of the local (within 3 km) dispersion environment as either urban or rural based on prevalent land use. According to US EPA modeling guidelines (US EPA, 2024a), if more than 50 percent of an area within a 3-km radius of the proposed project is classified as rural, then a rural modeling application is required. Conversely, if more than 50% of the area is urban, an urban dispersion adjustment can be used.

Using the Auer method recommended by the US EPA (US EPA, 2024a), urban land use types are classified as categories I1, I2, C1, R2, and R3. **Table 4-6** describes these categories and maps them to reasonably equivalent USGS 2016 National Land Cover Database (NLCD) categories. While the Auer method and NLCD do not use the same terms to define their categories, the similarities between the five Auer categories and NLCD categories 23 and 24 are apparent. Thus, it is reasonable to classify NLCD categories 23 and 24 as urban land use. A visual comparison of the 2023 (the most recent version) NCLD land use types to recent aerial imagery from Google™ Earth indicates only insignificant changes to the land use within 3 km since 2023. **Figure 4-1** displays the 2023 NLCD data superimposed over aerial imagery within 3 km of the Plant.

The NLCD data were processed with US EPA's AERSURFACE processor (version 24142) to determine the different land use types within 3 km of the Station. AERSURFACE is typically used to process NLCD data for

input to AERMET, the AERMOD model's meteorological data processor. In this case, AERSURFACE output in the form of the pixel count for each of NLCD's land use types was used to determine the total pixel count of urban land use types within 3 km.

As noted above, urban land use types were assumed to be NLCD categories 23 and 24: "Developed, Medium Intensity" and "Developed, High Intensity", respectively. The pixel count for these categories was 2.59% of the total pixel count for all categories. Thus, the overwhelming majority (>90%) of the 3 km area around the Plant can be classified as rural land use and AERMOD will not be applied with any urban source options. **Table 4-7** provides the pixel counts as reported in the AERSURFACE output along with respective percentages.

Table 4-6. Comparison of Auer and NLCD Land Use Categories

Auer Urban Land Use Categories[1]			USGS 2016 NLCD Categories[2]	
Type	**Use and Structure**	**Vegetation**	**Category**	**Description**
R2	Dense single/multi-family	< 30%	23	Developed, Medium Intensity – Areas with a mixture of constructed materials and vegetation. Impervious surfaces account for 50% to 79% of the total cover. These areas most commonly include single-family housing units.
R3	Multi-family, two story	< 35%	24	Developed, High Intensity – Highly developed areas where people reside or work in high numbers. Examples include apartment complexes, row houses and commercial/industrial. Impervious surfaces account for 80% to 100% of the total cover.
I1	Heavy Industrial	< 5%		
I2	Light/moderate industrial	< 5%		
C1	Commercial	< 15%		

Notes:
[1] US EPA, 2024a.
[2]Multi-Resolution Land Characteristics Consortium (MRLC).
https://www.mrlc.gov/data/legends/national-land-cover-database-class-legend-and-description

Table 4-7. AERSURFACE Surface Roughness Output

USGS 2016 NLCD Category	Description	Pixel counts	Percent of Total Pixels
0	Missing, Out-of-Bounds, or Undetermined	0	0%
11	Open Water	118	0.38%
12	Perennial Ice/Snow	0	0%
21	Developed, Open Space	1802	5.74%
22	Developed, Low Intensity	1488	4.74%
23	**Developed, Medium Intensity**	**720**	**2.29%**
24	**Developed, High Intensity**	**95**	**0.30%**
31	Barren Land (Rock/Sand/Clay)	2441	7.77%
32	Unconsolidated Shore	0	0%
41	Deciduous Forest	12860	40.94%
42	Evergreen Forest	2	0.01%
43	Mixed Forest	510	1.62%
51	Dwarf Scrub	0	0%
52	Shrub/Scrub	154	0.49%
71	Grasslands/Herbaceous	166	0.53%
72	Sedge/Herbaceous	0	0%
73	Lichens	0	0%

USGS 2016 NLCD Category	Description	Pixel counts	Percent of Total Pixels
74	Moss	0	0%
81	Pasture/Hay	4557	14.51%
82	Cultivated Crops	6437	20.49%
90	Woody Wetlands	61	0.19%
91	Palustrine Forested Wetland	0	0%
92	Palustrine Scrub/Shrub Wetland	0	0%
93	Estuarine Forested Wetland	0	0%
94	Estuarine Scrub/Shrub Wetland	0	0%
95	Emergent Herbaceous Wetland	1	0%
96	Palustrine Emergent Wetland	0	0%
97	Estuarine Emergent Wetland	0	0%
98	Palustrine Aquatic Bed	0	0%
99	Estuarine Aquatic Bed	0	0%
	Total	**31412**	

Urban land use types are shown in red, bold text.
Source: AERSURFACE (US EPA, 2024d)

4.5.2 Terrain

US EPA's GAQM requires that the differences in terrain elevations between the stack base and model receptor locations be considered in the modeling analyses. There are three types of terrain:

- simple terrain – locations where the terrain elevation is at or below the exhaust height of the stacks to be modeled;
- intermediate terrain – locations where the terrain is between the top of the stack and the modeled exhaust "plume" centerline (this varies as a function of plume rise, which in turn, varies as a function of meteorological condition);
- complex terrain – locations where the terrain is above the plume centerline.

Figure 4-2 provides a topographic map of the area in the vicinity of the Project site. The area near the Station is characterized as consisting of all terrain types relative to the modeled stacks.

Figure 4-1. NLCD Land Use (2023)

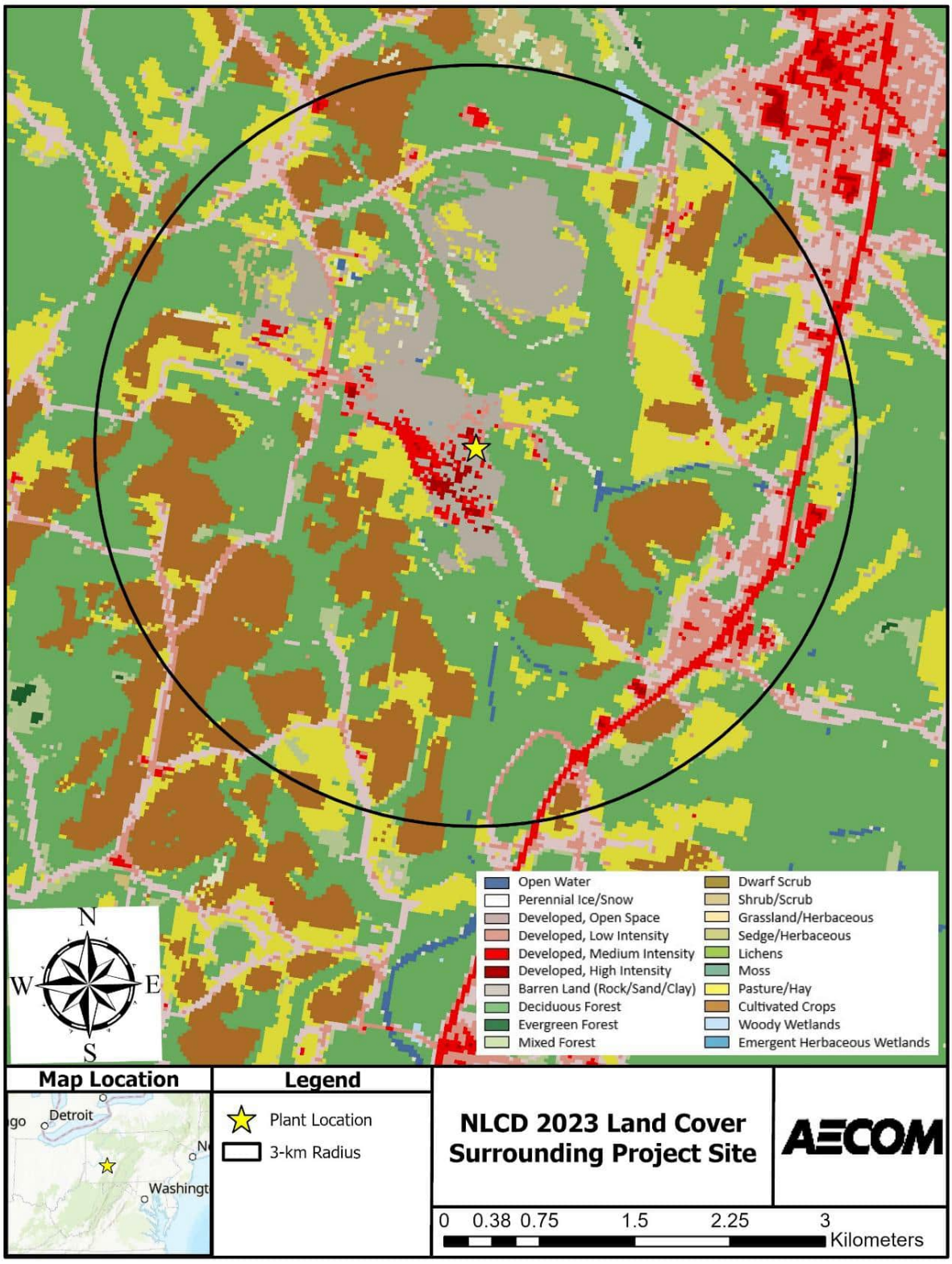
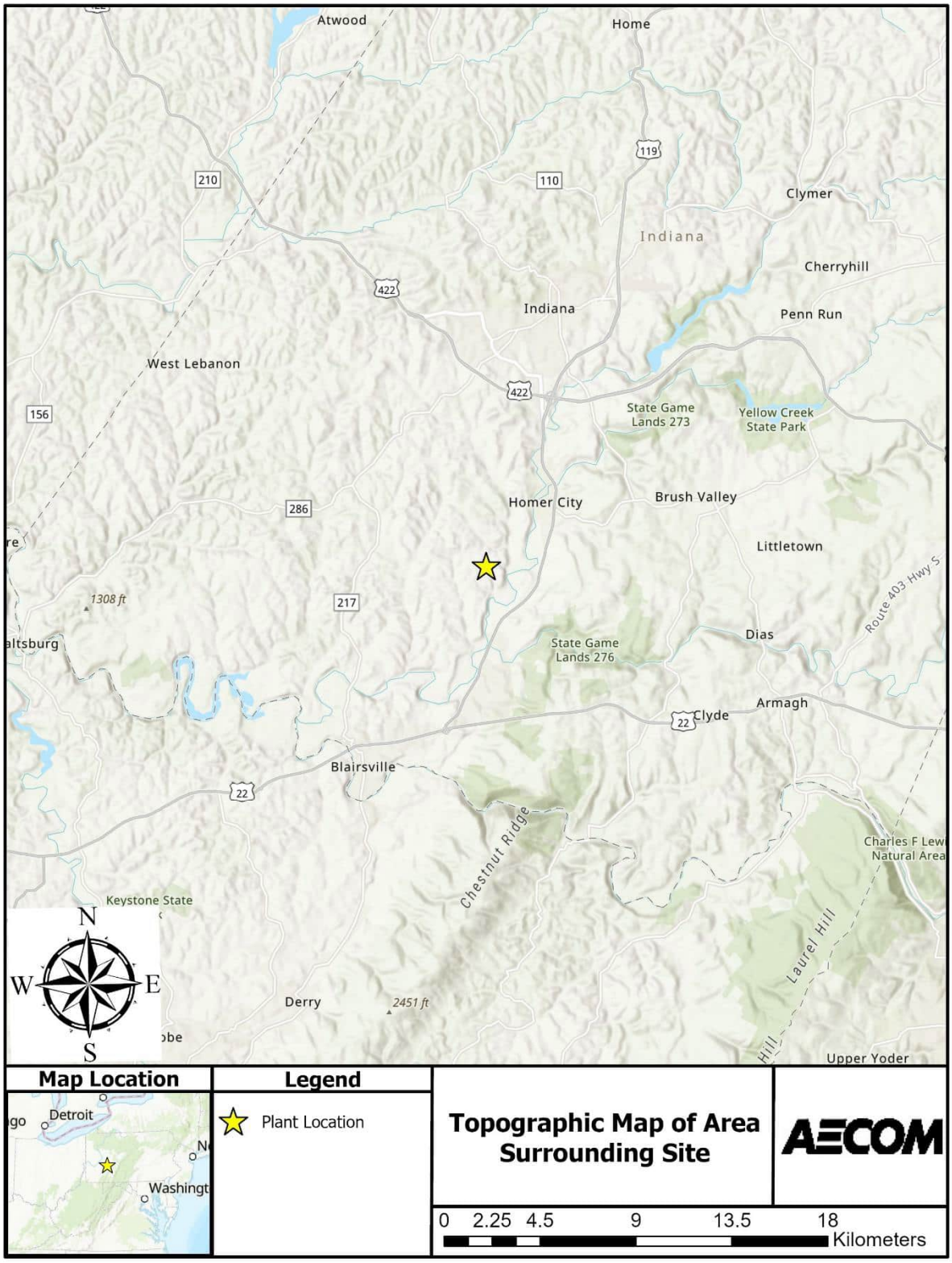


Figure 4-2. Topographic Map of Project Site Area



4.6 Meteorological Data

Homer City is proposing to use five years (2020-2024) of near-surface meteorological data from the John Murtha Johnstown-Cambria County Airport (Johnstown Airport) along with concurrent upper-level data from Pittsburgh International Airport for this modeling demonstration. The meteorological data from Johnstown Airport was processed by PADEP using AERMET version 24142 using regulatory options. The PROFBASE keyword in AERMOD, representing the base elevation of the surface dataset will be set to 696 m (NCEI, 2025). This is consistent with historical modeling conducted by PADEP and US EPA using the Johnstown Airport meteorological station.

Historically the Johnstown Airport meteorological data has been used for air dispersion modeling demonstrations at Homer City, including as recently as to support the redesignation of the Indiana County non-attainment area for 1-hour SO_2 to attainment (US EPA, 2024e). Past modeling has focused on dispersion from Homer City's approximately 800-foot coal-boiler stacks. In 2012, ERM conducted a robust evaluation (ERM, 2012) of nearby meteorological data for Homer City modeling and concluded that the Johnstown Airport was the most representative dataset available for modeling plumes emitted from the tall stacks. With it being more than 12 years removed from that evaluation and the lower stack heights from the Proposed Project compared to the coal stacks, an updated analysis was warranted. The following **Sections (4.6.1 through 4.6.3)** describes the updated analysis that was performed to identify the most representative meteorological dataset for use in dispersion modeling of the Proposed Project, consistent with Section 8.4 of US EPA's GAQM.

4.6.1 Review of Available Meteorological Data

The 2012 ERM report identified five locations of meteorological stations within approximately 80 kilometers (50 miles) of Homer City. These included Automated Surface Observing Systems (ASOS) at Pittsburgh International Airport and Johnstown Airport, an Automated Weather Observing System (AWOS) at Indiana County Airport, and two research-based multi-level towers (Ash Valley and Manor Tower). There has since been one additional meteorological dataset, Ash Site #1, located between Seward and Conemaugh Generating Stations in southeast Indiana County. The Ash Site #1 was a 1-year dataset from September 2015 through August 2016 that consisted of a 100-meter tower and SOund Detection And Ranging (SODAR) system (AECOM, 2015).

Table 4-8 provides the approximate distance to Homer City and most recent available data periods for each potential meteorological dataset. Both the Ash Valley and Ash Site #1 locations were sited to capture localized, terrain-driven effects in the vicinity of Conemaugh and Seward stations and would not be suitable for Homer City. Indiana County Airport has a history of reporting a higher number (greater than 30%) calm winds as it does not record sub-hourly measurements like ASOS sites. For these reasons, the Ash Valley, Ash Site #1, and Indiana County Airport sites would not be representative of conditions at Homer City. With other meteorological stations much closer in proximity to Homer City than Pittsburgh International Airport, this site is also not considered as the best fit. This leaves Manor Tower and Johnstown Airport as candidates to be further evaluated.

Table 4-8. Meteorological Stations Near Homer City

Meteorological Site	Distance (Direction) from Homer City	Recent Data Period Available
Pittsburgh Airport	85 km (west of Homer City)	2019-2023 (recent 5-years)
Johnstown Airport	38 km (southeast of Homer City)	2020-2024 (recent 5-years)
Indiana County Airport	15 km (northeast of Homer City)	2019-2023 (recent 5-years)
Ash Tower	17.8 km (southeast of Homer City)	August 1990 – July 1991
Manor Tower	9.9 km (northeast of Homer City)	August 1990 – July 1991
Ash Site #1	18 km (southeast of Homer City)	September 2015 – August 2016

Source: ERM, 2012; AECOM, 2015

4.6.2 Comparison of Surface Characteristics

Key data inputs to the processing of meteorological data for dispersion models include surface roughness, albedo, and Bowen ratio. According to Section 3.1.1 of AERMOD's Implementation Guide, the determination of representativeness should include a comparison of these key surface data inputs (US EPA, 2024f). US EPA has developed a tool, AERSURFACE, that can estimate these parameters for a given location based upon digitized land cover data and corresponding lookup tables. AERSURFACE User's Guide recommends a default radial distance of 1 km from the meteorological station or source location to evaluate surface roughness. Albedo and Bowen ratio are assessed within a 10 km by 10 km distance. **Table 4-9** lists the albedo, surface roughness, and Bowen ratios for Johnstown Airport, Homer City, and Manor Tower.

The surface roughness was computed using the AERSURFACE tool and National Land Cover Data (NLCD) available from the U.S. Geological Survey (USGS, 2024). In late 2024, USGS updated their NLCD files to new annual products. These newer NLCD products were used to generate the surface roughness values listed in **Table 4-9**. NLCD files for 2021 were used for the AERSURFACE processing of the Johnstown Airport and Homer City as it represented the most recent meteorological data year available for modeling. The 1991 NLCD file was used to process the AERSURFACE for Manor tower as that dataset spanned from August 1990 through July 1991.

It is well documented (Karvounis et al., 2007; Faulkner et al., 2008) that dispersion models are typically most sensitive to changes in surface roughness compared to albedo or Bowen ratios. **Figure 4-3** illustrates the differences of surface roughness by season between the Manor Tower and the other two sites (Johnstown Airport and Homer City). Due to the more forested surroundings at Manor Tower, the surface roughness values are approximately an order of magnitude higher than those at both Johnstown Airport and Homer City. The more forested surroundings of the Manor Tower location can also be seen in aerial imagery, as shown in **Figure 4-4**, **Figure 4-5**, and **Figure 4-6** for Manor Tower, Johnstown Airport, and Homer City, respectively. Given the vastly different surface roughness conditions compared to the Proposed Project location, the Manor Tower is not considered the most representative meteorological dataset for dispersion modeling at Homer City.

Table 4-9. Comparison of Surface Characteristics at Johnstown Airport, Homer City, and Manor Tower

	Johnstown Airport[1]			Homer City[1]			Manor Tower[2]		
Seasons	Albedo	Surface Roughness (m)	Bowen Ratio	Albedo	Surface Roughness (m)	Bowen Ratio	Albedo	Surface Roughness (m)	Bowen Ratio
Winter	0.17	0.077	0.91	0.17	0.088	0.88	0.17	0.197	0.91
Spring	0.16	0.106	0.58	0.15	0.111	0.53	0.16	0.295	0.60
Summer	0.16	0.142	0.43	0.17	0.152	0.41	0.17	0.451	0.38
Fall	0.16	0.124	0.91	0.17	0.149	0.88	0.17	0.447	0.91

[1] Values based on land cover from 2021 (most recent meteorological year available for Johnstown)
[2] Values based on land cover from 1991

Figure 4-3. Surface Roughness by Season

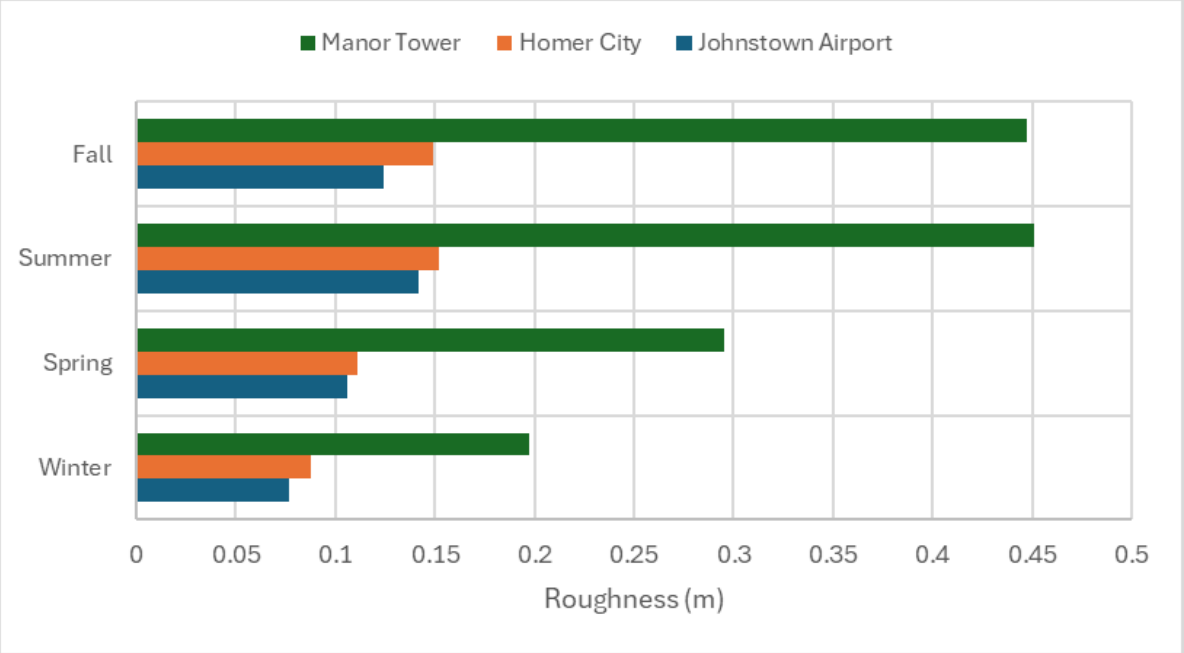


Figure 4-4. Aerial Image of Manor Tower

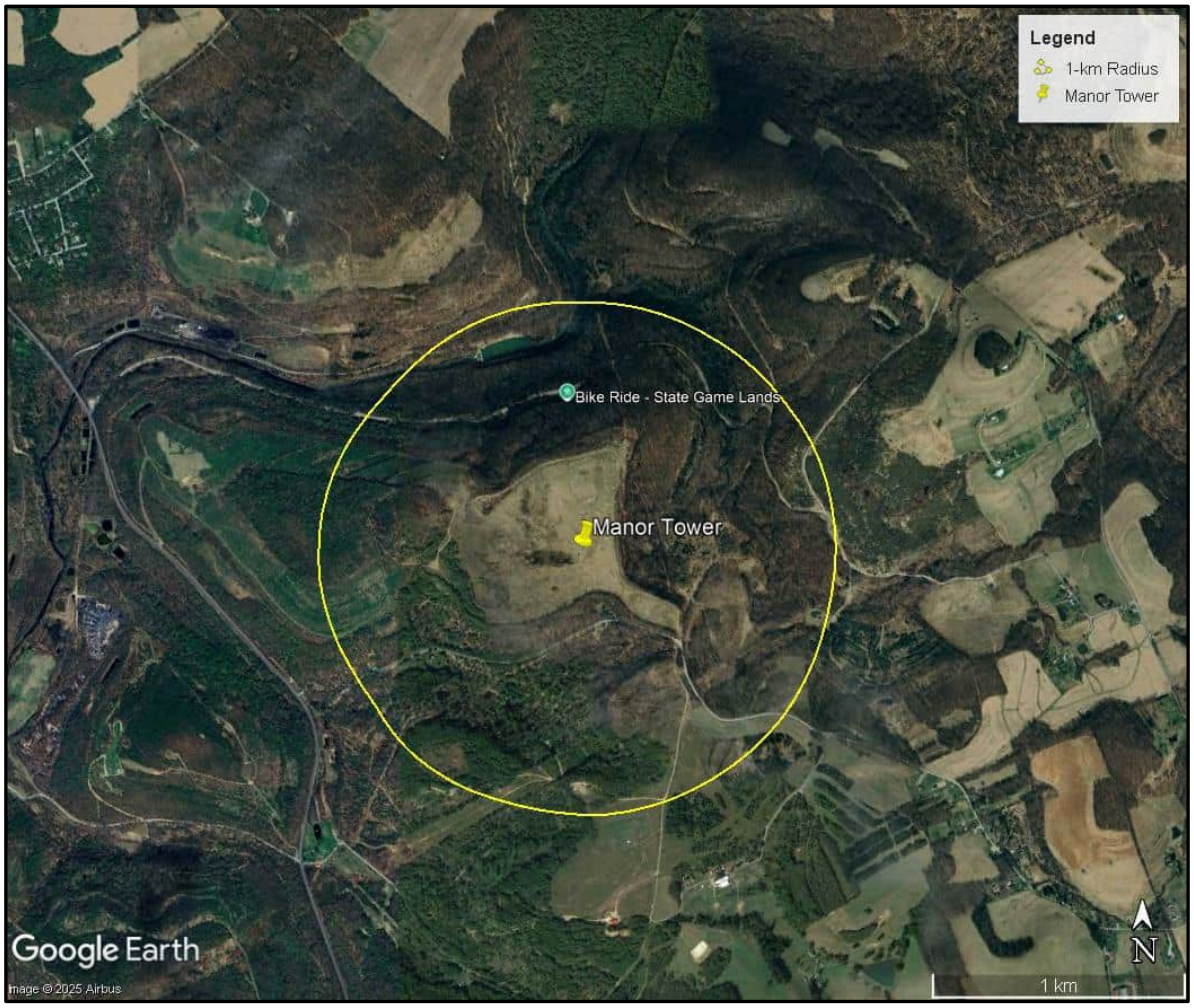


Figure 4-5. Aerial Image of Johnstown Airport

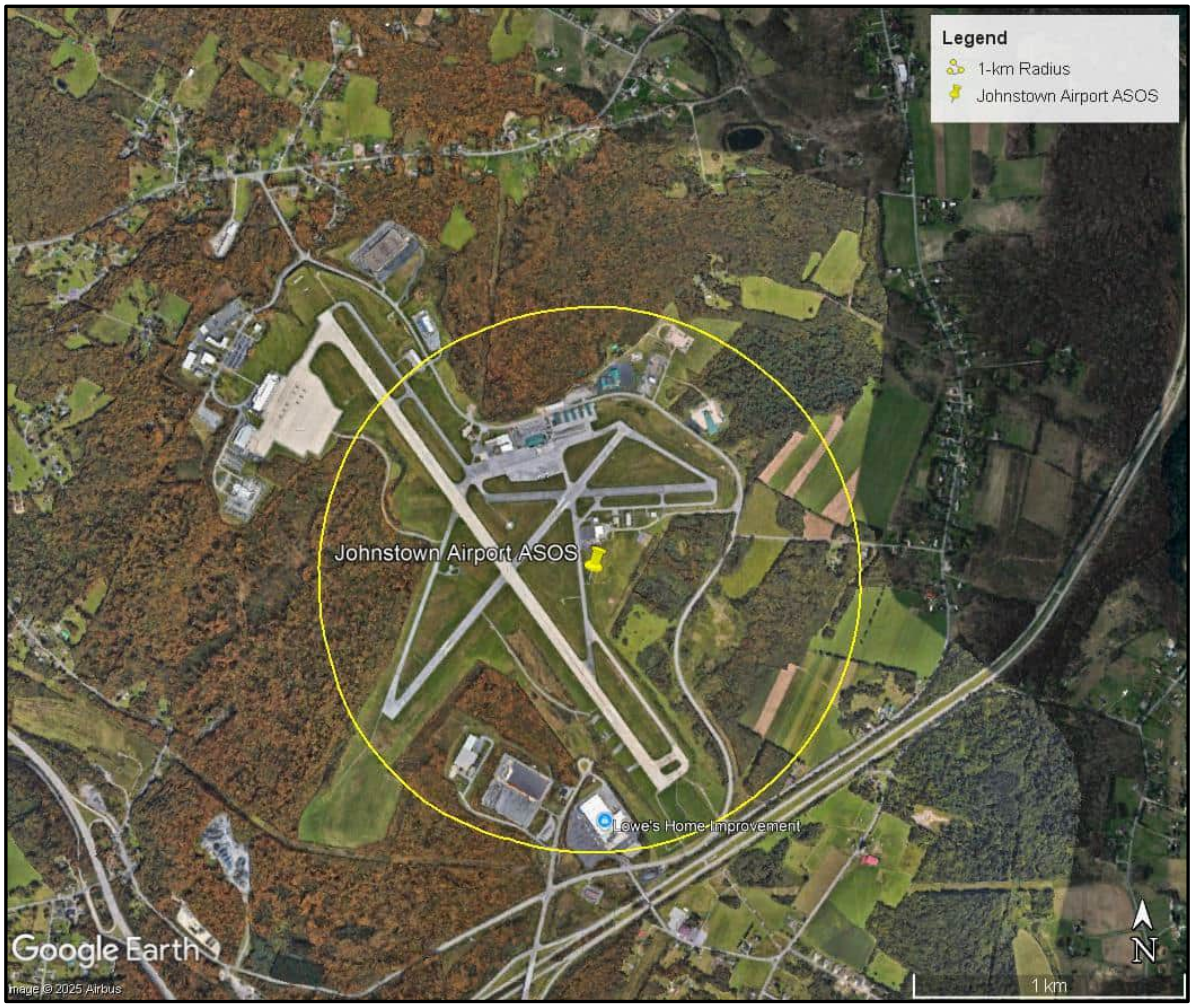
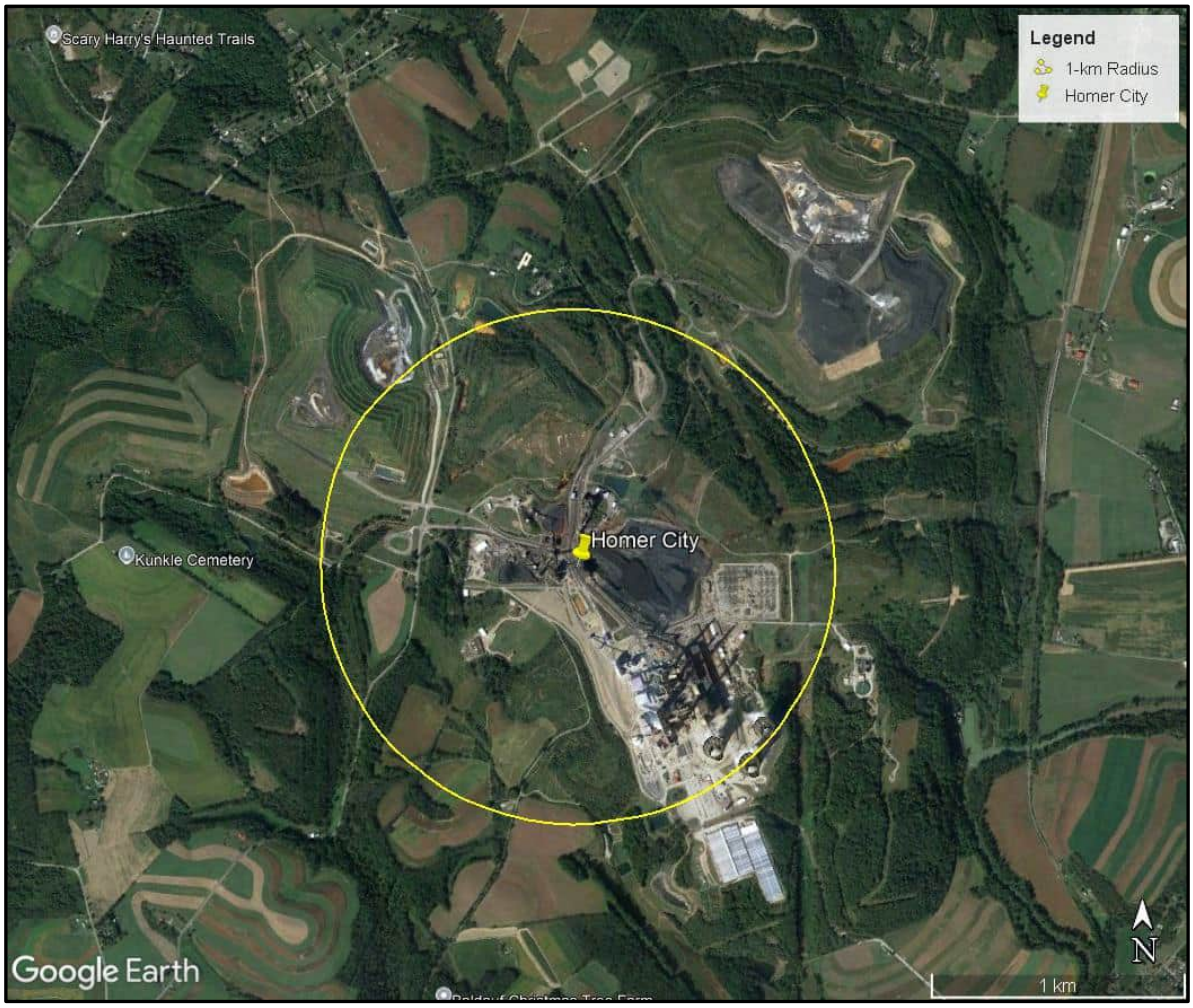


Figure 4-6. Aerial Image of Homer City



4.6.3 Evaluation of Winds at Plume Height of Modeled Sources

Another key component of evaluating the representativeness of the meteorological data for this proposed modeling demonstration is the winds at plume height. Historical modeling for Homer City has relied on the height of the 800-feet coal stacks as being sufficiently tall enough to clear regional terrain and therefore wind at that height (and higher) from Johnstown Airport would be comparable. As discussed in **Section 4.2**, the stack heights from the CCs are 190 feet, which is approximately 600 feet shorter as compared to the 800 feet coal stacks. However, with both the coal and CC stacks having good buoyancy and momentum rise, a quantified analysis to assess the plume heights of the CCs and coal stacks was performed, as opposed to focusing on just the physical stack heights.

EPA's SCREEN3 screening model (version 13043) (US EPA, 2013) was used to estimate the plume rise and ultimately final plume height generated from the 800-foot (243.8-m) coal stacks and 190-foot (57.9-m) CC stacks. SCREEN3 was identified as the most appropriate screening model for this purpose as it provides plume heights at various distances downwind. EPA's preferred screening model, AERSCREEN, was considered, but due to limitations in not having multiple downwind distances assessed for plume height and the inability to set static meteorological conditions, SCREEN3 proved to be the most suitable for a direct plume height comparison.

An initial run of SCREEN3 was conducted for both the coal stack and CC stack. **Table 4-10** provides a summary of the input parameters used in each of these runs. The “full meteorological” option was selected to initially identify the conditions that would produce the highest concentrations. For this run, the final plume height was 1,622 m and 1,237 m for the coal stack and CC stack, respectively. This yielded approximately a 24% difference in plume rise between the two stacks. The meteorological conditions producing these results were wind speeds under 1 m/s for both stacks, which would be typical of a low wind (< 2 m/s) condition and likely maximize the potential plume height. As a result, a second SCREEN3 run was performed to evaluate a more average wind speed of 3 m/s under neutral stability conditions. As anticipated, the 3 m/s SCREEN3 run for both coal and CC stacks showed lower plume heights compared to the low wind condition, with heights of 600 m and 400 m, respectively. These heights yield an approximate 33% difference in plume height between the two stacks. These two heights will serve as the basis for comparing wind data levels in **Section 4.6.3.3**. Printouts of the SCREEN3 3 m/s output files are provided in **Appendix A**.

Table 4-10. SCREEN3 Inputs for Full Meteorology Conditions

SIMPLE TERRAIN INPUTS	Coal Stack	CC Stack
SOURCE TYPE	POINT	POINT
EMISSION RATE (G/S)	100	100
STACK HEIGHT (M)	243.8	57.9[1]
STK INSIDE DIAM (M)	7.32	7.01[1]
STK EXIT VELOCITY (M/S)	25.51	18.38[1]
STK GAS EXIT TEMP (K)	351.7	350.8[1]
AMBIENT AIR TEMP (K)	293	293
RECEPTOR HEIGHT (M)	0	0
URBAN/RURAL OPTION	RURAL	RURAL

CC = Combined-cycle combustion turbines
[1] Base Load (100%) values from Table 4-3.

4.6.3.1 Surface Wind Rose Evaluation at Johnstown Airport

Prior to evaluating wind roses at plume height, an initial comparison was made between observed wind data from the Johnstown Airport and prognostic data. US EPA has been using the Weather Research and Forecasting (WRF) model to generate meteorological data for input into air quality models for several years. The US EPA recently revised Section A.1(b) of their GAQM to include prognostic data as meteorological input to AERMOD. US EPA now routinely processed annual WRF simulations for the entire contiguous U.S., with WRF output available for recent years (2019-2021). The WRF model (Skamarock et al., 2019) (version 4.1.1) was initialized with 0.25-degree Global Forecast System (GFS) analysis data, and a 12 km WRF nest was created using analysis data from the North American Mesoscale Model (NAM). For this application, the closest WRF grid cell to the Johnstown Airport was selected, with the grid cell center (40.309N, 78.880W) located approximately 4 km to the southwest of the Johnstown Airport. To generate wind roses at specific heights above ground level, the EPA’s Mesoscale Model Interface Program (MMIF) version 4.1.1 was used to extract specific vertical levels from the WRF output (US EPA, 2024g).

Figure 4-7 shows the 3-year (2019-2021) wind roses for (a) Johnstown Airport from the anemometer height of 7.9-meters and (b) the WRF at 10-m above ground level. Both wind roses capture the predominant wind direction from the west and the secondary flow pattern from the southeast. The WRF data agrees well with the Johnstown Airport in capturing the regional wind flow and direction. The overall average wind speed over the period between the WRF is only slightly lower by 0.4 m/s as compared to the Johnstown Airport ASOS, as shown in **Table 4-11**. Minor differences between the two datasets are likely attributed to localized effects that ground-based sensors are better suited at resolving.

As a means of providing a quantitative evaluation comparing the near surface Johnstown Airport and WRF wind rose, a statistical analysis was performed. **Table 4-11** provides the mean, mean bias, fractional bias (Fb), root mean square error (RMSE) and the Pearson correlation coefficient (r-squared or R^2) statistics for key meteorological parameters over the 3-year period (2019-2021).

Table 4-11. Statistical Comparison of Observed KJST ASOS to KJST WRF for Near Surface

Variable	Mean of KJST ASOS	Mean of KJST WRF	Mean Bias	Fb (unitless)	RMSE	R^2 (unitless)
Wind Speed (m/s)	4.36	3.95	-0.4088	-0.0984	1.3056	0.6670
Temp (°C)	283.20	283.28	0.0838	0.0003	1.6949	0.9710
Pressure (mb)	935.91	948.38	12.4782	0.0132	12.5035	0.9822
Relative Humidity (%)	68.86	78.47	9.6124	0.1305	14.9669	0.6539
Heat Flux	14.84	28.35	13.5095	0.6257	68.5387	0.5159
Surface Friction Velocity (m/s)	0.34	0.54	0.1992	0.4498	0.2761	0.6434

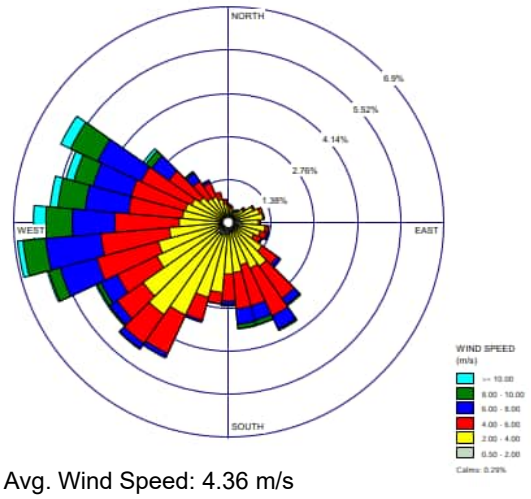
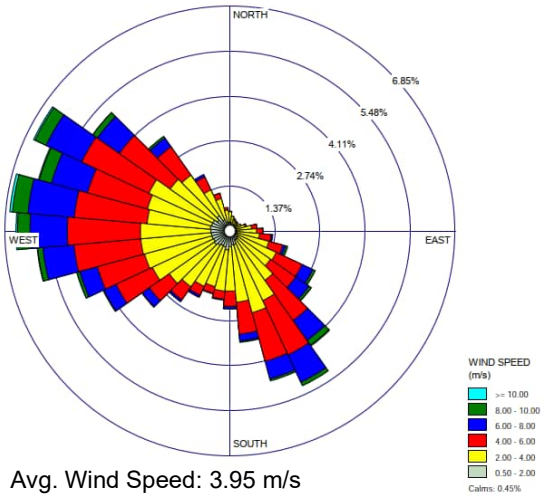
Notes: ASOS = Johnstown Airport ASOS; WRF = closest node to Johnstown Airport; Fb = fractional bias; RMSE = root mean square error

The Fb serves as a good indicator in assessing the WRF's tendency to overestimate or underestimate the observed (ASOS) values. Values of the Fb range between -2.0 (extreme overprediction) and +2.0 (extreme underprediction) and are unitless. A Fb of 0 (zero) means no bias. Temperature and wind speed are the most critical variables, and both show near zero Fb, meaning minimal bias exists. The R^2 indicates the correlation of the two datasets, while the RMSE is used to evaluate the accuracy. R^2 values range from 0 to 1 and are unitless. An R^2 value closer to 1 indicates a good correlation between the two datasets. Most of the variables presented in Table 4-11 have an R^2 value around 0.65, with temperature and pressure near 1 (0.97 and 0.98, respectively). RMSE values range from zero to infinity. A low RMSE means less difference between the two datasets. For wind speed and temperature, RMSE are near 1, meaning better performance between the ASOS and WRF data. Similar seasonal-based statistical tables and wind roses are presented in **Appendix A**. These supplemental statistics show a relatively small variability between seasons, thus the annual data presented in **Table 4-11** and

Figure 4-7 serve as a good indicator for this location.

Based on this comparison, the WRF dataset should yield representative winds aloft for comparison of plume height levels at Johnstown Airport and Homer City. The results of the plume height level are presented in **Section 4.6.3.3**.

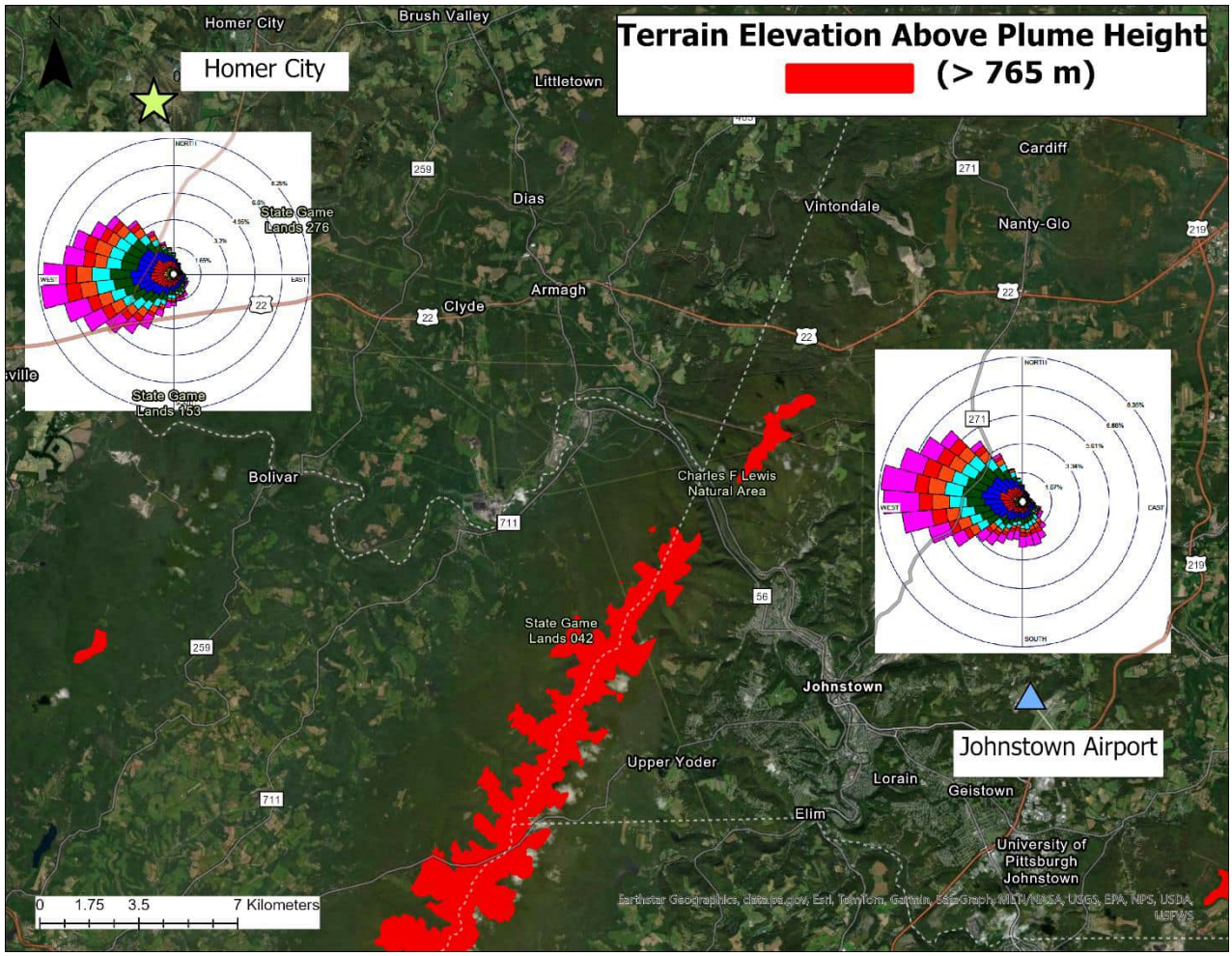
Figure 4-7. Near-Surface 3-year (2019-2021) Wind Roses for KJST ASOS vs. KJST WRF

(a) KJST ASOS at 7.9 m	(b) KJST WRF at 10 m
 Avg. Wind Speed: 4.36 m/s	 Avg. Wind Speed: 3.95 m/s

4.6.3.2 Plume Heights Relative to Nearby Terrain

A review of terrain elevations between Homer City and Johnstown Airport was conducted to assess whether there may be significant terrain interference of wind flow and/or plume transport between these two locations. **Figure 4-8** depicts the elevated terrain in the general vicinity of Homer City and the Johnstown Airport that exceed the plume height (805 m) of the CC stacks. The areas highlighted in “red” indicate the terrain that exceeds the plume height of 805 meters, which is primarily focused to the southwest of Johnstown Airport. With the exception of a few rogue peaks along Laurel Ridge near the Laurel Highlands Hiking Trails, the rest of the surrounding terrain is below this level. This analysis further supports the predominant westerly flow at plume height is not being heavily influenced by the terrain features.

Figure 4-8. Map of Terrain Heights Above Plume Height from CC Stacks



4.6.3.3 Wind Rose Comparison at Plume Heights

Figure 4-8 illustrates the wind rose comparison using the 2019-2021 WRF data at plume heights for the coal and CC stacks at Homer City to the equivalent height levels above ground at the Johnstown Airport. The grid cell for the Johnstown Airport in this analysis is the same as the one identified in **Section 4.6.3.1**. For Homer City, the closest grid cell center (40.586N, 79.244W) is approximately 8.5 km to the northwest of the Homer City, as shown in **Figure 4-9**.

As discussed in **Section 4.6.3**, the plume heights from the SCREEN3 analysis were 600 m and 440 m above ground for the coal and CC stacks, respectively. Accounting for the base elevation at Homer City of 365 m, the wind rose heights that were evaluated at Homer City are 965 m (365 + 600) and 765 m (365 + 400) for the coal and CC stacks, respectively. The closest WRF level was selected to generate the wind rose at Homer City. These corresponded to 1,000 m and 750 m. For the wind rose heights at the Johnstown Airport, which is situated at 330 m higher than Homer City, the above ground level heights would be 635 m and 435 m. This equates to WRF heights of 600 m and 450 m that the wind roses were generated for. As shown in **Figure 4-10**, there is a predominant westerly flow signature evident in all four wind roses. The average wind speeds were calculated to be within 5-6% between the two locations for the similar plume height levels.[1]

Statistics on wind speed and temperature comparing the WRF at plume height for both the Johnstown Airport and Homer City locations are shown in **Table 4-12**. These statistics are based on the entire 3-year (2019-2021) period. The results presented in **Table 4-12** show good agreement between the WRF data at plume height between the two locations. Minor seasonal variations are noted, which are included in **Appendix A**. Based on this analysis, the Johnstown Airport the most representative dataset available for dispersion modeling at Homer City.

Table 4-12. Statistical Comparison of WRF at CC Plume Height for KJST and Homer City

Variable	Mean of KJST WRF	Mean of Homer City WRF	Mean Bias	Fb (unitless)	RMSE	R^2 (unitless)
Wind Speed (m/s)	10.36	9.77	-0.5950	-0.0591	2.0713	0.8794
Temp (°C)	8.16	7.56	-0.5976	-0.0760	1.2317	0.9882

Notes: ASOS = Johnstown Airport ASOS; WRF = closest node to Johnstown Airport; Fb = fractional bias; RMSE = root mean square error

[1] Average wind speed at 1,000 m level Homer City was 10.22 m/s compared to 10.68 m/s at Johnstown Airport 600 m level. Average wind speed at 750 m level Homer City was 9.77 m/s compared to 10.36 m/s at Johnstown Airport 450 m level.

Figure 4-9. Location of WRF Grid Nodes Relative to Homer City and KJST

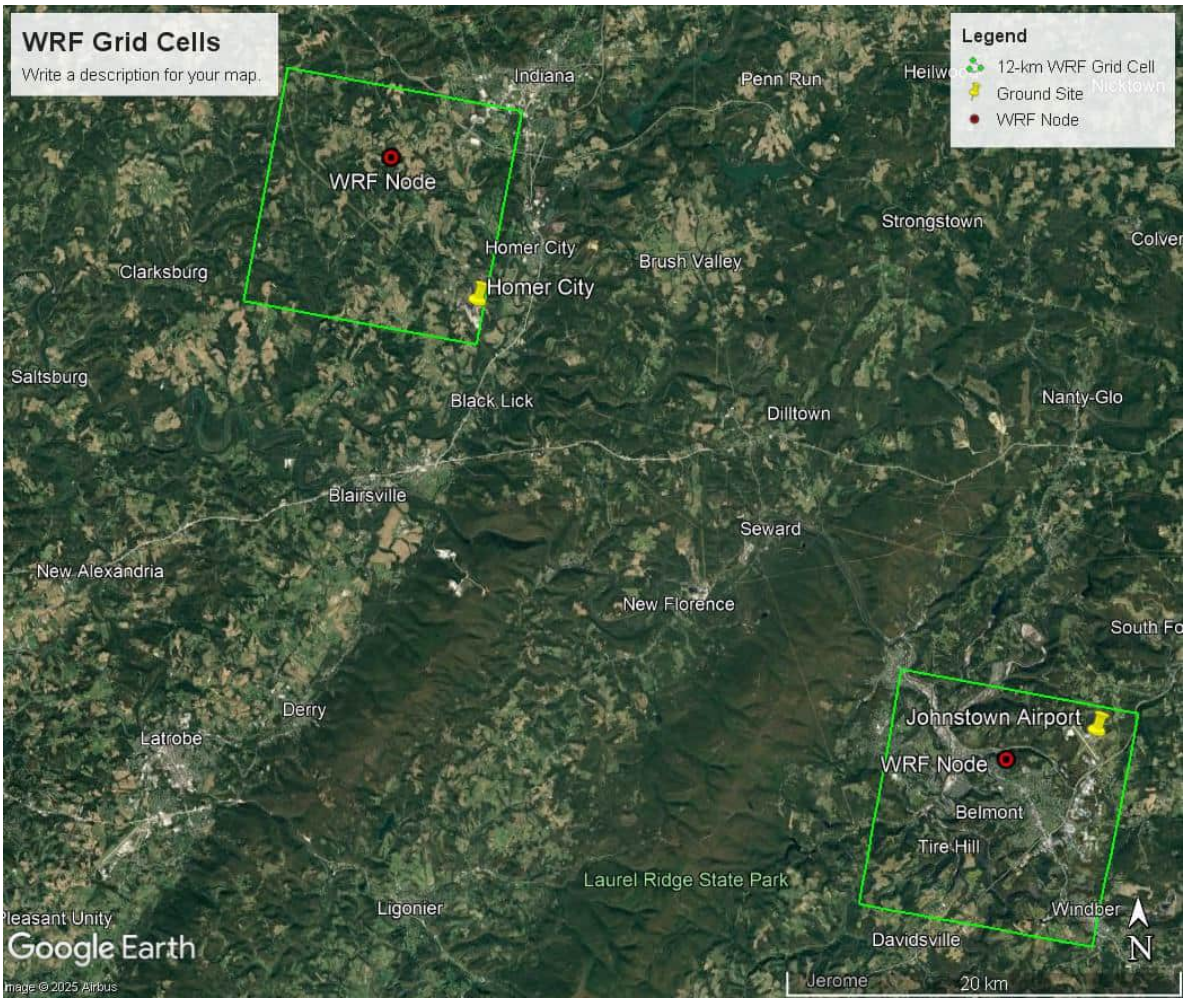
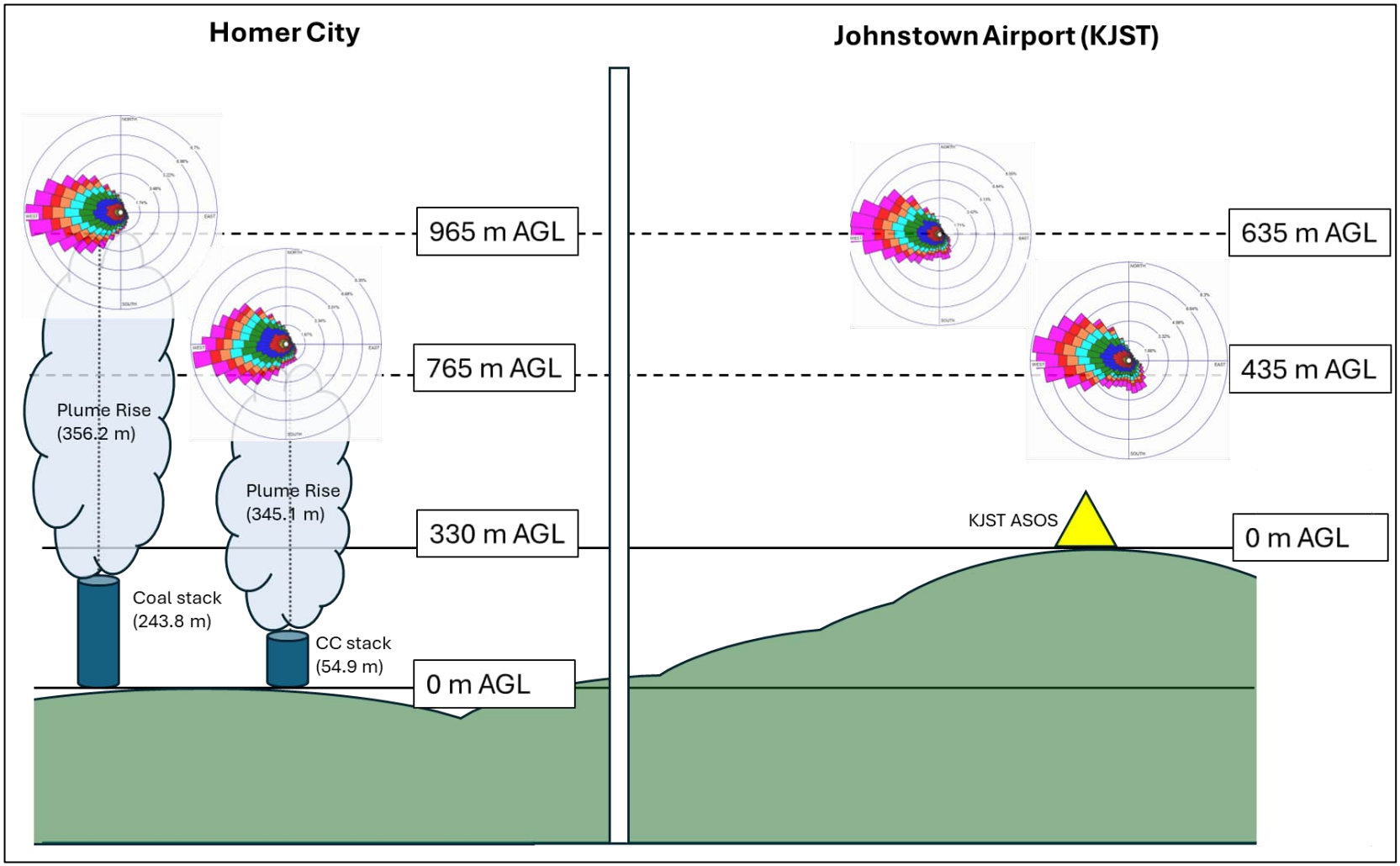


Figure 4-10: Johnstown WRF vs. Homer City WRF Schematic with Wind Roses at Plume Height



Note: Wind roses are generated based on closest WRF level (rounded to nearest 50 meters) to plume height shown. Therefore, wind roses shown for Homer City are at 1,000 m and 750 m. For Johnstown Airport, the heights of the winds depicted in the wind roses are 600 m and 450 m. Depiction of terrain is also not drawn to scale and does not account for the elevated terrain along Laurel Ridge between these two locations. Terrain relative to plume height is discussed in Section 4.6.3.2.

4.7 Receptors and AERMAP

A Cartesian receptor grid extending approximately 20 km from the approximate centroid (Easting = 652529.00 m; Northing = 4486825.00 m) of the proposed Project will be used in the modeling. The receptor grid will consist of the following spacing:

- 25-m spaced receptors along the ambient boundary;
- 50-m spaced receptors extending from ambient boundary to 200 m;
- 100-m spaced receptors between 200 m and 1 km from the proposed Project centroid;
- 250-m spaced receptors between 1 km and 2.5 km from the proposed Project centroid;
- 500-m spaced receptors between 2.5 m and 10 km from the proposed Project centroid; and
- 1,000-m spaced receptors between 10 m and 20 km from the proposed Project centroid.

Far-field and near-field views of the receptor grid and ambient air boundary are shown in **Figure 4-11** and **Figure 4-12**, respectively. If Project modeled concentrations are less than the SILs, then the controlling SIL impact for each pollutant and averaging period will be resolved with 50-m receptor spacing. If Project modeled concentration exceed the SILs, then the controlling concentration for each pollutant and averaging period associated with the NAAQS and PSD increment modeling will be resolved with 50-m spacing.

Figure 4-12 also shows the ambient air boundary comprising effective barriers to general public access along Homer City's property boundary. Consistent with US EPA's Revised Policy on Exclusions from Ambient Air (US EPA, 2019), effective barriers include physical obstacles (e.g., security fencing), active and passive deterrents (e.g., security patrols and surveillance), and natural barriers (e.g., dense vegetation, low lying water areas, ditches, creeks, and ponds) that collectively prevent reasonable access by unauthorized persons on Plant property. However, Pennsylvania State Route 3017 (Coal Road) running through the Plant property is accessible by the public. Because of this, receptors have been added to estimate concentrations along this road. Overall, the Plant is very secure and limits public access to all areas of the property.

AERMAP (version 24142) (US EPA 2024h), the AERMOD terrain preprocessor program, will be used to calculate terrain elevations and critical hill heights for the modeled receptors (NAD83 datum and Zone 17 using USGS National Elevation Data (NED). The dataset will consist of 1/3 arc second (~10 m) resolution. Consistent with the AERMAP User's Guide (US EPA, 2024h), the AERMAP domain will be sufficient to ensure that all significant nodes are included such that all terrain features that exceed a 10% elevation slope from any given receptor are considered. The NED files are referenced to Datum NAD83 (note all source locations and receptors will also be referenced to NAD83 UTM Zone 17. The NED files will be included in the electronic modeling archive that will be submitted along with the final modeling report.

Figure 4-11. Far-field Receptor Grid

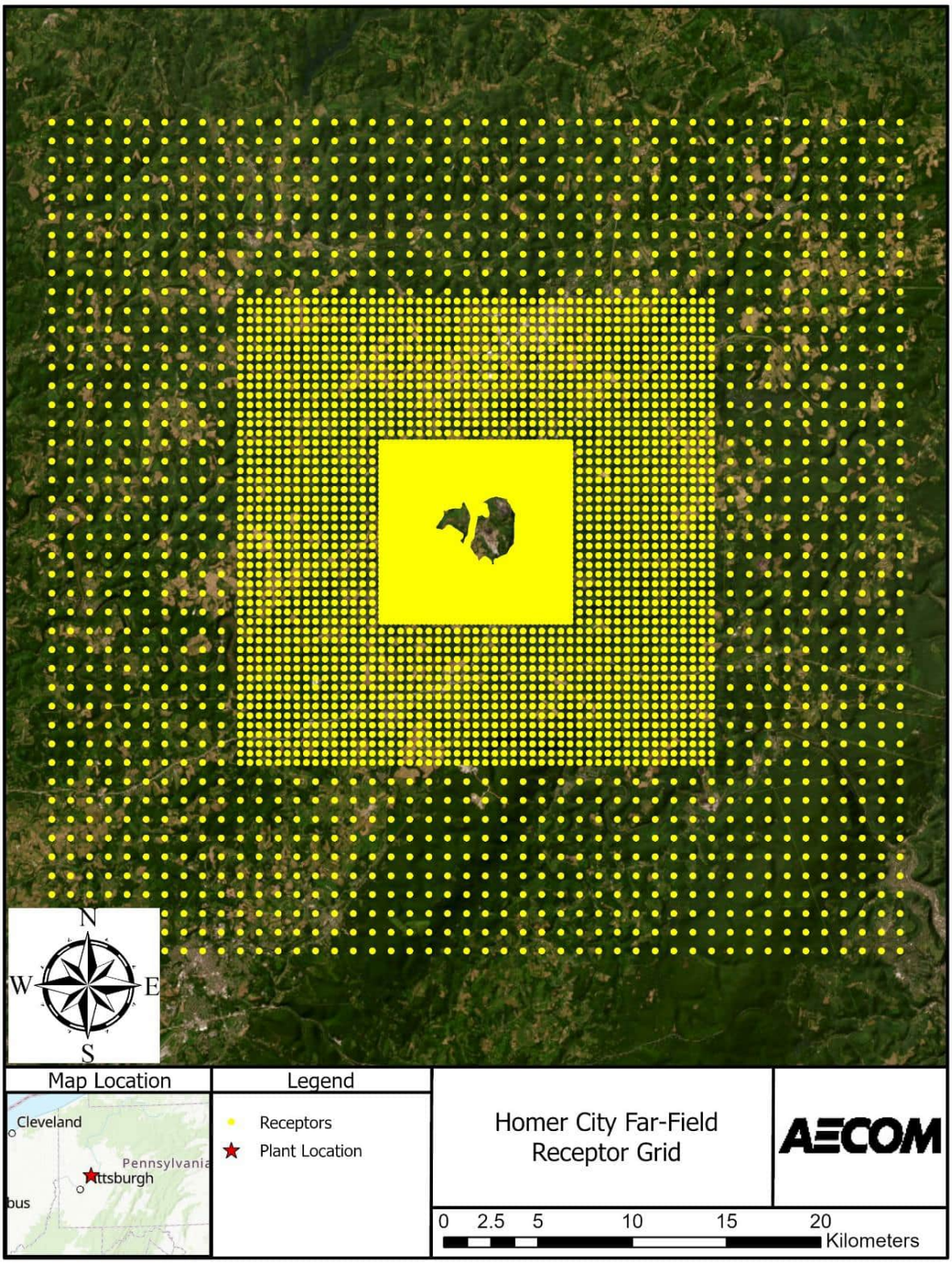
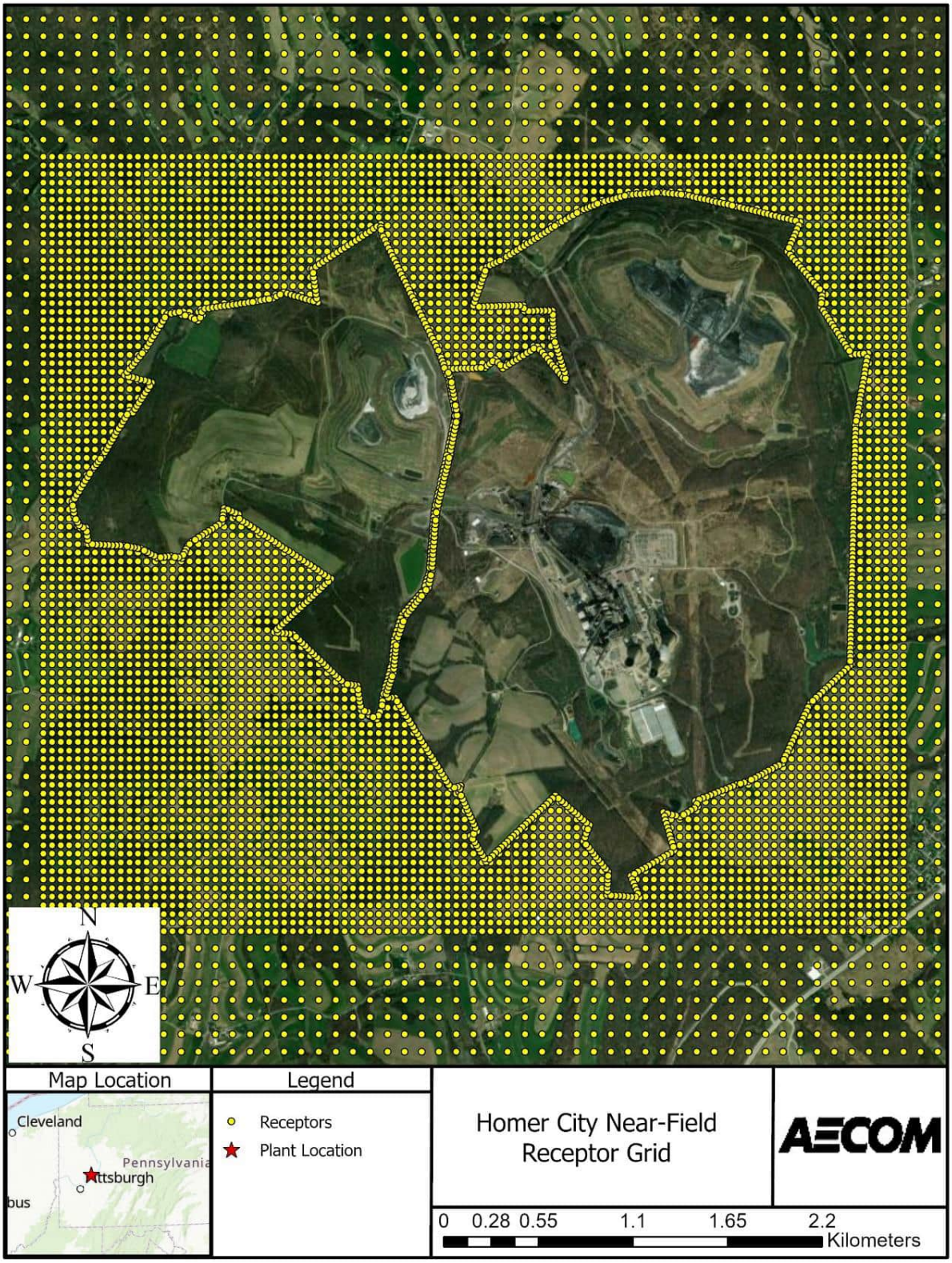


Figure 4-12. Near-field Receptor Grid



4.8 Secondary $PM_{2.5}$

As shown in **Table 2-1**, the Project will net out of PSD review for SO_2 and NO_X ($PM_{2.5}$ precursor emissions). The net change in emissions of SO_2 and NO_X will be a large negative value. Due to these SO_2 and NO_X reductions, the Project overall impact on secondary $PM_{2.5}$ would be a net benefit (i.e. result in reduction in secondary $PM_{2.5}$), as such, secondary $PM_{2.5}$ will not be accounted for as part of the Project's SIL analysis. The NAAQS and PSD increment analysis will account for secondary $PM_{2.5}$ due to emissions associated with the Project. This is a highly conservative approach given (1) the Project will expand PSD increment in Indiana Co. given the SO_2 and NO_X precursor reductions and (2) the $PM_{2.5}$ monitor at Strongstown likely includes influence of primary and secondary $PM_{2.5}$ associated with the coal plant operations which is no longer operating.

In April 2019, US EPA released the final "Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program" (EPA-454/R-19-003) (2019 EPA MERPs Guidance) (US EPA 2019). This guidance replaces the draft MERPs Guidance that was released in April 2016. MERP values expressed as an emission rate in the 2019 EPA MERPs Guidance represent an emission level that would result in a modeled concentration at or below specified SIL values. As such, if proposed Project emissions were less than MERP values, the project could be deemed to have an insignificant impact.

In February 2024, US EPA lowered the annual $PM_{2.5}$ NAAQS from 12 to 9 $\mu g/m^3$. As a result, in April 2024 US EPA issued supplemental guidance that included a new suggested SIL value for annual $PM_{2.5}$. In response to the updated SIL value for annual $PM_{2.5}$, US EPA also issued a *"Clarification on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program"* (US EPA 2024i). The purpose of this memo was to provide greater flexibility on the use of the MERPs as a direct comparison tool with critical air quality thresholds rather than direct comparison to emission rates considered equivalent to a significant air quality threshold. US EPA indicated that any MERP values presented as an emission rate published in the (2019) MERPs Guidance or through online tools should no longer be used for PSD permitting applications since the form of these values explicitly included a significant impact level that is no longer appropriate. In other words, since MERP values expressed as an emission rate in the 2019 guidance used SIL values relevant at the time the document was prepared, changes to the SIL values would essentially make any emission rate based MERP no longer valid. Therefore, US EPA has indicated that *"Any MERP values presented as an emission rate published in the MERPs Guidance or through online tools should no longer be used for PSD permitting applications since the form of these values explicitly included a significant impact level that is no longer appropriate."*

For this application, the 2019 EPA MERPs Guidance will be used to develop air quality concentrations of secondary $PM_{2.5}$ for comparison to critical air quality values. Specifically, Section 4.1.3 of the 2019 US EPA MERPs Guidance illustrates how the US EPA-model data used to develop the MERPs could be used as a Tier 1 demonstration tool to estimate air quality concentrations for $PM_{2.5}$ based on Project emissions.

The methodology described in Section 4.1.3 of the 2019 US EPA MERPs Guidance will be used to assess the Project impacts for secondary $PM_{2.5}$. To estimate the Project impact of secondary $PM_{2.5}$, the list of hypothetical sources that were modeled by US EPA were analyzed. The closest hypothetical site is 43 miles west of the Project site, located in Allegheny County. Two additional sites were considered but they are located further away in Tuscarawas, Ohio (120 miles west of the Project site) and Doddridge, West Virginia (115 miles southwest of the Project site).

The calculated secondary $PM_{2.5}$ concentrations associated with Project emissions is shown in **Table 4-13** for each of the three nearby hypothetical MERP sites. The most conservative of the three MERP sites happens to be the closest, located in Allegheny Co.

Table 4-13. Project Estimated Secondary $PM_{2.5}$ Concentrations

Averaging Period	NO_X				SO_2				Project Estimated Secondary $PM_{2.5}$ Concentration ($\mu g/m^3$)
	US EPA Precursor Emissions (TPY)	US EPA Modeled Concentration ($\mu g/m^3$)	Project Precursor Emissions (TPY)	Project Estimated Concentration ($\mu g/m^3$)	US EPA Precursor Emissions (TPY)	US EPA Modeled Concentration ($\mu g/m^3$)	Project Precursor Emissions (TPY)	Project Estimated Concentration ($\mu g/m^3$)	
Allegheny Co. PA									
24-hour	1,000	0.080	1,097	0.087	1000(1)	0.251	202	0.051	0.138
Annual	1,000	0.006	1,097	0.007	1000(1)	0.009	202	0.002	0.008
Doddridge, WV									
24-hour	1,000	0.037	1,097	0.0408	500	0.056	202	0.0224	0.063
Annual	1,000	0.001	1,097	0.0015	500	0.002	202	0.0009	0.002
Tuscarawas, OH									
24-hour	1,000	0.080	1,097	0.0875	500	0.084	202	0.0338	0.121
Annual	1,000	0.003	1,097	0.0038	500	0.004	202	0.0017	0.005

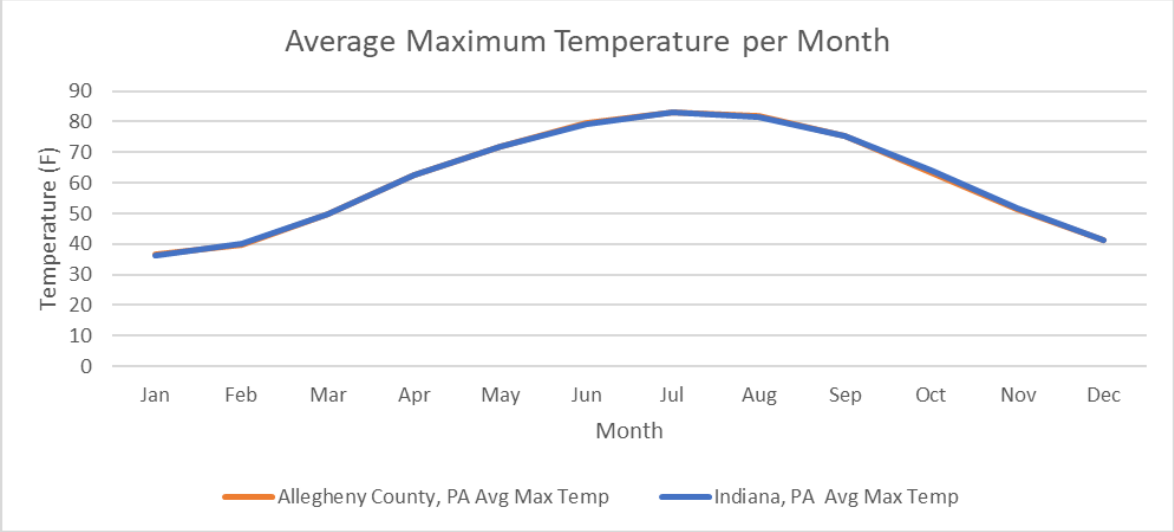
(1) A 500 TPY hypothetical SOx source is not available in the MERPs data for this location. Therefore, the 1000 TPY was used.

Due to its proximity and the fact it is the most conservative of the three nearby hypothetical MERP sites, the Allegheny Co. site will be the primary site considered, as it best represents the airshed of the Project. Climate summaries from the National Oceanic and Atmospheric Administration's (NOAA's) Online Weather products for Allegheny Co. indicate very similar 30-year climate normals when compared to the location of the Project site. The weather monitor chosen to represent the Project site is located in Indiana, PA since it was the closest in proximity to the Project. A comparison of 30-year (1993-2023) average maximum and average minimum, temperatures and total precipitation for the Project site and the Allegheny Co. hypothetical source is provided in **Figure 4-13**, **Figure 4-14**, and **Figure 4-15**. Data presented in these figures show a very similar annual average high temperatures in the low 60s°F, and low temperatures around 40°F. In addition, mid-summer high temperatures were in the range of 71 – 82°F for both the Project and Allegheny Co. locations. Precipitation averages are also close with approximately 40 inches of rain per year for Allegheny Co. and 48 inches of rain per year for the Project site. In addition, the MERP data for the 90-meter stack will be used for this assessment as opposed to the 10-meter stack MERP data. The 90-meter stack data is more representative of a tall stack with buoyancy and momentum rise like the main emission sources for the Project. **Section 4.6.3** references a plume height of 1,237 meters for the GE 7HA.02 stacks, this supports the use of the 90-meter MERP data.

There are some hills to the southeast of the Project site whereas the Allegheny Co. hypothetical source does not. However, the difference in terrain features would not create a substantial difference in climate regimes between the Project site and hypothetical source in Allegheny Co. Both have similar elevations: 1272 ft for Allegheny Co. and 1200 ft for the Project site. The Allegheny Co. hypothetical source also exhibits similar land use to the Project site. The Project area is primarily rural while the Allegheny Co. site is somewhat more suburban, primarily residential.

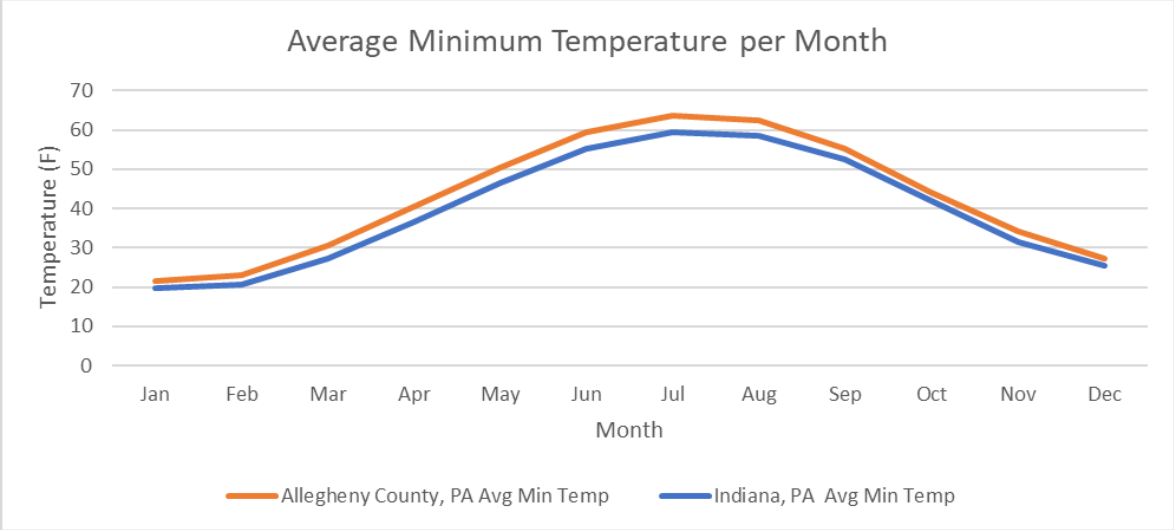
Based on the similarities in land use, climate, and overall terrain, the data associated with US EPA's hypothetical source in Allegheny Co., PA will be used for assessing the Project impact on secondary $PM_{2.5}$. The Allegheny Co. sites also has the highest concentration of secondary $PM_{2.5}$ of the three sites examined.

Figure 4-13. 30-Year Average Maximum Temperature of Allegheny County and Plant per Month



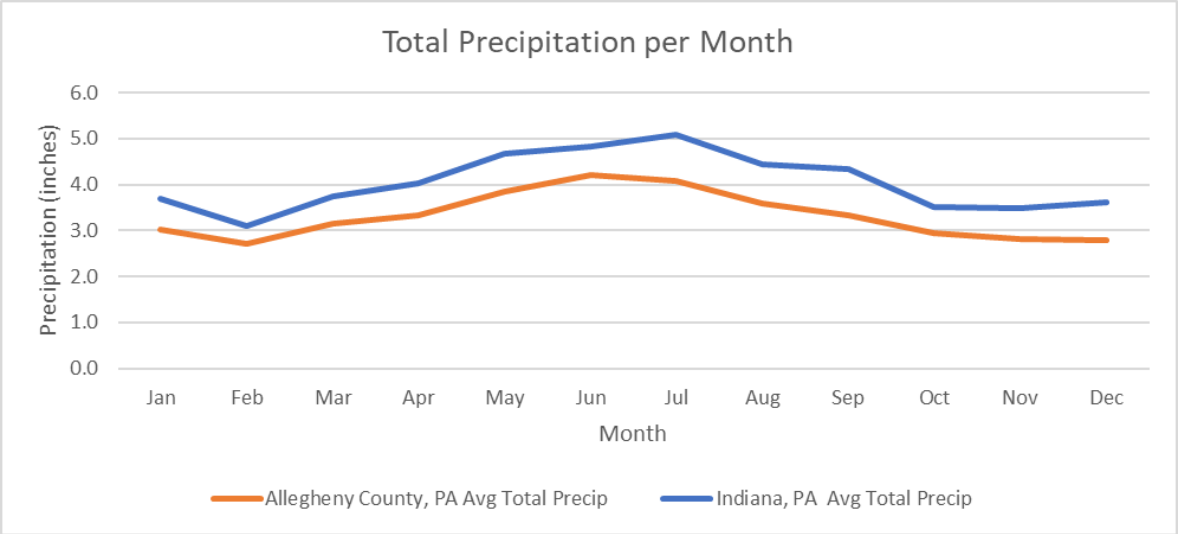
Note: Average maximum temperature at both sites are nearly identical, thus the plot shows Indiana on top of Allegheny.
Source: Data from NOAA Online Weather Data, https://weather.gov

Figure 4-14. 30-Year Average Minimum Temperature of Allegheny County and Plant per Month



Source: Data from NOAA Online Weather Data, https://weather.gov

Figure 4-15. 30-Year Average Total Precipitation for Allegheny County and Plant per Month



Source: Data from NOAA Online Weather Data, https://weather.gov

5. Class II Area Impact Assessment

5.1 Significant Impact Level Modeling

The Class II Area SIL analysis will be conducted with AERMOD using five years of meteorological data as described in **Section 4.6** and the Project emissions data. This modeling analysis will be used to make a determination of significance for PM_{10} and $PM_{2.5}$.

For those pollutants and averaging periods with modeled concentrations less than their SILs, no further modeling will be required because, by definition, those pollutants and averaging periods cannot cause or contribute to a violation of the NAAQS or exceedances of the PSD increments. For those pollutants and averaging periods with significant modeled concentrations, the significant impact area (SIA) will be determined, and a cumulative NAAQS and PSD Increment analysis will be conducted. For $PM_{2.5}$, the secondary $PM_{2.5}$ will not be accounted for as discussed in **Section 4.8**.

The SIL modeling will be performed in accordance with US EPA guidance and the form of the design concentration consistent with the pollutants and averaging periods being modeled. Specifically, the determination of significance for the Project will be based on the following:

- $PM_{2.5}$ 24-hour NAAQS – Highest 24-hour average modeled concentration averaged over 5 (five) years.
- $PM_{2.5}$ Annual NAAQS – Highest annual average modeled concentration averaged over 5 (five) years.
- $PM_{2.5}$ 24-hour PSD Increment – Highest 24-hour average modeled concentration per year taken over 5 (five) years.
- $PM_{2.5}$ Annual PSD Increment – Highest annual average modeled concentration per year taken over 5 (five) years.
- PM_{10} 24-hour NAAQS – Highest 24-hour average modeled concentration per year taken over 5 (five) years.
- PM_{10} 24-hour PSD Increment – Highest 24-hour average modeled concentration per year taken over 5 (five) years.
- PM_{10} Annual PSD Increment – Highest annual average modeled concentration per year taken over 5 (five) years.

5.2 NAAQS and PSD Increment Analysis

As stated previously, for those pollutants and averaging periods determined to have modeled concentrations less than the SILs, no further analysis will be performed. The discussion below applies only to those pollutants and averaging periods for which a significant impact is predicted with AERMOD.

Compliance with the PSD increments and NAAQS would be based on the sum of the following:

- Modeled concentrations attributable to the Project;
- Modeled concentrations from “nearby” sources; and
- Representative ambient background concentration (NAAQS only).

Modeled concentrations attributable to the Project and nearby sources will be estimated using AERMOD. Secondary $PM_{2.5}$ will be accounted for in the NAAQS and PSD Increment analysis as described in **Section 4.8**. This is a highly conservative approach given the reductions associated with the project that have (1) expanded PSD increment in Indiana Co. given the SO_2 and NO_X precursor reductions and (2) the $PM_{2.5}$ monitor at Strongstown likely includes influence of primary and secondary $PM_{2.5}$ associated with the coal plant operations.

5.2.1 NAAQS Analyses

Dispersion modeling using AERMOD will be conducted with the meteorological data discussed in **Section 4.6**, Project source data, and the regional source inventory described in **Section 5.3** (below) to determine model concentrations to be compared to the NAAQS for the applicable averaging periods. In addition to Project sources modeled for the SIL analysis, any existing sources at the Plant that have the potential to emit the pollutant of concern will be included within the NAAQS modeling. The analysis will compare the modeled

design short-term and annual concentrations from the proposed Project and existing Plant sources, as well as influencing nearby emission sources, to the NAAQS. For the NAAQS analysis, the background concentration will be added to modeled design short-term and annual impacts. **Section 5.4** provides recommended background concentrations for this application.

5.2.2 PSD Increment Analyses

Dispersion modeling using AERMOD will be conducted with the meteorological data discussed in **Section 4.6**, Project source data including an inventory of regional sources to determine model concentrations to be compared to the PSD increment for the applicable averaging periods. The PSD increment analysis will consider sources of emissions that either consume or expand the available PSD increment. PSD increment consumption and expansion will be based on the major and minor source baseline dates established for Indiana County to be provided by PADEP.

Sources in operation prior to the minor source baseline date do not impact the available PSD increment and are part of the baseline and can thus be excluded from modeling as applicable. Other sources of emissions that began operations or had a project that resulted in an emission increase after the minor source baseline dates consume PSD increment and must be included in modeling. Therefore, existing sources of $PM_{2.5}$ and PM_{10} at nearby facilities that have begun operating or resulted in an emission increase after the minor source baseline dates will be included in any PSD increment modeling, if applicable. Major sources that have begun operating or resulted in an emission increase after the major source baseline dates (PM_{10} = January 6, 1975 and $PM_{2.5}$ = October 20, 2010) will be included in any PSD increment modeling, if applicable. This project will trigger the minor source baseline date for $PM_{2.5}$ in Indiana Co. and it is not anticipated that the annual SIA for PM2.5 will extend outside of the county.

5.3 Regional Source Inventory

For PSD permitting, a cumulative impact analysis, if necessary, needs to appropriately characterize the spatial nature of air quality near a new or modifying PSD source to identify the potential for NAAQS or PSD increment violations. Characterization of local air quality around a new or modifying source for each pollutant and averaging period necessitates a full and comprehensive accounting for all source contributions. A cumulative impact analysis should account for the combined impacts of all direct and precursor emissions of a pollutant from:

- the new or modifying source,
- direct emissions from nearby sources, and
- monitored background concentrations accounting for primary and/or secondary impacts from regional background sources and nearby sources not explicitly modeled.

Appropriately accounting for all source contributions is an inherently discretionary exercise with use of best professional judgment in determining a representative background concentration and identifying nearby sources that need to be explicitly modeled. The development of the background source inventory for the proposed project will rely on US EPA's *Guidance on Developing Background Concentrations for Use in Modeling Demonstrations* (Background Concentration Guidance), which was finalized November 20,2024 (US EPA, 2024j).

The regional source inventory development will include ambient background concentrations (see **Section 5.4**) to account for non-modeled sources and the modeling of direct source emissions which are not adequately represented by the background monitors. The regional source inventory will consider the extent of the Project's significant impact area when determining the relevant sources to directly model. Based on US EPA Guidance, the hypothetical example in Appendix C of the Background Concentration Guidance, generally sources with less than 25 tons per year of actual PM_{10}/$PM_{2.5}$ emissions are likely represented in the selected regional

monitors and will be excluded from any modeling. Larger sources may be included if they are not adequately represented by the monitor.

The project anticipates having modeled concentrations exceeding the SIL for both PM_{10} and $PM_{2.5}$. As such a list of nearby sources within approximately 25-km of the Project was obtained from PADEP. This list included sources in Indiana, Armstrong, and Westmoreland counties. Of the sources provided, only four (4) sources had 2023 actual PM_{10}/$PM_{2.5}$ emissions greater than 25 TPY that are still operating. Those sources included: Keystone Generating Station, Conemaugh Generating Station, Seward Generating Station, and Armstrong Power. These sources will be evaluated further for potential inclusions as direct modeled sources if they are not adequately captured by the background monitors.

5.4 Ambient Background Concentrations

Ambient air quality data are used to represent the contribution to total ambient air pollutant concentrations from non-modeled sources. In accordance with 40 CFR 52.21(m), an application for a PSD permit must contain an analysis of ambient air quality in the vicinity of the proposed Project for each pollutant subject to PSD review. The objective of reviewing these data is to develop representative background concentrations which, when added to modeled impacts, are used in the NAAQS compliance analysis. This section summarizes the ambient background concentrations proposed to be used in the NAAQS analysis. The monitored concentrations presented in this section were obtained from values provided by US EPA design value spreadsheets.[2]

5.4.1 $PM_{2.5}$ Background Monitor Selection

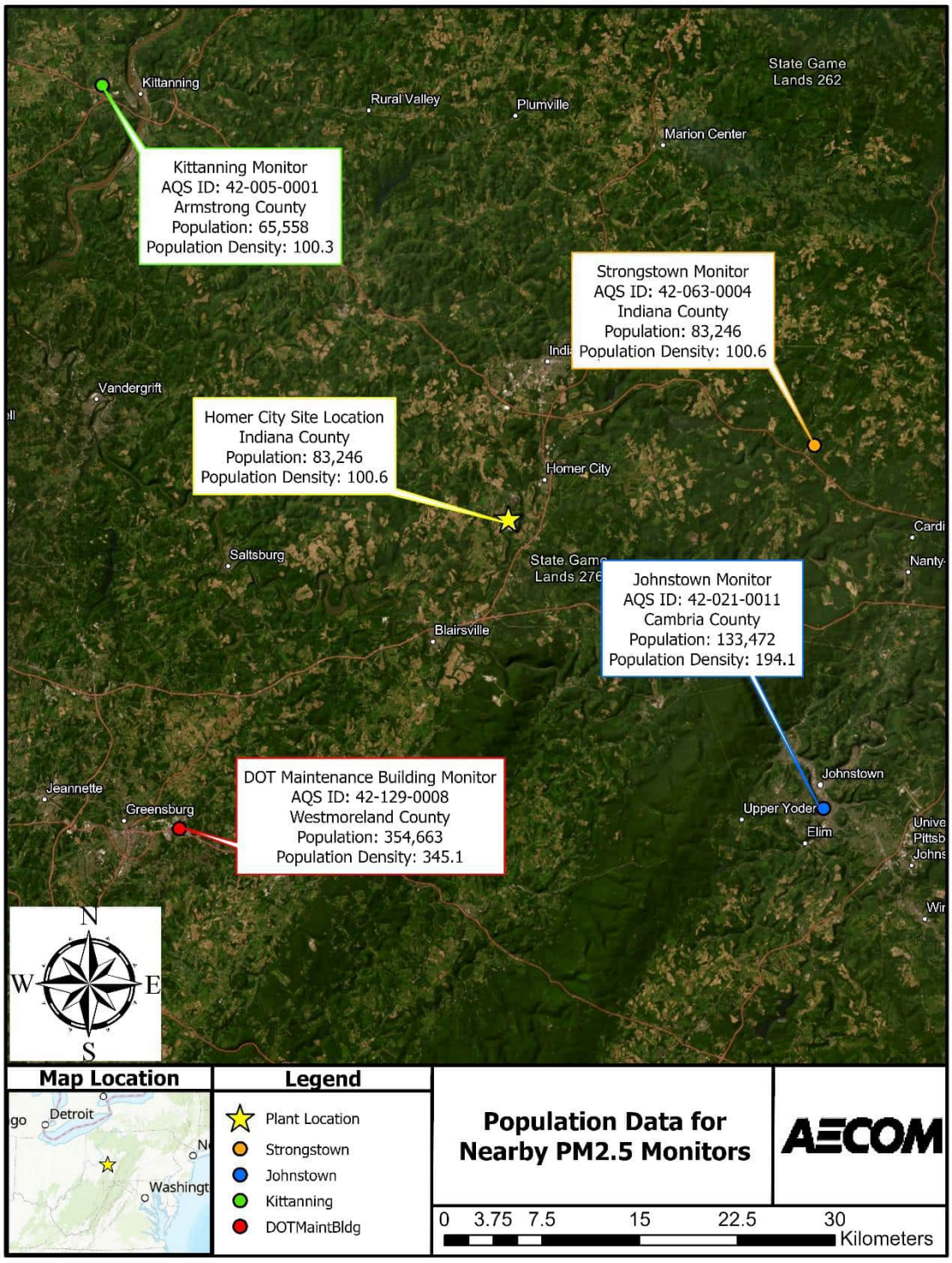
Using the EPA Air Quality Design Values interactive map, there are four (4) $PM_{2.5}$ monitor that were considered; Strongstown (AQS Site ID: 42-063-0004), Johnstown (AQS Site ID: 42-021-0011), Kittanning (AQS Site ID: 42-005-0001), and DOT Maintenance Building in Greensburg (AQS Site ID: 42-124-0008) (see **Figure 5-1**). Factors considered when determining the most representative monitor include: proximity to the Project, prevailing winds, and emission levels / population density near the monitor vs the source.

The Strongstown monitor is the closest monitor to the Project site and is in the same county. As such the county population density (see **Figure 5-1**) and emission totals are the same between the Strongstown monitor location and Project location. The wind rose shown in **Figure 4-7** also indicates that the Strongstown monitor is located in a downwind direction of the Project. The other monitors are located further away, have a higher population density or are not in as good of a prevailing wind direction. Based on these factors the Strongstown monitor provides a good representation of background $PM_{2.5}$ concentration in the vicinity of the Project and is likely conservative for the following reasons:

- The monitor is likely Influenced by Homer City primary and secondary $PM_{2.5}$ emissions from coal operations that have since been deactivated (July 2023). **Figure 5-2** show the relative comparison of SO_2, NO_X and PM emissions from Homer City and other major sources in Indiana County from the 2020 NEI. Removing the Homer City emissions alone will result in a downward trend in emissions since 2020.
- **Table 5-1** shows the 2021-2023 $PM_{2.5}$ design concentrations which were clearly influenced by the Canadian Wildfires from 2023.

[2] https://www.epa.gov/air-trends/air-quality-design-values

Figure 5-1. Location of Nearby $PM_{2.5}$ Monitors



Source: US Census, 2020

Figure 5-2. 2020 NEI Emission Data from Indiana County

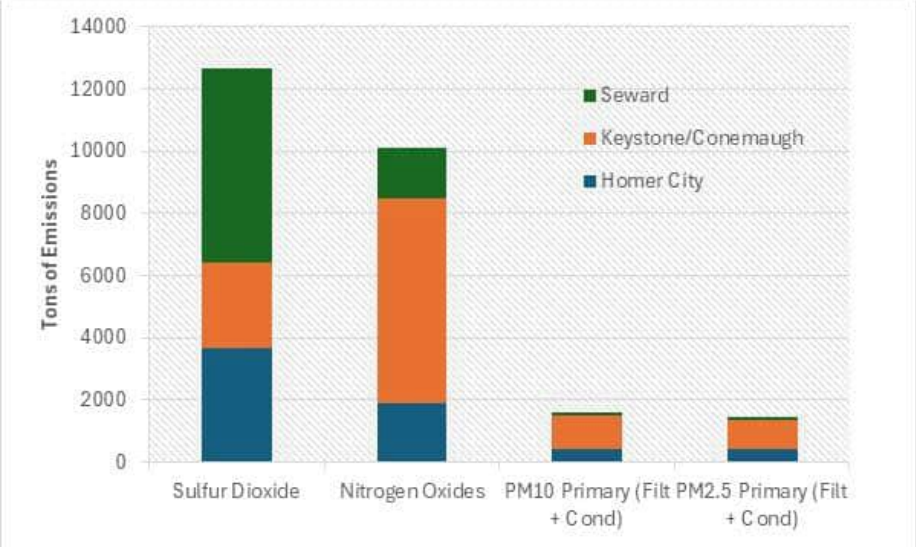


Table 5-1. $PM_{2.5}$ Ambient Background Concentrations

Pollutant	Averaging Period	AQS Site ID	Local Site Name	2021-2023 Design Value ($\mu g/m^3$)	2021 Concentration ($\mu g/m^3$)	2022 Concentration ($\mu g/m^3$)	2023 Concentration ($\mu g/m^3$)
$PM_{2.5}$	24-hour(1)	420630004	Strongstown	21	20.1	13.5	29.2
	Annual			7.3	7.34	6.37	8.07

(1) Concentrations reflect the 98th percentile value.

5.4.2 PM_{10} Background Monitor Selection

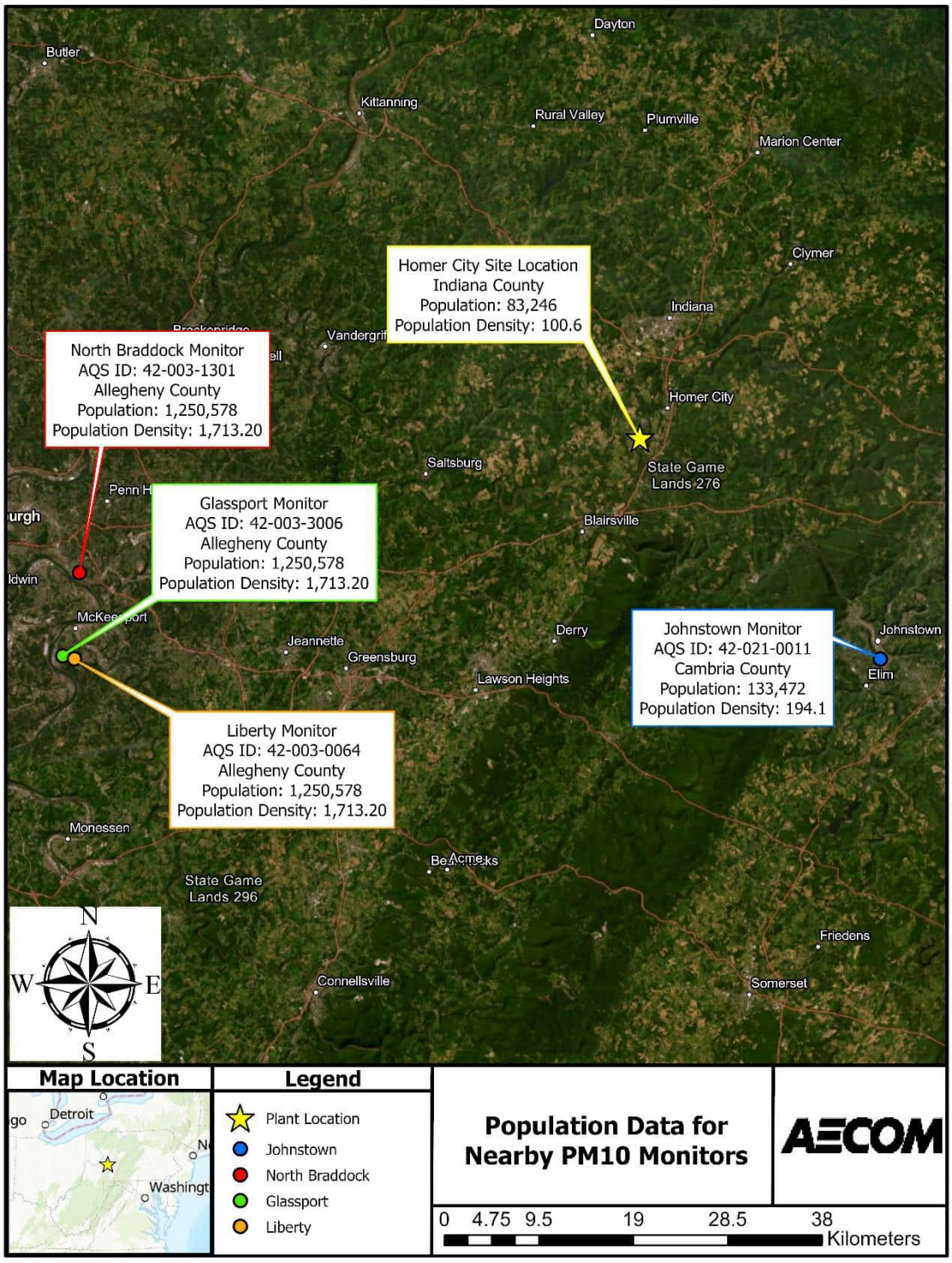
The monitors for PM_{10} background concentrations in western Pennsylvania near the Plant are as follows: Johnstown (AQS ID: 42-021-0011), North Braddock (AQS ID: 42-003-1201), Glassport (AQS ID: 42-003-3006), and Liberty (AQS ID: 42-003-0064). As discussed for $PM_{2.5}$, Factors considered when determining the most representative monitor include: proximity to the Project, prevailing winds, and emission levels / population density near the monitor vs the source.

The Johnstown monitor is located 20 miles to the southeast of the Project site, however, is not in an ideal of a prevailing wind direction. The next closest monitors to the Project are North Braddock, Liberty, and Glassport which are 35, 37, and 39 miles west of the Plant, respectively, just outside of Pittsburgh and likely influenced by the Pittsburgh urban area. Given the urban influence on these monitors near Pittsburgh, the more comparable population density (see **Figure 5-3**), and comparable emissions between Cambria County and Indiana County (**Figure 5-4**), the Johnstown PM_{10} monitor provides the best representation of background PM_{10} concentrations in the vicinity of the Project.

The top ten (10) PM_{10} background concentrations are provided in **Table 5-2**. The form of the PM10 NAAQS is not to be exceeded more than once per year on average over 3 years. PADEP typically suggests using the highest 24-hour concentration over the latest complete 3-year period for PM10 background concentrations in NAAQS analysis to represent non-modeled sources. For Johnstown the highest 24-hour concentration over the 2021-2023 period was 120 μ/m^3. This value was measured on a date where wildfire smoke was impacting the state along with the next two highest 24-hour concentrations from the 2021-2023 dataset. PADEP has

identified these days (June 28-July 1, 2023) as part of the $PM_{2.5}$ exceptional event analyses due to impacts from wildfire smoke. The exceptional event document can be found here (https://www.ahs.dep.pa.gov/eComment/). Based on the data presented, 54 μ/m^3 (the third highest value over the last three years) will be used as the PM_{10} background concentration as part of the NAAQS assessment. This is still conservative in the sense that this day was also impacted by wildfire smoke.

Figure 5-3. Population Data for Nearby PM_{10} Background Monitors



Source: US Census, 2020

Figure 5-4. 2020 NEI PM_{10} Emission Data

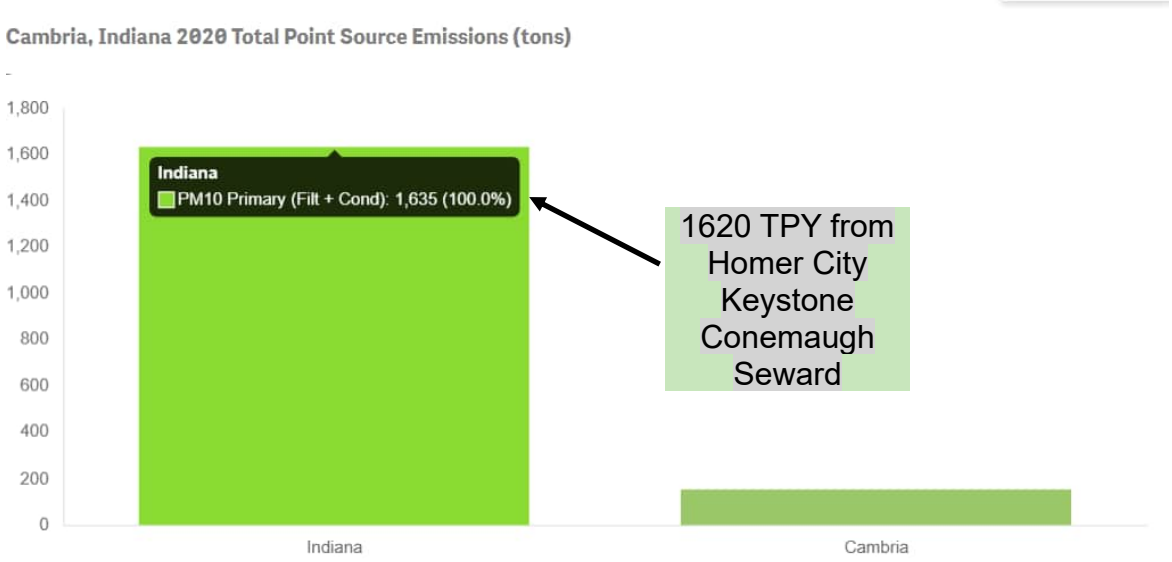


Table 5-2. PM_{10} Ambient Background Concentrations (Top 10 Values 2021-2023)

Pollutant	Averaging Period	AQS Site ID	Local Site Name	Date	Concentration (µg/m³)
PM_{10}	24-hour	420210011	Johnstown	6/29/2023	120
				6/28/2023	84
				6/30/2023	54
				7/20/2021	52
				6/16/2022	43
				3/9/2021	42
				12/22/2023	38
				6/6/2023	37
				7/17/2023	36
				12/21/2023	35

6. Other Requirements

6.1 Class I Area Impacts

PSD Class I areas are areas of special national or regional value from a natural, scenic, recreational, or historical perspective. The PSD program provides special protection for such areas. According to 40 CFR §52.21(p), sources located within 300 km of a Class I area may be required to demonstrate that the Project will not cause or contribute to an exceedance of the PSD Class I increments or adversely affect certain air quality-related values. The three (3) PSD Class I areas located within 300 km of the Project site are pictured in **Figure 6-1** and their approximate distances are:

- Dolly Sods Wilderness: 165 km
- Otter Creek Wilderness: 166 km
- Shenandoah National Park: 197 km

6.1.1 Air Quality Related Values

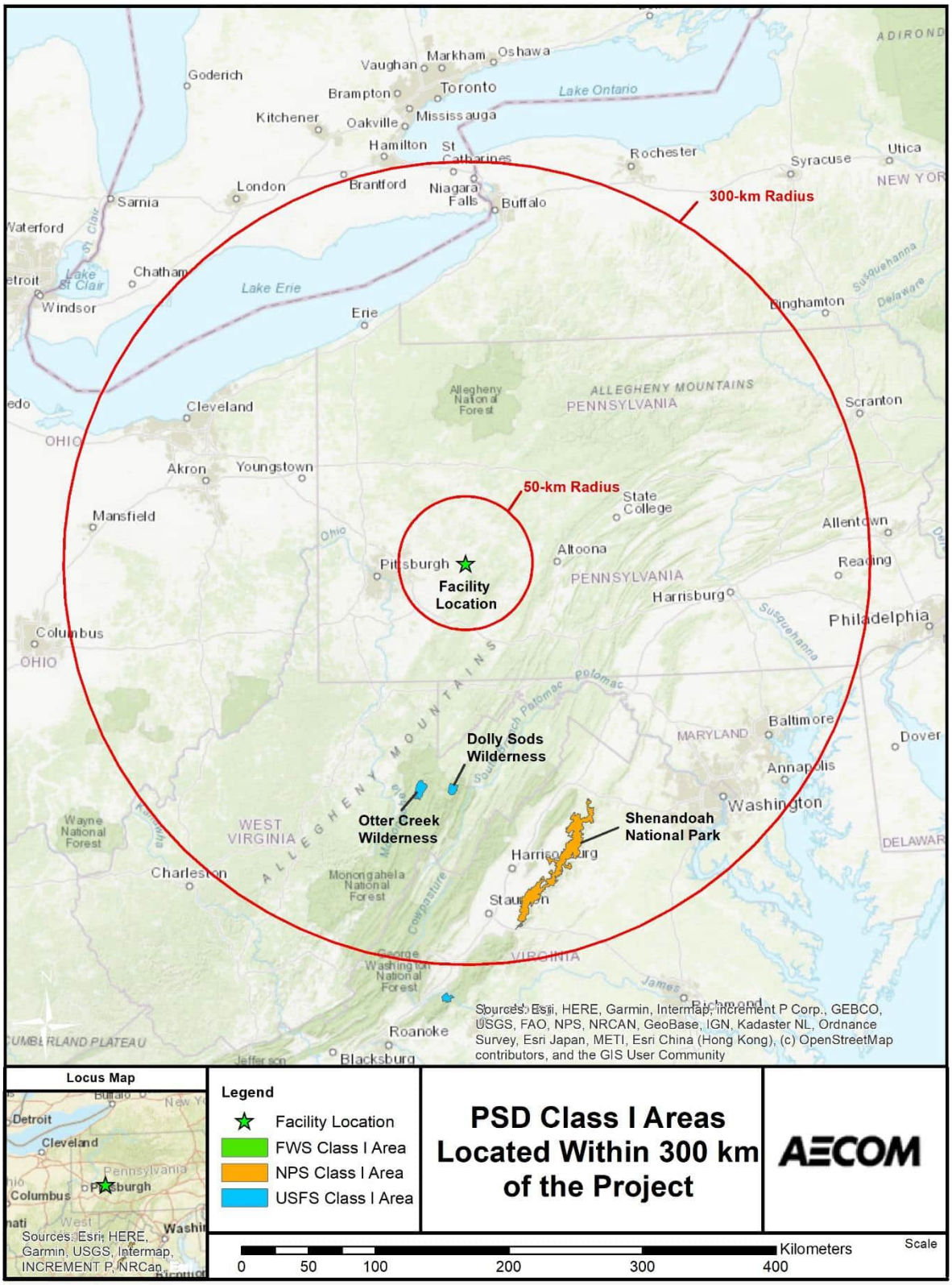
Per guidance in *Federal Land Managers' Air Quality Related Values Work Group* (NPS 2010), if the sum of short-term Project emissions for pollutants that trigger PSD Review (H_2SO_4 and PM_{10} (filterable)) expressed in tons per year is less than ten times the distance to the Class I area (in kilometers), the Federal Land Managers (FLM) will likely decide that an analysis of AQRVs (including regional haze and acid deposition) is not necessary (referred to as the "Q/D" screen).

The sum of the preliminary estimated Project emissions for the pollutants that trigger PSD review listed above will be used to perform a Q/D screen. If the Q/D is less than 10, a waiver from the FLMs will be requested to confirm that an AQRV analysis will not be required. Emissions for the Class I AQRV analysis should represent the annual maximum 24-hour average rate.

6.1.2 Class I PSD Increments

In accordance with Appendix W (Section 4.2.c.i), because AERMOD is proposed for the Project's nearfield assessment, it can be utilized in a screening-level analysis to estimate the Project's potential for a significant modeled impact at the PSD Class I areas. As such, initially, AERMOD will be used to assess the Class I PSD increments for PM_{10} and $PM_{2.5}$. AERMOD will be applied with a ring of receptors placed at 50 km, the maximum distance at which AERMOD is considered to be valid. Receptors will be limited to directions in which the plume could be transported from the source to the Class I area(s). At these receptors, the maximum concentrations associated with the Project will be modeled for comparison to the Class I PSD SILs (see **Table 3-3**). If the AERMOD concentrations at 50-km do not indicate insignificant impacts, the AERMOD modeling results will be extrapolated out to the Class I area distances.

Figure 6-1. PSD Class I Areas



6.2 Class II Visibility

A Class II visibility analysis is required to be completed for state parks and state historic sites located within the project's vicinity. This analysis would be performed beginning with a screening procedure similar to that outlined in the US EPA document *Workbook for Estimating Visibility Impairment* (US EPA 1980a).

The closest state park, Yellow Creek State Park, is approximately 13-14 km to the east-northeast. A visibility analysis will be conducted with US EPA's VISCREEN model. The analysis will be conducted in accordance with US EPA's *Workbook for Plume Visual Impacts Screening and Analysis* (Revised) (US EPA 1992).

The VISCREEN model Workbook offers two levels of analysis. The Level 1 screening analysis is the most simplified and conservative approach, employing worst-case default meteorological data, F stability (very stable) and 1 meter per second wind speed. The Level 2 analysis allows refinement of meteorological conditions and site-specific conditions such as complex terrain. In accordance with the Workbook, a visual range of 20-25 km will be used in the application of VISCREEN (see Figure 9 of the Workbook). VISCREEN will first be applied using the Level 1 approach and only be refined using a Level 2 approach if needed.

The VISCREEN model will be applied to estimate two visual impact parameters, plume perceptibility (ΔE) and plume contrast (C_p). Screening-level guidance indicates that values above 2.0 for ΔE and +/- 0.05 for C_p are considered perceptible. The VISCREEN analysis requires maximum hourly emissions associated with Project sources as inputs. The analysis will be conservatively based on the maximum hourly future NO_2 and PM potential emission rates from the Project.

6.3 Air Quality Review and Pre-construction Monitoring

According to 40 CFR §52.21(m), an analysis of ambient air quality in the vicinity of the Project for each pollutant subject to PSD review must be conducted.

Air quality data are obtained from pre-construction monitoring or, under certain conditions, from existing monitoring data. Existing air quality may be used in lieu of pre-constructing monitoring if:

- The data are representative of the proposed facility's impact areas;
- The data are of similar quality as would be obtained if the applicant monitored according to the PSD requirements; and
- The data are current; that is, the data have been collected during the two-year period preceding the permit application, provided the data are still representative of current conditions.

As noted in 40 CFR §52.21(i)(5), PADEP may exempt the source from the PSD program's ambient air quality monitoring analysis requirements contained in 40 CFR §52.21(m) on a pollutant-by-pollutant basis if the net emissions increase of pollutants subject to PSD review will cause air quality impacts less than the significant monitoring concentrations (SMCs). **Table 6-1** presents the applicable SMCs for the pollutants modeled.

Table 6-1. Significant Monitoring Concentrations

Pollutant[(1)]	Averaging Period	Significant Monitoring Concentration (µg/m^3)
PM_{10}	24-hour	10

6.4 Soils and Vegetation

The PSD regulations require an evaluation of the impact of Project emissions on soils and vegetation. If required, an analysis of the Project's potential impact on soils and vegetation in the vicinity of the facility will be performed. The analysis of a project's impact on soil and vegetation is typically performed by comparing the maximum modeled impacts from the project to the screening concentrations provided in US EPA's "A Screening Procedure for the impacts of Air Pollution Sources on Plants, Soils, and Animals" (December 12, 1980) as well as secondary NAAQS. Secondary NAAQS have been designed by US EPA to better protect public welfare against adverse effects caused by criteria air pollutants – including ecological effects such as damage to aquatic and terrestrial ecosystems. In addition, a comparison of Project modeled concentrations associated with non-criteria pollutants for which there are Project emissions and ambient air screening concentrations in Table 5-3 of US EPA 1980 guidance, (beryllium and lead) will be performed.

The US EPA screening guidance does not include any values for PM_{10} or $PM_{2.5}$. As such, the highest predicted impacts from the Project used in the SIL analysis will be compared to the secondary NAAQS, which are summarized in **Table 6-2**, to demonstrate the Project will not have an adverse impact on soils and vegetation.

Additional since the project does not trigger PSD review for SO_2 and NO_X and has a net project decrease of those pollutants, a soil buffering capacity associated with acid deposition will not be performed.

Table 6-2. Secondary NAAQS Values

Pollutants	Secondary NAAQS (µg/m^3)
PM_{10}	150 (24 hour)
$PM_{2.5}$	35 (24-hour) and 15 (annual)

6.5 Growth-Related Impacts

The growth analysis evaluates the impact associated with the project on the general commercial, residential, and industrial growth within the project vicinity. PSD requires an assessment of the secondary impacts from applicable projects. Negligible growth is expected to be associated with the Project, which only involves construction of new CCs, ADGTs, and associated ancillary equipment and infrastructure. Therefore, no analysis of secondary impacts from associated growth is needed for this project.

7. Submittal of Analysis Results

The findings of the air quality impact analyses will be submitted to PADEP in a formal report for review and approval. The report will address the following:

- Source Data: Source data required for evaluation of Project impacts will be provided. This will include criteria pollutant emission rates and stack exhaust parameters.
- Choice of Models: The chosen models, including version numbers and selected options, will be discussed.
- Receptor Data: A plot of the receptor grid used in the AERMOD analysis will be provided with the final application document.
- Meteorology: The meteorological conditions used in the analysis will be documented.
- Modeling Summary: Results of the modeling analyses for all operating scenarios will be documented and summarized.
- Compliance with NAAQS and PSD Increments: A demonstration of compliance with these standards will be presented and supported in the report in text, tabular, and/or graphical format.
- Additional impacts: The additional impacts analysis will consist of an analysis of visible plume impacts, a secondary growth analysis and an analysis on impacts of soils and vegetation.
- Model Output and Databases: The model input and output files will be provided via electronic submittal. Also, BPIP-Prime input and output files will be provided. The final modeling report will also include graphics (e.g., contour maps) that show the extent of the air quality impacts for the worst-case year for each pollutant and averaging period. The figures will utilize a base map that is readily understandable by the general public. Each map will clearly identify the proposed Project location relative to these air quality impacts.

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Appendix A : SCREEN3 Output and Supplemental Wind Analyses

SCREEN3 Output: Coal Stack

```
                                  12/23/24
                                  10:14:35
 *** SCREEN3 MODEL RUN ***
 *** VERSION DATED 13043 ***

 HOMERCITY POINT SOURCE COAL STACK

 SIMPLE TERRAIN INPUTS:
  SOURCE TYPE       =    POINT
  EMISSION RATE (G/S)  =   100.0000
  STACK HEIGHT (M)     =   243.8000
  STK INSIDE DIAM (M)  =    7.3200
  STK EXIT VELOCITY (M/S)=   25.5100
  STK GAS EXIT TEMP (K) =   351.7000
  AMBIENT AIR TEMP (K)  =   293.0000
  RECEPTOR HEIGHT (M)  =    0.0000
  URBAN/RURAL OPTION   =    RURAL
  BUILDING HEIGHT (M)  =    0.0000
  MIN HORIZ BLDG DIM (M) =    0.0000
  MAX HORIZ BLDG DIM (M) =    0.0000

 THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
 THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.

 BUOY. FLUX = 559.290 M**4/S**3; MOM. FLUX = 7262.371 M**4/S**2.

 *** STABILITY CLASS 4 ONLY ***
 *** ANEMOMETER HEIGHT WIND SPEED OF  3.00 M/S ONLY ***

 **********************************
 *** SCREEN AUTOMATED DISTANCES ***
 **********************************

 *** TERRAIN HEIGHT OF  0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

  DIST   CONC       U10M  USTK MIX HT  PLUME  SIGMA  SIGMA
  (M)  (UG/M**3)  STAB (M/S) (M/S)  (M)  HT (M)  Y (M)  Z (M) DWASH
 ------- ---------- ---- ----- ----- ------ ------ ------ ------ -----
   5.  0.000    4   3.0  4.8  960.0 599.62  7.36  7.35  NO
  100.  0.000    4   3.0  4.8  960.0 599.62  21.55  20.46  NO
  200.  0.000    4   3.0  4.8  960.0 599.62  30.81  27.92  NO
  300.  0.000    4   3.0  4.8  960.0 599.62  41.54  36.89  NO
  400.  0.000    4   3.0  4.8  960.0 599.62  51.47  44.89  NO
  500.  0.000    4   3.0  4.8  960.0 599.62  60.88  52.29  NO
  600.  0.000    4   3.0  4.8  960.0 599.62  69.89  59.24  NO
  700.  0.000    4   3.0  4.8  960.0 599.62  78.60  65.85  NO
  800.  0.1066E-11  4   3.0  4.8  960.0 599.62  87.06  72.16  NO
  900.  0.1558E-09  4   3.0  4.8  960.0 599.62  95.31  78.24  NO
  1000.  0.7005E-08  4   3.0  4.8  960.0 599.62 103.38  84.12  NO
  1100.  0.1249E-06  4   3.0  4.8  960.0 599.62 111.30  89.61  NO
  1200.  0.1265E-05  4   3.0  4.8  960.0 599.62 119.08  94.94  NO
  1300.  0.8408E-05  4   3.0  4.8  960.0 599.62 126.75 100.11  NO
```

```
  1400.  0.4052E-04  4   3.0  4.8  960.0 599.62 134.30 105.16  NO
  1500.  0.1440E-03  4   3.0  4.8  960.0 599.62 141.58 109.87  NO
  1600.  0.1669E-03  4   3.0  4.8  960.0 599.62 145.79 110.55  NO
  1700.  0.1933E-03  4   3.0  4.8  960.0 599.62 150.08 111.24  NO
  1800.  0.2236E-03  4   3.0  4.8  960.0 599.62 154.46 111.94  NO
  1900.  0.2584E-03  4   3.0  4.8  960.0 599.62 158.91 112.65  NO
  2000.  0.2981E-03  4   3.0  4.8  960.0 599.62 163.42 113.36  NO
  2100.  0.3434E-03  4   3.0  4.8  960.0 599.62 167.98 114.08  NO
  2200.  0.3950E-03  4   3.0  4.8  960.0 599.62 172.60 114.80  NO
  2300.  0.4536E-03  4   3.0  4.8  960.0 599.62 177.26 115.53  NO
  2400.  0.5200E-03  4   3.0  4.8  960.0 599.62 181.96 116.26  NO
  2500.  0.5950E-03  4   3.0  4.8  960.0 599.62 186.70 117.00  NO
  2600.  0.6797E-03  4   3.0  4.8  960.0 599.62 191.46 117.74  NO
  2700.  0.7751E-03  4   3.0  4.8  960.0 599.62 196.26 118.48  NO
  2800.  0.8822E-03  4   3.0  4.8  960.0 599.62 201.08 119.23  NO
  2900.  0.1002E-02  4   3.0  4.8  960.0 599.62 205.92 119.98  NO
  3000.  0.1136E-02  4   3.0  4.8  960.0 599.62 210.78 120.73  NO
  3500.  0.1980E-02  4   3.0  4.8  960.0 599.62 235.28 124.28  NO
  4000.  0.3297E-02  4   3.0  4.8  960.0 599.62 260.01 127.83  NO
  4500.  0.5262E-02  4   3.0  4.8  960.0 599.62 284.82 131.38  NO
  5000.  0.8078E-02  4   3.0  4.8  960.0 599.62 309.64 134.91  NO
  5500.  0.1196E-01  4   3.0  4.8  960.0 599.62 334.42 138.43  NO
  6000.  0.1715E-01  4   3.0  4.8  960.0 599.62 359.13 141.92  NO
  6500.  0.2387E-01  4   3.0  4.8  960.0 599.62 383.75 145.39  NO
  7000.  0.3234E-01  4   3.0  4.8  960.0 599.62 408.27 148.84  NO
  7500.  0.4276E-01  4   3.0  4.8  960.0 599.62 432.68 152.25  NO
  8000.  0.5530E-01  4   3.0  4.8  960.0 599.62 456.98 155.64  NO
  8500.  0.7011E-01  4   3.0  4.8  960.0 599.62 481.17 159.00  NO
  9000.  0.8730E-01  4   3.0  4.8  960.0 599.62 505.24 162.33  NO
  9500.  0.1069    4   3.0  4.8  960.0 599.62 529.19 165.63  NO
 10000.  0.1290    4   3.0  4.8  960.0 599.62 553.04 168.90  NO
 15000.  0.4272    4   3.0  4.8  960.0 599.62 785.82 197.80  NO
 20000.  0.8089    4   3.0  4.8  960.0 599.62 1009.88 224.06  NO
 25000.  1.168    4   3.0  4.8  960.0 599.62 1227.00 248.31  NO
 30000.  1.457    4   3.0  4.8  960.0 599.62 1438.45 270.96  NO
 40000.  1.741    4   3.0  4.8  960.0 599.62 1847.63 308.25  NO
 50000.  1.844    4   3.0  4.8  960.0 599.62 2242.16 341.68  NO

 MAXIMUM 1-HR CONCENTRATION AT OR BEYOND   5. M:
 54100.  1.855    4   3.0  4.8  960.0 599.62 2400.39 354.52  NO

 DWASH=  MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

   ************************************
   *** SUMMARY OF SCREEN MODEL RESULTS ***
   ************************************

 CALCULATION     MAX CONC  DIST TO  TERRAIN
  PROCEDURE     (UG/M**3)  MAX (M)  HT (M)
 --------------  -----------  ---------  -------
```

```
 SIMPLE TERRAIN    1.855    54100.    0.


 ************************************************
 ** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
 ************************************************
```

SCREEN3 Output: CC Stack

02/24/25
13:25:28

```
 ***  SCREEN3 MODEL RUN  ***
 *** VERSION DATED 13043 ***

 HOMERCITY POINT SOURCE COAL STACK WITHOUT BUILDING DOWNWASH

 SIMPLE TERRAIN INPUTS:
    SOURCE TYPE            =        POINT
    EMISSION RATE (G/S)    =     100.0000
    STACK HEIGHT (M)       =      57.9000
    STK INSIDE DIAM (M)    =       7.0100
    STK EXIT VELOCITY (M/S)=      18.3800
    STK GAS EXIT TEMP (K)  =     350.8000
    AMBIENT AIR TEMP (K)   =     293.0000
    RECEPTOR HEIGHT (M)    =       0.0000
    URBAN/RURAL OPTION     =        RURAL
    BUILDING HEIGHT (M)    =       0.0000
    MIN HORIZ BLDG DIM (M) =       0.0000
    MAX HORIZ BLDG DIM (M) =       0.0000

 THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
 THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


 BUOY. FLUX =  364.828 M**4/S**3;  MOM. FLUX = 3466.371 M**4/S**2.

 *** STABILITY CLASS  4 ONLY ***
 *** ANEMOMETER HEIGHT WIND SPEED OF   3.00 M/S ONLY ***

 **********************************
 *** SCREEN AUTOMATED DISTANCES ***
 **********************************

 *** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***
```

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
5.	0.000	4	3.0	3.9	960.0	399.53	6.46	6.45	NO
100.	0.000	4	3.0	3.9	960.0	399.53	19.80	18.62	NO
200.	0.000	4	3.0	3.9	960.0	399.53	32.57	29.85	NO
300.	0.000	4	3.0	3.9	960.0	399.53	43.78	39.40	NO
400.	0.2527E-11	4	3.0	3.9	960.0	399.53	54.14	47.92	NO
500.	0.1675E-07	4	3.0	3.9	960.0	399.53	63.91	55.79	NO
600.	0.3665E-05	4	3.0	3.9	960.0	399.53	73.26	63.19	NO
700.	0.1309E-03	4	3.0	3.9	960.0	399.53	82.28	70.20	NO
800.	0.1611E-02	4	3.0	3.9	960.0	399.53	91.03	76.92	NO
900.	0.1013E-01	4	3.0	3.9	960.0	399.53	99.56	83.37	NO
1000.	0.4069E-01	4	3.0	3.9	960.0	399.53	107.90	89.61	NO
1100.	0.1157	4	3.0	3.9	960.0	399.53	116.06	95.46	NO
1200.	0.2656	4	3.0	3.9	960.0	399.53	124.09	101.14	NO
1300.	0.4136	4	3.0	3.9	960.0	399.53	130.43	104.74	NO
1400.	0.4380	4	3.0	3.9	960.0	399.53	134.51	105.43	NO
1500.	0.4636	4	3.0	3.9	960.0	399.53	138.70	106.13	NO
1600.	0.4904	4	3.0	3.9	960.0	399.53	142.99	106.84	NO
1700.	0.5186	4	3.0	3.9	960.0	399.53	147.37	107.55	NO
1800.	0.5481	4	3.0	3.9	960.0	399.53	151.82	108.27	NO
1900.	0.5789	4	3.0	3.9	960.0	399.53	156.34	109.00	NO
2000.	0.6110	4	3.0	3.9	960.0	399.53	160.93	109.74	NO
2100.	0.6446	4	3.0	3.9	960.0	399.53	165.56	110.48	NO
2200.	0.6795	4	3.0	3.9	960.0	399.53	170.24	111.23	NO

2300.	0.7159	4	3.0	3.9	960.0	399.53	174.97	111.98	NO
2400.	0.7537	4	3.0	3.9	960.0	399.53	179.73	112.73	NO
2500.	0.7929	4	3.0	3.9	960.0	399.53	184.52	113.49	NO
2600.	0.8335	4	3.0	3.9	960.0	399.53	189.34	114.25	NO
2700.	0.8756	4	3.0	3.9	960.0	399.53	194.19	115.02	NO
2800.	0.9190	4	3.0	3.9	960.0	399.53	199.06	115.79	NO
2900.	0.9639	4	3.0	3.9	960.0	399.53	203.95	116.56	NO
3000.	1.010	4	3.0	3.9	960.0	399.53	208.85	117.33	NO
3500.	1.236	4	3.0	3.9	960.0	399.53	233.56	120.98	NO
4000.	1.485	4	3.0	3.9	960.0	399.53	258.45	124.63	NO
4500.	1.754	4	3.0	3.9	960.0	399.53	283.40	128.27	NO
5000.	2.038	4	3.0	3.9	960.0	399.53	308.33	131.88	NO
5500.	2.335	4	3.0	3.9	960.0	399.53	333.21	135.48	NO
6000.	2.640	4	3.0	3.9	960.0	399.53	358.00	139.05	NO
6500.	2.948	4	3.0	3.9	960.0	399.53	382.70	142.59	NO
7000.	3.258	4	3.0	3.9	960.0	399.53	407.28	146.10	NO
7500.	3.565	4	3.0	3.9	960.0	399.53	431.75	149.58	NO
8000.	3.866	4	3.0	3.9	960.0	399.53	456.10	153.02	NO
8500.	4.161	4	3.0	3.9	960.0	399.53	480.33	156.44	NO
9000.	4.445	4	3.0	3.9	960.0	399.53	504.44	159.82	NO
9500.	4.719	4	3.0	3.9	960.0	399.53	528.43	163.18	NO
10000.	4.981	4	3.0	3.9	960.0	399.53	552.31	166.50	NO
15000.	6.607	4	3.0	3.9	960.0	399.53	785.31	195.75	NO
20000.	7.222	4	3.0	3.9	960.0	399.53	1009.48	222.25	NO
25000.	7.258	4	3.0	3.9	960.0	399.53	1226.67	246.68	NO
30000.	7.009	4	3.0	3.9	960.0	399.53	1438.17	269.46	NO
40000.	6.163	4	3.0	3.9	960.0	399.53	1847.41	306.93	NO
50000.	5.366	4	3.0	3.9	960.0	399.53	2241.98	340.50	NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND 5. M:

22811.	7.291	4	3.0	3.9	960.0	399.53	1132.39	236.21	NO

DWASH= MEANS NO CALC MADE (CONC = 0.0)
DWASH=NO MEANS NO BUILDING DOWNWASH USED
DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

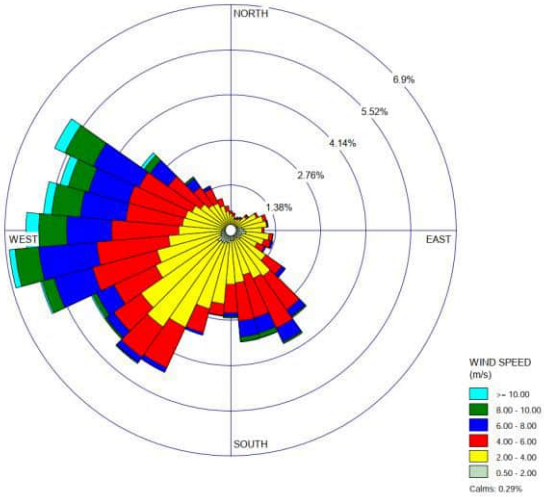
****
*** SUMMARY OF SCREEN MODEL RESULTS ***
****

CALCULATION PROCEDURE	MAX CONC (UG/M**3)	DIST TO MAX (M)	TERRAIN HT (M)
SIMPLE TERRAIN	7.291	22811.	0.

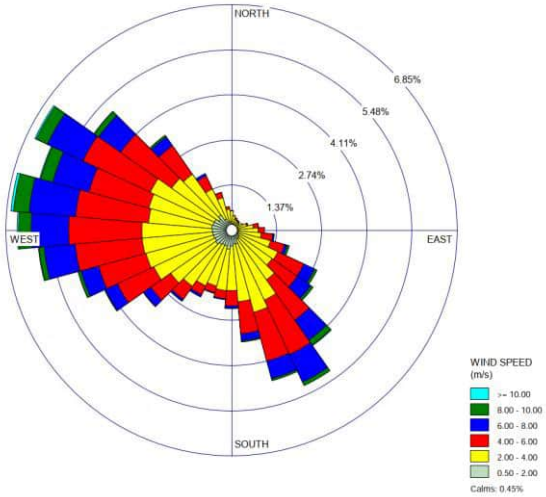
****
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
****

Annual Wind Roses – 2019–2021 (All Observations – Surface Level)

KJST ASOS (7.9 m)

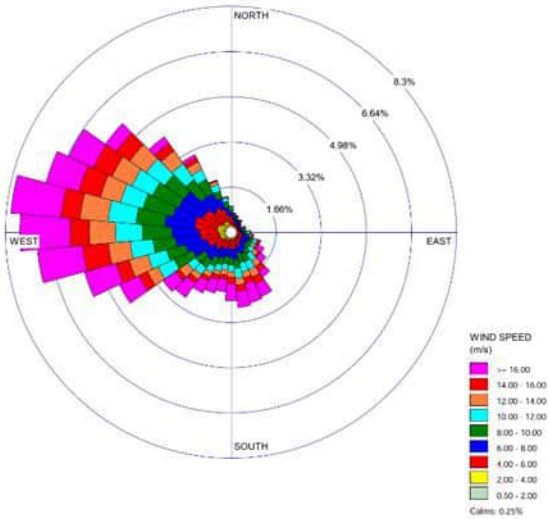


KJST WRF (10 m)

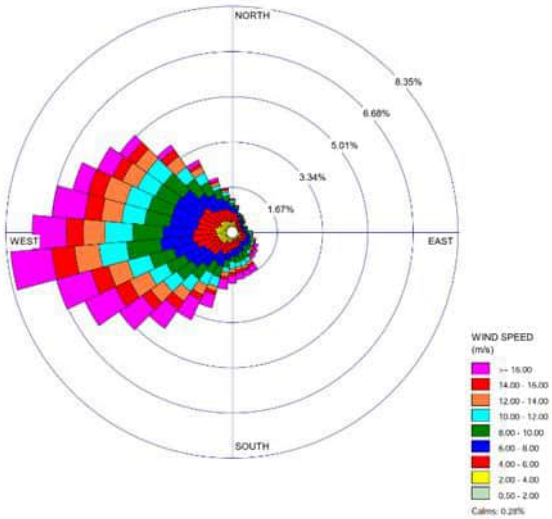


Annual Wind Roses – 2019-2021 (All Observations – KJST WRF and Homer City WRF – CC Stack Plume Level

KJST WRF (450 m)

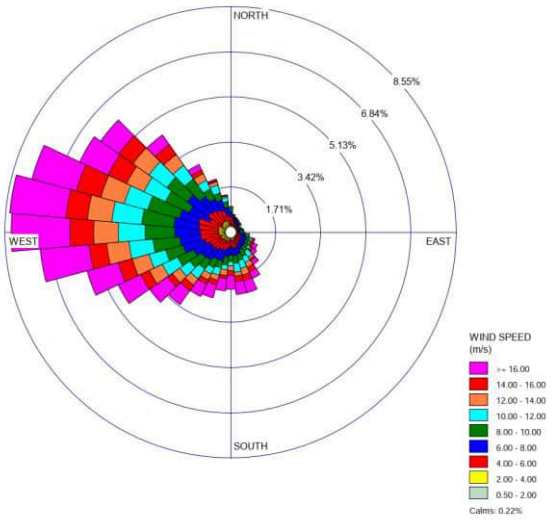


Homer City WRF (750 m)

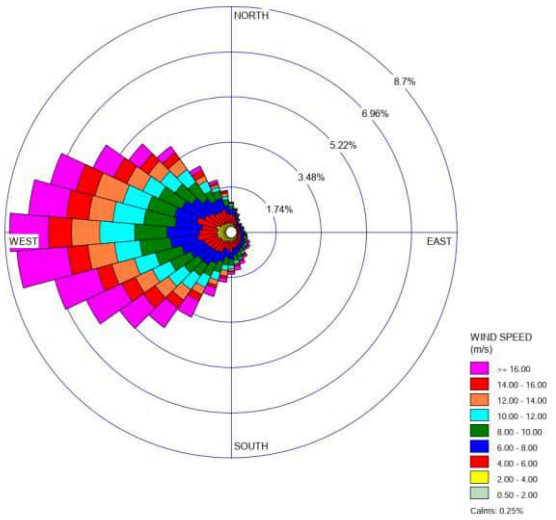


Annual Wind Roses – 2019-2021 (All Observations – KJST WRF and Homer City WRF – Coal Stack Plume Level

KJST WRF (600 m)

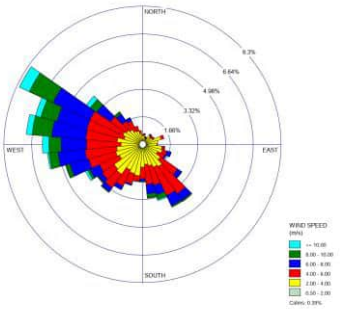


Homer City WRF (1000 m)

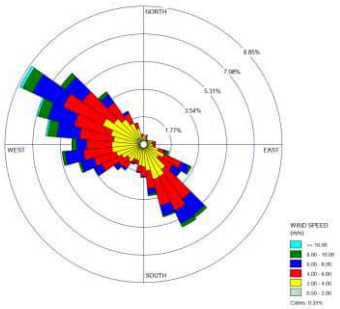


Seasonal Wind Roses 2019–2021 (Surface Level)

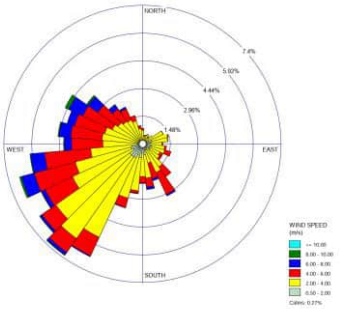
KJST ASOS (7.9 m) Spring



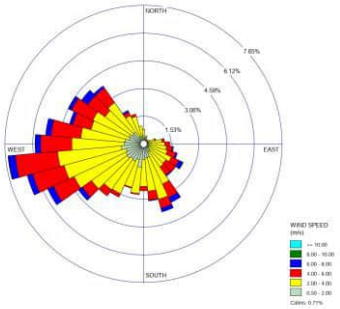
KJST WRF (10 m) Spring



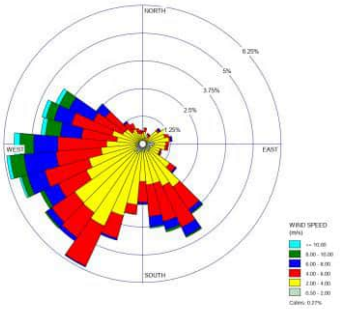
KJST ASOS (7.9 m) Summer



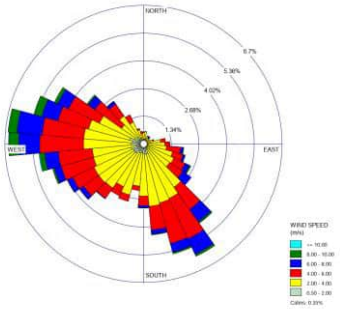
KJST WRF (10 m) Summer



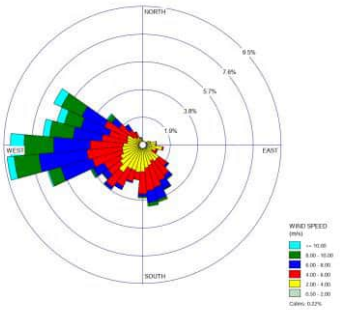
KJST ASOS (7.9 m) Autumn



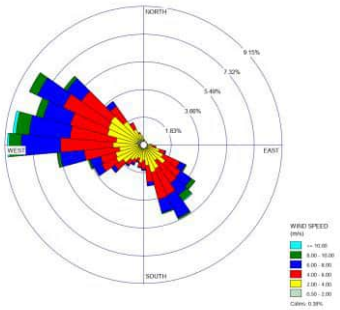
KJST WRF (10 m) Autumn



KJST ASOS (7.9 m) Winter

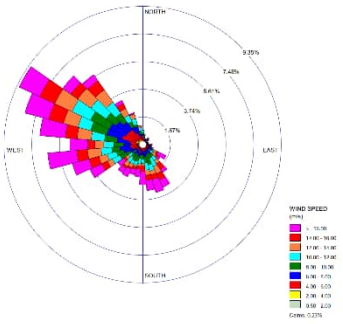


KJST WRF (10 m) Winter

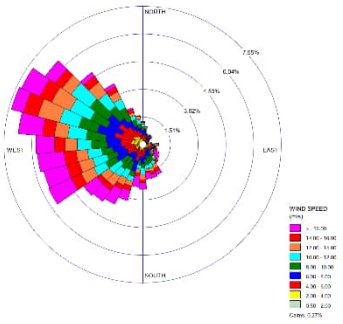


2019–2021 (Seasonal Breakdown – GE Stack Plume Level)

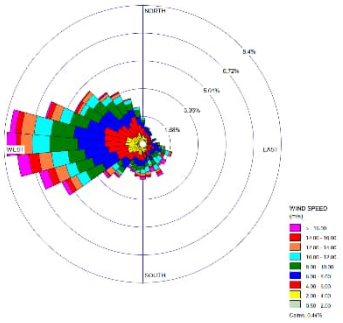
KJST (450 m) Spring



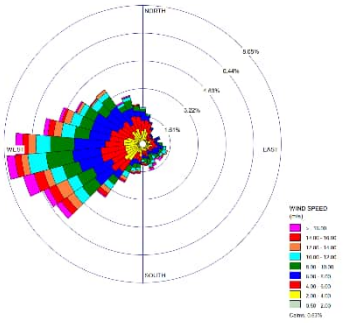
Homer City (750 m) Spring



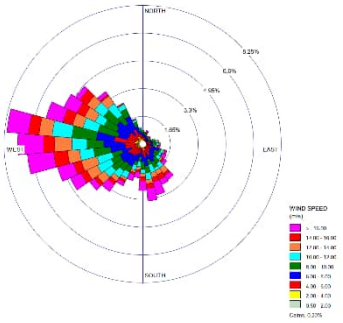
KJST (450 m) Summer



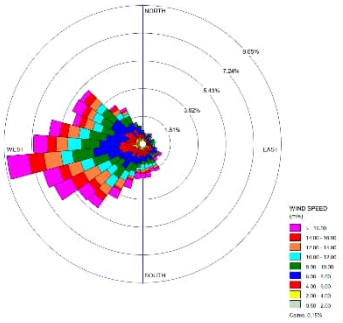
Homer City (750 m) Summer



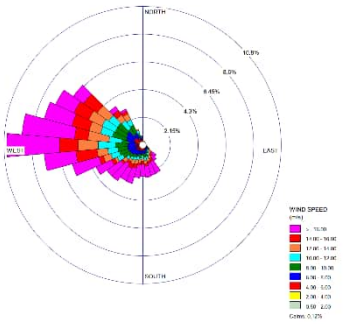
KJST (450 m) Autumn



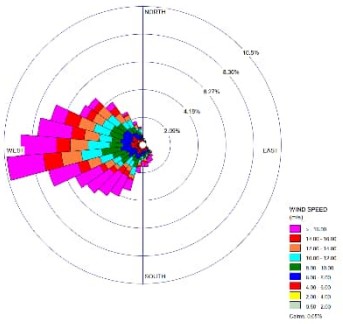
Homer City (750 m) Autumn



KJST (450 m) Winter

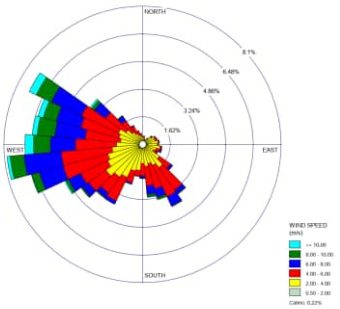


Homer City (750 m) Winter

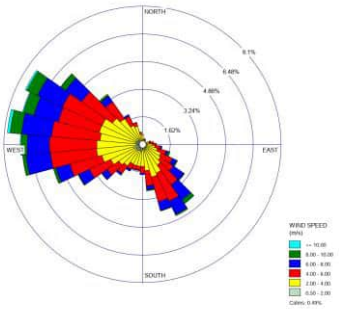


Day (7am-7pm) vs. Night (7pm-7am) Wind Roses 2019–2021

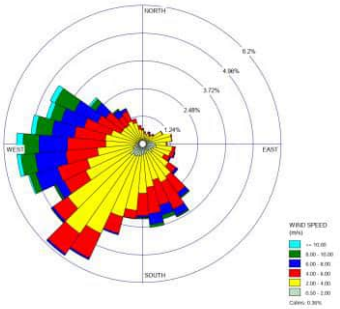
KJST ASOS (7.9 m) Day



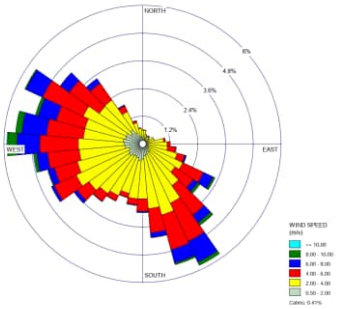
KJST MMIF (10 m) Day



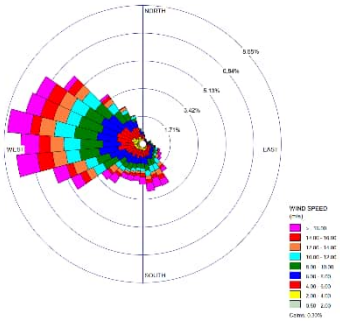
KJST ASOS (7.9 m) Night



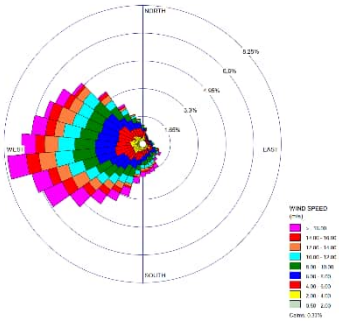
KJST MMIF (10 m) Night



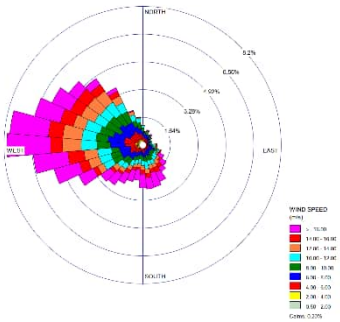
KJST (450 m) Day



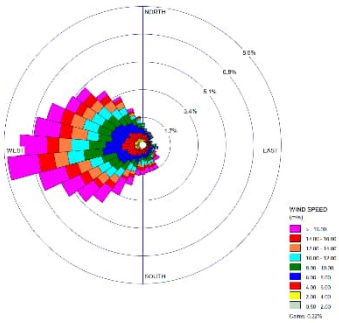
Homer City (750 m) Day



KJST (450 m) Night



Homer City (750 m) Night



Statistical Comparison of Observed KJST (ASOS) to KJST (WRF) for Near Surface – Spring (March – May)

Variable	Mean of KJST ASOS	Mean of KJST WRF	Mean Bias	Fb (unitless)	RMSE	R^2 (unitless)
Wind Speed (m/s)	4.77	4.39	-0.3823	-0.0835	1.4183	0.6316
Temp (°C)	281.96	282.18	0.2114	0.0007	1.9556	0.9339
Pressure (mb)	935.20	947.85	12.6540	0.0134	12.6729	0.9885
Relative Humidity (%)	64.12	71.70	7.5802	0.1116	15.2011	0.6779
Heat Flux	23.64	51.03	27.3886	0.7336	94.9723	0.5544
Surface Friction Velocity (m/s)	0.38	0.61	0.2319	0.4699	0.3086	0.6392

Notes: ASOS = Johnstown Airport ASOS; WRF = closest node to Johnstown Airport; Fb = fractional bias; RMSE = root mean square error

Statistical Comparison of Observed KJST (ASOS) to KJST (WRF) for Near Surface – Summer (June - August)

Variable	Mean of KJST ASOS	Mean of KJST WRF	Mean Bias	Fb (unitless)	RMSE	R^2 (unitless)
Wind Speed (m/s)	3.47	3.08	-0.3898	-0.1192	1.0683	0.5851
Temp (°C)	293.82	293.94	0.1129	0.0004	1.5478	0.8604
Pressure (mb)	936.76	948.63	11.8702	0.0126	11.8858	0.9760
Relative Humidity (%)	69.48	79.85	10.3692	0.1389	14.5425	0.6795
Heat Flux	36.22	35.49	-0.7314	-0.0204	58.2881	0.5741
Surface Friction Velocity (m/s)	0.30	0.43	0.1208	0.3313	0.2049	0.6202

Notes: ASOS = Johnstown Airport ASOS; WRF = closest node to Johnstown Airport; Fb = fractional bias; RMSE = root mean square error

Statistical Comparison of Observed KJST (ASOS) to KJST (WRF) for Near Surface – Autumn (September - November)

Variable	Mean of KJST ASOS	Mean of KJST WRF	Mean Bias	Fb (unitless)	RMSE	R^2 (unitless)
Wind Speed (m/s)	4.11	3.80	-0.3138	-0.0793	1.1572	0.6743
Temp (°C)	284.41	284.38	-0.0300	-0.0001	1.5783	0.9542
Pressure (mb)	937.34	949.64	12.2979	0.0130	12.3210	0.9825
Relative Humidity (%)	69.16	78.54	9.3833	0.1271	14.5031	0.6345
Heat Flux	13.21	19.06	5.8586	0.3631	54.4300	0.5327
Surface Friction Velocity (m/s)	0.33	0.51	0.1868	0.4432	0.2567	0.6555

Notes: ASOS = Johnstown Airport ASOS; WRF = closest node to Johnstown Airport; Fb = fractional bias; RMSE = root mean square error

Statistical Comparison of Observed KJST (ASOS) to KJST (WRF) for Near Surface – Winter (December - February)

Variable	Mean of KJST ASOS	Mean of KJST WRF	Mean Bias	Fb (unitless)	RMSE	R^2 (unitless)
Wind Speed (m/s)	5.09	4.54	-0.5512	-0.1144	1.5276	0.6517
Temp (°C)	272.40	272.44	0.0389	0.0001	1.6657	0.9219
Pressure (mb)	934.31	947.41	13.1006	0.0139	13.1119	0.9921
Relative Humidity (%)	72.75	83.89	11.1452	0.1423	15.6005	0.5501
Heat Flux	-14.29	7.33	21.6128	-6.2128	58.0355	0.3635
Surface Friction Velocity (m/s)	0.36	0.62	0.2582	0.5246	0.3197	0.6271

Notes: ASOS = Johnstown Airport ASOS; WRF = closest node to Johnstown Airport; Fb = fractional bias; RMSE = root mean square error

Statistical Comparison of Homer City (WRF) at KJST (WRF) at CC Plume Height – Spring (March – May)

Variable	Mean of Homer City WRF	Mean of KJST WRF	Mean Bias	Fb (unitless)	RMSE	R^2 (unitless)
Wind Speed (m/s)	11.05	10.43	-0.6140	-0.0572	2.1804	0.8669
Temp (°C)	6.68	6.07	-0.6030	-0.0946	1.2831	0.9787

Notes: ASOS = Johnstown Airport ASOS; WRF = closest node to Johnstown Airport; Fb = fractional bias; RMSE = root mean square error

Statistical Comparison of Homer City (WRF) at KJST (WRF) at CC Plume Height – Summer (June - August)

Variable	Mean of Homer City WRF	Mean of KJST WRF	Mean Bias	Fb (unitless)	RMSE	R^2 (unitless)
Wind Speed (m/s)	7.55	7.11	-0.4394	-0.0599	1.5534	0.8728
Temp (°C)	18.56	17.72	-0.8422	-0.0464	1.1016	0.9514

Notes: ASOS = Johnstown Airport ASOS; WRF = closest node to Johnstown Airport; Fb = fractional bias; RMSE = root mean square error

Statistical Comparison of Homer City (WRF) at KJST (WRF) at CC Plume Height – Autumn (September - November)

Variable	Mean of Homer City WRF	Mean of KJST WRF	Mean Bias	Fb (unitless)	RMSE	R^2 (unitless)
Wind Speed (m/s)	10.07	9.54	-0.5382	-0.0549	2.0339	0.8680
Temp (°C)	9.54	9.01	-0.5250	-0.0566	1.1844	0.9797

Notes: ASOS = Johnstown Airport ASOS; WRF = closest node to Johnstown Airport; Fb = fractional bias; RMSE = root mean square error

Statistical Comparison of Homer City (WRF) at KJST (WRF) at CC Plume Height – Winter (December - February)

Variable	Mean of Homer City WRF	Mean of KJST WRF	Mean Bias	Fb (unitless)	RMSE	R^2 (unitless)
Wind Speed (m/s)	12.83	12.04	-0.7916	-0.0637	2.4260	0.8621
Temp (°C)	-2.33	-2.75	-0.4158	0.1636	1.3455	0.9667

Notes: ASOS = Johnstown Airport ASOS; WRF = closest node to Johnstown Airport; Fb = fractional bias; RMSE = root mean square error

Appendix J : Vendor Data

GE VERNOVA

Gas Power

Andrew Dicke
Sr. Environmental Engineer
1 River Rd: Bldg. 40
Schenectady NY, 12345

+1 (518) 698-9807
andrew.dicke@GEVernova.com

July 7, 2025

Homer City Generation, L.P.
1750 Power Plant Road
Homer City, PA 15748
Email: JHeiser@homercityredevelopment.com

Subject: GE Vernova Confirms Emission Capabilities are Consistent with Homer City Generation, L.P. Permit Application

Dear Mr. Heiser,

GE Vernova has provided emission data to Homer City Generation, L.P. to support the Prevention of Significant Deterioration Permit Application. The provided data conveys the equipment emission capabilities for GE Vernova's 7HA.02 Gas Turbine scope of supply equipment.

GE Vernova has subsequently reviewed the Prevention of Significant Deterioration Permit Application submitted to the Pennsylvania Department of Environmental Protection. GE Vernova affirms the data submitted in the Permit Application represent the emission capabilities of the GE Vernova scope of equipment being provided for the Homer City installation and are consistent with the data GE Vernova provided to support the permit application.

Sincerely,



Andrew Dicke

CC.
Michael McCarrick, GEV Account Manager

GE Vernova Proprietary and Confidential Information

MITSUBISHI POWER

July 10, 2025

Aaron Danenberg
Manager and Senior Principal Engineer, Performance Engineering
628 Hebron Avenue, Suite 400
Glastonbury CT, 06033

+1 (860) 368-5463
aaron.danenberg@aeropowermhi.com

Homer City Generation, L.P.
1750 Power Plant Road
Homer City, PA 15748

Subject: Emissions Capability Data Confirmation

Dear Mr. Heiser,

Mitsubishi Power Aero (MPA) reviewed the "Prevention of Significant Deterioration Permit Application" submitted to the Pennsylvania Department of Environmental Protection dated April 2025.

MPA confirms the emissions data defined in the following tables submitted in the permit application is consistent with the data MPA furnished for Homer City Generation L.P. and the capability of the FT8 MOBILPAC® operating with an SCR and CO Catalyst.

- C-8 and C-9: FT8 MOBILEPAC Emissions
- C-11: FT8 MOBILEPAC Startup/Shutdown Emissions

Sincerely,

Aaron Danenberg

CC - Harsh Shah, Scott Milligan, Randy DaRos

Indirect Fired Heaters Datasheets

00-FGS-HTR01A / 00-FGS-HTR01B

Customer Name: Kiewit Power Engineers
Customer Project Number: 20015690
Project Name: Seminole Combined-Cycle Facility
Location: Palatka, FL
Aether DBS Job Number: 220012

10810 E. 45th Street, Tulsa, OK 74146
Phone: 918-250-6601 Fax: 918-254-5412
www.aetherdbs.com

DOC: 220012-DS-HTR-0001 REV: 1
CHK BY: ER DATE: 5/20/2021
APP BY: SR DATE: 5/20/2021

Approved - Returned: 06/09/2021

94.03.48.150-DA-0001-001 - Packet 94.03.48.150-070 - Seminole - 20015690 - Received: 05/20/2021

HEATER SPECIFICATION SHEET

aether dbs

Forced Draft Line Heater

DOCUMENT NUMBER: **220012-DS-HTR-0001**
REVISION NO: **1**
REVIEWED BY: **ER**
APPROVED BY: **SR**

CUSTOMER	Kiewit Power Engineers	DATE	11-Apr-20
ADDRESS		CUSTOMER SPEC NUMBER	94.03.48.150
CITY/STATE/ZIP		CUSTOMER PROJECT NO.	20015690
LOCATION	Palatka, FL	AETHER PROJECT NUMBER	220012
STATION	Seminole Combined-Cycle Facility	OPERATING DATA	1016 psig 40°F / 1011 psig 80°F
ENGINEER		QUANTITY	1
TAG	00-FGS-HTR-01A / 00-FGS-HTR-01B		

BASIC HEATER DATA

DIAMETER (inches)	102	BATH MEDIA VOLUME (Gal)	10,520	PROPYLENE GLYCOL	30/70
LENGTH (ft)	44' - 0"	HEATER WEIGHT (DRY lbs)	70,180	HORIZONTAL	WB10000-102H
WIDTH (ft)	10' - 0"	HEATER WEIGHT (WET lbs)	165,130	MAINTENANCE HOUSE	NO
HEIGHT (ft) (Shipping / Top of Stack)	11' - 0" / 15' - 0"	POWER INPUT	480 VAC / 60 hz / 3 PH	SKID STRUCTURE	YES
NOMINAL RATING (MMBtu/hr)	7.8260				

PROCESS CONDITIONS

		INLET	OUTLET
TYPE OF FLUID		Natural Gas	Natural Gas
TOTAL FLUID ENTERING	SCFH	7,133,998	7,133,998
VAPOR	lb/hr	319,208	319,208
LIQUID	lb/hr	------	------
STEAM	lb/hr	------	------
NON-CONDENSABLE	lb/hr	------	------
FLUID VAPORIZED OR COND	lb/hr	------	------
LIQUID DENSITY	lbs/ft3	------	------
LIQUID VISCOSITY	cP	------	------
LIQUID SPECIFIC HEAT	Btu/lb-F	------	------
LIQUID THERMAL COND	Btu/hr-ft-F	------	------
VAPOR MOLECULAR WT	lbs/lbs Mol	16.943	------
VAPOR DENSITY	lbs/ft3	3.9145	3.4176
VAPOR VISCOSITY	cP	0.0124	0.0128
VAPOR SPECIFIC HEAT	Btu/lb-F	0.6838	0.6433
VAPOR THERMAL COND	Btu/hr-ft-F	2.19E-02	2.28E-02
TEMPERATURE (IN/OUT)	F	40	80
OPERATING PRESSURE	psig	1016	1011
VELOCITY	ft/sec	------	36
PRESSURE DROP (ALLOW/EST)	psid	10	5
CLEANLINESS FACTOR	%	85%	

REMARKS

Forced Draft Burner	1
Each Blower Motor (HP)	15
Sparging System	NO
Sparging Pump Motor (HP)	NA
Safety include:	
Low Water Level	
High Water Temp	
Pilot Flame Failure	
Controls Include:	
Water Temp Control	
Nat Gas Disch Temp Control	
Heater Control Panel	RELAY LOGIC
Burner Management System	HONEYWELL
Burner Turn Down (80%)	5:1
Fluid Specific Gravity	0.586
After Regulation (psig)	605
After Regulation (F)	55
MINIMUM SUPPLY PRESSURE (MSP)	
Outlet Temp at MSP (F)	80
Min Supply Press (psig)	625
VEL @ Min Oper Press (ft/sec)	
Press Drop at MPS (psid)	

THERMAL DATA

HEAT TRANSFERRED	Btu/hr	7,825,962
BURNER'S HEAT RELEASE (HHV)	Btu/hr	9,782,452
TRANSFER RATE (CLEAN)	Btu/hr-ft2-F	57.26
TEMPERATURE DIFF (LMTD)		121

REMARKS

Operating Bath Temperature	180.0	F
Minimum Ambient Tempeature	-20	F
Maximum Ambient Temperature	104	F
Site Elevation	75	ft ASL

PROCESS COIL

MAWP	psig	1120	Fabrication Code	ASME Section VIII Div 1	
TEST PRESSURE	psig	1680	Radiographic (Percentage)	100%	
DESIGN TEMPERATURE	F	-20F to 200F	National Board Stamped	Yes	
NUMBER OF PASS / PATH		4	Coil Material	SA-106 Grade B Smls	SR Elbow
NUMBER OF PATHS		9	Coil Hydrotest Note:	1.5 x MAWP for 4 hours	
TOTAL NUMBER OF TUBES		36	Shell Pressure Test:	5 psig for 1 hour	
STRAIGHT TUBE LENGTH	ft	1080	Inlet	12 inch ANSI 600# RF	12.75
TYPE		Serpentine	Outlet	12 inch ANSI 600# RF	12.75
REMOVABLE		Yes	Inlet Header thk	0.843	in
HEAT FLUX	Btu/hr-ft2	6,003	Inlet Header Velocity	59	ft/sec
TUBE SIZE	inches OD	4.5	Outlet Header thk	0.843	in
TUBE WALL THICKNESS	inches	0.337	Outlet Header Velocity	65	ft/sec
CORROSION ALLOWANCE	inches	1/16	Surface Area Actual	1305	ft2

HEATER DATA

DESIGN CODE		NFPA 87
SHELL DIAMETER	inches	102
SHELL LENGTH	ft	32
SHELL (THICK)	inches	3/8
FIRETUBE DIAMETER	inches OD	36 / 4
NUMBER OF FIRETUBES		1 / 24
EACH FIRE / RETURN TUBE LENGTH	ft	31.75 / 29
FIRE TUBE MATERIAL THICKNESS	inches	0.375 / 0.12
FIRE TUBE HEAT DENSITY	Btu/hr-in2	10,024
FIRE TUBE FLUX RATE	Btu/hr-ft2	7,850
REMOVABLE		Yes
STACK DIAMETER	Qty / inches	1 / 30
STACK VELOCITY	ft/sec	11.66
STACK HEIGHT (ACT / OF GRADE)	ft	15' - 0"
STACK MATERIAL		SS304
WALL THICKNESS		Gauge 10 (0.1406") Thick
EXPANSION TANK DIAMETER	inches	36
EXPANSION TANK LENGTH	ft	16
EXPANSION TANK MATERIAL		CS
WALL THICKNESS	inches	1/4
NET SHELL VOL % (MIN / ACTUAL)	%	6 / 7.89
EXPANSION TANK VOLUME	Gal	830

REMARKS

Composition	Process Gas	
carbon dioxide	1.090%	
nitrogen	0.410%	
methane	95.040%	
ethane	3.173%	
propane	0.189%	
isobutane	0.030%	
butane	0.032%	
isopentane	0.012%	
pentane	0.007%	
hexane	0.017%	
Emission	Low NOx Burner	lbs/MMBtuh
NOx	25 PPM	0.0300
CO	50 PPM	0.0370
SOx	1 PPM	0.0010
Hydrocarbon/VOC	13 PPM	0.0050
PM	NA	0.0048
FUEL GAS CONSUMPTION	10570 / 480	SCFH / PPH
PREHEAT COIL (OD / LENGTH)	1 / 20	IN. / FT

Approved - Returned: 06/09/2021

27 June, 2025

FCX Performance
8055 Bond Street
Lenexa, KS 66214

Subject: Emissions for Homer City Auxiliary Boilers

To Whom it May Concern:

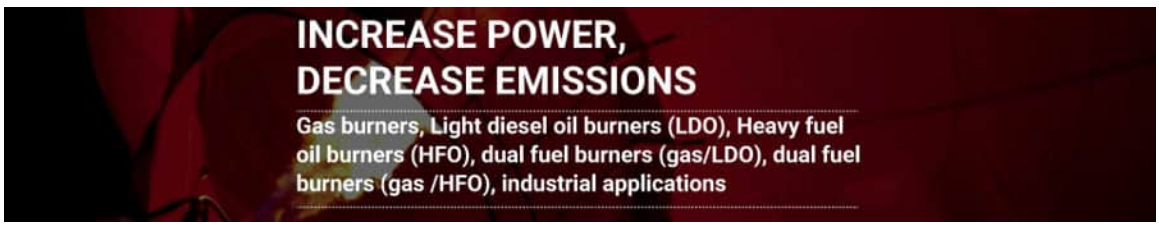
This letter is to inform you that the emissions values for the low NOx CIB Unigas burners for the watertube auxiliary boilers being proposed for subject project are guaranteed as follows based on AP-42 ***corrected to 3% O2*** when burning natural gas:

NOx:	0.05 lb/MMBtu
CO:	0.08 lb/MMBtu;
Total PM:	0.0075 lb/MMBtu
VOC:	0.00539 lb/MMBtu

These values are based on an auxiliary boiler maximum heat input of 67 MMBtu/hr. Should you have any questions regarding emissions values, please advise.

Best regards,

Gabriel Dauphin
Managing Director, CIB Unigas USA, Inc.



To Whom It May Concern:

With regards to Cummins Power Systems (CPS) manufactured diesel generator set model **DQKAN** rated for 60 Hz operation and equipped with Cummins **QSK60-G19 NR2** engine **EPA Engine Family (Cummins Emissions Family): XCEXL060.AAD**

The engine used in this generator set complies with Tier 2 emissions limits of U.S. EPA New Source Performance Standards (NSPS) for stationary emergency engines under the provisions of 40 CFR 60 Subpart IIII when tested per ISO 8178 D2. The Tier 2 EPA emissions are recorded per 40CFR Part 60, 89, 1039, 1065 and weighted at load points prescribed in the regulations for constant speed engines.

Tests conducted using alternate test methods, instrumentation, fuel or reference conditions can yield different results. Engine operation with excessive air intake or exhaust restriction beyond published maximum limits, or with improper maintenance, may result in elevated emission levels.

For the purposes of this proposal, the engine will be equipped with emissions controls technologies including, but not limited to, diesel particulate filter and selective catalytic reduction, designed and warranted by the emissions aftertreatment manufacturer to achieve the blended "Tier 4" emissions target from the D2 test cycle, when measured at 100% of the generator set's ISO Standby rating.

The data and information provided in this letter is for informational purposes to assist customers in making purchasing decisions appropriate for their site-specific compliance needs. Owners/operators of compression ignition internal combustion engines are responsible for ensuring compliance with applicable local, state, and federal standards when CI engines are installed at the owner/operator site.

This letter does not supersede any of the commercial terms of sale, including, but not limited to, warranty coverage and compliance with law obligations. As an APPENDIX to this letter, please reference below APPENDIX A, which contains a letter directly from MIRATECH, with additional information surrounding the aftertreatment solution:

APPENDIX A



ENGINEERED TO PERFORM™
800-640-3141 | MIRATECHCORP.COM

July 14, 2025

ATTN:

Cole Tucker
Senior Sales Executive – Power Generation – Southern US – Coastal
Cummins Southern Plains, LLC
7045 N. Loop 610 East
Houston, TX 77028
Email: william.tucker@cummins.com
Mobile: (346) 257-5806

Cole,

We truly appreciate the opportunity to work alongside Cummins Southern Plains, LLC on this significant project and we hope to provide you with an emission performance commitment that satisfies all the stakeholders in the process.

After reviewing the PA DEP Plan Approval, AECOM Air Dispersion modeling report and subsequent submitted addendums, we believe that our quotation, JB-25-004564 Rev (2), satisfies all the performance criteria as laid out in the documents.

Specifically in AECOM's report, the emissions values listed in Table 2-1 for NOx, CO, VOCs and PM for (10) generators and operating at 500 hours per year will be achievable with our specified system and the emission performance will be maintained as per our Terms and Conditions, of which, stipulate that these emissions levels will be met at 100% ISO Standby Load, are warranted based on 100% ISO Standby Load only, and if any field testing is required, it shall be tested at a single 100% load point.

Additionally, the emission threshold criteria as presented specifically in Table 1 on page 129 of the "5-2-2025 NW_AQ-Supplemental Data for PSD" document as submitted to the Pennsylvania Department of Environmental Protection will be met with our proposed system as constructed.

If you have any further questions or if we can provide further documentation, please do not hesitate to contact Jeff Brown from our Houston, TX US office.

Regards,

Jim McDonald
Director of Environmental Impact- MIRATECH Corporation

June 26, 2025

Subject: Emissions Standards

To Whom it may concern,

The C13H0-UFAD28 is certified to meet the requirements of EPA Tier 3. The Tier 3 emission limitations are the same requirements for fire water pump engines in Table 4 of 40 CFR Part 60 Subpart IIII for maximum engine power equal to or greater than 225 kW and less than 450 kW (300 ≤ HP < 600) for model years 2009 and later.

NOx + MNHC - 4.0 g/kW-hr (3.0 g/hp-hr)
CO – 3.5 g/kW-hr (2.6 g/hp-hr)
PM – 0.2 g/kW-hr (0.15 g/hp-hr

Best Regards,

Ryan Barrick
Engineer to Order (ETO) Manager

Ryan Barrick

Clarke Fire Protection Products, Inc.
100 Progress Place
Cincinnati, Ohio 45246
United States of America

www.clarkefire.com