MSCE Project

Facility-Wide Emissions

Table B-1 (Revised 22 March 2021)

	Combustion Turbine Emissions	Duct Burners	Startup/ Shutdown Emissions	Fuel Gas Preheaters	Auxiliary Generator Emissions	Fire Pump Emissions	Cooling Tower	Total Facility Emissions
PSD/NSR Pollutants	**(tons/yr)**	**(tons/year)**	**(tons/yr)**	**(tons/yr)**	**(tons/yr)**	**(tons/yr)**	**(tons/yr)**	**(tons/yr)**
NOx	284.7		32.2	2.21	1.23	0.079		320
CO	173.3		100.5	2.38	0.097	0.0688		276
VOC	99.3		41.2	0.429	0.0231	0.0794		141
PM/PM10/PM2.5	198.1		2.24	0.477	0.0116	0.0040	9.47	210
SO2	39.8			0.0795	0.0019	0.0001		39.9
H2SO4	35.8		0.010	0.0061	0.010	0.010		35.8
GHG	5,068,855		58,287	8,057	98.0	20.9		5,135,319
Lead		1.10E-03						0.00110
Flourides								0.00
Vinyl Chloride								0.00
Total Reduced Sulfur								0.00
Reduced Sulfur Compounds								0.00
Hazardous Air Pollutants (HAPS)								
1,3-Butadiene	1.43E-02					5.30E-06		1.43E-02
2 Methylnaphthalene		8.81E-05						8.81E-05
Acetaldehyde	1.33E+00					1.04E-04		1.33
Acrolein	2.12E-01					1.25E-05		2.12E-01
Arsenic		8.81E-04						8.81E-04
Benzene	3.98E-01	7.71E-03			6.92E-04	1.27E-04		4.07E-01
Beryllium		4.40E-05						4.40E-05
Cadmium		4.04E-03						4.04E-03
Chromium		5.14E-03						5.14E-03
Cobalt		1.54E-04						1.54E-04
Dichlorobenzene		4.40E-03						4.40E-03
Ethylbenzene	1.06							1.06
Formaldehyde	7.07	1.12			7.03E-05	1.60E-04		8.19
Hexane		4.62						4.62
Manganese		1.39E-03						1.39E-03
Mercury		9.54E-04						9.54E-04
Naphthalene	4.31E-02	2.24E-03			1.16E-04	1.15E-05		4.55E-02
Nickel		7.71E-03						7.71E-03
Phenanathrene		6.24E-05			3.64E-05	3.99E-06		1.03E-04
Propylene Oxide	9.62E-01							9.62E-01
Toluene	4.31	1.25E-02			2.50E-04	5.55E-05		4.33
Xylene	2.12					3.87E-05		2.12
Total HAPS								23.3

MSCE Project

Emergency Generator Emissions

Table B-4 (Revised 22 March 2021)

Rated Output (kilowatts)	**1,139**	
Rated Output (horsepower)	**1,528**	**2100**
Rated input (MMBtu/hr)	**13.0**	**17.8**
Hours of Operation	**100**	

Pollutant	Emission Factor (lbs/MMBtu)	Emission Factor (grams/hp hr)	Max Power Output (hp hr)	Max Fuel Input (MMBtu/hr)	Max Emission Rate (lbs/hr)	Annual Emissions (tons/yr)
NOx		5.32	2100		24.6	1.23
CO		0.42	2100		1.94	0.097
VOC		0.1	2100		0.46	0.023
PM10		0.05	2100		0.231	0.012
SO2		0.00809	2100		0.037	0.002
GHG	110			17.8	1,961	98.0
Acenapthene	4.7E-06			17.8	8.3E-05	4.2E-06
Acenaphthylene	9.2E-06			17.8	1.6E-04	8.2E-06
Acetaldehyde	2.5E-05			17.8	4.5E-04	2.2E-05
Acrolein	7.9E-06			17.8	1.4E-04	7.0E-06
Anthracene	1.2E-06			17.8	2.2E-05	1.1E-06
Benz(a)anthracene	6.2E-07			17.8	1.1E-05	5.5E-07
Benzene	7.8E-04			17.8	1.4E-02	6.9E-04
Benzo(a)pyrene	2.6E-07			17.8	4.6E-06	2.3E-07
Benzo(b)fluoroanthene	1.1E-06			17.8	2.0E-05	9.9E-07
Benzo(g,h,i)perylene	5.6E-07			17.8	9.9E-06	5.0E-07
Benzo(k)fluoranthene	2.2E-07			17.8	3.9E-06	1.9E-07
Chrysene	1.5E-06			17.8	2.7E-05	1.4E-06
Dibenzo(a,h)anthracene	3.5E-07			17.8	6.2E-06	3.1E-07
Fluoranthene	4.0E-06			17.8	7.2E-05	3.6E-06
Fluorene	1.3E-05			17.8	2.3E-04	1.1E-05
Formaldehyde	7.9E-05			17.8	1.4E-03	7.0E-05
Indeno(1,2,3-cd)pyrene	4.1E-07			17.8	7.4E-06	3.7E-07
Naphthalene	1.3E-04			17.8	2.3E-03	1.2E-04
Phenanathrene	4.1E-05			17.8	7.3E-04	3.6E-05
Pyrene	3.7E-06			17.8	6.6E-05	3.3E-06
Toluene	2.8E-04			17.8	5.0E-03	2.5E-04
Xylene	1.9E-04			17.8	3.4E-03	1.7E-04
Total Haps						1.4E-03

1. Emission rates estimated based upon AP-42 emission factors (Tables 3.4-1, 3 & 4)
2. Fuel throughput based upon similar Caterpillar diesel engine.

MSCE Project
Firewater Pump Emissions
Table B-5 (Revised 22 March 2021)

Rated Output (kilowatts)	**179**
Rated Output (horsepower)	**240**
Rated input (MMBtu/hr)	**2.71**
Hours of Operation	**100**

Pollutant	Emission Factor (lbs/MMBtu)	Emission Factor (grams/hp-hr)	Max Power Output (hp hr)	Max Fuel Input (MMBtu/hr)	Max Emission Rate (lb/hr)	Annual Emissions (tons/yr)
NOx		3	240		1.59	0.079
CO		2.6	240		1.38	0.069
VOC		3	240		1.59	0.079
PM10		0.15	240		0.08	0.004
SO2		0.00205	240		0.001	0.0001
H2SO4						
GHG	154			2.71	417.8	20.9
(1,3) Butadiene	3.9E-05			2.71	1.1E-04	5.3E-06
Acenapthene	1.4E-06			2.71	3.9E-06	1.9E-07
Acenaphthylene	5.1E-06			2.71	1.4E-05	6.9E-07
Acetaldehyde	7.7E-04			2.71	2.1E-03	1.0E-04
Acrolein	9.3E-05			2.71	2.5E-04	1.3E-05
Anthracene	1.9E-06			2.71	5.1E-06	2.5E-07
Benz(a)anthracene	1.7E-06			2.71	4.6E-06	2.3E-07
Benzene	9.3E-04			2.71	2.5E-03	1.3E-04
Benzo(a)pyrene	1.9E-07			2.71	5.1E-07	2.6E-08
Benzo(b)fluoroanthene	9.9E-08			2.71	2.7E-07	1.3E-08
Benzo(g,h,i)perylene	4.9E-07			2.71	1.3E-06	6.6E-08
Benzo(k)fluoranthene	1.6E-07			2.71	4.2E-07	2.1E-08
Chrysene	3.5E-07			2.71	9.6E-07	4.8E-08
Dibenzo(a,h)anthracene	5.8E-07			2.71	1.6E-06	7.9E-08
Fluoranthene	7.6E-06			2.71	2.1E-05	1.0E-06
Fluorene	2.9E-05			2.71	7.9E-05	4.0E-06
Formaldehyde	1.2E-03			2.71	3.2E-03	1.6E-04
Indeno(1,2,3-cd)pyrene	3.8E-07			2.71	1.0E-06	5.1E-08
Naphthalene	8.5E-05			2.71	2.3E-04	1.2E-05
Phenanathrene	2.9E-05			2.71	8.0E-05	4.0E-06
Pyrene	4.8E-06			2.71	1.3E-05	6.5E-07
Toluene	4.1E-04			2.71	1.1E-03	5.5E-05
Xylene	2.9E-04			2.71	7.7E-04	3.9E-05
Total Haps						5.2E-04

1. Emission rates estimated based upon AP-42 emission factors (Tables 3.3-1& 2)
2. Fuel throughput based upon similar Caterpillar diesel engine.

Table 3-3
Potential Maximum Hourly and Annual Emissions from the Fire Water Pump, Emergency Generator, Spray Dryer and Mechanical Draft Tower
(Revised 22 March 2021)

Pollutant	Fire Water Pump[1]		Emergency Generator		Fuel Gas Heaters (2)		Cooling Tower	
	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tons/year)	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tons/year)	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tons/year)	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tons/year)
NO_x	1.59	0.079	24.6	1.23	0.25	2.21	0.0	0.0
CO	1.38	0.069	1.94	0.097	0.27	2.38	0.0	0.0
VOCs	1.59	0.079	0.46	0.023	0.05	0.43	0.0	0.0
PM/PM_{10} ($PM_{2.5}$)	0.08	0.004	0.231	0.012	0.05	0.48	2.16 (1.08)	9.47 (4.73)
SO_2	0.001	0.0001	0.037	0.002	0.01	0.08	0.0	0.0
GHG	417.8	20.9	1,961	98.0	920	8,057	0.0	0.0

[1] Fire water pump and emergency generator limited to 100 hrs/yr of operation.

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION FOR THE MOUNTAIN STATE CLEAN ENERGY PROJECT

Submitted to:
West Virginia Department of Environmental Protection
Division of Air Quality
601 57th Street, SE,
Charleston, WV 25304

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107 Hidden Fox Dr.
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12 March 2021

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1. INTRODUCTION

Longview Power II, LLC (Longview Power) is proposing to develop a new nominal 1,200 megawatt (MW) gas-fired combined-cycle power plant and a photovoltaic renewable energy solar installation of up to 70 MW in size (collectively designated as the "Mountain State Clean Energy Center" or "MSCEC"). The MSCEC is proposed to be constructed on property owned by Longview Power in Monongalia County, near Maidsville, West Virginia.

The power plant, referred to as the Mountain State Clean Energy (MSCE) Project, consist of two natural gas-fired only (no oil backup) combined-cycle gas turbines (CCGT) and is proposed to be located to the north of the existing Longview Power Plant. The Project will be designed to achieve peak electrical outputs of approximately 1,200 MW (average ambient conditions at full load without duct firing) and approximately 1,300 MW (average ambient conditions at full load with duct firing). Electricity generated by the power plant will be supplied to the PJM power grid and connect to the grid via the existing interconnection used by the Longview Power Plant.

Major components of the proposed MSCE Project (the Project) include:

- One combined-cycle power train consisting of two state-of-the-art natural gas-fueled advanced class combustion turbines (CTs), two heat recovery steam generators (HRSGs) with duct burners, and one steam turbine (ST) in a 2 x 2 x 1 arrangement. The two CT/HRSG trains are referred to as MSCE Units 1 & 2.
- One diesel fuel-fired firewater pump
- One diesel fuel-fired emergency generator
- Wet mechanical draft cooling tower
- Two fuel gas pre-heaters
- Aqueous ammonia tanks for the selective catalytic reduction (SCR) pollution control system.

No auxiliary boiler is planned for the Project. Any start-up steam requirement will be supplied by the existing Longview Power Plant auxiliary boiler.

The proposed Project will be subject to West Virginia Department of Environmental Protection (WVDEP), Division of Air Quality (DAQ) regulations 45CSR13 and 45CSR14 (known as Part 13 and 14 regulations) and Federal Prevention of Significant Deterioration (PSD). This document is the air quality permit application package.

1.1 APPLICATION ORGANIZATION

This application package contains all of the information required for a complete plan approval application for the proposed Project. Included in the application are detailed specifications and operating conditions for the combustion turbines (CTs), heat recovery steam generators (HRSGs) with duct burners, fuel gas heaters, mechanical draft cooling tower, fire water pump and emergency generator along with the expected maximum pollutant emission rates from each emission unit. The permit application is organized into the following sections:

- Section 2 provides a description of the proposed Project.
- Section 3 provides an emissions inventory for the proposed emissions units. Included in the emissions inventory are the maximum short-term and annual emissions from the proposed emissions units. Additional documentation is provided in Appendix B.
- Section 4 summarizes all of the potentially applicable Federal and West Virginia air quality regulations.
- Section 5 contains a Best Available Control Technology (BACT) analysis as required by the applicable federal and state regulations for the construction of a major new stationary source.
- Section 6 contains a description of the air quality modeling approach.
- Section 7 contains a summary of expected air quality impacts analysis for the proposed Project.
- Section 8 contains a list of the references used in this document.

The permit application includes supporting documentation which is presented in the following appendices:

- Appendix A contains the applicable WV DAQ application forms.
- Appendix B describes the methods used to estimate emissions and contains supporting calculations for the emission rates from the proposed emissions units.
- Appendix C provides vendor information for the proposed emissions units and emissions control devices.
- Appendix D provides the results of the RACT/BACT/LAER Clearinghouse (RBLC) review.
- Appendix E provides backup information and modeling output data from the air quality modeling analysis.
- Appendix F provides Concentration Contour Plots Application Summary

The proposed MSCE Project will meet all applicable Federal and West Virginia air quality regulations. The proposed project will be subject to the following federal air quality regulations

- PSD Regulations, including 40 CFR Part 51 and applicable subparts

- New Source Performance Standards (NSPS) Regulations, including 40 CFR Part 60, Subpart Db (Steam Generating Units), Subpart KKKK (Combustion Turbines), Subpart IIII (Ignition Internal Combustion Engines), and Subpart TTTT (GHG from Electric Generating Units)
- National Emission Standards for Hazardous Air Pollutants (NESHAP), including 40 CFR Part 63 regulations if any single hazardous air pollutant (HAP) is emitted from the facility at a rate greater than 10 tpy or any combination of HAPs is greater than 25 tpy (Part 63, Subpart ZZZZ, Stationary Reciprocating Internal Combustion Engines).
- Title V Operating Permit Program, including Part 70 regulations

The proposed Project will also be subject to Prevention of Significant Deterioration (PSD) regulations (administered in WV under 45CSR14) for the following attainment pollutants: Carbon Monoxide (CO), Oxides of Nitrogen (NO_x), Particulate Matter less than 2.5 microns ($PM_{2.5}$), Particulate Matter less than 10 microns (PM_{10}), Particulate Matter (PM), Volatile Organic Compounds (VOCs), Sulfuric Acid Mist (H_2SO_4) and Greenhouse Gasses (GHGs). These air pollutants require the application of BACT requirements. Potential emissions of Sulfur Dioxide (SO_2), and Lead (Pb) are below the "major source" threshold and, therefore, the application will also be concurrently reviewed under the WV minor source program administered under 45CSR13.

The proposed BACT pollution control and emission rates for the Project for criteria pollutants are presented in Table 1-1. Based on the proposed BACT emission rates, the maximum facility-wide air emission inventory is shown

Table 1-2. As shown in this table PM/$PM_{10,}$/$PM_{2.5,}$ NO_x, CO, H_2SO_4 and GHG are all above the PSD major threshold levels.

Table 1-1
Summary of BACT Emission Levels and Control Technology

Emission Unit	Pollutant	Emission Limit	BACT
Combustion Turbines/ HRSG Duct Burners	NO_x	2.0 ppmvd	Dry Low NO_x Burners with SCR
	VOC	1.0 ppmvd w/o duct firing 2.0 ppmvd w/ duct firing	Oxidation catalyst and good combustion practice
	PM/PM10/PM2.5	0.0091 lb/MMBtu	Clean fuels and good combustion practice
	CO	2.0 ppmvd	Oxidation catalyst and good combustion practice
	H_2SO4	0.001 lb/MMBtu	Combustion of low sulfur fuel
Emergency Generator/ Fire Water Pump	NO_x	4.8 g/hp-hr/3.0 g/hp-hr	Combustion control (Retarded Timing and/or lean burn)
	VOC	1.2 lb/hr/1.0 lb/hr	Good combustion practice
	PM/PM10/PM2.5	NA	Clean fuels and good combustion practices
	CO	0.3 g/hp-hr/ 0.44 g/hp-hr	Good combustion practices
	H_2SO4	NA	Combustion of low sulfur fuel
Fuel Gas Pre Heaters	NO_x	0.036 lb/MMBtu	Low NO_x Burner and good combustion practices
	VOC	0.007 lb/MMBtu	Good combustion practice
	PM/PM10/PM2.5	0.008 lb/MMBtu	HEPA Filter
	CO	0.039 lb/MMBtu	Good combustion practice
	H_2SO4	0.0001 lb/MMBtu	Combustion of low sulfur fuel
Cooling Tower	$PM/PM_{10}/PM_{2.5}$	2.16 lb/hr	Drift Eliminators
Facility Wide Limit	GHG	5,135,347 tons/yr, on a CO_2 basis	Thermal efficiency/combustion air cooling and use of lower carbon fuels.

Table 1-2
Summary of Facility Wide Maximum Emissions for the Mt. State Clean Energy Project

Pollutant	Annual Emissions (tons/year)	PSD Significance Level (tons/year)	PSD Pollutant
NO_x	321	40	Yes
CO	276	100	Yes
VOCs	141	40	Yes
$PM/PM_{10}/PM_{2.5}$	210	25/15/10	Yes
SO_2	39.9	40	No
H_2SO_4	35.8	7	Yes
Ozone Precursor (NO_x)	321	40	Yes
Ozone Precursor (VOC)	141	40	Yes
$PM_{2.5}$ Precursor Pollutant (NO_x)	321	40	Yes
$PM_{2.5}$ Precursor Pollutant (SO_2)	39.9	40	No
Lead	0.0011	0.6	No
Fluorides	0	1	No
Vinyl Chloride	0	1	No
Total Reduced Sulfur	0	10	No
Sulfur Compounds	0	10	No
GHG (CO_2e)	5,135,347	100,000	Yes
Hazardous Air Pollutants (HAPS)	8.19 23.3	10 single 25 multiple	No No

2. PROJECT DESCRIPTION

2.1 FACILITY LOCATION

The proposed Project will be constructed on property located adjacent to the existing Longview Power site in Maidsville, Monongalia County, West Virginia. The site is situated approximately 2,500 feet south of the Pennsylvania border, 3,000 feet west of the Monongahela River, and one mile north of Morgantown, West Virginia. The location of the proposed Project site is shown in Figure 2-1.

The geographic coordinates for the approximate center of the proposed project site are:

- Latitude: 39.7124 and Longitude: -79.9608
- UTM Easting: 589,077.73 and Northing: 4,396353.40
- UTM Zone: 17 (UTM = Universal Traverse Mercator)

The area in which the Project will be located is in attainment of all of the National Ambient Air Quality Standards (NAAQS).

Dominant land features of the Project area are the Monongahela River and the rapid increase in elevation away from the river. The river elevation is approximately 820 ft. above mean sea level (amsl) (250 m amsl). Terrain of approximately 1,100 ft. amsl occurs within 700 feet (210 m) of the river. Moving further away from the river isolated terrain peaks of 1,300 ft. amsl (400 m amsl) occur within 5,000 ft. (1.5 km) of the Monongahela River. The highest terrain within 15 km of the Project site is 2,464 ft. amsl (751 m amsl).

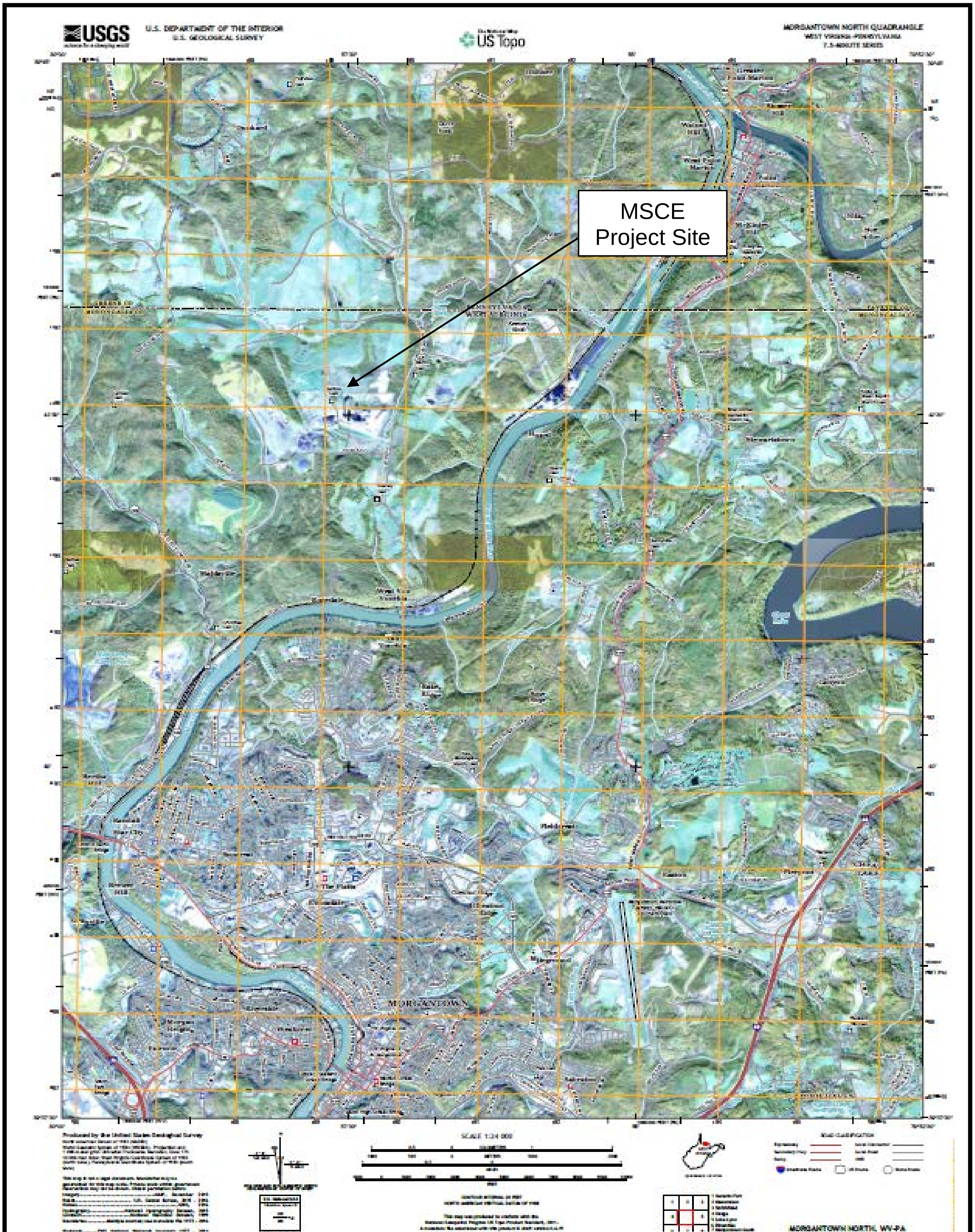

Figure 2-1
Location of Proposed MSCE Project

2.2 DESCRIPTION OF PROPOSED FACILITY

The Project is proposed to be a nominally rated 1,200 MW natural gas-fired only (no oil backup), combined-cycle power plant located immediately adjacent to the north of the existing Longview Power Plant. The Project will be designed to achieve peak electrical outputs during the summer season of approximately 1,200 MW without duct firing and approximately 1,300 MW with duct firing. Electricity generated by the Project will be supplied to the PJM power grid and connect to the grid via the existing interconnection used by the Longview Power Plant.

The major components of the proposed power plant include: one combined-cycle power train consisting of two combustion turbines, two heat recovery steam generators (HRSG) with duct burners, and one steam turbine; one diesel fuel-fired firewater pump; one diesel fired emergency generator; two fuel gas heaters; and one mechanical draft cooling tower.

To enhance the plant's overall efficiency and increase the amount of electricity generated by the Project, the hot exhaust gases from each combustion turbine will be routed to a downstream heat recovery steam generator. Each HRSG contains a series of heat exchangers designed to recover the heat from the combustion turbine's exhaust gas to produce steam. The Project includes the installation of duct burners to produce additional steam in the HRSGs for additional power output from the steam turbine generator. The duct burners will only fire natural gas. No oil backup is planned for the Project.

Exhaust gas passing through the HRSGs will be routed through the oxidation catalyst and Selective Catalytic Reduction (SCR) control systems used to control NO_x, CO and VOC emissions. The oxidation catalyst control system is used to enhance the oxidation of CO and VOCs to CO_2 without the addition of any chemical reagents. SCR involves the injection of aqueous ammonia (NH_3) at a concentration of approximately 19% by weight into the combustion turbine exhaust gas streams. Ammonia reacts with NO_x in the exhaust gas stream in the presence of a catalyst, reducing it to elemental nitrogen (N_2) and water vapor (H_2O). The aqueous ammonia will be stored on-site in dual 60,000 gallon (approximate) storage tanks.

Steam generated in the HRSGs will be routed to a steam driven turbine that will increase the output of the electric generator. This generator will produce additional electricity that will be sold on the grid. Electricity generated by the combustion turbines and the single steam driven turbine driving the electric generator represents the Project's total electrical output.

The Project will use a condenser and a 14 cell wet mechanical draft cooling tower for steam turbine generator steam condensation and waste heat rejection.

Figure 2-2 provides a General Arrangement Drawing and Figure 2-3 presents a plot plan of the plant. More detailed descriptions of the Project components are in the following subsections.

2.2.1 Combustion Turbines

The combustion turbines (CT) produce shaft power to drive an electric generator. Natural gas and combustion air are combusted producing a high velocity discharge which rotates a turbine shaft. Exhaust gases exiting the combustion turbine are routed to a HRSG to recover heat and generate steam. Combustion turbines proposed for the Project are the General Electric (GE) 7HA.02 or equivalent (i.e., Mitsubishi Hitachi Power System J-series), each with a nominal electric generation capacity of approximately 400 MW and a maximum design heat input capacity of approximately 3,990 MMBtu/hr. [Higher Heating Value (HHV)] at winter ambient temperatures of 12.9 °F. The combustion turbines will be fired with natural gas only and will be equipped with Dry Low NO_x burners.

2.2.2 Heat Recovery Steam Generators

Exhaust gas from the combustion turbine is routed to the HRSG through insulated ductwork, where it passes through the water and steam HRSG heat exchanging sections. The gas is then discharged to the atmosphere through the integral HRSG exhaust stack with a silencer. Heat is transferred by primary convection from the hot CT exhaust gas to the feed water and steam systems. The feed water and steam will flow inside the vertically oriented finned tubes, and the gas flow will be directed horizontally across the tube rows.

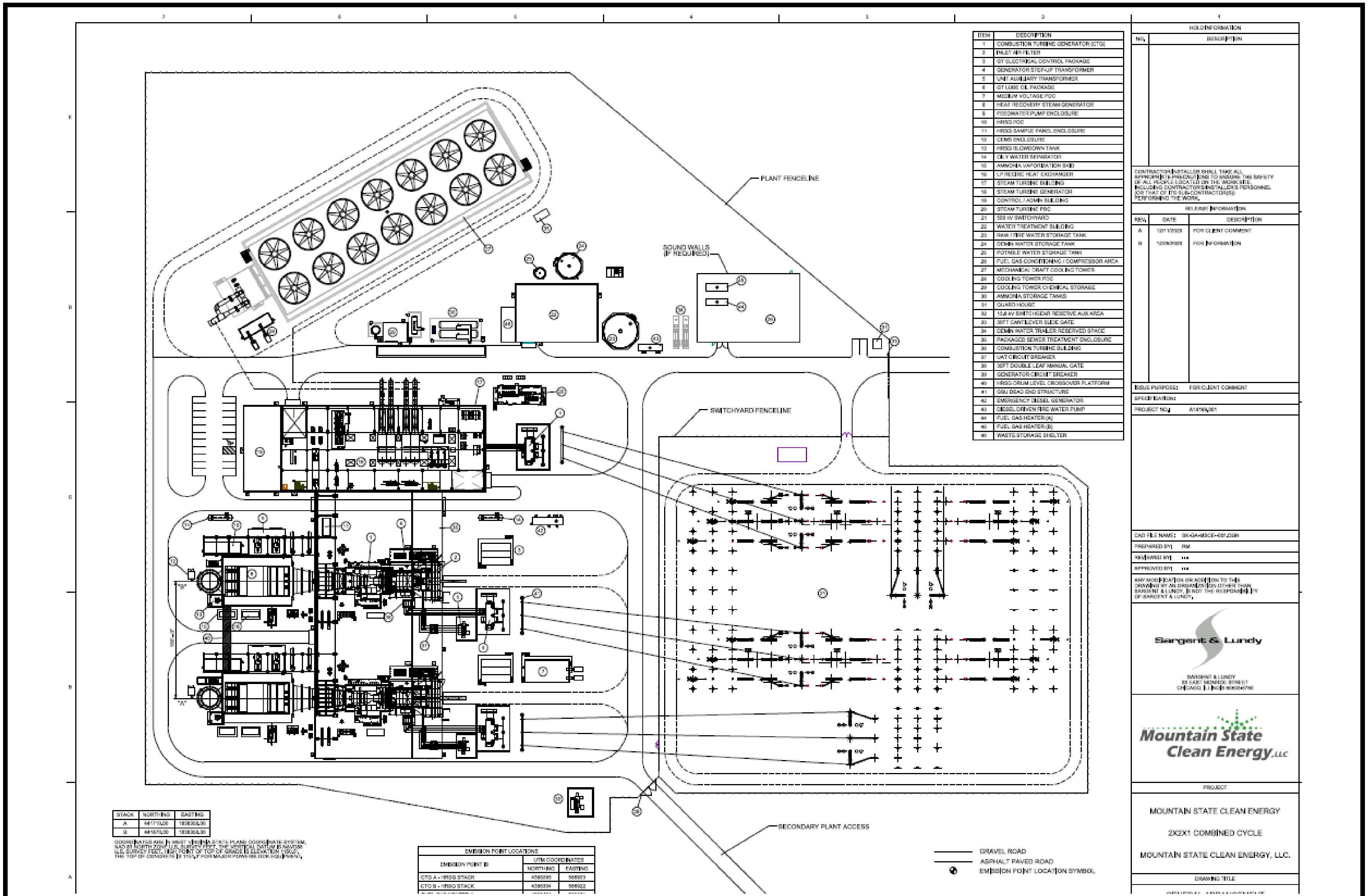

Figure 2-1
General Arrangement Drawing

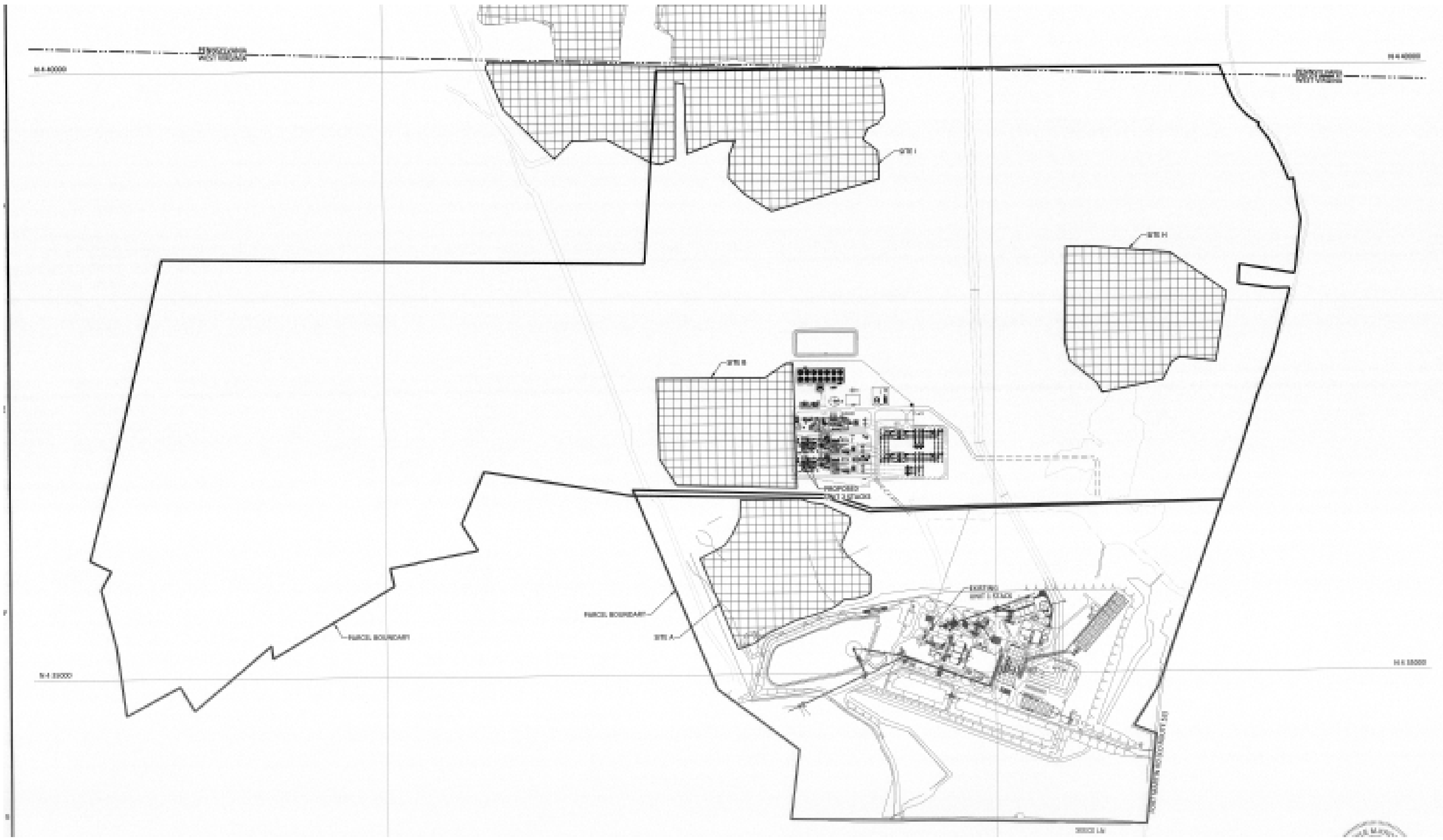

Figure 2-3
Plot Plan

For maximum flexibility, the bottoming cycle portion of a combined cycle is "oversized" to allow for higher output of the steam turbine (ST) than what could otherwise be achieved using the exhaust energy produced by the CT alone. Exhaust gases leaving the CT contain enough oxygen to support additional combustion of fuels. Additional heat is added to the bottoming cycle using Low NOx duct burners with a maximum rated heat capacity of approximately 590 MMBtu/hr-HHV per HRSG. This additional heat produces additional steam, which is passed through the ST flow path for additional electrical output (approximately 60 MW). The supplemental HRSG duct firing system consists of the duct burners, duct burner management system, duct burner fuel metering and regulation skid, and fuel supply.

Each HRSG will be equipped with an SCR system to limit NO_x emissions, and an oxidation catalyst control system to limit CO and VOC emissions. The duct burners will not operate independently of the combustion turbine.

No auxiliary boiler will be constructed for the Project. Instead, via an interconnect with the existing Longview Power Plant, steam will be provided via the existing Longview Unit 1 Auxiliary Boiler and also allow for bi-directional steam flow between Longview Unit 1 and MSCE Units 1 & 2.

2.2.3 Steam Turbine/Generator

The steam turbine/generator will utilize steam developed in the HRSGs to generate electricity. The steam turbine generator will receive steam from the HRSGs and will discharge the low-pressure exhaust steam to the condenser. The steam turbine generator will be designed to achieve a maximum rating of approximately 430 MW.

2.2.4 Mechanical Draft Cooling Tower

The ST exhausts directly into the condenser, where the steam is condensed by the circulating water passing through the condenser tubes. Condensate formed in the condenser is collected in the hot well. Recoverable steam and condensate from cycle drains and other reclaimable steam are also routed to the condenser hot well. The steam surface condenser relies on the circulating water system to provide cooling water for heat exchange. The circulating water system rejects the waste heat to atmosphere via a wet mechanical draft cooling tower by sensible heat transfer (increasing the temperature of the air passing across the tower) and latent heat transfer (evaporating a portion of the circulating water into the air passing across the tower). The cooling tower is designed to reject heat returned from the steam surface condenser and the plant auxiliary cooling water system. The cooled circulating water is collected in the cooling tower basin, and pumped back to the condenser water boxes, repeating the process. A circulating water chemical feed system will be included.

During the cooling process, small water droplets, known as cooling tower drift, escape to the atmosphere through the cooling tower exhaust. To minimize this effect, the cooling tower will be equipped with drift eliminators. Drift eliminators provide multiple directional changes of airflow which helps prevent the escape of water droplets and reduce particulate matter emissions from the cooling tower.

2.2.5 Diesel fired firewater pump

A 240 hp output (179 kW) standby firewater pump will be used to supply water during emergency conditions. The fire water pump will use ultra-low sulfur diesel (ULSD) fuel, with a sulfur content no greater than 0.0015% by weight. The fire water pump will also be periodically operated for short periods per manufacturer's maintenance instructions to ensure operational readiness in the event of an emergency. The fire water pump is expected to operate less than 100 hours per year.

2.2.6 Diesel fired emergency generator

An emergency generator (2,000 kW) will be used for emergency backup electric power. The fuel for the emergency generator will be ULSD with a sulfur content no greater than 0.0015% by weight. The emergency generator will be periodically operated for short periods per manufacturer's maintenance instructions to ensure operational readiness in the event of an emergency. The emergency generator is expected to operate less than 100 hours per year.

2.2.7 Fuel Gas Heaters

Two (2) fuel gas heaters (7 MMBtu/hr, approximate) will be used to preheat the pipeline natural gas received by the plant. Preheating the fuel prior to combustion in the CTs increases their efficiency, safeguards the fuel pipelines from icing, and protects the CTs from fuel condensates.

The fuel supply for the Project will be provided via a 6.2 mile 20" pipeline interconnecting onto both the Columbia 1804 and 10240 interstate pipelines located near Greensboro, PA. At this interconnection, there will be a metering station allowing connection with the dual supply lines that are integral to the Columbia pipeline. Electric gas compression equipment will be added to this line and will have those facilities located on the Unit 2 site.

2.2.8 Pipeline Gas Compressors

The Project will own and operate two pipeline gas compressor units. The compressors are electric-drive, 2,750 HP (Toshiba J2758, or equivalent) with a 4-throw reciprocating fluid end (Ariel JGC/4, or equivalent). The manufacturer states that there are no GHG/VOC emissions associated with the operation of the units. Additionally, the manufacturer states that there will be no GHG/VOC emissions associated with the startup and shutdown of compressor units during normal operation; since no purge will be necessary.

2.3 OPERATING SCENARIOS

The typical range of operating scenarios for the Project is shown in Table 2-1 and includes three load conditions (50%, 75%, and 100%) with the duct burner and/or evaporative cooler either operating or not operating and various start-up and shut-down conditions. Each of the operating scenarios has unique exhaust gas conditions and pollutant emission rates. The typical operating scenario is for the combustion turbine to operate at or near 100% of the design capacity and highest short-term (hourly) emission rates are generally associated with winter day, 100% load, with duct firing.

Start-up conditions for the combustion turbines represent periods from initial firing until the system reaches minimum emissions compliant load (MECL).

Start-up modes include:

- cold starts (restarts made more than 72 hours of shutdown).
- warm starts (between 8 and 72 hours of shutdown).
- hot starts (less than 8 hours of shutdown).

Shutdown conditions represent periods where system output is lowered below emissions compliant load conditions until the cessation of fuel firing. Shutdown commences when the

Table 2-1
Summary of Potential Operating Scenarios for Selected Design Conditions

Case Number	Case Description	CT Load	Ambient Dry Bulb Temp, Relative Humidity: M501JAC CC	Ambient Dry Bulb Temp, Relative Humidity: GE 7HA.03 CC	Evaporative Coolers	Duct Burners
2 x 1 Configuration						
1	Winter, 100% Load	100%	12.9 / 71.8	12.9 / 75	Off	Off
2	Winter, 100% Load,	100%	12.9 / 71.8	12.9 / 75	Off	On
3	Winter, 75% Load	75%	12.9 / 71.8	12.9 / 75	Off	Off
4	Winter, 50% Load	50%	12.9 / 71.8	12.9 / 75	Off	Off
5	Winter, MECL	MECL	12.9 / 71.8	12.9 / 75	Off	Off
6	Average, 100% Load	100%	53.7 / 69.6	53.7 / 69	Off	Off
7	Average, 100% Load	100%	53.7 / 69.6	53.7 / 69	Off	On
8	Average, 75% Load	75%	53.7 / 69.6	53.7 / 69	Off	Off
9	Average, 50% Load	50%	53.7 / 69.6	53.7 / 69	Off	Off
10	Average, MECL	MECL	53.7 / 69.6	53.7 / 69	Off	Off
11	Summer, 100% Load	100%	87.0 / 46.4	87.0 / 46.5	On	Off
12	Summer, 100% Load	100%	87.0 / 46.4	87.0 / 46.5	On	On
13	Summer, 100% Load	100%	87.0 / 46.4	87.0 / 46.5	Off	Off
14	Summer, 100% Load	100%	87.0 / 46.4	87.0 / 46.5	Off	On
15	Summer, 75% Load	75%	87.0 / 46.4	87.0 / 46.5	Off	Off
16	Summer, 50% Load	50%	87.0 / 46.4	87.0 / 46.5	Off	Off
17	Summer, MECL	MECL	87.0 / 46.4	87.0 / 46.5	Off	Off
1 x 1 Configuration						
18	Winter, 100% Load	100%	12.9 / 71.8	12.9 / 75	Off	Off
19	Winter, 100% Load	100%	12.9 / 71.8	12.9 / 75	Off	On
20	Winter, 75% Load	75%	12.9 / 71.8	12.9 / 75	Off	Off
21	Winter, 50% Load	50%	12.9 / 71.8	12.9 / 75	Off	Off
22	Winter, MECL	MECL	12.9 / 71.8	12.9 / 75	Off	Off
23	Average, 100% Load	100%	53.7 / 69.6	53.7 / 69	Off	Off
24	Average, 100% Load	100%	53.7 / 69.6	53.7 / 69	Off	On
25	Average, 75% Load	75%	53.7 / 69.6	53.7 / 69	Off	Off
26	Average, 50% Load	50%	53.7 / 69.6	53.7 / 69	Off	Off
27	Average, MECL	MECL	53.7 / 69.6	53.7 / 69	Off	Off
28	Summer, 100% Load	100%	87.0 / 46.4	87.0 / 46.5	On	Off
29	Summer, 100% Load	100%	87.0 / 46.4	87.0 / 46.5	On	On
30	Summer, 100% Load	100%	87.0 / 46.4	87.0 / 46.5	Off	Off
31	Summer, 100% Load	100%	87.0 / 46.4	87.0 / 46.5	Off	On
32	Summer, 75% Load	75%	87.0 / 46.4	87.0 / 46.5	Off	Off
33	Summer, 50% Load	50%	87.0 / 46.4	87.0 / 46.5	Off	Off
34	Summer, MECL	MECL	87.0 / 46.4	87.0 / 46.5	Off	Off

Note 1. The Duct Firing cases will be designed to provide an increase output of approximately 15% over the corresponding STG unfired output case.
Note 2. CTG = Combustion Turbine Generator; MECL – Minimum Emissions Compliant Load

turbine loads reach less than approximately 50% load with the intent to stop operations. The proposed emission limits for the combustion turbines should not apply during periods of start-up (cold, warm or hot) and shutdown. The annual emissions for the entire facility, which are discussed in Section 3, include 234 start-ups (187 hot startups, 36 warm startups, and 11 cold startups) and 234 shut-down.

The MSCE CCGT plant is a merchant plant designed to operate continuously, with very limited periods of startups and shutdowns.

3. EMISSION INVENTORY AND PSD/NSR APPLICABILITY DETERMINATION

3.1 PROPOSED PROJECT EMISSION RATES

The emission units associated with the proposed Project include the combustion turbines, HRSG duct burners, emergency generator, fire pump and fuel gas heaters. All units will be natural gas-fired except the fire water pump and emergency generator, which are diesel fuel fired. The following subsections provide brief summaries of the pertinent emissions data for each emission unit.

3.1.1 Combustion Turbines

3.1.1.1 Normal Operating Condition

Combustion turbines proposed for the Project are General Electric Frame GE 7HA.02 gas turbine or equivalent (i.e., Mitsubishi Hitachi Power System J-Series) with supplemental HRSG duct firing and inlet air-cooling. The combustion turbines will combust natural gas only. The combustion turbines will have a rated heat input of 3,875 MMBtu/hr (approximate) while operating at an average ambient temperature of 53.7 °F. The heat input capacity of the combustion turbines increases at lower ambient temperatures and decreases at higher ambient temperatures.

Each combustion turbine will be equipped with dry low NO_x combustor technology to minimize the formation of NO_x. Pollutant emission rates from the combustion turbines are based on performance data provided by the equipment manufacturers (e.g., General Electric and MHPS). Maximum projected emission rates are equal to the highest emission rate over a range of operating conditions (load and ambient air temperature). The temperature and load conditions analyzed are 50%, 75% and 100% load and 99% winter minimum, annual average and 1% summer maximum design temperatures of 12.9, 53.7 and 87 ºF, respectively.

A summary of the hourly mass emissions (i.e., lb/hr) for each operating condition of the combustion turbine/duct burner is provided in Table 3-1.

Table 3-1
Potential Maximum Hourly Emission Rate
from one Combustion Turbine/HRSG Set

Case Number	Case Description	CT Load	Ambient Dry Bulb Temp, Relative Humidity		Evaporative Coolers	Duct Burners	NOx	CO	VOC	PM	SO2
			M501JAC	GE7HA.03							
2x1 Configuration											
1	Winter, 100% Load, Duct Burners OFF	100%	12.9 / 71.8	12.9 / 75	Off	Off	30.3	18.5	5.3	17.8	5.4
2	Winter, 100% Load, Duct Burners ON	100%	12.9 / 71.8	12.9 / 75	Off	On	31.6	19.2	11.0	22.0	5.6
3	Winter, 75% Load	75%	12.9 / 71.8	12.9 / 75	Off	Off	24.5	14.9	4.3	17.0	4.3
4	Winter, 50% Load	50%	12.9 / 71.8	12.9 / 75	Off	Off	18.7	11.4	3.3	16.2	3.3
5	Winter, MECL	MECL	12.9 / 71.8	12.9 / 75	Off	Off	16.3	9.9	2.8	15.8	2.8
6	Average, 100% Load, Duct Burners OFF	100%	53.7 / 69.6	53.7 / 69	Off	Off	29.5	17.9	5.1	17.7	5.2
7	**Average, 100% Load, Duct Burners ON**	**100%**	**53.7 / 69.6**	**53.7 / 69**	**Off**	**On**	**31.7**	**19.3**	**11.0**	**23.1**	**5.6**
8	Average, 75% Load	75%	53.7 / 69.6	53.7 / 69	Off	Off	23.3	14.2	4.1	16.9	4.1
9	Average, 50% Load	50%	53.7 / 69.6	53.7 / 69	Off	Off	17.8	10.8	3.1	16.1	3.1
10	Average, MECL	MECL	53.7 / 69.6	53.7 / 69	Off	Off	15.6	9.5	2.7	15.5	2.4
11	Summer, 100% Load, Evap ON, Duct Burners OFF	100%	87.0 / 46.4	87.0 / 46.5	On	Off	28.5	17.4	5.0	17.6	5.1
12	Summer, 100% Load, Evap ON, Duct Burners ON	100%	87.0 / 46.4	87.0 / 46.5	On	On	32.1	19.5	11.2	25.0	5.7
13	Summer, 100% Load, Evap OFF, Duct Burners OFF	100%	87.0 / 46.4	87.0 / 46.5	Off	Off	27.0	16.5	4.7	17.4	4.8
14	Summer, 100% Load, Evap OFF, Duct Burners ON	100%	87.0 / 46.4	87.0 / 46.5	Off	On	31.4	19.1	10.9	25.3	5.4
15	Summer, 75% Load	75%	87.0 / 46.4	87.0 / 46.5	Off	Off	21.5	13.1	3.8	16.7	3.8
16	Summer, 50% Load	50%	87.0 / 46.4	87.0 / 46.5	Off	Off	16.5	10.0	2.9	16.0	2.9
17	Summer, MECL	MECL	87.0 / 46.4	87.0 / 46.5	Off	Off	15.7	9.6	2.7	15.6	2.5

Potential Maximum Hourly Emission Rate from one Combustion Turbine/HRSG Set (Con't)

Case Number	Case Description	CT Load	Ambient Dry Bulb Temp, Relative Humidity		Evaporative Coolers	Duct Burners	NOx	CO	VOC	PM	SO2
			M501JAC	GE7HA.03							
1 x 1 Configuration											
18	**Winter, 100% Load, Duct Burners OFF**	100%	12.9 / 71.8	12.9 / 75	Off	Off	30.4	18.5	5.3	17.8	5.4
19	Winter, 100% Load, Duct Burners ON	100%	12.9 / 71.8	12.9 / 75	Off	On	34.1	20.8	11.9	23.4	6.0
20	Winter, 75% Load	75%	12.9 / 71.8	12.9 / 75	Off	Off	24.5	14.9	4.3	17.0	4.3
21	Winter, 50% Load	50%	12.9 / 71.8	12.9 / 75	Off	Off	18.7	11.4	3.3	16.2	3.3
22	Winter, MECL	MECL	12.9 / 71.8	12.9 / 75	Off	Off	16.3	9.9	2.8	15.8	2.8
23	Average, 100% Load, Duct Burners OFF	100%	53.7 / 69.6	53.7 / 69	Off	Off	29.5	18.0	5.1	17.7	5.2
24	**Average, 100% Load, Duct Burners ON**	**100%**	**53.7 / 69.6**	**53.7 / 69**	**Off**	**On**	**33.2**	**20.2**	**11.6**	**23.1**	**5.9**
25	Average, 75% Load	75%	53.7 / 69.6	53.7 / 69	Off	Off	23.4	14.2	4.1	16.9	4.1
26	Average, 50% Load	50%	53.7 / 69.6	53.7 / 69	Off	Off	17.8	10.8	3.1	16.1	3.1
27	Average, MECL	MECL	53.7 / 69.6	53.7 / 69	Off	Off	15.5	9.4	2.7	15.5	2.4
28	Summer, 100% Load, Evap ON, Duct Burners OFF	100%	87.0 / 46.4	87.0 / 46.5	On	Off	28.6	17.4	5.0	17.6	5.1
29	Summer, 100% Load, Evap ON, Duct Burners ON	100%	87.0 / 46.4	87.0 / 46.5	On	On	32.3	19.7	11.3	25.0	5.7
30	Summer, 100% Load, Evap OFF, Duct Burners OFF	100%	87.0 / 46.4	87.0 / 46.5	Off	Off	27.1	16.5	4.7	17.4	4.8
31	Summer, 100% Load, Evap OFF, Duct Burners ON	100%	87.0 / 46.4	87.0 / 46.5	Off	On	31.4	19.1	10.9	25.3	5.4
32	Summer, 75% Load	75%	87.0 / 46.4	87.0 / 46.5	Off	Off	21.5	13.1	3.8	16.6	3.8
33	Summer, 50% Load	50%	87.0 / 46.4	87.0 / 46.5	Off	Off	16.5	10.0	2.9	15.9	2.9
34	Summer, MECL	MECL	87.0 / 46.4	87.0 / 46.5	Off	Off	15.7	9.6	2.7	15.4	2.5

3.1.1.2 Start-Up and Shutdown Conditions

Emissions during start-up and shutdowns of the combustion turbines were estimated for the air permit application using vendor supplied information and the expected number of cold, warm and hot start-ups expected to occur each year. A summary of the maximum hourly (lb/hr) and annual emission rates (assuming natural gas firing) for startup and shutdown conditions are provided in Table 3-2. The number of startups and shutdowns presented in Table 3-2 are the maximum expected annual number of startups/shutdowns, and the actual numbers of startups/shutdowns are expected to be significantly less since the Project is designed as a merchant power plant.

3.1.2 Heat Recovery Steam Generator Duct Burners

The HRSG duct burners will have a design heat input capacity of 590 MMBtu/hr (HHV) (approximate) and will combust natural gas. The HRSGs will primarily operate in the recovery or "unfired" mode (i.e., no duct burner) utilizing heat from the combustion turbine exhaust gases to generate steam. The HRSGs and duct burners cannot operate independently from the combustion turbines. Exhaust gases from the combustion turbines and duct burners will be discharged to the atmosphere downstream of the HRSG through a 180-ft. stack (i.e., 1 exhaust stack per CT/HRSG).

The duct burners will be designed with "low-NO_x" burners in order to control NO_x emissions. Emissions associated with the duct burners will be controlled with post-combustion emission controls (i.e., oxidation catalyst and SCR) and are included in the full load emission estimates provided in Table 3-1. Annual emissions from the CT/HRSGs are based on 8,618 hours per year per CT of normal operation at full load and average ambient conditions, and 142 hours per CT of startup/shutdown for the balance of the year (see, Table 3-2).

A summary of the maximum hourly emission rates for each potential operating condition of the combustion turbines with and without duct burners (assuming natural gas firing) is provided in Table 3-1.

Table 3-2
Potential Maximum Annual Emissions
from the Start-Up and Shut-Down Conditions[a]

Pollutant		Hot Start	Warm Start	Cold Start	Shutdown[d]	Annual tpy
NO_x	lb/event	137.5	242.0	319.0	113.3	
	lb/hr (max)	275.0	242.0	273.4	453.2	
	tons/year	12.9	4.36	1.75	13.2	32.2
CO	lb/event	583.0	726.0	1,782	198.0	
	lb/hr (max)	1,166	748.0[b]	1,527	792.0	
	tons/year	54.5	13.1	9.8	23.2	100.5
VOC	lb/event	148.5	154.0	572.0	182.6	
	lb/hr (max)	297.0	218.7[d]	490.3	730.4	
	tons/year	13.9	2.77	3.15	21.4	41.2
Total PM	lb/event	11.0	23.1	27.5	5.5	
	lb/hr (max)	22.0	23.1	23.6	22.0	
	tons/year	1.03	0.416	0.151	0.644	2.24
Duration	minutes	30	60	70	15	
No of events per year	No. per year	187	36	11	234	
Annual	Hours per year	94	36	13	55	

[a] 2 x 1 GE 7HA.03 Combined Cycle Emissions. One power train will be in startup/shutdown mode at a time. The two power trains are expected to start-up/shut-down sequentially

[b] 2 x 1 M501JAC Mitsubishi Hitachi Power System.

3.1.3 Other Combustion/Process Sources

Other minor combustion and/or process emission sources associated with the Project include:

- One (1) Firewater pump
- One (1) Emergency generator
- Two (2) Fuel gas heater
- Mechanical Draft Cooling Tower

The fire water pump and emergency generator will be ULSD fuel fired. The fire water pump has a rating of 240 HP and the emergency generator is rated at 2,500 kW. The fire water pumps and emergency generators will be limited to 100 hrs/year of operation, respectively.

Estimated emissions for the fire water pump, emergency generator, and fuel gas heater are presented in Table 3-3.

3.1.4 Facility Wide Maximum Potential Annual Emission Rates

A summary of the potential annual emissions for the entire Project (combustion turbines/duct burners, startup/shutdown and engines/pumps) is provided in Table 3-4. Potential annual emissions presented are for two CTs and Operating Case No. 24 in Table 3-1 for 8,563 hours/year (which is an average day, 100% CTG load, duct firing, and evaporation on) and 197 hours of startup/shut events.

3.2 HAZARDOUS AIR POLLUTANT EMISSIONS

A summary of the potential annual hazardous air pollutant (HAP) emissions from the combustion turbines and duct burners is provided in Table 3-5. Emissions for all HAPs, except formaldehyde and hexane, represent uncontrolled emissions (i.e., assuming no control in the oxidation catalyst or SCR) and were calculated using emission factors contained in AP-42 Section 3.1 for Stationary Gas Turbines (April, 2000).

Emissions for formaldehyde and hexane were developed using USEPA AP-42 emission factors for hazardous air pollutants from natural gas-fired stationary gas turbines and duct burners (Table 3.1-3, April, 2000 and Tables 1.4-2,3,4, respectively) and assuming 70% removal for formaldehyde and 30% removal for hexane by the catalytic oxidation system. These removal rates are based on information provided by the vendor of the catalytic oxidation system. These

Table 3-3
Potential Maximum Hourly and Annual Emissions from the Fire Water Pump, Emergency Generator, Spray Dryer and Mechanical Draft Tower

Pollutant	Fire Water Pump[c]		Emergency Generator		Fuel Gas Heaters (2)		Cooling Tower	
	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tons/year)	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tons/year)	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tons/year)	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tons/year)
NO_x	4.55	0.228	38.7	1.93	0.25	2.21	0.0	0.0
CO	1.27	0.063	3.10	0.155	0.27	2.38	0.0	0.0
VOCs	0.302	0.015	0.74	0.037	0.05	0.43	0.0	0.0
PM/PM_{10} ($PM_{2.5}$)	0.841	0.042	0.273	0.014	0.05	0.48	2.16 (1.08)	9.47 (4.73)
SO_2	0.492	0.025	0.060	0.003	0.01	0.08	0.0	0.0
GHG	418	20.9	2,530	127	920	8,057	0.0	0.0

[c] Fire water pump and emergency generator limited to 100 hrs/yr of operation.

Table 3-4
Facility Wide Maximum Potential Annual Emissions

Pollutant	Combustion Turbine and Duct Burner (tons/year)[1]	Other Sources[2] (tons/year)	Startup and Shut down (tons/year)[3]	Cooling Tower (tons/year)	Total Facility Wide Annual Emissions (tons/year)
NO_x	317	4.37	32.2	0	321
VOCs	274	2.60	100.5	0	276
CO	140	0.48	41.2	0	141
$PM/PM_{10}/PM_{2.5}$	200	0.53	2.24	9.47	210
SO_2	39.8	0.11	0	0	39.9
H_2SO_4	35.8	0.03	0.01	0	35.8
GHG (CO_2)	5,127,142	8,204	58,287	0	5,135,347

1. Calculated assuming 8,563 hours/year per CT (full load / average ambient conditions / duct firing). Operating case No. 24.

2. Includes fire water pump, emergency generator and fuel heaters. Fire water pump and emergency generator limited to 100 hrs/yr of operation.

3. Assumes 197 hours/year of SU/SD (see Table 3-2).

Table 3-5
Annual HAP Emissions[4] (tons/year)

Hazardous Air Pollutant	Combustion Turbine	Duct Burners	Auxiliary Generator	Fire Pump	Total Facility Emissions
1,3-Butadiene	1.43E-02			5.30E-06	1.43E-02
2 Methylnaphthalene		8.81E-05			8.81E-05
Acetaldehyde	1.33E+00			1.04E-04	1.33
Acrolein	2.12E-01			1.25E-05	2.12E-01
Arsenic		8.81E-04			8.81E-04
Benzene	3.98E-01	7.71E-03	8.92E-04	1.27E-04	4.07E-01
Beryllium		4.40E-05			4.40E-05
Cadmium		4.04E-03			4.04E-03
Chromium		5.14E-03			5.14E-03
Cobalt		1.54E-04			1.54E-04
Dichlorobenzene		4.40E-03			4.40E-03
Ethylbenzene	1.06				1.06
Formaldehyde	7.07	1.12	9.07E-05	1.60E-04	8.19
Hexane		4.62			4.62
Manganese		1.39E-03			1.39E-03
Mercury		9.54E-04			9.54E-04
Naphthalene	4.31E-02	2.24E-03	1.50E-04	1.15E-05	4.55E-02
Nickel		7.71E-03			7.71E-03
Phenanathrene		6.24E-05	4.69E-05	3.99E-06	1.13E-04
Propylene Oxide	9.62E-01				9.62E-01
Toluene	4.31	1.25E-02	3.23E-04	5.55E-05	4.33
Xylene	2.12			3.87E-05	2.12
Total HAPS					**23.3**

[4] Combustion turbine HAP emissions per AP-42 (Table 3.1-3) and Duct Burner HAP emissions per AP-42 (Table 1.4-2,3,4) except for formaldehyde, and hexane. Formaldehyde, hexane emissions assume 70 and 30% control efficiency, respectively.

removal efficiencies are consistent with USEPA December 30, 1999 Memorandum "Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines" which stated that the removal efficiencies of a CO catalyst are expected to be similar to that of a $SCONO_x$ catalyst which have been demonstrated through testing to be at least 90% for formaldehyde. Using a removal efficiency of 70% for formaldehyde and 30% for hexane results in a conservatively high estimate of the expected formaldehyde and hexane emissions from the

Project[a]. Additionally, the AP-24 HAP emission factors for natural gas fired combustion turbines are based on combustion turbine data such as jet derivatives or smaller Frame 3 turbines which are significantly different and may not be representative of combustion turbine technology proposed for the Project. HAP emission factors provided by the turbine manufacturers were lower than the AP-42 factors and would result in lower HAP emissions.

As seen from Table 3-5, annual HAP emissions from the proposed Project do not exceed 10 tons per year for any single HAP or 25 tons per year for HAPs in aggregate. Therefore, the proposed facility is not a major source of HAP emissions and will not be subject to Maximum Achievable Control Technology (MACT) (See Section 4 Regulatory Review).

3.3 PSD AND NSR APPLICABILITY DETERMINATION

Potential annual emissions associated with the proposed the Project are used to determine the applicability of PSD and non-attainment New Source Review (NSR) requirements. PSD applicability is determined by comparing potential annual emissions from the Project for each criteria pollutant that is in attainment with the National Ambient Air Quality Standards (NAAQS) to the respective significant emission threshold levels. The proposed Project will be located in

[a] The definition of a "major source" of HAPs in Section 12(a)(1) of the 1990 Clean Air Act Amendments is any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has a potential to emit considering controls, 10 tons per year (tpy) or more of any HAP or 25 tpy or more of any combination of HAPs. Accordingly, "in drafting Section 112 Congress specifically directed EPA to consider

Monongalia County, West Virginia which is designated as "in attainment" or "unclassifiable" for all regulated air pollutants so nonattainment NSR review does not apply.

The proposed Project, as a new standalone stationary emissions source, is classified as major stationary source of emissions pursuant to 40 CFR 52.21(b)(1)(i)(a) (i.e., fossil fuel-fired steam electric generating unit >250 MMBtu/hr with projected annual emissions of at least one criteria pollutant greater than 100 tpy). As a new major stationary emissions source, the Project triggers PSD applicability for each pollutant emitted above the applicable PSD significant levels provided in Table 3-6. As seen from this table, the proposed MSCE CCGT Project is subject to federal PSD requirements for NO_x, VOC, CO, particulates (PM/PM_{10} and $PM_{2.5}$), H_2SO_4, and GHG emissions.

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controls in determining which producers should be classified as "major sources." See also National Mining Ass'n v. EPA, 59 F.3d 1351, 1361-65 (D.C. Cir. 1995).

Table 3-6
Project Comparison of Facility Wide Maximum Emissions to PSD Significance Levels[5]

Pollutant	Annual Emissions (tons per year)	PSD/NSR Significance Level (tons/year)	PSD/NSR Pollutant
NO_x	321	40	Yes
CO	276	100	Yes
VOCs	141	40	Yes
$PM/PM_{10}/PM_{2.5}$	210	25/15/10	Yes
SO_2	39.9	40	No
H_2SO_4	35.8	7	Yes
GHG	5,135,347	100,000	Yes
Lead	0.0011	0.6	No
Beryllium	4.40E-05	0.004	No
Mercury	9.54E-04	0.1	No

[5] The facility is classified as a major stationary source pursuant to 40 CFR 52.2§(b)(1)(i)(a). It is a fossil fuel fired steam generating unit > 250 MMBtu/hr with projected emissions of at least one criteria pollutant > 100 tons/yr.

4. REGULATORY REVIEW

The following section contains an assessment of federal and State of West Virginia air regulations that are potentially applicable to the proposed Project. The Federal regulation are described in Subsection 4.1 and the State of West Virginia regulation are described in Subsection 4.2

4.1 FEDERAL REGULATIONS

For the purpose of this application, the following federal regulations have been reviewed for potential applicability to the Project:

- Standards of Performance for New Stationary Sources(NSPS)
- Prevention of Significant Deterioration (PSD) Regulations
- National Emission Standards for Hazardous Air Pollutants (NESHAP)
- Accidental Release Prevention (RMP)
- Compliance Assurance Monitoring (CAM)

A review of each specific federal requirement is provided in the following subsections.

4.1.1 New Source Performance Standards (NSPS)

The United States Environmental Protection Agency (EPA) has promulgated standards of performance for specific sources of air pollution at 40 CFR Part 60, Subparts A through UUUU. The following Subparts are determined to be applicable to the proposed project:

- Subpart A - General Provisions,
- Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units
- Subpart KKKK - Standards of Performance for Stationary Gas Turbines.
- Subpart TTTT - Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units
- Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

4.1.1.1 Subpart A - General Provisions

Certain provisions of 40 CFR Part 60 Subpart A apply to the owner or operator of any stationary source subject to a NSPS. Since the combustion turbines (Subpart KKKK) and the Heat Recovery Steam Generators (HRSGs) will be subject to a NSPS, the Project will be required to comply with all applicable provisions of Subpart A.

4.1.1.2 Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam

Pursuant to §60.40b(a), the affected facility to which Subpart Db applies is each steam generating unit that is capable of combusting greater than 29 megawatts (100 MMBtu/hour) heat input for which construction, reconstruction or modification is commenced after June 19, 1984. Although the duct burners have a heat input greater than 100 MMBtu/hour, HRSGs and duct burners subject to Subpart KKKK are exempt from the NSPS requirements of Subpart Db.

4.1.1.3 Subpart KKKK - Standard of Performance for Stationary Gas Turbines

Pursuant to §60.4305(a), Subpart KKKK applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005. Therefore, the Project's combustion gas turbines are subject to 40 CFR 60 Subpart KKKK.

Section §60.4320 requires that combustion gas turbines meet the NO_x emission standards in Table 1 of the Subpart. Since the combustion gas turbines at the Project will be new and greater than 850 MMBtu/hr each, Table 1 requires that they meet a NO_x emission limit of 15 ppmvd at 15% oxygen or 0.43 lb/MW-hr gross energy output.

Section §60.4330(a)(1) and (2) requires that the turbines meet an SO_2 standard of either 0.90 lb/MW-hr gross energy output or 0.060 lb/MMBtu heat input.

Subpart KKKK includes general compliance requirements (§60.4333), monitoring requirements reporting requirements (§§60.4375-60.4395), and performance testing requirements (§§60.4400-60.4415).

4.1.1.4 Subpart TTTT: Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

Since the Project consists of a "stationary combustion turbine that commenced construction after January 8, 2014" or commenced "reconstruction" after June 18, 2014 that has a "base load rating greater than 260 GJ/h (250 MMBtu/hr) of fossil fuel (either alone or in combination with any other fuel)" and "serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system" it will be subject to Subpart TTTT. Table 2 of Subpart TTTT limits CO_2 emissions from new stationary combustion turbines to 1,000 pounds of CO_2 per megawatt-hour on a gross energy output basis on a 12-operating month rolling average.

4.1.1.5 Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Subpart IIII contains requirements relating to the performance of compression ignition engines. The Project will use a fire water pump and an emergency generator that are Subject to Subpart IIII. Pursuant to §60.4200, compression ignition engines manufactured after July 11, 2005 are subject to the subpart. Therefore, Subpart IIII will be applicable to the fire water pump engine and the emergency generator at the proposed Project §60.4204 and §60.4205 establish the following standards for the engines (all standards in g/hp-hr):

- Fire Water Pump Engine 3 g/hp-hr NOx, 2.6 g/hp-hr CO, 0.15 g/hp-hr PM
- Emergency Generator 4.8 g/hp-hr NOx, 2.6 g/hp-hr CO and 0.15 g/hp-hr PM.

Since both engines have a displacement of less than 30 liters per cylinder, per §60.4207 (b), they must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

4.1.2 Prevention of Significant Deterioration (PSD)

PSD permitting requirements apply to projects considered a “major modification” or “major” stationary source located in an area designated as “in attainment” or “unclassifiable” for any criteria pollutant. The Project will be located in an area that is designated as “in attainment” or “unclassifiable” for all regulated air pollutants. A “major” stationary source is defined at 40 CFR § 52.21(b)(1)(i) as any source with the potential to emit greater than 250 tons per year of any regulated air pollutant or any stationary source defined as one of the 28 source categories listed in 40 CFR § 52.21(b)(1)(i)(a) with the potential to emit greater than 100 tons per year of any regulated air pollutant. Electric generation facilities are among the 28 listed 100-tons/year source categories. Major modification means any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase, and a significant net emissions increase, of a regulated NSR pollutant.

The Project, as a new standalone facility, is classified as a new “major” stationary emissions source as it falls into one of the 28-listed source categories (i.e., electric generation facilities) and has the potential to emit more than 100 tons/year of a regulated NSR pollutant. Since the proposed source is new major source, any regulated (attainment) pollutant, which exceeds the significant emissions threshold, is subject to a PSD review. The MSCE Project has established expected potential emission levels reflecting the combustion and control equipment to be installed at the proposed facility. The new facility will result in NOx, PM/PM_{10}/$PM_{2.5}$, CO, VOC and H_2SO_4 emissions above the applicable PSD significant levels (see Table 3-6). The PSD application for the project must include the following analyses for each PSD significant pollutant:

- BACT analysis.
- PSD increment consumption analysis, including other increment consuming sources in the area.
- NAAQS impact analysis.
- Class I area impact analysis.
- Additional impact analysis.

For each proposed emission unit, a control technology must be selected that will result in the maximum reduction in pollutant emissions considered achievable using current technology while considering energy requirements, environmental impacts, and economic impacts. The methodology used to determine BACT follows the "Top Down" approach recommended by the EPA in "New Source Review Workshop Manual", October 1990. The "Top Down" methodology requires the applicant to first evaluate the control technology which results in the maximum level of emission reduction for a similar source which is currently available. A detailed explanation of the "Top Down" applicable is presented in Section 5. If it is demonstrated that this level of control is not technically or economically feasible for the source under evaluation, then the next most stringent level of control is evaluated. The process continues until an acceptable level is identified. A "Top Down" BACT analysis for each significant attainment pollutant was performed and is described in Section 5 of this application.

Federal PSD increments are established for $PM_{2.5}$, $PM_{10,}$ SO_2 and NO_2. As part of the PSD regulations, an ambient air quality analysis is required to demonstrate that the PSD increment consumed by the proposed project for $PM_{2.5}$, $PM_{10,}$ and NO_2 does not exceed or contribute to a concentration that exceeds the PSD increments. As part of the air quality impact analysis, a preliminary dispersion modeling analysis was performed for those pollutants, with emissions above the significance levels. The pollutants for which preliminary modeling analyses were performed were NO_2, PM/PM_{10}/$PM_{2.5}$, and CO. The air quality analysis conducted for this project has indicated that the potential emissions associated with this project would result in predicted ambient pollutant concentrations that are above the PSD significant ambient impact levels for NO_2 and $PM_{2.5}$ but below the significant impact levels for CO. Accordingly, no further air quality modeling analysis is required for CO. (See October 1990 New Source Review Workshop Manual, Figure C-3, page C.27).

The Air Quality Modeling Analysis in Section 6 provides the detailed results and discussion of all air quality analyses performed for this project.

4.1.3 Acid Rain Provisions

The Acid Rain Program, codified at Parts 40 CFR 72 through 78, applies to:

- Electric generating units specifically identified in Table A to Section 404 of the Clean Air Act Amendments of 1990. These units are subject to Phase I of the Acid Rain Program.

- Electric generating units that commenced commercial operation after November 15, 1990 and serve a generator rated at greater than 25 MW nameplate capacity. These units are subject to Phase II of the Acid Rain Program.

The combustion turbines of the Project are subject to Phase II of the Acid Rain Program as the facility will serve a generator rated at over 25 MW. Applicability, or non-applicability, and requirements of specific sections of the Acid Rain Program are addressed in the following subsections.

4.1.3.1 Permit Regulations (40 CFR Part 72)

The Project is required to submit a Phase II Acid Rain Permit Application to the Administrator (i.e., DEP) pursuant to 40 CFR 72.30(b)(2)(ii) at least 24 months prior to the date on which the unit commences operation. The permit application must include information on the Designated Representative, general plant information, specific unit information, and a compliance plan for each affected unit, the date the unit will commence operating and the deadline for minor certification. The application forms were developed and are administered by the EPA. The Acid Rain Permit, when issued, will apply for 5 years.

4.1.3.2 Sulfur Dioxide Allowance System (40 CFR Part 73)

Sulfur Dioxide "allowances", defined as the permission to emit 1 ton of actual SO_2 emissions in any given year, are delineated in 40 CFR Part 73 for specific sources subject to Phase I and certain sources subject to Phase II of the Acid Rain Program. MSCE Project is a new source and is subject to Phase II of the program. However, no allowances have been specifically distributed to new Phase II sources. As a new source, the Project will be required to obtain SO_2 allowances equivalent to the actual annual SO_2 emissions from the facility each year. the Project will need to purchase SO_2 allowances via the auction or direct sale process outlined in 40 CFR Part 73, Subpart E. Regardless of the means used to obtain the allowances, the Allowance Tracking System outlined in 40 CFR Part 73, Subpart C requires that all subject sources hold and identify

SO_2 allowances for deduction within 60 days of the end of the calendar year (i.e., by March 1 or 2). The amount of allowances for deduction are determined based on the formula in 40 CFR § 72.95, but are typically equivalent to the total actual SO_2 emissions from the facility for the previous year. The maximum potential SO_2 emissions are estimated to be 39.9 tons per year.

4.1.3.3 Sulfur Dioxide Opt-Ins (40 CFR Part 74)

Part 74 is not applicable to the Project as the facility will be subject to the Acid Rain Program and will not be "opting-in" to the Program.

4.1.3.4 Continuous Emissions Monitoring (40 CFR Part 75)

Part 75 establishes requirements for the monitoring, record keeping, and reporting of sulfur dioxide, carbon dioxide and volumetric flow from units subject to the Acid Rain Program. Provisions for the substitution of missing data, specifications for Data Acquisition and Handling Systems (DAHS) and quality assurance and quality control procedures are also outlined. Multiple options are provided for monitoring a variety of exhaust configurations. Options for alternative monitoring in lieu of CEMS are provided for low mass emissions units and/or units that burn low sulfur fuels.

Since the Project's combustion turbines will only burn natural gas, the project has chosen to follow the optional SO_2 emissions data protocol for gas-fired units in Appendix D to Part 75. Pursuant to Appendix D, the Project will monitor SO_2 emissions by monitoring fuel flow pursuant to Section 2.1 and by applying a standard emission factor (0.0006 lb/MMBtu) representative of SO_2 emissions from pipeline quality gas in accordance with the procedures outline in Section 2.3.2. The Project will provide information on the contractual sulfur content from the pipeline gas supplier demonstrating that the gas has an H_2S content of less than 1 gr/100 scf and a Total Sulfur content of less than 20 gr/100 scf in the monitoring plan. Hourly SO_2 emissions will be calculated for each operating day.

4.1.3.5 Acid Rain Nitrogen Oxides Emission Reduction Program (40 CFR Part 76)

This part only applies to coal-fired utility units subject to an Acid Rain emissions limitation or reduction requirement for SO_2 under Phase I or II. **The Project's combustion turbines will not be capable of firing coal, thus this part is not applicable.**

4.1.3.6 Excess Emissions (40 CFR Part 77)

Excess emissions are defined as actual emissions in any calendar year greater than the ***Acid Rain Emissions Limitation*** established at 40 CFR Part 72 (i.e., in the acid rain permit). Sources with excess emissions in any calendar year are required to submit an "offset plan". A separate offset plan for each affected unit must be submitted to the Administrator within 60 days following the end of the calendar year.

4.1.3.7 Appeal Procedures for Acid Rain Program (40 CFR Part 78)

Part 78 establishes a regulatory vehicle for facilities that wish to contest any determinations made by the Administrator with respect to 40 CFR Part 77 - Excess Emissions. Part 78 will only be applicable in the event the Project has future excess emissions and decides to enter an appeal regarding their determination or the subsequent penalties.

4.1.4 National Emission Standards For Hazardous Air Pollutants (NESHAP)

NESHAP promulgated prior to the Clean Air Act Amendments (CAAA) of 1990, found in 40 CFR Part 61, apply to specific compounds emitted from specific processes. **None of the pollutant specific Part 61 NESHAPs apply to the Project.**

Pursuant to the CAAA of 1990, NESHAP specific to processes identified as emitters of listed hazardous air pollutants (HAPs) are promulgated at 40 CFR Part 63. These Part 63 "process-specific" NESHAP require affected sources to meet emission levels consistent with the Maximum Achievable Control Technology (MACT) and are typically referred to as "MACT standards". Specifically, listed area sources or stationary sources with the potential to emit greater than 10 tpy of a single listed HAP or over 25 tpy of a combination of HAPs are potentially subject to the MACT standards. The total potential HAP emissions for the Project are projected to be less than 25 tons/yr for all HAPs combined. Therefore, the Project is not considered a major HAP source, and no source-specific NESHAP standards apply.

Some MACT standards, known as "area source MACT" standards, apply to minor source HAP facilities (sources with less than 10/25 ton/yr HAP thresholds). The area source MACT standards that apply to emission units at the Project are discussed in the following section

4.1.4.1 Subpart ZZZZ: National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Stationary reciprocating internal combustion engines that are not being tested at a stationary RICE test cell/stand are subject to Subpart ZZZZ (40 CFR Part 63.6585). Therefore, Subpart ZZZZ will be applicable to the fire water pump engine and the emergency generator at the proposed Project.

New stationary RICEs at area sources of HAPs must meet the requirements of 40 CFR 60 Subpart IIII (see previous discussion and 40 CFR Part 63.6590(c)(1)). No other requirements apply to such engines.

4.1.5 Compliance Assurance Monitoring (CAM)

Pursuant to requirements concerning enhanced monitoring and compliance certification under the Clean Air Act Amendments of 1990, the EPA has promulgated regulations codified at 40 CFR Part 64 to implement compliance assurance monitoring (CAM) for major stationary sources of air pollution. The CAM regulations require owners or operators of such sources to conduct monitoring that satisfies particular criteria to provide a reasonable assurance of compliance with applicable standards. The requirements of this part apply to all pollutant-specified emissions units at a major stationary source if the emissions unit satisfies the following criteria:

- The unit is subject to an emission limitation or standard for the applicable regulated air pollutant.
- The unit uses a control device (as defined in 40 CFR § 64.1) to achieve compliance with the emission limitation or standard.

- The unit has the potential to emit (before the use of controls) emissions of the applicable air pollutant that are greater than 100 percent of the amount required for a source to be classified as a major source.

Emissions units that are subject to specific applicable requirements identified in 40 CFR § 64.2 (b) are exempt from CAM. These exempt applicable requirements are listed below:

- §64.2 (b)(1)(i) - Post-11/15/90 NSPS or NESHAP.
- §64.2 (b)(1)(ii) - Stratospheric ozone protection requirements.
- §64.2 (b)(1)(iii) - Acid Rain Program requirements.
- §64.2 (b)(1)(iv) - Emission limitations, standards, or other requirements that apply solely under an approved emission trading program.
- §64.2 (b)(1)(v) - Emissions cap that meets requirements of §70.4 (b) (12).
- §64.2 (b)(1)(vi) - Emission limitations or standards for which a Title V permit specifies a continuous compliance determination method that does not use an assumed control factor. Continuous emission monitoring systems (CEMS) which are used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard and provide data in units of the standard.

Since the combustion turbines will be subject to several of these applicable requirements listed above including the NSPS requirements and Title V permit continuous compliance methods, the combustion turbines at the Project will be exempt from the CAM rule.

4.1.6 Accidental Release Prevention

Section 112(r) of the Clean Air Act Amendments of 1990 mandates that EPA promulgate regulations and develop guidance to prevent, detect, and respond to accidental releases of toxic chemicals. Stationary sources covered by these regulations must develop and implement a risk management program that includes a hazard assessment, a prevention program, and an emergency response program. The risk management program must be described in a risk management plan (RMP) that must be registered with EPA, submitted to state and local authorities, and be made available to the public.

A facility is subject to 40 CFR Part 68 if a "process" contains a regulated substance in a quantity equal to or greater than the threshold quantities listed in 40 CFR §68.130. Threshold quantities for compounds associated with the proposed combustion turbines are summarized in Table 4-1.

Table 4-1
Accidental Release Program Threshold Quantities

Compound	Threshold Quantity (lbs)
Ammonia, aqueous (conc. ≥20% by wt.)	20,000

4.2 STATE OF WEST VIRGINIA REGULATIONS

4.2.1 45 CSR 1 - NO_x Budget Trading Program

45 CSR 1 sets forth NO_x budget trading requirements for boilers, combustion turbines and combined cycle systems greater than 250 MMBtu/hr and are providing 25 MW of electrical power for sale. This Rule follows the intent of 40 CFR Part 96 for non-electric generating units, while 45 CSR 26 (pending EPA approval) will apply to electric generating units. The Project will be subject to the NO_x trading program and will be required to control emissions to the applicable emission limitation and obtain NO_x allowances.

4.2.2 45 CSR 2 - Prevention and Control of Particulate Air Pollution Indirect Heat Exchanger PM Emissions

45 CSR 2 sets forth particulate and opacity emission standards for combustion of fuels from indirect heat exchangers. The rule also requires the control of particulate fugitive emissions from combustion-related source operations. Section 3.1 will limit opacity from all fuel burning sources to 10% (6-minute average). This regulation applies to the combustion turbine/HRSG at the Project. The particulate emission limit in Section 4.1 applies to the duct burners (a type "a" fuel burning unit).

4.2.3 45 CSR 3 - Air Pollution from Hot Mix Asphalt Plants

There will be no affected sources at the Project.

4.2.4 45 CSR 4 - Objectionable Odors

45 CSR 4 sets forth regulations prohibiting the discharge of air pollutants, which cause or contribute to an objectionable odor at any location occupied by the public. The Project will comply with the provisions of this regulation though good operating practices.

4.2.5 45 CSR 5 - PM Emissions from Coal Preparation and Handling Plants

There will be no affected sources at the Project.

4.2.6 45 CSR 6 - Air Pollution from the Combustion of Refuse

The proposed Project will not combust any refuse material as defined by 45 CSR 6. The only fuels to be utilized are pipeline natural gas and ultra-low sulfur diesel fuel.

4.2.7 45 CSR 7 - Prevention and Control of Particulate Matter Emissions from Manufacturing Processes and Associated Operations

There will be no affected sources at the Project.

4.2.8 45 CSR 7A - Compliance Test Procedures for 45 CSR 7 for PM

There will be no affected sources at the Project.

4.2.9 45 CSR 8 - Ambient Air Quality Standards for Sulfur Dioxide and Particulate Matter

The DAQ has adopted the national ambient air quality standards for both sulfur dioxide and particulate matter. The air quality modeling analysis in Section 6 of this permit application demonstrates that the proposed Project will be in compliance with these respective ambient air quality standards.

4.2.10 45 CSR 9 - Ambient Air Quality Standards for Carbon Monoxide and Ozone

The DAQ has adopted the national ambient air quality standards for carbon monoxide and ozone. The air quality modeling analysis in Section 6 demonstrates that the proposed Project will be in compliance with carbon monoxide standard.

4.2.11 45 CSR 10 - Prevention and Control of Sulfur Oxide Emissions

45 CSR 10 sets forth standards for emissions of sulfur oxides from fuel burning units, manufacturing process source operations, and process gas streams. The primary fuel burning units at the proposed Project are the natural gas combustion turbines and duct burners. However, the combustion turbines themselves do not meet said definition because they do not produce power through *indirect heat transfer.*

An Indirect Heat Exchanger' as defined in 45 CSR 10, means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. *This term includes any duct burner that combusts fuel and is part of a combined cycle system*".

The primary purpose of the duct burners are to generate steam to produce electricity for sale which defines the duct burners as type "a" fuel burning units under 45 CSR 10. For type "a" units, 45 CSR 10 lists SO_2 limits for specific existing units but does not have a generic limit for new units.

Therefore, there is no SO_2 mass emission standard for the duct burners under 45 CSR 10.

4.2.12 45 CSR 10A - Testing, Monitoring, Recordkeeping and Reporting Requirements for 45 CSR 10

There will be no affected sources at the proposed Project.

4.2.13 45 CSR 11 Prevention of Air Pollution Emergency Episodes

45 CSR 11 sets forth actions that must be taken in the event of air pollution episodes. The Project will, if required, prepare a Standby Plan, which will outline procedures that will be taken, to comply with the provisions of this regulation.

4.2.14 45 CSR 12 Ambient Air Quality Standard for Nitrogen Dioxide

The DAQ has adopted the national ambient air quality standards for nitrogen dioxide. The air quality modeling analysis in Section 6 demonstrates that the proposed Project will be in compliance with nitrogen dioxide standard.

4.2.15 45 CSR 13 - Permitting Requirements for the Construction, Modification, Relocation and Operation of Minor Stationary Sources

45 CSR 13 sets forth the criteria and procedures for obtaining an air permit for a minor modification or relocation of an existing stationary source or for the construction of a new minor stationary source of air pollutants. This regulation does not apply to "de mimimus" sources identified in Table 45-13B or sources which have emissions of regulated air pollutants below the thresholds set forth 45-13.2.24. The Project is submitting this permit application pursuant to the permitting provisions of 45 CSR 13 since SO_2 and Pb are below threshold.

4.2.16 45 CSR 14 Prevention of Significant Deterioration Permitting Requirements for the Construction of a Major Stationary Source

The proposed Project is considered a "major stationary source" since it potentially emits at least one regulated air pollutant greater than 100 tons per year. As shown in Table 3-6, emissions of $PM/PM_{10}/PM_{2.5}$, CO, NO_x, VOC, and H_2SO_4, exceed significant threshold values and, as a result, trigger Prevention of Significant Deterioration (PSD) requirements under 45 CSR 14. This permit application addresses the major source permitting requirements for those triggering air pollutants.

4.2.17 45 CSR 16 - Standards of Performance for New Stationary Sources

45 CSR 16 adopts the federal emission standards for new stationary sources (Part 60) by reference. As stated above, the Project's combustion turbines/HRSG units will be subject to Subpart KKKK and IIII.

4.2.18 45 CSR 17 - Fugitive Emissions from Material Handling/Fugitive Sources

There will be no affected sources at the Project.

4.2.19 45 CSR 19 - New Source Review Permitting for Non-Attainment Areas

The proposed Project is not located in any area designated as non-attainment for any criteria air pollutant. But Pennsylvania is in the Ozone Transport Region (OTR) and is considered moderate nonattainment for Ozone. The OTR is the region designated by section 184 of the federal Clean Air Act and comprised of the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and the Consolidated Metropolitan Statistical Area that includes the District of Columbia and northern Virginia. It is essentially a single 13 state nonattainment area.

The proposed project is significant for NO_x, a precursor for the formation of Ozone. But the air quality modeling analysis demonstrated that the proposed project will not significantly impact (predicted air quality concentration below the significance levels in 45 CDS 19, 3.3a) for NOx in the OTR. Therefore, the proposed project is not significantly contributing to the nonattainment of ozone.

4.2.20 45 CSR 20 - Good Engineering Practice as Applicable to Stack Heights

45 CSR 20 is promulgated to ensure that the degree of emission limitation required for the control of any air pollutant is not affected by that portion of the stack height which exceeds good engineering practice (GEP) or any other dispersion technique. Good engineering practice is defined as the greater of 65 meter above grade or the results of one of several GEP estimating methodologies. The results of a GEP stack height analysis are presented in Section 6.2.9 of the air quality modeling analysis. The results demonstrate that the stacks serving the various sources will not exceed GEP stack height.

4.2.21 45 CSR 21 - VOC Emission Standards

The proposed Project is not located in an affected area which must comply with 45 CSR 21.

4.2.22 45 CSR 22 Air Quality Management Fee Program

45 CSR 22 specifies a program to collect fees with for certificates to operate and for permits to construct, modify or relocate sources. The fees are assessed based on which regulations the new or modified source is subject. Based on the requirements of 45-22-3, the fee for the permit-to-construct is $12,000 which includes 45CSR13, NSPS and PSD fee requirements.

4.2.22.1 45 CSR 23 - Emissions From Municipal Solid Waste Landfills

There are no affected sources at the proposed Project.

4.2.23 45 CSR 24 - Emissions From Hospital/Medical and Infectious Waste Incinerators

There are no affected sources at the proposed Project.

4.2.24 45 CSR 25 - Emissions From Hazardous Waste TSD Facilities

There are no affected sources at the proposed Project.

4.2.25 45 CSR 27 - Emissions of Toxic Air Pollutants

The proposed Project will not operate any “chemical processing units” as defined in 45-27-2.4 and does not use listed chemicals.

4.2.26 45 CSR 28 - Air Pollutant Emissions Banking and Trading

The Project does not intend to bank or trade any air pollutant emissions.

4.2.27 45 CSR 29 – Emission Statements for VOCs and NOx

The proposed Project is not located in an affected area.

4.2.28 45 CSR 30 - Title V Operating Permit Requirements

Within 12 months of commercial operation, The Project will submit a Title V operating permit application for proposed facility for DAQ review and approval. The required air quality management fee will also be submitted.

4.2.29 45 CSR 33 Acid Rain Permits

Under 45 CSR 33 regulations, DAQ is the permitting authority for federal acid rain program. Specifically, the agency has adopted the provisions of federal program in its entirety including Parts 72, 74, 75, 76 and 77. The Projects combustion turbines will be subject to the applicable provisions of 45 CSR 33.

4.2.30 45 CSR 34 - Emission Standards for Hazardous Air Pollutants for Source Categories

45 CSR 34 adopts the federal emission standards for hazardous air pollutants (Parts 61, 63 and Section 112 of the Clean Air Act) by reference. As stated previously, the fire water pump engine and the emergency generator will be subject to Subpart ZZZZ.

5. CONTROL TECHNOLOGY EVALUATION

5.1 APPLICABLE REGULATORY PROGRAMS

Several federal and state regulatory programs require the potential implementation of emissions controls for the proposed project. The applicability of these programs is determined by a variety of factors including, but not limited to, pollutant type, pollutant emission rate, and facility location. Based on the information presented in the Regulatory Review (Section 4) and the Emissions Inventory (Section 3) sections of this application, the applicable control programs based on the project parameters are shown in Table 5-1.

The control technology selection process and the control technologies selected for each pollutant are presented in the following Sections:

- Section 5.2 – Combined Cycle Combustion Turbine System
- Section 5.3 – Emergency Generator/Fire Pump
- Section 5.4 – Fuel Gas Pre Heaters
- Section 5.5 – Cooling Tower
- Section 5.7 – Facility Wide Summary

5.1.1 Best Available Control Technology

A BACT analysis must be conducted for emissions of NO_x, CO, VOC, particulate matter and PM_{10}/ $PM_{2.5}$, H_2SO_4, and GHG. BACT determinations are case-by-case analyses that involve an assessment of the availability of applicable technologies capable of sufficiently reducing a specific pollutant emission, as well as the economic, energy, and environmental impacts of using each technology.

The methodology used in this study to determine BACT follows the "top-down" approach outlined in Chapter B of the EPA Draft "*New Source Review Workshop Manual*" dated October 1990. A "top-down" BACT analysis contains the following elements:

- Determination of the most stringent control alternatives potentially available

Table 5-1
Summary of Applicable Regulatory Control Programs

Applicable Pollutant(s)	Project Emissions (TPY)	PSD Applicable (Yes/No)	Governing Control Program(s)
Nitrogen Oxides (NO_x)	321	PSD	Best Available Control Technology (BACT)
Carbon Monoxide (CO)	276	PSD	BACT
Volatile Organic Compounds (VOC)	141	PSD	BACT
Particulate Matter	210	PSD	BACT
Particulate Matter less than 10 micron (PM_{10})	210	PSD	BACT
Particulate Matter less than2.5 micron ($PM_{2.5}$)	210	PSD	BACT
Sulfur Dioxide (SO_2)	39.9	No	State BACT
Hydro Sulfuric Acid (H_2SO_4)	35.8	PSD	BACT
Other Regulated Pollutants (i.e., Hazardous Air Pollutants [HAPs])	<10 single HAPs <25 multiple HAPs	State NSR	Maximum Achievable Control Technology (MACT)

- Discussion of the technical and economic feasibility of each alternative.
- Assessment of energy and environmental impacts, including toxic and hazardous pollutant impacts, of feasible alternatives.
- Selection of the most stringent control alternative that is technically and economically feasible and that provides the best overall control of all pollutants.
- Confirmation that the selected BACT is at least as stringent as NSPS and State Implementation Plan (SIP) limits for the source.

EPA Guidance recommends that the BACT analysis be conducted using a step by step approach. Specifically, a top-down BACT analysis includes the following 5 basic steps.

- Step 1 – Identify all Available Control Technologies. *Compilation of all potential control technologies available. List should not exclude technologies implemented outside the United States.*
- Step 2 – Eliminate Technically Infeasible Options. *Determine if any of the technologies identified in Step 1 are not technically feasible based on physical, chemical and engineering principles.*
- Step 3 – Rank Remaining Control Technologies by Control Effectiveness. *Remaining control alternatives not eliminated in Step 2 are ranked in order of most effective (i.e., lowest emission rate) to the least. Each technology is evaluated based on economic, environmental and energy impacts.*
- Step 4 – Evaluate Most Effective Controls and Document Results. *The information developed in Step 3 is objectively evaluated to determine whether economic, environmental, or energy impacts are sufficient to justify exclusion of the technology. The analysis begins with the top ranked technology and continues until the technology under consideration cannot be eliminated by any environmental, economic, and energy impacts which justify that the alternative is inappropriate as BACT.*
- Step 5 – Identify BACT. *The highest ranked remaining technology is identified as BACT.*

5.2 CONTROL TECHNOLOGY DETERMINATION FOR THE COMBINED CYCLE COMBUSTION TURBINE SYSTEM

Each combustion turbine and HRSG set has been evaluated as a single combined cycle system for the purposes of the control technology analysis. Consideration of the units as single system is consistent with the control evaluation results found in current U.S. EPA literature (i.e., Gas Turbine Alternative Control Technique or ACT) and the EPA and State Agency databases noted in Section 5.1. Each turbine/HRSG set will exhaust from the same stack and most of the applicable control options apply to the combined exhaust system. Although the combined cycle units are evaluated a single system, MSCE Project has not excluded analysis of controls that may apply only to the HRSG duct burners or combustion turbines (i.e. low NO_x burners). Control options that will apply specifically to the turbines or HRSG duct burners are noted throughout this analysis.

5.2.1 BACT for NO_x Emissions for the Combustion Turbine System

Nitrogen oxides are produced in the combined cycle system several different ways. Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_x forms in the high temperature area of the gas turbine combustor. Thermal NO_x increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low air to fuel ratio (i.e., lean combustion), the flame temperature will be lower, thus reducing the potential for NO_x formation. Prompt NO_x is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt to overall NO_x is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_x control by lean combustion.

Fuel NO_x is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas as the amount of fuel bound nitrogen is very low. A top down analysis to determine the best available NO_x control technology is provided in the following subsections.

5.2.1.1 Identification of Potential Control Technologies (Step 1)

Based on the data review process described previously, a list of potential technologies for controlling NO_x emissions from combined cycle combustion turbines was formulated. The following potential control technologies, ranked in order from the most effective to the least effective were identified:

1. Selective Catalytic Reduction (85-95% reduction)
2. SCONO$_x$™ (85-95% reduction)
3. XONON ™ (85-95% reduction)
4. Selective Non-Catalytic Reduction (80-95% reduction)

5. Combustion Controls (i.e., Dry Low NO_x Combustor for the turbines and low NO_x burners in the HRSGs) (80-95% reduction)
6. Wet Injection (60 to 80% reduction from uncontrolled emissions)

5.2.1.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down analysis is an evaluation of the technical feasibility of each of the identified control options. Each of the potential control technologies considered is described below along with a discussion of the technical feasibility with respect to the Project.

1. Selective Catalytic Reduction (SCR)

SCR is an add-on NO_x control technology that is employed in the combined exhaust stream within the HRSG. SCR reduces NO_x emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_x in the presence of the catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1,100 ^{o}F), such as simple cycle turbines, Zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with either wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming more available. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

Permit limits as low as 2.0 to 3.5 ppmvd NO_x have been specified using SCR on combined cycle GE F Class projects throughout the country. Permit BACT limits as low as 3.5 ppmvd NO_x have been specified using SCR for at least one F Class project (with large in-line duct burners). SCR is a technically viable control option to reduce NO_x emissions from large combined cycle combustion turbines.

2. SCONO$_x$™

$SCONO_x$™ is a catalytic technology that removes CO and NO_x by oxidizing and then absorbing the pollutants onto a platinum honeycomb catalyst coated with potassium carbonate. The pollutant is then released as molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas, carbon dioxide and steam. Consistent regeneration of the catalyst is required to maintain low NO_x emission rates. Steam requirements typically range from 1 to 4% of the boiler capacity. The catalyst is divided into multiple sections equipped with mechanical dampers to isolate sections of the catalyst for regeneration. The regeneration cycle typically takes 10 minutes and the catalyst life is approximately 6 months.

The technology is currently only in use at two facilities. A 32 MW GE LM2500 combined cycle unit at the Sunlaw Cogeneration Partners Federal Cold Storage Facility in Vernon, California and a 5 MW simple cycle turbine at the Genetics Institute in Andover, Massachusetts. The La Paloma Generating Company LLC plant near Bakersfield, CA was originally permitted for the installation of one 250 MW combined cycle block with $SCONO_x$™. However, the installation has proceeded with a standard SCR due to schedule constraints. PG&E has proposed the installation of $SCONO_x$™ on a GE F-frame unit at Otay Mesa in Southern California. The construction permit was written with a three year demonstration period for the $SCONO_x$™ system to prove that the system can consistently achieve 2.0 ppmdv @ 15% O_2. The facility is currently under construction.

There are significant technical differences and other considerations associated with the two facilities that currently utilize the $SCONO_x$™ system that will preclude the use of $SCONO_x$™ at the proposed Project. First, the Sunlaw facility is partially owned and operated by a partner of Goal Line Environmental Technologies ("Goal Line"), the manufacturer of $SCONO_x$™, thus the data generated by this facility is not from an independent, nonpartisan source. Second, the Sunlaw plant is 5% of the size of the Project's combustion turbines, and the combustion turbine is an aeroderivative model, which is significantly different than the frame-type units proposed in this application. The facility is also not equipped with duct burners. Third, although the California Air Resources Board has certified $SCONO_x$™ technology in a November 1998 report entitled "*Evaluation of Goal Line Environmental Technologies LLC $SCONO_x$™ System*" the Board specifically noted that while the technology has been demonstrated successfully on smaller turbines, there are "several factors which may affect successful scale-up". The CARB certification report acknowledged the potential issues associated with scale up and that the certification only applied to water injected, 34 MW natural gas fired turbines.

The Genetics Facility represents a non-partisan basis of comparison as Goal Line has no vested interest in the operation and ownership of the facility. Excerpts of a presentation given by Mr. Robert McGinnis, the Manager of Environmental Engineering and Compliance for Genetics Institute at the Northeast Energy and Commerce Association conference on May 17, 2000 provide a better understanding as to the commercial performance of the SCONO$_x$™ technology:

- Following 9 months of operation there were still a number of unresolved problems with the performance of the SCONO$_x$™ system and the system was not consistently meeting the permitted NO_x emission limit.

- SCONO$_x$™ performance was severely hampered by changes in NO_x inlet concentration. The unit was guaranteed to achieve the stated NO_x emission limits for NO_x inlet concentrations up to 25 ppm; however, the system was unable to achieve the permit limit if the turbine was not operating at least twice as clean as the manufacturer's guarantee (i.e., at lower than 12.5 ppm).

- Goal Line redesigned the dampers three times due to leakage and the catalyst blocks were washed every 2-2½ months. This substantially increased system downtime and maintenance costs.

- The technology has not been installed commercially on a source greater than 34 MW.

- Mr. McGinnis summarized by stating that after 9 months of operation it was still unclear if SCONO$_x$™ will work as promised.

As shown by the results of the Genetics Installation and the CARB review of the Sunlaw facility, it is clear that SCONO$_x$™, while potentially applicable in the future, cannot be considered as a "technically feasible" control technology. In the EPA *Draft New Source Review Guidance* document, "technically feasible" control technology is technology that has been commercially demonstrated, i.e., **installed and operated successfully on a source similar to that under review**. <u>Based on this guidance, and the information presented above, SCONO$_x$™ is not technically feasible for the proposed Project.</u>

3. <u>XONON™</u>

XONON™ works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_x formation) followed by flameless catalytic combustion to further limit NO_x formation. The technology has been demonstrated on combustors on the same order of size as SCONO$_x$™. XONON™ does not utilize ammonia in the process and does not require the generation of hydrogen.

Catalytica Combustion Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. In a press release on October 8, 1998 Catalytica announced the first installation of a gas turbine equipped with the XONON™ Combustion System in a municipally owned utility for the production of electricity. The turbine was started up on that day at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, Calif. Previously, this XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests which documented its ability to limit emissions of nitrogen oxides, a primary air pollutant, to less than 3 parts per million.

In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to cooperate in the design, application, and commercialization of XONON™ systems for both new and installed GE E and F-class turbines used in power generation and mechanical drive applications. Although this technology appears to be potentially viable for future applications, it has not been demonstrated commercially on any units similar in size and scope to the proposed Project. For these reasons, it is concluded that XONON™ is not a technically feasible control option.

4. Selective Non-Catalytic Reduction (SNCR)

SNCR works on the same principal as SCR. The main differences are that SNCR is applicable to hotter streams than conventional or SCR, no catalyst is required, and urea can be used as a source of ammonia. Certain manufacturers, such as Engelhard, market a SNCR for NO_x control within the temperature ranges for which this project will operate (700 – 1,400°F). However, the process also requires low oxygen content in the exhaust stream to be effective. Typically, the oxygen content in the exhaust stream of a combustion turbine is greater than 12%, rendering SNCR technically infeasible for these types of applications. Accordingly, SNCR is not technically feasible for the Project due to the oxygen content of the exhaust stream.

5. Combustion Controls

Combustions controls may be applied to the combustion turbine and/or HRSG duct burners independently. Combustion controls for these types of units primarily consist of Low NO_x combustors or Low NO_x burners. Since this technology is applicable to the individual components of the combined cycle system, the technical feasibility analysis has been separated for the combustion turbines and HRSG duct burners as follows.

Combustion Turbine

The U.S. Department of Energy has provided millions of dollars of funding to a number of combustion turbine manufacturers to develop inherently lower pollutant-emitting units. Efforts over the last ten years have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel with air prior to combustion in the primary zone. This technology is typically referred to as Dry Low NO_x (DLN) combustion. Typically, this occurs in four distinct modes: primary, lean-lean, secondary, and premix. In the primary mode, fuel is supplied only to the primary nozzles to ignite, accelerate, and operate the unit over a range of low- to mid-loads and up to a set combustion reference temperature. Once the first combustion reference temperature is reached, operation in the lean-lean mode begins when fuel is introduced into the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in the secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. The premix mode of operation occurs at loads between 50% to 100% of base load and results in the lowest NO_x emissions. Due to the intricate air and fuel staging necessary for dry low-NO_x combustor technology, the gas turbine control system becomes a very important component of the overall system. DLN systems are technically feasible for nearly all new frame-type combustion turbines. <u>DLN systems result in control efficiencies of 80% to 95% and are technically feasible for the Project.</u>

HRSG Duct Burners

Low NO_x burner designs are based on the principle of lowering the reaction temperature of the combustion process by limiting the amount of excess air available, low excess air (LEA), during the combustion process as much as possible and staging the combustion to reduce the occurrence of NO_x formation. Low NO_x burners are considered industry standard for applications such as HRSG duct burners and are, therefore, considered technically feasible.

6. Wet Injection

This technology is only applicable to the combustion turbines. Water or steam is injected into the primary turbine combustion zone to reduce the flame temperature, resulting in lower NO_x emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the same level of NO_x control. There is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine. Standard combustor designs with wet injection can generally achieve NO_x emissions up to 42 ppmvd for gas firing. Advanced combustor designs generate inherently lower NO_x emissions and can tolerate greater amounts of water or steam injection before causing flame instability. Advanced combustor designs with wet injection can achieve NO_x emissions up to 25 ppmvd for gas firing. Wet injection typically can achieve 60% to 80% control efficiencies and is technically feasible for the Project.

5.2.1.3 Rank Remaining Technically Feasible Control Technologies (Step 3)

Based on the reasons outlined in the above discussion, the following technologies were identified as technically feasible, ranked in order of most effective to least effective:

1. Selective Catalytic Reduction (85-95% reduction)
2. Combustion Controls (i.e., Dry Low NO_x Combustor for CTs and Low NO_x burners for DBs) (80-95% reduction)
3. Wet Injection (60 to 80% reduction from uncontrolled emissions)

5.2.1.4 Proposed NO_x BACT for the Combustion Turbine System

MSCE Project will elect to implement the two top ranked remaining technically feasible control technologies as BACT, thus further review of economic, environmental, and energy impacts is unnecessary. **Based on the above analysis, the Project proposes BACT for NO_x emissions from the combined cycle systems to be good combustion practices, DLN burners in the turbines,**

low NO_x duct burners and SCR on the combined exhaust stream. The proposed NOx BACT emission limit is 2.0 ppm at 15% oxygen.

5.2.2 BACT for VOC Emissions for the Combustion Turbine System

5.2.2.1 Identification of Potential Control Technologies (Step 1)

Like CO emissions, VOC emissions occur from incomplete combustion. Effective combustor design and post-combustion control using Oxidation Catalysts are the available technologies for controlling VOC emissions from combustion turbines. The GE Frame 7HA.01 and Mitsubishi J-series industrial combustion turbines proposed by the Project are able to achieve relatively low uncontrolled VOC emissions because their combustors have firing temperatures of approximately 2,500 °F with exhaust temperatures of approximately 1,100 °F. A DLN combustor-equipped combustion turbines using an Oxidation Catalyst can achieve VOC emissions in the 1 to 2 ppmvd @ 15% O_2 range. As noted above in the NO_x BACT analysis, the EMxTM and XONONTM technologies were determined not to be feasible for the proposed Combustion Turbines/Duct Burners, so they have not been considered further here.

1. Good Combustion Controls

As previously discussed, VOCs are formed from incomplete combustion of the carbon present in the fuel. VOC formation is minimized by designing the combustors to completely oxidize the fuel carbon to CO_2. This is achieved by ensuring that the combustors are designed to allow complete mixing of the combustion air and fuel at combustion temperatures with an excess of combustion air. Higher combustion temperatures reduce VOC formation, but at the expense of increased NO_x formation. The use of water/steam injection or DLN combustors tends to lower combustion temperatures to reduce NO_x formation, but potentially increases VOC formation. However, good combustor design and best operating practices will minimize VOC formation while reducing the combustion temperatures and NO_x emissions.

2. Oxidation Catalysts

Oxidation Catalysts typically use precious metal catalyst beds. Like SCR systems for combined-cycle combustion turbines, Oxidation Catalysts are typically placed inside the HRSGs. The catalyst enhances oxidation of VOC to CO_2, without the addition of any chemical reagents.

Oxidation Catalysts have been successfully installed on numerous simple- and combined-cycle combustion turbines.

5.2.2.2 Eliminate Technically Infeasible Options (Step 2)

Good combustor design and the use of Oxidation Catalysts are both technically feasible options for controlling VOC emissions from the proposed Combustion Turbines/Duct Burners.

5.2.2.3 Rank Remaining Control Technologies by Control Effectiveness (Step 3)

Based on the preceding discussions, using good combustor controls and Oxidation Catalysts are technically feasible combustion turbine VOC emission control technologies.

5.2.2.4 Proposed VOC BACT for the Combustion Turbine System

The Project will elect to implement the two top ranked remaining technically feasible control technologies as BACT, thus further review of economic, environmental, and energy impacts is unnecessary. Based on the above analysis, the Project proposes BACT for VOC to be **good combustor controls and Oxidation Catalysts and VOC emission limits of 1.0 and 2.0 ppmvd @ 15% O_2 without and with duct firing, respectively.**

5.2.3 BACT for PM/PM_{10}/$PM_{2.5}$ Emissions for the Combustion Turbine System

A top down analysis to determine the best available PM/PM_{10}/$PM_{2.5}$ control technology is provided in the following subsections.

5.2.3.1 Identification of Potential Control Technologies (Step 1)

Potential control technologies for PM emissions from gas fired combined cycle combustion turbines include the following, ranked in order of potential effectiveness:

1. Add-on control (i.e., baghouse, scrubber, electrostatic precipitation, etc.)
2. Combustion of clean fuels (i.e., natural gas)
3. Implementation of good combustion practices

No natural gas-fired combined cycle combustion turbines that utilize add-on control technology for PM/PM_{10} control were identified in the permit review. Acceptable control techniques identified include combustion of clean fuels (e.g., firing natural gas and/or minimizing the sulfur content of the fuel) and good combustion practices.

5.2.3.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down analysis is an evaluation of the technical feasibility of each of these control options. Each of the potential control technologies considered is described below along with a discussion of the technical feasibility of each with respect to the Project.

1. Add-on Controls

There are three reasons why add-on particulate matter control technologies are not technically feasible for PM/PM_{10} emissions control for a combustion turbine:

1. The installation of an add-on control will create an unacceptable back pressure on the turbine. Turbine performance is very sensitive to back pressure because it reduces the expansion-to-pressure ratio and energy efficiency, resulting in reduced power output, increased fuel consumption, and increased emission rates.

2. Combustion in a turbine requires a high level of excess air and thus produces high exhaust gas volumes. These high gas volumes in turn increase the size and cost of add-on particulate matter controls, making them unreasonable for economic reasons.

3. The increased gas volume results in a low pollutant concentration. Based on preliminary emissions estimates obtained from GE for a Frame 7FA turbine and Mitsubishi for the J-series turbine, the maximum expected PM_{10} concentration without add-on controls is expected to be approximately 0.005 gr/dscf. This number is believed to be a worst-case short-term particulate matter grain loading and is estimated assuming the turbine is firing natural gas at 60% load, 54ºF inlet temperature. Further reduction below this level would be minimal.

Based on the above, add-on particulate matter control technologies are not considered technically feasible for controlling $PM/PM_{10}/PM_{2.5}$ emissions from the turbine. Furthermore, there is no evidence that add-on controls have been installed for $PM/PM_{10}/PM_{2.5}$ control for turbines, and add-on controls are therefore not considered to be BACT for the proposed combustion turbine.

2. Combustion of Clean Fuels

The combustion of clean fuels to minimize $PM/PM_{10}/PM_{2.5}$ emissions is accomplished by burning fuels with minimal amounts of impurities in conjunction with good combustion practices. The cleanest fuel commercially available in large quantities is natural gas. Natural gas will be the only fuel fired in the combustion turbine. Combustion of clean fuels is technically feasible for the proposed combustion turbine as natural gas is available at the site.

3. Good Combustion Practices

Good combustion practices refers to the operation of the combustion turbine at high combustion efficiency, thus reducing products of incomplete combustion such as $PM/PM_{10}/PM_{2.5}$. The combustion turbine will be designed to maximize combustion efficiency. The combustion turbine manufacturer will provide Operator and Maintenance manual(s) detailing methods to maintain a high level of combustion efficiency.

5.2.3.3 Proposed PM/PM_{10} and PM2.5 BACT for the Combustion Turbine System

The Project will elect to implement all of the technically feasible control technologies, thus further review of economic, environmental, and energy impacts is unnecessary. **Based on the above analysis, The Project proposes BACT for PM/PM_{10}/PM2.5 emissions from the turbine to be combustion of clean fuels and good combustion practices and inlet air filtration to control PM, PM10, and PM2.5 emissions to no more than 0.0091 lb/hr.**

5.2.4 BACT for CO Emissions for the Combustion Turbine System

A top down analysis to determine the best available CO control technology is provided in the following subsections.

5.2.4.1 Identification of Potential Control Technologies (Step 1)

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation were identified as the potentially viable control alternatives for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst. Several recently permitted natural gas-fired combustion turbines are utilizing oxidation catalysts as add-on technology for CO control.

5.2.4.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down analysis is an evaluation of the technical feasibility of each of these control options. Each of the potential control technologies considered is described below along with a discussion of the technical feasibility of each with respect to the Project.

1. Oxidation Catalyst

Oxidation catalysts (typically a precious metal deposited onto a solid honeycomb substrate) convert carbon monoxide (CO) to carbon dioxide (CO_2) in the presence of oxygen. This technology has been demonstrated on similar combined cycle facilities as shown in the Appendix D summary of BACT/LAER determinations. This technology is considered a technically feasible option for CO emissions control.

2. Good Combustion Practices/Turbine Design

Good combustion practices refers to the operation of the combustion turbine at high combustion efficiency, thus reducing products of incomplete combustion such as CO. The combustion turbine will be designed to maximize combustion efficiency. The combustion turbine manufacturer will provide Operator and Maintenance manual(s) detailing methods to maintain a high level of combustion efficiency.

5.2.4.3 Proposed CO BACT for the Combustion Turbine System

The Project will elect to implement all of the technically feasible control technologies identified, thus further review of economic, environmental, and energy impacts is unnecessary. **Based on the evaluations above, the Project proposes the only two technically feasible CO reduction methods available as BACT: the use of an oxidation catalyst system in conjunction with** good combustion practices **to control CO emissions to 2.0 ppmvd @ 15% O_2.**

5.2.5 BACT for H_2SO_4 Emissions for the Combustion Turbine System

A top down analysis to determine the best available H_2SO_4 control technology is provided in the following subsections.

5.2.5.1 Identification of Potential Control Technologies (Step 1)

Potentially acceptable control techniques for H_2SO_4 emissions include combustion of low sulfur fuels and/or an H_2SO_4 scrubber.

5.2.5.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down analysis is an evaluation of the technical feasibility of each of these control options. Each of the potential control technologies considered is described below along with a discussion of the technical feasibility of each with respect to the Project.

1. Add-on Controls

There are three reasons why add-on controls are impractical for combustion turbine emissions control:

(a) The installation of an add-on control will create an unacceptable back pressure on the turbine. Turbine performance is very sensitive to back pressure because it reduces the expansion pressure ratio and energy efficiency, thus resulting in reduced power output, increased fuel consumption, and increased air emissions.

(b) Combustion in a turbine requires a large amount of excess air, which results in high exhaust gas volumes. These high gas volumes in turn increase the size and cost of add-on controls, making them unreasonable for economic reasons.

(c) The increased gas volume results in low pollutant concentrations; also increasing control device size and cost.

Based on the above, add-on controls are not considered to be technically feasible for controlling SO_2 emissions from turbines. There is no evidence that add-on controls have been installed to control SO_2 emissions from natural gas fired turbines; therefore, add-on controls are not considered to be BACT for the proposed project.

2. Combustion of Low Sulfur Fuels

As the name implies, this technique of SO_2 emission control limits the types of fuels burned to those with low sulfur contents, thus minimizing SO_2 formation. The lowest sulfur fuel commercially available in large quantities is natural gas. Natural gas supplied via pipeline with a sulfur content at or below 1 grain per 100 scf will be the only fuel fired in the combustion turbine. Combustion of clean fuels is technically feasible for the proposed combustion turbine as natural gas is available at the site.

5.2.5.3 Proposed H_2SO_4 BACT for the Combustion Turbine System

The Project will elect to implement the only technically feasible control technology, thus further review of economic, environmental, and energy impacts is unnecessary. **Based on the above analysis, the Project Unit 2 proposes BACT for H_2SO_4 emissions from the turbine to be combustion of low sulfur fuel and an emission limit of 0.001 lb/MMBtu.**

5.2.6 BACT Analysis for Other Regulated Pollutants

Other regulated pollutants consist of non-criteria pollutants for which a regulatory standard has been established. These pollutants primarily fall into the category of speciated organic or metal compounds and the majority of these compounds are considered Hazardous Air Pollutants as defined in Section 112 of the Clean Air Act. Based on the emission rates expected from the proposed combined cycle system, the level of emissions of "other regulated pollutants" will be very low. As discussed in Section 3, the major HAPs of concern from a combustion turbine are volatile organic HAPs or VOHAPs such as Formaldehyde and Hexane. BACT for VOHAPs will be met by the same technology as proposed for BACT for VOC emissions (i.e., an oxidation catalyst). Similarly, BACT for control of the low levels of particulate matter HAPS or PM-HAPs will also be controlled by the BACT proposed for PM/PM_{10} (i.e., restricting the system to firing an inherently low-ash fuel in natural gas). BACT for ammonia will be good operating and maintenance practices for the SCR system to minimize ammonia slip.

5.2.7 BACT for GHG Emissions for the Combustion Turbine System

The primary GHG of concern for the combustion turbine system is CO_2. The BACT analysis is for CO_2 emissions, as CH_4, N_2O and SF_6 emissions are insignificant, at less than 0.3 percent of facility GHG CO_2e emissions and there are no sources with HFCs or PFCs pollutants identified with this project.

5.2.7.1 Identify Potential Control Technologies – (Step 1)

The following potentially applicable technologies available were evaluated for the review of the CO_2 control technologies for the CTGs/HRSGs:

- Carbon Capture and Sequestration
- Lower Emitting Alternative Technology

- Thermal Efficiency/Combustion Air Cooling

Each of these technologies is further discussed in the following subsections.

1. Carbon Capture and Sequestration

CCS is a multiple step process which involves capturing of CO_2 emissions, transportation of CO_2 emissions to the sequestration site, and ultimate sequestration of CO_2 emissions. Instead of allowing the CO_2 to be emitted, it is captured and stored it (in a "reservoir") where it will not be re-emitted ("permanent storage"). A schematic of the CCS process is shown in Figure 5-1. Each step of the process is described below.

Capturing of CO_2 Emissions

Carbon capture begins with the separation and capture of CO_2 from the flue gas. The type of capture process used is dependent on the type of source generating the CO_2 emissions. There are generally four types of capture systems: industrial separation, post-combustion, pre-combustion and Oxyfuel. The four type and their characteristics are shown in Figure 5-2. All except Oxyfuel involve separation of the CO_2 from the process exhaust stream.

Industrial Separation

The industrial separation processes available include: sorbent/solvents, membranes and cryogenic distillation. Sorbent/solvent (solid or liquid) is used to capture the CO_2 and then the CO_2 is released by heating the sorbent, which also regenerates the sorbent/solvent for res-use. Solid sorbents can be used to capture CO_2 from flue gas through chemical adsorption, physical adsorption, or a combination of the two effects. Possible configurations for contacting the flue gas with solid sorbents include fixed, moving, and fluidized beds. Membranes use the physical properties of the molecules of the gas and pressure. Membrane-based capture uses permeable or semi-permeable materials that allow for the selective transport/separation of CO_2 from the flue gas. Cyrogenic distillation uses the properties of differences in boiling points of the gases to separate the CO_2. Since the gases have very low boiling points they need to be cooled to be separated.

Post Combustion

Post-combustion capture systems being developed are expected to be capable of capturing more than 90 percent of flue gas CO_2. Amine-based solvent systems are in commercial use for scrubbing CO_2 from industrial flue gases and process gases. However, solvents have yet to be applied and demonstrated in practice to remove the much larger volumes of CO_2 that are encountered in commercial scale power plants. The process of separating CO_2 from the flue has high energy demand and is cost intensive.

Pre-Combustion

A pre-combustion capture process typically comprises a first stage of reaction producing a mixture of hydrogen and carbon monoxide (syngas) from a primary fuel. The CO is converted to CO_2 with the application of steam. The CO_2 is then removed from the CO_2/H_2 mixture.

Oxyfuels

Oxyfuel combustion involves fuel combustion using oxygen-enriched gas, rather than ambient air which produces a flue gas mainly containing CO_2 and H_2O and very little N_2. The flue contains from about 80-98% CO_2 depending on the fuel used and the particular oxy-fuel combustion process. This concentrated CO_2 stream can be processed further to purified CO_2 before delivery into a pipeline for storage. The CO_2 capture efficiency is very close to 100% in oxy-fuel combustion capture systems.

Transportation of CO_2 Emissions

CO_2 captured by any of the above mentioned processes would have to be transported to a storage site. For geologic sequestration, a pipeline may be suitable. For other types of sequestration (e.g., ocean storage, mineral carbonation), transportation would depend on specific project requirements, and may involve pipelines, truck transport, ocean-going vessels, etc.

Storage (Sequestration) of CO_2 emissions

Storage or sequestration of CO2 is generally accomplished by injecting captured CO2 at high pressures into deep subsurface formations for long-term storage. These subsurface formations must be either local to the point of capture, or accessible via pipeline, to enable the transportation of recovered CO2 to the permanent storage location. The engineered injection of CO_2 into subsurface geological formations was first undertaken in Texas, USA, in the early 1970s, as part of enhanced oil recovery (EOR) projects and has been ongoing there and at many

Figure 5-1
Carbon Capture Process

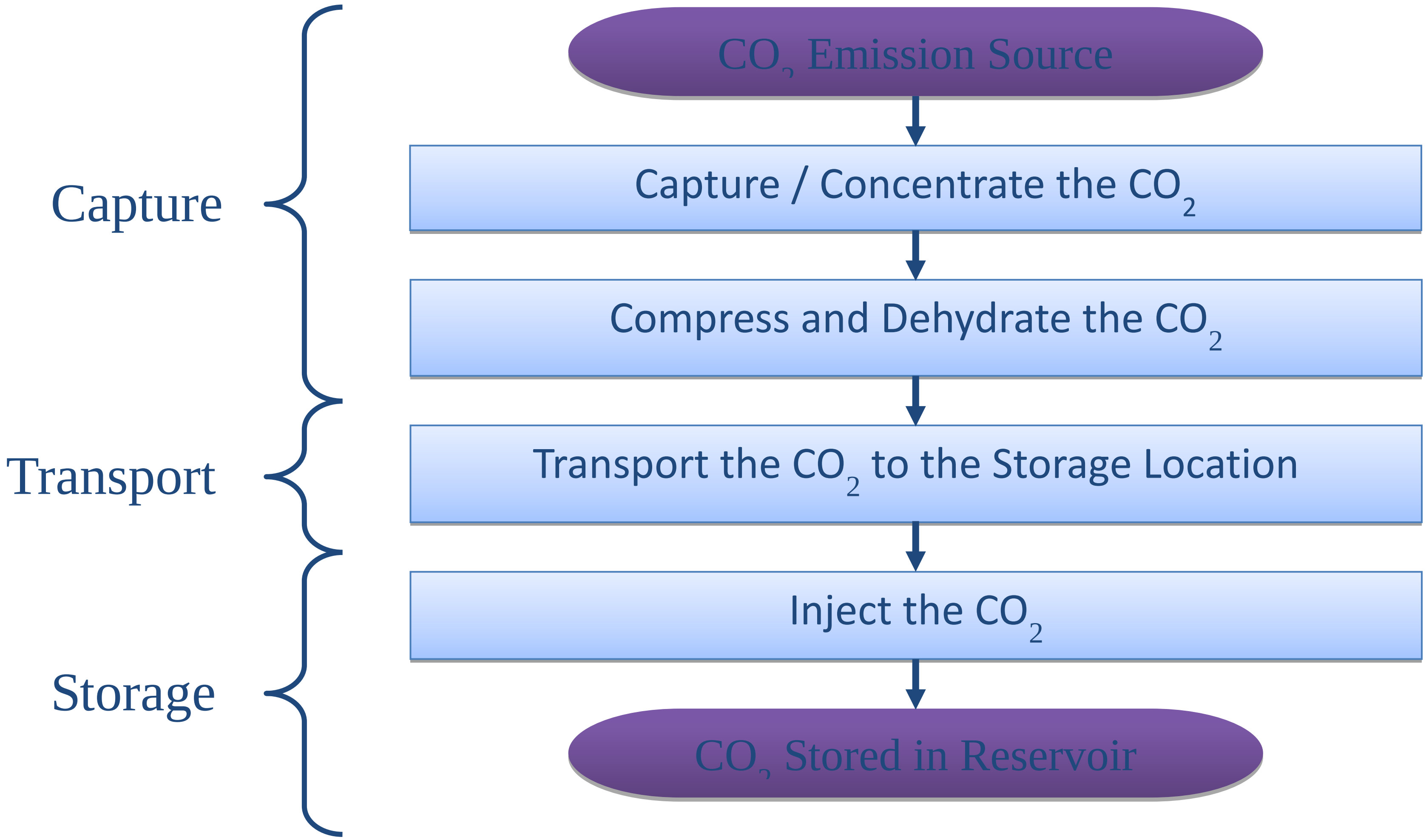


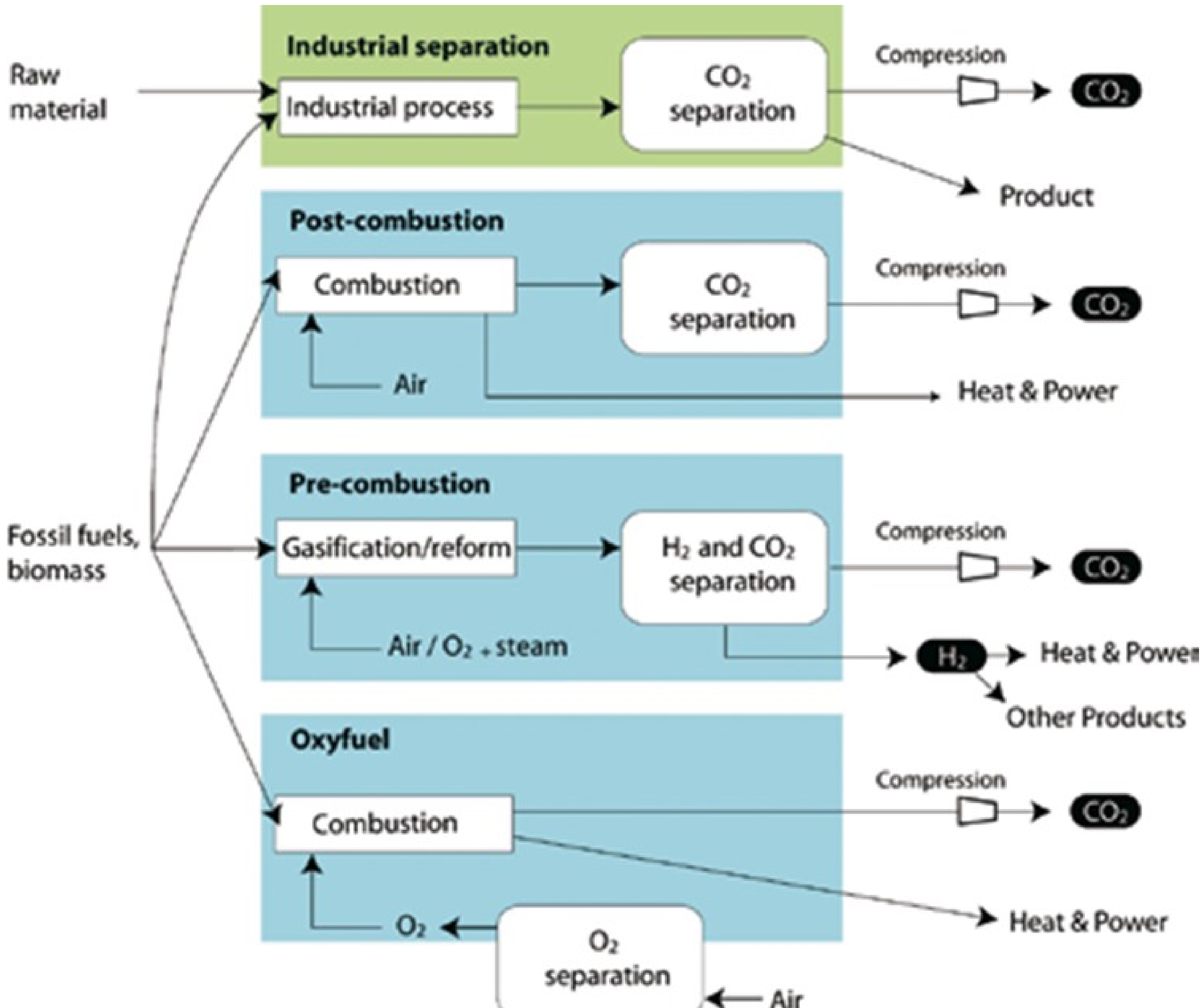
Figure 5-2
Types of CO2 Sources and Capture

Typically high-concentration CO_2 streams liberated from chemical processes or from natural gas

Burn the fuel, then capture; relatively low concentration CO_2 – most of flue gas is N_2

Processing of fuel without combustion, followed by capture

Fuel combustion using oxygen-enriched gas, rather than ambient air; flue gas mainly CO_2 and H_2O (no N_2)



Source: IPCC Special Report on Carbon Dioxide Capture and Storage, 2005, pg.5

other locations ever since. Storage facilities typically include:

- Geologic formations;
- Depleted oil and gas reservoirs;
- Unmineable coal seams;
- Saline formations;
- Basalt formations; or
- Terrestrial ecosystems.

To geologically store CO_2, it must first be compressed, usually to a dense fluid state known as 'supercritical'. Once injected, the pressurized CO_2 remains "supercritical" and behaves like a liquid and takes up less space than gaseous CO_2. The CO_2 occupies pore spaces in the surrounding rock. Over time, the CO_2 can dissolve in residual water, and chemical reactions between the dissolved CO_2 and rock can create solid carbonate minerals, more permanently trapping the CO_2.

2. Thermal Efficiency/Combustion Air Cooling

CO_2 emissions are directly related to the quantity of fuel burned, therefore less fuel burned per amount of energy produced (greater energy efficiency), the lower the GHG emissions per unit of energy produced. The only useful means to reduce CO_2 from a fossil fuel combustion process is to minimize the amount of fuel used, which is achieved by establishing a more thermally efficient process, or by substitution of a lower GHG emitting fuel. The largest efficiency losses for a combined-cycle combustion turbines are inherent in the design of the combustion turbines and the heat recovery system. Therefore, there is no opportunity for efficiency gains other than the differences in design between manufacturers or models.

Combustion inlet air cooling is a group of technologies and techniques consisting of cooling down the intake air of the gas turbine. The direct consequence of cooling the turbine inlet air is power output augmentation which improves the energy efficiency of the system. The most common method used to improve the energy efficiency of combustion turbines is to cool the combustion air entering the combustion turbines during the summer months which also coincides with peak electric demand.

3. Lower Carbon Fuels

Carbon dioxide is produced as a combustion product of any carbon containing fuel. The carbon content of the fuel, relative to its Btu value, can have significant impact on the overall GHG emissions. Gaseous fuels such as natural gas significantly less GHG emissions per Btu than liquid or solid fuels. The use of lower carbon content gaseous fuels such as natural gas compared to the use of higher carbon-containing fuels such as coal, pet-coke or residual fuel oils, can reduce CO_2 emissions from combustion.

Natural gas combustion result in significantly lower GHG emissions than coal combustion (117.0 lb/MMBtu, versus 205.6 lb/MMBtu for bituminous coal). Therefore, the use of lower carbon containing fuels in combustion turbines is an effective means to reduce the generation of CO_2 during the combustion process.

Step 2 - Eliminate Technically Infeasible Options

1. Carbon Capture and Storage

CCS is the only potentially available add-on control option at this time, and even this technology is limited and infantile in its development. The technologies needed for a full-scale electric generating facility such as the proposed Project are not yet commercially available and without local geological reservoirs and available pipelines dedicate to CO_2 transport, CCS is not currently feasible. Therefore, CCS is not considered technically feasible for the Project.

It is also noted that in USEPA PSD and Title V Permitting Guidance For Greenhouse Gases (March 2011), USEPA states that:

> *EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible. However, there may be cases at present where the economics of CCS are more favorable (for example, where the captured CO_2 could be readily sold for enhanced oil recovery), making CCS a more viable option under Step 4.*

2. Thermal Efficiency/ Combustion Air Cooling

The selection and use of combustion turbines with a higher thermal efficiency and combustion air cooling during the summer months is a technically feasible alternative to one with a lower thermal efficiency rating and no combustion air cooling. The Project will use the latest technically advanced high thermal efficiency combustion turbine operated in combined-cycle mode and will be equipped with inlet evaporative cooling systems, which is a form of combustion air cooling. Therefore, thermal efficiency/combustion air cooling is considered technically feasible for the Project.

3. Lower Carbon Fuels

The use of lower carbon content gaseous fuels such as natural gas compared to the use of higher carbon-containing fuels such as coal, pet-coke or residual fuel oils, is a technically feasible alternative to reduce CO_2 emissions. The project will only utilize natural gas for the combustion turbines/HRSG. Therefore, Lower Carbon Fuels is considered technically feasible for the Project.

Step 5 - Select BACT

The Project will elect to implement the only technically feasible control technologies, thus further review of economic, environmental, and energy impacts is unnecessary. **Based on the above analysis, the Project proposes BACT for GHG emissions from the turbine to thermal efficiency/combustion air cooling and use of lower carbon fuels.**

In addition, the Project proposes a facility-wide GHG emissions limit as GHG BACT for the Project. The proposed GHG emission limit from the Combustion Turbines/Duct Burners, Fuel Gas Heaters, Emergency Generator, Fire Water Pump, and gas pre-heaters is 5,109,617 tons/yr, on a CO_2 basis.

5.3 CONTROL TECHNOLOGY DETERMINATION FOR THE EMERGENCY GENERATOR AND FIRE PUMP

The control technology analysis for the proposed emergency generator and fire pump has been combined because these units are both similar diesel fuel fired internal combustion engines. Both units will only be used in emergency situations and the engines will be restricted to an annual utilization limitation equivalent to 100 hours of operation at maximum capacity with anticipated actual operation being much lower. Maximum annual emissions of any criteria pollutants is less than 1 tons per year for both the emergency generator and fire pump. Both engines will be equipped with a turbocharger and intercooler. The appropriate control evaluations for each pollutant are provided in the following subsections.

5.3.1 BACT for NO_x and VOC Emissions for the Emer. Gen. and Fire Pump

There are two mechanisms by which NO_x is formed in an IC engine: (1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_x) and (2) the conversion of nitrogen chemically bound in the fuel (fuel NO_x, or organic NO_x).

Thermal NO_x is formed in the combustion chamber when N_2 and O_2 molecules dissociate into free atoms at the elevated temperatures and pressures encountered during combustion and then recombine to form NO. The reaction rate toward NO formation increases exponentially with temperature. The NO further oxidizes to NO_2 and other NO_x compounds downstream of the combustion chamber.

Fuel NO_x (also known as organic NO_x) is formed when fuels containing nitrogen are burned. IC engines are typically fueled by natural gas or light distillate oil that typically contains little or no Fuel Bound NO_x (FBN). As a result, when compared to thermal NO_x, fuel bound NO_x is not a major contributor to overall NO_x emissions from most IC engines.

5.3.1.1 Proposed NO_x and VOC BACT for the Emer. Gen. and Fire Pump

The Project proposes BACT for the Emergency Generator as an emission limit of 4.8 g/hp-hr for NO_x and NMHC and the use of ULSD fuel, good combustion practices, limiting operations to emergency events and no more than 100 hr/yr for maintenance and readiness testing.

The Project proposes BACT for the Fire water pump as an emission limit of 3.0 g/hp-hr for NO_x and NMHC and the use of ULSD fuel, good combustion practices, limiting operations to emergency events and no more than 100 hr/yr for maintenance and readiness testing.

These are the applicable emission rates specified in 40 CFR 60, Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

5.3.2 BACT for PM/PM_{10} Emissions for the Emer. Gen. and Fire Pump

A top down analysis to determine the best available PM/PM_{10} control technology is provided in the following subsections.

5.3.2.1 Identification of Potential Control Technologies (Step 1)

Potential control technologies for PM emissions from diesel fired internal combustion engines include the following, ranked in order of potential effectiveness:

1. Add-on control (i.e., baghouse, scrubber, electrostatic precipitation, etc.)
2. Combustion of clean fuels (i.e., natural gas)
3. Implementation of good combustion practices

5.3.2.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down analysis is an evaluation of the technical feasibility of each of these control options.

1. Add-on Controls

No diesel fired internal combustion engines were identified in the permit review which utilized add-on control technology for PM/PM_{10} control. In the EPA *Draft New Source Review Guidance* document, technically feasible control technology is technology that has been commercially demonstrated (i.e., installed and operated successfully on a source similar to that under review.) Add-on PM/PM_{10} controls have not been commercially demonstrated on IC engines, thus this technology is not considered technically feasible for this application.

2. Combustion of Clean Fuels

The combustion of clean fuels to minimize PM/PM_{10} emissions is accomplished by burning fuels with minimal amounts of impurities in conjunction with good combustion practices. The Project proposes to burn very low sulfur diesel fuel (i.e., sulfur content less than or equal to 0.5% sulfur). Combustion of very low sulfur diesel fuel is technically feasible for the proposed engines.

3. Good Combustion Practices

Good combustion practices refer to the operation of the engines at high combustion efficiency, thus reducing products of incomplete combustion such as PM/PM_{10}. The engines will be designed to maximize combustion efficiency. The engine manufacturers will provide Operator and Maintenance manual(s) detailing methods to maintain a high level of combustion efficiency. Good combustion practices are technically feasible to control PM emissions from the proposed engines,

5.3.2.3 Proposed PM BACT for the Emer. Gen. and Fire Pump

The Project will elect to implement all of the remaining technically feasible control technologies, thus further review of economic, environmental, and energy impacts is unnecessary. **Based on the above analysis, the Project proposes BACT for PM/PM_{10} emissions from the Emergency Generator and Fire Water Pump to be combustion of low sulfur diesel fuel and good combustion practices.**

5.3.3 BACT for CO Emissions for the Emer. Gen. and Fire Pump

Carbon monoxide is an intermediate combustion product that forms when the oxidation of CO to CO_2 cannot proceed to completion. This situation occurs if there is a lack of available oxygen, if the combustion temperature is too low, or if the residence time in the cylinder is too short. A top down analysis to determine the best available CO control technology is provided in the following subsections.

5.3.3.1 Identification of Potential Control Technologies (Step 1)

Combustion design and catalytic oxidation are the potentially viable control alternatives.. The most stringent control technology for CO emissions is the use of an oxidation catalyst. Other acceptable control techniques include engine design, and good combustion practices.

5.3.3.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down analysis is an evaluation of the technical feasibility of each of these control options. Each of the potential control technologies considered is described below along with a discussion of the technical feasibility of each with respect to the Project.

1. <u>Oxidation Catalyst</u>

Oxidation catalysts (typically a precious metal deposited onto a solid honeycomb substrate) convert carbon monoxide (CO) to carbon dioxide (CO_2) in the presence of oxygen. This technology has not been applied on similar emergency use engines based on a review of BACT/LAER determinations. Therefore, the Project does not consider this technology technically feasible option for CO emissions control.

2. <u>Good Combustion Practices</u>

Good combustion practices refer to the operation of the engines at high combustion efficiency, thus reducing products of incomplete combustion such as CO. The engines will be designed to maximize combustion efficiency. The combustion turbine manufacturer will provide Operator and Maintenance manual(s) detailing methods to maintain a high level of combustion efficiency.

5.3.3.3 Proposed CO BACT for the Emer. Gen. and Fire Pump

The Project will elect to implement the remaining technically feasible control technology, thus further review of economic, environmental, and energy impacts is unnecessary. **Based on the evaluations above, the Project proposes good combustion practices as BACT.**

5.3.4 BACT for H_2SO_4 Emissions for the Emer. Gen. and Fire Pump

A top down BACT analysis is not applicable for H_2SO_4 emissions as the only control technique identified for H_2SO_4 emissions in the RBLC Database is the combustion of low sulfur fuels. There is no evidence that add-on controls have been installed for H_2SO_4 control from internal combustion engines; therefore, add-on controls are not considered as potential BACT for the proposed project. **The Project proposes BACT for H_2SO_4 emissions from the engines to be combustion of low sulfur fuel and an emission limit of 0.00023 lb/MMBtu.**

5.4 BACT FOR FUEL GAS PRE HEATERS

5.4.1 BACT for NOx and VOCs for Fuel Gas Pre Heaters

There is currently no technically feasible add-on control technology to reduce NOx or VOCs emissions from gaseous fuel-fired Fuel Gas Heaters of the size proposed for the Project. NOx is minimized in these units through good combustion practices, as well as LNB. LNB are designed to recirculate hot, oxygen-depleted flue gas from the flame or firebox back into the combustion zone. By doing this, the average oxygen concentration is reduced in the flame without reducing the flame temperatures below which is necessary for optimal combustion efficiency. Reducing oxygen concentrations in the flame reduces the amount of fuel NOx and VOCs generated. Although these efficient combustion techniques are targeted to reduce NOx emissions, they have a collateral benefit of reducing CO formation.

The Project proposed NOx and VOC emission level of 0.036 lb/MMBtu and 0.007 lb/MMBtu, respectively as BACT for the Fuel Gas Heaters.

5.4.1.1 BACT for PM for Fuel Gas Pre Heaters

A review of the RBLC, as well as USEPA and state permit databases indicates that there are no fuel gas pre heaters (i.e., small boilers) employing post-combustion control equipment to reduce PM, PM10, and PM2.5 to achieve BACT.

The Project proposes the use of clean fuels (i.e., low-sulfur, low-ash content), good combustion practices and an emission rate of 0.008 lb/MMBtu as BACT for PM, PM10, and PM2.5 emissions.

5.4.1.2 BACT for CO for Fuel Gas Pre Heaters

A review of the RBLC, as well as USEPA and state permit databases indicates that there are no fuel gas pre heaters (i.e., small boilers) employing post-combustion control equipment to minimize CO formation.

The Project proposes the use of clean fuels (i.e., low-sulfur, low-ash content), good combustion practices and an emission rate of 0.039 lb/MMBtu as BACT for CO emissions.

5.4.1.3 BACT for H_2SO_4 for Fuel Gas Pre Heaters

A review of the RBLC, as well as USEPA and state permit databases indicates that there are no fuel gas pre heaters (i.e., small boilers) employing post-combustion control equipment to minimize H_2SO_4 formation.

The Project proposes the use of clean fuels (i.e., low-sulfur, low-ash content), good combustion practices and an emission rate of 0.0001 lb/MMBtu as BACT for H_2SO_4 emissions.

5.4.2 BACT Analysis for Other Regulated Pollutants

Other regulated pollutants consist of non-criteria pollutants for which a regulatory standard has been established. These pollutants primarily fall into the category of speciated organic or metal compounds and the majority of these compounds are considered Hazardous Air Pollutants as defined in Section 112 of the Clean Air Act. Based on the emission rates expected from the proposed internal combustion engines, the level of emissions of "other regulated pollutants" will be very low. BACT for VOHAPs will be met by the same technology as proposed for BACT for

VOC emissions. Similarly, BACT for control of the low levels of particulate matter HAPS or PMHAPs will also be controlled by the BACT proposed for PM/PM_{10}.

5.5 CONTROL TECHNOLOGY DETERMINATION FOR THE MECHANICAL DRAFT COOLING TOWER

5.5.1 BACT for $PM/PM_{10}/PM_{2.5}$ Emissions for the Cooling Tower

Particulate emissions from the mechanical draft cooling towers consist of entrained dissolved solid impurities from water treatment chemicals and other solid impurities in the supply water used for the cooling tower circulation water. These impurities are in the water vapor exhausted from the tower and a portion of the water droplets emitted from the tower exhausts will evaporate, leaving the suspended or dissolved solids in the atmosphere. A search of BACT determinations for industrial wet cooling towers was conducted since the emissions profile from the evaporation tower is most similar to this type of process. The only control technology identified as BACT was mechanical drift eliminators.

The Project is proposing to install state-of-the-art demister to reduce drift and associated particulate matter emissions. This level of control is the maximum available from vendor of the mechanical draft cooling tower. No other types of $PM/PM_{10}/PM_{2.5}$ control equipment are known to be commercially available for this unique technology, and the RBLC search did not reveal any other types of control for similar industrial applications.

Therefore, the project proposes that the redundant baffle and mesh demister system is BACT for $PM/PM_{10}/PM_{2.5}$ emissions for the mechanical draft cooling tower. Since the top and technically feasible alternative has been selected as BACT, no further economic analyses are required, nor are they presented.

5.5.2 BACT Analysis for Other Regulated Pollutants for the Cooling Tower

The Project has estimated that emissions of other regulated air pollutants will be negligible from the cooling tower. Any potential regulated air pollutants will be entrained in the $PM/PM_{10}/PM_{2.5}$ emissions, which will be controlled by BACT as described in the previous section. The Project proposes that BACT for any negligible hazardous air pollutants potentially emitted from the evaporation tower be the same as BACT for $PM/PM_{10}/PM_{2.5}$ emissions.

5.6 FACILITY WIDE SUMMARY OF CONTROL TECHNOLOGY EVALUATION

A summary of the BACT emission limits and control technologies for the various emitting units of the Project is provided in Table 5-2.

Table 5-2
Control Technology Evaluation Summary

Emission Unit	Pollutant	Emission Limit	BACT
Combustion Turbines/ HRSG Duct Burners	NO_x	2.0 ppmvd	Dry Low NO_x Burners with SCR
	VOC	1.0 ppmvd w/o duct firing 2.0 ppmvd w/ duct firing	Oxidation catalyst and good combustion practice
	$PM/PM_{10}/PM_{2.5}$	0.0091 lb/MMBtu	Clean fuels and good combustion practice
	CO	2.0 ppmvd	Oxidation catalyst and good combustion practice
	H_2SO4	0.001 lb/MMBtu	Combustion of low sulfur fuel
Emergency Generator/ Fire Water Pump	NO_x	4.8 g/hp-hr/3.0 g/hp-hr	Combustion control (Retarded Timing and/or lean burn)
	VOC	1.2 lb/hr/1.0 lb/hr	Good combustion practice
	$PM/PM_{10}/PM_{2.5}$	NA	Clean fuels and good combustion practices
	CO	0.3 g/hp-hr/ 0.44 g/hp-hr	Good combustion practices
	H_2SO4	NA	Combustion of low sulfur fuel
Fuel Gas Pre Heaters	NO_x	0.036 lb/MMBtu	Low NO_x Burner and good combustion practices
	VOC	0.007 lb/MMBtu	Good combustion practice
	$PM/PM_{10}/PM_{2.5}$	0.008 lb/MMBtu	HEPA Filter
	CO	0.039 lb/MMBtu	Good combustion practice
	H_2SO4	0.0001 lb/MMBtu	Combustion of low sulfur fuel
Cooling Tower	$PM/PM_{10}/PM_{2.5}$	2.16 lb/hr	Drift Eliminators
Facility Wide Limit	GHG (CO_2)	5,135,347 tons/yr	Thermal efficiency/combustion air cooling and use of lower carbon fuels.

6. AIR QUALITY MODELING APPROACH

The air quality dispersion models used in the air quality modeling analysis of the MSCE Project were both screening and refined U.S. EPA air dispersion models. The procedures used in conducting the modeling analysis followed the requirements outlined in 40 CFR Part 51 Appendix W "Guideline on Air Quality Models" (U.S. EPA 2017), guidance provided by West Virginia DAQ, and other state and federal regulatory agency documents. An air quality modeling protocol was submitted to WV DAQ for review and approval.

6.1 AIR QUALITY MODEL SELECTION

6.1.1 Screening Air Quality Models

A screening level air quality model was used to obtain conservative modeled estimates of the air quality impact of the proposed project based on simplified assumptions of the model inputs (e.g., preset, worst-case meteorological conditions). The screening air quality model used is the AERSCREEN model (Version 16216). AERSCREEN is the EPA's recommended screening model for simple and complex terrain for single sources including point sources, area sources, horizontal stacks, capped stacks, and flares. AERSCREEN runs AERMOD (a refined air quality model) in a screening mode using a matrix of meteorological conditions.

6.1.2 Refined Air Quality Model

A second level of more sophisticated (Refined) models was also used. The refined air quality modeling analysis used the AERMOD (**AER**MIC **MOD**el) air dispersion model as the refined air quality model. A description of this model is provided in the following subsections.

6.1.3 AERMOD Model Selection

The **A**MS/**E**PA **R**egulatory **MOD**el (AERMOD, v19191) air dispersion model was used to perform the air quality modeling analysis. The AERMOD air dispersion model is an approved U.S. EPA air dispersion model for performing refined, multi-source air quality modeling studies. The AERMOD air dispersion model contains sophisticated dispersion algorithms. A description of the AERMOD model is provided below.

The American Meteorological Society (AMS) and the U.S. Environmental Protection Agency (EPA) formed the AMS/EPA **R**egulatory **M**odel **I**mprovement **C**ommittee (AERMIC) in 1991. The goal of the committee was to introduce planetary boundary layer (PBL) concepts into a new air dispersion model. The use of PBL concepts in AERMOD represents a more sophisticated approach to predicting plume dispersion than the approach used by the ISCST3 model. The PBL concepts include using dispersion parameters (sigma y and sigma z) that are based on either measured or estimated turbulent intensities, accounting for non-homogenous conditions throughout the PBL, improving the treatment of plume rise, and enhancing the way concentrations at complex terrain receptors (i.e. terrain receptors with elevations above stack top elevation) are predicted by incorporating the concept of a critical dividing streamline.

AERMOD uses an abbreviated approach to the three-dimensional terrain feature representation and critical dividing streamline approach that is used by the Complex Terrain Dispersion Model Plus Algorithms for Unstable Situations (CTDMPLUS). The AERMOD approach determines the fraction of the plume that is below the critical dividing streamline height (Φ from 0.0 to 1.0) and then uses that number as a scaling factor. The scaling factor, Φ, is multiplied by the concentration that represents the plume flowing around the terrain feature and then 1- Φ is multiplied by the concentration that represents the plume flowing over the terrain feature. The AERMOD concentration is the sum of the two, scaled concentrations. AERMOD differs from CTDMPLUS in its treatment of flow around a terrain feature by not considering the lateral splitting of the plume that occurs as the plume flows around a terrain feature. In its present form, AERMOD uses the Schulman-Scire and Huber-Synder downwash algorithms that are contained in ISCST3.

The AERMOD modeling system consists of two pre-processors and the dispersion model. AERMET (Version 19191) is the meteorological pre-processor and AERMAP (Version 18081) is the terrain pre-processor that characterizes the terrain and generates receptor elevations. The AERMET pre-processor, which is very similar to the CTDMPLUS meteorological pre-processor (METPRO), produces a file containing an hourly, vertical profile of the atmosphere and a file that includes surface and micrometeorological data. The AERMAP pre-processor is designed to develop receptor grid height information based on several potential sources including the National Elevation Database (NED) digital elevation data format. The development of the receptor grid includes assigning receptor elevations to the receptor locations and also assigning a hill height scale to each receptor. Receptor elevations are determined by finding the four closest NED elevation points to the receptor location and averaging the elevations to represent the receptor. Hill height scales for all receptors are determined by examining the height and proximity of all NED points within the modeled domain area to each receptor location. The domain used in AERMAP included the area covered by the Cartesian receptors plus an additional 5,000-meter buffer in the x and y-directions. Surface elevations for all receptors were obtained from the revised NED (National Elevation Database) data provided directly to the project by WVDEP.

Other components of this system include AERSURFACE, a surface characteristics preprocessor, and BPIPPRIME (BPIPPRM), a multi-building dimensions program incorporating the GEP technical procedures for PRIME applications.

The AERMOD air dispersion model has various options to simulate a variety of dispersion conditions for emissions from a stack or non-stack source. The U.S. EPA has recommended various default options to be used in dispersion modeling for regulatory purposes. These recommended regulatory default options will be used in the air quality impact analysis as follows:

- Stack-tip downwash.
- Model Accounts for Elevated Terrain Effects.
- Calms Processing Routine Used.
- No Exponential Decay for Rural Mode.
- Upper bound value for “super squat” buildings.
- Missing meteorological data processing used.

6.2 LANDUSE

The land use classification for the area was based on a quantitative review of land use patterns surrounding the proposed project site and Morgantown Airport. Satellite imagery from Google Earth for current conditions (2016) was inspected and compared to 2011 satellite imagery to determine the representativeness of the 2011 land use data. The satellite imagery for the 2011 and 2016 for the project area and Morgantown Airport are shown in Figures 6-1 and 6-2,

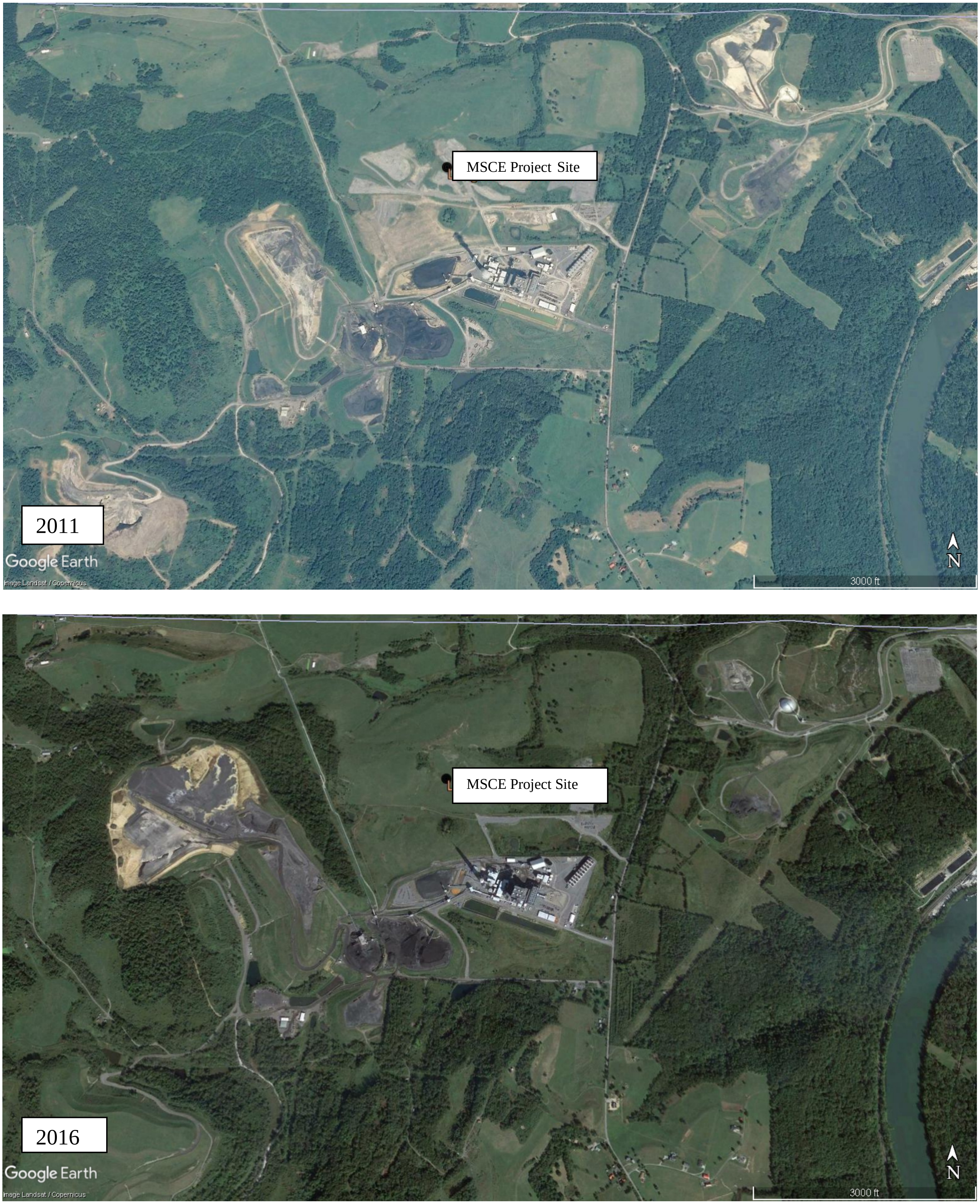


Figure 6-1
2011 and 2016 Satellite Imagery of the MSCE Project Area

Figure 6-2
2011 and 2016 Satellite Imagery of the Morgantown Airport Area

respectively. A qualitative visual assessment of these imageries indicates that the land use for 2011 is more than adequately representative of the current landuse conditions for both the project site and Morgantown Airport. Therefore, the 2011 National Land Cover Dataset (NLCD) was used to determine landuse for AERMOD and surface parameters for AERMET processing

The land use analysis followed the procedures recommended by the U.S. EPA (U.S. EPA 2000) and the typing scheme developed by Auer (Auer 1978). The Auer technique established four primary land use types: industrial, commercial, residential, and agricultural. Industrial, commercial, and compact residential areas are classified as urban, while agricultural and common residential areas are considered rural. For air quality modeling purposes, an area is defined as urban if more than 50 percent of the surface within 3 kilometers of the source falls under an urban land use type. Otherwise, the area is determined to be rural.

Although Morgantown, WV is in close proximity to the proposed site and represents a portion of the area that is classified as urban, a review of the gridded digital land use data and the 7.5 USGS topographic maps indicates that 98% of the area within the 3-kilometer radius is classified as rural for air quality modeling purposes (urban classifications were assumed to be category 22 (high intensity residential) and category 23 (commercial/industrial/transportation)). Based on the rural land use designation, AERMOD was used in the default (rural) mode to predict the ambient air concentrations associated with emissions from the proposed project.

6.3 RECEPTOR GRID

The AERMOD air quality modeling study used a Cartesian receptor grid network including fence line receptors. A description of the receptor grids network is provided in the following subsections.

6.3.1 AERMOD Receptor Grid

The receptor network for the AERMOD analysis minimally covered a square region 20-km on a side, centered on the proposed project site. All receptors were referenced to the UTM coordinate system (Zone 17), using the North American Datum of 1927 (NAD 27). A rectangular Cartesian coordinate receptor grid was used as the main receptor grid. The main receptor grid was centered on the CT stacks and have the following grid spacing:

- 100 meters out to ± 1 kilometer;
- 250 meters out to ± 2 kilometers;
- 500 meters out to ± 5 kilometers;
- 1,000 meters out to ± 10 kilometers.
- 2,000 meters out to ± 20 kilometers

In addition to the rectangular Cartesian coordinate receptor grid, a set of fenceline receptors were used. The fence line receptors were placed every 50 meters around the site fenced portion of the property.

Concentration contours maps were developed to determine the refined modeling grid requirements including extending the modeling domain and/or refining the resolution grid spacing. A more refined spaced receptor grid was developed and used in area of maximum predicted concentrations if the receptor spacing at the maximum location was greater than 100 meters. Further, the receptor grid was extended when maximum predicted concentrations occur near the edge of the receptor grid.

Terrain elevations were assigned to all receptors included in the air dispersion modeling analysis. The terrain elevations for the main receptor grid were developed using the AERMAP terrain preprocessor, and National Elevation Database (NED) format files as discussed in the previous section.

The Cartesian receptor grid were further refined based on the initial modeling results. Contour plots of the predicted concentrations were developed for each pollutant and averaging time. The contour plots were used to determine if refinements to the modeling domain and/or grid resolution are necessary. When predicted maximum or high concentrations occurred in a coarse section of the grid (greater than 100-meter spacing) that area of the grid was remodeled with a 50 meter spacing to determine refined maximum modeled concentrations.

6.4 METEOROLOGICAL DATA

The meteorological data for the AERMOD air dispersion model included both surface and upper air data from National Weather Service (NWS) observation stations. The representativeness and adequacy of the surface meteorological database was discussed in the Air Quality Modeling Protocol. A description of the procedures that were used to process the meteorological data is presented in the following subsections.

6.4.1 AERMOD Meteorological Data

The meteorological database for the AERMOD air dispersion model consisted of five years of surface meteorological data collected at the Morgantown Municipal Airport from 2014-2018. A wind rose for the Morgantown Airport is presented in Figure 6-3. The Morgantown meteorological data was previously used for the Longview Power Project (Unit 1) and a demonstration of the representativeness of the Morgantown Airport meteorological data for the MSCE Project is presented the Air Quality Modeling Protocol.

The Morgantown surface meteorological data were processed using the procedures described in the U.S. EPA AERMET meteorological processor. The AERMET preprocessor produces a file containing an hourly, vertical profile of the atmosphere and a file that includes surface and micrometeorological data.

The AERMET analysis included the use of both the AERMINUTE and the draft version of AERSURFACE. The use of the draft version of AERSURFACE required approval from US. EPA Region 3. The justification for the use of the draft version of AERSURFACE is contained in Appendix A of the Air Quality Modeling Protocol.

The AERMINUTE (Version 15272) meteorological data processor were used to produce wind speed and direction data based on archived 1-minute and 5- minute ASOS data for Morgantown Airport, for input into AERMET Stage 2. A 0.5 m/s wind speed threshold were applied to the 1-minute ASOS derived wind speeds in AERMET.

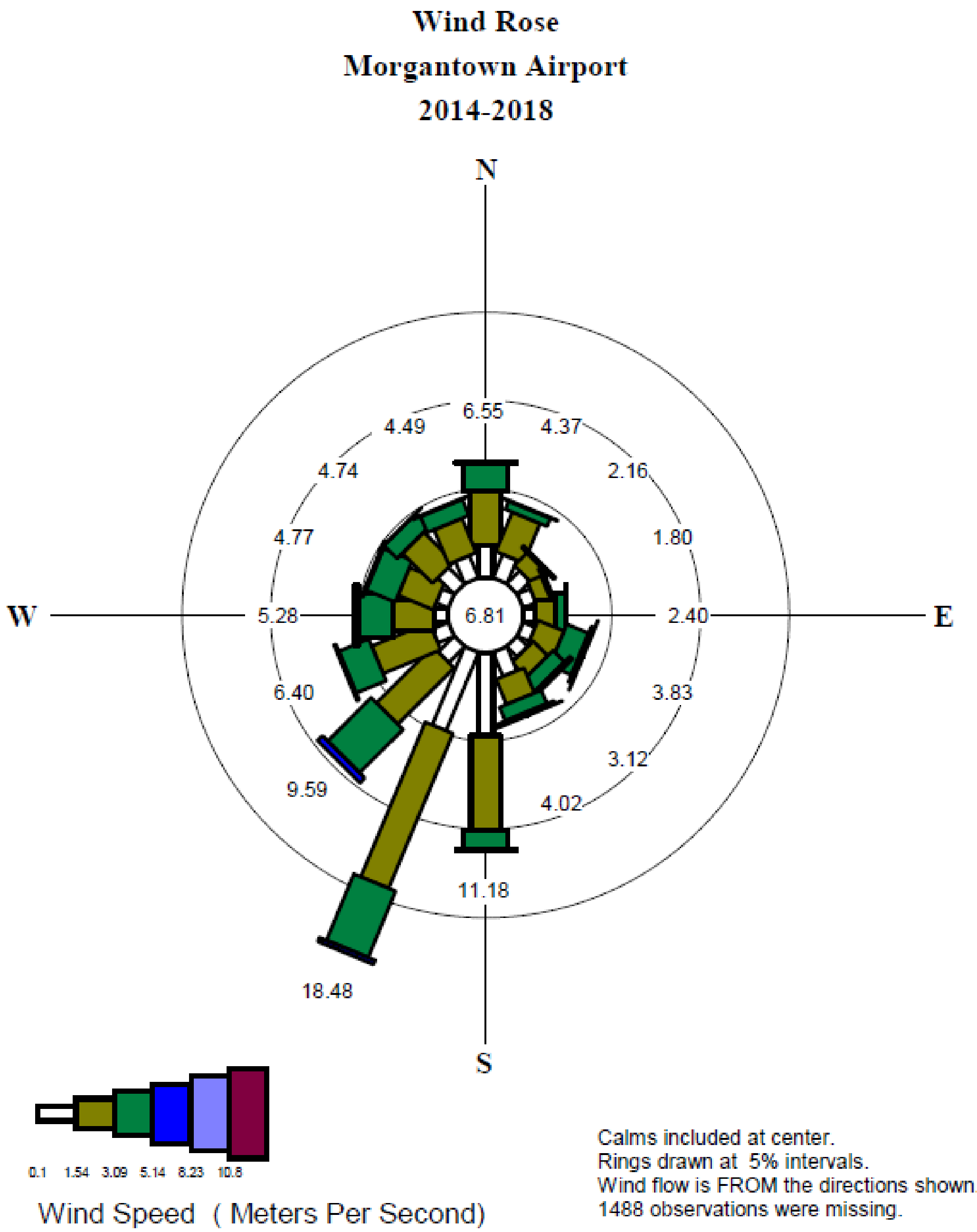


Figure 6-3
Wind Rose for Morgantown Airport (2014-2018)

The AERMET preprocessor also requires several micrometeorological variables for the project site area. The variables included surface roughness, Bowen ratio, and albedo. The values that were used in AERMET were determined using the latest version of the AERSURFACE pre-processor (Version 20060). AERSURFACE used 12 equal sectors by season and monthly moisture conditions.

The 2011 NLCD land use was used to develop the surface characteristics of the Morgantown Airport site and the MSCE Project site. Current satellite imagery (2016) was inspected and compared to the 2011 satellite imagery to determine the representativeness of the 2011 land use data. It was determined that the land use for 2011 is adequately representative of the current surface conditions.

A comparison of the surface characteristics of the Morgantown Airport site and the project site is presented in Table 6-1. As seen from this table the albedo and Bowen Ratios of the airport is consistent with the project site, but the surface roughness is not. Therefore, a sensitivity analysis of the impact of the difference in surface roughness on the predicted air quality concentrations of the project emission was performed. The procedure used is described in section 6.4.2.

Using the procedures described in AERMET, the surface meteorological data were combined with concurrent twice-daily rawinsonde data obtained from the NWS observation station in Pittsburgh, Pennsylvania. All NWS upper air and surface meteorological data were obtained from the National Climatic Data Center (NCDC).

6.4.2 Sensitivity Analysis

A site specific sensitivity analysis was performed following the AERMOD Implementation Guide (August 2019). The meteorological data (2014-2018) from Morgantown Airport (MGW) were processed through AERMET using both the micrometeorological variables (2011 NLCD data for albedo, Bowen ratio, and surface roughness length) associated with MGW as well as the

Table 6-1
Comparison of the Surface Characteristics of the Project Site and Meteorological Data Collection Site (Morgantown Airport – Average Moisture)

		Morgantown Airport			Project Site					Morgantown Airport			Project Site		
Season	Sector	Albedo	Bowen Ratio	Zo	Albedo	Bowen Ratio	Zo	Season	Sector	Albedo	Bowen Ratio	Zo	Albedo	Bowen Ratio	Zo
1	1	0.17	0.86	0.254	0.17	0.85	0.063	3	1	0.16	0.46	0.65	0.16	0.37	0.3
1	2	0.17	0.86	0.308	0.17	0.85	0.034	3	2	0.16	0.46	0.64	0.16	0.37	0.211
1	3	0.17	0.86	0.151	0.17	0.85	0.035	3	3	0.16	0.46	0.301	0.16	0.37	0.214
1	4	0.17	0.86	0.148	0.17	0.85	0.041	3	4	0.16	0.46	0.323	0.16	0.37	0.183
1	5	0.17	0.86	0.14	0.17	0.85	0.12	3	5	0.16	0.46	0.329	0.16	0.37	0.293
1	6	0.17	0.86	0.128	0.17	0.85	0.035	3	6	0.16	0.46	0.289	0.16	0.37	0.16
1	7	0.17	0.86	0.08	0.17	0.85	0.019	3	7	0.16	0.46	0.145	0.16	0.37	0.108
1	8	0.17	0.86	0.07	0.17	0.85	0.05	3	8	0.16	0.46	0.159	0.16	0.37	0.175
1	9	0.17	0.86	0.159	0.17	0.85	0.071	3	9	0.16	0.46	0.227	0.16	0.37	0.256
1	10	0.17	0.86	0.092	0.17	0.85	0.123	3	10	0.16	0.46	0.143	0.16	0.37	0.401
1	11	0.17	0.86	0.093	0.17	0.85	0.05	3	11	0.16	0.46	0.131	0.16	0.37	0.238
1	12	0.17	0.86	0.052	0.17	0.85	0.039	3	12	0.16	0.46	0.111	0.16	0.37	0.22
2	1	0.15	0.58	0.406	0.15	0.54	0.099	4	1	0.16	0.86	0.634	0.16	0.85	0.3
2	2	0.15	0.58	0.471	0.15	0.54	0.051	4	2	0.16	0.86	0.614	0.16	0.85	0.211
2	3	0.15	0.58	0.228	0.15	0.54	0.053	4	3	0.16	0.86	0.271	0.16	0.85	0.214
2	4	0.15	0.58	0.226	0.15	0.54	0.061	4	4	0.16	0.86	0.299	0.16	0.85	0.179
2	5	0.15	0.58	0.221	0.15	0.54	0.164	4	5	0.16	0.86	0.306	0.16	0.85	0.288
2	6	0.15	0.58	0.204	0.15	0.54	0.079	4	6	0.16	0.86	0.267	0.16	0.85	0.157
2	7	0.15	0.58	0.106	0.15	0.54	0.055	4	7	0.16	0.86	0.129	0.16	0.85	0.108
2	8	0.15	0.58	0.093	0.15	0.54	0.078	4	8	0.16	0.86	0.146	0.16	0.85	0.174
2	9	0.15	0.58	0.199	0.15	0.54	0.112	4	9	0.16	0.86	0.211	0.16	0.85	0.256
2	10	0.15	0.58	0.115	0.15	0.54	0.19	4	10	0.16	0.86	0.127	0.16	0.85	0.401
2	11	0.15	0.58	0.115	0.15	0.54	0.075	4	11	0.16	0.86	0.115	0.16	0.85	0.238
2	12	0.15	0.58	0.072	0.15	0.54	0.066	4	12	0.16	0.86	0.096	0.16	0.85	0.219

micrometeorological variables associated with the MSCE Project site using the latest version of AERSURFACE. The results of the CT/HRSG load analyses for all compounds and averaging periods using both meteorological data sets were compared to determine the meteorological data set (either MGW/MGW surface or MGW/MSCE surface) producing the maximum short-term concentrations. The meteorological dataset and CT/HRSG load identified as producing the maximum short-term concentrations were used for all further refined air quality modeling analyses.

6.5 GOOD ENGINEERING PRACTICE STACK HEIGHT ANALYSIS

Following U.S. EPA guidance contained in the "Guideline for Determination of Good Engineering Practice (GEP) Stack Height (Revised)" (U.S. EPA 1985), a GEP analysis was performed to evaluate the potential for building downwash on the stacks. The following procedures were used to analyze the stacks for downwash effects. The stacks and influencing buildings were located on a plant map and the coordinates were manually digitized. The stack height and relevant building dimensions were evaluated using the U.S. EPA Building Profile Input Program Prime (BPIPPRM, Date 04274). BPIPPRM determines, in each of the 36 wind directions (10° sectors), which building may produce the greatest downwash effects for a stack. The direction-specific dimensions produced by BPIPPRM were included in the AERMOD air quality modeling studies. Table 6-2 and Figures 6-2 summarizes and displays the building dimensions and structures that influence each stack. The BPIPPRM analysis indicated that the GEP height for all stacks is 250 ft., based on the preliminary height of the HRSG Drum Building. The CT, emergency generator, fire water pump and gas preheater stacks are within 500 ft. (the area of influence) of HRSG Drum Building which produced the controlling GEP heights for all sources. The stack height for the CT, gas preheater, emergency generators and fire water pumps are 180, 15, 35 and 35 ft. , respectively which are not GEP height and therefore do not avoid building downwash effects. Therefore, direction-specific building downwash dimensions were included in the AERMOD dispersion modeling analyses.

Table 6-2
Building Dimensions for GEP Height Analysis

Building/Structure	Height (ft.)	Maximum Projected Width (ft.)	Formula GEP height (ft.)	Radius of Influence (ft.)	Controlling Structure for Source(s)
Steam Turbine Building	96	350	240	480	No
Combustion Turbine					
Tier 1	50	405	125	250	Yes
Tier 2	100	304	250	500	Yes
HRSG Drum Platform North	100	276	250	500	Yes
HRSG Drum Platform South	100	276	250	500	Yes

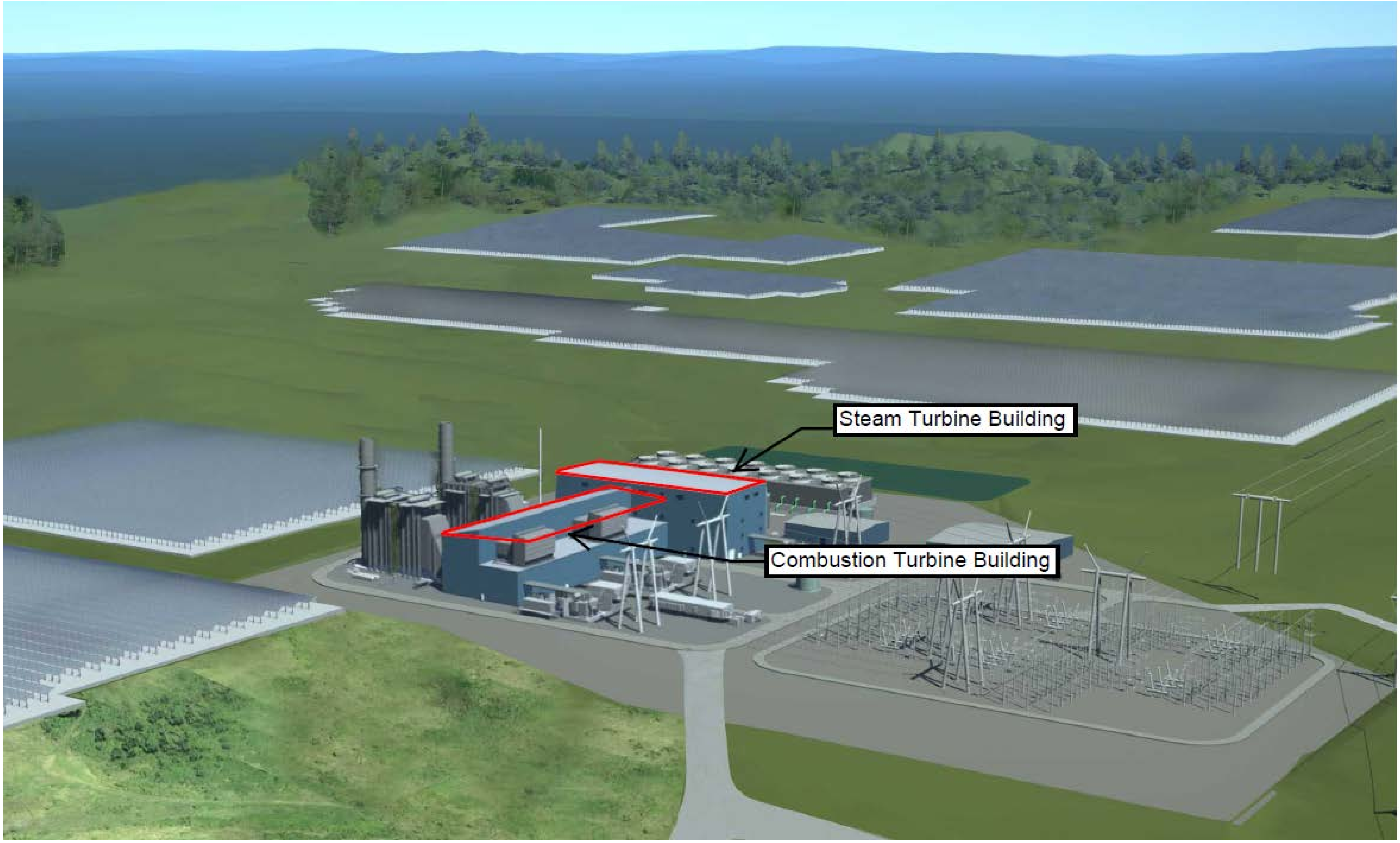


Figure 6-1
Structural Downwash Analysis

6.6 MODELED EMISSION RATES/STACK PARAMETERS

All loads and operating scenarios for normal operating conditions (34 operating scenarios, for winter, summer, average conditions, with and without duct burners and one and two combustion turbines operating) identified in Section 3 were initially modeled using meteorological data processed with the Morgantown Airport surface conditions and the stack parameters shown in Appendix E. The results are summarized in Table 6-3. As seen from this table operating conditions No 27 for the GE turbine produced the overall highest $PM_{2.5}$ concentrations (24-hr and annual), conditions No. 10 and 27 for the Mitsubishi turbine produced the overall highest 1-hr and annual NO_x concentrations, respectively. Conditions 10 and 14 for the Mitsubishi turbine produced the overall highest 1-hr and 8-hr CO concentrations, respectively.

These operating conditions and hourly emissions were used for all further pollutant and time period specific refined modeling including short-term and long-term averaging periods including SIL, cumulative multi-source and visibility analysis.

While the proposed MSCE Project is considered a base load power plant and thus is planned to operate 24 hrs/day, 7 days/week and 365 days/year with very infrequent startup and shutdown events, it is possible that as many as 234 combined hot, warm, and cold starts (and therefore shutdowns) could occur in a calendar year. As such, emissions expected for the startup and shutdown conditions were requested to be modeled to ensure compliance with the NAAQS for all pollutants with elevated startup emissions (1-hour NO_x and CO). Since these stacks undergo startup in series, only one unit will be in startup mode at a time, and were modeled as such, with both the north stack and south stack being analyzed, while the other unit was assumed to be at steady-state operation. The emission rates and stack parameters used for startup (based on vendor estimates) for the various pollutants are found in Table 6-4 below, while the NAAQS results of this startup/shutdown analysis are found in Section 7.

Table 6-3
Load Analysis Result

GE 7HA.03 Turbine		Max	MHPS Turbine		Max
Overall Max	Load No	µg/m³	Overall Max	Load No	µg/m³
NO_x 1hr	22	14.96	**NO_x 1hr**	**10**	16.23
NO_x Annual	22	0.223	**NO_x Annual**	**27**	0.249
CO 1hr	22	9.11	**CO 1hr**	**10**	9.88
CO 8hr	14	4.07	**CO 8hr**	**14**	4.16
$PM_{10/2.5}$ 24hr	**27**	3.06	$PM_{2.5}$ 24hr	14	2.36
$PM_{10/2.5}$ Annual	**27**	0.25	$PM_{2.5}$ Annual	14	0.17

Stack Parameter for Worst Case Loads

GE 7HA.03 Turbine		Case 10	Case 14	Case 19	Case 22	Case 27
Stack Height	ft.			180	180	180
Diameter	ft.			23.0	23.0	23.0
Temperature	°F			147.2	137.2	137.4
Actual Volume Flow	ft./sec			67.4	38.5	35.8
MHPS Turbine						
Stack Height	ft.	180	180			180
Diameter	ft.	23.0	23.0			23.0
Temperature	°F	209.6	163.0			206.7
Actual Volume Flow	ft./sec	45.1	62.6			44.9

Table 6-4
Startup/Shutdown Emission Rates and Stack Parameters

Turbine	GE	GE	MIT	GE	GE	MIT
SUSD	Cold Start	Warm Start	Warm Start	Hot Start	Shutdown	Shutdown
Final Blended Emissions (g/sec)						
NO_X	34.45	30.49		19.32		17.27
CO	192.46		56.04	74.67		26.77
$PM_{10/2.5}$	2.97	2.91		2.84	2.92	
Final Blended Stack Parameters						
Stack Height (m)	54.9	54.9	54.9	54.9	54.9	54.9
Stack Diameter (m)	7.01	7.01	7.01	7.01	7.01	7.01
Flow (mps)	10.0	9.56	15.5	14.08	18.0	18.0
Temp (K)	332.2	332.2	361.2	339.3	343.1	352.8

7. AIR QUALITY IMPACTS ANALYSIS

The air quality modeling analysis was used to determine the predicted ambient air concentrations resulting from emissions from the MSCE Project following the procedures and data described in Section 6 of this document and the approved Air Quality Modeling Protocol. The air quality modeling analyses were used to determine the significant impact area (SIA), the amount of PSD increment consumed, and the level of compliance with the National Ambient Air Quality Standards (NAAQS) and other air quality related values (AQRVs).

7.1 SIGNIFICANCE ANALYSIS

The air quality impact analysis initially evaluated emissions of CO, $PM/PM_{10}/PM_{2.5}$, and NO_x from the project to determine the significant area of impact. These were the only pollutant exceeding the PSD significant emission levels which required an air quality modeling analysis.

The Significant Impact Levels (SILs) are shown in Table 7-1. The EPA has historically cautioned states that the use of a SIL may not be appropriate when a substantial portion of any NAAQS or PSD increment is known to be consumed. Therefore, justification of the use of SILs is recommended in support of the PSD review record. To provide justification with respect to use of SILs in the significance and NAAQS analyses, the differences between the NAAQS and background concentrations determined to be representative of the Project impact area for applicable pollutant and averaging periods were compared to the applicable values. As shown in Table 7-2, the differences between the NAAQS and background concentrations are much higher than the corresponding SILs. Therefore, it is sufficient for WVDEP to conclude that an air quality modeled impact less than the SIL for each of the applicable compounds will not cause or contribute to a modeled violation of the NAAQS.

The Significant Impact Area (SIA) is defined as a circle with a radius extending from the reference origin of the proposed MSCE Project out to the greatest radius where a receptor has a maximum concentration equal to the significance levels. The SIA with the largest

Table 7-1
Significance Impact Levels (μg/m³)

Pollutant	Averaging Time	Class II	Class I EPA	Class I FLM
Sulfur Dioxide	Annual	1	0.1	0.03
	24-hour	5	0.2	0.07
	3-hour	25	1	0.48
	1-hour	7.8		
PM_{10}	Annual	1		
	24-hour	5	0.3	0.27
$PM_{2.5}$	Annual	0.3 0.2 proposed	0.27	
	24-hour	1.2	0.05	
Nitrogen Dioxide	Annual	1	0.1	0.03
	1-hr	7.5	NA	NA
Carbon Monoxide	8-hour	500	NA	NA
	1-hour	2,000	NA	NA

Table 7-2
Comparison of NAAQS, Representative Background Concentrations, and SILs

Pollutant and Averaging Period	Background	Background	NAAQS	NAAQS	SIL	NAAQS-Background Difference	Greater than SIL?
SO_2	(ppb)	(μg/m³)	(ppb)	(μg/m³)	(μg/m³)	(μg/m³)	
3-hour	20.6	53.6	75	195	5	141	YES
1-hour	16.0	41.6	500	1,300	1	1,258	YES
NO_2							
Annual	5.00	9.4	53	100	1	90.6	YES
1-hour	34.8	62.7	100	188	7.5	125	YES
$PM_{2.5}$							
Annual		7.6		12	0.2	4.4	YES
24-hour		18		35	1.2	17	YES
PM_{10}							
24-hour		135		150	5	15	YES
CO							
8-hour	0.9	1,028	35	40,000	2,000	38,972	YES
1-hour	1.9	2,169	9	10,000	500	7,830	YES

radial distance among the CO, $PM/PM_{10}/PM_{2.5}$, and NO_x is typically used for all further modeling, however since this SIA was approximately 16 km, the full 20-km grid was used for all subsequent modeling, outlined in Section 7.2. The further analysis was performed to determine compliance with the NAAQS and Class I and II PSD increments shown in Tables 7-3 and 7-4, respectively.

The air quality modeling analysis for the determination of the PSD pollutants with concentrations above the SIL used the maximum predicted concentrations (i.e. highest short-term and annual average concentrations) and NOT the statistical form of the NAAQS (i.e., 98th percentile, averaged over 3 years). As seen in Table 7-5 the 1-hr and annual NO_x and 24-hr and annual $PM_{2.5}$ had predicted concentrations above the SIL. Therefore, since only the NO_x and $PM_{2.5}$ had predicted concentrations above the SIL, these were the only pollutants and averaging periods requiring further analysis to demonstrate compliance with the NAAQS and PSD increments.

7.2 CLASS II AREA- MULTI-SOURCE IMPACT ANALYSIS

A discussion of the Class II area air quality impact analysis for NAAQS and PSD increment consumption is presented in the following sections.

7.2.1 NAAQS Analysis

Since the initial significance analysis indicated that the proposed project has significant impacts for 1-hr NO_x and 24-hr $PM_{2.5}$, a multi-source impact analysis was conducted. The multi-source impact analysis included all sources at the MSCE Project that emit $PM_{2.5}$ and NO_x. In addition, other major sources of the PSD pollutants (NO_x and $PM_{2.5}$) located within 30 km of proposed project were included in the offsite emission inventory.

The offsite emission inventory for West Virginia sources was obtained from a Freedom of Information Request (FOIA Request #2019-10-038) to WVDEP to obtain all major sources in the following counties: Marion, Monongalia, and Preston Counties. The inventory provided by WVDEP was actual emissions. The inventory was converted to maximum permitted emissions through a review of the Title V permit for each source and through the use of the offsite emission inventory previously developed for the Longview Power Unit 1 PSD application. The offsite emission inventory for Pennsylvania sources was obtained based on a review of Title V permits in the following counties: Greene and Fayette Counties and the most recent PSD permit application (APV Renaissance Energy Center, Monongahela Township, PA). The offsite emission inventory in Tables B-1 and B-2 of the APV Renaissance Energy Center PSD application

Table 7-3
National Ambient Air Quality Standards

Pollutant		Primary/Secondary	Averaging Time	Level	Form
Carbon Monoxide (CO)		primary	8 hours	9 ppm	Not to be exceeded more than once per year
			1 hour	35 ppm	
Lead (Pb)		primary and Secondary	Rolling 3 month average	0.15 µg/m3(1)	Not to be exceeded
Nitrogen Dioxide (NO2)		Primary	1 hour	100 ppb	98th percentile of 1-hour daily maximum concentrations, averaged over 3 years
		primary and Secondary	1 year	53 ppb (2)	Annual Mean
Ozone (O3)		primary and Secondary	8 hours	0.070 ppm (3)	Annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years
Particle Pollution (PM)	$PM_{2.5}$	Primary	1 year	12.0 µg/m^3	annual mean, averaged over 3 years
		Secondary	1 year	15.0 µg/m^3	annual mean, averaged over 3 years
		primary and Secondary	24 hours	35 µg/m^3	98th percentile, averaged over 3 years
	PM_{10}	primary and Secondary	24 hours	150 µg/m^3	Not to be exceeded more than once per year on average over 3 years
Sulfur Dioxide (SO2)		Primary	1 hour	75 ppb (4)	99th percentile of 1-hour daily maximum concentrations, averaged over 3 years
		Secondary	3 hours	0.5 ppm	Not to be exceeded more than once per year

(1) In areas designated nonattainment for the Pb standards prior to the promulgation of the current (2008) standards, and for which implementation plans to attain or maintain the current (2008) standards have not been submitted and approved, the previous standards (1.5 µg/m3 as a calendar quarter average) also remain in effect.
(2) The level of the annual NO2 standard is 0.053 ppm. It is shown here in terms of ppb for the purposes of clearer comparison to the 1-hour standard level.
(3) Final rule signed October 1, 2015, and effective December 28, 2015. The previous (2008) O3 standards additionally remain in effect in some areas. Revocation of the previous (2008) O3 standards and transitioning to the current (2015) standards will be addressed in the implementation rule for the current standards.
(4) The previous SO2 standards (0.14 ppm 24-hour and 0.03 ppm annual) will additionally remain in effect in certain areas: (1) any area for which it is not yet 1 year since the effective date of designation under the current (2010) standards, and (2)any area for which implementation plans providing for attainment of the current (2010) standard have not been submitted and approved and which is designated nonattainment under the previous SO2 standards or is not meeting the requirements of a SIP call under the previous SO2 standards (40 CFR 50.4(3)), A SIP call is an EPA action requiring a state to resubmit all or part of its State Implementation Plan to demonstrate attainment of the require NAAQS.

Table 7-4
Class I and II Areas
PSD Increments ($\mu g/m^3$)

Pollutant	Averaging Period	Class I	Class II
SO_2	Annual	2	20
	24-hour	5	91
	3-hour	25	512
PM_{10}	Annual	4	17
	24-hr	8	30
$PM_{2.5}$	Annual	1	4
	24-hour	2	9
NO_2	Annual	2.5	25

Table 7-5
Comparison of Maximum Predicted Concentrations (μg/m^3)
from the MSCE Project Emissions to SILs

Averaging Period	NO_x	PM_{10}	$PM_{2.5}$	CO
Normal Operation				
1-hr	**130.6**			66.4
8-hr				17.7
24-hr		3.87	3.17	
Secondary Formation			0.0195	
Total			**3.19**	
Annual	**1.24**		0.472	
Secondary Formation			0.000488	
Total			**0.472**	
Startup/Shutdown				
1-hr	**130.6**			867.1
Significant Impact Levels (SILs)				
Short-term (1-, or 24-hr)	7.5	5	1.2	2,000
Long-term (8-hr or Annual)	1	NA	0.2	500

were the basis for the PA and some WV major sources. The final offsite emission inventory used in the air quality modeling for the NAAQS and PSD increment analysis is presented in Table 7-6 and location of the facilities are presented in Figure 7-1.

An analysis of the location of minor sources and background air quality selected for the NAAQS analysis was performed to determine if the minor sources should be included in the multi-source modeling analysis or whether the existing background air quality data is conservatively high enough to represent the impact of the minor sources. It was determined that the minor sources were generally internal combustion engines and other small source of emissions and were already included in the maximum measured concentrations from ambient air monitoring stations over the previous 3 years (2016-2018). The background air quality selected for the NAAQS analysis is further discussed in Section 7.3. The NAAQS analysis was based on the form of the ambient standard either, maximum concentration or statistical analysis (i.e., highest second highest, annual maximum, 99^{th} percentile or 98^{th} percentile).

7.2.1.1 NAAQS Results

The NAAQS compliance assessment included the MSCE Project emissions, the offsite facilities including Longview Unit 1 (Table 7-6) and representative background concentrations (Table 7-8). The results of NAAQS modeling analysis are shown in Table 7-7. As seen from this table, the MSCE Project emissions did not produce ambient impacts above the SIL for either 1-hr NO_x or 24-hr $PM_{2.5}$ using the statistical form of the NAAQS for any modeled predicted concentrations above the NAAQS. Therefore, the Project is not causing or contributing to an exceedance of the NAAQS for NO_x or $PM_{2.5}$. Table 7-8 shows the startup and shutdown results as compared to the NAAQS for all Longview sources. Due to an offsite source, the NAAQS maximum impacts for the multi-source analysis do not change whether steady-state or SU/SD conditions are present for 1-hour NOx, and the NAAQS is similarly not threatened by any source in this analysis.

Table 7-6
Offsite Emission Inventory
NAAQS and PSD Increment Sources

Plant Name	Plant East (m)	Plant North (m)	Emission Unit	NOx (g/sec)	PM2.5 (g/sec)	Stack Height (m)	Diameter (m)	Temperature Deg (K)	Exit Velocity (mps)	Base Elevation (ft.)	Type of Stk	NAAQS /PSD
American Bituminous Power- Grant Town Plant	571850.0	4379442.9	Fluidized Bed Comb. Boil. (1S and 2S) Stack E1	5.57E+01	3.45E+00	99.7	1.068	435.9	24.31	1248	Vertical	NAAQS/PSD
Allegheny Gans Energy LLC / Gans Power Station U8	599464.3	4400417.6	Comb. Gas Turbine Unit 8	2.59E+00	1.81E-01	22.9	2.743	708.7	43.28	1152	Vertical	NAAQS
Allegheny Gans Energy LLC / Gans Power Station U9	599450.9	4400390.5	Comb. Gas Turbine Unit 9	2.59E+00	1.81E-01	22.9	2.743	708.7	43.28	1152	Vertical	NAAQS
Dynegy CTG 2 Stack	592544.2	4412645.3	CTG1, Firewater, Generator, Cooling, Boiler	4.40E+00	4.35E+00	61.0	6.096	366.5	17.10	1075	Vertical	NAAQS
Dynegy CTG 2 Stack	592511.3	4412671.4	CTG2	4.13E+00	4.27E+00	61.0	6.096	366.5	17.10	1075	Vertical	NAAQS
Longview Power Unit 1	589247.1	4395855.2	PC Boiler	5.01E+01	5.53E+00	168.9	7.849	324.8	15.12	1150	Vertical	NAAQS/PSD
Longview Power Unit 1	589510.1	4395873.5	Aux Boiler	3.71E-01	7.16E-03	61.0	1.219	435.9	24.00	1150	Vertical	NAAQS/PSD
Longview Power Unit 1	589517.8	4395822.6	Emergency Gen	3.02E-02	8.26E-04	6.7	0.229	588.7	13.11	1150	Vertical	NAAQS/PSD
Longview Power Unit 1	589542.8	4395905.2	Fire Water Pump	1.50E-02	2.75E-04	4.6	0.152	588.7	3.65	1150	Vertical	NAAQS/PSD
Longview Power Unit 1	589427.4	4395794.5	Coal Silos	0.00E+00	3.17E-02	58.5	0.305	294.3	38.81	1150	Vertical	NAAQS/PSD
Fort Martin Units 1 and 2 Stack	591846.3	4396059.8	Units 1 and 2	6.79E+02	3.47E+01	167.6	7.544	325.4	17.55	811	Vertical	NAAQS
Fort Martin EG1, EG2, Fire1, Fire2, Fire3 Stack	591846.3	4396059.8	EG s and Firewater Pumps	2.82E-01	2.44E-02	3.0	0.127	730.4	56.11	811	Vertical	NAAQS
Fort Martin Aux boiler 1 and 2 Stack	591846.3	4396059.8	Aux Boilers 1 and 2	5.15E-01	4.52E-02	67.1	2.012	569.3	7.98	811	Vertical	NAAQS
Morgantown Energy Facility Aux 1 and 2	589110.9	4388306.1	Aux 1 and 2	4.90E+00	5.71E-01	103.0	2.438	564.3	62.04	827	Vertical	NAAQS/PSD
Mylan EG 1 and 2	589329.1	4390554.0	EG 1 and 2 combined	4.54E-02	7.24E-04	3.0	0.305	949.8	19.40	1043	Vertical	NAAQS
Mylan Boilers 24524	589328.6	4390554.1	Boiler 24524*	7.41E-02	5.39E-03	4.9	0.396	505.4	9.33	1043	Rain Cap	NAAQS
Mylan Boiler 3	589329.1	4390554.0	Boiler 3	7.75E-02	5.63E-03	6.1	0.396	533.2	10.28	1043	Rain Cap	NAAQS
Mylan Boiler 5	589329.1	4390554.0	Boiler 5	7.41E-02	5.39E-03	6.1	0.396	533.2	9.84	1043	Rain Cap	NAAQS
Mylan Boiler 2	589329.1	4390554.0	Boiler 2	1.46E-02	1.06E-03	6.1	0.305	533.2	3.27	1043	Rain Cap	NAAQS

Table 7-6 (Con't)
Offsite Emission Inventory
NAAQS and PSD Increment Sources

Plant Name	Plant East (m)	Plant North (m)	Emission Unit	NOx (g/sec)	PM2.5 (g/sec)	Stack Height (m)	Diameter (m)	Temperature Deg (K)	Exit Velocity (mps)	Base Elevation (ft.)	Type of Stk	NAAQS /PSD
Mylan Boiler 1	589329.1	4390554.0	Boiler 1	4.13E-02	3.00E-03	6.1	0.305	533.2	9.26	1043	Rain Cap	NAAQS
Mylan Boilers 11 and 12	589331.0	4390516.9	Boilers 11 and 12	5.12E-02	3.72E-03	6.1	0.305	533.2	5.74	1043	Rain Cap	NAAQS
Mylan Boilers 2674, 2675	589343.4	4390476.8	Boilers 2674 and 2675	1.61E-02	1.17E-03	6.1	0.305	533.2	1.57	1043	Vertical	NAAQS
Mylan Pharmaceuticals Inc. Boiler 15	589343.4	4390476.8	Boiler 15	8.65E-02	6.29E-03	7.6	0.509	533.2	6.96	1043	Rain Cap	NAAQS
Mylan Pharmaceuticals Inc. Re Coating Pan	589343.4	4390476.8	Rep Coating Pan	0.00E+00	1.72E-01	8.2	0.701	255.4	3.67	1043	Vertical	NAAQS
Mylan Pharmaceuticals Inc. Re Rotclone	589343.4	4390476.8	Rep. Rotocolone	0.00E+00	2.41E-01	9.1	0.914	255.4	14.37	1043	Vertical	NAAQS
Mylan Pharmaceuticals Inc. Fluid Bed	589343.4	4390476.8	Fluid Beds	0.00E+00	2.17E-01	11.3	0.305	255.4	19.40	1043	Vertical	NAAQS
Mylan Boilers 7 and 8	589240.8	4390550.2	Boiler 7 and 8	1.77E-01	1.26E-02	18.9	0.549	533.2	5.98	1043	Rain Cap	NAAQS
Mylan Boiler 2342, 2344, 2345	589240.8	4390550.2	Boiler 2342, 2344, 2345	7.79E-01	7.24E-02	27.0	0.610	533.2	14.43	1043	Rain Cap	NAAQS
Mylan RTO	589246.0	4390507.1	RTO	4.29E-01	2.64E-02	24.4	1.372	374.3	6.71	1043	Vertical	NAAQS
Mylan Rep Dust Collector	589249.8	4390467.4	Rep Dust Collector	0.00E+00	9.22E-02	24.4	0.914	294.3	21.56	1043	Horizontal	NAAQS
Novelis	576728.9	4371605.9	#1 MILL APCD EMISSIONS	0.00E+00	2.75E-02	18.3	1.372	294.3	11.50	980	Vertical	NAAQS
Novelis	576776.8	4371623.5	#2 MILL APCD EMISSIONS	0.00E+00	2.75E-02	18.3	1.372	294.3	15.33	980	Vertical	NAAQS
Novelis	576780.5	4371630.8	#4 FCE COMB #4,5,6,7 PURG	2.96E-01	1.67E-02	61.0	0.457	352.6	0.05	980	Rain Cap	NAAQS
Novelis	576778.9	4371648.8	#5 FCE COMBUSTION	1.73E-01	1.26E-02	12.2	0.762	352.6	0.04	980	Rain Cap	NAAQS
Novelis	576728.8	4371628.2	#8 FCE PURGE & COMBUSTION	7.42E-02	5.39E-03	13.7	0.457	352.6	0.13	980	Rain Cap	NAAQS
ND Fairmont LLC	575073.0	4375238.0	Gas Boiler	2.34E+00	3.98E-02	18.3	1.829	435.9	6.40	920	Vertical	NAAQS
ND Fairmont LLC	575000.6	4375221.0	Dryer	0.00E+00	4.82E-01	22.6	1.829	304.5	13.39	920	Vertical	NAAQS
ND Fairmont LLC	575052.5	4375240.5	Emergency Generator	1.06E-02	5.23E-05	2.4	0.076	1015.9	57.23	920	Horizontal	NAAQS

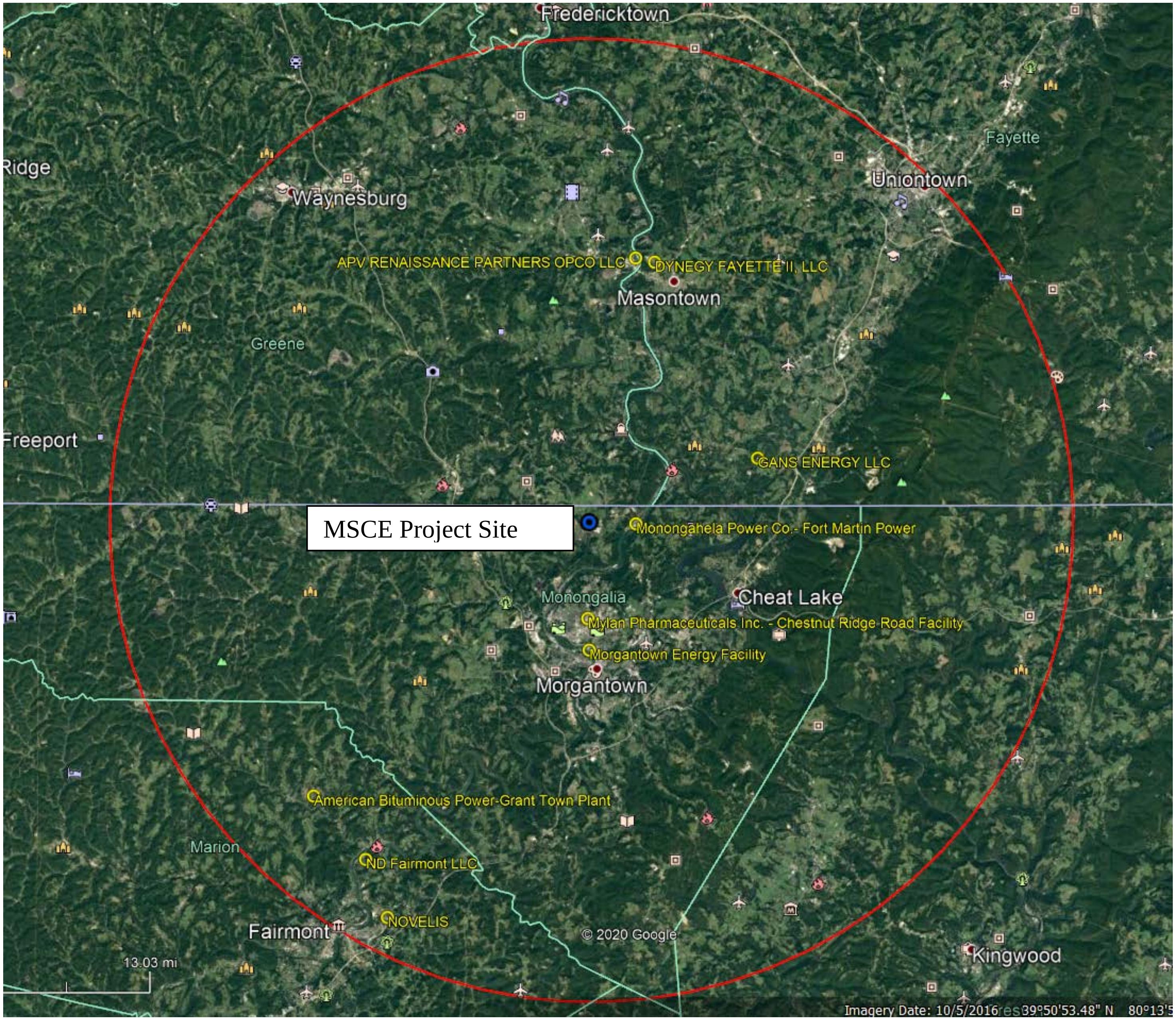


Figure 7-1
Location of Offsite Emission Inventory Facilities

Table 7-7
Comparison of Predicted Multi-Source Concentration to
SIL, NAAQS and PSD Increment

	NO_x (µg/m^3)	NO_x (µg/m^3)	$PM_{2.5}$ (µg/m^3)
NAAQS	**1-hr average H8H 5-yr Average (2014-2018)**	**Annual Average Max (2015)**	**24-hr average H8H 5-yr Average (2014-2018)**
All sources	163.5	8.70	139.4
Secondary Formation			0.0195
Background	62.7	9.4	18
Total	**226.2**	**18.1**	**157.4**
NAAQS	188	100	35
Maximum MSCE Project contribution to any predicted PSD Increment exceedance	1.92	0.04	0.20
SIL	7.5	1	1.2
PSD Increment			**24-hr average H2H (2014)**
All sources			3.83
Secondary Formation			0.0195
Total			**3.85**
Increment			8
Maximum MSCE Project contribution to any predicted PSD Increment exceedance			3.63
SIL			1.2

Table 7-8
Comparison of Predicted Maximum MSCE Concentrations to the NAAQS for Startup/Shutdown Conditions

Pollutant/Ave Period	Impact (µg/m³)	Background (µg/m³)	Total Impact (µg/m³)	NAAQS (µg/m³)	Exceeds NAAQS?	Max MSCE Project Contribution (µg/m³)	SIL (µg/m³)	Maximum Impact Case
NO_x/1-hr H8H/5-yr Average (2014-2018)	163.5	62.7	226.2	188	YES	7.48	7.5	Shutdown
CO/1-hr Maximum CT B (2017)	864.1	914.3	1,778.4	40,000	NO			Cold Start

7.2.2 PSD Increment Analysis

The PSD increment analysis included all PSD increment consuming sources identified in the offsite emission inventory for West Virginia and Pennsylvania and was used to assess PSD increment consumption. The PSD increment analysis was based on the maximum concentration for the form of the PSD increment.

Air quality increment consumption is tracked by tabulating the actual emissions changes at a stationary source, area source or mobile source since the minor source baseline date and changes in actual emissions at major stationary sources after the major source baseline date. To determine the air quality increment consumed in a region the net actual emissions changes are modeled to obtain an air quality increment consumption concentrations. The changes in emissions from existing sources and increases from proposed new sources since the baseline date are modeled together to determine the incremental change in air quality levels. These incremental changes in air quality levels are compared to the PSD increment.

The PSD major source baseline dates for West Virginia are January 6, 1975 for PM_{10} and SO_2, February 8, 1988 for NO_2 and October 20, 2010 for $PM_{2.5}$. The minor source baseline dates for Monongalia County, West Virginia are August 28, 1978 for SO_2, March 31, 2003 for NO_2, May 14, 2020 for $PM_{2.5}$ and November 25, 1980 for PM_{10}.

The results of PSD increment modeling analysis are shown in Table 7-7. As seen from this table, the MSCE Project emissions did not produce ambient impacts above the SIL for 1-hr NO_x. Further, it is shown that the project is not causing or contributing to an exceedance of the PSD increment for NO_x or $PM_{2.5}$ and no further modeling analysis is required.

7.2.3 Visibility Analysis

A screening Level 1 visibility assessment using VISCREEN (Version: 13190) was performed to assess potential visibility impact from the project. The model calculates the change in the color difference index (ΔE) and contrast between the plume and the viewing background. The selected sites for the Class II visibility analysis using VISCREEN are Mylan Park and the Morgantown Airport. Both represent areas where visibility is important for either recreational or commercial purposes. Mylan Park and the Morgantown Airport are approximately 10 km southwest and 9 km southeast, respectively of the MSCE Project site.

The results of the VISCREEN Level 1 analysis for Mylan Park and Morgantown Airport are shown in Table 7-9. As seen from this table, the plume perceptibility and contrast calculated by VISCREEN are below the Class I area criteria for the all sky and terrain background angles for Mylan Park and Morgantown Airport except for the 10 degree angle for plume perception. But these impacts are considered not significant since the Class I plume visibility screening criteria do not apply to Mylan Park and the Morgantown Airport which are in Class II areas and the emission rates used for MSCE Project are worst case conditions unlikely to occur in any one hour period. The emission used in the VISCREEN analysis included emissions from the two turbines operating at maximum hourly emissions simultaneously with the firewater pumps, emergency generator, gas pre-heaters and 234 startup and shut down events.

Although the Class I plume visibility screening criteria do not apply to Mylan Park and the Morgantown Airport which are in Class II areas, a Level 2 plume impact was performed using more realistic input for meteorological conditions and direction of transport of the emissions from the Project. The Level 2 analysis uses a joint frequency distribution of wind speed, wind direction and atmospheric stability (Pasquil Gifford stability classes) to determine the persistence, frequency and occurrence of worst case meteorological conditions for plume impairment.

The USEPA STAR program was used to prepare a joint frequency table of winds, and atmospheric stability for five years of meteorological data (2014-2018) from Morgantown Airport. The joint frequency was used to identify the worst case meteorological conditions for the wind directions that would transport the Project emissions to both Mylan Park and Morgantown Airport. The critical wind directions are Northeast for Mylan Park and Northwest for Morgantown Airport. The worst case meteorological condition is defined as:

Worst case meteorological condition = $\sigma_y \sigma_z U$

Table 7-9
Level 1 Plume Visual Impact Analysis

Pollutant	Emission Rate (tons/year)	Meteorological and Transport Parameters						
Particulates	215	Plume-Source-Observer Angle (degrees)	11.25					
Total NOx as NO_2	303	Stability	F					
Primary NO_2	0.0	Wind Speed (mps)	1					
Soot (elemental C)	0	Background Ozone (ppm)	0.04					
Primary SO_4	0	Background visual range	20					
Visual Impact: Mylan Park		**Source-observer distance: 10 km**						
					Plume Perceptibility [d] (ΔE)		**Contrast (|C|) [e]**	
Background	**Theta [a] (degrees)**	**Azimuth [b] (degrees)**	**Distance (km)**	**Alpha [c] (degrees)**	**Criteria**	**Plume**	**Criteria**	**Plume**
Sky	10	84	10	84	2.30	2.755	0.05	0.023
Sky	140	84	10	84	2.00	0.889	0.05	-0.018
Terrain	10	84	10	84	2.00	3.732	0.05	0.039
Terrain	140	84	10	84	2.00	0.598	0.05	0.022
Visual Impact: Morgantown Airport		**Source-observer distance: 9 km**						
Sky	10	84	9	84	2.43	2.986	0.05	0.025
Sky	140	84	9	84	2.00	0.980	0.05	-0.019
Terrain	10	84	9	84	2.00	4.413	0.05	0.044
Terrain	140	84	9	84	2.00	0.696	0.05	0.024

a Theta is the vertical angle subtended by the plume
b Azimuth is the angle between the line connecting the source, observer and the line of sight
c Alpha is the angle between the line of sight and the plume centerline
d Plume perceptibility parameter (dimensionless)
e Visual contrast against background parameter (dimensionless)

which is the product of Pasquill Gifford horizontal (σ_y) and vertical (σ_z) diffusion coefficient and maximum wind speed (U) for the given wind speed category in the joint frequency table and which has a cumulative probability of occurring 1% of the year (88 hours).

The summary of the joint frequency analysis indicates that wort case meteorological conditions for Northeast winds is stability class D with winds speed 4-7 mph and for Northwest winds is stability class E with winds speeds of 4-7 mph. These meteorological conditions were then used as input to the VISCREEN model to determine the Level 2 visibility impact. The results of the VISCREEN Level 2 analysis for Mylan Park and Morgantown Airport are shown in Table 7-10. As seen from this table, the plume perceptibility and contrast calculated by VISCREEN are below the Class I area criteria for the all sky and terrain background angles for Mylan Park and Morgantown Airport.

7.2.4 Secondary Aerosol Formation (MERP)

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 (USEPA, 2019) was used to demonstrate the effects of NO_x, SO_2 and VOC emissions from the proposed project on ozone and secondary formation of $PM_{2.5}$. A representative hypothetical source was identified from the Appendix Table A-1 of the guidance document. The hypothetical source selected was Doddridge in West Virginia (Source No. 7) which is located 74 km, south southeast of the proposed project. The Doddridge source is the only source located in West Virginia but more importantly is also in a similar regional airshed as the proposed project. Due to the close regional proximity of the Doddridge source and the similar regional airshed, the MERP for this source can be used to assess the Project's emissions of precursors against the appropriate "critical air quality threshold".

The MERP values for NO_x, SO_2 and VOC for Doddridge used in this analysis are based on a hypothetical 500 ton/year source and a 90 ft. stack (USEPA, Support Center for Regulatory Atmospheric Modeling (SCRAM), MERPs View Qlik).

Table 7-10
Level 2 Plume Visual Impact Analysis

Pollutant	Emission Rate (tons/year)	Meteorological and Transport Parameters						
Particulates	210	Plume-Source-Observer Angle (degrees)					11.25	
							Mylan	MGW
Total NOx as NO_2	321	Stability					D	E
Primary NO_2	0.0	Wind Speed (mps)					2.5	2.5
Soot (elemental C)	0	Background Ozone (ppm)					0.04	
Primary SO_4	0	Background visual range					20	
Visual Impact: Mylan Park		**Source-observer distance: 10 km**						
					Plume Perceptibility [d] (ΔE)		**Contrast (|C|) [e]**	
Background	**Theta [a] (degrees)**	**Azimuth [b] (degrees)**	**Distance (km)**	**Alpha [c] (degrees)**	**Criteria**	**Plume**	**Criteria**	**Plume**
Sky	10	84	10	84	6.11	0.403	0.10	0.003
Sky	140	84	10	84	2.00	0.132	0.10	-0.003
Terrain	10	84	10	84	5.01	0.537	0.10	0.005
Terrain	140	84	10	84	2.00	0.083	0.10	0.003
Visual Impact: Morgantown Airport		**Source-observer distance: 9 km**						
Sky	10	84	9	84	3.92	0.745	0.06	0.006
Sky	140	84	9	84	2.00	0.248	0.06	-0.005
Terrain	10	84	9	84	3.14	1.083	0.06	0.011
Terrain	140	84	9	84	2.00	0.164	0.06	0.006

7.2.4.1 SIL Analysis for Ozone

The following equations were used to evaluate the Project's secondary impact to the SI for Ozone. An impact of less than 1 indicates that the Project would not produce a concentration exceeding the SIL.

$MERP_{Ozone}$ = (MSCE NO_x emissions (tpy)/NO_X MERP (tpy)) + (MSCE VOC emissions (tpy)/VOC MERP (tpy))

The results of the MERP analysis in Table 7-11 indicate that ozone is in excess of the SIL but when combined with the background is less than the ozone NAAQS. $PM_{2.5}$ was already shown to be in excess of the SIL therefore, the calculation of the MERP is not needed.

7.2.4.2 Secondary Analysis for $PM_{2.5}$

Since $PM_{2.5}$ was shown to be in excess of the SIL from primary (direct) emission from the Project, the determination of secondary formation of $PM_{2.5}$ from direct emissions of NOx and SO_2 is required. The USEPA model results for the hypothetical source No. 7 in West Virginia (Doddridge) were used to develop linear equation for the predicted $PM_{2.5}$ concentrations from direct emissions of NO_x and SO_2 for a 90ft stack ht. The equations are shown in Figure 7-2. The Project's emission for NO_x and SO_2 were used with these linear equations to determine the secondary formation of 24hr and annual $PM_{2.5}$ concentrations. The secondary 24-hr and annual $PM_{2.5}$ concentrations were then added to the predicted concentration from direct (primary) Project emissions to assess compliance with NAAQS and PSD increments. The secondary concentrations are included in Tables 7-5 and 7-7.

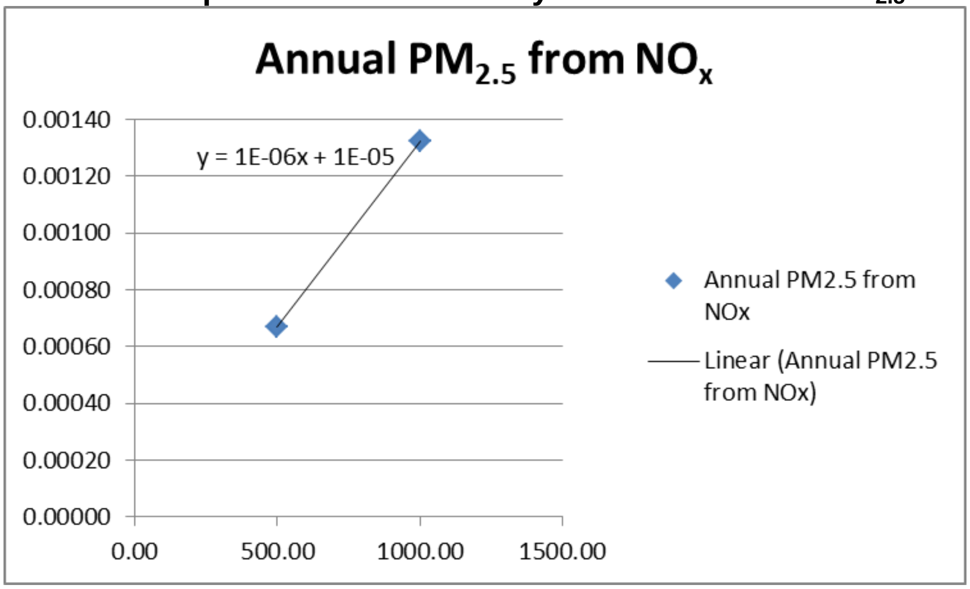
7.3 BACKGROUND AMBIENT AIR DATA

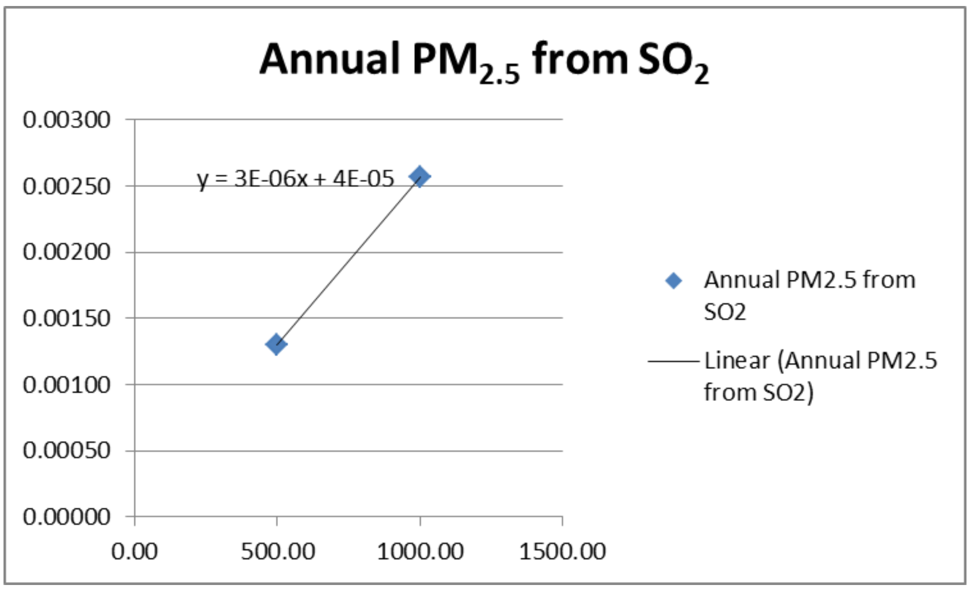
Background ambient air quality values are required as part of the NAAQS analysis. The background values should be representative of the background pollutant concentration levels that could be expected to occur in the vicinity of the MSCE Project. Therefore, ambient air

Table 7-11
MERP Analysis for O_3 for SIL and NAAQS

Ozone MERP - SIL Results									
MSCE NO_X	MERP NO_X	MSCE VOC	MERP VOC	Cumulative MERP O_3					
Tons/year	Tons/year	Tons/year	Tons/year						
321	262	141	5,170	1.25					
Ozone - NAAQS MERP Results									
Background O3	MSCE NO_X	MERP NO_X	MSCE VOC	MERP VOC	SIL O_3		Cumulative Ozone	NAAQS	Below
ppb	Tons/year	Tons/year	Tons/year	Tons/year	µg/m^3		ppb	ppb	
60	321	262	141	5,170	1		61.2	70	Yes

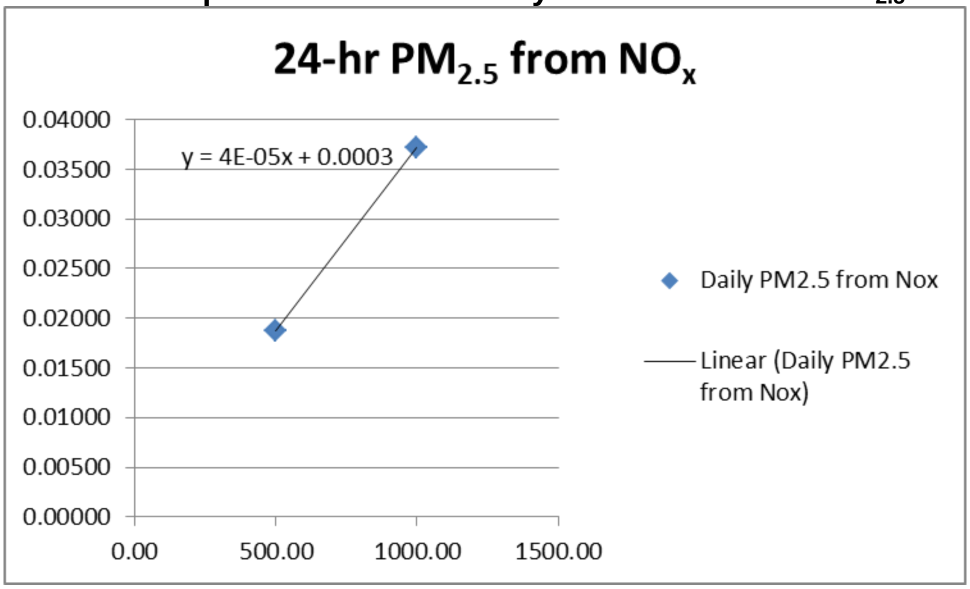
Figure 7-2
Linear Equations for Secondary 24-hr and Annual $PM_{2.5}$

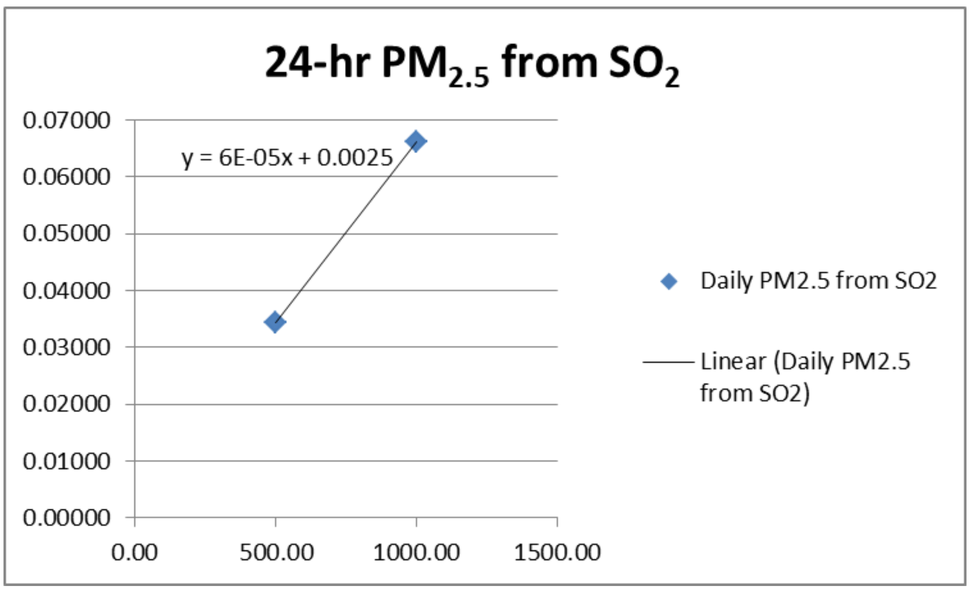




Annual Secondary $PM_{2.5}$ due to NO_X = 1E-06*(321 tpy) +1E-5 = 0.000331 $\mu g/m^3$
Annual Secondary $PM_{2.5}$ due to SO_2 = 3E-06*(39.9 tpy) +4E-05 = 0.000157 $\mu g/m^3$
Total Secondary $PM_{2.5}$ (Annual) = 0.000488 $\mu g/m^3$

Figure 7-1 (con't)
Linear Equations for Secondary 24-hr and Annual $PM_{2.5}$





24-hr Secondary $PM_{2.5}$ due to NO_X = 4E-05*(321 tpy) +0.0003 = 0.0147 µg/m3
24-hr Secondary $PM_{2.5}$ due to SO_2 = 6E-05*(39.9 tpy) +0.0025 = 0.00489 µg/m3
Total Secondary PM2.5 (24-hr) = 0.0195 µg/m3

data from a West Virginia DAQ monitoring station in Morgantown, WV, Ohio EPA monitoring station in Shadyside, OH and Pennsylvania DEP monitoring station in Charleroi, PA were reviewed in order to select representative background pollutant concentration data. A summary of the air quality data from monitoring stations in Morgantown, WV, Shadyside, OH and Charleroi, PA are presented in Table 7-12. The maximum measured concentrations from these monitoring stations over the previous 3 years (2016-2018) were used to establish the existing ambient air quality levels for NAAQS compliance evaluation. A demonstration of the representativeness of these monitoring stations for the MSCE Project was discussed in the Air Quality Modeling Protocol submitted to WV DEP.

7.4 CLASS I AREA ASSESSMENT

An assessment of potential project impacts on increment consumption, visibility and other air quality related values (AQRVs) in Class I areas is a requirement for PSD projects. Air quality impacts at Class I areas must be assessed under PSD regulations if they are within 100 km of the PSD source, or if the PSD source is judged to have a potential effect at Class I areas at distances beyond 100 km

There are four (4) Class I areas within 250 km of the proposed site of the MSCE Project. These areas are the Dolly Sods, Otter Creek and James River Face National Wilderness Areas and the Shenandoah National Park. The Dolly Sods, Otter Creek, James River Face and Shenandoah areas are approximately 91 km southeast, 78 km south-southeast, 237 south-southeast, and 173 km southeast respectively, of the proposed project site. The locations of the Class I areas relative to the proposed plant site are shown in Figure 7-3.

The initial screening method described in Section 3.2 of the FLAG (2010) document was used to evaluate the impacts of the proposed MSCE Project on the Class I areas. The FLAG member agencies that administer Federal Class I areas (U.S. Forest Service (USFS) the National Park Service (NPS) and U.S. Fish and Wildlife Service (FWS)) will consider a source locating greater than 50 km from a Class I area to have negligible impacts with respect to Class I AQRVs if its total SO_2, NO_x, PM_{10}, and H_2SO_4 annual emissions (in tons per year, based on 24-hour

Table 7-12
Proposed Background
Ambient Air Data for NAAQS Analysis

Pollutant and Averaging Period	Design Values			Site Location
	2017	2018	2019	
SO_2 (ppb)				
3-hour	10.6	6	20.6	Morgantown Airport US 119 & Airport Blvd. (AQS Site ID 54-061-0003)
1-hour	11.0	14.0	16.0	
NO_2 (ppb)				
Annual	5.00	5.00	5.00	220 Meddings Road Charleroi, PA (AQS Site ID 42-125-0005)
1-hour	35	34	33	
$PM_{2.5}$ (µg/m3)				
Annual	7.60	7.20	7.10	Morgantown Airport US 119 & Airport Blvd. (AQS Site ID 54-061-0003)
24-hour	18	17	17	
PM_{10} (µg/m3)				
24-hour	135	61	73	2 Ball Park Rd Shadyside, OH (AQS Site ID 39-013-0006)
CO (ppm)				
8-hour	0.60	0.60	0.90	2 Ball Park Rd Shadyside, OH (AQS Site ID 39-013-0006)
1-hour	0.80	0.80	1.90	
O3 (ppm)				
8-hr	0.06	0.06	0.06	Morgantown Airport US 119 & Airport Blvd. (AQS Site ID 54-061-0003)

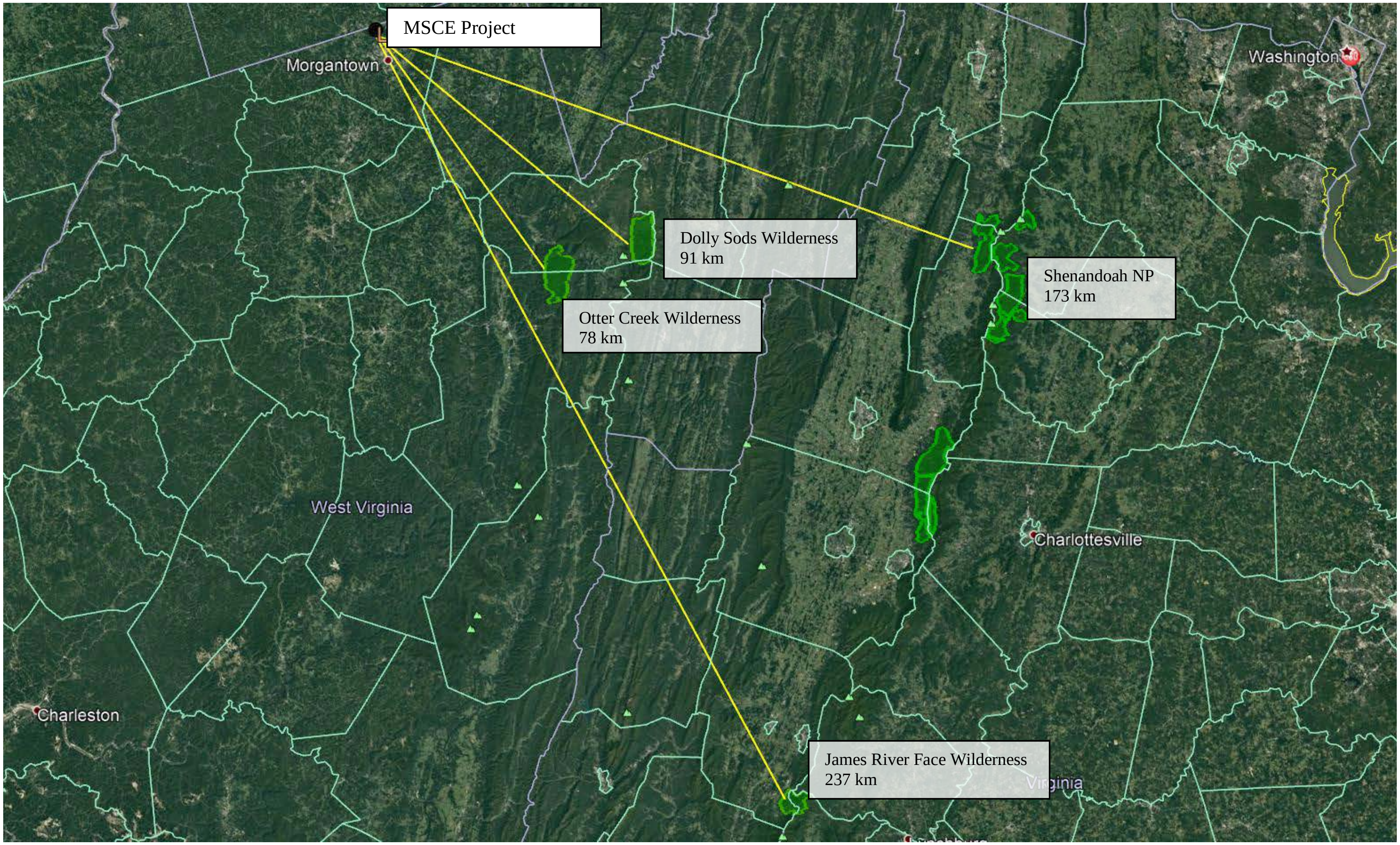


Figure 7-3
Location of Class I Areas

maximum allowable emissions), divided by the distance (in km) from the Class I area (Q/D) is 10 or less. The Agencies would not request any further Class I AQRV impact analyses from such sources. The Q/D calculation for the proposed project is shown in Table 7-13. As seen from this table the Q/D calculation is less than ten for all four Class I Areas, therefore, no further Class I impact analysis is required for AQRV.

A Class I NAAQS and PSD increment screening level assessment following the procedure described in Section 4.2 of Appendix W was also performed. Preliminary modeling using the preferred near field refined air quality model (AERMOD) was used to determine the significance of the ambient impacts at 50 km from the proposed MSCE project. These results are shown in Table 7-14. As seen from this table all of the impacts are less than significance levels for Class I areas.

Since the predicted concentrations are less than the significance levels at 50 km, no further analysis was performed for the screening Class I NAAQS/PSD increment screening analysis. The nearest Class I area is Otter Creek Wilderness which 78 km south-southeast of the project site.

7.5 OTHER AIR QUALITY RELATED VALUES ANALYSIS

PSD regulations also require an analysis of the effects of the proposed project on AQRVs in areas surrounding the project. These AQRVs include effects of other growth (residential, commercial, or industrial) associated with the project and possible impacts on sensitive flora, fauna, and soils. Growth-related AQRVs, such as influxes of additional population or increases in vehicular traffic, will not be significantly affected by the proposed project. The electricity produced by the project will be transmitted over a multi-state power grid and will not directly enable or support any additional local commercial, industrial, or residential development. The

labor force required to operate the facility will be small and will be drawn from the local communities. Therefore, there are no anticipated effects on growth.

Table 7-13
Q/D Calculations for Class I Areas

Total Project Emissions	**Q (tpy)**		
SO_2, NO_x, PM_{10}, and H_2SO_4	607		
Class I Area	**D (km)**	**Q/D**	**Q/D < 10?**
Shenandoah National Park	173	3.51	Yes
Dolly Sods	91	6.67	Yes
Otter Creek	78	7.79	Yes
James River Face	237	2.56	Yes

Table 7-14
Maximum Predicted Impact from the MSCE Project at 50km Distance

Averaging Period	NO_x	PM_{10}	$PM_{2.5}$	CO
1-hr	2.84			0.78
8-hr				0.30
24-hr		0.09	0.09	
Annual	0.01	0.011	0.011	
Significant Impact Levels (SILs)				
Short-term (1-,3-,-8, or 24-hr)	NA	0.3	0.27	NA
Long-term (Annual)	0.1	0.2	0.05	NA

Evaluation of potential impacts on vegetation and soils were performed by comparison of maximum modeled impacts from the Project to Air Quality Related Value (AQRV) screening concentrations provided in the EPA document "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals" and to NAAQS secondary standards. The screening levels represent the minimum concentrations in either plant tissue or soils at which adverse growth effects or tissue injury was reported in the literature. The NAAQS secondary standards were set to protect public welfare, including protection against damage to crops and vegetation. Therefore, comparing maximum predicted concentration due to the project to the AQRVs and the secondary NAAQS provides an indication as to whether potential impacts are likely to be significant. A comparison of the predicted concentrations to the screening AQRV is presented in Table 7-15. As seen from this table, maximum predicted concentrations due to the Project are well below the AQRVs and the secondary NAAQS.

Table 7-15
Comparison of the Maximum Predicted Air Quality Concentrations (µg/m³) to the Screening Level AQRVs and the NAAQS Secondary Standards

Pollutant	Averaging Period	AQRV Screening Levels	Secondary NAAQS	Maximum Predicted Concentration
PM_{10}	24-hour	NA	150	3.87
	Annual	NA	50	0.472
$PM_{2.5}$	24-hour	NA	35	3.19
	Annual	NA	15	0.472
NO_2	4-hour	3,760	NA	130.6
	8-hour	3,760	NA	130.6
	1-month	564	NA	1.24
	Annual	100	100	1.24
CO	Weekly	1,800,000	NA	867.1

As further analysis of the potential impact of the proposed project on air quality related values a screening level visibility assessment using VISCREEN (Version: 13190) was performed for the Class I areas between the plume and the viewing background. If the hourly estimates of ΔE is less than to 2.0 or the absolute value of the contrast values ($|C|$) is less than 0.05, then no further visibility analysis is required. The results indicate that the potential emission of NO_x and $PM_{2.5}$ would produce a change in color difference of 0.062 and a contrast of 0.001 in the nearest Class I area, Otter Creek Wilderness.

8. REFERENCES

U.S. EPA 1985 – “Guidelines for Determination of Good Engineering Practice Stack Height (Technical Support Document for Stack Height Regulations) Revised” EPA-450:4-80-023R, June 1985.

U.S. EPA 1987 – “Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD) May 1987.

U.S. EPA 1993 – “User's Guide to the Building Profile Input Program”, October 1993.

U.S. EPA 2018 – “Users Guide for the AERMOD Terrain Preprocessor (AERMAP) Revised – Draft” April 2018.

U.S. EPA 2017 – 40 CFR Part 51 Appendix W “Guideline on Air Quality Models (Revised)”, January 17, 2017

U.S. FS 2010 – “Federal Land Managers’ Air Quality Related Values Workgroup (FLAG) Phase I Report” 2010.

APPENDICES

APPENDIX A - WV DAQ APPLICATION FORMS

WEST VIRGINIA DEPARTMENT OF ENVIRONMENTAL PROTECTION

DIVISION OF AIR QUALITY

601 57th Street, SE
Charleston, WV 25304
(304) 926-0475
www.dep.wv.gov/daq

APPLICATION FOR NSR PERMIT AND TITLE V PERMIT REVISION (OPTIONAL)

PLEASE CHECK ALL THAT APPLY TO **NSR (45CSR13)** (IF KNOWN):

☒ **CONSTRUCTION** ☐ **MODIFICATION** ☐ **RELOCATION**
☐ **CLASS I ADMINISTRATIVE UPDATE** ☐ **TEMPORARY**
☐ **CLASS II ADMINISTRATIVE UPDATE** ☐ **AFTER-THE-FACT**

PLEASE CHECK TYPE OF **45CSR30 (TITLE V)** REVISION (IF ANY):

☐ **ADMINISTRATIVE AMENDMENT** ☐ **MINOR MODIFICATION**
☐ **SIGNIFICANT MODIFICATION**

IF ANY BOX ABOVE IS CHECKED, INCLUDE TITLE V REVISION INFORMATION AS **ATTACHMENT S** TO THIS APPLICATION

FOR TITLE V FACILITIES ONLY: Please refer to "Title V Revision Guidance" in order to determine your Title V Revision options (Appendix A, "Title V Permit Revision Flowchart") and ability to operate with the changes requested in this Permit Application.

Section I. General

1. Name of applicant *(as registered with the WV Secretary of State's Office):*
Mountain State Clean Energy, LLC

2. Federal Employer ID No. ***(FEIN):***
45-0543713

3. Name of facility *(if different from above):*
Mountain State Clean Energy

4. The applicant is the:
☒ **OWNER** ☐ **OPERATOR** ☐ **BOTH**

5A. Applicant's mailing address:
1375 Fort Martin Road
Maidsville, WV 26541

5B. Facility's present physical address:
1375 Fort Martin Road
Maidsville, WV 26541

6. **West Virginia Business Registration.** Is the applicant a resident of the State of West Virginia? ☒ **YES** ☐ **NO**

- If **YES,** provide a copy of the **Certificate of Incorporation/Organization/Limited Partnership** (one page) including any name change amendments or other Business Registration Certificate as **Attachment A.**
- If **NO,** provide a copy of the **Certificate of Authority/Authority of L.L.C./Registration** (one page) including any name change amendments or other Business Certificate as **Attachment A.**

7. If applicant is a subsidiary corporation, please provide the name of parent corporation: Mountain State Energy Holdings, LLC

8. Does the applicant own, lease, have an option to buy or otherwise have control of the *proposed site?* ☒ **YES** ☐ **NO**

- If **YES,** please explain: Yes, there exists a Memorandum of Understanding that will lead to a Payment In Lieu Of Taxes (PILOT) and Lease Agreement with Monongalia County.
- If **NO,** you are not eligible for a permit for this source.

9. Type of plant or facility (stationary source) to be **constructed, modified, relocated, administratively updated** or **temporarily permitted** (e.g., coal preparation plant, primary crusher, etc.): Combined Cycle Combustion Turbine - Electric Generating Unit

10. North American Industry Classification System **(NAICS)** code for the facility:
221112

11A. DAQ Plant ID No. (for existing facilities only):
N/A

11B. List all current 45CSR13 and 45CSR30 (Title V) permit numbers associated with this process (for existing facilities only):
None

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

12A.

- For **Modifications, Administrative Updates** or **Temporary permits** at an existing facility, please provide directions to the *present location* of the facility from the nearest state road;
- For **Construction** or **Relocation permits,** please provide directions to the *proposed new site location* from the nearest state road. Include a **MAP** as **Attachment B**.

12.B. New site address (if applicable):	12C. Nearest city or town:	12D. County:
1375 Fort Martin Road Maidsville, WV 26541	Maidsville	Monongalia
12.E. UTM Northing (KM): 4,396.353	12F. UTM Easting (KM): 589.078	12G. UTM Zone: 17

13. Briefly describe the proposed change(s) at the facility:

Construction of the following:

1. One combined cycle power train consisting of two state-of-the-art natural gas-fueled advanced class combustion turbines, two heat recovery steam generators (with duct burners), and one steam turbine.
2. Diesel fuel-fired firewater pump.
3. Diesel fuel-fired emergency generator.
4. Wet mechanical draft cooling tower.
5. Gas preheaters

14A. Provide the date of anticipated installation or change: First quarter 2021 If this is an **After-The-Fact** permit application, provide the date upon which the proposed change did happen: / /	14B. Date of anticipated Start-Up if a permit is granted: First quarter 2024

14C. Provide a **Schedule** of the planned **Installation** of/**Change** to and **Start-Up** of each of the units proposed in this permit application as **Attachment C** (if more than one unit is involved).

15. Provide maximum projected **Operating Schedule** of activity/activities outlined in this application:
Hours Per Day 24 Days Per Week 7 Weeks Per Year 52

16. Is demolition or physical renovation at an existing facility involved? ☐ **YES** ☒ **NO**

17**. Risk Management Plans.** If this facility is subject to 112(r) of the 1990 CAAA, or will become subject due to proposed changes (for applicability help see www.epa.gov/ceppo), submit your **Risk Management Plan (RMP)** to U. S. EPA Region III.

NOT APPLICABLE

18**. Regulatory Discussion.** List all Federal and State air pollution control regulations that you believe are applicable to the proposed process *(if known).* A list of possible applicable requirements is also included in Attachment S of this application (Title V Permit Revision Information). Discuss applicability and proposed demonstration(s) of compliance *(if known).* Provide this information as **Attachment D.**

Section II. Additional attachments and supporting documents.

19. Include a check payable to WVDEP – Division of Air Quality with the appropriate **application fee** (per 45CSR22 and 45CSR13).

20. Include a **Table of Contents** as the first page of your application package.

See Table of Contents in the PSP Permit Application Document

21. Provide a **Plot Plan,** e.g. scaled map(s) and/or sketch(es) showing the location of the property on which the stationary source(s) is or is to be located as **Attachment E** (Refer to ***Plot Plan Guidance***) **.**

- Indicate the location of the nearest occupied structure (e.g. church, school, business, residence).

22. Provide a **Detailed Process Flow Diagram(s)** showing each proposed or modified emissions unit, emission point and control device as **Attachment F.**

23. Provide a **Process Description** as **Attachment G.**
   – Also describe and quantify to the extent possible all changes made to the facility since the last permit review (if applicable).

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

24. Provide **Material Safety Data Sheets (MSDS)** for all materials processed, used or produced as **Attachment H.**

– For chemical processes, provide a MSDS for each compound emitted to the air.

25. Fill out the **Emission Units Table** and provide it as **Attachment I.**

26. Fill out the **Emission Points Data Summary Sheet (Table 1 and Table 2)** and provide it as **Attachment J.**

27. Fill out the **Fugitive Emissions Data Summary Sheet** and provide it as **Attachment K.**

28. Check all applicable **Emissions Unit Data Sheets** listed below:

☐ Bulk Liquid Transfer Operations
☐ Chemical Processes
☐ Concrete Batch Plant
☐ Grey Iron and Steel Foundry
☐ Haul Road Emissions
☐ Hot Mix Asphalt Plant
☐ Incinerator
☒ Indirect Heat Exchanger
☐ Quarry
☐ Solid Materials Sizing, Handling and Storage Facilities
☒ Storage Tanks
☒ General Emission Unit, specify: Combined-Cycle Combustion Turbines

Fill out and provide the **Emissions Unit Data Sheet(s)** as **Attachment L.**

29. Check all applicable **Air Pollution Control Device Sheets** listed below:

☐ Absorption Systems
☐ Adsorption Systems
☐ Afterburner
☐ Baghouse
☐ Condenser
☐ Electrostatic Precipitator
☐ Flare
☐ Mechanical Collector
☐ Wet Collecting System

☒ Other Collectors, specify

The Combined-Cycle Combustion Turbines and the HRSG Duct Burners will be equipped with Selective Catalytic Reduction (SCR) systems and dry low-NOx combustors (DLNC). These combustion controls along will control emissions of nitrogen oxides (NOx). Oxidation catalysts will be used to control the turbines' carbon monoxide (CO) and volatile organic compounds (VOC) emissions. The Fuel Gas Preheaters will be equipped with low- NOx burners (LNB) to control NOx emissions. The Mechanical Draft Cooling Tower will be equipped with demisters.

The proposed emission control systems including the determination of Best Available Control Technology determination are described in Section 4 of the PSD Permit Application Document.

Fill out and provide the **Air Pollution Control Device Sheet(s)** as **Attachment M.**

30. Provide all **Supporting Emissions Calculations** as **Attachment N,** or attach the calculations directly to the forms listed in Items 28 through 31.

31. **Monitoring, Recordkeeping, Reporting and Testing Plans.** Attach proposed monitoring, recordkeeping, reporting and testing plans in order to demonstrate compliance with the proposed emissions limits and operating parameters in this permit application. Provide this information as **Attachment O.**

➢ Please be aware that all permits must be practically enforceable whether or not the applicant chooses to propose such measures. Additionally, the DAQ may not be able to accept all measures proposed by the applicant. If none of these plans are proposed by the applicant, DAQ will develop such plans and include them in the permit.

32. **Public Notice.** At the time that the application is submitted, place a **Class I Legal Advertisement** in a newspaper of general circulation in the area where the source is or will be located (See 45CSR§13-8.3 through 45CSR§13-8.5 and ***Example Legal Advertisement*** for details). Please submit the **Affidavit of Publication** as **Attachment P** immediately upon receipt.

33**. Business Confidentiality Claims.** Does this application include confidential information (per 45CSR31)?

☐ **YES** ☒ **NO**

➢ If **YES,** identify each segment of information on each page that is submitted as confidential and provide justification for each segment claimed confidential, including the criteria under 45CSR§31-4.1, and in accordance with the DAQ's ***"Precautionary Notice – Claims of Confidentiality"*** guidance found in the ***General Instructions*** as **Attachment Q.**

Section III. Certification of Information

34. **Authority/Delegation of Authority.** Only required when someone other than the responsible official signs the application. Check applicable **Authority Form** below:

☐ Authority of Corporation or Other Business Entity ☐ Authority of Partnership

☐ Authority of Governmental Agency ☐ Authority of Limited Partnership

Submit completed and signed **Authority Form** as **Attachment R.**

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

35A. **Certification of Information.** To certify this permit application, a Responsible Official (per 45CSR§13-2.22 and 45CSR§30-2.28) or Authorized Representative shall check the appropriate box and sign below.

Certification of Truth, Accuracy, and Completeness

I, the undersigned ☒ **Responsible Official** / ☐ **Authorized Representative,** hereby certify that all information contained in this application and any supporting documents appended hereto, is true, accurate, and complete based on information and belief after reasonable inquiry I further agree to assume responsibility for the construction, modification and/or relocation and operation of the stationary source described herein in accordance with this application and any amendments thereto, as well as the Department of Environmental Protection, Division of Air Quality permit issued in accordance with this application, along with all applicable rules and regulations of the West Virginia Division of Air Quality and W.Va. Code § 22-5-1 et seq. (State Air Pollution Control Act). If the business or agency changes its Responsible Official or Authorized Representative, the Director of the Division of Air Quality will be notified in writing within 30 days of the official change.

Compliance Certification

Except for requirements identified in the Title V Application for which compliance is not achieved, I, the undersigned hereby certify that, based on information and belief formed after reasonable inquiry, all air contaminant sources identified in this application are in compliance with all applicable requirements.

SIGNATURE ______________________________ DATE: ________________

(Please use blue ink) *(Please use blue ink)*

35B. Printed name of signee: Stephen H. Nelson		35C. Title: Chief Operating Officer
35D. E-mail: snelson@longviewpower.net	36E. Phone: 304-599-0930 x3054	36F. FAX:
36A. Printed name of contact person (if different from above): Brian P. Hoyt II		36B. Title: Compliance & Environmental Manager
36C. E-mail: bhoyt@longviewpower.net	36D. Phone: 304-599-0930 x2203	36E. FAX:

PLEASE CHECK ALL APPLICABLE ATTACHMENTS INCLUDED WITH THIS PERMIT APPLICATION:

☒ **Attachment A: Business Certificate**
☒ **Attachment B: Map(s)**
☒ **Attachment C: Installation and Start Up Schedule**
☒ **Attachment D: Regulatory Discussion**
☒ **Attachment E: Plot Plan**
☒ **Attachment F: Detailed Process Flow Diagram(s)**
☒ **Attachment G: Process Description**
☒ **Attachment H: Material Safety Data Sheets (MSDS)**
☒ **Attachment I: Emission Units Table**
☒ **Attachment J: Emission Points Data Summary Sheet**
☒ **Attachment K: Fugitive Emissions Data Summary Sheet**
☒ **Attachment L: Emissions Unit Data Sheet(s)**
☒ **Attachment M: Air Pollution Control Device Sheet(s)**
☒ **Attachment N: Supporting Emissions Calculations**
☒ **Attachment O: Monitoring/Recordkeeping/Reporting/Testing Plans**
☒ **Attachment P: Public Notice**
☒ **Attachment Q: Business Confidential Claims**
☒ **Attachment R: Authority Forms**
☒ **Attachment S: Title V Permit Revision Information**
☒ **Application Fee**

Please mail an original and three (3) copies of the complete permit application with the signature(s) to the DAQ, Permitting Section, at the address listed on the first page of this application. Please DO NOT fax permit applications.

FOR AGENCY USE ONLY – IF THIS IS A TITLE V SOURCE:

☐ ***Forward 1 copy of the application to the Title V Permitting Group and:***
☐ ***For Title V Administrative Amendments:***
- ☐ ***NSR permit writer should notify Title V permit writer of draft permit,***

☐ ***For Title V Minor Modifications:***
- ☐ ***Title V permit writer should send appropriate notification to EPA and affected states within 5 days of receipt,***
- ☐ ***NSR permit writer should notify Title V permit writer of draft permit.***

☐ ***For Title V Significant Modifications processed in parallel with NSR Permit revision:***
- ☐ ***NSR permit writer should notify a Title V permit writer of draft permit,***
- ☐ ***Public notice should reference both 45CSR13 and Title V permits,***
- ☐ ***EPA has 45 day review period of a draft permit.***

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

ATTACHMENT A
BUSINESS CERTIFICATE

ATTACHMENT B
LOCATION MAP

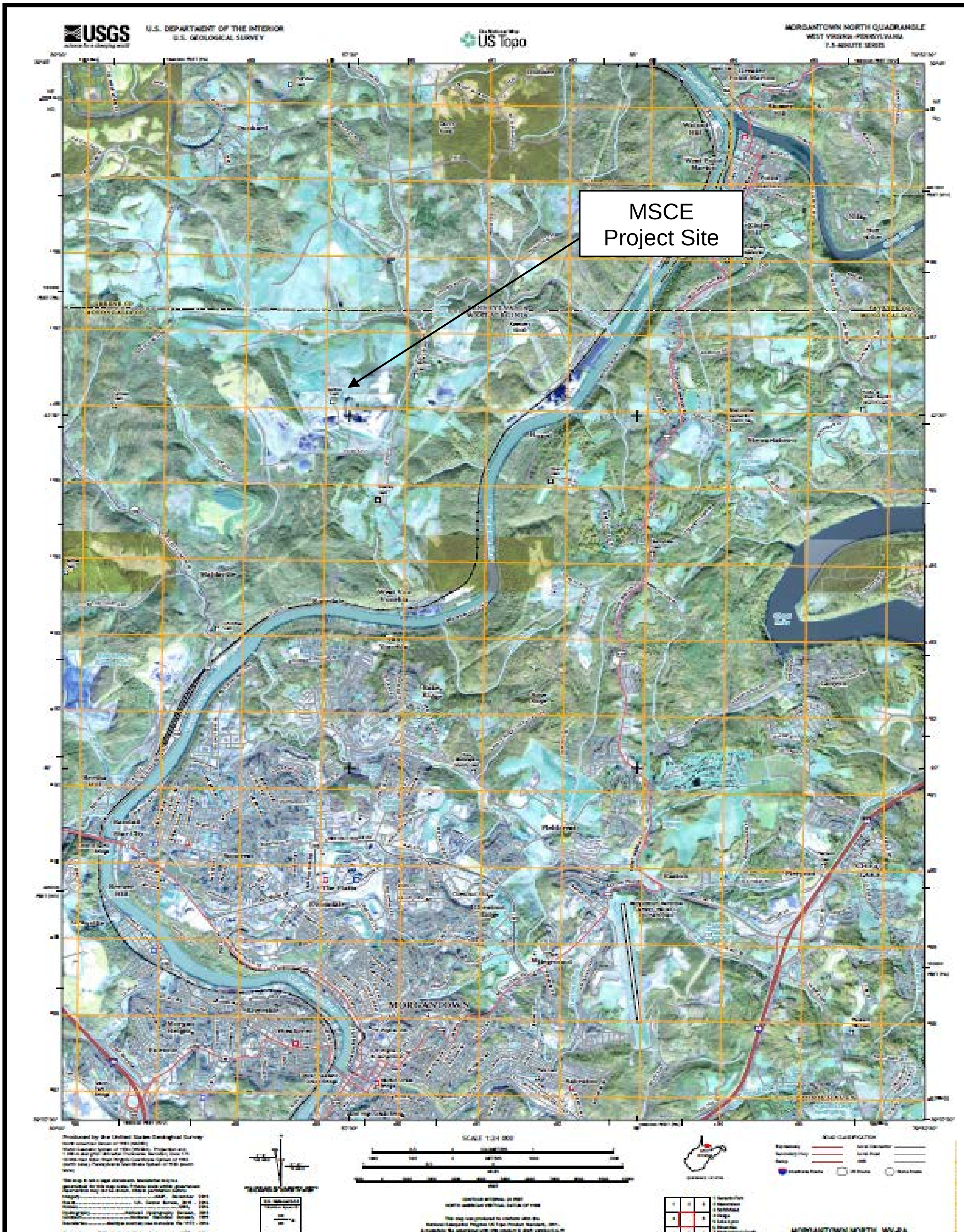


Figure B-1 Location Map
Location of Proposed MSCE

ATTACHMENT C
SCHEDULE OF INSTALLATION AND START-UP

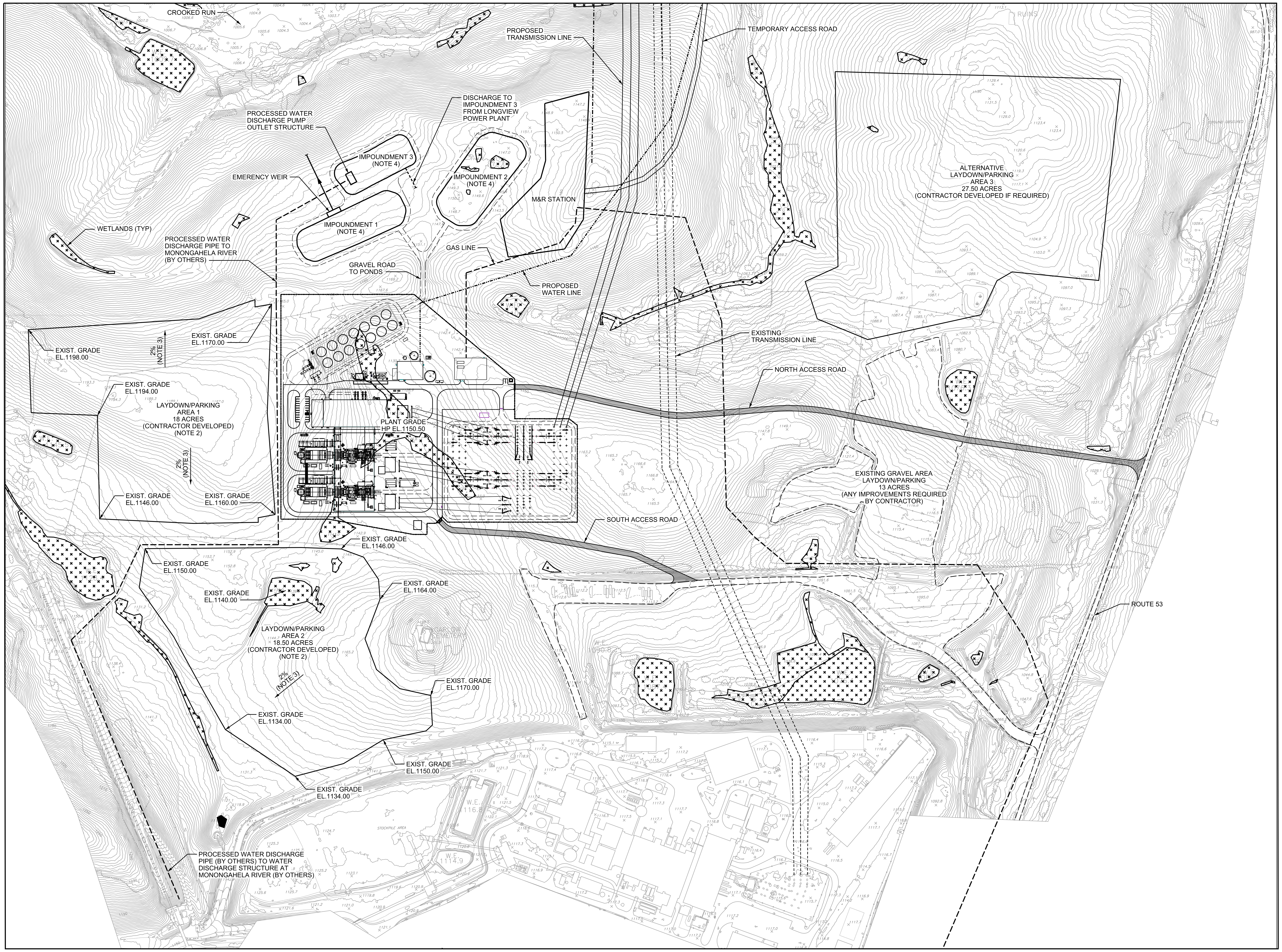
Mountain State Clean Energy (MSCE) has tentatively scheduled to begin construction related activities during the first quarter of 2022. Final installation of equipment and start-up of the facility is tentatively scheduled for the first quarter of 2025. This schedule may vary depending on actual delivery of equipment, unforeseen construction delays, etc.

ATTACHMENT D
REGULATORY DISCUSSION

The MSCE will be designed and operated in accordance with applicable State of West Virginia and Federal regulations. Regulations potentially impacting the proposed project are described in Section 4 of the Permit Application Document including

4.1 Federal Regulations
4.1.1 New Source Performance Standards (NSPS)
4.1.2 Prevention of Significant Deterioration (PSD)
4.1.3 Acid Rain Provisions
4.1.4 National Emission Standards For Hazardous Air Pollutants (NESHAP)
4.1.5 Compliance Assurance Monitoring (CAM)
4.1.6 Accidental Release Prevention
4.2 State of West Virginia Regulations

ATTACHMENT E
PLOT PLAN



NORTH

160' 0' 160' 320'

GRAPHIC SCALE

PRELIMINARY
NOT FOR CONSTRUCTION

UNDERGROUND OR EMBEDDED UTILITIES MAY BE LOCATED WITHIN OR ADJACENT TO THE AREA IN WHICH EXCAVATION, DEMOLITION, FOUNDATION, OR MODIFICATION WORK IS TO BE PERFORMED.

REFERENCES RELATING TO THE UNDERGROUND OR EMBEDDED UTILITIES ARE PROVIDED TO ASSIST THE CONTRACTOR/INSTALLER IN THE FIELD LOCATING THOSE UTILITIES AND OTHER POSSIBLE UNDERGROUND OR EMBEDDED INTERFERENCES WITH THE WORK.

THE CONTRACTOR/INSTALLER SHALL EXERCISE DUE CAUTION DURING ALL EXCAVATION/FOUNDATION/DEMOLITION WORK.

NOTES

1. THE TOPOGRAPHIC INFORMATION SHOWN WAS OBTAINED FROM THE OWNER AND IS PROVIDED FOR INFORMATION. ANY COORDINATES ARE IN U.S. SURVEY FEET, WEST VIRGINIA STATE PLANE NAD 83 (NORTH ZONE) WHICH WERE CONVERTED FROM THE PENNSYLVANIA STATE PLANE NAD 83 (SOUTH ZONE) COORDINATES PROVIDED IN THE ORIGINAL CAD FILE (U2 - PIPELINE BASE MAP.DWG).
2. LAYDOWN/PARKING AREAS 1 AND 2 SHALL BE DEVELOPED BY THE EPC CONTRACTOR AS PART OF THE PROJECT.
3. EPC CONTRACTOR SHALL COORDINATE THE ELEVATION AND GRADING OF THE AREA WITH THE OWNER. THE OWNER INTENDS TO USE THIS AREA FOR A FUTURE SOLAR FIELD.
4. PONDS SHOWN ARE INDICATIVE SHALL BE DESIGNED BY THE EPC CONTRACTOR.

HOLD INFORMATION

NO.	DESCRIPTION

CONTRACTOR/INSTALLER SHALL TAKE ALL APPROPRIATE PRECAUTIONS TO ENSURE THE SAFETY OF ALL PEOPLE LOCATED ON THE WORK SITE, INCLUDING CONTRACTOR'S/INSTALLER'S PERSONNEL (OR THAT OF ITS SUB-CONTRACTOR(S)) PERFORMING THE WORK.

RELEASE INFORMATION

REV.	DATE	DESCRIPTION
A	01-11-2021	FOR COMMENT

ISSUE PURPOSE: FOR COMMENT

SPECIFICATION:

PROJECT NO.: A14169.001

I HEREBY CERTIFY THAT THIS ENGINEERING DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT PERSONAL SUPERVISION AND THAT I AM A DULY LICENSED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF ENTER NAME.

ENTER NAME
ENTER DATE

MY LICENSE RENEWAL DATE IS: ENTER DATE
PAGES OR SHEETS COVERED BY THIS SEAL:
THIS DOCUMENT ONLY.

CERTIFICATE OF AUTHORIZATION (WHEN REQ'D)

CAD FILE NAME: MSCE-CSK-100.DGN

PREPARED BY: A. PAAPE

REVIEWED BY: ----

APPROVED BY: ----

ANY MODIFICATION OR ADDITION TO THIS DRAWING BY AN ORGANIZATION OTHER THAN SARGENT & LUNDY, IS NOT THE RESPONSIBILITY OF SARGENT & LUNDY.

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55 EAST MONROE STREET
CHICAGO, ILLINOIS 60603-5780

Mountain State Clean Energy, LLC

PROJECT

MOUNTAIN STATE CLEAN ENERGY

2X2X1 COMBINED CYCLE

MOUNTAIN STATE CLEAN ENERGY, LLC.

DRAWING TITLE

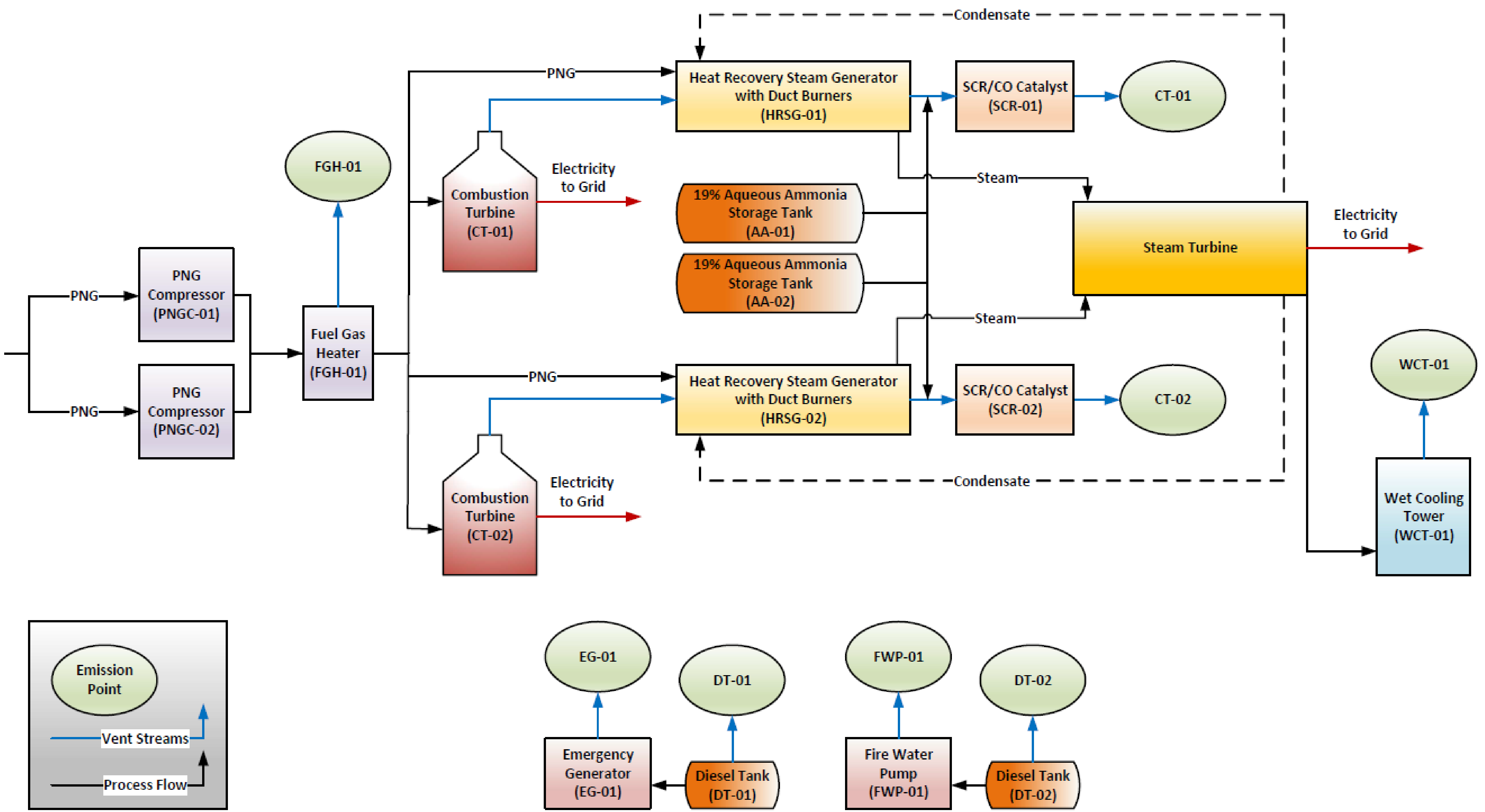
SITE PLAN

DRAWING NUMBER	REVISION
MSCE-CSK-100	A

SHEET 01 OF 01

ATTACHMENT F
DETAILED PROCESS FLOW DIAGRAM

MSCE Project
Process Flow Diagram



ATTACHMENT G
PROCESS DESCRIPTION

The MSCE Project is proposed to be a nominally rated 1,200 MW natural gas-fired only (no oil backup), combined-cycle power plant located immediately adjacent to the north of the existing Longview Power Unit 1. The Project will be designed to achieve a peak electrical output during the summer season of approximately 1,200 MW. Electricity generated by Unit 2 will be supplied to the PJM power grid and connect to the grid via the existing interconnection used by the Longview Power Unit 1.

The major components of the proposed power plant include: One combined cycle power train consisting of two combustion turbines, two heat recovery steam generators (HRSG) with duct burners, one steam turbine, one diesel fuel-fired firewater pump, one diesel fired emergency generator and one mechanical draft cooling tower.

To enhance the plant's overall efficiency and increase the amount of electricity generated by the Project, the hot exhaust gases from each combustion turbine will be routed to a downstream Heat Recovery Steam Generator. The HRSGs contains a series of heat exchangers designed to recover the heat from the turbine's exhaust gas and produce steam. The Project includes the installation of duct burners to produce additional steam in the HRSGs for additional power output from the steam turbine generator. The duct burners will only fire natural gas. No oil backup is planned for the Project.

Cooled exhaust gas passing through the HRSGs will be vented to the Selective Catalytic Reduction (SCR) and Oxidation Catalyst control system used to control NOx and CO emissions. Selective Catalytic Reduction involves the injection of aqueous ammonia (NH_3) at a concentration of approximately 19% by weight into the combustion turbine exhaust gas streams. The ammonia reacts with NOx in the exhaust gas stream in the presence of a catalyst, reducing it to elemental nitrogen (N_2) and water vapor (H_2O). The aqueous ammonia will be stored on-site in dual 60,000 gallon (approximate) storage tanks.

Steam generated in the HRSGs will be routed to a steam driven turbine that will increase the output of the electric generator. This generator will produce additional electricity that will be sold on the grid. Electricity generated by the combustion turbines and the single steam driven turbine driving the electric generator represents the Project's total electrical output.

The Project will use a condenser and a 14 cell wet mechanical draft cooling tower for steam turbine generator steam condensation and waste heat rejection.

A 240 hp, 179 kW standby firewater pump will be used to supply water during emergency conditions. The fire water pump will use ultra-low sulfur diesel (ULSD) fuel, with a sulfur content no greater than 0.0015% by weight. The fire water pump will also be periodically operated for short periods per manufacturer's maintenance instructions to ensure operational readiness in the event of an emergency. The fire water pump is expected to operate less than 100 hours per year.

An emergency generator (3,353 hp, 2,500 kW) will be used for emergency backup electric power. The fuel for the emergency generator will be ULSD with a sulfur content no greater than 0.0015% by weight. The emergency generator will be periodically operated for short periods per manufacturer's maintenance instructions to ensure operational readiness in the event of an emergency. The emergency generator is expected to operate less than 100 hours per year.
Two (2) fuel gas heaters (7 MMBtu/hr, approximate) will be used to preheat the pipeline natural gas received by the plant. Preheating the fuel prior to combustion in the CTs increases their efficiency, safeguards the fuel pipelines from icing, and protects the CTs from fuel condensates.

The fuel supply for the MSCE 2 CCGT will be provided via a 6.2 mile 20" pipeline interconnecting onto both the Columbia 1804 and 10240 interstate pipelines located near Greensboro, PA. At this interconnection, there will be a metering station allowing connection with the dual supply lines that are integral to the Columbia pipeline. Electric gas compression equipment will be added to this line and will have those facilities located on the Unit 2 site.

The Project will own and operate two pipeline gas compressor units. The compressors are electric-drive, 2,750 HP (Toshiba J2758, or equivalent) with a 4-throw reciprocating fluid end (Ariel JGC/4, or equivalent). The manufacturer recommends states that there are no GHG/VOC emissions associated with the operation of the units. Additionally, the manufacturer states that there will be no GHG/VOC emissions associated with the startup and shutdown of compressor units during normal operation; since no purge will be necessary.

Additional details of the process is contained in Sections 2 and 3 of the PSD Application Document.

ATTACHMENT H
MSDS

The Material Data Sheets (MDS) for natural gas and diesel fuel are attached. These are the only fuels to be used at the MSCE Project.

Safety Data Sheet

Material Name: Natural Gas Odorized **SDS No. 8010**
US GHS

Synonyms: Compressed Natural Gas (CNG); Dry Natural Gas ; Methane; Pipeline Spec Gas; Processed Gas; Residue Gas; Sweet Natural Gas; Natural Gas (odorized); Treated Gas

* * * Section 1 - Product and Company Identification * * *

Manufacturer Information

Hess Corporation
1 Hess Plaza
Woodbridge, NJ 07095-0961

Phone: 732-750-6000 Corporate EHS
Emergency # 800-424-9300 CHEMTREC
www.hess.com (Environment, Health, Safety Internet Website)

* * * Section 2 - Hazards Identification * * *

GHS Classification:

Flammable Gas - Category 1
Gases Under Pressure - Liquefied Gas
Specific Target Organ Systemic Toxicity (STOT) - Single Exposure Category 2

GHS LABEL ELEMENTS

Symbol(s)

Signal Word

Danger

Hazard Statements

Extremely flammable gas.
Contains gas under pressure, may explode if heated.
May cause damage to central nervous and respiratory systems.

Precautionary Statements

Prevention

Keep away from heat/sparks/open flames/hot surfaces. No smoking
Do not breathe fume/gas/mist/vapours/spray.
Wash thoroughly after handling.
Do not eat, drink or smoke when using this product.

Response

Leaking gas fire: Do not extinguish, unless leak can be stopped safely. Eliminate all ignition sources if safe to do so.
IF exposed or concerned: Call a POISON CENTER or doctor/physician.

Storage

Protect from sunlight. Store in a well-ventilated place.

Store locked up.

Disposal

Dispose of contents/container in accordance with local/regional/national/international regulations.

* * * Section 3 - Composition / Information on Ingredients * * *

CAS #	Component	Percent
68410-63-9	Natural gas, dried	100
74-82-8	Methane	<90
74-84-0	Ethane	<1

A complex mixture of light gases separated from raw natural gas consisting of aliphatic hydrocarbons having carbon numbers in the range of C1 through C4, predominantly methane (C1) and ethane (C2); may contain carbon dioxide (CO_2). May be odorized with trace amounts of odorant (see Section 9). This is for natural gas that has been processed and is in commerce.

* * * Section 4 - First Aid Measures * * *

First Aid: Eyes

In case of freeze burn cover eyes to protect from light. Seek immediate medical attention.

First Aid: Skin

Remove contaminated clothing. In case of blistering, frostbite or freeze burns seek immediate medical attention.

First Aid: Ingestion

Risk of ingestion is extremely low. However, if oral exposure occurs, seek immediate medical assistance.

First Aid: Inhalation

Remove person to fresh air. If person is not breathing, provide artificial respiration. If necessary, provide additional oxygen once breathing is restored if trained to do so. Seek medical attention immediately.

* * * Section 5 - Fire Fighting Measures * * *

General Fire Hazards

See Section 9 for Flammability Properties.
Dangerous fire and explosion hazard when exposed to heat, sparks or flame. Natural gas is lighter than air and may travel long distances to a point of ignition and flash back. Container may explode in heat or fire. Liquefied Natural Gas (LNG) releases flammable gas at well below ambient temperatures and readily forms a flammable mixture with air.

Hazardous Combustion Products

Carbon monoxide, carbon dioxide and non-combusted hydrocarbons (smoke).

Extinguishing Media

Any extinguisher suitable for Class B fires, dry chemical, fire fighting foam, CO_2, and other gaseous agents. However, fire should not be extinguished unless flow of gas can be immediately stopped.

Unsuitable Extinguishing Media

None

Fire Fighting Equipment/Instructions

Gas fires should not be extinguished unless flow of gas can be immediately stopped. Shut off gas source and allow gas to burn out. If spill or leak has not ignited, determine if water spray may assist in dispersing gas or vapor to protect personnel attempting to stop leak. Use water to cool equipment, surfaces and containers exposed to fire and excessive heat. For large fire the use of unmanned hose holders or monitor nozzles may be advantageous to further minimize personnel exposure. Isolate area, particularly around ends of storage vessels. Let vessel, tank car or container burn unless leak can be stopped. Withdraw immediately in the event of a rising sound from a venting safety device. Large fires typically require specially trained personnel and equipment to isolate and extinguish the fire.

Firefighting activities that may result in potential exposure to high heat, smoke or toxic by-products of combustion should require NIOSH- approved pressure-demand self-contained breathing apparatus with full facepiece and full protective clothing.

* * * Section 6 - Accidental Release Measures * * *

Recovery and Neutralization

Stop the source of the release, if safe to do so.

Materials and Methods for Clean-Up

Do not flush down sewer or drainage systems. Do not touch spilled liquid (frostbite/freeze burn hazard!). Consider the use of water spray to disperse vapors. Isolate the area until gas has dispersed. Ventilate and gas test area before entering.

Emergency Measures

Evacuate nonessential personnel and secure all ignition sources. No road flares, smoking or flames in hazard area. Consider wind direction, stay upwind and uphill, if possible. Evaluate the direction of product travel. Vapor cloud may be white, but color will dissipate as cloud disperses - fire and explosion hazard is still present!

Personal Precautions and Protective Equipment

Do not touch spilled liquid (frostbite/freeze burn hazard!).

Environmental Precautions

Do not flush down sewer or drainage systems.

Prevention of Secondary Hazards

None

* * * Section 7 - Handling and Storage * * *

Handling Procedures

Keep away from flame, sparks and excessive temperatures. Bond and ground containers. Use only in well ventilated areas.

Storage Procedures

Store only in approved containers. Bond and ground containers. Keep away from flame, sparks, excessive temperatures and open flame. Keep containers closed and clearly labeled. Empty product containers or vessels may contain explosive vapors. Do not pressurize, cut, heat, weld or expose such containers to sources of ignition.

Incompatibilities

Keep away from strong oxidizers, ignition sources and heat.

* * * Section 8 - Exposure Controls / Personal Protection * * *

Component Exposure Limits

Methane (74-82-8)

ACGIH: 1000 ppm TWA (listed under Aliphatic hydrocarbon gases: Alkane C1-4)

Ethane (74-84-0)

ACGIH: 1000 ppm TWA (listed under Aliphatic hydrocarbon gases: Alkane C1-4)

Engineering Measures

Use adequate ventilation to keep gas and vapor concentrations of this product below occupational exposure and flammability limits, particularly in confined spaces. Use explosion-proof equipment and lighting in classified/controlled areas.

Personal Protective Equipment: Respiratory

Use a NIOSH approved positive-pressure, supplied air respirator with escape bottle or self-contained breathing apparatus (SCBA) for gas concentrations above occupational exposure limits, for potential for uncontrolled release, if exposure levels are not known, or in an oxygen-deficient atmosphere. CAUTION: Flammability limits (i.e., explosion hazard) should be considered when assessing the need to expose personnel to concentrations requiring respiratory protection.

Personal Protective Equipment: Hands

Use cold-impervious, insulating gloves where contact with pressurized gas may occur.

Personal Protective Equipment: Eyes

Where there is a possibility of pressurized gas contact, wear splash-proof safety goggles and faceshield.

Personal Protective Equipment: Skin and Body

Where contact with pressurized gas may occur, wear apron and faceshield.

* * * Section 9 - Physical & Chemical Properties * * *

Appearance:	Colorless	**Odor:**	Distinctive "natural gas"
Physical State:	Gas	**pH:**	ND
Vapor Pressure:	40 atm @ -187 °F (-86 °C)	**Vapor Density:**	0.6
Boiling Point:	-259°F (-162°C)	**Melting Point:**	ND
Solubility (H2O):	3.5%	**Specific Gravity:**	0.4 @ -263 °F (-164 °C)
Evaporation Rate:	ND	**VOC:**	ND
Octanol/H2O Coeff.:	ND	**Flash Point:**	Flammable Gas
Flash Point Method:	NA	**Upper Flammability Limit (UFL):**	13-17
Lower Flammability Limit (LFL):	3.8-6.5	**Burning Rate:**	ND
Auto Ignition:	900-1170°F (482-632°C)		

* * * Section 10 - Chemical Stability & Reactivity Information * * *

Chemical Stability

This is a stable material.

Hazardous Reaction Potential

Will not occur.

Conditions to Avoid

Keep away from strong oxidizers, ignition sources and heat.

Incompatible Products

Strong oxidizers

Hazardous Decomposition Products

Carbon monoxide, carbon dioxide and non-combusted hydrocarbons (smoke).

* * * Section 11 - Toxicological Information * * *

Acute Toxicity

A: General Product Information

Methane and ethane, the main components of natural gas, are considered practically inert in terms of physiological effects. At high concentrations these materials act as simple asphyxiants and may cause death due to lack of oxygen.

B: Component Analysis - LD50/LC50

Methane (74-82-8)

Inhalation LC50 Mouse 326 g/m3 2 h

Ethane (74-84-0)

Inhalation LC50 Rat 658 mg/L 4 h

Potential Health Effects: Skin Corrosion Property/Stimulativeness

Vapors are not irritating. Direct contact to skin or mucous membranes with pressurized vapor may cause freeze burns and frostbite. Signs of frostbite include a change in the color of the skin to gray or white, possibly followed by blistering. Skin may become inflamed and painful.

Potential Health Effects: Eye Critical Damage/ Stimulativeness

Vapors are not irritating. However, contact with liquid or cold vapor may cause frostbite, freeze burns, and permanent eye damage.

Potential Health Effects: Ingestion

Risk of ingestion is extremely unlikely.

Potential Health Effects: Inhalation

This product is considered to be non-toxic by inhalation. Inhalation of high concentrations may cause central nervous system depression such as dizziness, drowsiness, headache, and similar narcotic symptoms, but no long-term effects. Numbness, a "chilly" feeling, and vomiting have been reported from accidental exposures to high concentrations. This product is a simple asphyxiant. In high concentrations it will displace oxygen from the breathing atmosphere, particularly in confined spaces. Signs of asphyxiation will be noticed when oxygen is reduced to below 16%, and may occur in several stages. Symptoms may include rapid breathing and pulse rate, headache, dizziness, visual disturbances, mental confusion, incoordination, mood changes, muscular weakness, tremors, cyanosis, narcosis and numbness of the extremities. Unconsciousness leading to central nervous system injury and possibly death will occur when the atmospheric oxygen concentration is reduced to about 6% to 8% or less.

WARNING: The burning of any hydrocarbon as a fuel in an area without adequate ventilation may result in hazardous levels of combustion products, including carbon monoxide, and inadequate oxygen levels, which may cause unconsciousness, suffocation, and death.

Respiratory Organs Sensitization/Skin Sensitization

This product is not reported to have any skin sensitization effects.

Generative Cell Mutagenicity

This product is not reported to have any mutagenic effects.

Carcinogenicity

A: General Product Information

This product is not reported to have any carcinogenic effects.

B: Component Carcinogenicity

None of this product's components are listed by ACGIH, IARC, OSHA, NIOSH, or NTP.

Reproductive Toxicity

This product is not reported to have any reproductive toxicity effects.

Specified Target Organ General Toxicity: Single Exposure

This product may cause damage to heart.

Specified Target Organ General Toxicity: Repeated Exposure

This product is not reported to have any specific target organ repeat effects.

Aspiration Respiratory Organs Hazard

This product is not reported to have any aspiration hazard effects.

* * * Section 12 - Ecological Information * * *

Ecotoxicity

A: General Product Information

Keep out of sewers, drainage areas, and waterways. Report spills and releases, as applicable, under Federal and State regulations.

B: Component Analysis - Ecotoxicity - Aquatic Toxicity

No ecotoxicity data are available for this product's components.

Persistence/Degradability

No information available.

Bioaccumulation

No information available.

Mobility in Soil

No information available.

* * * Section 13 - Disposal Considerations * * *

Waste Disposal Instructions

See Section 7 for Handling Procedures. See Section 8 for Personal Protective Equipment recommendations.

Disposal of Contaminated Containers or Packaging

Dispose of contents/container in accordance with local/regional/national/international regulations.

* * * Section 14 - Transportation Information * * *

DOT Information

Shipping Name: Natural Gas, Compressed
UN #: 1971 **Hazard Class:** 2.1

Placard:

* * * Section 15 - Regulatory Information * * *

Regulatory Information

Component Analysis

None of this products components are listed under SARA Section 302 (40 CFR 355 Appendix A), SARA Section 313 (40 CFR 372.65), or CERCLA (40 CFR 302.4).

SARA Section 311/312 – Hazard Classes

Acute Health	Chronic Health	Fire	Sudden Release of Pressure	Reactive
--	--	X	X	--

SARA SECTION 313 - SUPPLIER NOTIFICATION

This product does not contain any chemicals subject to the reporting requirements of section 313 of the Emergency Planning and Community Right-To-Know Act (EPCRA) of 1986 and of 40 CFR 372:

State Regulations

Component Analysis - State

The following components appear on one or more of the following state hazardous substances lists:

Component	CAS	CA	MA	MN	NJ	PA	RI
Methane	74-82-8	No	Yes	Yes	Yes	Yes	No
Ethane	74-84-0	No	Yes	Yes	Yes	Yes	No

Component Analysis - WHMIS IDL

No components are listed in the WHMIS IDL.

Additional Regulatory Information

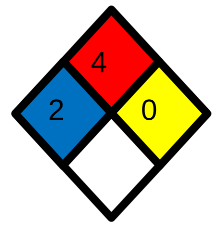
Component Analysis - Inventory

Component	CAS #	TSCA	CAN	EEC
Natural gas, dried	68410-63-9	Yes	DSL	EINECS
Methane	74-82-8	Yes	DSL	EINECS
Ethane	74-84-0	Yes	DSL	EINECS

* * * Section 16 - Other Information * * *

NFPA® Hazard Rating

Health	2
Fire	4
Reactivity	0



HMIS® Hazard Rating

Health	2	Moderate
Fire	4	Severe
Physical	0	Minimal
		*Chronic

Key/Legend

EPA = Environmental Protection Agency; TSCA = Toxic Substance Control Act; ACGIH = American Conference of Governmental Industrial Hygienists; IARC = International Agency for Research on Cancer; NIOSH = National Institute for Occupational Safety and Health; NTP = National Toxicology Program; OSHA = Occupational Safety and Health Administration., NJTSR = New Jersey Trade Secret Registry.

Literature References

None

Other Information

Information presented herein has been compiled from sources considered to be dependable, and is accurate and reliable to the best of our knowledge and belief, but is not guaranteed to be so. Since conditions of use are beyond our control, we make no warranties, expressed or implied, except those that may be contained in our written contract of sale or acknowledgment.

Vendor assumes no responsibility for injury to vendee or third persons proximately caused by the material if reasonable safety procedures are not adhered to as stipulated in the data sheet. Additionally, vendor assumes no responsibility for injury to vendee or third persons proximately caused by abnormal use of the material, even if reasonable safety procedures are followed. Furthermore, vendee assumes the risk in their use of the material.

End of Sheet

Safety Data Sheet

Material Name: Fuel Oil No. 2

SDS No. 0088
EU/CLP GHS

Synonyms: #2 Heating Oil; 2 Oil; Off-road Diesel Fuel

* * * Section 1 - Product and Company Identification * * *

Manufacturer Information

Hess Corporation
1 Hess Plaza
Woodbridge, NJ 07095-0961

Phone: 732-750-6000 Corporate EHS
Emergency # 800-424-9300 CHEMTREC
www.hess.com (Environment, Health, Safety Internet Website)

* * * Section 2 - Hazards Identification * * *

GHS Classification:

Flammable Liquids - Category 3
Acute Toxicity, Inhalation - Category 4
Skin Corrosion/Irritation – Category 2
Eye Damage/Irritation – Category 2
Carcinogenicity - Category 2
Specific Target Organ Toxicity (Single Exposure) – Category 3 (respiratory irritation, narcosis)
Aspiration Hazard – Category 1
Hazardous to the Aquatic Environment, Acute Hazard – Category 3

GHS LABEL ELEMENTS

Symbol(s)

Signal Word

DANGER

Hazard Statements

Flammable liquid and vapor.
Harmful if inhaled.
Causes skin irritation.
Causes eye irritation.
Suspected of causing cancer.
Suspected of causing genetic defects.
May cause respiratory irritation.
May cause drowsiness or dizziness.
May be fatal if swallowed and enters airways.
Harmful to aquatic life.

Precautionary Statements

Prevention

Keep away from heat/sparks/open flames/hot surfaces. No smoking
Keep container tightly closed.
Ground/bond container and receiving equipment.
Use explosion-proof electrical/ventilating/lighting/equipment.
Use only non-sparking tools.
Take precautionary measures against static discharge.
Wear protective gloves/protective clothing/eye protection/face protection.
Avoid breathing fume/mist/vapors/spray.
Use only outdoors or in a well-ventilated area.
Wash hands and forearms thoroughly after handling.
Obtain special instructions before use.
Do not handle until all safety precautions have been read and understood.
Avoid release to the environment.

Response

In case of fire: Use water spray, fog or foam.
If on skin (or hair): Wash with plenty of soap and water. Take off immediately all contaminated clothing and wash it before reuse. If skin irritation occurs, get medical advice/attention.
If inhaled: Remove person to fresh air and keep comfortable for breathing. Call a poison center or doctor if you feel unwell.
If in eyes: Rinse cautiously with water for several minutes. Remove contact lenses, if present and easy to do. Continue rinsing. If eye irritation persists: Get medical advice/attention.
If exposed or concerned: Get medical advice/attention.
If swallowed: Immediately all a poison center or doctor/physician if you feel unwell. Do NOT induce vomiting.

Storage

Store in a well ventilated place.
Keep cool. Keep container tightly closed.
Store locked up.

Disposal

Dispose of contents/container in accordance with local/regional/national/international regulations.

* * * Section 3 - Composition / Information on Ingredients * * *

CAS #	Component	Percent
68476-30-2	Fuel oil No. 2	100
91-20-3	Naphthalene	<0.1

A complex combination of hydrocarbons with carbon numbers in the range C9 and higher produced from the distillation of petroleum crude oil.

* * * Section 4 - First Aid Measures * * *

First Aid: Eyes

In case of contact with eyes, immediately flush with clean, low-pressure water for at least 15 min. Hold eyelids open to ensure adequate flushing. Seek medical attention.

First Aid: Skin

Remove contaminated clothing. Wash contaminated areas thoroughly with soap and water or with waterless hand cleanser. Obtain medical attention if irritation or redness develops.

First Aid: Ingestion

DO NOT INDUCE VOMITING. Do not give liquids. Obtain immediate medical attention. If spontaneous vomiting occurs, lean victim forward to reduce the risk of aspiration. Monitor for breathing difficulties. Small amounts of material which enter the mouth should be rinsed out until the taste is dissipated.

First Aid: Inhalation

Remove person to fresh air. If person is not breathing, provide artificial respiration. If necessary, provide additional oxygen once breathing is restored if trained to do so. Seek medical attention immediately.

* * * Section 5 - Fire Fighting Measures * * *

General Fire Hazards

See Section 9 for Flammability Properties.

Vapors may be ignited rapidly when exposed to heat, spark, open flame or other source of ignition. When mixed with air and exposed to an ignition source, flammable vapors can burn in the open or explode in confined spaces. Being heavier than air, vapors may travel long distances to an ignition source and flash back. Runoff to sewer may cause fire or explosion hazard.

Hazardous Combustion Products

Carbon monoxide, carbon dioxide and non-combusted hydrocarbons (smoke).

Extinguishing Media

SMALL FIRES: Any extinguisher suitable for Class B fires, dry chemical, CO2, water spray, fire fighting foam, or gaseous extinguishing agent.

LARGE FIRES: Water spray, fog or fire fighting foam. Water may be ineffective for fighting the fire, but may be used to cool fire-exposed containers.

Unsuitable Extinguishing Media

None

Fire Fighting Equipment/Instructions

Small fires in the incipient (beginning) stage may typically be extinguished using handheld portable fire extinguishers and other fire fighting equipment. Firefighting activities that may result in potential exposure to high heat, smoke or toxic by-products of combustion should require NIOSH/MSHA- approved pressure-demand self-contained breathing apparatus with full facepiece and full protective clothing. Isolate area around container involved in fire. Cool tanks, shells, and containers exposed to fire and excessive heat with water. For massive fires the use of unmanned hose holders or monitor nozzles may be advantageous to further minimize personnel exposure. Major fires may require withdrawal, allowing the tank to burn. Large storage tank fires typically require specially trained personnel and equipment to extinguish the fire, often including the need for properly applied fire fighting foam.

* * * Section 6 - Accidental Release Measures * * *

Recovery and Neutralization

Carefully contain and stop the source of the spill, if safe to do so.

Materials and Methods for Clean-Up

Take up with sand or other oil absorbing materials. Carefully shovel, scoop or sweep up into a waste container for reclamation or disposal.

Emergency Measures

Evacuate nonessential personnel and remove or secure all ignition sources. Consider wind direction; stay upwind and uphill, if possible. Evaluate the direction of product travel, diking, sewers, etc. to confirm spill areas. Spills may infiltrate subsurface soil and groundwater; professional assistance may be necessary to determine the extent of subsurface impact.

Personal Precautions and Protective Equipment

Response and clean-up crews must be properly trained and must utilize proper protective equipment (see Section 8).

Environmental Precautions

Protect bodies of water by diking, absorbents, or absorbent boom, if possible. Do not flush down sewer or drainage systems, unless system is designed and permitted to handle such material. The use of fire fighting foam may be useful in certain situations to reduce vapors. The proper use of water spray may effectively disperse product vapors or the liquid itself, preventing contact with ignition sources or areas/equipment that require protection.

Prevention of Secondary Hazards

None

* * * Section 7 - Handling and Storage * * *

Handling Procedures

Handle as a combustible liquid. Keep away from heat, sparks, excessive temperatures and open flame! No smoking or open flame in storage, use or handling areas. Bond and ground containers during product transfer to reduce the possibility of static-initiated fire or explosion.

Special slow load procedures for "switch loading" must be followed to avoid the static ignition hazard that can exist when this product is loaded into tanks previously containing low flash point products (such as gasoline) - see API Publication 2003, "Protection Against Ignitions Arising Out Of Static, Lightning and Stray Currents."

Storage Procedures

Keep containers closed and clearly labeled. Use approved vented storage containers. Empty product containers or vessels may contain explosive vapors. Do not pressurize, cut, heat, weld or expose such containers to sources of ignition.

Store in a well-ventilated area. This storage area should comply with NFPA 30 "Flammable and Combustible Liquid Code". Avoid storage near incompatible materials. The cleaning of tanks previously containing this product should follow API Recommended Practice (RP) 2013 "Cleaning Mobile Tanks In Flammable and Combustible Liquid Service" and API RP 2015 "Cleaning Petroleum Storage Tanks."

Incompatibilities

Keep away from strong oxidizers; Fluorel ®

* * * Section 8 - Exposure Controls / Personal Protection * * *

Component Exposure Limits

Fuel oil No. 2 (270-671-4)

ACGIH:	100 mg/m3 TWA (inhalable fraction and vapor, as total hydrocarbons, listed under Diesel fuel) Skin - potential significant contribution to overall exposure by the cutaneous route (listed under Diesel fuel)
Belgium:	100 mg/m3 TWA (as total hydrocarbon, aerosol and vapor) Skin (listed under Gas oil)
Portugal:	100 mg/m3 TWA [VLE-MP] (aerosol and vapor, as total Hydrocarbons, listed under Fuel diesel)

Naphthalene (202-049-5)

ACGIH:	15 ppm STEL 10 ppm TWA Skin - potential significant contribution to overall exposure by the cutaneous route
Austria:	10 ppm TWA [TMW]; 50 mg/m3 TWA [TMW] skin notation
Belgium:	15 ppm STEL; 80 mg/m3 STEL 10 ppm TWA; 53 mg/m3 TWA Skin
Denmark:	10 ppm TWA; 50 mg/m3 TWA
Finland:	2 ppm STEL; 10 mg/m3 STEL 1 ppm TWA; 5 mg/m3 TWA
France:	10 ppm TWA [VME]; 50 mg/m3 TWA [VME]
Germany:	0.1 ppm TWA AGW (The risk of damage to the embryo or fetus can be excluded when MAK and BAT values are observed, inhalable fraction, exposure factor 1); 0.5 mg/m3 TWA AGW (The risk of damage to the embryo or fetus can be excluded when MAK and BAT values are observed, inhalable fraction, exposure factor 1)
Greece:	10 ppm TWA; 50 mg/m3 TWA
Ireland:	15 ppm STEL; 75 mg/m3 STEL 10 ppm TWA; 50 mg/m3 TWA
Netherlands:	80 mg/m3 STEL 50 mg/m3 TWA
Portugal:	10 ppm TWA [VLE-MP]
Spain:	15 ppm STEL [VLA-EC]; 80 mg/m3 STEL [VLA-EC] 10 ppm TWA [VLA-ED]; 53 mg/m3 TWA [VLA-ED] skin - potential for cutaneous exposure
Sweden:	10 ppm LLV; 50 mg/m3 LLV 15 ppm STV; 80 mg/m3 STV

Engineering Measures

Use adequate ventilation to keep vapor concentrations of this product below occupational exposure and flammability limits, particularly in confined spaces.

Personal Protective Equipment: Respiratory

A NIOSH/MSHA-approved air-purifying respirator with organic vapor cartridges or canister may be permissible under certain circumstances where airborne concentrations are or may be expected to exceed exposure limits or for odor or irritation. Protection provided by air-purifying respirators is limited.

Use a positive pressure, air-supplied respirator if there is a potential for uncontrolled release, exposure levels are not known, in oxygen-deficient atmospheres, or any other circumstance where an air-purifying respirator may not provide adequate protection.

Personal Protective Equipment: Hands

Gloves constructed of nitrile, neoprene, or PVC are recommended.

Personal Protective Equipment: Eyes

Safety glasses or goggles are recommended where there is a possibility of splashing or spraying.

Personal Protective Equipment: Skin and Body

Chemical protective clothing such as of E.I. DuPont TyChem®, Saranex® or equivalent recommended based on degree of exposure. Note: The resistance of specific material may vary from product to product as well as with degree of exposure. Consult manufacturer specifications for further information.

* * * Section 9 - Physical & Chemical Properties * * *

Appearance:	Red or reddish/orange colored (dyed)	**Odor:**	Mild, petroleum distillate odor
Physical State:	Liquid	**pH:**	ND
Vapor Pressure:	0.009 psia @ 70 °F (21 °C)	**Vapor Density:**	>1.0
Boiling Point:	340 to 700 °F (171 to 371 °C)	**Melting Point:**	ND
Solubility (H2O):	Negligible	**Specific Gravity:**	AP 0.823-0871
Evaporation Rate:	Slow; varies with conditions	**VOC:**	ND
Octanol/H2O Coeff.:	ND	**Flash Point:**	100 °F (38 °C) minimum
Flash Point Method:	PMCC	**Upper Flammability Limit (UFL):**	7.5
Lower Flammability Limit (LFL):	0.6	**Burning Rate:**	ND
Auto Ignition:	494°F (257°C)		

* * * Section 10 - Chemical Stability & Reactivity Information * * *

Chemical Stability

This is a stable material.

Hazardous Reaction Potential

Will not occur.

Conditions to Avoid

Avoid high temperatures, open flames, sparks, welding, smoking and other ignition sources.

Incompatible Products

Keep away from strong oxidizers; Fluorel ®

Hazardous Decomposition Products

Carbon monoxide, carbon dioxide and non-combusted hydrocarbons (smoke).

* * * Section 11 - Toxicological Information * * *

Acute Toxicity

A: General Product Information

Harmful if swallowed.

B: Component Analysis - LD50/LC50

Fuel oil No. 2 (68476-30-2)

Oral LD50 Rat 12 g/kg; Dermal LD50 Rabbit 4720 µL/kg; Dermal LD50 Rabbit >2000 mg/kg; Inhalation LC50 Rat 4.6 mg/L 4 h

Naphthalene (91-20-3)

Inhalation LC50 Rat >340 mg/m3 1 h; Oral LD50 Rat 490 mg/kg; Dermal LD50 Rat >2500 mg/kg; Dermal LD50 Rabbit >20 g/kg

Product Mixture

Oral LD50 Rat 14.5 ml/kg; Dermal LD50 Rabbit >5 mL/kg; Guinea Pig Sensitization: negative; Primary dermal irritation: moderately irritating (Draize mean irritation score - 3.98 rabbits); Draize eye irritation: mildly irritating (Draize score, 48 hours, unwashed - 2.0 rabbits)

Potential Health Effects: Skin Corrosion Property/Stimulativeness

Practically non-toxic if absorbed following acute (single) exposure. May cause skin irritation with prolonged or repeated contact. Liquid may be absorbed through the skin in toxic amounts if large areas of skin are repeatedly exposed.

Potential Health Effects: Eye Critical Damage/ Stimulativeness

Contact with eyes may cause mild irritation.

Potential Health Effects: Ingestion

Ingestion may cause gastrointestinal disturbances, including irritation, nausea, vomiting and diarrhea, and central nervous system (brain) effects similar to alcohol intoxication. In severe cases, tremors, convulsions, loss of consciousness, coma, respiratory arrest, and death may occur.

Potential Health Effects: Inhalation

Excessive exposure may cause irritations to the nose, throat, lungs and respiratory tract. Central nervous system (brain) effects may include headache, dizziness, loss of balance and coordination, unconsciousness, coma, respiratory failure, and death.

WARNING: the burning of any hydrocarbon as a fuel in an area without adequate ventilation may result in hazardous levels of combustion products, including carbon monoxide, and inadequate oxygen levels, which may cause unconsciousness, suffocation, and death.

Respiratory Organs Sensitization/Skin Sensitization

This product is not reported to have any skin sensitization effects.

Generative Cell Mutagenicity

This product is not reported to have any mutagenic effects. Material of similar composition has been positive in a mutagenicity study.

Carcinogenicity

A: General Product Information

Suspected of causing cancer.

Dermal carcinogenicity: positive - mice

Studies have shown that similar products produce skin tumors in laboratory animals following repeated applications without washing or removal. The significance of this finding to human exposure has not been determined. Other studies with active skin carcinogens have shown that washing the animal's skin with soap and water between applications reduced tumor formation.

This product is similar to Diesel Fuel. IARC classifies whole diesel fuel exhaust particulates as probably carcinogenic to humans (Group 2A) and NIOSH regards it as a potential cause of occupational lung cancer based on animal studies and limited evidence in humans.

B: Component Carcinogenicity

Fuel oil No. 2 (68476-30-2)

ACGIH:	A3 - Confirmed Animal Carcinogen with Unknown Relevance to Humans (listed under Diesel fuel)

Naphthalene (91-20-3)

ACGIH:	A4 - Not Classifiable as a Human Carcinogen
NTP:	Reasonably Anticipated To Be A Human Carcinogen (Possible Select Carcinogen)
IARC:	Monograph 82 [2002] (Group 2B (possibly carcinogenic to humans))

Reproductive Toxicity

This product is not reported to have any reproductive toxicity effects.

Specified Target Organ General Toxicity: Single Exposure

This product is not reported to have any specific target organ general toxicity single exposure effects.

Specified Target Organ General Toxicity: Repeated Exposure

This product is not reported to have any specific target organ general toxicity repeat exposure effects.

Aspiration Respiratory Organs Hazard

The major health threat of ingestion occurs from the danger of aspiration (breathing) of liquid drops into the lungs, particularly from vomiting. Aspiration may result in chemical pneumonia (fluid in the lungs), severe lung damage, respiratory failure and even death.

* * * Section 12 - Ecological Information * * *

Ecotoxicity

A: General Product Information

Very toxic to aquatic life with long lasting effects. Keep out of sewers, drainage areas and waterways. Report spills and releases, as applicable, under Federal and State regulations.

B: Component Analysis - Ecotoxicity - Aquatic Toxicity

Fuel oil No. 2 (68476-30-2)

Test & Species		Conditions
96 Hr LC50 Pimephales promelas	35 mg/L [flow-through]	

Naphthalene (91-20-3)

Test & Species		Conditions
96 Hr LC50 Pimephales promelas	5.74-6.44 mg/L [flow-through]	
96 Hr LC50 Oncorhynchus mykiss	1.6 mg/L [flow-through]	

96 Hr LC50 Oncorhynchus mykiss	0.91-2.82 mg/L [static]
96 Hr LC50 Pimephales promelas	1.99 mg/L [static]
96 Hr LC50 Lepomis macrochirus	31.0265 mg/L [static]
72 Hr EC50 Skeletonema costatum	0.4 mg/L
48 Hr LC50 Daphnia magna	2.16 mg/L
48 Hr EC50 Daphnia magna	1.96 mg/L [Flow through]
48 Hr EC50 Daphnia magna	1.09 - 3.4 mg/L [Static]

Persistence/Degradability
No information available.

Bioaccumulation
No information available.

Mobility in Soil
No information available.

* * * Section 13 - Disposal Considerations * * *

Waste Disposal Instructions
See Section 7 for Handling Procedures. See Section 8 for Personal Protective Equipment recommendations.

Disposal of Contaminated Containers or Packaging
Dispose of contents/container in accordance with local/regional/national/international regulations.

* * * Section 14 - Transportation Information * * *

IATA Information
Shipping Name: Heating oil, light
UN #: 1202 **Hazard Class:** 3 **Packing Group:** III

ICAO Information
Shipping Name: Heating oil, light
UN #: 1202 **Hazard Class:** 3 **Packing Group:** III

IMDG Information
Shipping Name: Heating oil, light
UN #: 1202 **Hazard Class:** 3 **Packing Group:** III

* * * Section 15 - Regulatory Information * * *

Regulatory Information

Component Analysis – Inventory

Component/CAS	EC #	EEC	CAN	TSCA
Fuel oil No. 2 68476-30-2	270-671-4	EINECS	DSL	Yes
Naphthalene 91-20-3	202-049-5	EINECS	DSL	Yes

* * * Section 16 - Other Information * * *

Key/Legend

ACGIH = American Conference of Governmental Industrial Hygienists; ADG = Australian Code for the Transport of Dangerous Goods by Road and Rail; ADR/RID = European Agreement of Dangerous Goods by Road/Rail; AS = Standards Australia; DFG = Deutsche Forschungsgemeinschaft; DOT = Department of Transportation; DSL = Domestic Substances List; EEC = European Economic Community; EINECS = European Inventory of Existing Commercial Chemical Substances; ELINCS = European List of Notified Chemical Substances; EU = European Union; HMIS = Hazardous Materials Identification System; IARC = International Agency for Research on Cancer; IMO = International Maritime Organization; IATA = International Air Transport Association; MAK = Maximum Concentration Value in the Workplace; NDSL = Non-Domestic Substances List; NFPA = National Fire Protection Association; NOHSC = National Occupational Health & Safety Commission; NTP = National Toxicology Program; STEL = Short-term Exposure Limit; TDG = Transportation of Dangerous Goods; TLV = Threshold Limit Value; TSCA = Toxic Substances Control Act; TWA = Time Weighted Average

Literature References

None

Other Information

Information presented herein has been compiled from sources considered to be dependable, and is accurate and reliable to the best of our knowledge and belief, but is not guaranteed to be so. Since conditions of use are beyond our control, we make no warranties, expressed or implied, except those that may be contained in our written contract of sale or acknowledgment.

Vendor assumes no responsibility for injury to vendee or third persons proximately caused by the material if reasonable safety procedures are not adhered to as stipulated in the data sheet. Additionally, vendor assumes no responsibility for injury to vendee or third persons proximately caused by abnormal use of the material, even if reasonable safety procedures are followed. Furthermore, vendee assumes the risk in their use of the material.

End of Sheet

ATTACHMENT I
EMISSION UNITS TABLE

Attachment I

Emission Units Table

(includes all emission units and air pollution control devices that will be part of this permit application review, regardless of permitting status)

Emission Unit ID[1]	Emission Point ID[2]	Emission Unit Description	Year Installed/ Modified	Design Capacity	Type[3] and Date of Change	Control Device [4]
CT-1	CT-1	Combined-Cycle Combustion Turbine No. 1	2025	3,875 MMBtu/hr (approx)	New	DLNC, SCR, Oxidation Catalyst
CT-2	CT-2	Combined-Cycle Combustion Turbine No. 2	2025	3,875 MMBtu/hr (approx)	New	DLNC, SCR, Oxidation Catalyst
NA	NA	HRSG-1 Heat Recovery Steam Generator with Duct Burners No. 1	2025	485 MMBtu/hr (HHV) (approx)	New	NA
NA	NA	HRSG-2 Heat Recovery Steam Generator with Duct Burners No. 2	2025	485 MMBtu/hr (HHV) (approx)	New	NA
FGH-1	FGH-1	Fuel Gas Heater	2025	7 MMBtu/hr (approx)	New	LNB
FGH-2	FGH-2	Fuel Gas Heater	2025	7 MMBtu/hr (approx)	New	LNB
EG-1	EG-1	Emergency Electric Generator	2025	3,353 hp 2,500 kW	New	NA
FWP-1	FWP-1	Firewater Pump	2025	240 hp, 179 kW	New	NA
DT-1	DT-1	Emergency Generator Fuel Storage Tanks	2025	300 gallons	New	NA
DT-2	DT-2	Firewater Pump Fuel Storage Tank	2025	125 gallons	New	NA
NA	NA	AA-1 Aqueous Ammonia Storage Tank 1	2025	60,000 gallons	New	NA
NA	NA	AA-2 Aqueous Ammonia Storage Tank 2	2025	60,000 gallons	New	NA

[1] For Emission Units (or Sources) use the following numbering system:1S, 2S, 3S,... or other appropriate designation.
[2] For Emission Points use the following numbering system:1E, 2E, 3E, ... or other appropriate designation.
[3] New, modification, removal
[4] For Control Devices use the following numbering system: 1C, 2C, 3C,... or other appropriate designation.

Attachment I

Emission Units Table

(includes all emission units and air pollution control devices that will be part of this permit application review, regardless of permitting status)

Emission Unit ID[1]	Emission Point ID[2]	Emission Unit Description	Year Installed/ Modified	Design Capacity	Type[3] and Date of Change	Control Device[4]
WCT-1	WCT-1	Mechanical Draft Cooling Tower 1	2025	270,000 gals/min	New	Demisters

[1] For Emission Units (or Sources) use the following numbering system:1S, 2S, 3S,... or other appropriate designation.
[2] For Emission Points use the following numbering system:1E, 2E, 3E, ... or other appropriate designation.
[3] New, modification, removal
[4] For Control Devices use the following numbering system: 1C, 2C, 3C,... or other appropriate designation.

ATTACHMENT J
EMISSION POINTS DATA SUMMARY SHEET

Attachment J
EMISSION POINTS DATA SUMMARY SHEET

Table 1: Emissions Data

Emission Point ID No. *(Must match Emission Units Table & Plot Plan)*	Emission Point Type[1]	Emission Unit Vented Through This Point *(Must match Emission Units Table & Plot Plan)*		Air Pollution Control Device *(Must match Emission Units Table & Plot Plan)*		Vent Time for Emission Unit *(chemical processes only)*		All Regulated Pollutants - Chemical Name/CAS[3] *(Speciate VOCs & HAPS)*	Maximum Potential Uncontrolled Emissions [4]		Maximum Potential Controlled Emissions [5]		Emission Form or Phase *(At exit conditions, Solid, Liquid or Gas/Vapor)*	Est. Method Used [6]	Emission Concentration [7] (ppmv or mg/m^3)
		ID No.	Source	ID No.	Device Type	Short Term[2]	Max (hr/yr)		lb/hr	ton/yr	lb/hr	ton/yr			
CT-1	Upward Vertical Stack	CT-1	Combined Cycle Combustion Turbine	NA	LNB, SCR and Oxidation Catalyst	C	8,760	See Section 3 and Appendix B of the PSD Permit Application Document							
CT-2	Upward Vertical Stack	CT-2	Combined Cycle Combustion Turbine	NA	LNB, SCR and Oxidation Catalyst	C	8,760	See Section 3 and Appendix B of the PSD Permit Application Document							
FGH-1	Exhaust	FGH-1	Fuel Gas Heater	NA	LNB	As required	8.760	See Section 3 and Appendix B of the PSD Permit Application Document							
FGH-2	Exhaust	FGH-2	Fuel Gas Heater	NA	LNB	As required	8.760	See Section 3 and Appendix B of the PSD Permit Application Document							

Attachment J
EMISSION POINTS DATA SUMMARY SHEET

Table 1: Emissions Data

Emission Point ID No. *(Must match Emission Units Table & Plot Plan)*	Emission Point Type[1]	Emission Unit Vented Through This Point *(Must match Emission Units Table & Plot Plan)*		Air Pollution Control Device *(Must match Emission Units Table & Plot Plan)*		Vent Time for Emission Unit *(chemical processes only)*		All Regulated Pollutants - Chemical Name/CAS[3] *(Speciate VOCs & HAPS)*	Maximum Potential Uncontrolled Emissions [4]		Maximum Potential Controlled Emissions [5]		Emission Form or Phase *(At exit conditions, Solid, Liquid or Gas/Vapor)*	Est. Method Used [6]	Emission Concentration [7] (ppmv or mg/m³)
		ID No.	Source	ID No.	Device Type	Short Term[2]	Max (hr/yr)		lb/hr	ton/yr	lb/hr	ton/yr			
EG-1	Exhaust	EG-1	Emergency Electric Generator	NA	NA	As Required	100	See Section 3 and Appendix B of the PSD Permit Application Document							
FWP-1	Exhaust	FWP-1	Firewater Pump	NA	NA	As Required	100	See Section 3 and Appendix B of the PSD Permit Application Document							
DT-1	Upward Vertical Stack	ST-1	Diesel Storage Tank	NA	NA	C	8,760	Total VOC	0.09	0.39	0.09	0.39	Gas	EE	NA
DT-2	Upward Vertical Stack	ST-2	Diesel Storage Tank	NA	NA	C	8,760	Total VOC	0.09	0.39	0.09	0.39	Gas	EE	NA
WCT-1	Upward Vertical Stack	MDCT-1	Mechanical Draft Cooling Tower	NA	NA	C	8,760	See Section 3 and Appendix B of the PSD Permit Application Document							

The EMISSION POINTS DATA SUMMARY SHEET provides a summation of emissions by emission unit. Note that uncaptured process emission unit emissions are not typically considered to be fugitive and must be accounted for on the appropriate EMISSIONS UNIT DATA SHEET and on the EMISSION POINTS DATA SUMMARY SHEET. Please note that total emissions from the source are equal to all vented emissions, all fugitive emissions, plus all other emissions (e.g. uncaptured emissions). Please complete the FUGITIVE EMISSIONS DATA SUMMARY SHEET for fugitive emission activities.

[1] Please add descriptors such as upward vertical stack, downward vertical stack, horizontal stack, relief vent, rain cap, etc.

[2] Indicate by "C" if venting is continuous. Otherwise, specify the average short-term venting rate with units, for intermittent venting (ie., 15 min/hr). Indicate as many rates as needed to clarify frequency of venting (e.g., 5 min/day, 2 days/wk).

[3] List all regulated air pollutants. Speciate VOCs, including all HAPs. Follow chemical name with Chemical Abstracts Service (CAS) number. **LIST** Acids, CO, CS_2, VOCs, H_2S, Inorganics, Lead, Organics, O_3, NO, NO_2, SO_2, SO_3, all applicable Greenhouse Gases (including CO_2 and methane), etc. **DO NOT LIST** H_2, H_2O, N_2, O_2, and Noble Gases.

[4] Give maximum potential emission rate with no control equipment operating. If emissions occur for less than 1 hr, then record emissions per batch in minutes (e.g. 5 lb VOC/20 minute batch).

[5] Give maximum potential emission rate with proposed control equipment operating. If emissions occur for less than 1 hr, then record emissions per batch in minutes (e.g. 5 lb VOC/20 minute batch).

[6] Indicate method used to determine emission rate as follows: MB = material balance; ST = stack test (give date of test); EE = engineering estimate; O = other (specify).

[7] Provide for all pollutant emissions. Typically, the units of parts per million by volume (ppmv) are used. If the emission is a mineral acid (sulfuric, nitric, hydrochloric or phosphoric) use units of milligram per dry cubic meter (mg/m^3) at standard conditions (68 °F and 29.92 inches Hg) (see 45CSR7). If the pollutant is SO_2, use units of ppmv (See 45CSR10).

Attachment J
EMISSION POINTS DATA SUMMARY SHEET

Table 2: Release Parameter Data

Emission Point ID No. *(Must match Emission Units Table)*	Inner Diameter (ft.)	Exit Gas			Emission Point Elevation (ft)		UTM Coordinates (km)	
		Temp. (^oF)	Volumetric Flow [1] (acfm) *at operating conditions*	Velocity (fps)	Ground Level *(Height above mean sea level)*	Stack Height [2] *(Release height of emissions above ground level)*	Northing	Easting
CT-1	23	148	1,669,503	67.0	1,150	180	4,396.353	589.077
CT-2	23	148	1,669,503	67.0	1,150	180	4,396.353	589.077
FGH-1	0.6	600	1,017	60	1,150	35	4,396.353	589.077
FGH-2	0.6	600	1,017	60	1,150	35	4,396.353	589.077
EG-1	0.5	961	1,400	118.8	1,150	75	4,396.353	589.077
FWP-1	0.7	752	15,295	730.3	1,150	12	4,396.353	589.077

WCT-1	NA	Ambient	NA	NA	1,150	NA	4,396.353	589.077
DT-1	NA	Ambient	NA	NA	1,150	NA	4,396.353	589.077
DT-2	NA	Ambient	NA	NA	1,150	NA	4,396.353	589.077

[1] Give at operating conditions. Include inerts.
[2] Release height of emissions above ground level.

ATTACHMENT K
FUGITIVE EMISSIONS DATA SUMMARY SHEET

Attachment K

FUGITIVE EMISSIONS DATA SUMMARY SHEET

The FUGITIVE EMISSIONS SUMMARY SHEET provides a summation of fugitive emissions. Fugitive emissions are those emissions which could not reasonably pass through a stack, chimney, vent or other functionally equivalent opening. Note that uncaptured process emissions are not typically considered to be fugitive, and must be accounted for on the appropriate EMISSIONS UNIT DATA SHEET and on the EMISSION POINTS DATA SUMMARY SHEET.

Please note that total emissions from the source are equal to all vented emissions, all fugitive emissions, plus all other emissions (e.g. uncaptured emissions).

APPLICATION FORMS CHECKLIST - FUGITIVE EMISSIONS
1.) Will there be haul road activities? ☐ Yes ☒ No ☐ If YES, then complete the HAUL ROAD EMISSIONS UNIT DATA SHEET.
2.) Will there be Storage Piles? ☐ Yes ☒ No o ☐ If YES, complete Table 1 of the NONMETALLIC MINERALS PROCESSING EMISSIONS UNIT DATA SHEET.
3.) Will there be Liquid Loading/Unloading Operations? ☐ Yes ☒ No ☐ If YES, complete the BULK LIQUID TRANSFER OPERATIONS EMISSIONS UNIT DATA SHEET.
4.) Will there be emissions of air pollutants from Wastewater Treatment Evaporation? ☐ Yes ☒ No ☐ If YES, complete the GENERAL EMISSIONS UNIT DATA SHEET.
5.) Will there be Equipment Leaks (e.g. leaks from pumps, compressors, in-line process valves, pressure relief devices, open-ended valves, sampling connections, flanges, agitators, cooling towers, etc.)? ☒ Yes ☐ No ☐ If YES, complete the LEAK SOURCE DATA SHEET section of the CHEMICAL PROCESSES EMISSIONS UNIT DATA SHEET.
6.) Will there be General Clean-up VOC Operations? ☐ Yes ☒ No ☐ If YES, complete the GENERAL EMISSIONS UNIT DATA SHEET.
7.) Will there be any other activities that generate fugitive emissions? ☐ Yes ☒ No ☐ If YES, complete the GENERAL EMISSIONS UNIT DATA SHEET or the most appropriate form.
If you answered “NO” to all of the items above, it is not necessary to complete the following table, “Fugitive Emissions Summary.”

FUGITIVE EMISSIONS SUMMARY	All Regulated Pollutants - Chemical Name/CAS [1]	Maximum Potential Uncontrolled Emissions [2]		Maximum Potential Controlled Emissions [3]		Est. Method Used [4]
		lb/hr	ton/yr	lb/hr	ton/yr	
Haul Road/Road Dust Emissions Paved Haul Roads	NA					
Unpaved Haul Roads	NA					
Storage Pile Emissions	NA					
Loading/Unloading Operations	NA					
Wastewater Treatment Evaporation & Operations	NA					
Equipment Leaks	**Some equipment leak emissions from natural gas processing and are non-regulated chemicals.**	Does not apply		Does not apply		
General Clean-up VOC Emissions	NA					
Other	NA					

[1] List all regulated air pollutants. Speciate VOCs, including all HAPs. Follow chemical name with Chemical Abstracts Service (CAS) number. LIST Acids, CO, CS_2, VOCs, H_2S, Inorganics, Lead, Organics, O_3, NO, NO_2, SO_2, SO_3, all applicable Greenhouse Gases (including CO_2 and methane), etc. DO NOT LIST H_2, H_2O, N_2, O_2, and Noble Gases.
[2] Give rate with no control equipment operating. If emissions occur for less than 1 hr, then record emissions per batch in minutes (e.g. 5 lb VOC/20 minute batch).
[3] Give rate with proposed control equipment operating. If emissions occur for less than 1 hr, then record emissions per batch in minutes (e.g. 5 lb VOC/20 minute batch).
[4] Indicate method used to determine emission rate as follows: MB = material balance; ST = stack test (give date of test); EE = engineering estimate; O = other (specify).

ATTACHMENT L
EMISSIONS UNIT DATA SHEETS

Attachment L

Emission Unit Data Sheet

(INDIRECT HEAT EXCHANGER)

Control Device ID No. (must match List Form): Combine Cycle Gas Turbine CT-1

Equipment Information

1. Manufacturer: GE or MHPS JAC	2. Model No. GE:7HA.02 /MHPS JAC 501 Serial No.
3. Number of units: 1	4. Use Electric Generation
5. Rated Boiler Horsepower: NA hp	6. Boiler Serial No.: NA
7. Date constructed: 2021	8. Date of last modification and explain: NA
9. Maximum design heat input per unit: 3,875 $\times 10^6$ BTU/hr	10. Peak heat input per unit: 3,875 $\times 10^6$ BTU/hr
11. Steam produced at maximum design output: NA LB/hr NA psig	12. Projected Operating Schedule: Hours/Day 24 Days/Week 7 Weeks/Year 52
13. Type of firing equipment to be used: ☐ Pulverized coal ☐ Spreader stoker ☐ Oil burners ☒ Natural Gas Burner ☐ Others, specify	14. Proposed type of burners and orientation: ☐ Vertical ☐ Front Wall ☐ Opposed ☐ Tangential ☒ Others, specify LNB
15. Type of draft: ☒ Forced ☐ Induced	16. Percent of ash retained in furnace: NA %
17. Will flyash be reinjected? ☐ Yes ☒ No	18. Percent of carbon in flyash: NA %

Stack or Vent Data

19. Inside diameter or dimensions: 23 ft.	20. Gas exit temperature: 148.3 °F
21. Height: 180 ft.	22. Stack serves: ☒ This equipment only ☐ Other equipment also (submit type and rating of all other equipment exhausted through this stack or vent)
23. Gas flow rate: 1,669,503 ft^3/min	
24. Estimated percent of moisture: NA %	

Fuel Requirements

25. Type	Fuel Oil No.	Natural Gas	Gas (other, specify)	Coal, Type:	Other:
Quantity (at Design Output)	gph@60°F	3,300,000 ft^3/hr	ft^3/hr	TPH	
Annually	$\times 10^3$ gal	28,575 $\times 10^6$ ft^3/hr	$\times 10^6$ ft^3/hr	tons	
Sulfur	Maximum: wt. % Average: wt. %	0.4 gr/100 ft^3	gr/100 ft^3	Maximum: wt. %	
Ash (%)		NA		Maximum	
BTU Content	BTU/Gal. Lbs/Gal.@60°F	1,030 BTU/ft^3	BTU/ft^3	BTU/lb	
Source		Local Suppliers			
Supplier		Local Supplier of Pipeline Natural Gas			
Halogens (Yes/No)		NA			
List and Identify Metals		NA			

26. Gas burner mode of control:
☐ Manual ☐ Automatic hi-low
☒ Automatic full modulation ☐ Automatic on-off

27. Gas burner manufacture: GE of MHPS

28. Oil burner manufacture: NA

29. If fuel oil is used, how is it atomized? ☐ Oil Pressure ☐ Steam Pressure ☐ Compressed Air ☐ Rotary Cup ☐ Other, specify

30. Fuel oil preheated: ☒ Yes ☐ No

31. If yes, indicate temperature: °F

32. Specify the calculated theoretical air requirements for combustion of the fuel or mixture of fuels described above actual cubic feet (ACF) per unit of fuel:
NA @ NA °F, NA PSIA, NA % moisture

33. Emission rate at rated capacity: See Attachment J and Section 3 and Appendix B of the PSD Application Document lb/hr

34. Percent excess air actually required for combustion of the fuel described: NA %

Coal Characteristics

35. Seams: NA

36. Proximate analysis (dry basis): % of Fixed Carbon: % of Sulfur:
% of Moisture: % of Volatile Matter:
% of Ash:

Emissions Stream

37. What quantities of pollutants will be emitted from the boiler before controls?

Pollutant	Pounds per Hour lb/hr	grain/ACF	@ °F	PSIA
CO	See Attachment J			
Hydrocarbons				
NO_x				
Pb				
PM_{10}				
SO_2				
VOCs				
Other (specify)				

38. What quantities of pollutants will be emitted from the boiler after controls?

Pollutant	Pounds per Hour lb/hr	grain/ACF	@ °F	PSIA
CO	See Attachment J			
Hydrocarbons				
NO_x				
Pb				
PM_{10}				
SO_2				
VOCs				
Other (specify)				

39. How will waste material from the process and control equipment be disposed of?
NA

40. Have you completed an *Air Pollution Control Device Sheet(s)* for the control(s) used on this Emission Unit.

41. Have you included the ***air pollution rates*** on the Emissions Points Data Summary Sheet?

42. **Proposed Monitoring, Recordkeeping, Reporting, and Testing**
Please propose monitoring, recordkeeping, and reporting in order to demonstrate compliance with the proposed operating parameters. Please propose testing in order to demonstrate compliance with the proposed emissions limits.

MONITORING PLAN: Please list (1) describe the process parameters and how they were chosen (2) the ranges and how they were established for monitoring to demonstrate compliance with the operation of this process equipment operation or air pollution control device.

See Attachment O

TESTING PLAN: Please describe any proposed emissions testing for this process equipment or air pollution control device.

See Attachment O

RECORDKEEPING: Please describe the proposed recordkeeping that will accompany the monitoring.

See Attachment O

REPORTING: Please describe the proposed frequency of reporting of the recordkeeping.

See Attachment O

43. Describe all operating ranges and maintenance procedures required by Manufacturer to maintain warranty.
NA

Attachment L

Emission Unit Data Sheet

(INDIRECT HEAT EXCHANGER)

Control Device ID No. (must match List Form): Combine Cycle Gas Turbine CT-2

Equipment Information

1. Manufacturer: GE or MHPS JAC	2. Model No. GE:7HA.02 /MHPS JAC 501 Serial No.
3. Number of units: 1	4. Use Electric Generation
5. Rated Boiler Horsepower: NA hp	6. Boiler Serial No.: NA
7. Date constructed: 2021	8. Date of last modification and explain: NA
9. Maximum design heat input per unit: 3,875 $\times 10^6$ BTU/hr	10. Peak heat input per unit: 3,875 $\times 10^6$ BTU/hr
11. Steam produced at maximum design output: NA LB/hr NA psig	12. Projected Operating Schedule: Hours/Day 24 Days/Week 7 Weeks/Year 52
13. Type of firing equipment to be used: ☐ Pulverized coal ☐ Spreader stoker ☐ Oil burners ☒ Natural Gas Burner ☐ Others, specify	14. Proposed type of burners and orientation: ☐ Vertical ☐ Front Wall ☐ Opposed ☐ Tangential ☒ Others, specify LNB
15. Type of draft: ☒ Forced ☐ Induced	16. Percent of ash retained in furnace: NA %
17. Will flyash be reinjected? ☐ Yes ☒ No	18. Percent of carbon in flyash: NA %

Stack or Vent Data

19. Inside diameter or dimensions: 23 ft.	20. Gas exit temperature: 148.3 °F
21. Height: 180 ft.	22. Stack serves: ☒ This equipment only ☐ Other equipment also (submit type and rating of all other equipment exhausted through this stack or vent)
23. Gas flow rate: 1,669,503 ft^3/min	
24. Estimated percent of moisture: NA %	

Fuel Requirements

25. Type	Fuel Oil No.	Natural Gas	Gas (other, specify)	Coal, Type:	Other:
Quantity (at Design Output)	gph@60°F	3,300,000 ft^3/hr	ft^3/hr	TPH	
Annually	$\times 10^3$ gal	28,575 $\times 10^6$ ft^3/hr	$\times 10^6$ ft^3/hr	tons	
Sulfur	Maximum: wt. % Average: wt. %	0.4 gr/100 ft^3	gr/100 ft^3	Maximum: wt. %	
Ash (%)		NA		Maximum	
BTU Content	BTU/Gal. Lbs/Gal.@60°F	1,030 BTU/ft^3	BTU/ft^3	BTU/lb	
Source		Local Suppliers			
Supplier		Local Supplier of Pipeline Natural Gas			
Halogens (Yes/No)		NA			
List and Identify Metals		NA			

26. Gas burner mode of control:
☐ Manual ☐ Automatic hi-low
☒ Automatic full modulation ☐ Automatic on-off

27. Gas burner manufacture: GE of MHPS

28. Oil burner manufacture: NA

29. If fuel oil is used, how is it atomized? ☐ Oil Pressure ☐ Steam Pressure ☐ Compressed Air ☐ Rotary Cup ☐ Other, specify

30. Fuel oil preheated: ☒ Yes ☐ No

31. If yes, indicate temperature: °F

32. Specify the calculated theoretical air requirements for combustion of the fuel or mixture of fuels described above actual cubic feet (ACF) per unit of fuel:
NA @ NA °F, NA PSIA, NA % moisture

33. Emission rate at rated capacity: See Attachment J and Section 3 and Appendix B of the PSD Application Document lb/hr

34. Percent excess air actually required for combustion of the fuel described: NA %

Coal Characteristics

35. Seams: NA

36. Proximate analysis (dry basis): % of Fixed Carbon: % of Sulfur:
% of Moisture: % of Volatile Matter:
% of Ash:

Emissions Stream

37. What quantities of pollutants will be emitted from the boiler before controls?

Pollutant	Pounds per Hour lb/hr	grain/ACF	@ °F	PSIA
CO	See Attachment J			
Hydrocarbons				
NO_x				
Pb				
PM_{10}				
SO_2				
VOCs				
Other (specify)				

38. What quantities of pollutants will be emitted from the boiler after controls?

Pollutant	Pounds per Hour lb/hr	grain/ACF	@ °F	PSIA
CO	See Attachment J			
Hydrocarbons				
NO_x				
Pb				
PM_{10}				
SO_2				
VOCs				
Other (specify)				

39. How will waste material from the process and control equipment be disposed of?
NA

40. Have you completed an *Air Pollution Control Device Sheet(s)* for the control(s) used on this Emission Unit.

41. Have you included the ***air pollution rates*** on the Emissions Points Data Summary Sheet?

42. **Proposed Monitoring, Recordkeeping, Reporting, and Testing**
Please propose monitoring, recordkeeping, and reporting in order to demonstrate compliance with the proposed operating parameters. Please propose testing in order to demonstrate compliance with the proposed emissions limits.

MONITORING PLAN: Please list (1) describe the process parameters and how they were chosen (2) the ranges and how they were established for monitoring to demonstrate compliance with the operation of this process equipment operation or air pollution control device.
See Attachment O

TESTING PLAN: Please describe any proposed emissions testing for this process equipment or air pollution control device.
See Attachment O

RECORDKEEPING: Please describe the proposed recordkeeping that will accompany the monitoring.
See Attachment O

REPORTING: Please describe the proposed frequency of reporting of the recordkeeping.
See Attachment O

43. Describe all operating ranges and maintenance procedures required by Manufacturer to maintain warranty.
NA

Attachment L
Emission Unit Data Sheet
(INDIRECT HEAT EXCHANGER)

Control Device ID No. (must match List Form): FGH-1

Equipment Information

1. Manufacturer: TBD	2. Model No. NA Serial No. NA
3. Number of units: 1	4. UseSteam to preheat natural gas
5. Rated Boiler Horsepower: NA hp	6. Boiler Serial No.: NA
7. Date constructed: 2021	8. Date of last modification and explain: NA
9. Maximum design heat input per unit: 7 $\times 10^6$ BTU/hr	10. Peak heat input per unit: 7 $\times 10^6$ BTU/hr
11. Steam produced at maximum design output: NA LB/hr NA psig	12. Projected Operating Schedule: Hours/Day 24 Days/Week 7 Weeks/Year 52
13. Type of firing equipment to be used: ☐ Pulverized coal ☐ Spreader stoker ☐ Oil burners ☒ Natural Gas Burner ☐ Others, specify	14. Proposed type of burners and orientation: ☐ Vertical ☒ Front Wall ☐ Opposed ☐ Tangential ☐ Others, specify
15. Type of draft: ☒ Forced ☐ Induced	16. Percent of ash retained in furnace: NA %
17. Will flyash be reinjected? ☐ Yes ☒ No	18. Percent of carbon in flyash: NA %

Stack or Vent Data

19. Inside diameter or dimensions: 0.6 ft.	20. Gas exit temperature: 600 °F
21. Height: 15 ft.	22. Stack serves: ☒ This equipment only ☐ Other equipment also (submit type and rating of all other equipment exhausted through this stack or vent)
23. Gas flow rate: 1,017 ft^3/min	
24. Estimated percent of moisture: %	

Fuel Requirements

25. Type	Fuel Oil No.	Natural Gas	Gas (other, specify)	Coal, Type:	Other:
Quantity (at Design Output)	gph@60°F	5,250 ft^3/hr	ft^3/hr	TPH	
Annually	$\times 10^3$ gal	4.6 $\times 10^6$ ft^3/hr	$\times 10^6$ ft^3/hr	tons	
Sulfur	Maximum: wt. % Average: wt. %	0.4 gr/100 ft^3	gr/100 ft^3	Maximum: wt. %	
Ash (%)		NA		Maximum	
BTU Content	BTU/Gal. Lbs/Gal.@60°F	1,030 BTU/ft^3	BTU/ft^3	BTU/lb	
Source					
Supplier					
Halogens (Yes/No)					
List and Identify Metals					

26. Gas burner mode of control:
☐ Manual ☐ Automatic hi-low
☒ Automatic full modulation ☐ Automatic on-off

27. Gas burner manufacture: TBD

28. Oil burner manufacture: NA

29. If fuel oil is used, how is it atomized? ☐ Oil Pressure ☐ Steam Pressure ☐ Compressed Air ☐ Rotary Cup ☐ Other, specify

30. Fuel oil preheated: ☐ Yes ☐ No

31. If yes, indicate temperature: °F

32. Specify the calculated theoretical air requirements for combustion of the fuel or mixture of fuels described above actual cubic feet (ACF) per unit of fuel:
NA @ NA °F, NA PSIA, NA % moisture

33. Emission rate at rated capacity: See Attachment J and Section 3 and Appendix B of the PSD Application Document lb/hr

34. Percent excess air actually required for combustion of the fuel described: NA %

Coal Characteristics

35. Seams: NA

36. Proximate analysis (dry basis): % of Fixed Carbon: % of Sulfur:
% of Moisture: % of Volatile Matter:
% of Ash:

Emissions Stream

37. What quantities of pollutants will be emitted from the boiler before controls?

Pollutant	Pounds per Hour lb/hr	grain/ACF	@ °F	PSIA
CO	See Attachment J and Section 3 and			
Hydrocarbons				
NO_x				
Pb				
PM_{10}				
SO_2				
VOCs				
Other (specify)				

38. What quantities of pollutants will be emitted from the boiler after controls?

Pollutant	Pounds per Hour lb/hr	grain/ACF	@ °F	PSIA
CO	See Attachment J and Section 3 and			
Hydrocarbons				
NO_x				
Pb				
PM_{10}				
SO_2				
VOCs				
Other (specify)				

39. How will waste material from the process and control equipment be disposed of?
NA

40. Have you completed an *Air Pollution Control Device Sheet(s)* for the control(s) used on this Emission Unit.

41. Have you included the ***air pollution rates*** on the Emissions Points Data Summary Sheet?

42. **Proposed Monitoring, Recordkeeping, Reporting, and Testing**
Please propose monitoring, recordkeeping, and reporting in order to demonstrate compliance with the proposed operating parameters. Please propose testing in order to demonstrate compliance with the proposed emissions limits.

MONITORING PLAN: Please list (1) describe the process parameters and how they were chosen (2) the ranges and how they were established for monitoring to demonstrate compliance with the operation of this process equipment operation or air pollution control device.
See Attachment O

TESTING PLAN: Please describe any proposed emissions testing for this process equipment or air pollution control device.
See Attachment

RECORDKEEPING: Please describe the proposed recordkeeping that will accompany the monitoring.
See Attachment

REPORTING: Please describe the proposed frequency of reporting of the recordkeeping.
See Attachment

43. Describe all operating ranges and maintenance procedures required by Manufacturer to maintain warranty.
NA

Attachment L
Emission Unit Data Sheet
(INDIRECT HEAT EXCHANGER)

Control Device ID No. (must match List Form): FGH-2

Equipment Information

1. Manufacturer: TBD	2. Model No. NA Serial No. NA
3. Number of units: 1	4. UseSteam to preheat natural gas
5. Rated Boiler Horsepower: NA hp	6. Boiler Serial No.: NA
7. Date constructed: 2021	8. Date of last modification and explain: NA
9. Maximum design heat input per unit: 7 $\times 10^6$ BTU/hr	10. Peak heat input per unit: 7 $\times 10^6$ BTU/hr
11. Steam produced at maximum design output: NA LB/hr NA psig	12. Projected Operating Schedule: Hours/Day 24 Days/Week 7 Weeks/Year 52
13. Type of firing equipment to be used: ☐ Pulverized coal ☐ Spreader stoker ☐ Oil burners ☒ Natural Gas Burner ☐ Others, specify	14. Proposed type of burners and orientation: ☐ Vertical ☒ Front Wall ☐ Opposed ☐ Tangential ☐ Others, specify
15. Type of draft: ☒ Forced ☐ Induced	16. Percent of ash retained in furnace: NA %
17. Will flyash be reinjected? ☐ Yes ☒ No	18. Percent of carbon in flyash: NA %

Stack or Vent Data

19. Inside diameter or dimensions: 0.6 ft.	20. Gas exit temperature: 600 °F
21. Height: 15 ft.	22. Stack serves: ☒ This equipment only ☐ Other equipment also (submit type and rating of all other equipment exhausted through this stack or vent)
23. Gas flow rate: 1,017 ft^3/min	
24. Estimated percent of moisture: %	

Fuel Requirements

25. Type	Fuel Oil No.	Natural Gas	Gas (other, specify)	Coal, Type:	Other:
Quantity (at Design Output)	gph@60°F	5,250 ft^3/hr	ft^3/hr	TPH	
Annually	$\times 10^3$ gal	4.6 $\times 10^6$ ft^3/hr	$\times 10^6$ ft^3/hr	tons	
Sulfur	Maximum: wt. % Average: wt. %	0.4 gr/100 ft^3	gr/100 ft^3	Maximum: wt. %	
Ash (%)		NA		Maximum	
BTU Content	BTU/Gal. Lbs/Gal.@60°F	1,030 BTU/ft^3	BTU/ft^3	BTU/lb	
Source					
Supplier					
Halogens (Yes/No)					
List and Identify Metals					

26. Gas burner mode of control:
☐ Manual ☐ Automatic hi-low
☒ Automatic full modulation ☐ Automatic on-off

27. Gas burner manufacture: TBD

28. Oil burner manufacture: NA

29. If fuel oil is used, how is it atomized? ☐ Oil Pressure ☐ Steam Pressure ☐ Compressed Air ☐ Rotary Cup ☐ Other, specify

30. Fuel oil preheated: ☐ Yes ☐ No

31. If yes, indicate temperature: °F

32. Specify the calculated theoretical air requirements for combustion of the fuel or mixture of fuels described above actual cubic feet (ACF) per unit of fuel:
NA @ NA °F, NA PSIA, NA % moisture

33. Emission rate at rated capacity: See Attachment J and Section 3 and Appendix B of the PSD Application Document lb/hr

34. Percent excess air actually required for combustion of the fuel described: NA %

Coal Characteristics

35. Seams: NA

36. Proximate analysis (dry basis): % of Fixed Carbon: % of Sulfur: % of Moisture: % of Volatile Matter: % of Ash:

Emissions Stream

37. What quantities of pollutants will be emitted from the boiler before controls?

Pollutant	Pounds per Hour lb/hr	grain/ACF	@ °F	PSIA
CO	See Attachment J and Section 3 and			
Hydrocarbons				
NO_x				
Pb				
PM_{10}				
SO_2				
VOCs				
Other (specify)				

38. What quantities of pollutants will be emitted from the boiler after controls?

Pollutant	Pounds per Hour lb/hr	grain/ACF	@ °F	PSIA
CO	See Attachment J and Section 3 and			
Hydrocarbons				
NO_x				
Pb				
PM_{10}				
SO_2				
VOCs				
Other (specify)				

39. How will waste material from the process and control equipment be disposed of?
NA

40. Have you completed an *Air Pollution Control Device Sheet(s)* for the control(s) used on this Emission Unit.

41. Have you included the ***air pollution rates*** on the Emissions Points Data Summary Sheet?

42. **Proposed Monitoring, Recordkeeping, Reporting, and Testing**
Please propose monitoring, recordkeeping, and reporting in order to demonstrate compliance with the proposed operating parameters. Please propose testing in order to demonstrate compliance with the proposed emissions limits.

MONITORING PLAN: Please list (1) describe the process parameters and how they were chosen (2) the ranges and how they were established for monitoring to demonstrate compliance with the operation of this process equipment operation or air pollution control device.
See Attachment O

TESTING PLAN: Please describe any proposed emissions testing for this process equipment or air pollution control device.
See Attachment

RECORDKEEPING: Please describe the proposed recordkeeping that will accompany the monitoring.
See Attachment

REPORTING: Please describe the proposed frequency of reporting of the recordkeeping.
See Attachment

43. Describe all operating ranges and maintenance procedures required by Manufacturer to maintain warranty.
NA

Attachment L
EMISSIONS UNIT DATA SHEET
GENERAL

To be used for affected sources other than asphalt plants, foundries, incinerators, indirect heat exchangers, and quarries.

Identification Number (as assigned on *Equipment List Form*): EG-1

1. Name or type and model of proposed affected source: Emergency Electric Generator (Diesel Fuel Fired) – 3,353 kW (2,500 hp)
2. On a separate sheet(s), furnish a sketch(es) of this affected source. If a modification is to be made to this source, clearly indicated the change(s). Provide a narrative description of all features of the affected source which may affect the production of air pollutants.
3. Name(s) and maximum amount of proposed process material(s) charged per hour: NA
4. Name(s) and maximum amount of proposed material(s) produced per hour: NA
5. Give chemical reactions, if applicable, that will be involved in the generation of air pollutants: NA

* The identification number which appears here must correspond to the air pollution control device identification number appearing on the *List Form*.

6. Combustion Data (if applicable):

(a) Type and amount in appropriate units of fuel(s) to be burned:

Ultra Low Sulfur Diesel Fuel – As Required

(b) Chemical analysis of proposed fuel(s), excluding coal, including maximum percent sulfur and ash:

0.0015 % sulfur by weight

(c) Theoretical combustion air requirement (ACF/unit of fuel):

NA @ NA °F and NA psia.

(d) Percent excess air: NA

(e) Type and BTU/hr of burners and all other firing equipment planned to be used:

NA/Internal Combustion Engine

(f) If coal is proposed as a source of fuel, identify supplier and seams and give sizing of the coal as it will be fired:

NA

(g) Proposed maximum design heat input: 13.0 $\times 10^6$ BTU/hr.

7. Projected operating schedule:

Hours/Day 0.4	Days/Week 5	Weeks/Year 50

8. Projected amount of pollutants that would be emitted from this affected source if no control devices were used:		
@ NA	°F and Ambient	psia
a. NO_X	See Attachment J and Section 3 and Appendix B of the PSD Application Document lb/hr	grains/ACF
b. SO_2	lb/hr	grains/ACF
c. CO	lb/hr	grains/ACF
d. PM_{10}	lb/hr	grains/ACF
e. Hydrocarbons	lb/hr	grains/ACF
f. VOCs	lb/hr	grains/ACF
g. Pb	lb/hr	grains/ACF
h. Specify other(s)		
	lb/hr	grains/ACF
	lb/hr	grains/ACF
	lb/hr	grains/ACF
	lb/hr	grains/ACF

NOTE: (1) An Air Pollution Control Device Sheet must be completed for any air pollution device(s) used to control emissions from this affected source.

(2) Complete the Emission Points Data Sheet.

9. Proposed Monitoring, Recordkeeping, Reporting, and Testing
Please propose monitoring, recordkeeping, and reporting in order to demonstrate compliance with the proposed operating parameters. Please propose testing in order to demonstrate compliance with the proposed emissions limits.

MONITORING	RECORDKEEPING
See Attachment O	See Attachment O
REPORTING	**TESTING**
See Attachment O	See Attachment O

MONITORING. PLEASE LIST AND DESCRIBE THE PROCESS PARAMETERS AND RANGES THAT ARE PROPOSED TO BE MONITORED IN ORDER TO DEMONSTRATE COMPLIANCE WITH THE OPERATION OF THIS PROCESS EQUIPMENT OPERATION/AIR POLLUTION CONTROL DEVICE.

RECORDKEEPING. PLEASE DESCRIBE THE PROPOSED RECORDKEEPING THAT WILL ACCOMPANY THE MONITORING.

REPORTING. PLEASE DESCRIBE THE PROPOSED FREQUENCY OF REPORTING OF THE RECORDKEEPING.

TESTING. PLEASE DESCRIBE ANY PROPOSED EMISSIONS TESTING FOR THIS PROCESS EQUIPMENT/AIR POLLUTION CONTROL DEVICE.

10. Describe all operating ranges and maintenance procedures required by Manufacturer to maintain warranty
NA

Attachment L
EMISSIONS UNIT DATA SHEET
GENERAL

To be used for affected sources other than asphalt plants, foundries, incinerators, indirect heat exchangers, and quarries.

Identification Number (as assigned on *Equipment List Form*): Firewater Pump FWP-1

1. Name or type and model of proposed affected source: Firewater Pump (Diesel Fuel Fired) – 179 kW (240 hp)
2. On a separate sheet(s), furnish a sketch(es) of this affected source. If a modification is to be made to this source, clearly indicated the change(s). Provide a narrative description of all features of the affected source which may affect the production of air pollutants.
3. Name(s) and maximum amount of proposed process material(s) charged per hour: NA
4. Name(s) and maximum amount of proposed material(s) produced per hour: NA
5. Give chemical reactions, if applicable, that will be involved in the generation of air pollutants: NA

* The identification number which appears here must correspond to the air pollution control device identification number appearing on the *List Form*.

6. Combustion Data (if applicable):

(a) Type and amount in appropriate units of fuel(s) to be burned:

Ultra Low Sulfur Diesel Fuel – As Required

(b) Chemical analysis of proposed fuel(s), excluding coal, including maximum percent sulfur and ash:

0.0015 % sulfur by weight

(c) Theoretical combustion air requirement (ACF/unit of fuel):

NA @ NA °F and NA psia.

(d) Percent excess air: NA

(e) Type and BTU/hr of burners and all other firing equipment planned to be used:

NA/Internal Combustion Engine

(f) If coal is proposed as a source of fuel, identify supplier and seams and give sizing of the coal as it will be fired:

NA

(g) Proposed maximum design heat input: 2.710 $\times 10^6$ BTU/hr.

7. Projected operating schedule:

Hours/Day	0.4	Days/Week	5	Weeks/Year	50

8. Projected amount of pollutants that would be emitted from this affected source if no control devices were used:		
@ 0NA °F and Ambient psia		
a. NO_X	See Attachment J and Section 3 and Appendix B of the PSD Application Document lb/hr	grains/ACF
b. SO_2	lb/hr	grains/ACF
c. CO	lb/hr	grains/ACF
d. PM_{10}	lb/hr	grains/ACF
e. Hydrocarbons	lb/hr	grains/ACF
f. VOCs	lb/hr	grains/ACF
g. Pb	lb/hr	grains/ACF
h. Specify other(s)		
	lb/hr	grains/ACF
	lb/hr	grains/ACF
	lb/hr	grains/ACF
	lb/hr	grains/ACF

NOTE: (1) An Air Pollution Control Device Sheet must be completed for any air pollution device(s) used to control emissions from this affected source.

(2) Complete the Emission Points Data Sheet.

9. Proposed Monitoring, Recordkeeping, Reporting, and Testing
Please propose monitoring, recordkeeping, and reporting in order to demonstrate compliance with the proposed operating parameters. Please propose testing in order to demonstrate compliance with the proposed emissions limits.

MONITORING	RECORDKEEPING
See Attachment O	See Attachment O
REPORTING	**TESTING**
See Attachment O	See Attachment O

MONITORING. PLEASE LIST AND DESCRIBE THE PROCESS PARAMETERS AND RANGES THAT ARE PROPOSED TO BE MONITORED IN ORDER TO DEMONSTRATE COMPLIANCE WITH THE OPERATION OF THIS PROCESS EQUIPMENT OPERATION/AIR POLLUTION CONTROL DEVICE.

RECORDKEEPING. PLEASE DESCRIBE THE PROPOSED RECORDKEEPING THAT WILL ACCOMPANY THE MONITORING.

REPORTING. PLEASE DESCRIBE THE PROPOSED FREQUENCY OF REPORTING OF THE RECORDKEEPING.

TESTING. PLEASE DESCRIBE ANY PROPOSED EMISSIONS TESTING FOR THIS PROCESS EQUIPMENT/AIR POLLUTION CONTROL DEVICE.

10. Describe all operating ranges and maintenance procedures required by Manufacturer to maintain warranty
NA

Attachment L
EMISSIONS UNIT DATA SHEET
GENERAL

To be used for affected sources other than asphalt plants, foundries, incinerators, indirect heat exchangers, and quarries.

Identification Number (as assigned on *Equipment List Form*): WCT-1

1. Name or type and model of proposed affected source: Mechanical Draft Cooling Tower
2. On a separate sheet(s), furnish a sketch(es) of this affected source. If a modification is to be made to this source, clearly indicated the change(s). Provide a narrative description of all features of the affected source which may affect the production of air pollutants.
3. Name(s) and maximum amount of proposed process material(s) charged per hour: Process cooling water, approximately 270,000 gals/min
4. Name(s) and maximum amount of proposed material(s) produced per hour: NA
5. Give chemical reactions, if applicable, that will be involved in the generation of air pollutants: NA

* The identification number which appears here must correspond to the air pollution control device identification number appearing on the *List Form*.

6. Combustion Data (if applicable):

(a) Type and amount in appropriate units of fuel(s) to be burned:

NA

(b) Chemical analysis of proposed fuel(s), excluding coal, including maximum percent sulfur and ash:

NA

(c) Theoretical combustion air requirement (ACF/unit of fuel):

NA @ NA °F and NA psia.

(d) Percent excess air: NA

(e) Type and BTU/hr of burners and all other firing equipment planned to be used:

NA

(f) If coal is proposed as a source of fuel, identify supplier and seams and give sizing of the coal as it will be fired:

NA

(g) Proposed maximum design heat input: NA $\times 10^6$ BTU/hr.

7. Projected operating schedule:

Hours/Day	24	Days/Week	7	Weeks/Year	52

8. Projected amount of pollutants that would be emitted from this affected source if no control devices were used:

@ NA °F and Ambient psia

a.	NO_X	See Attachment J and Section 3 and Appendix B of the PSD Application Document	lb/hr		grains/ACF
b.	SO_2		lb/hr		grains/ACF
c.	CO		lb/hr		grains/ACF
d.	PM_{10}	4.11	lb/hr		grains/ACF
e.	Hydrocarbons		lb/hr		grains/ACF
f.	VOCs		lb/hr		grains/ACF
g.	Pb		lb/hr		grains/ACF
h.	Specify other(s)				
			lb/hr		grains/ACF
			lb/hr		grains/ACF
			lb/hr		grains/ACF
			lb/hr		grains/ACF

NOTE: (1) An Air Pollution Control Device Sheet must be completed for any air pollution device(s) used to control emissions from this affected source.

(2) Complete the Emission Points Data Sheet.

9. Proposed Monitoring, Recordkeeping, Reporting, and Testing
Please propose monitoring, recordkeeping, and reporting in order to demonstrate compliance with the proposed operating parameters. Please propose testing in order to demonstrate compliance with the proposed emissions limits.

MONITORING See Attachment O	RECORDKEEPING See Attachment O
REPORTING See Attachment O	TESTING See Attachment O

MONITORING. PLEASE LIST AND DESCRIBE THE PROCESS PARAMETERS AND RANGES THAT ARE PROPOSED TO BE MONITORED IN ORDER TO DEMONSTRATE COMPLIANCE WITH THE OPERATION OF THIS PROCESS EQUIPMENT OPERATION/AIR POLLUTION CONTROL DEVICE.

RECORDKEEPING. PLEASE DESCRIBE THE PROPOSED RECORDKEEPING THAT WILL ACCOMPANY THE MONITORING.

REPORTING. PLEASE DESCRIBE THE PROPOSED FREQUENCY OF REPORTING OF THE RECORDKEEPING.

TESTING. PLEASE DESCRIBE ANY PROPOSED EMISSIONS TESTING FOR THIS PROCESS EQUIPMENT/AIR POLLUTION CONTROL DEVICE.

10. Describe all operating ranges and maintenance procedures required by Manufacturer to maintain warranty
NA

Attachment L
EMISSIONS UNIT DATA SHEET
STORAGE TANKS

Provide the following information for <u>each</u> new or modified bulk liquid storage tank as shown on the *Equipment List Form* and other parts of this application. A tank is considered modified if the material to be stored in the tank is different from the existing stored liquid.

IF USING US EPA'S TANKS EMISSION ESTIMATION PROGRAM (AVAILABLE AT **www.epa.gov/tnn/tanks.html**), APPLICANT MAY ATTACH THE SUMMARY SHEETS IN LIEU OF COMPLETING SECTIONS III, IV, & V OF THIS FORM. HOWEVER, SECTIONS I, II, AND VI OF THIS FORM MUST BE COMPLETED. US EPA'S AP-42, SECTION 7.1, "ORGANIC LIQUID STORAGE TANKS," MAY ALSO BE USED TO ESTIMATE VOC AND HAP EMISSIONS (**http://www.epa.gov/tnn/chief/**).

I. GENERAL INFORMATION (required)

1. Bulk Storage Area Name Diesel	2. Tank Name Diesel Storage Tank DT-1
3. Tank Equipment Identification No. (as assigned on *Equipment List Form*) DT-1	4. Emission Point Identification No. (as assigned on *Equipment List Form*) DT-1
5. Date of Commencement of Construction (for existing tanks) 2021	
6. Type of change ☒ New Construction ☐ New Stored Material ☐ Other Tank Modification	
7. Description of Tank Modification (if applicable) NA	
7A. Does the tank have more than one mode of operation? (e.g. Is there more than one product stored in the tank?) ☐ Yes ☒ No	
7B. If YES, explain and identify which mode is covered by this application (Note: A separate form must be completed for each mode). NA	
7C. Provide any limitations on source operation affecting emissions, any work practice standards (e.g. production variation, etc.): NA	

II. TANK INFORMATION (required)

8. Design Capacity (specify barrels or gallons). Use the internal cross-sectional area multiplied by internal height. 300 gallons	
9A. Tank Internal Diameter (ft) 3.5	9B. Tank Internal Height (or Length) (ft) 7
10A. Maximum Liquid Height (ft) 7	10B. Average Liquid Height (ft) 3.5
11A. Maximum Vapor Space Height (ft) 6.25	11B. Average Vapor Space Height (ft) 3.5
12. Nominal Capacity (specify barrels or gallons). This is also known as "working volume" and considers design liquid levels and overflow valve heights. 500	

13A. Maximum annual throughput (gal/yr) 1,000	13B. Maximum daily throughput (gal/day) As required

14. Number of Turnovers per year (annual net throughput/maximum tank liquid volume)
2

15. Maximum tank fill rate (gal/min) 25

16. Tank fill method ☒ Submerged ☐ Splash ☐ Bottom Loading

17. Complete 17A and 17B for Variable Vapor Space Tank Systems ☒ Does Not Apply

17A. Volume Expansion Capacity of System (gal) NA	17B. Number of transfers into system per year NA

18. Type of tank (check all that apply):
☒ Fixed Roof ___ vertical ___ horizontal ___ flat roof ___ cone roof ___ dome roof
___ other (describe)
☐ External Floating Roof ___ pontoon roof ___ double deck roof
☐ Domed External (or Covered) Floating Roof
☐ Internal Floating Roof ___ vertical column support ___ self-supporting
☐ Variable Vapor Space ___ lifter roof ___ diaphragm
☐ Pressurized ___ spherical ___ cylindrical
☐ Underground
☐ Other (describe)

III. TANK CONSTRUCTION & OPERATION INFORMATION (optional if providing TANKS Summary Sheets)

19. Tank Shell Construction:
☐ Riveted ☐ Gunite lined ☐ Epoxy-coated rivets ☒ Other (describe)

20A. Shell Color White of grey	20B. Roof Color White of grey	20C. Year Last Painted NEW

21. Shell Condition (if metal and unlined):
☒ No Rust ☐ Light Rust ☐ Dense Rust ☐ Not applicable

22A. Is the tank heated? ☐ YES ☒ NO

22B. If YES, provide the operating temperature (°F) NA

22C. If YES, please describe how heat is provided to tank. NA

23. Operating Pressure Range (psig): to

24. Complete the following section for **Vertical Fixed Roof Tanks** ☒ Does Not Apply

24A. For dome roof, provide roof radius (ft) NA

24B. For cone roof, provide slope (ft/ft) NA

25. Complete the following section for **Floating Roof Tanks** ☒ Does Not Apply

25A. Year Internal Floaters Installed: NA

25B. Primary Seal Type: (check one)
☐ Metallic (Mechanical) Shoe Seal ☐ Liquid Mounted Resilient Seal
☐ Vapor Mounted Resilient Seal ☐ Other (describe):

25C. Is the Floating Roof equipped with a Secondary Seal? ☐ YES ☐ NO

25D. If YES, how is the secondary seal mounted? (check one) ☐ Shoe ☐ Rim ☐ Other (describe):

25E. Is the Floating Roof equipped with a weather shield? ☐ YES ☐ NO

25F. Describe deck fittings; indicate the number of each type of fitting:		
ACCESS HATCH		
BOLT COVER, GASKETED:	UNBOLTED COVER, GASKETED:	UNBOLTED COVER, UNGASKETED:
AUTOMATIC GAUGE FLOAT WELL		
BOLT COVER, GASKETED:	UNBOLTED COVER, GASKETED:	UNBOLTED COVER, UNGASKETED:
COLUMN WELL		
BUILT-UP COLUMN – SLIDING COVER, GASKETED:	BUILT-UP COLUMN – SLIDING COVER, UNGASKETED:	PIPE COLUMN – FLEXIBLE FABRIC SLEEVE SEAL:
LADDER WELL		
PIP COLUMN – SLIDING COVER, GASKETED:	PIPE COLUMN – SLIDING COVER, UNGASKETED:	
GAUGE-HATCH/SAMPLE PORT		
SLIDING COVER, GASKETED:	SLIDING COVER, UNGASKETED:	
ROOF LEG OR HANGER WELL		
WEIGHTED MECHANICAL ACTUATION, GASKETED:	WEIGHTED MECHANICAL ACTUATION, UNGASKETED:	SAMPLE WELL-SLIT FABRIC SEAL (10% OPEN AREA)
VACUUM BREAKER		
WEIGHTED MECHANICAL ACTUATION, GASKETED:	WEIGHTED MECHANICAL ACTUATION, UNGASKETED:	
RIM VENT		
WEIGHTED MECHANICAL ACTUATION GASKETED:	WEIGHTED MECHANICAL ACTUATION, UNGASKETED:	
DECK DRAIN (3-INCH DIAMETER)		
OPEN:	90% CLOSED:	
STUB DRAIN		
1-INCH DIAMETER:		
OTHER (DESCRIBE, ATTACH ADDITIONAL PAGES IF NECESSARY)		

26. Complete the following section for Internal Floating Roof Tanks ☐ Does Not Apply	
26A. Deck Type: ☐ Bolted ☐ Welded	
26B. For Bolted decks, provide deck construction:	
26C. Deck seam: ☐ Continuous sheet construction 5 feet wide ☐ Continuous sheet construction 6 feet wide ☐ Continuous sheet construction 7 feet wide ☐ Continuous sheet construction 5 × 7.5 feet wide ☐ Continuous sheet construction 5 × 12 feet wide ☐ Other (describe)	
26D. Deck seam length (ft)	26E. Area of deck (ft^2)
For column supported tanks: 26F. Number of columns:	26G. Diameter of each column:

IV. SITE INFORMANTION (optional if providing TANKS Summary Sheets)

27. Provide the city and state on which the data in this section are based. Morganwtown, WV
28. Daily Average Ambient Temperature (°F)
29. Annual Average Maximum Temperature (°F)
30. Annual Average Minimum Temperature (°F)
31. Average Wind Speed (miles/hr)
32. Annual Average Solar Insulation Factor (BTU/(ft^2·day))
33. Atmospheric Pressure (psia)

V. LIQUID INFORMATION (optional if providing TANKS Summary Sheets)

34. Average daily temperature range of bulk liquid:	
34A. Minimum (°F)	34B. Maximum (°F)
35. Average operating pressure range of tank:	
35A. Minimum (psig)	35B. Maximum (psig)
36A. Minimum Liquid Surface Temperature (°F)	36B. Corresponding Vapor Pressure (psia)
37A. Average Liquid Surface Temperature (°F)	37B. Corresponding Vapor Pressure (psia)
38A. Maximum Liquid Surface Temperature (°F)	38B. Corresponding Vapor Pressure (psia)

39. Provide the following for each liquid or gas to be stored in tank. Add additional pages if necessary.

39A. Material Name or Composition			
39B. CAS Number			
39C. Liquid Density (lb/gal)			
39D. Liquid Molecular Weight (lb/lb-mole)			
39E. Vapor Molecular Weight (lb/lb-mole)			

Maximum Vapor Pressure 39F. True (psia) 39G. Reid (psia)			
Months Storage per Year 39H. From 39I. To			

VI. EMISSIONS AND CONTROL DEVICE DATA (required)

40. Emission Control Devices (check as many as apply): ☐ Does Not Apply

- ☐ Carbon Adsorption[1]
- ☐ Condenser[1]
- ☐ Conservation Vent (psig)
  Vacuum Setting Pressure Setting
- ☐ Emergency Relief Valve (psig)
- ☐ Inert Gas Blanket of
- ☐ Insulation of Tank with
- ☐ Liquid Absorption (scrubber)[1]
- ☐ Refrigeration of Tank
- ☐ Rupture Disc (psig)
- ☐ Vent to Incinerator[1]
- ☐ Other[1] (describe):

[1] Complete appropriate Air Pollution Control Device Sheet.

41. Expected Emission Rate (submit Test Data or Calculations here or elsewhere in the application).

Material Name & CAS No.	Breathing Loss (lb/hr)	Working Loss		Annual Loss (lb/yr)	Estimation Method[1]
		Amount	Units		

[1] EPA = EPA Emission Factor, MB = Material Balance, SS = Similar Source, ST = Similar Source Test, Throughput Data, O = Other (specify)

☐ Remember to attach emissions calculations, including TANKS Summary Sheets if applicable.

Attachment L

EMISSIONS UNIT DATA SHEET
STORAGE TANKS

Provide the following information for <u>each</u> new or modified bulk liquid storage tank as shown on the *Equipment List Form* and other parts of this application. A tank is considered modified if the material to be stored in the tank is different from the existing stored liquid.

IF USING US EPA'S TANKS EMISSION ESTIMATION PROGRAM (AVAILABLE AT **www.epa.gov/tnn/tanks.html**), APPLICANT MAY ATTACH THE SUMMARY SHEETS IN LIEU OF COMPLETING SECTIONS III, IV, & V OF THIS FORM. HOWEVER, SECTIONS I, II, AND VI OF THIS FORM MUST BE COMPLETED. US EPA'S AP-42, SECTION 7.1, "ORGANIC LIQUID STORAGE TANKS," MAY ALSO BE USED TO ESTIMATE VOC AND HAP EMISSIONS (**http://www.epa.gov/tnn/chief/**).

I. GENERAL INFORMATION (required)

1. Bulk Storage Area Name Diesel	2. Tank Name Diesel Storage Tank DT-2
3. Tank Equipment Identification No. (as assigned on *Equipment List Form*) DT-2	4. Emission Point Identification No. (as assigned on *Equipment List Form*) DT-2
5. Date of Commencement of Construction (for existing tanks) 2021	
6. Type of change ☒ New Construction ☐ New Stored Material ☐ Other Tank Modification	
7. Description of Tank Modification (if applicable) NA	
7A. Does the tank have more than one mode of operation? ☐ Yes ☒ No (e.g. Is there more than one product stored in the tank?)	
7B. If YES, explain and identify which mode is covered by this application (Note: A separate form must be completed for each mode). NA	
7C. Provide any limitations on source operation affecting emissions, any work practice standards (e.g. production variation, etc.): NA	

II. TANK INFORMATION (required)

8. Design Capacity (specify barrels or gallons). Use the internal cross-sectional area multiplied by internal height. 125 gallons	
9A. Tank Internal Diameter (ft) 3.5	9B. Tank Internal Height (or Length) (ft) 7
10A. Maximum Liquid Height (ft) 7	10B. Average Liquid Height (ft) 3.5
11A. Maximum Vapor Space Height (ft) 6.25	11B. Average Vapor Space Height (ft) 3.5
12. Nominal Capacity (specify barrels or gallons). This is also known as "working volume" and considers design liquid levels and overflow valve heights. 500	

13A. Maximum annual throughput (gal/yr)	13B. Maximum daily throughput (gal/day)
1,000	As required

14. Number of Turnovers per year (annual net throughput/maximum tank liquid volume)
2

15. Maximum tank fill rate (gal/min) 25

16. Tank fill method ☒ Submerged ☐ Splash ☐ Bottom Loading

17. Complete 17A and 17B for Variable Vapor Space Tank Systems ☒ Does Not Apply

17A. Volume Expansion Capacity of System (gal)	17B. Number of transfers into system per year
NA	NA

18. Type of tank (check all that apply):
- ☒ Fixed Roof ___ vertical ___ horizontal ___ flat roof ___ cone roof ___ dome roof ___ other (describe)
- ☐ External Floating Roof ___ pontoon roof ___ double deck roof
- ☐ Domed External (or Covered) Floating Roof
- ☐ Internal Floating Roof ___ vertical column support ___ self-supporting
- ☐ Variable Vapor Space ___ lifter roof ___ diaphragm
- ☐ Pressurized ___ spherical ___ cylindrical
- ☐ Underground
- ☐ Other (describe)

III. TANK CONSTRUCTION & OPERATION INFORMATION (optional if providing TANKS Summary Sheets)

19. Tank Shell Construction:
☐ Riveted ☐ Gunite lined ☐ Epoxy-coated rivets ☒ Other (describe)

20A. Shell Color White of grey	20B. Roof Color White of grey	20C. Year Last Painted NEW

21. Shell Condition (if metal and unlined):
☒ No Rust ☐ Light Rust ☐ Dense Rust ☐ Not applicable

22A. Is the tank heated? ☐ YES ☒ NO

22B. If YES, provide the operating temperature (°F) NA

22C. If YES, please describe how heat is provided to tank. NA

23. Operating Pressure Range (psig): to

24. Complete the following section for **Vertical Fixed Roof Tanks** ☒ Does Not Apply

24A. For dome roof, provide roof radius (ft) NA

24B. For cone roof, provide slope (ft/ft) NA

25. Complete the following section for **Floating Roof Tanks** ☒ Does Not Apply

25A. Year Internal Floaters Installed: NA

25B. Primary Seal Type: (check one) ☐ Metallic (Mechanical) Shoe Seal ☐ Liquid Mounted Resilient Seal ☐ Vapor Mounted Resilient Seal ☐ Other (describe):

25C. Is the Floating Roof equipped with a Secondary Seal? ☐ YES ☐ NO

25D. If YES, how is the secondary seal mounted? (check one) ☐ Shoe ☐ Rim ☐ Other (describe):

25E. Is the Floating Roof equipped with a weather shield? ☐ YES ☐ NO

25F. Describe deck fittings; indicate the number of each type of fitting:		
ACCESS HATCH		
BOLT COVER, GASKETED:	UNBOLTED COVER, GASKETED:	UNBOLTED COVER, UNGASKETED:
AUTOMATIC GAUGE FLOAT WELL		
BOLT COVER, GASKETED:	UNBOLTED COVER, GASKETED:	UNBOLTED COVER, UNGASKETED:
COLUMN WELL		
BUILT-UP COLUMN – SLIDING COVER, GASKETED:	BUILT-UP COLUMN – SLIDING COVER, UNGASKETED:	PIPE COLUMN – FLEXIBLE FABRIC SLEEVE SEAL:
LADDER WELL		
PIP COLUMN – SLIDING COVER, GASKETED:	PIPE COLUMN – SLIDING COVER, UNGASKETED:	
GAUGE-HATCH/SAMPLE PORT		
SLIDING COVER, GASKETED:	SLIDING COVER, UNGASKETED:	
ROOF LEG OR HANGER WELL		
WEIGHTED MECHANICAL ACTUATION, GASKETED:	WEIGHTED MECHANICAL ACTUATION, UNGASKETED:	SAMPLE WELL-SLIT FABRIC SEAL (10% OPEN AREA)
VACUUM BREAKER		
WEIGHTED MECHANICAL ACTUATION, GASKETED:	WEIGHTED MECHANICAL ACTUATION, UNGASKETED:	
RIM VENT		
WEIGHTED MECHANICAL ACTUATION GASKETED:	WEIGHTED MECHANICAL ACTUATION, UNGASKETED:	
DECK DRAIN (3-INCH DIAMETER)		
OPEN:	90% CLOSED:	
STUB DRAIN		
1-INCH DIAMETER:		
OTHER (DESCRIBE, ATTACH ADDITIONAL PAGES IF NECESSARY)		

26. Complete the following section for Internal Floating Roof Tanks ☐ Does Not Apply	
26A. Deck Type: ☐ Bolted ☐ Welded	
26B. For Bolted decks, provide deck construction:	
26C. Deck seam: ☐ Continuous sheet construction 5 feet wide ☐ Continuous sheet construction 6 feet wide ☐ Continuous sheet construction 7 feet wide ☐ Continuous sheet construction 5 × 7.5 feet wide ☐ Continuous sheet construction 5 × 12 feet wide ☐ Other (describe)	
26D. Deck seam length (ft)	26E. Area of deck (ft^2)
For column supported tanks: 26F. Number of columns:	26G. Diameter of each column:

IV. SITE INFORMANTION (optional if providing TANKS Summary Sheets)

27. Provide the city and state on which the data in this section are based. Morganwtown, WV
28. Daily Average Ambient Temperature (°F)
29. Annual Average Maximum Temperature (°F)
30. Annual Average Minimum Temperature (°F)
31. Average Wind Speed (miles/hr)
32. Annual Average Solar Insulation Factor (BTU/(ft^2·day))
33. Atmospheric Pressure (psia)

V. LIQUID INFORMATION (optional if providing TANKS Summary Sheets)

34. Average daily temperature range of bulk liquid:	
34A. Minimum (°F)	34B. Maximum (°F)
35. Average operating pressure range of tank:	
35A. Minimum (psig)	35B. Maximum (psig)
36A. Minimum Liquid Surface Temperature (°F)	36B. Corresponding Vapor Pressure (psia)
37A. Average Liquid Surface Temperature (°F)	37B. Corresponding Vapor Pressure (psia)
38A. Maximum Liquid Surface Temperature (°F)	38B. Corresponding Vapor Pressure (psia)

39. Provide the following for <u>each</u> liquid or gas to be stored in tank. Add additional pages if necessary.			
39A. Material Name or Composition			
39B. CAS Number			
39C. Liquid Density (lb/gal)			
39D. Liquid Molecular Weight (lb/lb-mole)			
39E. Vapor Molecular Weight (lb/lb-mole)			

Maximum Vapor Pressure 39F. True (psia) 39G. Reid (psia)			
Months Storage per Year 39H. From 39I. To			

VI. EMISSIONS AND CONTROL DEVICE DATA (required)

40. Emission Control Devices (check as many as apply): ☐ Does Not Apply

- ☐ Carbon Adsorption[1]
- ☐ Condenser[1]
- ☐ Conservation Vent (psig)
  Vacuum Setting Pressure Setting
- ☐ Emergency Relief Valve (psig)
- ☐ Inert Gas Blanket of
- ☐ Insulation of Tank with
- ☐ Liquid Absorption (scrubber)[1]
- ☐ Refrigeration of Tank
- ☐ Rupture Disc (psig)
- ☐ Vent to Incinerator[1]
- ☐ Other[1] (describe):

[1] Complete appropriate Air Pollution Control Device Sheet.

41. Expected Emission Rate (submit Test Data or Calculations here or elsewhere in the application).

Material Name & CAS No.	**Breathing Loss (lb/hr)**	**Working Loss**		**Annual Loss (lb/yr)**	**Estimation Method[1]**
		Amount	**Units**		

[1] EPA = EPA Emission Factor, MB = Material Balance, SS = Similar Source, ST = Similar Source Test, Throughput Data, O = Other (specify)

☐ Remember to attach emissions calculations, including TANKS Summary Sheets if applicable.

ATTACHMENT M
AIR POLLUTION CONTROL DEVICES

The Combined-Cycle Combustion Turbines and the HRSG Duct Burners will be equipped with Selective Catalytic Reduction (SCR) systems and dry low-NOx combustors (DLNC). These combustion controls along will control emissions of nitrogen oxides (NOx). Oxidation catalysts will be used to control the turbines' carbon monoxide (CO) and volatile organic compounds (VOC) emissions. The Fuel Gas Preheaters will be equipped with low- NOx burners (LNB) to control NOx emissions. The Mechanical Draft Cooling Tower will be equipped with demisters.

The proposed emission control systems including the determination of Best Available Control Technology determination are described in Section 5 of the PSD Permit Application Document.

ATTACHMENT N
SUPPORTING EMISSION CALCULATIONS

The MSCE Project potential regulated pollutant emission from the combined cycle power train consisting of two combustion turbines, two heat recovery steam generators (HRSG) with duct burners, one diesel fuel-fired firewater pump, one diesel fired emergency generator, two gas preheaters and one mechanical draft cooling tower were estimated using some or all of the following: vendor supplied data, material balances, engineering estimates, assumptions calculations, USEPA's Compilation of Air Pollutant Emission Factors (AP-42) for combustion turbines and engines, New Source Performance Standards (NSPS) emission standards and USEPA's Mandatory Greenhouse Gas Reporting Rule (40 CFR Part 98).

The emission calculations are described and presented in Section 4 and Appendix B of the Air Permit Application document.

ATTACHMENT O
MONITORING, RECORDKEEPING, REPORTING AND TESTING PLANS

The MSCE Project proposes the following as Monitoring, Recordkeeping, Reporting and Testing Plans for Unit 2:

1. Limit the annual fuel consumption for the combined-cycle Combustion Turbine (with HRSG Duct Burners) and Fuel Gas Heaters as presented in this permit application.
2. Record the amount of fuel consumed in the combined-cycle Combustion Turbine (with HRSG Duct Burners), and Fuel Gas Heaters on a daily, monthly, and 12-month rolling total.
3. Operate and maintain SCR and Oxidation Catalyst for the combined-cycle Combustion Turbines (with HRSG Duct Burners) for NOx and CO control.
4. Limit the sulfur content of the natural gas to the level indicated in the permit application.
5. Install, operate, calibrate, and maintain continuous emission monitoring systems (CEMS) on the combined-cycle Combustion Turbines as required and in accordance with applicable regulations.
6. Conduct performance testing for pollutants requiring testing in accordance with the methods, standards, and deadlines mandated by regulation.
7. Combust only ultra-low sulfur diesel (ULSD) fuel in the Emergency Generator and Fire Water Pump engines.
8. Record the annual hours of operation for the Emergency Generator and Fire Water Pump engines.
9. Maintain required records for at least five (5) years.

ATTACHMENT P
AIR QUALITY PERMIT NOTICE

AIR QUALITY PERMIT NOTICE

Notice of Application

Notice is given that Mountain State Clean Energy, LLC has applied to the West Virginia Department of Environmental Protection, Division of Air Quality, for a Prevention of Significant Deterioration (PSD) Construction Air Permit for an electric power generation facility located on Route 53 (Fort Martin Road), Maidsville, in Monongalia County, West Virginia. The latitude and longitude coordinates are: 39.7124, -79.9608

The applicant estimates the potential to discharge the following Regulated Air Pollutants: 321 tons per year of nitrogen oxides, 276 tons per year of carbon monoxide, 5,135,347 tons per year of carbon dioxide equivalent emissions, 141 tons per year of volatile organic compounds, 210 tons per year of particulate matter, 39.9 tons per year of sulfur dioxide, 0.001 tons per year of lead, 35.8 tons of sulfuric acid, and 23.3 tons per year of hazardous air pollutants.

Startup of operation is planned to begin on or about the first quarter of 2024. Written comments will be received by the West Virginia Department of Environmental Protection, Division of Air Quality, 601 57th Street, SE, Charleston, WV 25304, for at least 30 calendar days from the date of publication of this notice.

Any questions regarding this permit application should be directed to the DAQ at (304) 926- 0499, extension 1250, during normal business hours.

Dated this the 5th day of March, 2021.

By: Mountain State Clean Energy, LLC
Stephen H. Nelson
Chief Operating Officer
1375 Fort Martin Road
Maidsville, WV 26541

ATTACHMENT Q
BUSINESS CONFIDENTIAL CLAIMS

The air permit application for the MSCE Project is considered non-confidential since it does not contain any business confidential information.

ATTACHMENT R
AUTHORITY FORMS

No Authority Forms are required since the air permit application for the MSCE Project is signed by a Responsible Official of MSCE, LLC.

ATTACHMENT S
TITLE V PERMIT REVISION INFORMATION

The MSCE Project does not currently hold a Title V Permit since it is a new emission source. TVOP application will be prepared and submitted once the air permit has been issued.

APPENDIX B - EMISSION ESTIMATES

MSCE Project
Facility-Wide Emissions
Table B-1

PSD/NSR Pollutants	Combustion Turbine Emissions (tons/yr)	Duct Burners (tons/year)	Startup/ Shutdown Emissions (tons/yr)	Fuel Gas Preheaters (tons/yr)	Auxiliary Generator Emissions (tons/yr)	Fire Pump Emissions (tons/yr)	Cooling Tower (tons/yr)	Total Facility Emissions (tons/yr)
NOx	284.7		32.2	2.21	1.93	0.228		321
CO	173.3		100.5	2.38	0.155	0.0633		276
VOC	99.3		41.2	0.429	0.0370	0.0151		141
PM/PM10/PM2.5	198.1		2.24	0.477	0.0137	0.0421	9.47	210
SO2	39.8			0.0795	0.0030	0.0246		39.9
H2SO4	35.8		0.010	0.0061	0.010	0.010		35.8
GHG	5,068,855		58,287	8,057	126.5	20.9		5,135,347
Lead		1.10E-03						0.00110
Flourides								0.00
Vinyl Chloride								0.00
Total Reduced Sulfur								0.00
Reduced Sulfur Compounds								0.00
Hazardous Air Pollutants (HAPS)								
1,3-Butadiene	1.43E-02					5.30E-06		1.43E-02
2 Methylnaphthalene		8.81E-05						8.81E-05
Acetaldehyde	1.33E+00					1.04E-04		1.33
Acrolein	2.12E-01					1.25E-05		2.12E-01
Arsenic		8.81E-04						8.81E-04
Benzene	3.98E-01	7.71E-03			8.92E-04	1.27E-04		4.07E-01
Beryllium		4.40E-05						4.40E-05
Cadmium		4.04E-03						4.04E-03
Chromium		5.14E-03						5.14E-03
Cobalt		1.54E-04						1.54E-04
Dichlorobenzene		4.40E-03						4.40E-03
Ethylbenzene	1.06							1.06
Formaldehyde	7.07	1.12			9.07E-05	1.60E-04		8.19
Hexane		4.62						4.62
Manganese		1.39E-03						1.39E-03
Mercury		9.54E-04						9.54E-04
Naphthalene	4.31E-02	2.24E-03			1.50E-04	1.15E-05		4.55E-02
Nickel		7.71E-03						7.71E-03
Phenanathrene		6.24E-05			4.69E-05	3.99E-06		1.13E-04
Propylene Oxide	9.62E-01							9.62E-01
Toluene	4.31	1.25E-02			3.23E-04	5.55E-05		4.33
Xylene	2.12					3.87E-05		2.12
Total HAPS								23.3

MSCE Project
Facility-Wide Emissions
Table B-2

Mountain State Clean Energy
M501JAC 2x1 CC -- SU/SD Emissions

Parameter	Cold Start	Warm Start	Hot Start	Shutdown
Duration, minutes	40	35	35	15
Heat Input, MMBtu/event	1,219	993	993	348
Stack Exhaust Flowrate (average), acfm	1,023,454	1,009,146	1,009,146	1,001,349
Stack Temperature (average), deg F	209.6	209.6	209.6	209.6
NO_X Emissions, lb/event	85.8	79.2	70.4	113.3
CO Emissions, lb/event	552.2	436.7	160.6	198.0
VOC Emissions, lb/event	143.0	127.6	104.5	182.6
PM Emissions, lb/event	3.3	2.2	2.2	1.1
SO_2 Emissions, lb/event	1.37	1.12	1.12	0.39

Mountain State Clean Energy
GE 7HA.03 2x1 CC -- SU/SD Emissions

Parameter	Cold Start	Warm Start	Hot Start	Shutdown
Duration, minutes	70	60	30	14
Heat Input, MMBtu/event	2,640	2,244	946	220
Stack Exhaust Flowrate (average), acfm	817,787	782,149	674,174	941,044
Stack Temperature (average), deg F	138.2	138.2	138.2	138.2
NO_X Emissions, lb/event	319.0	242.0	137.5	44.0
CO Emissions, lb/event	1782.0	726.0	583.0	126.5
VOC Emissions, lb/event	572.0	154.0	148.5	99.0
PM Emissions, lb/event	27.5	23.1	11.0	5.5
SO_2 Emissions, lb/event	2.96	2.52	1.06	0.25

MSCE Project

Fuel Gas Pre-Heaters Emissons

Table B-3

Pollutant	Emission Factor (lb/MMBtu)	Maximum Short Term Emissions (1 FGH) (lb/hr)	Maximum Annual Emissions (1 FGH) (tons/yr)	Maximum Annual Emissions (2 FGHs) (tons/yr)
NOx	0.0360	0.25	1.10	2.21
CO	0.0388	0.27	1.19	2.38
VOC	0.00700	0.05	0.21	0.43
PM10	0.00777	0.05	0.24	0.48
SO2	0.00130	0.01	0.04	0.08
H2SO4	0.00010	0.00	0.00	0.01
GHG	131.4	919.77	4029	8057
CH4	0.0066	0.05	0.20	0.41
N2O	0.00132	0.01	0.04	0.08

MSCE Project

Emergency Generator Emissions

Table B-4

Rated Output (kilowatts)	**1,139**	**2500**
Rated Output (horsepower)	**1,528**	**3353**
Rated input (MMBtu/hr)	**13.0**	**23**
Hours of Operation	**100**	**100**

Pollutant	Emission Factor (lbs/MMBtu)	Emission Factor (grams/hp hr)	Max Power Output (hp hr)	Max Fuel Input (MMBtu/hr)	Max Emission Rate (lbs/hr)	Annual Emissions (tons/yr)
NOx		5.23	3353		38.7	1.93
CO		0.42	3353		3.10	0.155
VOC		0.1	3353		0.74	0.037
PM10		0.037	3353		0.273	0.014
SO2		0.00809	3353		0.060	0.003
GHG	110			23	2,530	126.5
Acenapthene	4.7E-06			23	1.1E-04	5.4E-06
Acenaphthylene	9.2E-06			23	2.1E-04	1.1E-05
Acetaldehyde	2.5E-05			23	5.8E-04	2.9E-05
Acrolein	7.9E-06			23	1.8E-04	9.1E-06
Anthracene	1.2E-06			23	2.8E-05	1.4E-06
Benz(a)anthracene	6.2E-07			23	1.4E-05	7.2E-07
Benzene	7.8E-04			23	1.8E-02	8.9E-04
Benzo(a)pyrene	2.6E-07			23	5.9E-06	3.0E-07
Benzo(b)fluoroanthene	1.1E-06			23	2.6E-05	1.3E-06
Benzo(g,h,i)perylene	5.6E-07			23	1.3E-05	6.4E-07
Benzo(k)fluoranthene	2.2E-07			23	5.0E-06	2.5E-07
Chrysene	1.5E-06			23	3.5E-05	1.8E-06
Dibenzo(a,h)anthracene	3.5E-07			23	8.0E-06	4.0E-07
Fluoranthene	4.0E-06			23	9.3E-05	4.6E-06
Fluorene	1.3E-05			23	2.9E-04	1.5E-05
Formaldehyde	7.9E-05			23	1.8E-03	9.1E-05
Indeno(1,2,3-cd)pyrene	4.1E-07			23	9.5E-06	4.8E-07
Naphthalene	1.3E-04			23	3.0E-03	1.5E-04
Phenanathrene	4.1E-05			23	9.4E-04	4.7E-05
Pyrene	3.7E-06			23	8.5E-05	4.3E-06
Toluene	2.8E-04			23	6.5E-03	3.2E-04
Xylene	1.9E-04			23	4.4E-03	2.2E-04
Total Haps						1.8E-03

1. Emission rates estimated based upon AP-42 emission factors (Tables 3.4-1, 3 & 4)
2. Fuel throughput based upon similar Caterpillar diesel engine.

MSCE Project
Firewater Pump Emissions
Table B-5

Rated Output (kilowatts)	**179**
Rated Output (horsepower)	**240**
Rated input (MMBtu/hr)	**2.71**
Hours of Operation	**100**

Pollutant	Emission Factor (lbs/MMBtu)	Emission Factor (grams/hr)	Max Power Output (hp hr)	Max Fuel Input (MMBtu/hr)	Max Emission Rate (lb/hr)	Annual Emissions (tons/yr)
NOx		2064	240		4.55	0.228
CO		574	240		1.27	0.063
VOC		137	240		0.302	0.015
PM10	0.31		240		0.841	0.042
SO2		0.00205	240		0.492	0.025
H2SO4						
GHG	154			2.71	417.8	20.9
(1,3) Butadiene	3.9E-05			2.71	1.1E-04	5.3E-06
Acenapthene	1.4E-06			2.71	3.9E-06	1.9E-07
Acenaphthylene	5.1E-06			2.71	1.4E-05	6.9E-07
Acetaldehyde	7.7E-04			2.71	2.1E-03	1.0E-04
Acrolein	9.3E-05			2.71	2.5E-04	1.3E-05
Anthracene	1.9E-06			2.71	5.1E-06	2.5E-07
Benz(a)anthracene	1.7E-06			2.71	4.6E-06	2.3E-07
Benzene	9.3E-04			2.71	2.5E-03	1.3E-04
Benzo(a)pyrene	1.9E-07			2.71	5.1E-07	2.6E-08
Benzo(b)fluoroanthene	9.9E-08			2.71	2.7E-07	1.3E-08
Benzo(g,h,i)perylene	4.9E-07			2.71	1.3E-06	6.6E-08
Benzo(k)fluoranthene	1.6E-07			2.71	4.2E-07	2.1E-08
Chrysene	3.5E-07			2.71	9.6E-07	4.8E-08
Dibenzo(a,h)anthracene	5.8E-07			2.71	1.6E-06	7.9E-08
Fluoranthene	7.6E-06			2.71	2.1E-05	1.0E-06
Fluorene	2.9E-05			2.71	7.9E-05	4.0E-06
Formaldehyde	1.2E-03			2.71	3.2E-03	1.6E-04
Indeno(1,2,3-cd)pyrene	3.8E-07			2.71	1.0E-06	5.1E-08
Naphthalene	8.5E-05			2.71	2.3E-04	1.2E-05
Phenanathrene	2.9E-05			2.71	8.0E-05	4.0E-06
Pyrene	4.8E-06			2.71	1.3E-05	6.5E-07
Toluene	4.1E-04			2.71	1.1E-03	5.5E-05
Xylene	2.9E-04			2.71	7.7E-04	3.9E-05
Total Haps						5.2E-04

1. Emission rates estimated based upon AP-42 emission factors (Tables 3.3-1& 2)
2. Fuel throughput based upon similar Caterpillar diesel engine.

MSCE Project
Mechanical Draft Coolling Tower Emissions
Table B-6

Parameter	**Units**	**PM**	**PM10**	**PM2.5**
Flow	gal/min	270000	270000	270000
Drift	%	0.0005	0.0005	0.0005
Maxium TDS	ppm	400	400	400
Cycles of Concentration		8	8	8
Minutes per Hour Conversion	min/hr	60	60	60
Pound Per Gallon Conversion	lb/gal	8.34	8.34	8.34
Cooling Tower Availability	%	100%	100%	100%
PM10 to PM2.5 Conversion		1	1	0.5
lb/hr		2.16	2.16	1.08
tons/yr		9.47	9.47	4.73

PM (lb/hr) = Flow*[(Drift%)/100]*[TDS/10^6]*CoC*60*8.34

APPENDIX C - VENDOR INFORMATION

7HA POWER PLANTS

290-430 MW
SIMPLE CYCLE OUTPUT

>64%
COMBINED CYCLE EFFICIENCY

CAPABILITY
55+ MW/minute ramping capability within emissions compliance

VERSATILITY
Turndown 2x1 plant load to about 15% of baseload while maintaining emissions compliance

SUSTAINABILITY
Simplified dual fuel system uses less water and eliminates recirculation

Whether your plant operates at baseload, load follows, or operates as a peaking unit, you can count on GE's 7HA gas turbine to deliver world class performance. Its industry-leading operational flexibility enables increased dispatch and ancillary revenue while fuel flexibility accommodates a wide range of gaseous fuels (shale gas, high ethane, H_2) and liquid fuels (#2 diesel, crude oils). The 7HA combined cycle plant ramps up to full load in less than 30 minutes and features a novel configuration that supports simplified installation and maintenance.

		7HA.01	7HA.02	7HA.03
SC Plant Performance	SC Net Output (MW)	290	384	430
	SC Net Heat Rate (Btu/kWh, LHV)	8,120	8,009	7,897
	SC Net Heat Rate (kJ/kWh, LHV)	8,567	8,450	8,332
	SC Net Efficiency (%, LHV)	42.0%	42.6%	43.2%
1x CC Plant Performance	CC Net Output (MW)	438	573	640
	CC Net Heat Rate (Btu/kWh, LHV)	5,481	5,381	5,342
	CC Net Heat Rate (kJ/kWh, LHV)	5,783	5,677	5,636
	CC Net Efficiency (%, LHV)	62.3%	63.4%	63.9%
	Plant Turndown – Minimum Load (%)	33.0%	33.0%	33.0%
	Ramp Rate (MW/min)	55	60	75
	Startup Time (RR Hot, Minutes)	<30	<30	<30
2x CC Plant Performance	CC Net Output (MW)	880	1,148	1,282
	CC Net Heat Rate (Btu/kWh, LHV)	5,453	5,365	5,331
	CC Net Heat Rate (kJ/kWh, LHV)	5,753	5,660	5,624
	CC Net Efficiency (%, LHV)	62.6%	63.6%	64.0%
	Plant Turndown – Minimum Load (%)	15.0%	15.0%	15.0%
	Ramp Rate (MW/min)	110	120	150
	Startup Time (RR Hot, Minutes)	<30	<30	<30

NOTE: All ratings are net plant, based on ISO conditions and natural gas fuel. Actual performance will vary with project-specific conditions and fuel.

www.ge.com/power/7HA03

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GEA34163 (09/2019)

MHPS Gas Turbine

J Series

MITSUBISHI HITACHI POWER SYSTEMS, LTD.

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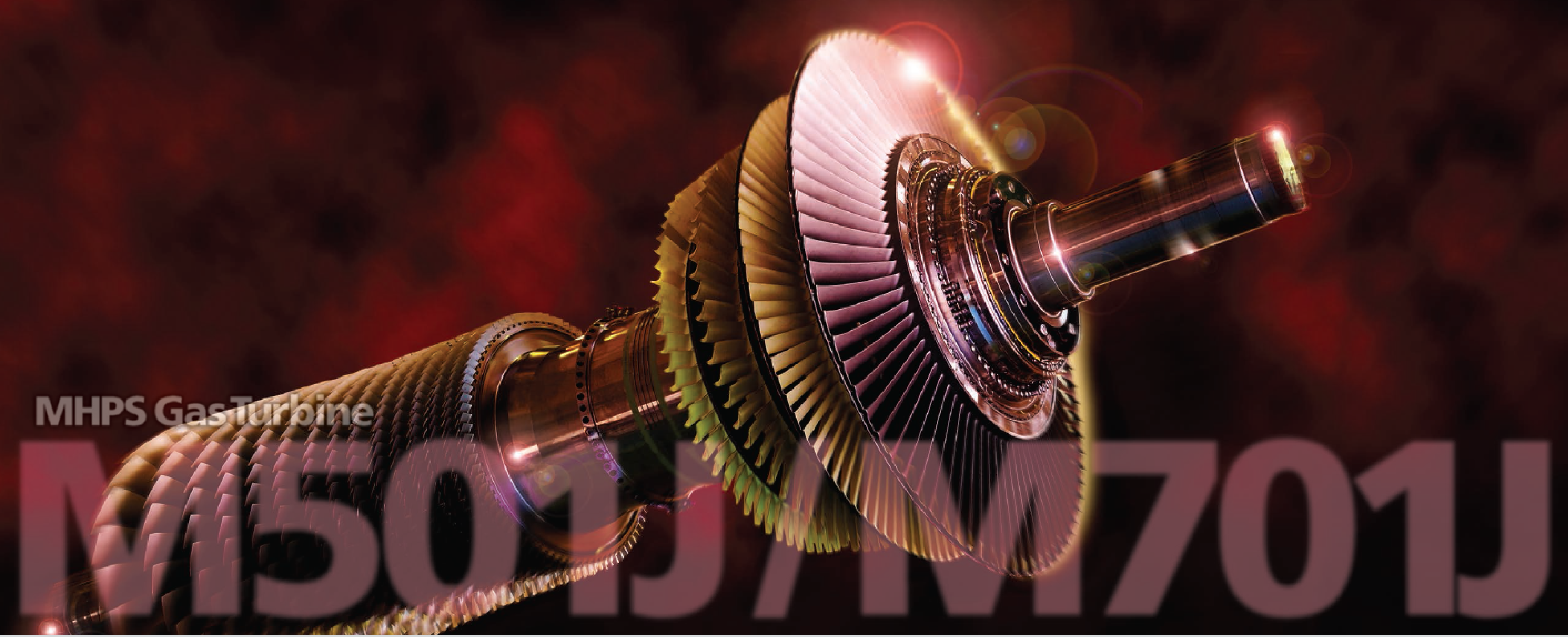
MHPS Gas Turbine
M501J / M701J

MITSUBISHI HITACHI POWER SYSTEMS



Tomorrow's Turbine Technology...Today

When developing the J-series gas turbine, the main focus was on technology that would enable a higher firing temperature and improved efficiency. Due to the great success of these continuous efforts, the J-series gas turbine is able to operate at a turbine inlet temperature of 1,600°C (2,912°F), 100°C (180°F) higher than the G-series gas turbine.

Introducing the air cooled JAC

After validating integrated disciplines of the proven G and J-series technologies, the advanced JAC gas turbine is introduced based on air cooled combustor technology for high efficiency and operational flexibility by eliminating any need for steam cooling from the bottoming cycle.

Current production models are M501J / JAC for 60Hz and M701J / JAC for 50Hz.

Proven design based on over 40 years of experience

The J-series incorporates basic design features and concepts developed through years of experience, such as cold-end generator drive, single shaft rotor construction and axial exhaust. These fundamental and proven features are based on our experience of more than 40 years.

Environmental protection

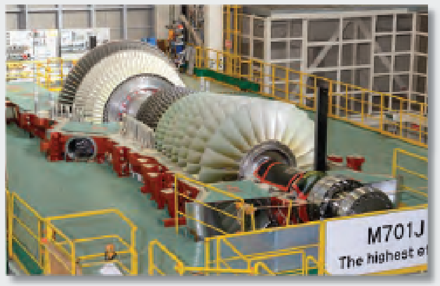
- Most efficient use of fossil fuel resources
- Low NO_x, CO, UHC and VOC emissions
- Reduction of CO_2 emissions is approximately 70% in combined cycle operation when compared to conventional coal plants

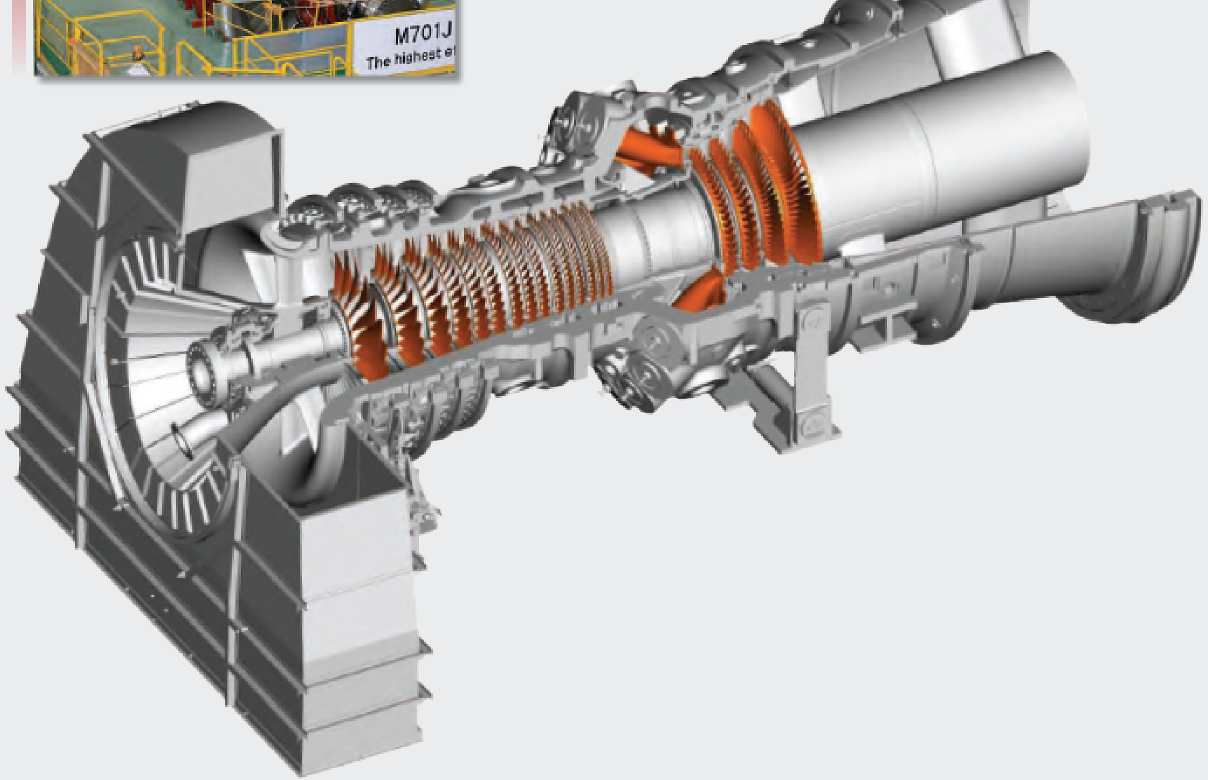
Longitudinal Section

Overall Design

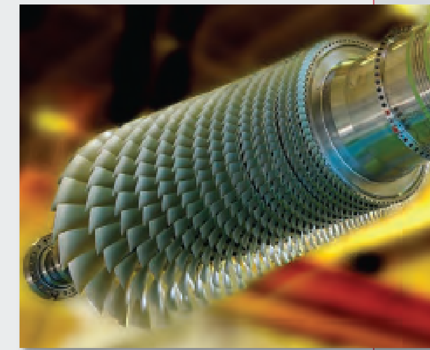
The design of J-series gas turbine is based on proven F and G-series features.

- The compressor shaft end drive reduces the effect of thermal expansion on alignment and eliminates the need for a flexible coupling
- The rotor has a two-bearing structure to support the compressor and turbine ends
- An axial flow exhaust structure is used to optimize the combined-cycle plant layout
- The rotor structure has bolt-connected discs with the torque pins in the compressor rotor, and discs with CURVIC couplings in the turbine rotor to ensure reliable torque transmission
- Horizontally split casings that facilitate field removal of the blades with the rotor in place





Compressor

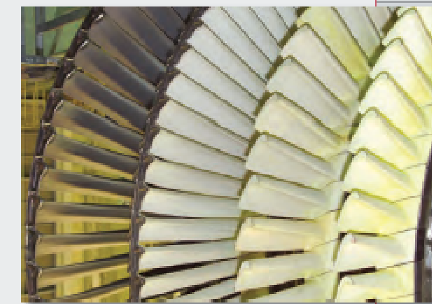


3D advanced design techniques are used to improve the performance and reduce the shockwave loss in the initial stages and frictional loss in the intermediate and final stages. This concept was evaluated by 3D computational fluid dynamics (CFD) software and verified using a full-scale high-speed research compressor.
In addition to variable inlet guide vanes used to modulate air flow, the J-series gas turbine is equipped with three variable vanes at the front stages of the compressor. The four stages operate together to modulate the gas turbine air flow in order to maintain relatively high exhaust temperatures (at part load) for improved bottoming cycle efficiency.

Combustor

The J-series combustor was based on the proven steam cooling system used in G-series gas turbines.
The turbine inlet temperature of 1,600°C (2,912°F) is 100°C (180°F) higher than the G-series. We are also able to maintain emissions to equivalent levels as that of the G-series.
This is accomplished through the use of low-NO_X technologies including optimization of the local flame temperature in the combustion zone, and by improving the combustion nozzle to produce a more homogeneous mixture of fuel and air.
The advanced JAC with the air cooled combustors adds operational flexibility by eliminating any need for steam cooling from the bottoming cycle.

Turbine



Turbine rows 1 to 4 blades are cooled by the compressor bleed air, which is cooled by the external air cooler.
Turbine rows 1 to 4 vanes are also air cooled, with row 1 vane cooled from compressor discharge air, and the remaining vane rows cooled by compressor intermediate stage bleeds respectively.
The cooling structure was improved for the G-series turbine, and again for the J-series.
Application of the high-performance film cooling developed from the Japanese National Project further offsets the temperature increase.
The metal temperature is maintained at the same level of G-series by utilizing the 1,700°C (3,092°F) class technology developed in the Japanese National Project. The 100°C (180°F) temperature increase from G-series to J-series is offset in part due to the advanced thermal barrier coating (TBC).

In 1971, MHPS delivered the first combined cycle plant in Japan to a Japanese utility company.
Since then, through the experience in supplying many combined cycle plants,
we have earned an excellent reputation from our customers.
In order to satisfy customers' needs, MHPS offers its expertise
not only in supplying plants systems and equipment,
but also in providing a wide range of after-market services.

Gas Turbine Simple Cycle Performance (as of December, 2017)

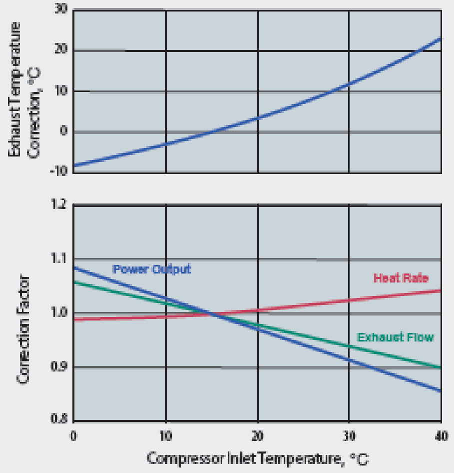
GT Model	M701J	M701JAC	M501J	M501JAC
	50Hz		60Hz	
ISO Base Rating, kW	478,000	493,000	330,000	400,000
LHV Heat Rate, kJ/kWh	8,511	8,392	8,552	8,182
Exhaust Flow, kg/s	896	896	620	694
Exhaust Temperature, °C	630	641	635	653

Combined Cycle Power Plant (as of December, 2017)

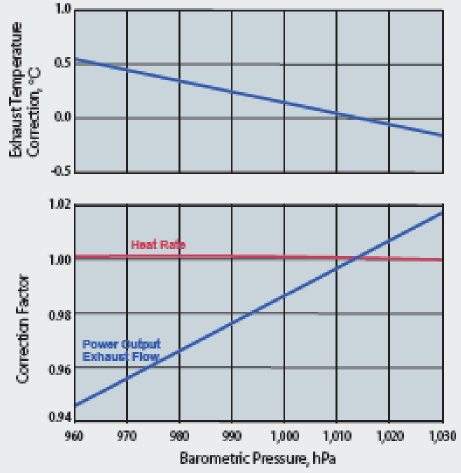
	GT Model	M701J	M701JAC	M501J	M501JAC
		50Hz		60Hz	
1on1	Plant Output, kW	701,000	717,000	484,000	575,000
	LHV Heat Rate, kJ/kWh	5,779	5,706	5,807	5,625
	Plant Efficiency, %	62.3	63.1	62.0	64.0
2on1	Plant Output, kW	—	—	971,000	1,153,000
	LHV Heat Rate, kJ/kWh	—	—	5,788	5,608
	Plant Efficiency, %	—	—	62.2	64.2

- All ratings are defined at ISO standard reference conditions: 101.3kPa, 15°C and 60%RH
- All ratings are at the generator terminals and based on the use of natural gas fuel

Effects of Compressor inlet Temperature on Gas Turbine Performance (Typical)



Effects of Barometric Pressure on Gas Turbine Performance (Typical)

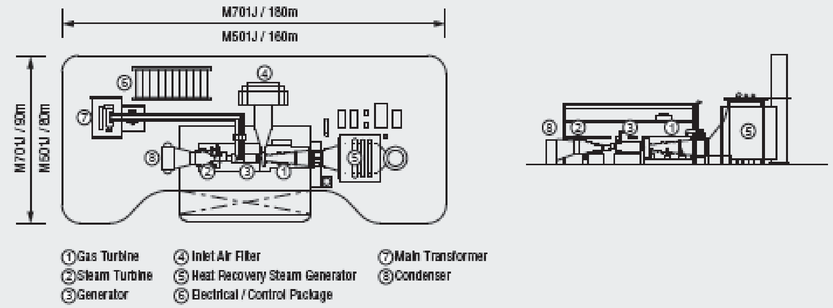


Flexible Configurations

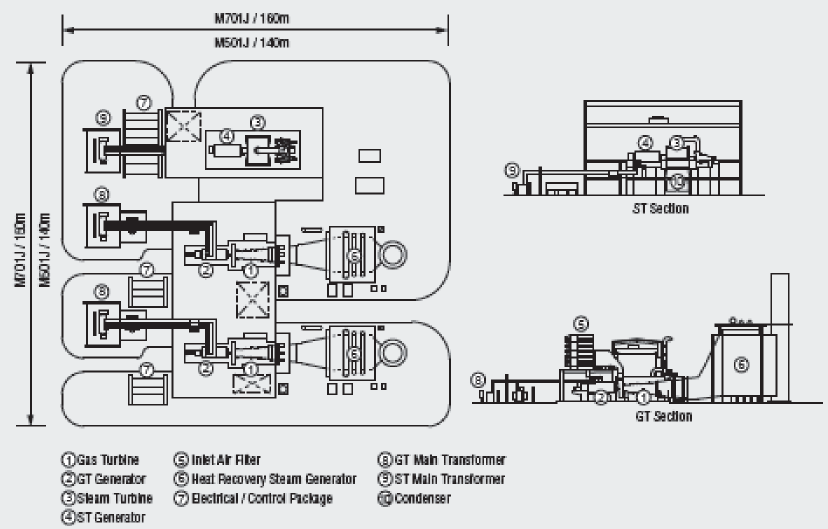
Based on our sophisticated combined cycle plant technology and diverse product application, we can offer our customers not only the multi-shaft arrangement such as 2 on 1 configuration, but also 1 on 1 configuration having the gas turbine, steam turbine and generator connected on the same shaft.

Typical Plant Layout

1 on 1 configuration, single-shaft



2 on 1 configuration



APPENDIX D - RACT/BACT/LAER CLEARINGHOUSE (RBLC) RESULTS

Table D-1 RBLC Search Results CCCT: NO_x, PM and CO BACT Limits/Technology

	RBLCID	Facility Name	State	Permit Issuance Date	NOx (PPM)	Technology	PM (LB/MMBTU)	Technology	CO (PPM)	Technology
1	IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	2	SCR w/ DLNB	0.0026	GCP	2	OC
2	MI-0441	LBWL--ERICKSON STATION	MI	12/31/2018	3	SCR w/ DLNB	6.02 lb/hr	GCP	4	OC
3	LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	2.5	SCR w/ DLNB	9.53 lb/hr	GCP	5	OC
4	WV-0032	BROOKE COUNTY POWER PLANT	WV	9/21/2018	2	SCR w/ DLNB	16.9 lb/hr	GCP	2	OC
5	PA-0319	RENAISSANCE ENERGY CENTER	PA	8/27/2018	2	SCR w/ DLNB	0.0043	GCP	2	OC
6	IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	2	SCR w/ DLNB	0.0037	GCP	2	OC
7	MI-0432	NEW COVERT GENERATING FACILITY	MI	7/30/2018	2	SCR w/ DLNB	10.7 lb/hr	GCP	2	OC
8	FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	FL	7/30/2018	2	SCR w/ DLNB	NA	GCP	4.3	OC
9	MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	2	SCR w/ DLNB	16 lb/hr	GCP	0.0045 lb/MMBtu	OC
10	MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	2	SCR w/ DLNB	19.1	GCP	4	OC
11	MI-0431	INDECK NILES LLC	MI	6/26/2018	2	SCR w/ DLNB	NA	GCP	NA	OC
12	VA-0328	C4GT, LLC	VA	4/26/2018	2	SCR w/ DLNB	0.0065	GCP	1.8	OC
13	OH-0377	HARRISON POWER	OH	4/19/2018	29.5 lb/hr	SCR w/ DLNB	0.0052	GCP	17.9 lb/hr	OC
14	MI-0439	JACKSON GENERATING STATION	MI	4/2/2018	25	SCR w/ DLNB	4.9	GCP	NA	OC
15	TX-0834	MONTGOMERY COUNTY POWER STATION	TX	3/30/2018	2	SCR w/ DLNB	125.7	GCP	2	OC
16	WV-0029	HARRISON COUNTY POWER PLANT	WV	3/26/2018	2	SCR w/ DLNB	18.2	GCP	2	OC
17	TN-0164	TVA - JOHNSONVILLE COGENERATION	TN	2/1/2018	2	SCR w/ DLNB	0.005	GCP	2	OC
18	PA-0316	RENOVO ENERGY CENTER, LLC	PA	1/26/2018	2	SCR w/ DLNB	0.00433	GCP	2	OC

Table D-2 RBLC Search Results CCCT: VOC, H_2SO_4 and CO_2e BACT Limits/Technology

	RBLCID	Facility Name	State	Permit Issuance Date	VOC (PPM)	Technology	H2SO4	Technology	CO2e (lb/MW-hr)	Technology
1	IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	NA	OC	5 lb/hr	None	4733910 TPY	GP
2	MI-0441	LBWL--ERICKSON STATION	MI	12/31/2018	3	OC	NA	NA	430349 TPY	GP
3	LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	1.1	OC	NA	NA	2602275 TPY	GP
4	WV-0032	BROOKE COUNTY POWER PLANT	WV	9/21/2018	2	OC	0.00085 lb/MMBtu, 0.4 grains/100 DSCF Sulfur	CF	829	GP
5	PA-0319	RENAISSANCE ENERGY CENTER	PA	8/27/2018	1.4	OC	2.3 lb/hr	CF	875	GP
6	IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	NA	OC	NA	None	None	None
7	MI-0432	NEW COVERT GENERATING FACILITY	MI	7/30/2018	1	OC	1 lb/hr. 0.8 grains 100 DSCF sulfur	CF	1425081 TPY	GP
8	FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	FL	7/30/2018	NA	OC	NA	CF	850	CF
9	MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	0.0026 lb/MMBtu	OC	0.0013 lb/MMBtu	CF,GCP	2042773 TPY	EF
10	MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	4	OC	2.7	CF,GCP	1978297 TPY	EF
11	MI-0431	INDECK NILES LLC	MI	6/26/2018	NA	OC	NA	NA	NA	NA
12	VA-0328	C4GT, LLC	VA	4/26/2018	0.7	OC	2.5 lb/hr	CF,GCP	883	CP, EF
13	OH-0377	HARRISON POWER	OH	4/19/2018	9.8 lb/hr	OC	0.0022	CF,GCP	1000	CP, EF
14	MI-0439	JACKSON GENERATING STATION	MI	4/2/2018	NA	OC	NA	NA	1000257 TPY	CP, EF
15	TX-0834	MONTGOMERY COUNTY POWER STATION	TX	3/30/2018	2	OC	1 grain/100 DSCF sulfur	CF	884	CP
16	WV-0029	HARRISON COUNTY POWER PLANT	WV	3/26/2018	2	OC	0.0009 lb/MMBTU, 0.4 grains/100 DSCF sulfur	CF	826	CF
17	TN-0164	TVA - JOHNSONVILLE COGENERATION	TN	2/1/2018	NA	OC	NA	NA	1800	CP
18	PA-0316	RENOVO ENERGY CENTER, LLC	PA	1/26/2018	1.4	OC	0.8 lb/hr, 0.2 grains 100 DCF sulfur	CF	875	CF,EF

Notes: CP=Good Combustion Practices; SCR = Selective Catalytic Reduction; DLNB = Dry Low NOx Burners; LNB = Low NOx, Burners;
OC = Oxidation Catalyst, CF=Clean Fuels, EF=Energy efficiency measures

APPENDIX E - MODELING INPUT/OUTPUT DATA FROM THE AIR QUALITY MODELING ANALYSIS.

APPENDIX F – CONCENTRATION CONTOUR PLOTS

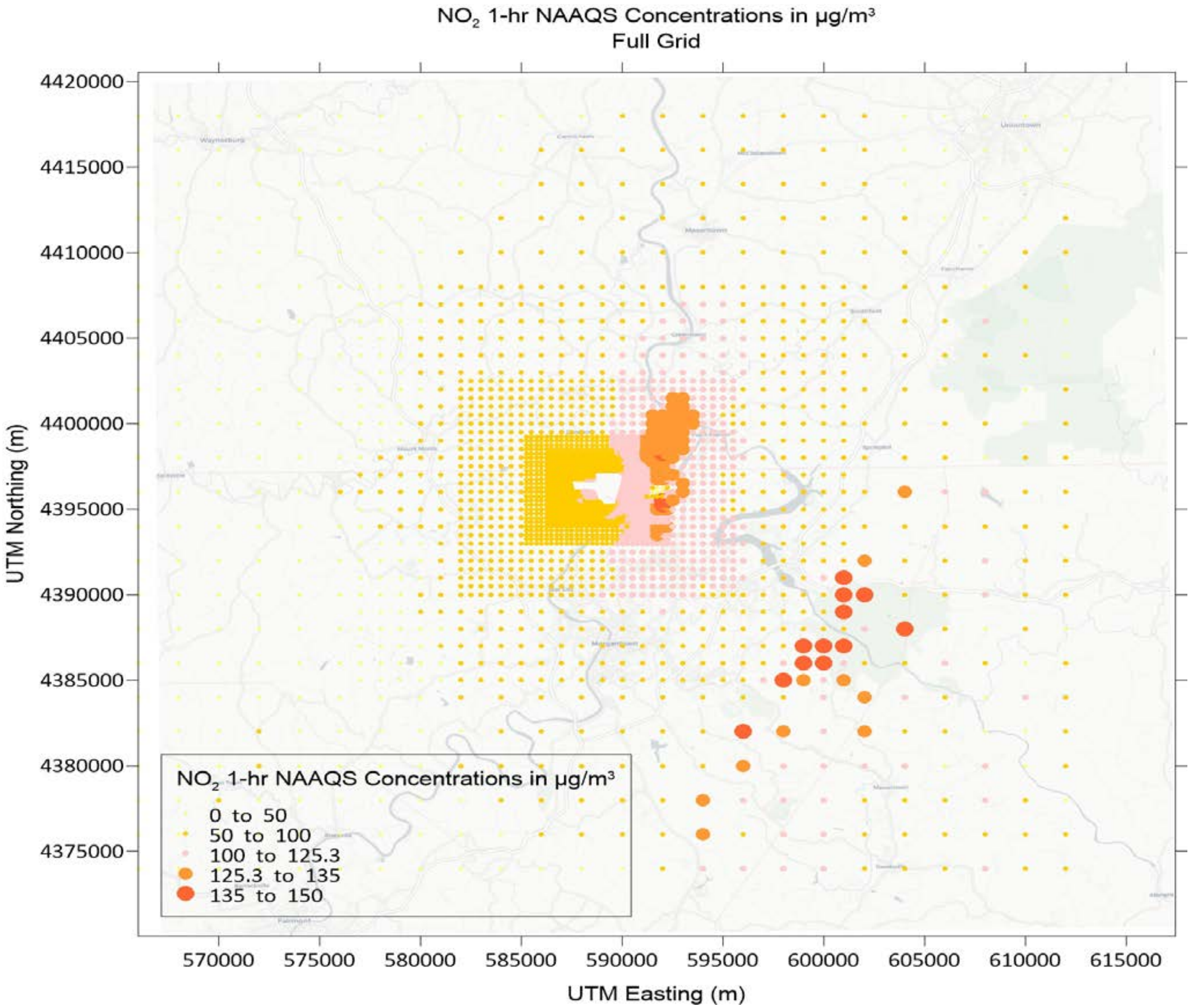


Figure F-1
NO_2 1-hr NAAQS Concentration (µ/m^3)
Full Grid

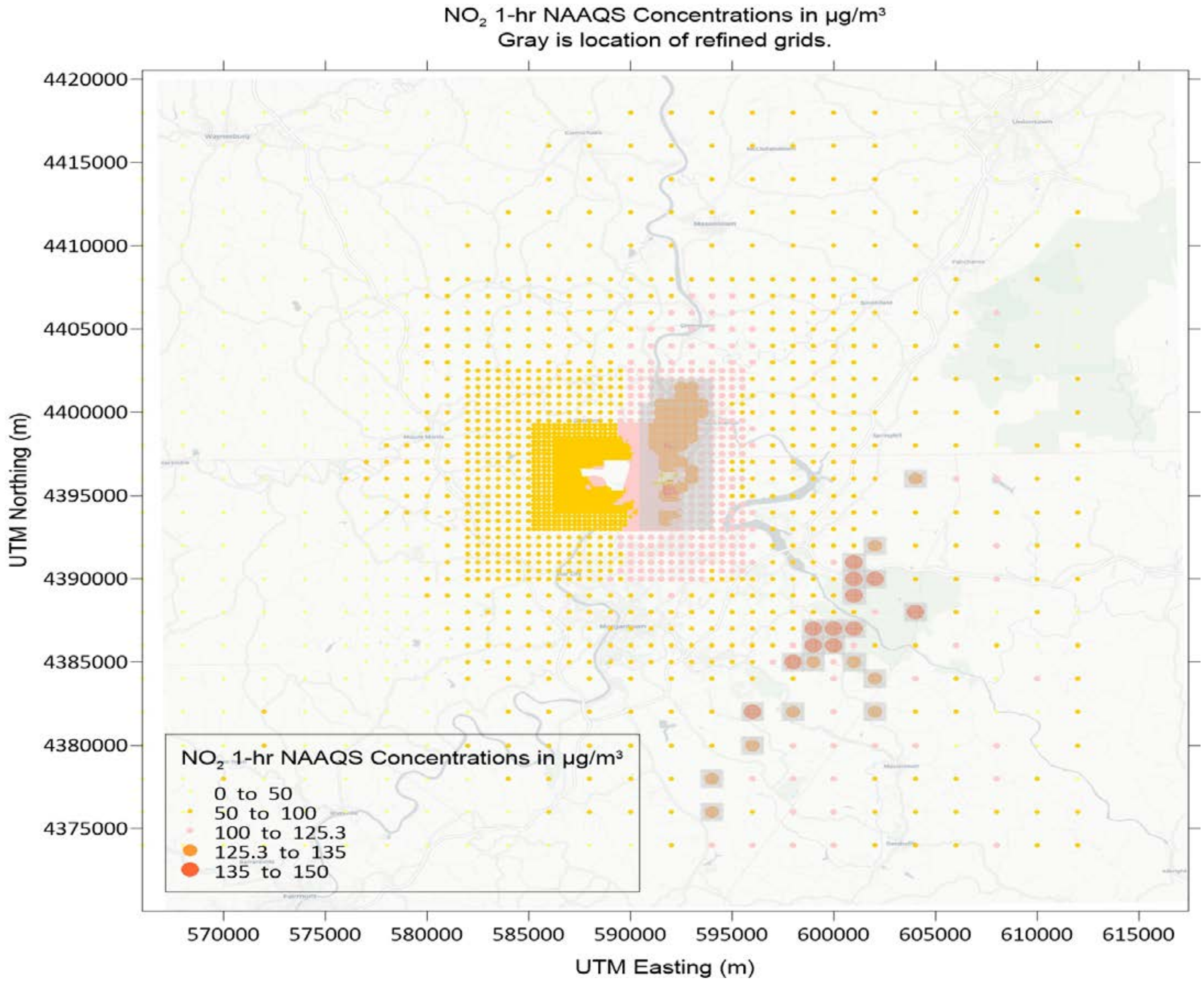


Figure F-2
NO$_2$ 1-hr NAAQS Concentration (µ/m^3)
Refined Grid

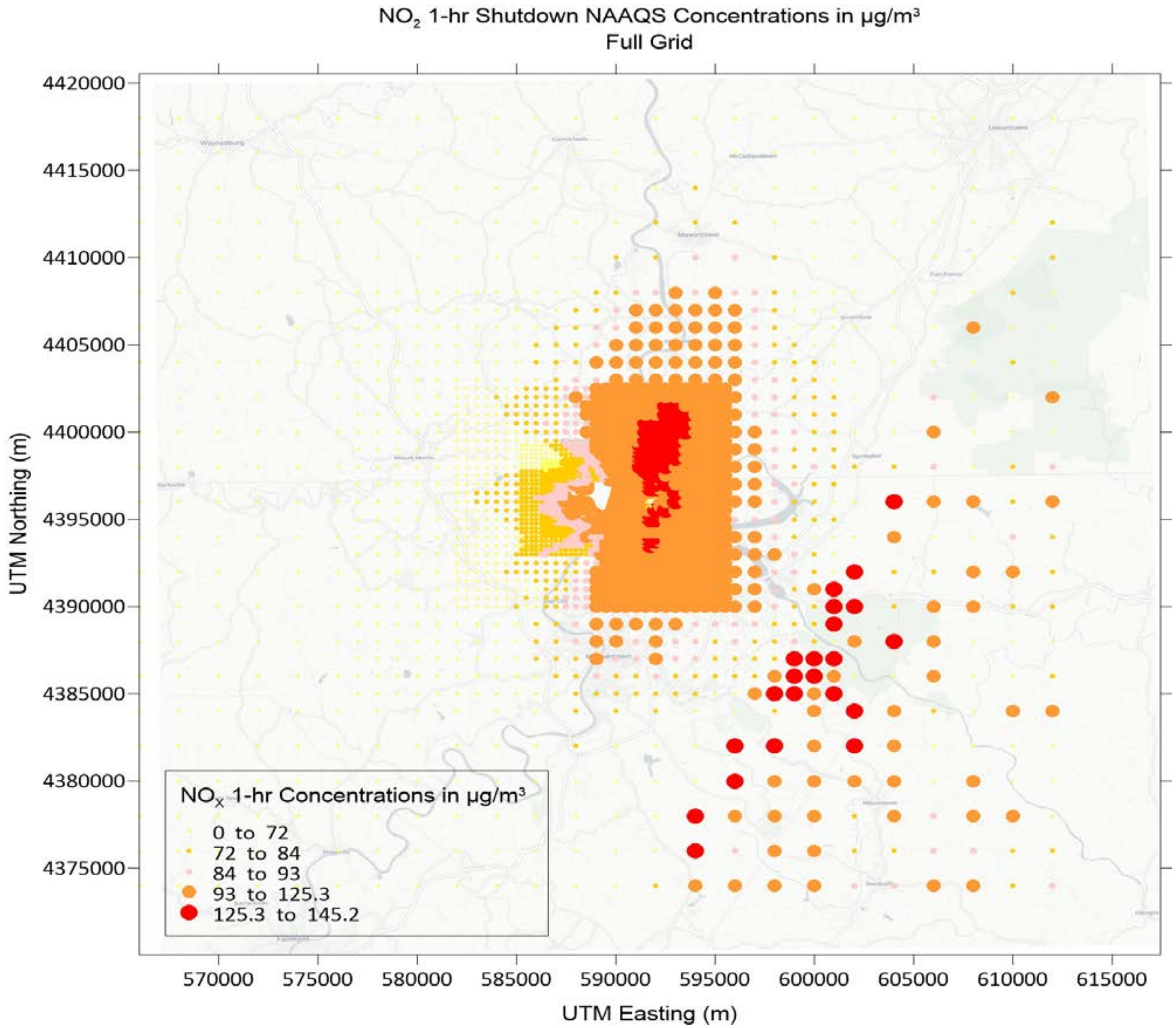


Figure F-3
NO_2 1-hr Startup/Shutdown NAAQS Concentration (µ/m^3)
Full Grid

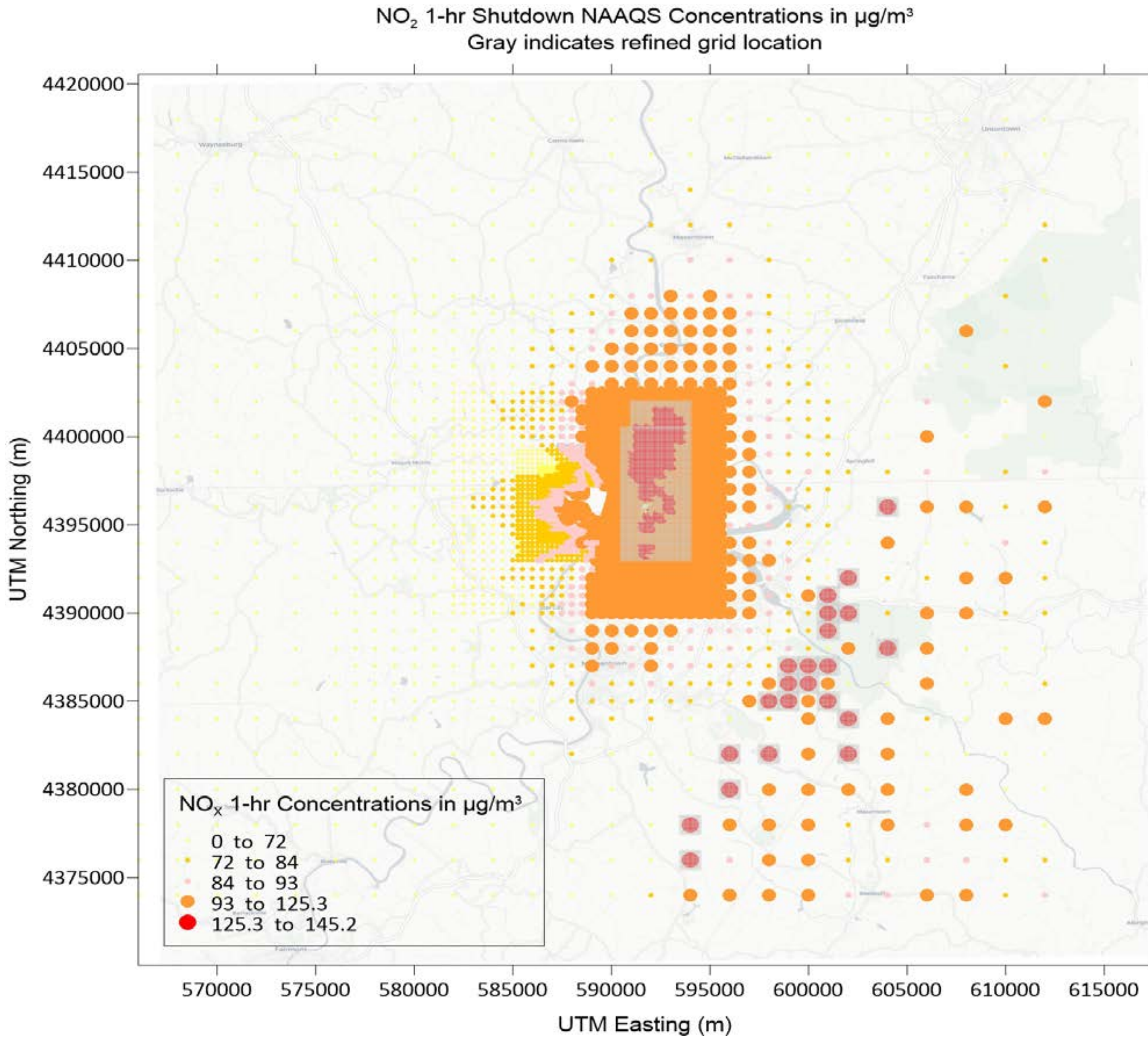


Figure F-4
NO_2 1-hr Startup/Shutdown NAAQS Concentration (µ/m^3)
Refined Grid

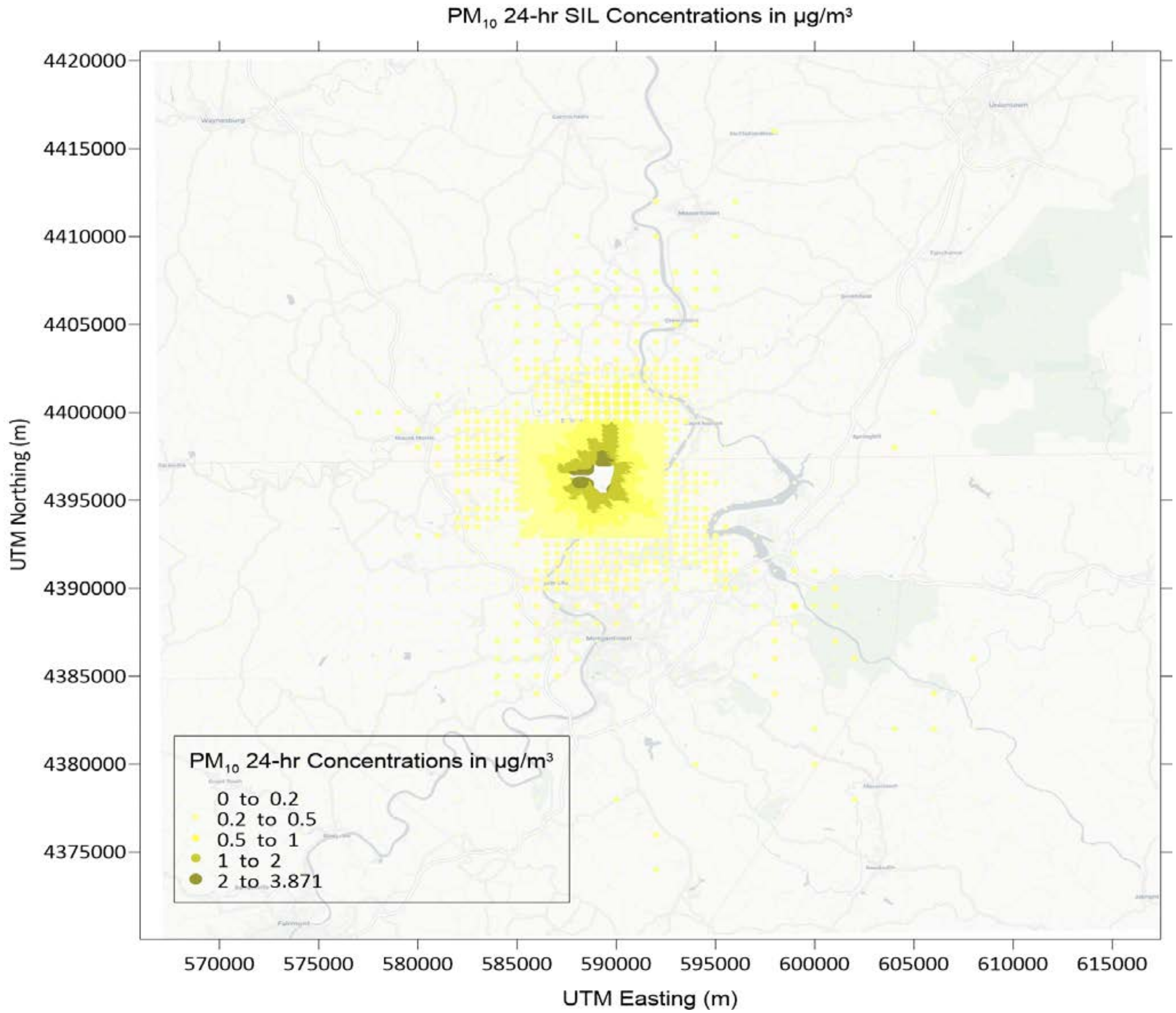


Figure F-5
PM_{10} 24-hr SIL Concentration (µ/m^3)
Full Grid

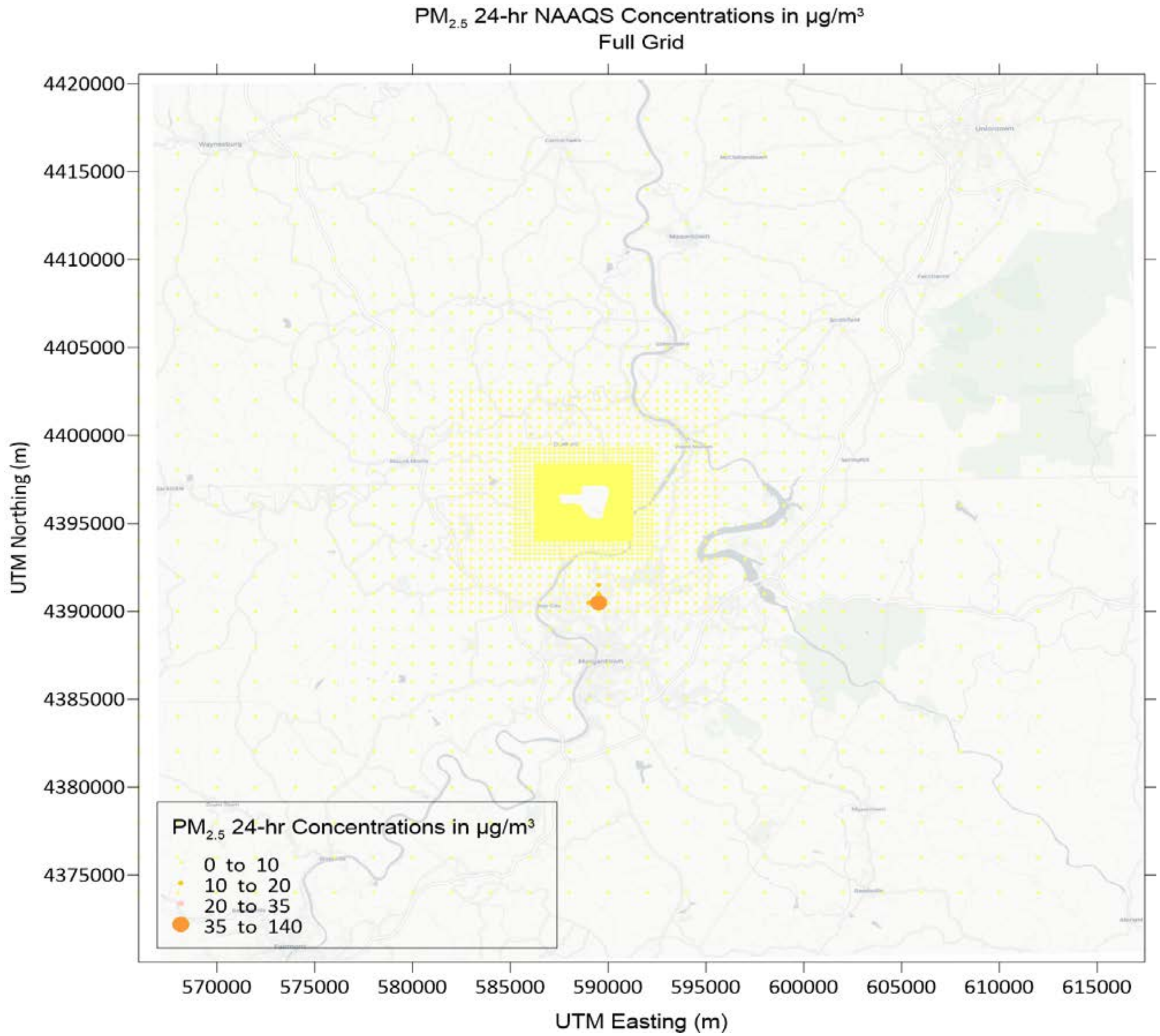


Figure F-6
PM_{10} 24-hr NAAQS Concentration (µ/m^3)
Full Grid

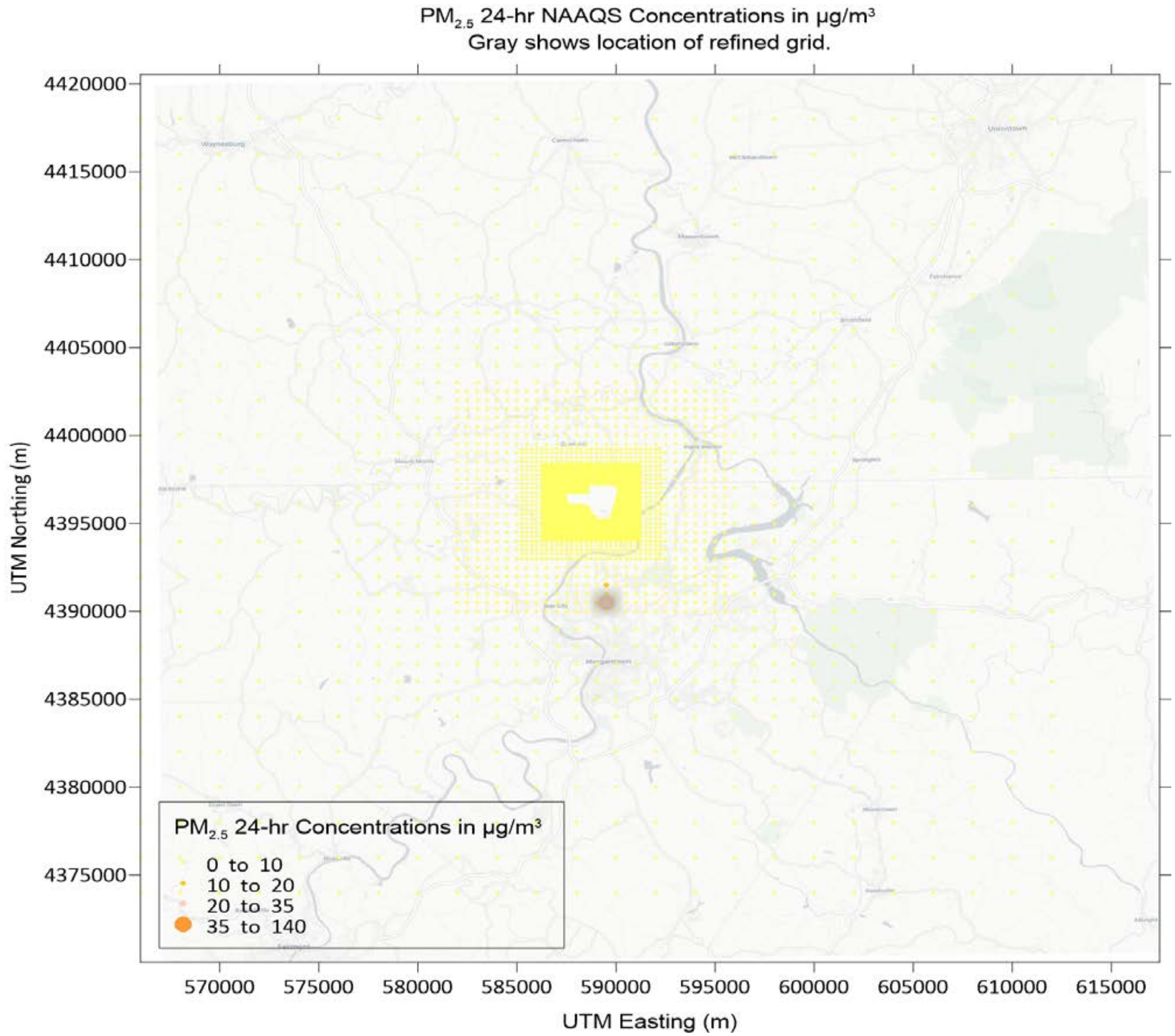


Figure F-7
PM_{10} 24-hr NAAQS Concentration (µ/m^3)
Refined Grid

Ambient Air Quality Services, Inc.

RECEIVED
DEC 10 2019
WV DEP / DIV OF AIR QUALITY

December 9, 2019

Edward S. Andrews, P.E.
WVDEP
Division of Air Quality
601 57th St.
Charleston, WV 25304

RE: **Prevention of Significant Deterioration (PSD) Air Permit Application for the Longview Power Unit 2 Project.**

Dear Mr. Andrews:

Enclosed are one original and two (2) paper copies of the Prevention of Significant Deterioration (PSD) Air Application for the Longview Power Unit 2 Project.

The fee payment and proof of advertisement will be submitted separately.

The air quality modeling is still being performed and will be submitted separately once it is completed

After reviewing the PSD Application if you have any comments or questions please contact me at (484) 224 6218 ext 101 or by email at lmilitana@aaqsinc.com.

Very truly yours,
AAQS Inc.

Louis M. Militana

Louis M. Militana, QEP
Partner/Principal Consultant

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Longview Power

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION FOR THE LONGVIEW UNIT 2 PROJECT

Submitted to:
West Virginia Department of Environmental Protection
Division of Air Quality
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December 5, 2019

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1. INTRODUCTION

1. INTRODUCTION

Longview Power II, LLC (Longview Power) is proposing to develop a two-phase expansion which includes a 1,200 megawatt (MW) Combined Cycle Gas fired Turbine (CCGT) Unit 2 facility and a photovoltaic renewable energy Unit 3 that will be up to 70 MW in size. The CCGT facility is referred to as the Longview Unit 2 Project (Project).

The Unit 2 Project is proposed to be a nominally rated 1,200 MW natural gas-fired only (no oil backup), combined-cycle gas turbine (CCGT) located immediately adjacent to the North of the current Longview Power Unit 1 location. The facility will be designed to achieve a peak electrical output of approximately 1,200 MW. Electricity generated by the Project will be supplied to the PJM power grid and connect to the grid via the existing interconnection used by the Longview Power Plant.

The major components of the proposed project include:

- One combined cycle power train consisting of two state-of-the-art natural gas-fueled advanced class combustion turbines, two heat recovery steam generators (with duct burners), and one steam turbine.
- Diesel fuel-fired firewater pump.
- Diesel fuel-fired emergency generator.
- Wet mechanical draft cooling tower.
- Fuel gas pre-heaters
- Aqueous ammonia tanks for the selective catalytic reduction pollution control system.

No auxiliary boiler is planned for the project. Any start-up steam requirement will be supplied by the Longview Power Unit 1 auxiliary boiler.

The proposed project will be subject to West Virginia Department of Environmental Protection (WVDEP), Division of Air Quality (DAQ) regulations 45CSR13 and 45CSR14 (known as Part 13 and 14 regulations) and Federal Prevention of Significant Deterioration (PSD). This document is the air quality permit application package.

1.1 APPLICATION ORGANIZATION

This application package contains all of the information required for a complete plan approval application for the proposed Longview Power Unit 2. Included in the application are detailed specifications and operating conditions for the combustion turbine, heat recovery steam generator (HRSG) with duct burner, fuel gas heaters, mechanical draft cooling tower, fire water pump and emergency generator along with the expected maximum pollutant emission rates from the project. The permit application is organized into the following sections:

- Section 2 provides a description of the proposed project.
- Section 3 provides an emissions inventory for the proposed emissions units. Included in the emissions inventory are the maximum short-term and annual emissions from the proposed emissions units. Additional documentation is provided in Appendix B.
- Section 4 summarizes all of the potentially applicable Federal and West Virginia air quality regulations.
- Section 5 contains a Best Available Control Technology (BACT) required by the applicable federal and state regulations for the construction of a major new stationary source
- Section 6 contains a description of the air quality modeling approach
- Section 7 contains a summary of expected air quality impacts analysis for the proposed project.
- Section 8 contains a list of the references used in this document.

The permit application includes supporting documentation which is presented in the following appendices:

- Appendix A contains the applicable WV DAQ application forms.
- Appendix B describes the methods used to estimate emissions and contains supporting calculations for the emission rates from the proposed emissions units.
- Appendix C provides vendor information for the proposed emissions units and emissions control devices.
- Appendix D provides the results of the RACT/BACT/LAER Clearinghouse (RBLC).
- Appendix E provides backup information and modeling output data from the air quality modeling analysis.

1.2 APPLICATION SUMMARY

The proposed Longview Unit 2 Project will meet all applicable Federal and West Virginia air quality regulations. The proposed project will be subject to the following federal air quality regulations

- PSD Regulations, including Part 51 and applicable subparts
- New Source Performance Standards (NSPS) Regulations, including Part 60, Db (Steam Generating Units), KKKK (Combustion Turbines), IIII (Ignition Internal Combustion Engines), TTTT (GHG from Electric Generating Units)
- National Emission Standards for Hazardous Air Pollutants (NESHAP), including Part 63 regulations if any single HAP is greater than 10 tpy or any combination is greater than 25 tpy (ZZZZ, Stationary Reciprocating Internal Combustion Engines).
- Title V Operating Permit Program, including Part 70 regulations

The proposed project will also be subject to Prevention of Significant Deterioration (PSD) regulations (administered in WV under 45CSR14) for the following attainment pollutants: Carbon Monoxide (CO), Oxides of Nitrogen (NO_x), Particulate Matter less than 2.5 microns ($PM_{2.5}$), Particulate Matter less than 10 microns (PM_{10}), Particulate Matter (PM), Volatile Organic Compounds (VOCs), Sulfuric Acid Mist (H_2SO_4) and Greenhouse Gasses (GHGs). These air pollutants require the application of BACT requirements. The potential emission rates of Sulfur Dioxide (SO_2), and Lead (Pb) are below the “major source” threshold and, therefore, the application will also be concurrently reviewed under the WV minor source program administered under 45CSR13.

The proposed BACT pollution control and emission rates for the Longview Unit 2 Project for criteria pollutants are presented in Table 1-1. Based on the proposed BACT emission rates, the maximum facility-wide air emission inventory is shown Table 1-2. As shown in this table PM/PM_{10},/$PM_{2.5}$, NO_x, CO, H_2SO_4 and GHG are all above the PSD major threshold levels.

An ambient air quality modeling analysis was performed for the following PSD triggering pollutants: PM/PM_{10},/$PM_{2.5}$, NO_x, CO. The predicted ambient air concentrations are all below the PSD significant impact levels, ambient air quality monitoring thresholds, PSD increments and West Virginia and National Ambient Air Quality Standards (NAAQS). Therefore, no

Table 1-1
Summary of BACT Emission Levels and Control Technology

Emission Unit	Pollutant	Emission Limit	BACT
Combustion Turbines/ HRSG Duct Burners	NO_x	2.0 ppmvd	Dry Low NO_x Burners with SCR
	VOC	1.0 ppmvd w/o duct firing 2.0 ppmvd w/ duct firing	Oxidation catalyst and good combustion practice
	PM/PM10 /PM2.5	0.008 lb/mmBtu	Clean fuels and good combustion practice
	CO	2.0 ppmvd	Oxidation catalyst and good combustion practice
	H_2SO4	0.00085 lb/mmBtu	Combustion of low sulfur fuel
Emergency Generator/ Fire Water Pump	NO_x	4.8 g/hp-hr/3.0 g/hp-hr	Combustion control (Retarded Timing and/or lean burn)
	VOC	1.2 lb/hr/1.0 lb/hr	Good combustion practice
	PM/PM10 /PM2.5	NA	Clean fuels and good combustion practices
	CO	0.3 g/hp-hr/ 0.44 g/hp-hr	Good combustion practices
	H_2SO4	NA	Combustion of low sulfur fuel
Fuel Gas Pre Heaters	NO_x	0.036 lb/MMBtu	Low NO_x Burner and good combustion practices
	VOC	0.007 lb/MMBtu	Good combustion practice
	PM/PM10 /PM2.5	0.008 lb/MMBtu	HEPA Filter
	CO	0.039 lb/MMBtu	Good combustion practice
	H_2SO4	0.0001 lb/MMBtu	Combustion of low sulfur fuel
Cooling Tower	$PM/PM_{10}/PM_{2.5}$	4.11 lb/hr	Drift Eliminators
Facility Wide Limit	GHG	4,282,215 tons/yr, on a CO2e basis	Thermal efficiency/combustion air cooling and use of lower carbon fuels.

Table 1-2
Summary of Facility Wide Maximum Emissions for the Longview Power Unit 2 Project

Pollutant	Annual Emissions (tons/year)	PSD Significance Level (tons/year)	PSD Pollutant
NO_x	302	40	Yes
VOCs	503	40	Yes
CO	693	100	Yes
$PM/PM_{10}/PM_{2.5}$	208	25/15/10	Yes
SO_2	38.7	40	No
H_2SO_4	32.5	7	Yes
Ozone Precursor (NO_x)	302	40	Yes
Ozone Precursor (VOC)	503	40	Yes
$PM_{2.5}$ Precursor Pollutant (NO_x)	302	40	Yes
$PM_{2.5}$ Precursor Pollutant (SO_2)	38.7	40	No
Lead	0.0005	0.6	No
Fluorides	0	1	No
Vinyl Chloride	0	1	No
Total Reduced Sulfur	0	10	No
Sulfur Compounds	0	10	No
GHG (CO2e)	3,931,696	100,000	Yes
Hazardous Air Pollutants (HAPS)	3.69 9.96	10 single 25 multiple	No No

preconstruction monitoring is required for the project. A summary of the maximum predicted ambient concentrations (based on the worst case dispersion conditions) due to emissions from the proposed Longview Power Unit 2 is presented in Table 1-3

Table 1-3
Summary of Maximum Predicted Ambient Concentrations (μg/m³)

Pollutant	Averaging Period	Maximum Predicted Concentration		PSD Significant Impact Levels	PSD Monitoring Threshold Levels	PSD Increment	NAAQS
Nitrogen Oxides (NO_x)	1-hour			7.5	NA	NA	188 (100 ppb)
	Annual			1	14	25	100 (53 ppb)
Carbon Monoxide (CO)	1-hour			2,000	NA	NA	40,000
	8-hour			500	575	NA	10,000
Particulate Matter less than ten micron (PM_{10})	24-hour			5	10	30	150
Particulate Matter less than 2.5 micron	24-hour			1.2	NA	9	35
	Annual			0.3	NA	4	12

[a] highest 8th highest

[b] highest 2nd highest

SECTION 2

2. PROJECT DESCRIPTION

2. PROJECT DESCRIPTION

2.1 FACILITY LOCATION

The proposed Project will be located on the Longview Power site in Maidsville, Monongalia County, West Virginia. The site is situated approximately 2,500 feet south of the Pennsylvania border, 3,000 feet west of the Monongahela River, and one mile north of Morgantown, West Virginia. The location of the Longview Power site is shown in Figure 2-1.

The geographic coordinates for the approximate center of the proposed project site are:

- Latitude: 39.7124 and Longitude: -79.9608
- UTM Easting: 589,077.73 and Northing: 4,396353.40
- UTM Zone: 17 (UTM = Universal Traverse Mercator)

The area in which the project will be located is in attainment of all of the National Ambient Air Quality Standards (NAAQS) pollutants.

The dominant land features of the Project area are the Monongahela River and the rapid increase in elevation away from the river. The river elevation is approximately 820 ft. above mean sea level (amsl) (250 m amsl). Terrain of approximately 1,100 ft. amsl occurs within 700 feet (210 m) of the river. Moving further away from the river isolated terrain peaks of 1,300 ft. amsl (400 m amsl) occur within 5,000 ft. (1.5 km) of the Monongahela River. The highest terrain within 15 km of the project site is 2,464 ft. amsl (751 m amsl).

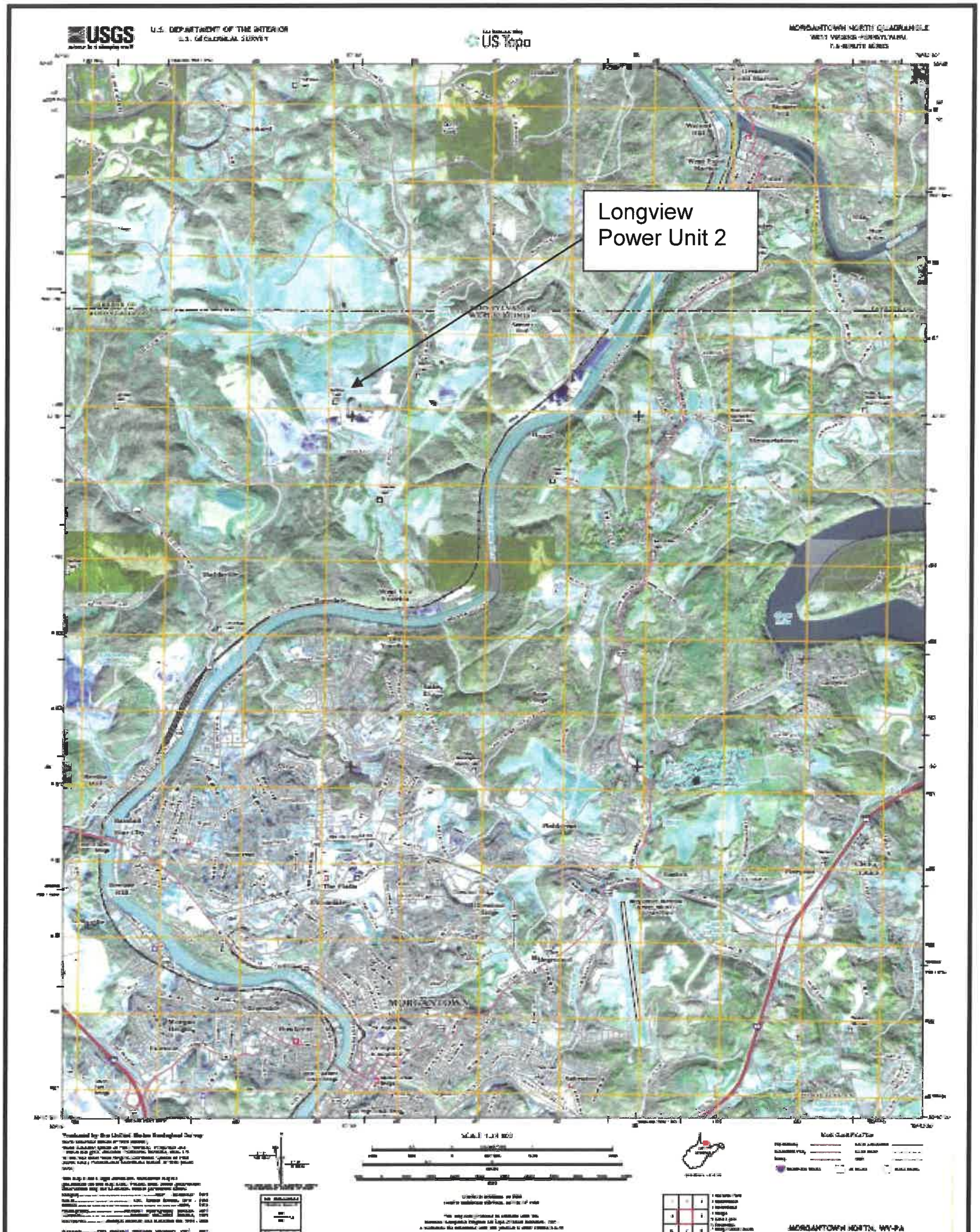


Figure 2-1
Location of Proposed Longview Power Unit 2

2.2 DESCRIPTION OF PROPOSED FACILITY

The Longview Power Unit 2 Project is proposed to be a nominally rated 1,200 MW natural gas-fired only (no oil backup), combined-cycle power plant located immediately adjacent to the north of the existing Longview Power Unit 1. The Project will be designed to achieve a peak electrical output during the summer season of approximately 1,200 MW. Electricity generated by Unit 2 will be supplied to the PJM power grid and connect to the grid via the existing interconnection used by the Longview Power Unit 1.

The major components of the proposed power plant include: One combined cycle power train consisting of two combustion turbines, two heat recovery steam generators (HRSG) with duct burners, one steam turbine, one diesel fuel-fired firewater pump, one diesel fired emergency generator, two fuel gas heaters and one mechanical draft cooling tower.

To enhance the plant's overall efficiency and increase the amount of electricity generated by the Project, the hot exhaust gases from each combustion turbine will be routed to a downstream Heat Recovery Steam Generator. The HRSGs contains a series of heat exchangers designed to recover the heat from the turbine's exhaust gas and produce steam. The Project includes the installation of duct burners to produce additional steam in the HRSGs for additional power output from the steam turbine generator. The duct burners will only fire natural gas. No oil backup is planned for the Project.

Cooled exhaust gas passing through the HRSGs will be vented to the Selective Catalytic Reduction (SCR) and Oxidation Catalyst control system used to control NO_x, CO and VOC emissions. Selective Catalytic Reduction involves the injection of aqueous ammonia (NH_3) at a concentration of approximately 19% by weight into the combustion turbine exhaust gas streams. The ammonia reacts with NO_x in the exhaust gas stream in the presence of a catalyst, reducing it to elemental nitrogen (N_2) and water vapor (H_2O). The aqueous ammonia will be stored on-site in dual 60,000 gallon (approximate) storage tanks. The catalyst enhances oxidation of CO to CO2, without the addition of any chemical reagents.

Steam generated in the HRSGs will be routed to a steam driven turbine that will increase the output of the electric generator. This generator will produce additional electricity that will be sold on the grid. Electricity generated by the combustion turbines and the single steam driven turbine driving the electric generator represents the Project's total electrical output.

The Project will use a condenser and a 14 cell wet mechanical draft cooling tower for steam turbine generator steam condensation and waste heat rejection.

Figure 2-2 provides a General Arrangement Drawing and Figure 2-3 presents a plot plan of the plant. More detailed descriptions of the Project components are in the following subsections.

2.2.1 Combustion Turbines

The combustion turbines (CT) produce shaft power to drive an electric generator. Natural gas and combustion air are combusted producing a high velocity discharge which rotates a turbine shaft. The exhaust gases exiting the combustion turbines are routed to an HRSG to recover heat and generate steam. The combustion turbines will be General Electric (GE) 7HA.02 or equivalent (i.e. Mitsubishi Hitachi Power System J series), each with a nominal electric generation capacity of approximately 400 MW and a maximum rated heat capacity of 3,970 MMBtu/hr. [Higher Heating Value (HHV)] at cold day ambient temperature of -5 °F. The combustion turbines will be fired with natural gas only and will be equipped with Dry Low NO_x burners.

2.2.2 Heat Recovery Steam Generators

Exhaust gas from the combustion turbine is routed to the HRSG through insulated ductwork, where it passes through the water and steam HRSG heat exchanging sections. The gas is then discharged to the atmosphere through the integral HRSG exhaust stack with a silencer. Heat is transferred by primary convection from the hot CT exhaust gas to the feed water and steam systems. The feed water and steam will flow inside the vertically oriented finned tubes, and the gas flow will be directed horizontally across the tube rows.

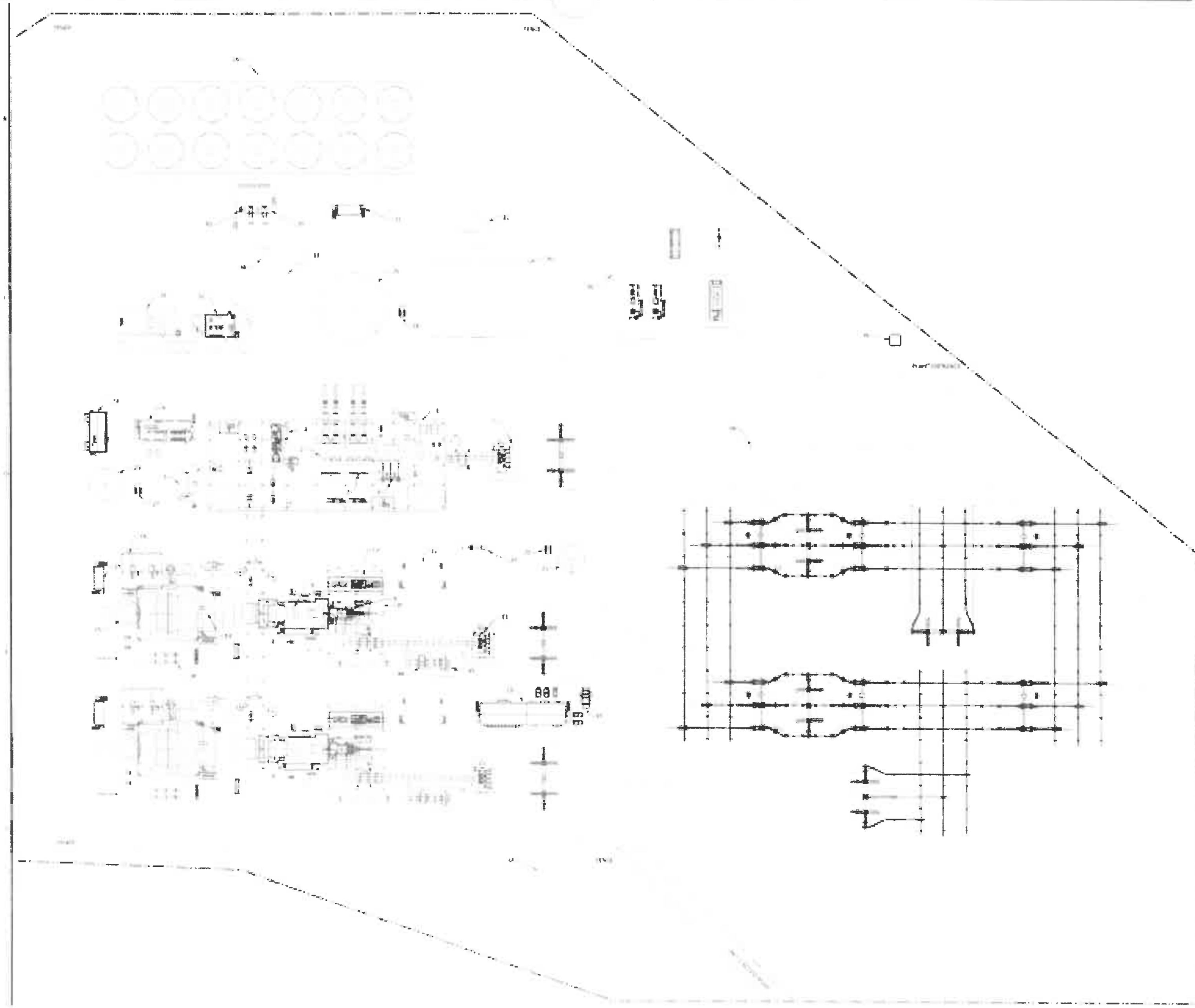


Figure 2-1
General Arrangement Drawing

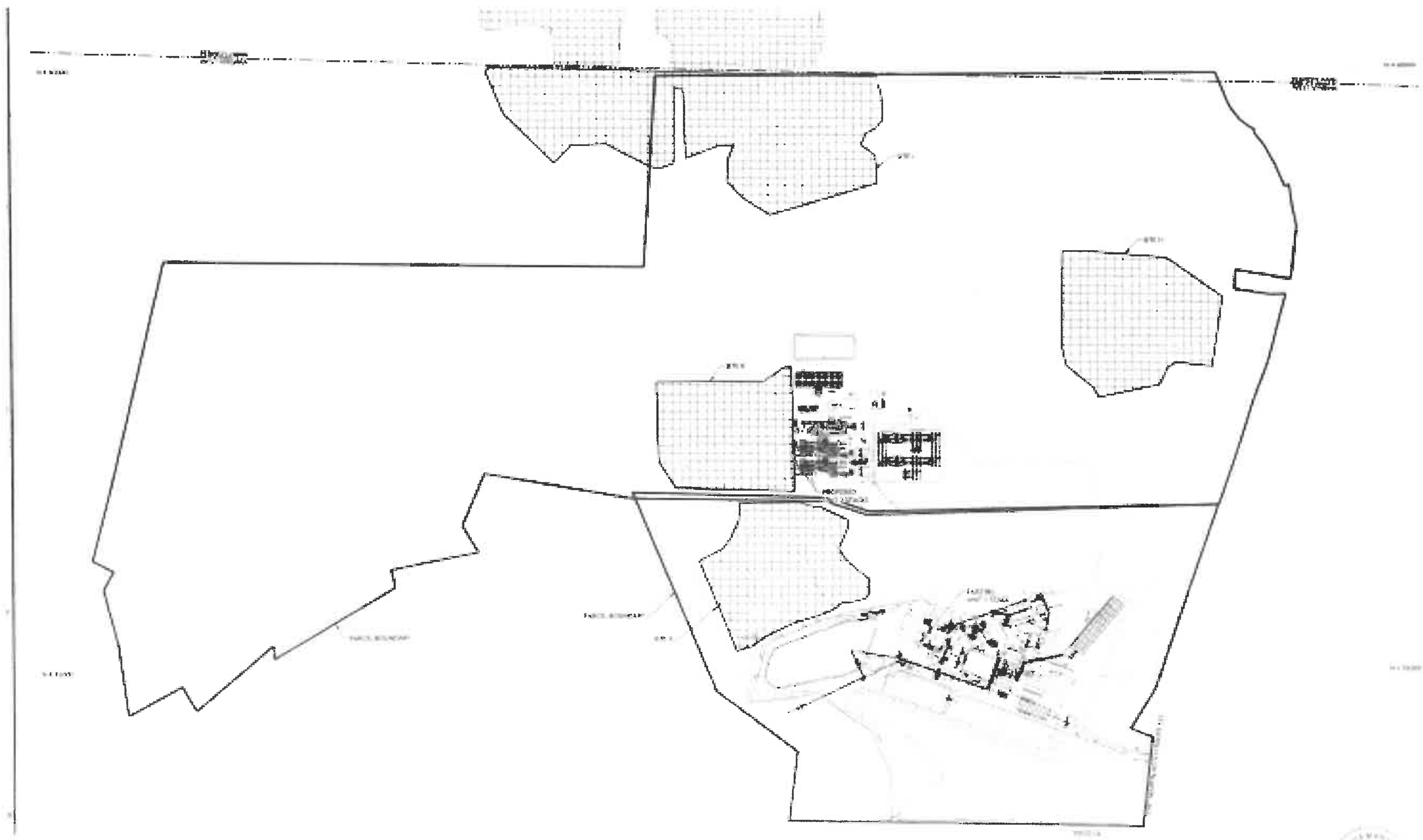


Figure 2-3
Plot Plan

For maximum flexibility, the bottoming cycle portion of a combined cycle is "oversized" to allow for higher output of the steam turbine (ST) than what could otherwise be achieved using the exhaust energy produced by the CT alone. The exhaust gases leaving the CT contain enough oxygen to support additional combustion of fuels. Additional heat is added to the bottoming cycle using Low NOx duct burners with a maximum rated heat capacity of 250 MMBtu/hr-HHV per HRSG. This additional heat produces additional steam, which is passed through the ST flow path for additional electrical output (approximately 60 MW). The supplemental HRSG duct firing system consists of the duct burners, duct burner management system, duct burner fuel metering and regulation skid, and fuel supply.

The HRSG will be equipped with a selective catalytic reduction (SCR) system to limit NO_x emissions, and a catalytic Oxidation (CO) system to limit carbon monoxide and volatile organic compound emissions. The duct burners will not operate independently of the combustion turbine.

No auxiliary boiler will be constructed for the Project. Instead, via an interconnect with existing Unit 1, steam will be provided via the existing Unit 1 Auxiliary Boiler and also allow for bi-directional steam flow between Units 1 and 2.

2.2.3 Steam Turbine/Generator

The steam turbine/generator will utilize the steam developed in the HRSG to generate electricity. The steam turbine generator will receive steam from the HRSG and will discharge the low-pressure exhaust steam to the condenser. The steam turbines have a maximum rating of 430 MW each (maximum).

2.2.4 Mechanical Draft Cooling Tower

The ST exhausts directly into the condenser, where the steam is condensed by the circulating water passing through the condenser tubes. Condensate formed in the condenser is collected in the hot well. Recoverable steam and condensate from cycle drains and other reclaimable steam are also routed to the condenser hot well. The steam surface condenser relies on the circulating water system to provide cooling water for heat exchange. The circulating water system rejects the waste heat to atmosphere via a wet mechanical draft cooling tower by sensible heat transfer (increasing the temperature of the air passing across the tower) and latent heat transfer (evaporating a portion of the circulating water into the air passing across the tower). The cooling tower is designed to reject heat returned from the steam surface condenser and the plant auxiliary cooling water system. The cooled circulating water is collected in the cooling tower basin, and pumped back to the condenser water boxes, repeating the process. A circulating water chemical feed system will be included.

During the cooling process, small water droplets, known as cooling tower drift, escape to the atmosphere through the cooling tower exhaust To minimize this effect, the cooling tower will be equipped with drift eliminators The drift eliminators provide multiple directional changes of airflow which helps prevent the escape of water droplets.

2.2.5 Diesel fired firewater pump

A 240 hp, 179 kW standby firewater pump will be used to supply water during emergency conditions. The fire water pump will use ultra-low sulfur diesel (ULSD) fuel, with a sulfur content no greater than 0.0015% by weight. The fire water pump will also be periodically operated for short periods per manufacturer's maintenance instructions to ensure operational readiness in the event of an emergency. The fire water pump is expected to operate less than 100 hours per year.

2.2.6 Diesel fired emergency generator

An emergency generator (1,528 hp, 1,139 kW) will be used for emergency backup electric power. The fuel for the emergency generator will be ULSD with a sulfur content no greater than 0.0015% by weight. The emergency generator will be periodically operated for short periods per manufacturer's maintenance instructions to ensure operational readiness in the event of an emergency. The emergency generator is expected to operate less than 100 hours per year.

2.2.7 Fuel Gas Heaters

Two (2) fuel gas heaters (5.4 MMBtu/hr, approximate) will be used to preheat the pipeline natural gas received by the plant. Preheating the fuel prior to combustion in the CTs increases their efficiency, safeguards the fuel pipelines from icing, and protects the CTs from fuel condensates.

The fuel supply for the Unit 2 CCGT will be provided via a 6.2 mile 20" pipeline interconnecting onto both the Columbia 1804 and 10240 interstate pipelines located near Greensboro, PA. At this interconnection, there will be a metering station allowing connection with the dual supply lines that are integral to the Columbia pipeline. Electric gas compression equipment will be added to this line and will have those facilities located on the Unit 2 site.

2.2.8 Pipeline Gas Compressors

The Project will own and operate two pipeline gas compressor units. The compressors are electric-drive, 2,750 HP (Toshiba J2758, or equivalent) with a 4-throw reciprocating fluid end (Ariel JGC/4, or equivalent). The manufacturer recommends states that there are no GHG/VOC emissions associated with the operation of the units. Additionally, the manufacturer states that there will be no GHG/VOC emissions associated with the startup and shutdown of compressor units during normal operation; since no purge will be necessary.

2.3 OPERATING SCENARIOS

The typical range of operating scenarios for the Project is shown in Table 2-1 and includes three load conditions (50%, 75%, and 100%) with the duct burner and/or evaporative cooler either operating or not operating and various start-up and shut-down conditions. Each of the operating scenarios has unique exhaust gas conditions and pollutant emission rates. The typical operating scenario is for the combustion turbine to operate at or near 100% of the design capacity and highest short-term (hourly) emission rates are associated with winter day, 100% load, with duct firing.

Start-up conditions for the combustion turbines represent periods from initial firing until the system reaches steady state operations.

Start-up modes include:

- cold starts (restarts made more than 72 hours of shutdown).
- warm starts (between 8 and 72 hours of shutdown).

- hot starts (less than 8 hours of shutdown).

Shutdown conditions represent periods where system output is lowered below steady state conditions until the cessation of fuel firing. Shutdown commences when the turbine loads reach less than 50% load with the intent to stop operations. The proposed emission limits for the combustion turbines should not apply during periods of start-up (cold, warm or hot) and shutdown. The annual emissions for the entire facility, which are discussed in Section 3, include 260 start-ups (208 hot startups, 40 warm startups, and 12 cold startups) and 260 shut-down.

The Longview Power Unit 2 plant is a merchant plant designed to operate continuously, with very limited periods of startups and shutdowns.

Table 2-1
Summary of Potential Operating Scenarios for Selected Design Conditions

	Case Description	CTG Load	Ambient DBT/RH	Inlet Cooling	Duct Firing	Blowdown	Fuel Type	Configuration
	2x1 Configuration							
1	Summer Day,100% CTG Load, Duct Firing, Evap ON	100	92.0/45.7	On	On	0%	NG	2x1
2	Summer Day,100% CTG Load, Evap ON	100	92.0/45.7	On	Off	0%	NG	2x1
3	Summer Day,100% CTG Load, Duct Firing	100	92.0/45.7	Off	On	0%	NG	2x1
4	Summer Day,100% CTG Load	100	92.0/45.7	Off	Off	0%	NG	2x1
5	Summer Day,75% CTG Load	75	92.0/45.7	Off	Off	0%	NG	2x1
6	Summer Day,50% CTG Load	50	92.0/45.7	Off	Off	0%	NG	2x1
7	Summer Day, MECL CTG Load	MECL	92.0/45.7	Off	Off	0%	NG	2x1
8	Average Day,100% CTG Load, Duct Firing, Evap ON	100	63.0/70.1	On	On	0%	NG	2x1
9	Average Day,100% CTG Load, Evap ON	100	63.0/70.1	On	Off	0%	NG	2x1
10	Average Day,100% CTG Load, Duct Firing	100	63.0/70.2	Off	On	0%	NG	2x1
11	Average Day,100% CTG Load	100	63.0/70.2	Off	Off	0%	NG	2x1
12	Average Day,75% CTG Load	75	63.0/70.2	Off	Off	0%	NG	2x1
13	Average Day,50% CTG Load	50	63.0/70.2	Off	Off	0%	NG	2x1
14	Average Day, MECL CTG Load	MECL	63.0/70.2	Off	Off	0%	NG	2x1
15	Winter Day,100% CTG Load, Duct Firing	100	-5.0/90.0	Off	On	0%	NG	2x1
16	Winter Day,100% CTG Load	100	-5.0/90.0	Off	Off	0%	NG	2x1
17	Winter Day,75% CTG Load	75	-5.0/90.0	Off	Off	0%	NG	2x1
18	Winter Day,50% CTG Load	50	-5.0/90.0	Off	Off	0%	NG	2x1
19	Winter Day, MECL CTG Load	MECL	-5.0/90.0	Off	Off	0%	NG	2x1
	1x1 Configuration							
20	Summer Day,100% CTG Load, Duct Firing, Evap ON	100	92.0/45.7	On	On	0%	NG	1x1
21	Summer Day,100% CTG ON	100	92.0/45.7	On	Off	0%	NG	1x1
22	Summer Day,100% CTG Load, Duct Firing	100	92.0/45.7	Off	On	0%	NG	1x1
23	Summer Day,100% CTG Load	100	92.0/45.7	Off	Off	0%	NG	1x1
24	Summer Day,75% CTG Load	75	92.0/45.7	Off	Off	0%	NG	1x1
25	Summer Day,50% CTG Load	50	92.0/45.7	Off	Off	0%	NG	1x1
26	Summer Day, MECL CTG Load	MECL	92.0/45.7	Off	Off	0%	NG	1x1
27	Average Day,100% CTG Load, Duct Firing, Evap ON	100	63.0/70.1	On	On	0%	NG	1x1
28	Average Day,100% CTG Load, Evap ON	100	63.0/70.1	On	Off	0%	NG	1x1
29	Average Day,100% CTG Load, Duct Firing	100	63.0/70.2	Off	On	0%	NG	1x1
30	Average Day,100% CTG Load	100	63.0/70.2	Off	Off	0%	NG	1x1
31	Average Day,75% CTG Load	75	63.0/70.2	Off	Off	0%	NG	1x1
32	Average Day,50% CTG Load	50	63.0/70.2	Off	Off	0%	NG	1x1
33	Average Day, MECL CTG Load	MECL	63.0/70.2	Off	Off	0%	NG	1x1
34	Winter Day,100% CTG Load, Duct Firing	100	-5.0/90.0	Off	On	0%	NG	1x1
35	Winter Day,100% CTG Load	100	-5.0/90.0	Off	Off	0%	NG	1x1
36	Winter Day,75% CTG Load	75	-5.0/90.0	Off	Off	0%	NG	1x1
37	Winter Day,50% CTG Load	50	-5.0/90.0	Off	Off	0%	NG	1x1
38	Winter Day, MECL CTG Load	MECL	-5.0/90.0	Off	Off	0%	NG	1x1

Notes: 1. The Duct Firing cases shall be designed to provide approximately a 15% increase over the STG unfired output.
2. CTG - Combustion Turbine Generator, DBT - Dry-Bulb Temperature (deg F), RH - Relative Humidity, NG - Natural Gas, Listed steam conditions: M (kpph), P (psia), T (deg F), MECL - Minimum Emissions Compliance Load

3. EMISSION INVENTORY AND PSD/NSR APPLICABILITY DETERMINATION

SECTION 3

3. EMISSION INVENTORY AND PSD/NSR APPLICABILITY DETERMINATION

3.1 PROPOSED PROJECT EMISSION RATES

The emission units associated with the proposed Longview Unit 2 Project include the combustion turbines, HRSG duct burners, emergency generator, fire pump and fuel gas heaters. All units will be natural gas-fired except the fire water pump and emergency generator, which are diesel fuel fired. The following subsections provide brief summaries of the pertinent emissions data for each emission unit.

3.1.1 Combustion Turbines

3.1.1.1 Normal Operating Condition

The combustion turbine will be a General Electric Frame GE 7HA.02 gas turbine (or equivalent) with supplemental HRSG duct firing with inlet air-cooling and will combust natural gas only. The combustion turbine will have a rated heat input of 3,561.2 MMBtu/hr (approximate) while operating at an average ambient temperature of 63° F. The heat input capacity of the combustion turbine increases at lower ambient temperatures and decreases at higher ambient temperatures.

The combustion turbine will be equipped with dry low NO_x combustor technology to minimize the formation of NO_x. Pollutant emission rates from the combustion turbine are obtained directly from the performance data provided by the manufacturer (e.g., General Electric). The maximum projected emission rates are equal to the highest emission rate over a range of operating conditions (load and ambient air temperature). The temperature and load conditions analyzed are 50%, 75% and 100% load and minimum, average and maximum design temperatures of -5, 63 and 92 °F, respectively.

A summary of the maximum hourly for each potential operating conditions of the combustion turbine/duct burner is provided in Table 3-. 1

Table 3-1
Potential Maximum Hourly Emission Rate from one Combustion Turbine/HRSG Set

Case Description		CTG Load	Ambient DBT/RH	Inlet Cooling	Duct Firing	Blowdown	Fuel Type	Configuration	NO_2	CO	VOC	SO_2 [a]	PM
	2x1 Configuration												
1	Summer Day,100% CTG Load, Duct ON	100	92.0/45.7	On	On	0%	NG	2x1	28	16.8	5.5	4.13	19.1
2	Summer Day,100% CTG ON	100	92.0/45.7	On	Off	0%	NG	2x1	26.5	16.1	4.6	3.88	13.2
3	Summer Day,100% CTG Load, Duct Firing	100	92.0/45.7	Off	On	0%	NG	2x1	27.1	16.3	5.4	3.99	18.7
4	Summer Day,100% CTG Load	100	92.0/45.7	Off	Off	0%	NG	2x1	25.5	15.5	4.4	3.74	12.9
5	Summer Day,75% CTG Load	75	92.0/45.7	Off	Off	0%	NG	2x1	20.3	12.4	3.6	2.99	10.4
6	Summer Day,50% CTG Load	50	92.0/45.7	Off	Off	0%	NG	2x1	15.7	10.4	7.1	2.32	8.5
7	Summer Day, MECL CTG Load	MECL	92.0/45.7	Off	Off	0%	NG	2x1	15.7	10.4	7.1	2.32	8.5
8	**Average Day,100% CTG Load, Duct Firing, Evap ON**	**100**	**63.0/70.1**	**On**	**On**	**0%**	**NG**	**2x1**	**28.4**	**17**	**5.6**	**4.18**	**19.2**
9	Average Day,100% CTG Load, Evap ON	100	63.0/70.1	On	Off	0%	NG	2x1	26.8	16.3	4.7	3.93	13.4
10	Average Day,100% CTG Load, Duct Firing	100	63.0/70.2	Off	On	0%	NG	2x1	28.2	17	5.5	4.16	19.2
11	Average Day,100% CTG Load	100	63.0/70.2	Off	Off	0%	NG	2x1	26.6	16.2	4.6	3.91	13.4
12	Average Day,75% CTG Load	75	63.0/70.2	Off	Off	0%	NG	2x1	21.2	12.9	3.7	3.12	10.9
13	Average Day,50% CTG Load	50	63.0/70.2	Off	Off	0%	NG	2x1	16.4	9.8	3.7	2.41	8.7
14	Average Day, MECL CTG Load	MECL	63.0/70.2	Off	Off	0%	NG	2x1	16.4	9.8	3.7	2.41	8.7
15	Winter Day,100% CTG Load, Duct Firing	100	-5.0/90.0	Off	On	0%	NG	2x1	29.1	17.4	5.6	4.28	19.6
16	Winter Day,100% CTG Load	100	-5.0/90.0	Off	Off	0%	NG	2x1	27.5	16.7	4.9	4.03	13.7
17	Winter Day,75% CTG Load	75	-5.0/90.0	Off	Off	0%	NG	2x1	24.5	14.9	4.3	3.59	12.4
18	Winter Day,50% CTG Load	50	-5.0/90.0	Off	Off	0%	NG	2x1	18.2	16	10.5	2.7	9.7
19	Winter Day, MECL CTG Load	MECL	-5.0/90.0	Off	Off	0%	NG	2x1	18.2	16	10.5	2.7	9.7
	1x1 Configuration												
20	Summer Day,100% CTG Load, Duct ON	100	92.0/45.7	On	On	0%	NG	1x1	28	16.8	5.5	4.13	19.1
21	Summer Day,100% CTG ON	100	92.0/45.7	On	Off	0%	NG	1x1	26.5	16.1	4.6	3.88	13.2
22	Summer Day,100% CTG Load, Duct Firing	100	92.0/45.7	Off	On	0%	NG	1x1	27.1	16.3	5.4	3.99	18.7
23	Summer Day,100% CTG Load	100	92.0/45.7	Off	Off	0%	NG	1x1	25.5	15.5	4.4	3.74	12.9
24	Summer Day,75% CTG Load	75	92.0/45.7	Off	Off	0%	NG	1x1	20.3	12.4	3.6	2.99	10.4
25	Summer Day,50% CTG Load	50	92.0/45.7	Off	Off	0%	NG	1x1	15.7	10.4	7.1	2.32	8.5
26	Summer Day, MECL CTG Load	MECL	92.0/45.7	Off	Off	0%	NG	1x1	15.7	10.4	7.1	2.32	8.5
27	**Average Day,100% CTG Load, Duct Firing, Evap ON**	**100**	**63.0/70.1**	**On**	**On**	**0%**	**NG**	**1x1**	**28.4**	**17**	**5.6**	**4.18**	**19.2**
28	Average Day,100% CTG Load, Evap ON	100	63.0/70.1	On	Off	0%	NG	1x1	26.8	16.3	4.7	3.93	13.4
29	Average Day,100% CTG Load, Duct Firing	100	63.0/70.2	Off	On	0%	NG	1x1	28.2	17	5.5	4.16	19.2
30	Average Day,100% CTG Load	100	63.0/70.2	Off	Off	0%	NG	1x1	26.6	16.2	4.6	3.91	13.4
31	Average Day,75% CTG Load	75	63.0/70.2	Off	Off	0%	NG	1x1	21.2	12.9	3.7	3.12	10.9
32	Average Day,50% CTG Load	50	63.0/70.2	Off	Off	0%	NG	1x1	16.4	9.8	3.7	2.41	8.7
33	Average Day, MECL CTG Load	MECL	63.0/70.2	Off	Off	0%	NG	1x1	16.4	9.8	3.7	2.41	8.7
34	Winter Day,100% CTG Load, Duct Firing	100	-5.0/90.0	Off	On	0%	NG	1x1	29.1	17.4	5.6	4.28	19.6
35	Winter Day,100% CTG Load	100	-5.0/90.0	Off	Off	0%	NG	1x1	27.5	16.7	4.9	4.03	13.7
36	Winter Day,75% CTG Load	75	-5.0/90.0	Off	Off	0%	NG	1x1	24.5	14.9	4.3	3.59	12.4
37	Winter Day,50% CTG Load	50	-5.0/90.0	Off	Off	0%	NG	1x1	18.2	16	10.5	2.7	9.7
38	Winter Day, MECL CTG Load	MECL	-5.0/90.0	Off	Off	0%	NG	1x1	18.2	16	10.5	2.7	9.7

[a] Sulfur content of 0.4 grains/100 scf of natural gas.

3.1.1.2 Start-Up and Shutdown Conditions

Emissions during start-up and shutdowns of the combustion turbines were estimated for the air permit application using vendor supplied information and the expected number of cold, warm and hot start-ups which would occur each year. A summary of the maximum hourly and annual emission rates (assuming natural gas firing) for startups and shutdowns conditions are provided in Table 3-2. The number of startups and shutdowns presented in Table 3-2 are worst case conditions and the actual number are expected to be significantly less since the Longview Power Unit 2 project is designed as a merchant power plant.

3.1.2 Heat Recovery Steam Generator Duct Burners

The Heat Recovery Steam Generator (HRSG) duct burner will have a design heat input capacity of 227 MMBtu/hr (HHV) (approximate) and will combust natural gas. The HRSG will primarily operate in the recovery or "unfired" mode (i.e., no duct burner) utilizing heat from the proposed combustion turbine exhaust gases to generate steam. The HRSG and duct burner cannot operate independently from the proposed combustion turbine. The exhaust gases from the combustion turbines and duct burners will be discharged to the atmosphere downstream of the HRSG through a 180-ft stack.

The duct burner will be of a "low-NO_x" design in order to control emissions of nitrogen oxides. Maximum hourly emissions from the duct burner are estimated based on operation at full capacity and on emission factors from performance data sheets for the units as supplied by the manufacturer. Annual emissions are based on 8,500 hours per year of normal operation which assumes 260 hours of startup/shutdown for the balance of the year.

A summary of the maximum hourly emission rates for each potential operating conditions of the combustion turbine and duct burner (assuming natural gas firing) is provided in Table 3-1.

3.1.3 Other Combustion/Process Sources

The other minor combustion and/or process sources of the Project include:

- Firewater pump
- Emergency generator
- Fuel gas heaters
- Mechanical Draft Cooling Tower

Table 3-2
Potential Maximum Annual Emissions from the Start-Up and Shut-Down Conditions[b]

Pollutant		Hot Start	Warm Start	Cold Start	Shutdown	Two CT Units
NOx	lb/event	165	528	1,848	23	
	lb/hr (max)	271	441	523	45	
	tons/year	17	11	11	3	38
CO	lb/event	3,180	7,820	10,200	360	
	lb/hr (max)	3,252	4,838	18,862	2,741	
	tons/year	331	156	61	47	534
VOC (w/formaldehyde)	lb/event	2,860	5,920	6,520	380	
	lb/hr (max)	2,781	4,306	4,306	2,753	
	tons/year	297	118	39	49	452
Formaldehyde	lb/event	780	1,360	1,580	120	
	lb/hr (max)	860	862	862	862	
	tons/year	81	27	9	16	119
Total PM	lb/event	26	45	54	4	
	lb/hr (max)	33	33	33	22	
	tons/year	3	5	6	0.42	11
Duration	minutes	108	196	229	12	
No of events per year		188	36	11	212	

[b] 2X1 M501JAC Combined Cycle Emissions. Mitsubishi Hitachi Power System

The fire water pump and emergency generator will be ULSD fuel fired. The fire water pump has a rating of 240 HP and the emergency generator is rated at 1,000 kW. The fire water pumps and emergency generators will be limited to 100 hrs/year of operation, respectively.

The estimated emissions for the fire water pump, emergency generator, and fuel gas heaters are presented in Table 3-3.

3.1.4 Facility Wide Maximum Potential Annual Emission Rates

A summary of the potential annual emission rates for the entire Longview Unit 2 Project (combustion turbines/duct burners, startup/shutdown and engines/pumps) is provided in Table 3-4. The potential annual emissions presented are for two CTs and Operating Case No 27 in Table 3-1 which is an average day, 100% CTG load, duct firing, and evaporation on.

3.2 HAZARDOUS AIR POLLUTANT EMISSIONS

A summary of the potential annual hazardous air pollutant (HAP) emissions from the combustion turbines and duct burners is provided in Table 3-5. The emissions for all HAPs except formaldehyde and hexane are uncontrolled emissions and were calculated using emission factors contained in AP-42 Section 3.1 for Stationary Gas Turbines (April, 2000). The emissions for formaldehyde and hexane was developed using USEPA AP-42 emission for hazardous air pollutants from natural gas-fired stationary gas turbines and duct burners (Table 3.1-3, April, 2000 and Tables 1.4-2,3,4, respectively) and then assuming 70% removal for formaldehyde and 30% removal for hexane by the catalytic oxidation system. These removal rates are based on information provided by the vendor of the catalytic oxidation system. These removal efficiencies are consistent with USEPA December 30, 1999 Memorandum "Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines" which stated that the removal efficiencies of a CO catalyst are expected to be similar to that of a $SCONO_x$ catalyst which have been demonstrated through testing to be at least 90% for formaldehyde. Therefore, using a removal efficiency of 70% for formaldehyde and 30% for hexane results in a conservatively high estimate of the expected formaldehyde and hexane

Table 3-3

Potential Maximum Hourly and Annual Emissions from the Fire Water Pump, Emergency Generator, Spray Dryer and Mechanical Draft Tower

Pollutant	Fire Water Pump[c]		Emergency Generator		Fuel Gas Heaters (2)		Cooling Tower	
	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tons/year)	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tons/year)	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tons/year)	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tons/year)
NO_x	4.55	0.228	15.2	0.76	0.19	1.70	0.0	0.0
VOCs	0.302	0.015	1.01	0.051	0.04	0.33	0.0	0.0
CO	1.27	0.063	8.76	0.44	0.21	1.83	0.0	0.0
$PM/PM_{10}/PM_{2.5}$	0.841	0.042	0.505	0.025	0.04	0.37	4.11	18.0
SO_2	0.492	0.025	0.027	0.001	0.01	0.06	0.0	0.0
GHG	418	20.9	1,427	71.3	712	6,240	0.0	0.0

[c] Fire water pump and emergency generator limited to 100 hrs/yr of operation.

Table 3-4

Facility Wide Maximum Potential Annual Emissions

Pollutant	Combustion Turbine and Duct Burner (tons/year)	Other Sources[d] (tons/year)	Startup and Shut down (tons/year)	Cooling Tower (tons/year)	Total Facility Wide Annual Emissions (tons/year)
NO_x	262	2.69	37.6	0	302
VOCs	51.4	0.40	451.5	0	503
CO	157	2.33	533.9	0	693
$PM/PM_{10}/PM_{2.5}$	179	0.44	10.9	18	208
SO_2	38.6	0.09	NA	0	38.7
H_2SO_4	32.5	0	NA	0	32.5
GHG	3,925,364	6332.22	NA	0	3,931,696

[d] Includes cooling tower, fire water pump and emergency generator. Fire water pump and emergency generator limited to 100 hrs/yr of operation.

Table 3-5
Annual HAP Emissions[e] (tons/year)

Hazardous Air Pollutant	Combustion Turbine	Duct Burners	Auxiliary Generator	Fire Pump	Total Facility Emissions
1,3-Butadiene	6.83E-03			5.30E-06	6.84E-03
2 Methylnaphthalene		2.38E-05			2.38E-05
Acetaldehyde	6.35E-01			1.04E-04	6.36E-01
Acrolein	1.02E-01			1.25E-05	1.02E-01
Arsenic		2.38E-04			2.38E-04
Benzene	1.91E-01	2.08E-03	5.03E-04	1.27E-04	1.93E-01
Beryllium		1.19E-05			1.19E-05
Cadmium		1.09E-03			1.09E-03
Chromium		1.09E-03			1.09E-03
Cobalt		1.39E-03			1.39E-03
Dichlorobenzene		1.19E-03			1.19E-03
Ethylbenzene	5.08E-01				5.08E-01
Formaldehyde	3.38	3.03E-01	5.12E-05	1.60E-04	3.69
Hexane		1.25			1.25
Manganese		8.33E-05			8.33E-05
Mercury		3.77E-04			3.77E-04
Naphthalene	2.07E-02	6.05E-04	8.43E-05	1.15E-05	2.14E-02
Nickel		2.58E-04			2.58E-04
Phenanathrene		1.69E-05	2.65E-05	3.99E-06	4.73E-05
Propylene Oxide	4.61E-01				4.61E-01
Toluene	2.07	3.37E-03	1.82E-04	5.55E-05	2.07
Xylene	1.02			3.87E-05	1.02
Total HAPS					9.96

e [a]Combustion turbine HAP emissions per AP-42 (Table 3.1-3) and Duct Burner HAP emissions per AP-42 (Table 1.4-2,3,4) except for formaldehyde, and hexane. Formaldehyde, hexane emissions assume 70 and 30% control efficiency, respectively.

emissions from the Longview Unit 2 Project[a]. Additionally, the AP-24 HAP emission factors for natural gas fired combustion turbines are based on combustion turbine data such as jet derivatives or smaller Frame 3 turbines which are significantly different and thus not representative of combustion turbine technology proposed for the Longview Power Unit 2 Project. Uncontrolled emission factors provided by the turbine manufacturer were lower than AP-42 factors and would result in significantly lower uncontrolled emissions.

As seen from Table 3-5, the emissions from the proposed facility are 9 tons/year and will not exceed 10 tons per year for any single HAP or 25 tons per year for HAPs in aggregate. Therefore, the proposed facility is not a major source of HAP emissions and will not be subject to Maximum Achievable Control Technology (MACT) (See Section 4 Regulatory Review).

The HAPs emissions from Longview Unit 2 Project were also combined with the estimated HAPs emissions from Longview Unit 1 to assess the applicability of the HAPs regulation on the total Longview Power facility, although the Unit 2 is considered a separate facility. The estimated HAPS emissions from Unit 1 are 13 tons/year (from information contained in the Unit 2 PSD Application, March 2003). Thus, the total HAPs emissions from Unit 1 and 2 are estimated to the 22 tons/year and below the 25 tons/year threshold.

3.4 PSD AND NSR APPLICABILITY DETERMINATION

The potential annual emission rates associated with the proposed Longview Unit 2 Project are used to determine the applicability of PSD and non-attainment New Source Review (NSR) requirements. PSD applicability is determined by comparing the potential emission rate from the project for each criteria pollutant that is in attainment with the National Ambient Air Quality Standards (NAAQS) to the respective significant emission threshold levels. The Longview Unit 2 Project will be located in Monongalia County, West Virginia that is designated as "in attainment" or "unclassifiable" for all regulated air pollutants so nonattainment NSR review does not apply.

[a] The definition of a "major source" of HAPs in Section 12(a)(1) of the 1990 Clean Air Act Amendments is any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has a potential to emit considering controls, 10 tons per year (tpy) or more of any HA or 25 tpy or more of any combination of HAPs. Accordingly, "in drafting Section 112 Congress specifically directed EPA to consider controls in determining which producers should be classified as "major sources." See also National Mining Ass'n v. EPA, 59 F.3d 1351, 1361-65 (D.C. Cir. 1995).

Table 3-6
Project Comparison of Facility Wide Maximum Emissions to PSD Significance Levels[f]

Pollutant	Annual Emissions (tons per year)	PSD/NSR Significance Level (tons/year)	PSD/NSR Pollutant
NO_x	302	40	Yes
VOCs	503	40	Yes
CO	693	100	Yes
$PM/PM_{10}/PM_{2.5}$	208	25/15/10	Yes
SO_2	38.7	40	No
H_2SO_4	32.5	7	Yes
Lead	0.0005	0.6	No
Beryllium	1.19E-05	0.004	No
Mercury	3.77E-04	0.1	No
GHG	3,931,696	100,000	Yes

[f] The facility is classified as a major stationary source pursuant to 40 CFR 52.2§(b)(1)(i)(a). It is a fossil fuel fired steam generating unit > 250 MMBtu/hr with projected emissions of at least one criteria pollutant > 100 tons/yr.

The Project triggers PSD applicable since it is a new source "listed" 100 TPY source under 40 CFR 52.21 and the project's potential to emit of at least one criteria pollutant is greater the PSD significant emission levels presented in Table 3-6. As seen from this table the proposed project is subject to federal PSD requirements for NO_x, VOC, CO, particulates (PM/PM_{10} and $PM_{2.5}$), H_2SO_4, and GHG.

4. REGULATORY REVIEW

SECTION 4

4. REGULATORY REVIEW

The following section contains an assessment of federal and State of West Virginia air regulations that are potentially applicable to the proposed Longview Power Unit 2 project. The Federal regulation are described in Subsection 4.1 and the State of West Virginia regulation are described in Subsection 4.2

4.1 FEDERAL REGULATIONS

For the purpose of this application, the following federal regulations have been reviewed for potential applicability to the Longview Power Unit 2:

- Standards of Performance for New Stationary Sources(NSPS)
- Prevention of Significant Deterioration (PSD) Regulations
- National Emission Standards for Hazardous Air Pollutants (NESHAP)
- Accidental Release Prevention (RMP)
- Compliance Assurance Monitoring (CAM)

A review of each specific federal requirement is provided in the following subsections.

4.1.1 New Source Performance Standards (NSPS)

The United States Environmental Protection Agency (EPA) has promulgated standards of performance for specific sources of air pollution at 40 CFR Part 60, Subparts A through UUUU. The following Subparts are determined to be applicable to the proposed project:

- Subpart A - General Provisions,
- Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units
- Subpart KKKK - Standards of Performance for Stationary Gas Turbines.
- Subpart TTTT - Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units
- Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

4.1.1.1 Subpart A - General Provisions

Certain provisions of 40 CFR Part 60 Subpart A apply to the owner or operator of any stationary source subject to a NSPS. Since the combustion turbines (Subpart KKK) and the Heat Recovery Steam Generators (HRSGs) will be subject to a NSPS, Longview Power Unit 2 will be required to comply with all applicable provisions of Subpart A.

4.1.1.2 Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam

Pursuant to §60.40b(a), the affected facility to which Subpart Db applies is each steam generating unit that is capable of combusting greater than 29 megawatts (100 million Btu/hour) heat input for which construction, reconstruction or modification is commenced after June 19, 1984. The duct burners meet these requirements and are potentially subject to the applicable requirements of Subpart Db.

Per §60.44b, NOx emissions are limited to either 0.10 lb/mmbtu or 0.20 lb/mmbtu depending on whether the boiler has a low or high volumetric heat release. Per §60.48b(b) the Project must install, calibrate and maintain a Continuous Emissions Monitoring System (CEMS) for NO_x and O_2 (or CO_2).

Section §60.49b(a) outlines the notification of construction and actual startup requirements that the Project will be subject and Sections §60.48b(b) and (g) outline the monitoring and record-keeping requirements.

4.1.1.3 Subpart KKKK - Standard of Performance for Stationary Gas Turbines

Pursuant to §60.4305(a), Subpart KKKK applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 mmbtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005. Therefore, the Longview Power Unit 2 combustion gas turbines are subject to 40 CFR 60 Subpart KKKK.

Section §60.4320 requires that combustion gas turbines meet the NO_x emission standards in Table 1 of the Subpart. Since the combustion gas turbines at Longview Power Unit 2 will be new and greater than 850 mmbtu/hr each, Table 1 requires that they meet a NO_x emission limit of 15 ppmvd at 15% oxygen or 0.43 lb/MW-hr gross energy output.

Section §60.4330(a)(1) and (2) requires that the turbines meet an SO_2 standard of either 0.90 lb/MW-hr gross energy output or 0.060 lb/mmbtu heat input.

Subpart KKKK includes general compliance requirements (60.4333), monitoring requirements reporting requirements (60.4375-60.4395), and performance testing requirements (60.4400-60.4415).

4.1.1.4 Subpart TTTT: Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

Since the Longview Power Unit 2 consists of a "stationary combustion turbine that commenced construction after January 8, 2014" or commenced "reconstruction" after June 18, 2014 that has a "base load rating greater than 260 GJ/h (250 mmbtu/h) of fossil fuel (either alone or in combination with any other fuel)" and "serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system" it will be subject to Subpart TTTT. Table 2 of Subpart TTTT limits CO2 emissions from new stationary combustion turbines to 1,000 pounds of CO2 per megawatt-hour on a gross energy output basis on a 12-operating month rolling average.

4.1.1.5 Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Subpart IIII contains requirements relating to the performance of compression ignition engines. The Longview Power Unit 2 will use a fire water pump and an emergency generator that are Subject to Subpart IIII. Pursuant to §60.4200, compression ignition engines manufactured after July 11, 2005 are subject to the subpart. Therefore, Subpart IIII will be applicable to the fire water pump engine and the emergency generator at the proposed Longview Power Unit 2.

§60.4204 and §60.4205 sets the following standards for the engines (all standards in g/hp-hr): Fire Water Pump Engine 3 g/hp-hr NOx, 2.6 g/hp-hr CO, 0.15 g/hp-hr PM and the Emergency Generator 4.8 g/hp-hr NOx, 2.6 g/hp-hr CO and 0.15 g/hp-hr PM.

Since both engines have a displacement of less than 30 liters per cylinder, per §60.4207 (b), they must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

4.1.2 Prevention of Significant Deterioration (PSD)

PSD permitting requirements apply to projects considered a "major modification" or "major" stationary source located in an area designated as "in attainment" or "unclassifiable" for any criteria pollutant. The Longview Unit 2 project will be located in an area that is designated as "in attainment" or "unclassifiable" for all regulated air pollutants except ozone. A "major" stationary source is defined at 40 CFR § 52.21(b)(1)(i) as any source with the potential to emit greater than 250 tons per year of any regulated air pollutant or any stationary source defined as one of the 28 source categories listed in 40 CFR § 52.21(b)(1)(i)(a) with the potential to emit greater than 100 tons per year of any regulated air pollutant. Electric generation facilities are among the 28 listed 100- tons/year source categories. Major modification means any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase of a regulated NSR pollutant.

The Longview Power Unit 2 is a new "major" source since is a listed source (electric generation facilities) with potential to emit more than 100 tons/year of a regulated NSR pollutants in excess of the significant emission increase limits. Since the proposed source is new major source, any regulated (attainment) pollutant, which exceeds the significant emissions threshold, is subject to a PSD review. The Longview Unit 2 project has established expected potential emission levels reflecting the combustion and control equipment to be installed at the proposed facility. The new facility will result in a significant emissions increase of NO_2, PM/PM_{10} CO, VOC and H_2SO_4.(see Table 3-6). The PSD application for the project must include the following analyses for each PSD significant pollutant:

- BACT analysis.
- PSD increment consumption analysis, including other increment consuming sources in the area.
- NAAQS impact analysis.
- Class I area impact analysis.
- Additional impact analysis.

For each proposed emission unit, a control technology must be selected that will result in the maximum reduction in pollutant emissions considered achievable using current technology while considering energy requirements, environmental impacts, and economic impacts. The methodology used to determine BACT follows the "Top Down" approach recommended by the EPA in "New Source Review Workshop Manual", October 1990. The "Top Down" methodology requires the applicant to first evaluate the control technology which results in the maximum level of emission reduction for a similar source which is currently available. A detailed explanation of the "Top Down" applicable is presented in Section 5. If it is demonstrated that this level of control is not technically or economically feasible for the source under evaluation, then the next most stringent level of control is evaluated. The process continues until an acceptable level is identified. A "Top Down" BACT analysis for each significant attainment pollutant was performed and is described in Section 5 of this application.

Federal PSD increments are established for $PM_{2.5}$, $PM_{10,}$ SO_2 and NO_2. As part of the PSD regulations, an ambient air quality analysis is required to demonstrate that the PSD increment consumed by the proposed project for $PM_{2.5}$, $PM_{10,}$ and NO_2 does not exceed or contribute to a concentration that exceeds the PSD increments. As part of the air quality impact analysis, a preliminary dispersion modeling analysis was performed for those pollutants, with emission above the significance levels. The pollutants for which preliminary modeling analyses were performed were NO_2, $PM/PM_{10}/PM_{2.5}$, and CO. The air quality analysis conducted for this project has indicated that the potential emissions associated with this project would result in predicted ambient pollutant concentrations that are above the PSD significant ambient impact levels for NO_2 and $PM_{2.5}$ but below the significant impact levels for CO. Accordingly, no further air quality modeling analysis is required for CO. (See October 1990 New Source Review Workshop Manual, Figure C-3, page C.27).

The Air Quality Modeling Analysis in Section 6 provides the detailed results and discussion of all air quality analyses performed for this project.

4.1.3 Acid Rain Provisions

The Acid Rain Program, codified at Parts 40 CFR 72 through 78, applies to:

- Electric generating units specifically identified in Table A to Section 404 of the Clean Air Act Amendments of 1990. These units are subject to Phase I of the Acid Rain Program.

- Electric generating units that commenced commercial operation after November 15, 1990 and serve a generator rated at greater than 25 MW nameplate capacity. These units are subject to Phase II of the Acid Rain Program.

Longview Power Unit 2 is subject to Phase II of the Acid Rain Program as the facility will serve a generator rated at over 25 MW. Applicability, or non-applicability, and requirements of specific sections of the Acid Rain Program are addressed in the following subsections.

4.1.3.1 Permit Regulations (40 CFR Part 72)

Longview Power Unit 2 is required to submit a Phase II Acid Rain Permit Application to the Administrator (i.e., DEP) pursuant to 40 CFR 72.30(b)(2)(ii) at least 24 months prior to the date on which the unit commences operation. The permit application must include information on the Designated Representative, general plant information, specific unit information, and a compliance plan for each affected unit, the date the unit will commence operating and the deadline for minor certification. The application forms were developed and are administered by the EPA. The Acid Rain Permit, when issued, will apply for 5 years.

4.1.3.2 Sulfur Dioxide Allowance System (40 CFR Part 73)

Sulfur Dioxide "allowances", defined as the permission to emit 1 ton of actual SO_2 emissions in any given year, are delineated in 40 CFR Part 73 for specific sources subject to Phase I and certain sources subject to Phase II of the Acid Rain Program. Longview Power Unit 2 is a new source and is subject to Phase II of the program. However, no allowances have been specifically distributed to new Phase II sources. As a new source, Longview Power Unit 2 will be required to obtain SO_2 allowances equivalent to the actual annual SO_2 emissions from the facility each year. Longview Power Unit 2 will need to purchase SO_2 allowances via the auction or direct sale process outlined in 40 CFR Part 73, Subpart E. Regardless of the means used to obtain the allowances, the Allowance Tracking System outlined in 40 CFR Part 73, Subpart C requires that all subject sources hold and identify SO_2 allowances for deduction within 60 days of the end of the calendar year (i.e., by March 1 or 2). The amount of allowances for deduction are determined based on the formula in 40 CFR § 72.95, but are typically equivalent to the total actual SO_2 emissions from the facility for the previous year. The maximum potential SO_2 emissions are estimated to be 99 tons per year.

4.1.3.3 Sulfur Dioxide Opt-Ins (40 CFR Part 74)

Part 74 is not applicable to Longview Power Unit 2 as the facility will be subject to the Acid Rain Program and will not be "opting-in" to the Program.

4.1.3.4 Continuous Emissions Monitoring (40 CFR Part 75)

Part 75 establishes requirements for the monitoring, record keeping, and reporting of sulfur dioxide, carbon dioxide and volumetric flow from units subject to the Acid Rain Program. Provisions for the substitution of missing data, specifications for Data Acquisition and Handling Systems (DAHS) and quality assurance and quality control procedures are also outlined. Multiple options are provided for monitoring a variety of exhaust configurations. Options for alternative monitoring in lieu of CEMS are provided for low mass emissions units and/or units that burn low sulfur fuels.

Since Longview Power Unit 2 will only burn natural gas, the project has chosen to follow the optional SO_2 emissions data protocol for gas-fired units in Appendix D to Part 75. Pursuant to Appendix D, Longview Power Unit 2 will monitor SO_2 emissions by monitoring fuel flow pursuant to Section 2.1 and by applying a standard emission factor (0.0006 lb/MMBtu) representative of SO_2 emissions from pipeline quality gas in accordance with the procedures outline in Section 2.3.2. Longview Power Unit 2 will provide information on the contractual sulfur content from the pipeline gas supplier demonstrating that the gas has an H_2S content of less than 1 gr/100 scf and a Total Sulfur content of less than 20 gr/100 scf in the monitoring plan. Hourly SO_2 emissions will be calculated for each operating day.

4.1.3.5 Acid Rain Nitrogen Oxides Emission Reduction Program (40 CFR Part 76)

This part only applies to coal-fired utility units subject to an Acid Rain emissions limitation or reduction requirement for SO_2 under Phase I or II. **Longview Power Unit 2 will not be capable of firing coal thus this part is not applicable.**

4.1.3.6 Excess Emissions (40 CFR Part 77)

Excess emissions are defined as actual emissions in any calendar year greater than the ***Acid Rain Emissions Limitation*** established at 40 CFR Part 72 (i.e., in the acid rain permit). Sources with excess emissions in any calendar year are required to submit an "offset plan". A separate offset plan for each affected unit must be submitted to the Administrator within 60 days following the end of the calendar year.

4.1.3.7 Appeal Procedures for Acid Rain Program (40 CFR Part 78)

Part 78 establishes a regulatory vehicle for facilities that wish to contest any determinations made by the Administrator with respect to 40 CFR Part 77 - Excess Emissions. Part 78 will only be applicable in the event Longview Power Unit 2 has future excess emissions and decides to enter an appeal regarding their determination or the subsequent penalties.

4.1.4 National Emission Standards For Hazardous Air Pollutants (NESHAP)

NESHAP promulgated prior to the Clean Air Act Amendments (CAAA) of 1990, found in 40 CFR Part 61, apply to specific compounds emitted from specific processes. **None of the pollutant specific Part 61 NESHAPs apply to the Longview Power Unit 2.**

Pursuant to the CAAA of 1990, NESHAP specific to processes identified as emitters of listed hazardous air pollutants (HAPs) are promulgated at 40 CFR Part 63. These Part 63 "process-specific" NESHAP require affected sources to meet emission levels consistent with the Maximum Achievable Control Technology (MACT) and are typically referred to as "MACT standards". Specifically listed area sources or stationary sources with the potential to emit greater than 10 tpy of a single listed HAP or over 25 tpy of a combination of HAPs are potentially subject to the MACT standards. The total potential HAP emissions for the Longview Unit 2 project are projected to be less than 25 tons/yr for all HAPs combined. Therefore, the Project is not considered a major HAP source, and so no source-specific MACT standards apply.

Some MACT standards, known as "area source MACT" standards, apply to minor source HAP facilities (sources with less than 10/25 ton/yr HAP thresholds). The area MACT standards that apply to emission units at Longview Power Unit 2 are discussed in the following section

4.1.4.1 Subpart ZZZZ: National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Stationary reciprocating internal combustion engines that are not being tested at a stationary RICE test cell/stand are subject to Subpart ZZZZ (40 CFR Part 63.6585). Therefore, Subpart ZZZZ will be applicable to the fire water pump engine and the emergency generator at the proposed Longview Power Unit 2.

New stationary RICEs at area sources of HAPs must meet the requirements of 40 CFR 60 Subpart IIII (see previous discussion and 40 CFR Part 63.6590(c)(1)). No other requirements apply to such engines.

4.1.5 Compliance Assurance Monitoring (CAM)

Pursuant to requirements concerning enhanced monitoring and compliance certification under the Clean Air Act Amendments of 1990, the EPA has promulgated regulations codified at 40 CFR Part 64 to implement compliance assurance monitoring (CAM) for major stationary sources of air pollution. The CAM regulations require owners or operators of such sources to conduct monitoring that satisfies particular criteria to provide a reasonable assurance of compliance with applicable standards. The requirements of this part apply to all pollutant-specified emissions units at a major stationary source if the emissions unit satisfies the following criteria:

- The unit is subject to an emission limitation or standard for the applicable regulated air pollutant.
- The unit uses a control device (as defined in 40 CFR § 64.1) to achieve compliance with the emission limitation or standard.
- The unit has the potential to emit (before the use of controls) emissions of the applicable air pollutant that are greater than 100 percent of the amount required for a source to be classified as a major source.

Emissions units that are subject to specific applicable requirements identified in 40 CFR § 64.2 (b) are exempt from CAM. These exempt applicable requirements are listed below:

- §64.2 (b)(1)(i) - Post-11/15/90 NSPS or NESHAP.
- §64.2 (b)(1)(ii) - Stratospheric ozone protection requirements.
- §64.2 (b)(1)(iii) - Acid Rain Program requirements.
- §64.2 (b)(1)(iv) - Emission limitations, standards, or other requirements that apply solely under an approved emission trading program.

- §64.2 (b)(1)(v) - Emissions cap that meets requirements of §70.4 (b) (12).
- §64.2 (b)(1)(vi) - Emission limitations or standards for which a Title V permit specifies a continuous compliance determination method that does not use an assumed control factor. Continuous emission monitoring systems (CEMS) which are used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard and provide data in units of the standard.

Since the combustion turbines will be subject to several of these applicable requirements listed above including the NSPS requirements and Title V permit continuous compliance methods, the Longview Power Unit 2 will be exempt from the CAM rule.

4.1.6 Accidental Release Prevention

Section 112(r) of the Clean Air Act Amendments of 1990 mandates that EPA promulgate regulations and develop guidance to prevent, detect, and respond to accidental releases of toxic chemicals. Stationary sources covered by these regulations must develop and implement a risk management program that includes a hazard assessment, a prevention program, and an emergency response program. The risk management program must be described in a risk management plan (RMP) that must be registered with EPA, submitted to state and local authorities, and be made available to the public.

A facility is subject to 40 CFR Part 68 if a "process" contains a regulated substance in a quantity equal to or greater than the threshold quantities listed in 40 CFR §68.130. Threshold quantities for compounds associated with the proposed combustion turbines are summarized in the Table 4-1.

4.2 STATE OF WEST VIRGINIA REGULATIONS

4.2.1 45 CSR 1 - NO_x Budget Trading Program

45 CSR 1 sets forth NO_x budget trading requirements for boilers, combustion turbines and combined cycle systems greater than 250 MMBtu/hr and are providing 25 MW of electrical power for sale. This Rule follows the intent of 40 CFR Part 96 for non-electric generating units, while 45 CSR 26 (pending EPA approval) will apply to electric generating units. The Longview Power Project will be subject to the NO_x trading program and will be required to control emissions to the applicable emission limitation and obtain NO_x allowances..

Table 4-1

Accidental Release Program
Threshold Quantities

Compound	Threshold Quantity (lbs)
Ammonia, aqueous (conc. ≥20% by wt.)	20,000

4.2.2 45 CSR 2 - Prevention and Control of Particulate Air Pollution Indirect Heat Exchanger PM Emissions

45 CSR 2 sets forth particulate and opacity emission standards for combustion of fuels from indirect heat exchangers. The rule also requires the control of particulate fugitive emissions from combustion-related source operations. Section 3.1 will limit opacity from all fuel burning sources to 10% (6-minute average). This regulation applies to the combustion turbine/HRSG at the Longview Power Unit 2 project. The particulate emission limit in Section 4.1 applies to the duct burners (a type "a" fuel burning unit).

4.2.3 45 CSR 3 - Air Pollution from Hot Mix Asphalt Plants

There will be no affected sources at Longview Power Unit 2.

4.2.4 45 CSR 4 - Objectionable Odors

45 CSR 4 sets forth regulations prohibiting the discharge of air pollutants, which cause or contribute to an objectionable odor at any location occupied by the public. The Longview Power Project will comply with the provisions of this regulation though good operating practices.

4.2.5 45 CSR 5 - PM Emissions from Coal Preparation and Handling Plants

There will be no affected sources at Longview Power Unit 2.

4.2.6 45 CSR 6 - Air Pollution from the Combustion of Refuse

The proposed Longview Power Unit 2 will not combust any refuse material as defined by 45 CSR 6. The only fuels to be utilized are pipeline natural gas and ultra-low sulfur diesel fuel.

4.2.7 45 CSR 7 - Prevention and Control of Particulate Matter Emissions from Manufacturing Processes and Associated Operations

There will be no affected sources at Longview Power Unit 2.

4.2.8 45 CSR 7A - Compliance Test Procedures for 45 CSR 7 for PM

There will be no affected sources at Longview Power Unit 2.

4.2.9 45 CSR 8 - Ambient Air Quality Standards for Sulfur Dioxide and Particulate Matter

The DAQ has adopted the national ambient air quality standards for both sulfur dioxide and particulate matter. The air quality modeling analysis in Section 6 of this permit application demonstrates that the proposed Longview Power Unit 2 will be in compliance with these respective ambient air quality standards.

4.2.10 45 CSR 9 - Ambient Air Quality Standards for Carbon Monoxide and Ozone

The DAQ has adopted the national ambient air quality standards for carbon monoxide and ozone. The air quality modeling analysis in Section 6 demonstrates that the proposed Longview Power Un it 2 will be in compliance with carbon monoxide standard.

4.2.11 45 CSR 10 - Prevention and Control of Sulfur Oxide Emissions

45 CSR 10 sets forth standards for emissions of sulfur oxides from fuel burning units, manufacturing process source operations, and process gas streams. The primary fuel burning unit at the proposed Longview Power Unit 2 are the natural gas combustion turbines and duct burners. However, the combustion turbines themselves do not meet said definition because they do not produce power through *indirect heat transfer.*

An Indirect Heat Exchanger' as defined in 45 CSR 10, means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. *This term includes any duct burner that combusts fuel and is part of a combined cycle system"*

The primary purpose of the duct burners are to generate steam to produce electricity for sale which defines the duct burners as type "a" fuel burning units under 45 CSR 10. For type "a" units, 45 CSR 10 lists SO_2 limits for specific existing units but does not have a generic limit for new units.

Therefore, there is no SO_2 mass emission standard for the duct burners under 45 CSR 10.

4.2.12 45 CSR 10A - Testing, Monitoring, Recordkeeping and Reporting Requirements for 45 CSR 10

There will be no affected sources at Longview Power Unit 2.

4.2.13 45 CSR 11 Prevention of Air Pollution Emergency Episodes

45 CSR 11 sets forth actions that must be taken in the event of air pollution episodes. The Longview Power Unit 2 will, if required, prepare a Standby Plan, which will outline procedures that will be taken, to comply with the provisions of this regulation.

4.2.14 45 CSR 12 Ambient Air Quality Standard for Nitrogen Dioxide

The DAQ has adopted the national ambient air quality standards for nitrogen dioxide. The air quality modeling analysis in Section 6 demonstrates that the proposed Longview Power Unit 2 will be in compliance with nitrogen dioxide standard.

4.2.15 45 CSR 13 - Permitting Requirements for the Construction, Modification, Relocation and Operation of Minor Stationary Sources

45 CSR 13 sets forth the criteria and procedures for obtaining an air permit for a minor modification or relocation of an existing stationary source or for the construction of a new minor stationary source of air pollutants. This regulation does not apply to "de mimimus" sources identified in Table 45-13B or sources which have emissions of regulated air pollutants below the thresholds set forth 45-13.2.24. The Longview Power Unit 2 Project is submitting this permit application pursuant to the permitting provisions of 45 CSR 13 since SO_2 and Pb are below threshold.

4.2.16 45 CSR 14 Prevention of Significant Deterioration Permitting Requirements for the Construction of a Major Stationary Source

The proposed Longview Power Unit 2 Project is considered a "major stationary source" since it potentially emits at least one regulated air pollutant greater than 100 tons per year. As shown in Table 3-6, emissions of $PM/PM_{10}/PM_{2.5}$, CO, NO_x, VOC, and H_2SO_4, exceed significant threshold values and, as a result, trigger Prevention of Significant Deterioration (PSD) requirements under 45 CSR 14. This permit application addresses the major source permitting requirements for those triggering air pollutants.

4.2.17 45 CSR 16 - Standards of Performance for New Stationary Sources

45 CSR 16 adopts the federal emission standards for new stationary sources (Part 60) by reference. As stated above, the Longview Power Unit 2 will be subject to Subpart KKKK and IIII.

4.2.18 45 CSR 17 - Fugitive Emissions from Material Handling/Fugitive Sources

There will be no affected sources at Longview Power Unit 2

4.2.19 45 CSR 19 - New Source Review Permitting for Non-Attainment Areas

The proposed Longview Power Unit 2 Project is not located in any area designated as non-attainment for any criteria air pollutant. But Pennsylvania is in the Ozone Transport Region (OTR) and is considered moderate nonattainment for Ozone. The OTR is the region designated by section 184 of the federal Clean Air Act and comprised of the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and the Consolidated Metropolitan Statistical Area that includes the District of Columbia and northern Virginia. It is essentially a single 13 state nonattainment area.

The proposed project is significant for NO_x, a precursor for the formation of Ozone. But the air quality modeling analysis demonstrated that the proposed project will not significantly impact (predicted air quality concentration below the significance levels in 45 CDS 19, 3.3a) for NOx in the OTR. Therefore, the proposed project is not significantly contributing to the nonattainment of ozone.

4.2.20 45 CSR 20 - Good Engineering Practice as Applicable to Stack Heights

45 CSR 20 is promulgated to ensure that the degree of emission limitation required for the control of any air pollutant is not affected by that portion of the stack height which exceeds good engineering practice (GEP) or any other dispersion technique. Good engineering practice is defined as the greater of 65 meter above grade or the results of one of several GEP estimating methodologies. The results of a GEP stack height analysis are presented in Section 6.2.9 of the air quality modeling analysis. The results demonstrate that the stacks serving the various sources will not exceed GEP stack height.

4.2.21 45 CSR 21 - VOC Emission Standards

The proposed Longview Power Unit 2 is not located in an affected area which must comply with 45 CSR 21.

4.2.22 45 CSR 22 Air Quality Management Fee Program

45 CSR 22 specifies a program to collect fees with for certificates to operate and for permits to construct, modify or relocate sources. The fees are assessed based on which regulations the new or modified source is subject. Based on the requirements of 45-22-3, the fee for the permit-to-construct is $12,000 which includes 45CSR13, NSPS and PSD fee requirements.

4.2.22.1 45 CSR 23 - Emissions From Municipal Solid Waste Landfills

There are no affected sources at the proposed Longview Power Unit 2.

4.2.23 45 CSR 24 - Emissions From Hospital/Medical and Infectious Waste Incinerators

There are no affected sources at the proposed Longview Power Unit 2.

4.2.24 45 CSR 25 - Emissions From Hazardous Waste TSD Facilities

There are no affected sources at the proposed Longview Power Unit 2.

4.2.25 45 CSR 27 - Emissions of Toxic Air Pollutants

The proposed Longview Power Unit 2 will not operate any “chemical processing units” as defined in 45-27-2.4 and does not use listed chemicals.

4.2.26 45 CSR 28 - Air Pollutant Emissions Banking and Trading

The Longview Power Project does not intend to bank or trade any air pollutant emissions.

4.2.27 45 CSR 29 – Emission Statements for VOCs and NOx

The proposed Longview Power Unit 2 is not located in an affected area.

4.2.28 45 CSR 30 - Title V Operating Permit Requirements

Within 12 months of commercial operation, Longview Power Unit 2 will submit a Title V operating permit application for proposed facility for DAQ review and approval. The required air quality management fee will also be submitted.

4.2.29 45 CSR 33 Acid Rain Permits

Under 45 CSR 33 regulations, DAQ is the permitting authority for federal acid rain program. Specifically, the agency has adopted the provisions of federal program in its entirety including Parts 72, 74, 75, 76 and 77. The proposed Longview Power Unit 2 will be subject to the applicable provisions of 45 CSR 33.

4.2.30 45 CSR 34 - Emission Standards for Hazardous Air Pollutants for Source Categories

45 CSR 34 adopts the federal emission standards for hazardous air pollutants (Parts 61, 63 and Section 112 of the Clean Air Act) by reference. As stated previously, the fire water pump engine and the emergency generator will be subject to Subpart ZZZZ.

5. CONTROL TECHNOLOGY EVALUATION

SECTION 5

5. CONTROL TECHNOLOGY EVALUATION

5.1 APPLICABLE REGULATORY PROGRAMS

Several federal and state regulatory programs require the potential implementation of emissions controls for the proposed project. The applicability of these programs is determined by a variety of factors including, but not limited to, pollutant type, pollutant emission rate, and facility location. Based on the information presented in the Regulatory Review (Section 4) and the Emissions Inventory (Section 3) sections of this application, the applicable control programs based on the project parameters are shown in Table 5-1.

The control technology selection process and the control technologies selected for each pollutant are presented in the following Sections:

- Section 5.2 – Combined Cycle Combustion Turbine System
- Section 5.3 – Emergency Generator/Fire Pump
- Section 5.4 – Fuel Gas Pre Heaters
- Section 5.5 – Cooling Tower
- Section 5.7 – Facility Wide Summary

5.1.1 Best Available Control Technology

A BACT analysis must be conducted for emissions of NO_X, CO, particulate matter and PM_{10}, and SO_2. BACT determinations are case-by-case analyses that involve an assessment of the availability of applicable technologies capable of sufficiently reducing a specific pollutant emission, as well as the economic, energy, and environmental impacts of using each technology.

The methodology used in this study to determine BACT follows the "top-down" approach outlined in Chapter B of the EPA Draft *"New Source Review Workshop Manual"* dated October 1990. A "top-down" BACT analysis contains the following elements:

- Determination of the most stringent control alternatives potentially available

Table 5-1

Summary of Applicable Regulatory Control Programs

Applicable Pollutant(s)	Project Emissions (TPY)	PSD Applicable (Yes/No)	Governing Control Program(s)
Nitrogen Oxides (NO_x)	302	PSD	Best Available Control Technology (BACT)
Volatile Organic Compounds (VOC)	503	PSD	BACT
Carbon Monoxide (CO)	693	PSD	BACT
Particulate Matter	208	PSD	BACT
Particulate Matter less than 10 micron (PM_{10})	208	PSD	BACT
Particulate Matter less than2.5 micron ($PM_{2.5}$)	208	PSD	BACT
Sulfur Dioxide (SO_2)	38.7	No	State BACT
Hydro Sulfuric Acid (H_2SO_4)	32.5	PSD	BACT
Other Regulated Pollutants (i.e., Hazardous Air Pollutants [HAPs])	<10 single HAPs <25 multiple HAPs	State NSR	Maximum Achievable Control Technology (MACT)

- Discussion of the technical and economic feasibility of each alternative.
- Assessment of energy and environmental impacts, including toxic and hazardous pollutant impacts, of feasible alternatives.
- Selection of the most stringent control alternative that is technically and economically feasible and that provides the best overall control of all pollutants.
- Confirmation that the selected BACT is at least as stringent as NSPS and State Implementation Plan (SIP) limits for the source.

EPA Guidance recommends that the BACT analysis be conducted using a step by step approach. Specifically, a top-down BACT analysis includes the following 5 basic steps.

Step 1 – Identify all Available Control Technologies. *Compilation of all potential control technologies available. List should not exclude technologies implemented outside the United States.*

Step 2 – Eliminate Technically Infeasible Options. *Determine if any of the technologies identified in Step 1 are not technically feasible based on physical, chemical and engineering principles.*

Step 3 – Rank Remaining Control Technologies by Control Effectiveness. *Remaining control alternatives not eliminated in Step 2 are ranked in order of most effective (i.e., lowest emission rate) to the least. Each technology is evaluated based on economic, environmental and energy impacts.*

Step 4 – Evaluate Most Effective Controls and Document Results. *The information developed in Step 3 is objectively evaluated to determine whether economic, environmental, or energy impacts are sufficient to justify exclusion of the technology. The analysis begins with the top ranked technology and continues until the technology under consideration cannot be eliminated by any environmental, economic, and energy impacts which justify that the alternative is inappropriate as BACT.*

Step 5 – Identify BACT. *The highest ranked remaining technology is identified as BACT.*

5.2 CONTROL TECHNOLOGY DETERMINATION FOR THE COMBINED CYCLE COMBUSTION TURBINE SYSTEM

Each combustion turbine and HRSG set has been evaluated as a single combined cycle system for the purposes of the control technology analysis. Consideration of the units as single system is consistent with the control evaluation results found in current U.S. EPA literature (i.e., Gas Turbine Alternative Control Technique or ACT) and the EPA and State Agency databases noted in Section 5.1. Each turbine/HRSG set will exhaust from the same stack and most of the applicable control options apply to the combined exhaust system. Although the combined cycle units are evaluated a single system, Longview Power has not excluded analysis of controls that may apply only to the HRSG duct burners or combustion turbines (i.e. low NO_x burners). Control options that will apply specifically to the turbines or HRSG duct burners are noted throughout this analysis.

5.2.1 BACT for NO_x Emissions for the Combustion Turbine System

Nitrogen oxides are produced in the combined cycle system several different ways. Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_x forms in the high temperature area of the gas turbine combustor. Thermal NO_x increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low air to fuel ratio (i.e., lean combustion), the flame temperature will be lower, thus reducing the potential for NO_x formation. Prompt NO_x is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt to overall NO_x is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_x control by lean combustion.

Fuel NO_x is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas as the amount of fuel bound nitrogen is very low. A top down analysis to determine the best available NO_x control technology is provided in the following subsections.

5.2.1.1 Identification of Potential Control Technologies (Step 1)

Based on the data review process described previously, a list of potential technologies for controlling NO_x emissions from combined cycle combustion turbines was formulated. The following potential control technologies, ranked in order from the most effective to the least effective were identified:

1. Selective Catalytic Reduction (85-95% reduction)

2. SCONO$_x$™ (85-95% reduction)
3. XONON ™ (85-95% reduction)
4. Selective Non-Catalytic Reduction (80-95% reduction)
5. Combustion Controls (i.e., Dry Low NO_x Combustor for the turbines and low NO_x burners in the HRSGs) (80-95% reduction)
6. Wet Injection (60 to 80% reduction from uncontrolled emissions)

5.2.1.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down analysis is an evaluation of the technical feasibility of each of the identified control options. Each of the potential control technologies considered is described below along with a discussion of the technical feasibility with respect to the Longview Unit 2 Project.

1. Selective Catalytic Reduction (SCR)

SCR is an add-on NO_x control technology that is employed in the combined exhaust stream within the HRSG. SCR reduces NO_x emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_x in the presence of the catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1,100 ^oF), such as simple cycle turbines, Zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with either wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming more available. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

Permit limits as low as 2.0 to 3.5 ppmvd NO_x have been specified using SCR on combined cycle GE F Class projects throughout the country. Permit BACT limits as low as 3.5 ppmvd NO_x have been specified using SCR for at least one F Class project (with large in-line duct burners). SCR is a technically viable control option to reduce NO_x emissions from large combined cycle combustion turbines.

2. $SCONO_x$™

$SCONO_x$™ is a catalytic technology that removes CO and NO_x by oxidizing and then absorbing the pollutants onto a platinum honeycomb catalyst coated with potassium carbonate. The pollutant is then released as molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas, carbon dioxide and steam. Consistent regeneration of the catalyst is required to maintain low NO_x emission rates. Steam requirements typically range from 1 to 4% of the boiler capacity. The catalyst is divided into multiple sections equipped with mechanical dampers to isolate sections of the catalyst for regeneration. The regeneration cycle typically takes 10 minutes and the catalyst life is approximately 6 months.

The technology is currently only in use at two facilities. A 32 MW GE LM2500 combined cycle unit at the Sunlaw Cogeneration Partners Federal Cold Storage Facility in Vernon, California and a 5 MW simple cycle turbine at the Genetics Institute in Andover, Massachusetts. The La Paloma Generating Company LLC plant near Bakersfield, CA was originally permitted for the installation of one 250 MW combined cycle block with $SCONO_x$™. However, the installation has proceeded with a standard SCR due to schedule constraints. PG&E has proposed the installation of $SCONO_x$™ on a GE F-frame unit at Otay Mesa in Southern California. The construction permit was written with a three year demonstration period for the $SCONO_x$™ system to prove that the system can consistently achieve 2.0 ppmdv @ 15% O_2. The facility is currently under construction.

There are significant technical differences and other considerations associated with the two facilities that currently utilize the $SCONO_x$™ system that will preclude the use of $SCONO_x$™ at the proposed Longview Unit 2. First, the Sunlaw facility is partially owned and operated by a partner of Goal Line Environmental Technologies ("Goal Line"), the manufacturer of $SCONO_x$™, thus the data generated by this facility is not from an independent, nonpartisan source. Second, the Sunlaw plant is 5% of the size of the Longview Unit 2 and the combustion turbine is an aeroderivative model, which is significantly different than the frame-type units proposed in this application. The facility is also not equipped with duct burners. Third, although the California Air Resources Board has certified $SCONO_x$™ technology in a November 1998 report entitled *"Evaluation of Goal Line Environmental Technologies LLC $SCONO_x$™ System"* the Board specifically noted that while the technology has been demonstrated successfully on smaller turbines, there are "several factors which may affect successful scale-up". The CARB certification report acknowledged the potential issues associated with scale up and that the certification only applied to water injected, 34 MW natural gas fired turbines.

The Genetics Facility represents a non-partisan basis of comparison as Goal Line has no vested interest in the operation and ownership of the facility. Excerpts of a presentation given by Mr. Robert McGinnis, the Manager of Environmental Engineering and Compliance for Genetics Institute at the Northeast Energy and Commerce Association conference on May 17, 2000 provide a better understanding as to the commercial performance of the $SCONO_x$™ technology:

- Following 9 months of operation there were still a number of unresolved problems with the performance of the $SCONO_x$™ system and the system was not consistently meeting the permitted NO_x emission limit.

- $SCONO_x$™ performance was severely hampered by changes in NO_x inlet concentration. The unit was guaranteed to achieve the stated NO_x emission limits for NO_x inlet concentrations up to 25 ppm; however, the system was unable to achieve the permit limit if the turbine was not operating at least twice as clean as the manufacturer's guarantee (i.e., at lower than 12.5 ppm).

- Goal Line redesigned the dampers three times due to leakage and the catalyst blocks were washed every 2-2½ months. This substantially increased system downtime and maintenance costs.

- The technology has not been installed commercially on a source greater than 34 MW.

- Mr. McGinnis summarized by stating that after 9 months of operation it was still unclear if $SCONO_x$™ will work as promised.

As shown by the results of the Genetics Installation and the CARB review of the Sunlaw facility, it is clear that $SCONO_x$™, while potentially applicable in the future, cannot be considered as a "technically feasible" control technology. In the EPA *Draft New Source Review Guidance* document, "technically feasible" control technology is technology that has been commercially demonstrated, i.e., **installed and operated successfully on a source similar to that under**

review. Based on this guidance, and the information presented above, $SCONO_x$™ is not technically feasible for the proposed Longview Unit 2 Project.

3. XONON™

XONON™ works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_x formation) followed by flameless catalytic combustion to further limit NO_x formation. The technology has been demonstrated on combustors on the same order of size as $SCONO_x$™. XONON™ does not utilize ammonia in the process and does not require the generation of hydrogen.

Catalytica Combustion Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. In a press release on October 8, 1998 Catalytica announced the first installation of a gas turbine equipped with the XONON™ Combustion System in a municipally owned utility for the production of electricity. The turbine was started up on that day at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, Calif. Previously, this XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests which documented its ability to limit emissions of nitrogen oxides, a primary air pollutant, to less than 3 parts per million.

In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to cooperate in the design, application, and commercialization of XONON™ systems for both new and installed GE E and F-class turbines used in power generation and mechanical drive applications. Although this technology appears to be potentially viable for future applications, it has not been demonstrated commercially on any units similar in size and scope to the proposed Longview Unit 2 Project. For these reasons, it is concluded that XONON™ is not a technically feasible control option.

4. Selective Non-Catalytic Reduction (SNCR)

SNCR works on the same principal as SCR. The main differences are that SNCR is applicable to hotter streams than conventional or SCR, no catalyst is required, and urea can be used as a source of ammonia. Certain manufacturers, such as Engelhard, market a SNCR for NO_x control within the temperature ranges for which this project will operate (700 – 1,400°F). However, the process also requires low oxygen content in the exhaust stream to be effective. Typically, the oxygen content in the exhaust stream of a combustion turbine is greater than 12%, rendering SNCR technically infeasible for these types of applications. Accordingly, SNCR is not technically feasible for the Longview Unit 2 Project due to the oxygen content of the exhaust stream.

5. Combustion Controls

Combustions controls may be applied to the combustion turbine and/or HRSG duct burners independently. Combustion controls for these types of units primarily consist of Low NO_x combustors or Low NO_x burners. Since this technology is applicable to the individual components of the combined cycle system, the technical feasibility analysis has been separated for the combustion turbines and HRSG duct burners as follows.

Combustion Turbine

The U.S. Department of Energy has provided millions of dollars of funding to a number of combustion turbine manufacturers to develop inherently lower pollutant-emitting units. Efforts over the last ten years have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel with air prior to combustion in the primary zone. This technology is typically referred to as Dry Low NO_x (DLN) combustion. Typically, this occurs in four distinct modes: primary, lean-lean, secondary, and premix. In the primary mode, fuel is supplied only to the primary nozzles to ignite, accelerate, and operate the unit over a range of low- to mid-loads and up to a set combustion reference temperature. Once the first combustion reference temperature is reached, operation in the lean-lean mode begins when fuel is introduced into the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in the secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. The premix mode of operation occurs at loads between 50% to 100% of base load and results in the lowest NO_x emissions. Due to the intricate air and fuel staging necessary for dry low-NO_x combustor technology, the gas turbine control system becomes a very important component of the overall system. DLN systems are technically feasible for nearly all new frame-type combustion turbines. DLN systems result in control efficiencies of 80% to 95% and are technically feasible for the Longview Unit 2 Project.

HRSG Duct Burners

Low NO_x burner designs are based on the principle of lowering the reaction temperature of the combustion process by limiting the amount of excess air available, low excess air (LEA), during the combustion process as much as possible and staging the combustion to reduce the occurrence of NO_x formation. Low NO_x burners are considered industry standard for applications such as HRSG duct burners and are, therefore, considered technically feasible.

6. Wet Injection

This technology is only applicable to the combustion turbines. Water or steam is injected into the primary turbine combustion zone to reduce the flame temperature, resulting in lower NO_x emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the same level of NO_x control. There is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine. Standard combustor designs with wet injection can generally achieve NO_x emissions up to 42 ppmvd for gas firing. Advanced combustor designs generate inherently lower NO_x emissions and can tolerate greater amounts of water or steam injection before causing flame instability. Advanced combustor designs with wet injection can achieve NO_x emissions up to 25 ppmvd for gas firing. Wet injection typically can achieve 60% to 80% control efficiencies and is technically feasible for the Longview Unit 2 Project.

5.2.1.3 Rank Remaining Technically Feasible Control Technologies (Step 3)

Based on the reasons outlined in the above discussion, the following technologies were identified as technically feasible, ranked in order of most effective to least effective:

1. Selective Catalytic Reduction (85-95% reduction)

2. Combustion Controls (i.e., Dry Low NO_x Combustor for CTs and Low NO_x burners for DBs) (80-95% reduction)

3. Wet Injection (60 to 80% reduction from uncontrolled emissions)

5.2.1.4 Proposed NO_x BACT for the Combustion Turbine System

Longview Power Unit 2 will elect to implement the two top ranked remaining technically feasible control technologies as BACT, thus further review of economic, environmental, and energy impacts is unnecessary. **Based on the above analysis, Longview Power Unit 2 proposes BACT for NO_x emissions from the combined cycle systems to be good combustion practices, DLN burners in the turbines, low NO_x duct burners and SCR on the combined exhaust stream. The proposed NOx BACT emission limit is 2.0 ppm at 15% oxygen.**

5.2.2 BACT for VOC Emissions for the Combustion Turbine System

5.2.2.1 Identification of Potential Control Technologies (Step 1)

Like CO emissions, VOC emissions occur from incomplete combustion. Effective combustor design and post-combustion control using Oxidation Catalysts are the available technologies for controlling VOC emissions from combustion turbines. The GE Frame 7HA.01 industrial combustion turbines proposed by ESC are able to achieve relatively low uncontrolled VOC emissions because their combustors have firing temperatures of approximately 2,500 °F with exhaust temperatures of approximately 1,000 °F. A DLN combustor-equipped combustion turbines using an Oxidation Catalyst can achieve VOC emissions in the 1 to 2 ppmvd @ 15% O_2 range. As noted above in the NO_x BACT analysis, the EMxTM and XONONTM technologies were determined not to be feasible for the proposed Combustion Turbines/Duct Burners, so they have not been considered further here.

1. Good Combustion Controls

As previously discussed, VOCs are formed from incomplete combustion of the carbon present in the fuel. VOC formation is minimized by designing the combustors to completely oxidize the fuel carbon to CO_2. This is achieved by ensuring that the combustors are designed to allow complete mixing of the combustion air and fuel at combustion temperatures with an excess of combustion air. Higher combustion temperatures reduce VOC formation, but at the expense of increased NO_x formation. The use of water/steam injection or DLN combustors tends to lower combustion temperatures to reduce NO_x formation, but potentially increases VOC formation. However, good combustor design and best operating practices will minimize VOC formation while reducing the combustion temperatures and NO_x emissions.

2. Oxidation Catalysts

Oxidation Catalysts typically use precious metal catalyst beds. Like SCR systems for combined-cycle combustion turbines, Oxidation Catalysts are typically placed inside the HRSGs. The catalyst enhances oxidation of VOC to CO_2, without the addition of any chemical reagents. Oxidation Catalysts have been successfully installed on numerous simple- and combined-cycle combustion turbines.

5.2.2.2 Eliminate Technically Infeasible Options (Step 2)

Good combustor design and the use of Oxidation Catalysts are both technically feasible options for controlling VOC emissions from the proposed Combustion Turbines/Duct Burners.

5.2.2.3 Rank Remaining Control Technologies by Control Effectiveness (Step 3)

Based on the preceding discussions, using good combustor controls and Oxidation Catalysts are technically feasible combustion turbine VOC emission control technologies.

5.2.2.4 Proposed VOC BACT for the Combustion Turbine System

Longview Power Unit 2 will elect to implement the two top ranked remaining technically feasible control technologies as BACT, thus further review of economic, environmental, and energy impacts is unnecessary. **Based on the above analysis, Longview Power Unit 2 proposes BACT for VOC to be good combustor controls and Oxidation Catalysts and VOC emission limits of 1.0 and 2.0 ppmvd @ 15% O_2 without and with duct firing, respectively.**

5.2.3 BACT for PM/PM_{10} Emissions for the Combustion Turbine System

A top down analysis to determine the best available PM/PM_{10} control technology is provided in the following subsections.

5.2.3.1 Identification of Potential Control Technologies (Step 1)

Potential control technologies for PM emissions from gas fired combined cycle combustion turbines include the following, ranked in order of potential effectiveness:

1. Add-on control (i.e., baghouse, scrubber, electrostatic precipitation, etc.)
2. Combustion of clean fuels (i.e., natural gas)
3. Implementation of good combustion practices

No natural gas-fired combined cycle combustion turbines that utilize add-on control technology for PM/PM_{10} control were identified in the permit review. Acceptable control techniques identified include combustion of clean fuels (e.g., firing natural gas and/or minimizing the sulfur content of the fuel) and good combustion practices.

5.2.3.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down analysis is an evaluation of the technical feasibility of each of these control options. Each of the potential control technologies considered is described below along with a discussion of the technical feasibility of each with respect to the Longview Unit 2 Project.

1. <u>Add-on Controls</u>

There are three reasons why add-on particulate matter control technologies are not technically feasible for PM/PM_{10} emissions control for a combustion turbine:

1. The installation of an add-on control will create an unacceptable back pressure on the turbine. Turbine performance is very sensitive to back pressure because it reduces the expansion-to-pressure ratio and energy efficiency, resulting in reduced power output, increased fuel consumption, and increased emission rates.

2. Combustion in a turbine requires a high level of excess air and thus produces high exhaust gas volumes. These high gas volumes in turn increase the size and cost of add-on particulate matter controls, making them unreasonable for economic reasons.

3. The increased gas volume results in a low pollutant concentration. Based on preliminary emissions estimates obtained from GE for a Frame 7FA turbine, the maximum expected PM_{10} concentration without add-on controls is expected to be approximately 0.005 gr/dscf. This number is believed to be a worst-case short-term particulate matter grain loading and is estimated assuming the turbine is firing natural gas at 60% load, 54°F inlet temperature. Further reduction below this level would be minimal.

Based on the above, add-on particulate matter control technologies are not considered technically feasible for controlling PM/PM_{10} emissions from the turbine. Furthermore, there is no evidence that add-on controls have been installed for PM/PM_{10} control for turbines, and add-on controls are therefore not considered to be BACT for the proposed combustion turbine.

2. Combustion of Clean Fuels

The combustion of clean fuels to minimize PM/PM_{10} emissions is accomplished by burning fuels with minimal amounts of impurities in conjunction with good combustion practices. The cleanest fuel commercially available in large quantities is natural gas. Natural gas will be the only fuel fired in the combustion turbine. Combustion of clean fuels is technically feasible for the proposed combustion turbine as natural gas is available at the site.

3. Good Combustion Practices

Good combustion practices refers to the operation of the combustion turbine at high combustion efficiency, thus reducing products of incomplete combustion such as PM/PM_{10}. The combustion turbine will be designed to maximize combustion efficiency. The combustion turbine manufacturer will provide Operator and Maintenance manual(s) detailing methods to maintain a high level of combustion efficiency.

5.2.3.3 Proposed PM/PM_{10} and PM2.5 BACT for the Combustion Turbine System

Longview Power Unit 2 will elect to implement all of the technically feasible control technologies, thus further review of economic, environmental, and energy impacts is unnecessary. **Based on the above analysis, Longview Power Unit 2 proposes BACT for PM/PM_{10}/PM2.5 emissions from the turbine to be combustion of clean fuels and good**

combustion practices and inlet air filtration to control PM, PM10, and PM2.5 emissions to no more than 0.008 lb/hr.

5.2.4 BACT for CO Emissions for the Combustion Turbine System

A top down analysis to determine the best available CO control technology is provided in the following subsections.

5.2.4.1 Identification of Potential Control Technologies (Step 1)

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation were identified as the potentially viable control alternatives for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst. Several recently permitted natural gas-fired combustion turbines are utilizing oxidation catalysts as add-on technology for CO control.

5.2.4.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down analysis is an evaluation of the technical feasibility of each of these control options. Each of the potential control technologies considered is described below along with a discussion of the technical feasibility of each with respect to the Longview Unit 2 Project.

1. Oxidation Catalyst

Oxidation catalysts (typically a precious metal deposited onto a solid honeycomb substrate) convert carbon monoxide (CO) to carbon dioxide (CO_2) in the presence of oxygen. This technology has been demonstrated on similar combined cycle facilities as shown in the Appendix F summary of BACT/LAER determinations. This technology is considered a technically feasible option for CO emissions control.

2. Good Combustion Practices/Turbine Design

Good combustion practices refers to the operation of the combustion turbine at high combustion efficiency, thus reducing products of incomplete combustion such as CO. The combustion turbine will be designed to maximize combustion efficiency. The combustion turbine manufacturer will provide Operator and Maintenance manual(s) detailing methods to maintain a high level of combustion efficiency.

5.2.4.3 Proposed CO BACT for the Combustion Turbine System

The Longview Unit 2 Project will elect to implement all of the technically feasible control technologies identified, thus further review of economic, environmental, and energy impacts is unnecessary. **Based on the evaluations above, Longview Power Unit 2 proposes the only two technically feasible CO reduction methods available as BACT: the use of an oxidation catalyst system in conjunction with good combustion practices** to control CO emissions to 2.0 ppmvd @ 15% O_2.

5.2.5 BACT for H_2SO_4 Emissions for the Combustion Turbine System

A top down analysis to determine the best available H_2SO_4 control technology is provided in the following subsections.

5.2.5.1 Identification of Potential Control Technologies (Step 1)

Potentially acceptable control techniques for H_2SO_4 emissions include combustion of low sulfur fuels and/or an H_2SO_4 scrubber.

5.2.5.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down analysis is an evaluation of the technical feasibility of each of these control options. Each of the potential control technologies considered is described below along with a discussion of the technical feasibility of each with respect to the Longview Unit 2 Project.

1. Add-on Controls

There are three reasons why add-on controls are impractical for combustion turbine emissions control:

> (a) The installation of an add-on control will create an unacceptable back pressure on the turbine. Turbine performance is very sensitive to back pressure because it reduces the expansion pressure ratio and energy efficiency, thus resulting in reduced power output, increased fuel consumption, and increased air emissions.

(b) Combustion in a turbine requires a large amount of excess air, which results in high exhaust gas volumes. These high gas volumes in turn increase the size and cost of add-on controls, making them unreasonable for economic reasons.

(c) The increased gas volume results in low pollutant concentrations; also increasing control device size and cost.

Based on the above, add-on controls are not considered to be technically feasible for controlling SO_2 emissions from turbines. There is no evidence that add-on controls have been installed to control SO_2 emissions from natural gas fired turbines; therefore, add-on controls are not considered to be BACT for the proposed project.

2. Combustion of Low Sulfur Fuels

As the name implies, this technique of SO_2 emission control limits the types of fuels burned to those with low sulfur contents, thus minimizing SO_2 formation. The lowest sulfur fuel commercially available in large quantities is natural gas. Natural gas supplied via pipeline with a sulfur content at or below 1 grain per 100 scf will be the only fuel fired in the combustion turbine. Combustion of clean fuels is technically feasible for the proposed combustion turbine as natural gas is available at the site.

5.2.5.3 Proposed H_2SO_4 BACT for the Combustion Turbine System

Longview Power Unit 2 will elect to implement the only technically feasible control technology, thus further review of economic, environmental, and energy impacts is unnecessary. **Based on the above analysis, Longview Power Unit 2 proposes BACT for H_2SO_4 emissions from the turbine to be combustion of low sulfur fuel and an emission limit of 0.00085 lb/MMBtu.**

5.2.6 BACT Analysis for Other Regulated Pollutants

Other regulated pollutants consist of non-criteria pollutants for which a regulatory standard has been established. These pollutants primarily fall into the category of speciated organic or metal compounds and the majority of these compounds are considered Hazardous Air Pollutants as defined in Section 112 of the Clean Air Act. Based on the emission rates expected from the proposed combined cycle system, the level of emissions of "other regulated pollutants" will be very low. As discussed in Section 3, the major HAPs of concern from a combustion turbine are volatile organic HAPs or VOHAPs such as Formaldehyde and Hexane. BACT for VOHAPs will be met by the same technology as proposed for BACT for VOC emissions (i.e., an oxidation catalyst). Similarly, BACT for control of the low levels of particulate matter HAPS or PM-HAPs will also be controlled by the BACT proposed for PM/PM_{10} (i.e., restricting the system to firing an inherently low-ash fuel in natural gas). BACT for ammonia will be good operating and maintenance practices for the SCR system to minimize ammonia slip.

5.2.7 BACT for GHG Emissions for the Combustion Turbine System

The primary GHG of concern for the combustion turbine system is CO_2. The BACT analysis is for CO_2 emissions, as CH_4, N_2O and SF_6 emissions are insignificant, at less than 0.3 percent of facility GHG CO_2e emissions and there are no sources with HFCs or PFCs pollutants identified with this project.

5.2.7.1 Identify Potential Control Technologies – (Step 1)

The following potentially applicable technologies available were evaluated for the review of the CO_2 control technologies for the CTGs/HRSGs:

- Carbon Capture and Sequestration
- Lower Emitting Alternative Technology
- Thermal Efficiency/Combustion Air Cooling

Each of these technologies is further discussed in the following subsections.

1. <u>Carbon Capture and Sequestration</u>

CCS is a multiple step process which involves capturing of CO2 emissions, transportation of CO2 emissions to the sequestration site, and ultimate sequestration of CO2 emissions. Instead of allowing the CO2 to be emitted, it is captured and stored it (in a "reservoir") where it will not be re-emitted ("permanent storage"). A schematic of the CCS process is shown in Figure 5-1. Each step of the process is described below.

Capturing of CO2 Emissions

Carbon capture begins with the separation and capture of CO2 from the flue gas. The type of capture process used is dependent on the type of source generating the CO2 emissions. There are generally four types of capture systems: industrial separation, post-combustion, pre-combustion and Oxyfuel. The four type and their characteristics are shown in Figure 5-2. All except Oxyfuel involve separation of the CO2 from the process exhaust stream.

Industrial Separation

The industrial separation processes available include: sorbent/solvents, membranes and cryogenic distillation. Sorbent/solvent (solid or liquid) is used to capture the CO2 and then the CO2 is released by heating the sorbent, which also regenerates the sorbent/solvent for res-use. Solid sorbents can be used to capture CO2 from flue gas through chemical adsorption, physical adsorption, or a combination of the two effects. Possible configurations for contacting the flue gas with solid sorbents include fixed, moving, and fluidized beds

Membranes use the physical properties of the molecules of the gas and pressure. Membrane-based capture uses permeable or semi-permeable materials that allow for the selective transport/separation of CO2 from the flue gas

Cyrogenic distillation uses the properties of differences in boiling points of the gases to separate the CO2. Since the gases have very low boiling points they need to be cooled to be separated.

Post Combustion

Post-combustion capture systems being developed are expected to be capable of capturing more than 90 percent of flue gas CO2. Amine-based solvent systems are in commercial use for scrubbing CO2 from industrial flue gases and process gases. However, solvents have yet to be applied and demonstrated in practice to remove the much larger volumes of CO2 that are encountered in commercial scale power plants. The process of separating CO2 from the flue has high energy demand and is cost intensive.

Pre-Combustion

A pre-combustion capture process typically comprises a first stage of reaction producing a mixture of hydrogen and carbon monoxide (syngas) from a primary fuel. The CO is converted to CO2 with the application of steam. The CO2 is then removed from the CO2/H2 mixture

Figure 5-1
Carbon Capture Process

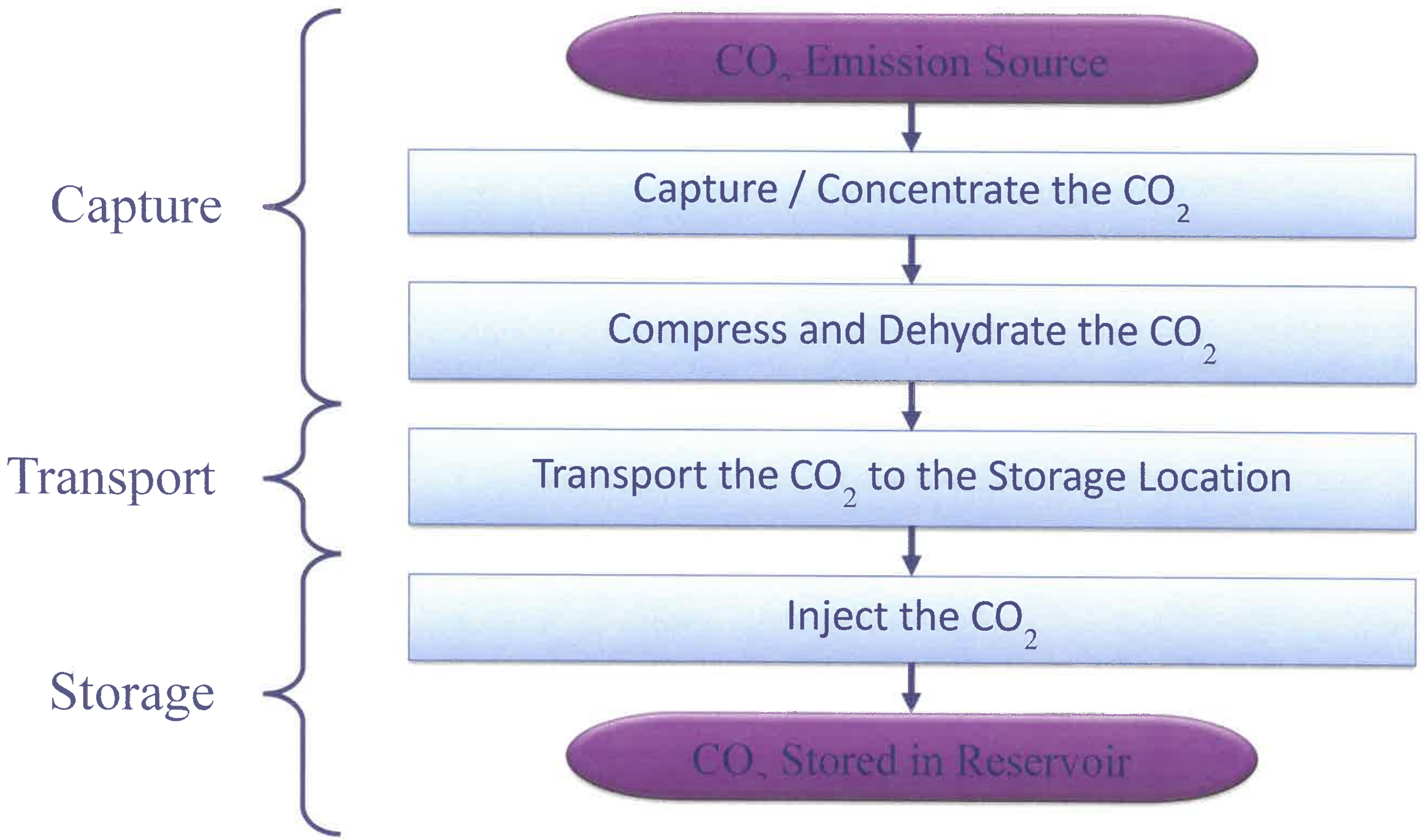
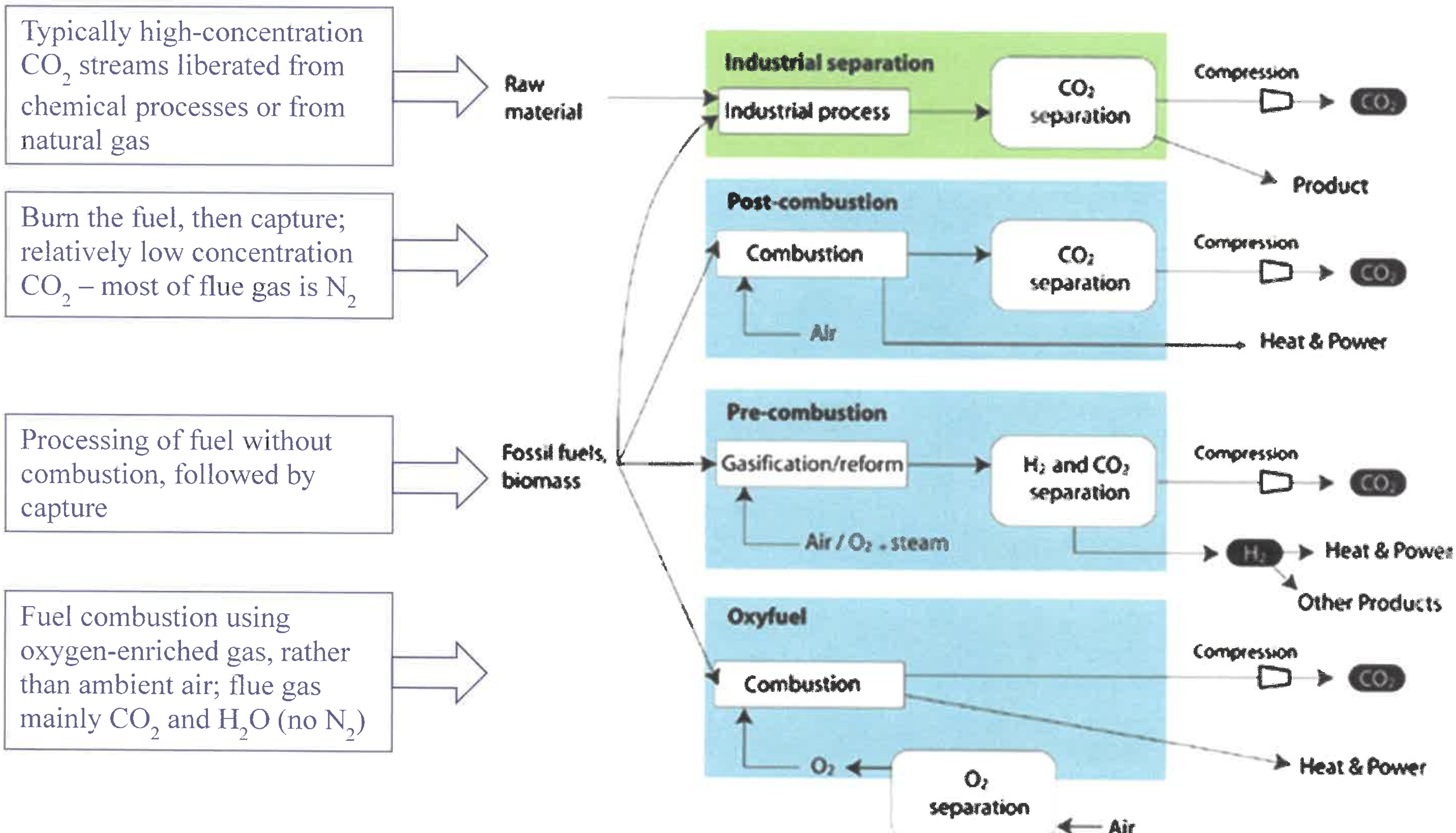


Figure 5-2
Types of CO2 Sources and Capture



Source: IPCC Special Report on Carbon Dioxide Capture and Storage, 2005, pg.5

Oxyfuels

Oxyfuel combustion involves fuel combustion using oxygen-enriched gas, rather than ambient air which produces a flue gas mainly containing CO2 and H2O and very little N2. The flue contains from about 80-98% CO2 depending on the fuel used and the particular oxy-fuel combustion process. This concentrated CO2 stream can be processed further to purified CO2 before delivery into a pipeline for storage. The CO2 capture efficiency is very close to 100% in oxy-fuel combustion capture systems.

Transportation of CO2 Emissions

CO2 captured by any of the above mentioned processes would have to be transported to a storage site. For geologic sequestration, a pipeline may be suitable. For other types of sequestration (e.g., ocean storage, mineral carbonation), transportation would depend on specific project requirements, and may involve pipelines, truck transport, ocean-going vessels, etc.

Storage (Sequestration) of CO2 emissions

Storage or sequestration of CO_2 is generally accomplished by injecting captured CO_2 at high pressures into deep subsurface formations for long-term storage. These subsurface formations must be either local to the point of capture, or accessible via pipeline, to enable the transportation of recovered CO_2 to the permanent storage location. The engineered injection of CO2 into subsurface geological formations was first undertaken in Texas, USA, in the early 1970s, as part of enhanced oil recovery (EOR) projects and has been ongoing there and at many other locations ever since. Storage facilities typically include:

- Geologic formations;
- Depleted oil and gas reservoirs;
- Unmineable coal seams;
- Saline formations;
- Basalt formations; or
- Terrestrial ecosystems.

To geologically store CO2, it must first be compressed, usually to a dense fluid state known as 'supercritical' Once injected, the pressurized CO_2 remains "supercritical" and behaves like a liquid and takes up less space than gaseous CO_2. The CO_2 occupies pore spaces in the surrounding rock. Over time, the CO_2 can dissolve in residual water, and chemical reactions between the dissolved CO_2 and rock can create solid carbonate minerals, more permanently trapping the CO_2.

2. Thermal Efficiency/Combustion Air Cooling

CO2 emissions are directly related to the quantity of fuel burned, therefore less fuel burned per amount of energy produced (greater energy efficiency), the lower the GHG emissions per unit of energy produced. The only useful means to reduce CO2 from a fossil fuel combustion process is to minimize the amount of fuel used, which is achieved by establishing a more thermally efficient process, or by substitution of a lower GHG emitting fuel. The largest efficiency losses for a combined-cycle combustion turbines are inherent in the design of the combustion turbines and the heat recovery system. Therefore, there is no opportunity for efficiency gains other than the differences in design between manufacturers or models.

Combustion inlet air cooling is a group of technologies and techniques consisting of cooling down the intake air of the gas turbine. The direct consequence of cooling the turbine inlet air is power output augmentation which improves the energy efficiency of the system The most common method used to improve the energy efficiency of combustion turbines is to cool the combustion air entering the combustion turbines during the summer months which also coincides with peak electric demand.

3. Lower Carbon Fuels

Carbon dioxide is produced as a combustion product of any carbon containing fuel. The carbon content of the fuel, relative to its Btu value, can have significant impact on the overall GHG emissions. Gaseous fuels such as natural gas significantly less GHG emissions per Btu than liquid or solid fuels. The use of lower carbon content gaseous fuels such as natural gas compared to the use of higher carbon-containing fuels such as coal, pet-coke or residual fuel oils, can reduce CO_2 emissions from combustion.

Natural gas combustion result in significantly lower GHG emissions than coal combustion (117.0 lb/MMBtu, versus 205.6 lb/MMBtu for bituminous coal). Therefore, the use of lower carbon containing fuels in combustion turbines is an effective means to reduce the generation of CO_2 during the combustion process.

Step 2 - Eliminate Technically Infeasible Options

1. Carbon Capture and Storage

CCS is the only potentially available add-on control option at this time, and even this technology is limited and infantile in its development. The technologies needed for a full-scale electric generating facility such as the proposed Longview Unit 2 Project are not yet commercially available and without local geological reservoirs and available pipelines dedicate to CO2 transport, CCS is not currently feasible. Therefore, CCS is not considered technically feasible for the Project.

It is also noted that in USEPA PSD and Title V Permitting Guidance For Greenhouse Gases (March 2011), USEPA states that:

EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible. However, there may be cases at present where the economics of CCS are more favorable (for example, where the captured CO_2 could be readily sold for enhanced oil recovery), making CCS a more viable option under Step 4.

2. Thermal Efficiency/ Combustion Air Cooling

The selection and use of combustion turbines with a higher thermal efficiency and combustion air cooling during the summer months is a technically feasible alternative to one with a lower thermal efficiency rating and no combustion air cooling. The Project will use the latest technically advanced high thermal efficiency combustion turbine operated in combined-cycle mode and will be equipped with inlet evaporative cooling systems, which is a form of combustion air cooling.. Therefore, thermal efficiency/combustion air cooling is considered technically feasible for the Project.

3. Lower Carbon Fuels

The use of lower carbon content gaseous fuels such as natural gas compared to the use of higher carbon-containing fuels such as coal, pet-coke or residual fuel oils, is a technically feasible alternative to reduce CO_2 emissions. The project will only utilize natural gas for the combustion turbines/HRSG. Therefore, Lower Carbon Fuels is considered technically feasible for the Project.

Step 5 - Select BACT

Longview Power Unit 2 will elect to implement the only technically feasible control technologies, thus further review of economic, environmental, and energy impacts is unnecessary. **Based on the above analysis, Longview Power Unit 2 proposes BACT for GHG emissions from the turbine to thermal efficiency/combustion air cooling and use of lower carbon fuels.**

In addition, Longview Power Unit 2 proposes a facility-wide GHG emissions limit as GHG BACT for the Project. The proposed GHG emission limit from the Combustion Turbines/Duct Burners, Fuel Gas Heaters, Emergency Generator, Fire Water Pump, and gas pre-heaters is 4,282,215 tons/yr, on a CO_2e basis.

5.3 CONTROL TECHNOLOGY DETERMINATION FOR THE EMERGENCY GENERATOR AND FIRE PUMP

The control technology analysis for the proposed emergency generator and fire pump has been combined because these units are both similar diesel fuel fired internal combustion engines. Both units will only be used in emergency situations and the engines will be restricted to an annual utilization limitation equivalent to 100 hours of operation at maximum capacity with anticipated actual operation being much lower. Maximum annual emissions of any criteria pollutants is less than 1 tons per year for both the emergency generator and fire pump. Both engines will be equipped with a turbocharger and intercooler. The appropriate control evaluations for each pollutant are provided in the following subsections.

5.3.1 BACT for NO_x and VOC Emissions for the Emer. Gen. and Fire Pump

There are two mechanisms by which NO_x is formed in an IC engine: (1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_x) and (2) the conversion of nitrogen chemically bound in the fuel (fuel NO_x, or organic NO_x).

Thermal NO_x is formed in the combustion chamber when N_2 and O_2 molecules dissociate into free atoms at the elevated temperatures and pressures encountered during combustion and then recombine to form NO. The reaction rate toward NO formation increases exponentially with temperature. The NO further oxidizes to NO_2 and other NO_x compounds downstream of the combustion chamber.

Fuel NO_x (also known as organic NO_x) is formed when fuels containing nitrogen are burned. IC engines are typically fueled by natural gas or light distillate oil that typically contains little or no Fuel Bound NO_x (FBN). As a result, when compared to thermal NO_x, fuel bound NO_x is not a major contributor to overall NO_x emissions from most IC engines.

5.3.1.1 Proposed NO_x and VOC BACT for the Emer. Gen. and Fire Pump

Longview Power Unit 2 proposes BACT for the Emergency Generator as an emission limit of 4.8 g/hp-hr for NO_x and NMHC and the use of ULSD fuel, good combustion practices, limiting operations to emergency events and no more than 100 hr/yr for maintenance and readiness testing.

Longview Power Unit 2 proposes BACT for the Fire water pump as an emission limit of 3.0 g/hp-hr for NO_x and NMHC and the use of ULSD fuel, good combustion practices, limiting operations to emergency events and no more than 100 hr/yr for maintenance and readiness testing.

These are the applicable emission rates specified in 40 CFR 60, Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

5.3.2 BACT for PM/PM_{10} Emissions for the Emer. Gen. and Fire Pump

A top down analysis to determine the best available PM/PM_{10} control technology is provided in the following subsections.

5.3.2.1 Identification of Potential Control Technologies (Step 1)

Potential control technologies for PM emissions from diesel fired internal combustion engines include the following, ranked in order of potential effectiveness:

1. Add-on control (i.e., baghouse, scrubber, electrostatic precipitation, etc.)
2. Combustion of clean fuels (i.e., natural gas)
3. Implementation of good combustion practices

5.3.2.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down analysis is an evaluation of the technical feasibility of each of these control options.

1. Add-on Controls

No diesel fired internal combustion engines were identified in the permit review which utilized add-on control technology for PM/PM_{10} control. In the EPA *Draft New Source Review Guidance* document, technically feasible control technology is technology that has been commercially demonstrated (i.e., installed and operated successfully on a source similar to that under review.) Add-on PM/PM_{10} controls have not been commercially demonstrated on IC engines, thus this technology is not considered technically feasible for this application.

2. Combustion of Clean Fuels

The combustion of clean fuels to minimize PM/PM_{10} emissions is accomplished by burning fuels with minimal amounts of impurities in conjunction with good combustion practices. The Project proposes to burn very low sulfur diesel fuel (i.e., sulfur content less than or equal to 0.5% sulfur). Combustion of very low sulfur diesel fuel is technically feasible for the proposed engines.

3. Good Combustion Practices

Good combustion practices refer to the operation of the engines at high combustion efficiency, thus reducing products of incomplete combustion such as PM/PM_{10}. The engines will be designed to maximize combustion efficiency. The engine manufacturers will provide Operator and Maintenance manual(s) detailing methods to maintain a high level of combustion efficiency. Good combustion practices are technically feasible to control PM emissions from the proposed engines,

5.3.2.3 Proposed PM BACT for the Emer. Gen. and Fire Pump

Longview Power Unit 2 will elect to implement all of the remaining technically feasible control technologies, thus further review of economic, environmental, and energy impacts is unnecessary. **Based on the above analysis, Longview Power Unit 2 proposes BACT for PM/PM_{10} emissions from the Emergency Generator and Fire Water Pump to be combustion of low sulfur diesel fuel and good combustion practices.**

5.3.3 BACT for CO Emissions for the Emer. Gen. and Fire Pump

Carbon monoxide is an intermediate combustion product that forms when the oxidation of CO to CO_2 cannot proceed to completion. This situation occurs if there is a lack of available oxygen, if the combustion temperature is too low, or if the residence time in the cylinder is too short. A top down analysis to determine the best available CO control technology is provided in the following subsections.

5.3.3.1 Identification of Potential Control Technologies (Step 1)

Combustion design and catalytic oxidation are the potentially viable control alternatives.. The most stringent control technology for CO emissions is the use of an oxidation catalyst. Other acceptable control techniques include engine design, and good combustion practices.

5.3.3.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down analysis is an evaluation of the technical feasibility of each of these control options. Each of the potential control technologies considered is described below along with a discussion of the technical feasibility of each with respect to the Project.

1. <u>Oxidation Catalyst</u>

Oxidation catalysts (typically a precious metal deposited onto a solid honeycomb substrate) convert carbon monoxide (CO) to carbon dioxide (CO_2) in the presence of oxygen. This technology has not been applied on similar emergency use engines based on a review of BACT/LAER determinations. Therefore, the Project does not consider this technology technically feasible option for CO emissions control.

2. <u>Good Combustion Practices</u>

Good combustion practices refer to the operation of the engines at high combustion efficiency, thus reducing products of incomplete combustion such as CO. The engines will be designed to maximize combustion efficiency. The combustion turbine manufacturer will provide Operator and Maintenance manual(s) detailing methods to maintain a high level of combustion efficiency.

5.3.3.3 Proposed CO BACT for the Emer. Gen. and Fire Pump

Longview Power Unit 2 will elect to implement the remaining technically feasible control technology, thus further review of economic, environmental, and energy impacts is unnecessary. **Based on the evaluations above, Longview Power Unit 2 proposes good combustion practices as BACT.**

5.3.4 BACT for H_2SO_4 Emissions for the Emer. Gen. and Fire Pump

A top down BACT analysis is not applicable for H_2SO_4 emissions as the only control technique identified for H_2SO_4 emissions in the RBLC Database is the combustion of low sulfur fuels. There is no evidence that add-on controls have been installed for H_2SO_4 control from internal combustion engines; therefore, add-on controls are not considered as potential BACT for the proposed project. **Longview Power Unit 2 proposes BACT for H_2SO_4 emissions from the engines to be combustion of low sulfur fuel and an emission limit of 0.00023 lb/MMBtu.**

5.4 BACT FOR FUEL GAS PRE HEATERS

5.4.1 BACT for NOx and VOCs for Fuel Gas Pre Heaters

There is currently no technically feasible add-on control technology to reduce NOx or VOCs emissions from gaseous fuel-fired Fuel Gas Heaters of the size proposed for the Project. NOx is minimized in these units through good combustion practices, as well as LNB. LNB are designed to recirculate hot, oxygen-depleted flue gas from the flame or firebox back into the combustion zone. By doing this, the average oxygen concentration is reduced in the flame without reducing the flame temperatures below which is necessary for optimal combustion efficiency. Reducing oxygen concentrations in the flame reduces the amount of fuel NOx and VOCs generated. Although these efficient combustion techniques are targeted to reduce NOx emissions, they have a collateral benefit of reducing CO formation.

Longview Power Unit 2 proposed NOx and VOC emission level of 0.036 lb/MMBtu and 0.007 lb/mmBtu, respectively as BACT for the Fuel Gas Heaters.

5.4.1.1 BACT for PM for Fuel Gas Pre Heaters

A review of the RBLC, as well as USEPA and state permit databases indicates that there are no fuel gas pre heaters (i.e., small boilers) employing post-combustion control equipment to reduce PM, PM10, and PM2.5 to achieve BACT.

Longview Power Unit 2 proposes the use of clean fuels (i.e., low-sulfur, low-ash content), good combustion practices and an emission rate of 0.008 lb/mmBtu as BACT for PM, PM10, and PM2.5 emissions.

5.4.1.2 BACT for CO for Fuel Gas Pre Heaters

A review of the RBLC, as well as USEPA and state permit databases indicates that there are no fuel gas pre heaters (i.e., small boilers) employing post-combustion control equipment to minimize CO formation.

Longview Power Unit 2 proposes the use of clean fuels (i.e., low-sulfur, low-ash content), good combustion practices and an emission rate of 0.039 lb/mmBtu as BACT for CO emissions.

5.4.1.3 BACT for H_2SO_4 for Fuel Gas Pre Heaters

A review of the RBLC, as well as USEPA and state permit databases indicates that there are no fuel gas pre heaters (i.e., small boilers) employing post-combustion control equipment to minimize H_2SO_4 formation.

Longview Power Unit 2 proposes the use of clean fuels (i.e., low-sulfur, low-ash content), good combustion practices and an emission rate of 0.0001 lb/mmBtu as BACT for H_2SO_4 emissions.

5.4.2 BACT Analysis for Other Regulated Pollutants

Other regulated pollutants consist of non-criteria pollutants for which a regulatory standard has been established. These pollutants primarily fall into the category of speciated organic or metal compounds and the majority of these compounds are considered Hazardous Air Pollutants as defined in Section 112 of the Clean Air Act. Based on the emission rates expected from the proposed internal combustion engines, the level of emissions of "other regulated pollutants" will be very low. BACT for VOHAPs will be met by the same technology as proposed for BACT for VOC emissions. Similarly, BACT for control of the low levels of particulate matter HAPS or PMHAPs will also be controlled by the BACT proposed for PM/PM_{10}.

5.5 CONTROL TECHNOLOGY DETERMINATION FOR THE MECHANICAL DRAFT COOLING TOWER

5.5.1 BACT for $PM/PM_{10}/PM_{2.5}$ Emissions for the Cooling Tower

Particulate emissions from the mechanical draft cooling towers consist of entrained dissolved solid impurities from water treatment chemicals and other solid impurities in the supply water used for the cooling tower circulation water. These impurities are in the water vapor exhausted from the tower and a portion of the water droplets emitted from the tower exhausts will evaporate, leaving the suspended or dissolved solids in the atmosphere. A search of BACT determinations for industrial wet cooling towers was conducted since the emissions profile from the evaporation tower is most similar to this type of process. The only control technology identified as BACT was mechanical drift eliminators.

The Longview Power Unit 2 Project is proposing to install two types of redundant demisters on the tower; a series of baffle-type demisters and an additional mesh-type demister. This level of control is the maximum available from vendor of the mechanical draft cooling tower. No other types of $PM/PM_{10}/PM_{2.5}$ control equipment are known to be commercially available for this unique technology, and the RBLC search did not reveal any other types of control for similar industrial applications.

Therefore, the project proposes that the redundant baffle and mesh demister system is BACT for $PM/PM_{10}/PM_{2.5}$ emissions for the mechanical draft cooling tower. Since the top and technically feasible alternative has been selected as BACT, no further economic analyses are required, nor are they presented.

5.5.2 BACT Analysis for Other Regulated Pollutants for the Cooling Tower

The Project has estimated that emissions of other regulated air pollutants will be negligible from the cooling tower. Any potential regulated air pollutants will be entrained in the $PM/PM_{10}/PM_{2.5}$ emissions, which will be controlled by BACT as described in the previous section. The Project proposes that BACT for any negligible hazardous air pollutants potentially emitted from the evaporation tower be the same as BACT for $PM/PM_{10}/PM_{2.5}$ emissions.

5.6 FACILITY WIDE SUMMARY OF CONTROL TECHNOLOGY EVALUATION

A summary of the BACT emission limits and control technologies for the various emitting units of the Longview Unit 2 Project is provided in Table 5-8.

Table 5-8
Control Technology Evaluation Summary

Emission Unit	Pollutant	Emission Limit	BACT
Combustion Turbines/ HRSG Duct Burners	NO_x	2.0 ppmvd	Dry Low NO_x Burners with SCR
	VOC	1.0 ppmvd w/o duct firing 2.0 ppmvd w/ duct firing	Oxidation catalyst and good combustion practice
	$PM/PM_{10}/PM_{2.5}$	0.008 lb/mmBtu	Clean fuels and good combustion practice
	CO	2.0 ppmvd	Oxidation catalyst and good combustion practice
	H_2SO4	0.00085 lb/mmBtu	Combustion of low sulfur fuel
Emergency Generator/ Fire Water Pump	NO_x	4.8 g/hp-hr/3.0 g/hp-hr	Combustion control (Retarded Timing and/or lean burn)
	VOC	1.2 lb/hr/1.0 lb/hr	Good combustion practice
	$PM/PM_{10}/PM_{2.5}$	NA	Clean fuels and good combustion practices
	CO	0.3 g/hp-hr/ 0.44 g/hp-hr	Good combustion practices
	H_2SO4	NA	Combustion of low sulfur fuel
Fuel Gas Pre Heaters	NO_x	0.036 lb/MMBtu	Low NO_x Burner and good combustion practices
	VOC	0.007 lb/MMBtu	Good combustion practice
	$PM/PM_{10}/PM_{2.5}$	0.008 lb/MMBtu	HEPA Filter
	CO	0.039 lb/MMBtu	Good combustion practice
	H_2SO4	0.0001 lb/MMBtu	Combustion of low sulfur fuel
Cooling Tower	$PM/PM_{10}/PM_{2.5}$	4.11 lb/hr	Drift Eliminators
Facility Wide Limit	GHG	4,282,215 tons/yr, on a CO2e basis	Thermal efficiency/combustion air cooling and use of lower carbon fuels.

SECTION 6

6. AIR QUALITY MODELING APPROACH

6. AIR QUALITY MODELING APPROACH

SECTION 7

7. AIR QUALITY IMPACTS ANALYSIS

7. AIR QUALITY IMPACTS ANALYSIS

8. REFERENCES

8. REFERENCES

U.S. EPA 1985 – "Guidelines for Determination of Good Engineering Practice Stack Height (Technical Support Document for Stack Height Regulations) Revised" EPA-450:4-80-023R, June 1985.

U.S. EPA 1987 – "Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD) May 1987.

U.S. EPA 1993 – "User's Guide to the Building Profile Input Program", October 1993.

U.S. EPA 2018 – "Users Guide for the AERMOD Terrain Preprocessor (AERMAP) Revised – Draft" April 2018.

U.S. EPA 2017 – 40 CFR Part 51 Appendix W "Guideline on Air Quality Models (Revised)", January 17, 2017

U.S. FS 2010 – "Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report" 2010.

APPENDICES

APPENDICES

APPENDICES

APPENDIX A - WV DAQ APPLICATION FORMS.

WEST VIRGINIA DEPARTMENT OF ENVIRONMENTAL PROTECTION

DIVISION OF AIR QUALITY

601 57th Street, SE
Charleston, WV 25304
(304) 926-0475
www.dep.wv.gov/daq

APPLICATION FOR NSR PERMIT AND TITLE V PERMIT REVISION (OPTIONAL)

PLEASE CHECK ALL THAT APPLY TO **NSR (45CSR13)** (IF KNOWN):

☒ **CONSTRUCTION** ☐ **MODIFICATION** ☐ **RELOCATION**
☐ **CLASS I ADMINISTRATIVE UPDATE** ☐ **TEMPORARY**
☐ **CLASS II ADMINISTRATIVE UPDATE** ☐ **AFTER-THE-FACT**

PLEASE CHECK TYPE OF **45CSR30 (TITLE V)** REVISION (IF ANY):

☐ **ADMINISTRATIVE AMENDMENT** ☐ **MINOR MODIFICATION**
☐ **SIGNIFICANT MODIFICATION**

IF ANY BOX ABOVE IS CHECKED, INCLUDE TITLE V REVISION INFORMATION AS **ATTACHMENT S** TO THIS APPLICATION

FOR TITLE V FACILITIES ONLY: Please refer to "Title V Revision Guidance" in order to determine your Title V Revision options (Appendix A, "Title V Permit Revision Flowchart") and ability to operate with the changes requested in this Permit Application.

Section I. General

1. Name of applicant *(as registered with the WV Secretary of State's Office):*
Longview Power II, LLC

2. Federal Employer ID No. ***(FEIN):***
45-0543713

3. Name of facility *(if different from above):*
Longview Power II

4. The applicant is the:
☒ **OWNER** ☐**OPERATOR** ☐ **BOTH**

5A. Applicant's mailing address:
1375 Fort Martin Road
Maidsville, WV 26541

5B. Facility's present physical address:
1375 Fort Martin Road
Maidsville, WV 26541

6. **West Virginia Business Registration.** Is the applicant a resident of the State of West Virginia? ☒ **YES** ☐ **NO**
- If **YES,** provide a copy of the **Certificate of Incorporation/Organization/Limited Partnership** (one page) including any name change amendments or other Business Registration Certificate as **Attachment A.**
- If **NO,** provide a copy of the **Certificate of Authority/Authority of L.L.C./Registration** (one page) including any name change amendments or other Business Certificate as **Attachment A.**

7. If applicant is a subsidiary corporation, please provide the name of parent corporation: Genpower Services, LLC

8. Does the applicant own, lease, have an option to buy or otherwise have control of the *proposed site?* ☒ **YES** ☐ **NO**
- If **YES,** please explain: Yes, there exists a Memorandum of Understanding that will lead to a Payment In Lieu Of Taxes (PILOT) and Lease Agreement with Monongalia County.
- If **NO,** you are not eligible for a permit for this source.

9. Type of plant or facility (stationary source) to be **constructed, modified, relocated, administratively updated** or **temporarily permitted** (e.g., coal preparation plant, primary crusher, etc.): Combined Cycle Combustion Turbine - Electric Generating Unit

10. North American Industry Classification System **(NAICS)** code for the facility:
221112

11A. DAQ Plant ID No. (for existing facilities only):
N/A

11B. List all current 45CSR13 and 45CSR30 (Title V) permit numbers associated with this process (for existing facilities only):
None

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

12A.

- For **Modifications, Administrative Updates** or **Temporary permits** at an existing facility, please provide directions to the *present location* of the facility from the nearest state road;
- For **Construction** or **Relocation permits,** please provide directions to the *proposed new site location* from the nearest state road. Include a **MAP** as **Attachment B**.

12.B. New site address (if applicable):	12C. Nearest city or town:	12D. County:
1375 Fort Martin Road Maidsville, WV 26541	Maidsville	Monongalia
12.E. UTM Northing (KM): 4,396.353	12F. UTM Easting (KM): 589.078	12G. UTM Zone: 17

13. Briefly describe the proposed change(s) at the facility:
Construction of the following:
1. One combined cycle power train consisting of two state-of-the-art natural gas-fueled advanced class combustion turbines, two heat recovery steam generators (with duct burners), and one steam turbine.
2. Diesel fuel-fired firewater pump.
3. Diesel fuel-fired emergency generator.
4. Wet mechanical draft cooling tower.
5. Gas preheaters

14A. Provide the date of anticipated installation or change: First quarter 2021 If this is an **After-The-Fact** permit application, provide the date upon which the proposed change did happen: / /	14B. Date of anticipated Start-Up if a permit is granted: First quarter 2024

14C. Provide a **Schedule** of the planned **Installation** of/**Change** to and **Start-Up** of each of the units proposed in this permit application as **Attachment C** (if more than one unit is involved).

15. Provide maximum projected **Operating Schedule** of activity/activities outlined in this application:
Hours Per Day 24 Days Per Week 7 Weeks Per Year 52

16. Is demolition or physical renovation at an existing facility involved? ☐ **YES** ☒ **NO**

17. **Risk Management Plans.** If this facility is subject to 112(r) of the 1990 CAAA, or will become subject due to proposed changes (for applicability help see www.epa.gov/ceppo), submit your **Risk Management Plan (RMP)** to U. S. EPA Region III.
NOT APPLICABLE

18. **Regulatory Discussion.** List all Federal and State air pollution control regulations that you believe are applicable to the proposed process *(if known)*. A list of possible applicable requirements is also included in Attachment S of this application (Title V Permit Revision Information). Discuss applicability and proposed demonstration(s) of compliance *(if known)*. Provide this information as **Attachment D.**

Section II. Additional attachments and supporting documents.

19. Include a check payable to WVDEP – Division of Air Quality with the appropriate **application fee** (per 45CSR22 and 45CSR13).

20. Include a **Table of Contents** as the first page of your application package.
See Table of Contents in the PSP Permit Application Document

21. Provide a **Plot Plan,** e.g. scaled map(s) and/or sketch(es) showing the location of the property on which the stationary source(s) is or is to be located as **Attachment E** (Refer to ***Plot Plan Guidance***) .
- Indicate the location of the nearest occupied structure (e.g. church, school, business, residence).

22. Provide a **Detailed Process Flow Diagram(s)** showing each proposed or modified emissions unit, emission point and control device as **Attachment F.**

23. Provide a **Process Description** as **Attachment G.**

– Also describe and quantify to the extent possible all changes made to the facility since the last permit review (if applicable).

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

24. Provide **Material Safety Data Sheets (MSDS)** for all materials processed, used or produced as **Attachment H.**

– For chemical processes, provide a MSDS for each compound emitted to the air.

25. Fill out the **Emission Units Table** and provide it as **Attachment I.**

26. Fill out the **Emission Points Data Summary Sheet (Table 1 and Table 2)** and provide it as **Attachment J.**

27. Fill out the **Fugitive Emissions Data Summary Sheet** and provide it as **Attachment K.**

28. Check all applicable **Emissions Unit Data Sheets** listed below:

☐ Bulk Liquid Transfer Operations
☐ Chemical Processes
☐ Concrete Batch Plant
☐ Grey Iron and Steel Foundry
☐ Haul Road Emissions
☐ Hot Mix Asphalt Plant
☐ Incinerator
☒ Indirect Heat Exchanger
☐ Quarry
☐ Solid Materials Sizing, Handling and Storage Facilities
☒ Storage Tanks
☒ General Emission Unit, specify: Combined-Cycle Combustion Turbines

Fill out and provide the **Emissions Unit Data Sheet(s)** as **Attachment L.**

29. Check all applicable **Air Pollution Control Device Sheets** listed below:

☐ Absorption Systems
☐ Adsorption Systems
☐ Afterburner
☐ Baghouse
☐ Condenser
☐ Electrostatic Precipitator
☐ Flare
☐ Mechanical Collector
☐ Wet Collecting System

☒ Other Collectors, specify

The Combined-Cycle Combustion Turbines and the HRSG Duct Burners will be equipped with Selective Catalytic Reduction (SCR) systems and dry low-NOx combustors (DLNC). These combustion controls along will control emissions of nitrogen oxides (NOx). Oxidation catalysts will be used to control the turbines' carbon monoxide (CO) and volatile organic compounds (VOC) emissions. The Fuel Gas Preheaters will be equipped with low- NOx burners (LNB) to control NOx emissions. The Mechanical Draft Cooling Tower will be equipped with demisters.

The proposed emission control systems including the determination of Best Available Control Technology determination are described in Section 4 of the PSD Permit Application Document.

Fill out and provide the **Air Pollution Control Device Sheet(s)** as **Attachment M.**

30. Provide all **Supporting Emissions Calculations** as **Attachment N,** or attach the calculations directly to the forms listed in Items 28 through 31.

31. **Monitoring, Recordkeeping, Reporting and Testing Plans.** Attach proposed monitoring, recordkeeping, reporting and testing plans in order to demonstrate compliance with the proposed emissions limits and operating parameters in this permit application. Provide this information as **Attachment O.**

➢ Please be aware that all permits must be practically enforceable whether or not the applicant chooses to propose such measures. Additionally, the DAQ may not be able to accept all measures proposed by the applicant. If none of these plans are proposed by the applicant, DAQ will develop such plans and include them in the permit.

32. **Public Notice.** At the time that the application is submitted, place a **Class I Legal Advertisement** in a newspaper of general circulation in the area where the source is or will be located (See 45CSR§13-8.3 through 45CSR§13-8.5 and ***Example Legal Advertisement*** for details). Please submit the **Affidavit of Publication** as **Attachment P** immediately upon receipt.

33. **Business Confidentiality Claims.** Does this application include confidential information (per 45CSR31)?

☐ **YES** ☒ **NO**

➢ If **YES,** identify each segment of information on each page that is submitted as confidential and provide justification for each segment claimed confidential, including the criteria under 45CSR§31-4.1, and in accordance with the DAQ's ***"Precautionary Notice – Claims of Confidentiality"*** guidance found in the ***General Instructions*** as **Attachment Q.**

Section III. Certification of Information

34. **Authority/Delegation of Authority.** Only required when someone other than the responsible official signs the application. Check applicable **Authority Form** below:

☐ Authority of Corporation or Other Business Entity

☐ Authority of Partnership

☐ Authority of Governmental Agency

☐ Authority of Limited Partnership

Submit completed and signed **Authority Form** as **Attachment R.**

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

35A. **Certification of Information.** To certify this permit application, a Responsible Official (per 45CSR§13-2.22 and 45CSR§30-2.28) or Authorized Representative shall check the appropriate box and sign below.

Certification of Truth, Accuracy, and Completeness

I, the undersigned ☒ **Responsible Official** / ☐ **Authorized Representative,** hereby certify that all information contained in this application and any supporting documents appended hereto, is true, accurate, and complete based on information and belief after reasonable inquiry I further agree to assume responsibility for the construction, modification and/or relocation and operation of the stationary source described herein in accordance with this application and any amendments thereto, as well as the Department of Environmental Protection, Division of Air Quality permit issued in accordance with this application, along with all applicable rules and regulations of the West Virginia Division of Air Quality and W.Va. Code § 22-5-1 et seq. (State Air Pollution Control Act). If the business or agency changes its Responsible Official or Authorized Representative, the Director of the Division of Air Quality will be notified in writing within 30 days of the official change.

Compliance Certification

Except for requirements identified in the Title V Application for which compliance is not achieved, I, the undersigned hereby certify that, based on information and belief formed after reasonable inquiry, all air contaminant sources identified in this application are in compliance with all applicable requirements.

SIGNATURE ______________________ (Please use blue ink)   DATE: December 6 2019 (Please use blue ink)

35B. Printed name of signee: Stephen H. Nelson		35C. Title: Chief Operating Officer
35D. E-mail: snelson@longviewpower.net	36E. Phone: 304-599-0930 x3054	36F. FAX:
36A. Printed name of contact person (if different from above): Brian P. Hoyt II		36B. Title: Compliance & Environmental Manager
36C. E-mail: bhoyt@longviewpower.net	36D. Phone: 304-599-0930 x2203	36E. FAX:

PLEASE CHECK ALL APPLICABLE ATTACHMENTS INCLUDED WITH THIS PERMIT APPLICATION:

- ☒ **Attachment A: Business Certificate**
- ☒ **Attachment B: Map(s)**
- ☒ **Attachment C: Installation and Start Up Schedule**
- ☒ **Attachment D: Regulatory Discussion**
- ☒ **Attachment E: Plot Plan**
- ☒ **Attachment F: Detailed Process Flow Diagram(s)**
- ☒ **Attachment G: Process Description**
- ☒ **Attachment H: Material Safety Data Sheets (MSDS)**
- ☒ **Attachment I: Emission Units Table**
- ☒ **Attachment J: Emission Points Data Summary Sheet**
- ☒ **Attachment K: Fugitive Emissions Data Summary Sheet**
- ☒ **Attachment L: Emissions Unit Data Sheet(s)**
- ☒ **Attachment M: Air Pollution Control Device Sheet(s)**
- ☒ **Attachment N: Supporting Emissions Calculations**
- ☒ **Attachment O: Monitoring/Recordkeeping/Reporting/Testing Plans**
- ☒ **Attachment P: Public Notice**
- ☒ **Attachment Q: Business Confidential Claims**
- ☒ **Attachment R: Authority Forms**
- ☒ **Attachment S: Title V Permit Revision Information**
- ☒ **Application Fee**

Please mail an original and three (3) copies of the complete permit application with the signature(s) to the DAQ, Permitting Section, at the address listed on the first page of this application. Please DO NOT fax permit applications.

FOR AGENCY USE ONLY – IF THIS IS A TITLE V SOURCE:

- ☐ *Forward 1 copy of the application to the Title V Permitting Group and:*
- ☐ *For Title V Administrative Amendments:*
  - ☐ *NSR permit writer should notify Title V permit writer of draft permit,*
- ☐ *For Title V Minor Modifications:*
  - ☐ *Title V permit writer should send appropriate notification to EPA and affected states within 5 days of receipt,*
  - ☐ *NSR permit writer should notify Title V permit writer of draft permit.*
- ☐ *For Title V Significant Modifications processed in parallel with NSR Permit revision:*
  - ☐ *NSR permit writer should notify a Title V permit writer of draft permit,*
  - ☐ *Public notice should reference both 45CSR13 and Title V permits,*
  - ☐ *EPA has 45 day review period of a draft permit.*

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

ATTACHMENT A
BUSINESS CERTIFICATE

Delaware

The First State

I, JEFFREY W. BULLOCK, SECRETARY OF STATE OF THE STATE OF DELAWARE, DO HEREBY CERTIFY THE ATTACHED IS A TRUE AND CORRECT COPY OF THE CERTIFICATE OF AMENDMENT OF "GENPOWER SERVICES, LLC", CHANGING ITS NAME FROM "GENPOWER SERVICES, LLC" TO "LONGVIEW POWER II, LLC", FILED IN THIS OFFICE ON THE FIFTH DAY OF SEPTEMBER, A.D. 2018, AT 1:46 O`CLOCK P.M.

Jeffrey W. Bullock, Secretary of State

SECRETARY'S OFFICE 1793 DELAWARE 1833

4225204 8100
SR# 20186506929

Authentication: 203423787
Date: 09-14-18

You may verify this certificate online at corp.delaware.gov/authver.shtml

State of Delaware
Secretary of State
Division of Corporations
Delivered 01:46 PM 09/05/2018
FILED 01:46 PM 09/05/2018
SR 20186506929 - File Number 4225204

STATE OF DELAWARE
CERTIFICATE OF AMENDMENT

1. Name of Limited Liability Company: GenPower Services, LLC

2. The Certificate of Formation of the limited liability company is hereby amended as follows:

Strike the statement relating to the limited liability company's name and substitute in lieu thereof the following statement: "The name of the limited liability company is Longview Power II, LLC"

IN WITNESS WHEREOF, the undersigned have executed this Certificate on the 5th day of September, A.D. 2018.

By: Jeffery Keffer
Authorized Person(s)

Name: Jeffery L. Keffer, Esq.
Print or Type

State of West Virginia

Certificate

I, Mac Warner, Secretary of State,
of the State of West Virginia, hereby certify that

Articles of Amendment to the Articles of Incorporation of

GENPOWER SERVICES, LLC

Therefore, I issue this

CERTIFICATE OF AMENDMENT TO THE

CERTIFICATE OF AUTHORITY

Changing the name of the organization to

LONGVIEW POWER II, LLC

STATE OF WEST VIRGINIA
JUNE 20 1863
MONTANI SEMPER LIBERI.

Given under my hand and
the Great Seal of West Virginia
on this day of

October 16, 2018

Mac Warner

Secretary of State

ATTACHMENT B
LOCATION MAP

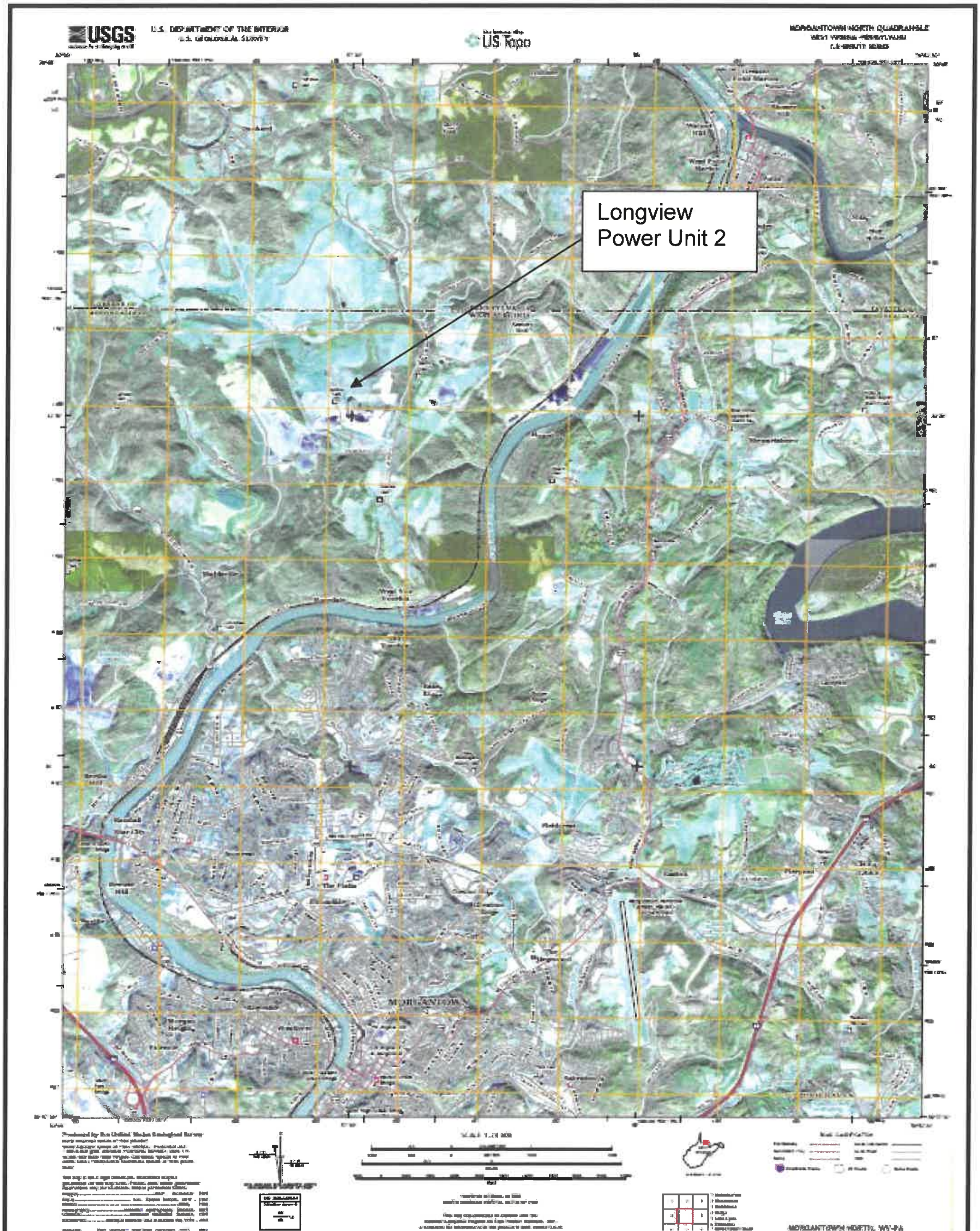


Figure B-1 Location Map
Location of Proposed Longview Power Unit 2

ATTACHMENT C
SCHEDULE OF INSTALLATION AND START-UP

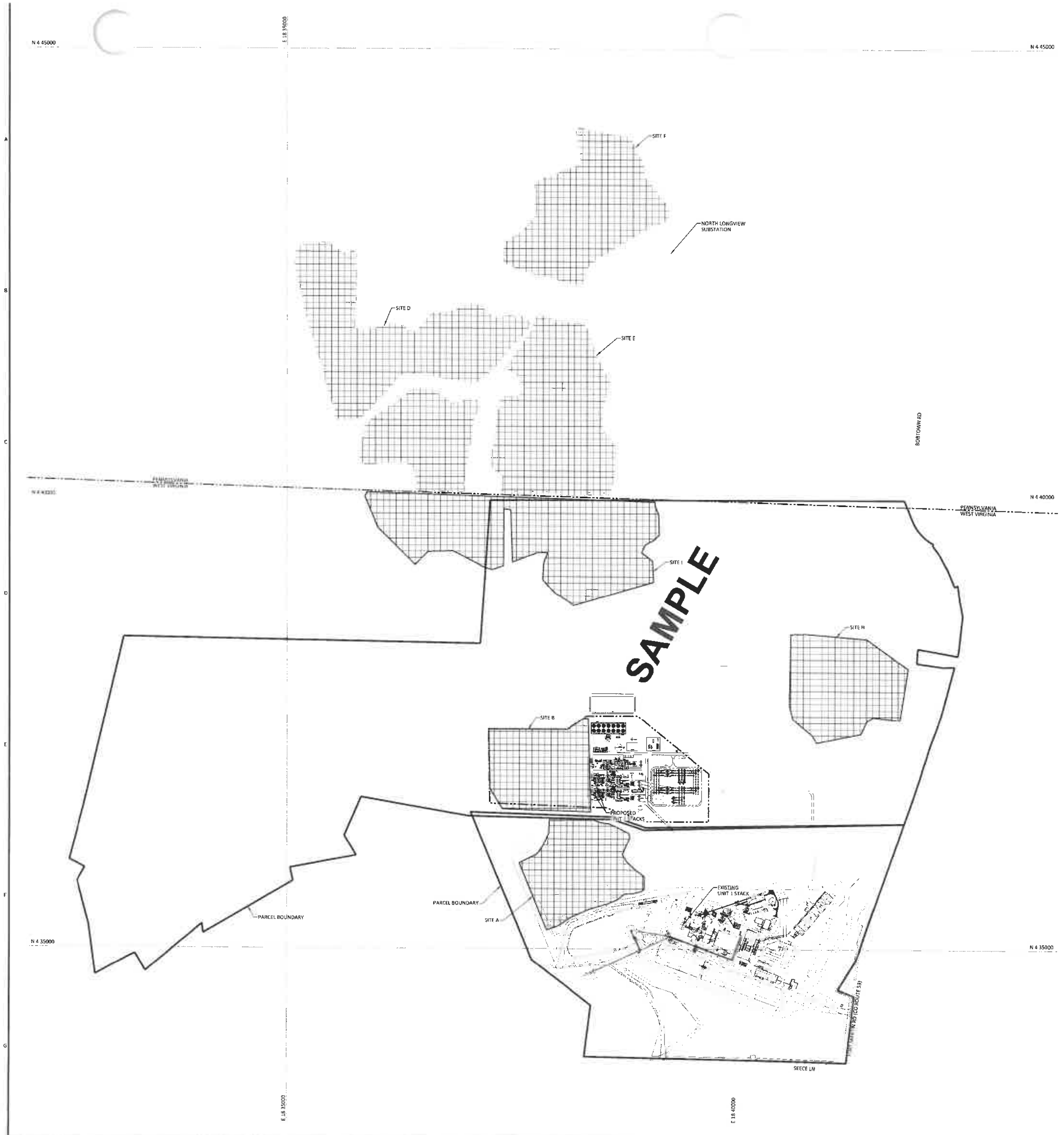
Longview Power Unit 2 has tentatively scheduled to begin construction related activities during the first quarter of 2021. Final installation of equipment and start-up of the facility is tentatively scheduled for the first quarter of 2024. This schedule may vary depending on actual delivery of equipment, unforeseen construction delays, etc.

ATTACHMENT D
REGULATORY DISCUSSION

The Longview Power Unit 2 will be designed and operated in accordance with applicable State of West Virginia and Federal regulations. Regulations potentially impacting the proposed project are described in Section 4 of the Permit Application Document including

4.1 Federal Regulations
4.1.1 New Source Performance Standards (NSPS)
4.1.2 Prevention of Significant Deterioration (PSD)
4.1.3 Acid Rain Provisions
4.1.4 National Emission Standards For Hazardous Air Pollutants (NESHAP)
4.1.5 Compliance Assurance Monitoring (CAM)
4.1.6 Accidental Release Prevention
4.2 State of West Virginia Regulations

ATTACHMENT E
PLOT PLAN



STACK LOCATIONS

CL UNIT 1 STACK (EXISTING)	CL NORTHERN UNIT 2 STACK (PRELIMINARY)	CL SOUTHERN UNIT 2 STACK (PRELIMINARY)
STATE PLANE (US SURVEY FEET)	STATE PLANE (US SURVEY FEET)	STATE PLANE (US SURVEY FEET)
ZONE: 4701 - WEST VIRGINIA NORTH	ZONE: 4701 - WEST VIRGINIA NORTH	ZONE: 4701 - WEST VIRGINIA NORTH
NORTHING: 440268.492	NORTHING: 441894.002	NORTHING: 441724.002
EASTING: 1839397.875	EASTING: 1838417.691	EASTING: 1838417.691

GENERAL LEGEND

PROPOSED SOLAR FIELD

NOTES

1. THIS DRAWING IS THE BASIS FOR THE SITE ARRANGEMENT AND IS SUBJECT TO REVISIONS AS A RESULT OF DETAILED DESIGN AND DUE TO VARIATIONS IN SUPPLIERS OF MAJOR EQUIPMENT.

NOT TO BE USED FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

0 15/NOV/18 INITIAL ISSUE MJW MJW MMD BCR

400' 200' 0 400' 800'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF WEST VIRGINIA.

SIGNED KYLE M. KROPF
DATE 15/NOV/18 REG NO. 22497

BLACK & VEATCH

MJW MJW DRAWN MJW CHECKED DATE

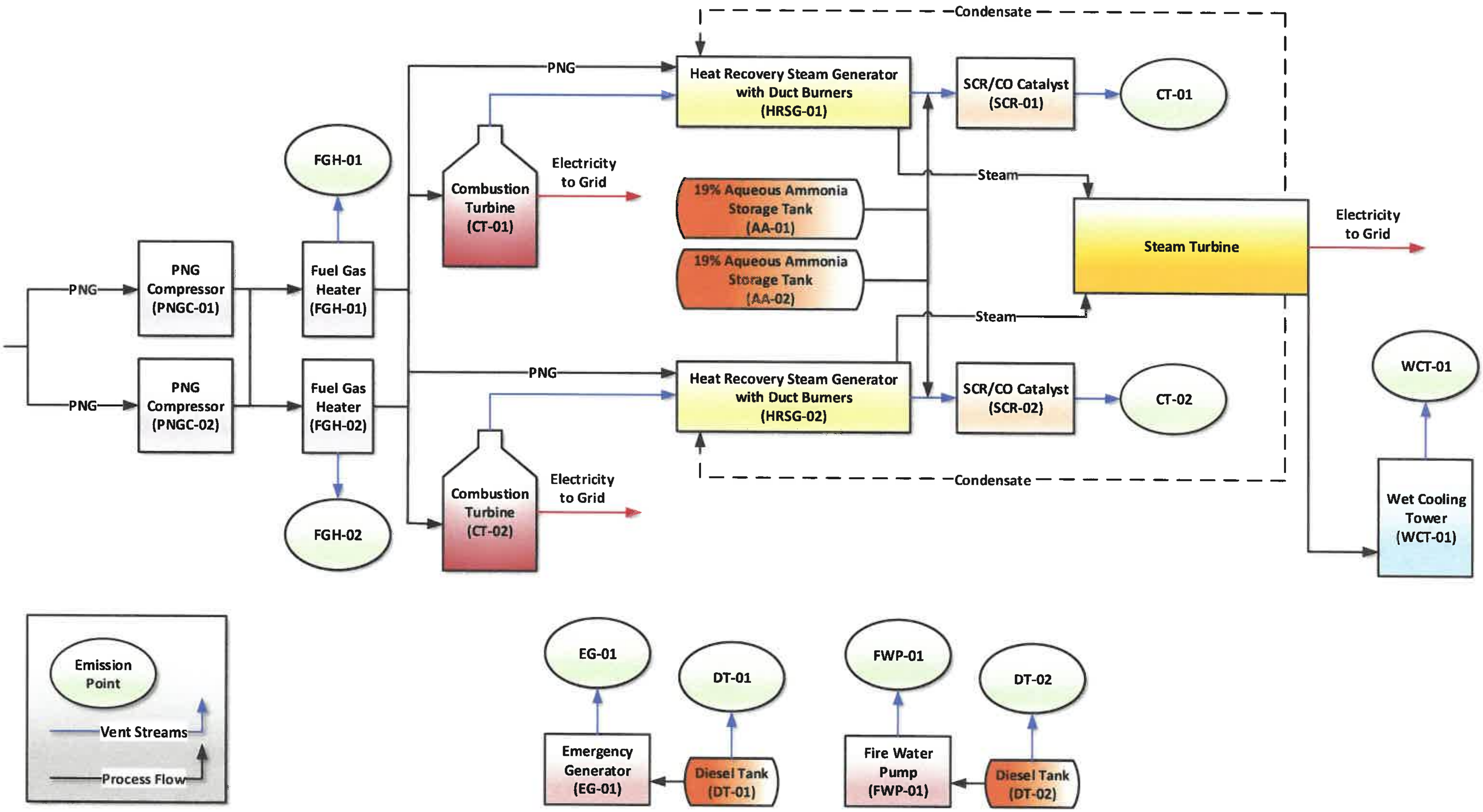
LONGVIEW POWER, LLC.
LONGVIEW CLEAN ENERGY CENTER
PLOT PLAN

PROJECT DRAWING NUMBER 199480-2GAU-G1000 REV 0

CODE
AREA

ATTACHMENT F
DETAILED PROCESS FLOW DIAGRAM

Longview Power
Unit 2 Process Flow Diagram



ATTACHMENT G
PROCESS DESCRIPTION

The Longview Power Unit 2 Project is proposed to be a nominally rated 1,200 MW natural gas-fired only (no oil backup), combined-cycle power plant located immediately adjacent to the north of the existing Longview Power Unit 1. The Project will be designed to achieve a peak electrical output during the summer season of approximately 1,200 MW. Electricity generated by Unit 2 will be supplied to the PJM power grid and connect to the grid via the existing interconnection used by the Longview Power Unit 1.

The major components of the proposed power plant include: One combined cycle power train consisting of two combustion turbines, two heat recovery steam generators (HRSG) with duct burners, one steam turbine, one diesel fuel-fired firewater pump, one diesel fired emergency generator and one mechanical draft cooling tower.

To enhance the plant's overall efficiency and increase the amount of electricity generated by the Project, the hot exhaust gases from each combustion turbine will be routed to a downstream Heat Recovery Steam Generator. The HRSGs contains a series of heat exchangers designed to recover the heat from the turbine's exhaust gas and produce steam. The Project includes the installation of duct burners to produce additional steam in the HRSGs for additional power output from the steam turbine generator. The duct burners will only fire natural gas. No oil backup is planned for the Project.

Cooled exhaust gas passing through the HRSGs will be vented to the Selective Catalytic Reduction (SCR) and Oxidation Catalyst control system used to control NOx and CO emissions. Selective Catalytic Reduction involves the injection of aqueous ammonia (NH_3) at a concentration of approximately 19% by weight into the combustion turbine exhaust gas streams. The ammonia reacts with NOx in the exhaust gas stream in the presence of a catalyst, reducing it to elemental nitrogen (N_2) and water vapor (H_2O). The aqueous ammonia will be stored on-site in dual 60,000 gallon (approximate) storage tanks.

Steam generated in the HRSGs will be routed to a steam driven turbine that will increase the output of the electric generator. This generator will produce additional electricity that will be sold on the grid. Electricity generated by the combustion turbines and the single steam driven turbine driving the electric generator represents the Project's total electrical output.

The Project will use a condenser and a 14 cell wet mechanical draft cooling tower for steam turbine generator steam condensation and waste heat rejection.

A 240 hp, 179 kW standby firewater pump will be used to supply water during emergency conditions. The fire water pump will use ultra-low sulfur diesel (ULSD) fuel, with a sulfur content no greater than 0.0015% by weight. The fire water pump will also be periodically operated for short periods per manufacturer's maintenance instructions to ensure operational readiness in the event of an emergency. The fire water pump is expected to operate less than 100 hours per year.

An emergency generator (1,528 hp, 1,139 kW) will be used for emergency backup electric power. The fuel for the emergency generator will be ULSD with a sulfur content no greater than 0.0015% by weight. The emergency generator will be periodically operated for short periods per manufacturer's maintenance instructions to ensure operational readiness in the event of an emergency. The emergency generator is expected to operate less than 100 hours per year. Two (2) fuel gas heaters (5.4 MMBtu/hr, approximate) will be used to preheat the pipeline natural gas received by the plant. Preheating the fuel prior to combustion in the CTs increases their efficiency, safeguards the fuel pipelines from icing, and protects the CTs from fuel condensates.

The fuel supply for the Unit 2 CCGT will be provided via a 6.2 mile 20" pipeline interconnecting onto both the Columbia 1804 and 10240 interstate pipelines located near Greensboro, PA. At this interconnection, there will be a metering station allowing connection with the dual supply lines that are integral to the Columbia pipeline. Electric gas compression equipment will be added to this line and will have those facilities located on the Unit 2 site.

The Project will own and operate two pipeline gas compressor units. The compressors are electric-drive, 2,750 HP (Toshiba J2758, or equivalent) with a 4-throw reciprocating fluid end (Ariel JGC/4, or equivalent). The manufacturer recommends states that there are no GHG/VOC emissions associated with the operation of the units. Additionally, the manufacturer states that there will be no GHG/VOC emissions associated with the startup and shutdown of compressor units during normal operation; since no purge will be necessary.

Additional details of the process is contained in Sections 2 and 3 of the PSD Application Document.

ATTACHMENT H
MSDS

The Material Data Sheets (MDS) for natural gas and diesel fuel are attached. These are the only fuels to be used at the Longview Power Unit 2 project.

Safety Data Sheet

Material Name: Natural Gas Odorized **SDS No. 8010**

US GHS

Synonyms: Compressed Natural Gas (CNG); Dry Natural Gas ; Methane; Pipeline Spec Gas; Processed Gas; Residue Gas; Sweet Natural Gas; Natural Gas (odorized); Treated Gas

* * * Section 1 - Product and Company Identification * * *

Manufacturer Information

Hess Corporation
1 Hess Plaza
Woodbridge, NJ 07095-0961

Phone: 732-750-6000 Corporate EHS
Emergency # 800-424-9300 CHEMTREC
www.hess.com (Environment, Health, Safety Internet Website)

* * * Section 2 - Hazards Identification * * *

GHS Classification:

Flammable Gas - Category 1
Gases Under Pressure - Liquefied Gas
Specific Target Organ Systemic Toxicity (STOT) - Single Exposure Category 2

GHS LABEL ELEMENTS

Symbol(s)

Signal Word

Danger

Hazard Statements

Extremely flammable gas.
Contains gas under pressure, may explode if heated.
May cause damage to central nervous and respiratory systems.

Precautionary Statements

Prevention

Keep away from heat/sparks/open flames/hot surfaces. No smoking
Do not breathe fume/gas/mist/vapours/spray.
Wash thoroughly after handling.
Do not eat, drink or smoke when using this product.

Response

Leaking gas fire: Do not extinguish, unless leak can be stopped safely. Eliminate all ignition sources if safe to do so.
IF exposed or concerned: Call a POISON CENTER or doctor/physician.

Storage

Protect from sunlight. Store in a well-ventilated place.

Store locked up.

Disposal
Dispose of contents/container in accordance with local/regional/national/international regulations.

* * * Section 3 - Composition / Information on Ingredients * * *

CAS #	Component	Percent
68410-63-9	Natural gas, dried	100
74-82-8	Methane	<90
74-84-0	Ethane	<1

A complex mixture of light gases separated from raw natural gas consisting of aliphatic hydrocarbons having carbon numbers in the range of C1 through C4, predominantly methane (C1) and ethane (C2); may contain carbon dioxide (CO_2). May be odorized with trace amounts of odorant (see Section 9). This is for natural gas that has been processed and is in commerce.

* * * Section 4 - First Aid Measures * * *

First Aid: Eyes
In case of freeze burn cover eyes to protect from light. Seek immediate medical attention.

First Aid: Skin
Remove contaminated clothing. In case of blistering, frostbite or freeze burns seek immediate medical attention.

First Aid: Ingestion
Risk of ingestion is extremely low. However, if oral exposure occurs, seek immediate medical assistance.

First Aid: Inhalation
Remove person to fresh air. If person is not breathing, provide artificial respiration. If necessary, provide additional oxygen once breathing is restored if trained to do so. Seek medical attention immediately.

* * * Section 5 - Fire Fighting Measures * * *

General Fire Hazards
See Section 9 for Flammability Properties.
Dangerous fire and explosion hazard when exposed to heat, sparks or flame. Natural gas is lighter than air and may travel long distances to a point of ignition and flash back. Container may explode in heat or fire. Liquefied Natural Gas (LNG) releases flammable gas at well below ambient temperatures and readily forms a flammable mixture with air.

Hazardous Combustion Products
Carbon monoxide, carbon dioxide and non-combusted hydrocarbons (smoke).

Extinguishing Media
Any extinguisher suitable for Class B fires, dry chemical, fire fighting foam, CO_2, and other gaseous agents. However, fire should not be extinguished unless flow of gas can be immediately stopped.

Unsuitable Extinguishing Media
None

Fire Fighting Equipment/Instructions

Gas fires should not be extinguished unless flow of gas can be immediately stopped. Shut off gas source and allow gas to burn out. If spill or leak has not ignited, determine if water spray may assist in dispersing gas or vapor to protect personnel attempting to stop leak. Use water to cool equipment, surfaces and containers exposed to fire and excessive heat. For large fire the use of unmanned hose holders or monitor nozzles may be advantageous to further minimize personnel exposure. Isolate area, particularly around ends of storage vessels. Let vessel, tank car or container burn unless leak can be stopped. Withdraw immediately in the event of a rising sound from a venting safety device. Large fires typically require specially trained personnel and equipment to isolate and extinguish the fire.

Firefighting activities that may result in potential exposure to high heat, smoke or toxic by-products of combustion should require NIOSH- approved pressure-demand self-contained breathing apparatus with full facepiece and full protective clothing.

* * * Section 6 - Accidental Release Measures * * *

Recovery and Neutralization

Stop the source of the release, if safe to do so.

Materials and Methods for Clean-Up

Do not flush down sewer or drainage systems. Do not touch spilled liquid (frostbite/freeze burn hazard!). Consider the use of water spray to disperse vapors. Isolate the area until gas has dispersed. Ventilate and gas test area before entering.

Emergency Measures

Evacuate nonessential personnel and secure all ignition sources. No road flares, smoking or flames in hazard area. Consider wind direction, stay upwind and uphill, if possible. Evaluate the direction of product travel. Vapor cloud may be white, but color will dissipate as cloud disperses - fire and explosion hazard is still present!

Personal Precautions and Protective Equipment

Do not touch spilled liquid (frostbite/freeze burn hazard!).

Environmental Precautions

Do not flush down sewer or drainage systems.

Prevention of Secondary Hazards

None

* * * Section 7 - Handling and Storage * * *

Handling Procedures

Keep away from flame, sparks and excessive temperatures. Bond and ground containers. Use only in well ventilated areas.

Storage Procedures

Store only in approved containers. Bond and ground containers. Keep away from flame, sparks, excessive temperatures and open flame. Keep containers closed and clearly labeled. Empty product containers or vessels may contain explosive vapors. Do not pressurize, cut, heat, weld or expose such containers to sources of ignition.

Incompatibilities

Keep away from strong oxidizers, ignition sources and heat.

* * * Section 8 - Exposure Controls / Personal Protection * * *

Component Exposure Limits

Methane (74-82-8)

ACGIH: 1000 ppm TWA (listed under Aliphatic hydrocarbon gases: Alkane C1-4)

Ethane (74-84-0)

ACGIH: 1000 ppm TWA (listed under Aliphatic hydrocarbon gases: Alkane C1-4)

Engineering Measures

Use adequate ventilation to keep gas and vapor concentrations of this product below occupational exposure and flammability limits, particularly in confined spaces. Use explosion-proof equipment and lighting in classified/controlled areas.

Personal Protective Equipment: Respiratory

Use a NIOSH approved positive-pressure, supplied air respirator with escape bottle or self-contained breathing apparatus (SCBA) for gas concentrations above occupational exposure limits, for potential for uncontrolled release, if exposure levels are not known, or in an oxygen-deficient atmosphere. CAUTION: Flammability limits (i.e., explosion hazard) should be considered when assessing the need to expose personnel to concentrations requiring respiratory protection.

Personal Protective Equipment: Hands

Use cold-impervious, insulating gloves where contact with pressurized gas may occur.

Personal Protective Equipment: Eyes

Where there is a possibility of pressurized gas contact, wear splash-proof safety goggles and faceshield.

Personal Protective Equipment: Skin and Body

Where contact with pressurized gas may occur, wear apron and faceshield.

* * * Section 9 - Physical & Chemical Properties * * *

Appearance:	Colorless	**Odor:**	Distinctive "natural gas"
Physical State:	Gas	**pH:**	ND
Vapor Pressure:	40 atm @ -187 °F (-86 °C)	**Vapor Density:**	0.6
Boiling Point:	-259°F (-162°C)	**Melting Point:**	ND
Solubility (H2O):	3.5%	**Specific Gravity:**	0.4 @ -263 °F (-164 °C)
Evaporation Rate:	ND	**VOC:**	ND
Octanol/H2O Coeff.:	ND	**Flash Point:**	Flammable Gas
Flash Point Method:	NA	**Upper Flammability Limit (UFL):**	13-17
Lower Flammability Limit (LFL):	3.8-6.5	**Burning Rate:**	ND
Auto Ignition:	900-1170°F (482-632°C)		

* * * Section 10 - Chemical Stability & Reactivity Information * * *

Chemical Stability

This is a stable material.

Hazardous Reaction Potential

Will not occur.

Conditions to Avoid

Keep away from strong oxidizers, ignition sources and heat.

Incompatible Products

Strong oxidizers

Hazardous Decomposition Products

Carbon monoxide, carbon dioxide and non-combusted hydrocarbons (smoke).

* * * Section 11 - Toxicological Information * * *

Acute Toxicity

A: General Product Information

Methane and ethane, the main components of natural gas, are considered practically inert in terms of physiological effects. At high concentrations these materials act as simple asphyxiants and may cause death due to lack of oxygen.

B: Component Analysis - LD50/LC50

Methane (74-82-8)

Inhalation LC50 Mouse 326 g/m3 2 h

Ethane (74-84-0)

Inhalation LC50 Rat 658 mg/L 4 h

Potential Health Effects: Skin Corrosion Property/Stimulativeness

Vapors are not irritating. Direct contact to skin or mucous membranes with pressurized vapor may cause freeze burns and frostbite. Signs of frostbite include a change in the color of the skin to gray or white, possibly followed by blistering. Skin may become inflamed and painful.

Potential Health Effects: Eye Critical Damage/ Stimulativeness

Vapors are not irritating. However, contact with liquid or cold vapor may cause frostbite, freeze burns, and permanent eye damage.

Potential Health Effects: Ingestion

Risk of ingestion is extremely unlikely.

Potential Health Effects: Inhalation

This product is considered to be non-toxic by inhalation. Inhalation of high concentrations may cause central nervous system depression such as dizziness, drowsiness, headache, and similar narcotic symptoms, but no long-term effects. Numbness, a "chilly" feeling, and vomiting have been reported from accidental exposures to high concentrations. This product is a simple asphyxiant. In high concentrations it will displace oxygen from the breathing atmosphere, particularly in confined spaces. Signs of asphyxiation will be noticed when oxygen is reduced to below 16%, and may occur in several stages. Symptoms may include rapid breathing and pulse rate, headache, dizziness, visual disturbances, mental confusion, incoordination, mood changes, muscular weakness, tremors, cyanosis, narcosis and numbness of the extremities. Unconsciousness leading to central nervous system injury and possibly death will occur when the atmospheric oxygen concentration is reduced to about 6% to 8% or less.

WARNING: The burning of any hydrocarbon as a fuel in an area without adequate ventilation may result in hazardous levels of combustion products, including carbon monoxide, and inadequate oxygen levels, which may cause unconsciousness, suffocation, and death.

Respiratory Organs Sensitization/Skin Sensitization

This product is not reported to have any skin sensitization effects.

Generative Cell Mutagenicity

This product is not reported to have any mutagenic effects.

Carcinogenicity

A: General Product Information

This product is not reported to have any carcinogenic effects.

B: Component Carcinogenicity

None of this product's components are listed by ACGIH, IARC, OSHA, NIOSH, or NTP.

Reproductive Toxicity

This product is not reported to have any reproductive toxicity effects.

Specified Target Organ General Toxicity: Single Exposure

This product may cause damage to heart.

Specified Target Organ General Toxicity: Repeated Exposure

This product is not reported to have any specific target organ repeat effects.

Aspiration Respiratory Organs Hazard

This product is not reported to have any aspiration hazard effects.

* * * Section 12 - Ecological Information * * *

Ecotoxicity

A: General Product Information

Keep out of sewers, drainage areas, and waterways. Report spills and releases, as applicable, under Federal and State regulations.

B: Component Analysis - Ecotoxicity - Aquatic Toxicity

No ecotoxicity data are available for this product's components.

Persistence/Degradability

No information available.

Bioaccumulation

No information available.

Mobility in Soil

No information available.

* * * Section 13 - Disposal Considerations * * *

Waste Disposal Instructions

See Section 7 for Handling Procedures. See Section 8 for Personal Protective Equipment recommendations.

Disposal of Contaminated Containers or Packaging

Dispose of contents/container in accordance with local/regional/national/international regulations.

* * * Section 14 - Transportation Information * * *

DOT Information

Shipping Name: Natural Gas, Compressed

UN #: 1971 **Hazard Class:** 2.1

Placard:

*** Section 15 - Regulatory Information ***

Regulatory Information

Component Analysis

None of this products components are listed under SARA Section 302 (40 CFR 355 Appendix A), SARA Section 313 (40 CFR 372.65), or CERCLA (40 CFR 302.4).

SARA Section 311/312 – Hazard Classes

Acute Health	Chronic Health	Fire	Sudden Release of Pressure	Reactive
--	--	X	X	--

SARA SECTION 313 - SUPPLIER NOTIFICATION

This product does not contain any chemicals subject to the reporting requirements of section 313 of the Emergency Planning and Community Right-To-Know Act (EPCRA) of 1986 and of 40 CFR 372:

State Regulations

Component Analysis - State

The following components appear on one or more of the following state hazardous substances lists:

Component	CAS	CA	MA	MN	NJ	PA	RI
Methane	74-82-8	No	Yes	Yes	Yes	Yes	No
Ethane	74-84-0	No	Yes	Yes	Yes	Yes	No

Component Analysis - WHMIS IDL

No components are listed in the WHMIS IDL.

Additional Regulatory Information

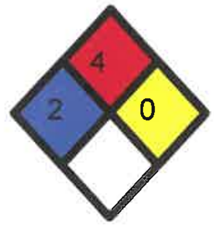
Component Analysis - Inventory

Component	CAS #	TSCA	CAN	EEC
Natural gas, dried	68410-63-9	Yes	DSL	EINECS
Methane	74-82-8	Yes	DSL	EINECS
Ethane	74-84-0	Yes	DSL	EINECS

* * * Section 16 - Other Information * * *

NFPA® Hazard Rating

Health	2	
Fire	4	
Reactivity	0	



HMIS® Hazard Rating

Health	2	Moderate
Fire	4	Severe
Physical	0	Minimal
		*Chronic

Key/Legend

EPA = Environmental Protection Agency; TSCA = Toxic Substance Control Act; ACGIH = American Conference of Governmental Industrial Hygienists; IARC = International Agency for Research on Cancer; NIOSH = National Institute for Occupational Safety and Health; NTP = National Toxicology Program; OSHA = Occupational Safety and Health Administration., NJTSR = New Jersey Trade Secret Registry.

Literature References

None

Other Information

Information presented herein has been compiled from sources considered to be dependable, and is accurate and reliable to the best of our knowledge and belief, but is not guaranteed to be so. Since conditions of use are beyond our control, we make no warranties, expressed or implied, except those that may be contained in our written contract of sale or acknowledgment.

Vendor assumes no responsibility for injury to vendee or third persons proximately caused by the material if reasonable safety procedures are not adhered to as stipulated in the data sheet. Additionally, vendor assumes no responsibility for injury to vendee or third persons proximately caused by abnormal use of the material, even if reasonable safety procedures are followed. Furthermore, vendee assumes the risk in their use of the material.

End of Sheet

Safety Data Sheet

Material Name: Fuel Oil No. 2 **SDS No. 0088**

EU/CLP GHS

Synonyms: #2 Heating Oil; 2 Oil; Off-road Diesel Fuel

* * * Section 1 - Product and Company Identification * * *

Manufacturer Information

Hess Corporation
1 Hess Plaza
Woodbridge, NJ 07095-0961

Phone: 732-750-6000 Corporate EHS
Emergency # 800-424-9300 CHEMTREC
www.hess.com (Environment, Health, Safety Internet Website)

* * * Section 2 - Hazards Identification * * *

GHS Classification:

Flammable Liquids - Category 3
Acute Toxicity, Inhalation - Category 4
Skin Corrosion/Irritation – Category 2
Eye Damage/Irritation – Category 2
Carcinogenicity - Category 2
Specific Target Organ Toxicity (Single Exposure) – Category 3 (respiratory irritation, narcosis)
Aspiration Hazard – Category 1
Hazardous to the Aquatic Environment, Acute Hazard – Category 3

GHS LABEL ELEMENTS

Symbol(s)

Signal Word

DANGER

Hazard Statements

Flammable liquid and vapor.
Harmful if inhaled.
Causes skin irritation.
Causes eye irritation.
Suspected of causing cancer.
Suspected of causing genetic defects.
May cause respiratory irritation.
May cause drowsiness or dizziness.
May be fatal if swallowed and enters airways.
Harmful to aquatic life.

Precautionary Statements

Prevention
Keep away from heat/sparks/open flames/hot surfaces. No smoking
Keep container tightly closed.
Ground/bond container and receiving equipment.
Use explosion-proof electrical/ventilating/lighting/equipment.
Use only non-sparking tools.
Take precautionary measures against static discharge.
Wear protective gloves/protective clothing/eye protection/face protection.
Avoid breathing fume/mist/vapors/spray.
Use only outdoors or in a well-ventilated area.
Wash hands and forearms thoroughly after handling.
Obtain special instructions before use.
Do not handle until all safety precautions have been read and understood.
Avoid release to the environment.

Response
In case of fire: Use water spray, fog or foam.
If on skin (or hair): Wash with plenty of soap and water. Take off immediately all contaminated clothing and wash it before reuse. If skin irritation occurs, get medical advice/attention.
If inhaled: Remove person to fresh air and keep comfortable for breathing. Call a poison center or doctor if you feel unwell.
If in eyes: Rinse cautiously with water for several minutes. Remove contact lenses, if present and easy to do. Continue rinsing. If eye irritation persists: Get medical advice/attention.
If exposed or concerned: Get medical advice/attention.
If swallowed: Immediately all a poison center or doctor/physician if you feel unwell. Do NOT induce vomiting.

Storage
Store in a well ventilated place.
Keep cool. Keep container tightly closed.
Store locked up.

Disposal
Dispose of contents/container in accordance with local/regional/national/international regulations.

* * * Section 3 - Composition / Information on Ingredients * * *

CAS #	Component	Percent
68476-30-2	Fuel oil No. 2	100
91-20-3	Naphthalene	<0.1

A complex combination of hydrocarbons with carbon numbers in the range C9 and higher produced from the distillation of petroleum crude oil.

* * * Section 4 - First Aid Measures * * *

First Aid: Eyes

In case of contact with eyes, immediately flush with clean, low-pressure water for at least 15 min. Hold eyelids open to ensure adequate flushing. Seek medical attention.

First Aid: Skin

Remove contaminated clothing. Wash contaminated areas thoroughly with soap and water or with waterless hand cleanser. Obtain medical attention if irritation or redness develops.

First Aid: Ingestion

DO NOT INDUCE VOMITING. Do not give liquids. Obtain immediate medical attention. If spontaneous vomiting occurs, lean victim forward to reduce the risk of aspiration. Monitor for breathing difficulties. Small amounts of material which enter the mouth should be rinsed out until the taste is dissipated.

First Aid: Inhalation

Remove person to fresh air. If person is not breathing, provide artificial respiration. If necessary, provide additional oxygen once breathing is restored if trained to do so. Seek medical attention immediately.

* * * Section 5 - Fire Fighting Measures * * *

General Fire Hazards

See Section 9 for Flammability Properties.

Vapors may be ignited rapidly when exposed to heat, spark, open flame or other source of ignition. When mixed with air and exposed to an ignition source, flammable vapors can burn in the open or explode in confined spaces. Being heavier than air, vapors may travel long distances to an ignition source and flash back. Runoff to sewer may cause fire or explosion hazard.

Hazardous Combustion Products

Carbon monoxide, carbon dioxide and non-combusted hydrocarbons (smoke).

Extinguishing Media

SMALL FIRES: Any extinguisher suitable for Class B fires, dry chemical, CO2, water spray, fire fighting foam, or gaseous extinguishing agent.

LARGE FIRES: Water spray, fog or fire fighting foam. Water may be ineffective for fighting the fire, but may be used to cool fire-exposed containers.

Unsuitable Extinguishing Media

None

Fire Fighting Equipment/Instructions

Small fires in the incipient (beginning) stage may typically be extinguished using handheld portable fire extinguishers and other fire fighting equipment. Firefighting activities that may result in potential exposure to high heat, smoke or toxic by-products of combustion should require NIOSH/MSHA- approved pressure-demand self-contained breathing apparatus with full facepiece and full protective clothing. Isolate area around container involved in fire. Cool tanks, shells, and containers exposed to fire and excessive heat with water. For massive fires the use of unmanned hose holders or monitor nozzles may be advantageous to further minimize personnel exposure. Major fires may require withdrawal, allowing the tank to burn. Large storage tank fires typically require specially trained personnel and equipment to extinguish the fire, often including the need for properly applied fire fighting foam.

* * * Section 6 - Accidental Release Measures * * *

Recovery and Neutralization

Carefully contain and stop the source of the spill, if safe to do so.

Materials and Methods for Clean-Up

Take up with sand or other oil absorbing materials. Carefully shovel, scoop or sweep up into a waste container for reclamation or disposal.

Emergency Measures

Evacuate nonessential personnel and remove or secure all ignition sources. Consider wind direction; stay upwind and uphill, if possible. Evaluate the direction of product travel, diking, sewers, etc. to confirm spill areas. Spills may infiltrate subsurface soil and groundwater; professional assistance may be necessary to determine the extent of subsurface impact.

Personal Precautions and Protective Equipment

Response and clean-up crews must be properly trained and must utilize proper protective equipment (see Section 8).

Environmental Precautions

Protect bodies of water by diking, absorbents, or absorbent boom, if possible. Do not flush down sewer or drainage systems, unless system is designed and permitted to handle such material. The use of fire fighting foam may be useful in certain situations to reduce vapors. The proper use of water spray may effectively disperse product vapors or the liquid itself, preventing contact with ignition sources or areas/equipment that require protection.

Prevention of Secondary Hazards

None

* * * Section 7 - Handling and Storage * * *

Handling Procedures

Handle as a combustible liquid. Keep away from heat, sparks, excessive temperatures and open flame! No smoking or open flame in storage, use or handling areas. Bond and ground containers during product transfer to reduce the possibility of static-initiated fire or explosion.

Special slow load procedures for "switch loading" must be followed to avoid the static ignition hazard that can exist when this product is loaded into tanks previously containing low flash point products (such as gasoline) - see API Publication 2003, "Protection Against Ignitions Arising Out Of Static, Lightning and Stray Currents."

Storage Procedures

Keep containers closed and clearly labeled. Use approved vented storage containers. Empty product containers or vessels may contain explosive vapors. Do not pressurize, cut, heat, weld or expose such containers to sources of ignition.

Store in a well-ventilated area. This storage area should comply with NFPA 30 "Flammable and Combustible Liquid Code". Avoid storage near incompatible materials. The cleaning of tanks previously containing this product should follow API Recommended Practice (RP) 2013 "Cleaning Mobile Tanks In Flammable and Combustible Liquid Service" and API RP 2015 "Cleaning Petroleum Storage Tanks."

Incompatibilities

Keep away from strong oxidizers; Fluorel ®

*** Section 8 - Exposure Controls / Personal Protection ***

Component Exposure Limits

Fuel oil No. 2 (270-671-4)

ACGIH:	100 mg/m3 TWA (inhalable fraction and vapor, as total hydrocarbons, listed under Diesel fuel) Skin - potential significant contribution to overall exposure by the cutaneous route (listed under Diesel fuel)
Belgium:	100 mg/m3 TWA (as total hydrocarbon, aerosol and vapor) Skin (listed under Gas oil)
Portugal:	100 mg/m3 TWA [VLE-MP] (aerosol and vapor, as total Hydrocarbons, listed under Fuel diesel)

Naphthalene (202-049-5)

ACGIH:	15 ppm STEL 10 ppm TWA Skin - potential significant contribution to overall exposure by the cutaneous route
Austria:	10 ppm TWA [TMW]; 50 mg/m3 TWA [TMW] skin notation
Belgium:	15 ppm STEL; 80 mg/m3 STEL 10 ppm TWA; 53 mg/m3 TWA Skin
Denmark:	10 ppm TWA; 50 mg/m3 TWA
Finland:	2 ppm STEL; 10 mg/m3 STEL 1 ppm TWA; 5 mg/m3 TWA
France:	10 ppm TWA [VME]; 50 mg/m3 TWA [VME]
Germany:	0.1 ppm TWA AGW (The risk of damage to the embryo or fetus can be excluded when MAK and BAT values are observed, inhalable fraction, exposure factor 1); 0.5 mg/m3 TWA AGW (The risk of damage to the embryo or fetus can be excluded when MAK and BAT values are observed, inhalable fraction, exposure factor 1)
Greece:	10 ppm TWA; 50 mg/m3 TWA
Ireland:	15 ppm STEL; 75 mg/m3 STEL 10 ppm TWA; 50 mg/m3 TWA
Netherlands:	80 mg/m3 STEL 50 mg/m3 TWA
Portugal:	10 ppm TWA [VLE-MP]
Spain:	15 ppm STEL [VLA-EC]; 80 mg/m3 STEL [VLA-EC] 10 ppm TWA [VLA-ED]; 53 mg/m3 TWA [VLA-ED] skin - potential for cutaneous exposure
Sweden:	10 ppm LLV; 50 mg/m3 LLV 15 ppm STV; 80 mg/m3 STV

Engineering Measures

Use adequate ventilation to keep vapor concentrations of this product below occupational exposure and flammability limits, particularly in confined spaces.

Personal Protective Equipment: Respiratory

A NIOSH/MSHA-approved air-purifying respirator with organic vapor cartridges or canister may be permissible under certain circumstances where airborne concentrations are or may be expected to exceed exposure limits or for odor or irritation. Protection provided by air-purifying respirators is limited.

Use a positive pressure, air-supplied respirator if there is a potential for uncontrolled release, exposure levels are not known, in oxygen-deficient atmospheres, or any other circumstance where an air-purifying respirator may not provide adequate protection.

Personal Protective Equipment: Hands

Gloves constructed of nitrile, neoprene, or PVC are recommended.

Personal Protective Equipment: Eyes

Safety glasses or goggles are recommended where there is a possibility of splashing or spraying.

Personal Protective Equipment: Skin and Body

Chemical protective clothing such as of E.I. DuPont TyChem®, Saranex® or equivalent recommended based on degree of exposure. Note: The resistance of specific material may vary from product to product as well as with degree of exposure. Consult manufacturer specifications for further information.

* * * Section 9 - Physical & Chemical Properties * * *

Appearance:	Red or reddish/orange colored (dyed)	**Odor:**	Mild, petroleum distillate odor
Physical State:	Liquid	**pH:**	ND
Vapor Pressure:	0.009 psia @ 70 °F (21 °C)	**Vapor Density:**	>1.0
Boiling Point:	340 to 700 °F (171 to 371 °C)	**Melting Point:**	ND
Solubility (H2O):	Negligible	**Specific Gravity:**	AP 0.823-0871
Evaporation Rate:	Slow; varies with conditions	**VOC:**	ND
Octanol/H2O Coeff.:	ND	**Flash Point:**	100 °F (38 °C) minimum
Flash Point Method:	PMCC	**Upper Flammability Limit (UFL):**	7.5
Lower Flammability Limit (LFL):	0.6	**Burning Rate:**	ND
Auto Ignition:	494°F (257°C)		

* * * Section 10 - Chemical Stability & Reactivity Information * * *

Chemical Stability

This is a stable material.

Hazardous Reaction Potential

Will not occur.

Conditions to Avoid

Avoid high temperatures, open flames, sparks, welding, smoking and other ignition sources.

Incompatible Products

Keep away from strong oxidizers; Fluorel ®

Hazardous Decomposition Products

Carbon monoxide, carbon dioxide and non-combusted hydrocarbons (smoke).

* * * Section 11 - Toxicological Information * * *

Acute Toxicity

A: General Product Information

Harmful if swallowed.

B: Component Analysis - LD50/LC50

Fuel oil No. 2 (68476-30-2)

Oral LD50 Rat 12 g/kg; Dermal LD50 Rabbit 4720 µL/kg; Dermal LD50 Rabbit >2000 mg/kg; Inhalation LC50 Rat 4.6 mg/L 4 h

Naphthalene (91-20-3)

Inhalation LC50 Rat >340 mg/m3 1 h; Oral LD50 Rat 490 mg/kg; Dermal LD50 Rat >2500 mg/kg; Dermal LD50 Rabbit >20 g/kg

Product Mixture

Oral LD50 Rat 14.5 ml/kg; Dermal LD50 Rabbit >5 mL/kg; Guinea Pig Sensitization: negative; Primary dermal irritation: moderately irritating (Draize mean irritation score - 3.98 rabbits); Draize eye irritation: mildly irritating (Draize score, 48 hours, unwashed - 2.0 rabbits)

Potential Health Effects: Skin Corrosion Property/Stimulativeness

Practically non-toxic if absorbed following acute (single) exposure. May cause skin irritation with prolonged or repeated contact. Liquid may be absorbed through the skin in toxic amounts if large areas of skin are repeatedly exposed.

Potential Health Effects: Eye Critical Damage/ Stimulativeness

Contact with eyes may cause mild irritation.

Potential Health Effects: Ingestion

Ingestion may cause gastrointestinal disturbances, including irritation, nausea, vomiting and diarrhea, and central nervous system (brain) effects similar to alcohol intoxication. In severe cases, tremors, convulsions, loss of consciousness, coma, respiratory arrest, and death may occur.

Potential Health Effects: Inhalation

Excessive exposure may cause irritations to the nose, throat, lungs and respiratory tract. Central nervous system (brain) effects may include headache, dizziness, loss of balance and coordination, unconsciousness, coma, respiratory failure, and death.

WARNING: the burning of any hydrocarbon as a fuel in an area without adequate ventilation may result in hazardous levels of combustion products, including carbon monoxide, and inadequate oxygen levels, which may cause unconsciousness, suffocation, and death.

Respiratory Organs Sensitization/Skin Sensitization

This product is not reported to have any skin sensitization effects.

Generative Cell Mutagenicity

This product is not reported to have any mutagenic effects. Material of similar composition has been positive in a mutagenicity study.

Carcinogenicity

A: General Product Information

Suspected of causing cancer.

Dermal carcinogenicity: positive - mice

Studies have shown that similar products produce skin tumors in laboratory animals following repeated applications without washing or removal. The significance of this finding to human exposure has not been determined. Other studies with active skin carcinogens have shown that washing the animal's skin with soap and water between applications reduced tumor formation.

This product is similar to Diesel Fuel. IARC classifies whole diesel fuel exhaust particulates as probably carcinogenic to humans (Group 2A) and NIOSH regards it as a potential cause of occupational lung cancer based on animal studies and limited evidence in humans.

B: Component Carcinogenicity

Fuel oil No. 2 (68476-30-2)

ACGIH: A3 - Confirmed Animal Carcinogen with Unknown Relevance to Humans (listed under Diesel fuel)

Naphthalene (91-20-3)

ACGIH: A4 - Not Classifiable as a Human Carcinogen
NTP: Reasonably Anticipated To Be A Human Carcinogen (Possible Select Carcinogen)
IARC: Monograph 82 [2002] (Group 2B (possibly carcinogenic to humans))

Reproductive Toxicity

This product is not reported to have any reproductive toxicity effects.

Specified Target Organ General Toxicity: Single Exposure

This product is not reported to have any specific target organ general toxicity single exposure effects.

Specified Target Organ General Toxicity: Repeated Exposure

This product is not reported to have any specific target organ general toxicity repeat exposure effects.

Aspiration Respiratory Organs Hazard

The major health threat of ingestion occurs from the danger of aspiration (breathing) of liquid drops into the lungs, particularly from vomiting. Aspiration may result in chemical pneumonia (fluid in the lungs), severe lung damage, respiratory failure and even death.

* * * Section 12 - Ecological Information * * *

Ecotoxicity

A: General Product Information

Very toxic to aquatic life with long lasting effects. Keep out of sewers, drainage areas and waterways. Report spills and releases, as applicable, under Federal and State regulations.

B: Component Analysis - Ecotoxicity - Aquatic Toxicity

Fuel oil No. 2 (68476-30-2)

Test & Species		Conditions
96 Hr LC50 Pimephales promelas	35 mg/L [flow-through]	

Naphthalene (91-20-3)

Test & Species		Conditions
96 Hr LC50 Pimephales promelas	5.74-6.44 mg/L [flow-through]	
96 Hr LC50 Oncorhynchus mykiss	1.6 mg/L [flow-through]	

96 Hr LC50 Oncorhynchus mykiss	0.91-2.82 mg/L [static]
96 Hr LC50 Pimephales promelas	1.99 mg/L [static]
96 Hr LC50 Lepomis macrochirus	31.0265 mg/L [static]
72 Hr EC50 Skeletonema costatum	0.4 mg/L
48 Hr LC50 Daphnia magna	2.16 mg/L
48 Hr EC50 Daphnia magna	1.96 mg/L [Flow through]
48 Hr EC50 Daphnia magna	1.09 - 3.4 mg/L [Static]

Persistence/Degradability
No information available.

Bioaccumulation
No information available.

Mobility in Soil
No information available.

* * * Section 13 - Disposal Considerations * * *

Waste Disposal Instructions
See Section 7 for Handling Procedures. See Section 8 for Personal Protective Equipment recommendations.

Disposal of Contaminated Containers or Packaging
Dispose of contents/container in accordance with local/regional/national/international regulations.

* * * Section 14 - Transportation Information * * *

IATA Information
Shipping Name: Heating oil, light
UN #: 1202 **Hazard Class:** 3 **Packing Group:** III

ICAO Information
Shipping Name: Heating oil, light
UN #: 1202 **Hazard Class:** 3 **Packing Group:** III

IMDG Information
Shipping Name: Heating oil, light
UN #: 1202 **Hazard Class:** 3 **Packing Group:** III

* * * Section 15 - Regulatory Information * * *

Regulatory Information

Component Analysis – Inventory

Component/CAS	EC #	EEC	CAN	TSCA
Fuel oil No. 2 68476-30-2	270-671-4	EINECS	DSL	Yes
Naphthalene 91-20-3	202-049-5	EINECS	DSL	Yes

* * * Section 16 - Other Information * * *

Key/Legend

ACGIH = American Conference of Governmental Industrial Hygienists; ADG = Australian Code for the Transport of Dangerous Goods by Road and Rail; ADR/RID = European Agreement of Dangerous Goods by Road/Rail; AS = Standards Australia; DFG = Deutsche Forschungsgemeinschaft; DOT = Department of Transportation; DSL = Domestic Substances List; EEC = European Economic Community; EINECS = European Inventory of Existing Commercial Chemical Substances; ELINCS = European List of Notified Chemical Substances; EU = European Union; HMIS = Hazardous Materials Identification System; IARC = International Agency for Research on Cancer; IMO = International Maritime Organization; IATA = International Air Transport Association; MAK = Maximum Concentration Value in the Workplace; NDSL = Non-Domestic Substances List; NFPA = National Fire Protection Association; NOHSC = National Occupational Health & Safety Commission; NTP = National Toxicology Program; STEL = Short-term Exposure Limit; TDG = Transportation of Dangerous Goods; TLV = Threshold Limit Value; TSCA = Toxic Substances Control Act; TWA = Time Weighted Average

Literature References

None

Other Information

Information presented herein has been compiled from sources considered to be dependable, and is accurate and reliable to the best of our knowledge and belief, but is not guaranteed to be so. Since conditions of use are beyond our control, we make no warranties, expressed or implied, except those that may be contained in our written contract of sale or acknowledgment.

Vendor assumes no responsibility for injury to vendee or third persons proximately caused by the material if reasonable safety procedures are not adhered to as stipulated in the data sheet. Additionally, vendor assumes no responsibility for injury to vendee or third persons proximately caused by abnormal use of the material, even if reasonable safety procedures are followed. Furthermore, vendee assumes the risk in their use of the material.

End of Sheet

ATTACHMENT I
EMISSION UNITS TABLE

Attachment I

Emission Units Table

(includes all emission units and air pollution control devices that will be part of this permit application review, regardless of permitting status)

Emission Unit ID[1]	Emission Point ID[2]	Emission Unit Description	Year Installed/ Modified	Design Capacity	Type[3] and Date of Change	Control Device [4]
CT-1	CT-1	Combined-Cycle Combustion Turbine No. 1	2021	3,561.2 MMBtu/hr (approx)	New	DLNC, SCR, Oxidation Catalyst
CT-2	CT-2	Combined-Cycle Combustion Turbine No. 2	2021	3,561.2 MMBtu/hr (approx)	New	DLNC, SCR, Oxidation Catalyst
NA	NA	HRSG-1 Heat Recovery Steam Generator with Duct Burners No. 1	2021	227 MMBtu/hr (HHV) (approx)	New	NA
NA	NA	HRSG-2 Heat Recovery Steam Generator with Duct Burners No. 2	2021	227 MMBtu/hr (HHV) (approx)	New	NA
FGH-1	FGH-1	Fuel Gas Heater	2021	5.4 MMBtu/hr	New	LNB
FGH-2	FGH-2	Fuel Gas Heater	2021	5.4 MMBtu/hr	New	LNB
EG-1	EG-1	Emergency Electric Generator	2021	1,528 hp 1,139 kW	New	NA
FWP-1	FWP-1	Firewater Pump	2021	240 hp, 179 kW	New	NA
DT-1	DT-1	Emergency Generator Fuel Storage Tanks	2021	300 gallons	New	NA
DT-2	DT-2	Firewater Pump Fuel Storage Tank	2021	125 gallons	New	NA
NA	NA	AA-1 Aqueous Ammonia Storage Tank 1	2021	60,000 gallons	New	NA
NA	NA	AA-2 Aqueous Ammonia Storage Tank 2	2021	60,000 gallons	New	NA

[1] For Emission Units (or Sources) use the following numbering system:1S, 2S, 3S,... or other appropriate designation.
[2] For Emission Points use the following numbering system:1E, 2E, 3E, ... or other appropriate designation.
[3] New, modification, removal
[4] For Control Devices use the following numbering system: 1C, 2C, 3C,... or other appropriate designation.

Attachment I

Emission Units Table

(includes all emission units and air pollution control devices that will be part of this permit application review, regardless of permitting status)

Emission Unit ID[1]	Emission Point ID[2]	Emission Unit Description	Year Installed/ Modified	Design Capacity	Type[3] and Date of Change	Control Device [4]
WCT-1	WCT-1	Mechanical Draft Cooling Tower 1	2021	270,000 gals/min	New	Demisters

[1] For Emission Units (or Sources) use the following numbering system:1S, 2S, 3S,... or other appropriate designation.
[2] For Emission Points use the following numbering system:1E, 2E, 3E, ... or other appropriate designation.
[3] New, modification, removal
[4] For Control Devices use the following numbering system: 1C, 2C, 3C,... or other appropriate designation.

ATTACHMENT J
EMISSION POINTS DATA SUMMARY SHEET

Attachm J
EMISSION POINTS DATA SUMMARY SHEET

Table 1: Emissions Data

Emission Point ID No. *(Must match Emission Units Table & Plot Plan)*	Emission Point Type[1]	Emission Unit Vented Through This Point *(Must match Emission Units Table & Plot Plan)*		Air Pollution Control Device *(Must match Emission Units Table & Plot Plan)*		Vent Time for Emission Unit *(chemical processes only)*		All Regulated Pollutants - Chemical Name/CAS[3] *(Speciate VOCs & HAPS)*	Maximum Potential Uncontrolled Emissions [4]		Maximum Potential Controlled Emissions [5]		Emission Form or Phase *(At exit conditions, Solid, Liquid or Gas/Vapor)*	Est. Method Used [6]	Emission Concentration [7] (ppmv or mg/m^3)
		ID No.	Source	ID No.	Device Type	Short Term[2]	Max (hr/yr)		lb/hr	ton/yr	lb/hr	ton/yr			
CT-1	Upward Vertical Stack	CT-1	Combined Cycle Combustion Turbine	NA	LNB, SCR and Oxidation Catalyst	C	8,760	See Section 3 and Appendix B of the PSD Permit Application Document							
CT-2	Upward Vertical Stack	CT-2	Combined Cycle Combustion Turbine	NA	LNB, SCR and Oxidation Catalyst	C	8,760	See Section 3 and Appendix B of the PSD Permit Application Document							
FGH-1	Exhaust	FGH-1	Fuel Gas Heater	NA	LNB	As required	8.760	See Section 3 and Appendix B of the PSD Permit Application Document							
FGH-2	Exhaust	FGH-2	Fuel Gas Heater	NA	LNB	As required	8.760	See Section 3 and Appendix B of the PSD Permit Application Document							

Attachment J
EMISSION POINTS DATA SUMMARY SHEET

Table 1: Emissions Data

Emission Point ID No. *(Must match Emission Units Table & Plot Plan)*	Emission Point Type[1]	Emission Unit Vented Through This Point *(Must match Emission Units Table & Plot Plan)*		Air Pollution Control Device *(Must match Emission Units Table & Plot Plan)*		Vent Time for Emission Unit *(chemical processes only)*		All Regulated Pollutants - Chemical Name/CAS[3] *(Speciate VOCs & HAPS)*	Maximum Potential Uncontrolled Emissions [4]		Maximum Potential Controlled Emissions [5]		Emission Form or Phase *(At exit conditions, Solid, Liquid or Gas/Vapor)*	Est. Method Used [6]	Emission Concentration [7] (ppmv or mg/m³)
		ID No.	Source	ID No.	Device Type	Short Term[2]	Max (hr/yr)		lb/hr	ton/yr	lb/hr	ton/yr			
EG-1	Exhaust	EG-1	Emergency Electric Generator	NA	NA	As Required	100	See Section 3 and Appendix B of the PSD Permit Application Document							
FWP-1	Exhaust	FWP-1	Firewater Pump	NA	NA	As Required	100	See Section 3 and Appendix B of the PSD Permit Application Document							
DT-1	Upward Vertical Stack	ST-1	Diesel Storage Tank	NA	NA	C	8,760	Total VOC	0.09	0.39	0.09	0.39	Gas	EE	NA
DT-2	Upward Vertical Stack	ST-2	Diesel Storage Tank	NA	NA	C	8,760	Total VOC	0.09	0.39	0.09	0.39	Gas	EE	NA
WCT-1	Upward Vertical Stack	MDCT-1	Mechanical Draft Cooling Tower	NA	NA	C	8,760	See Section 3 and Appendix B of the PSD Permit Application Document							

The EMISSION POINTS DATA SUMMARY SHEET provides a summation of emissions by emission unit. Note that uncaptured process emission unit emissions are not typically considered to be fugitive and must be accounted for on the appropriate EMISSIONS UNIT DATA SHEET and on the EMISSION POINTS DATA SUMMARY SHEET. Please note that total emissions from the source are equal to all vented emissions, all fugitive emissions, plus all other emissions (e.g. uncaptured emissions). Please complete the FUGITIVE EMISSIONS DATA SUMMARY SHEET for fugitive emission activities.

[1] Please add descriptors such as upward vertical stack, downward vertical stack, horizontal stack, relief vent, rain cap, etc.

[2] Indicate by "C" if venting is continuous. Otherwise, specify the average short-term venting rate with units, for intermittent venting (ie., 15 min/hr). Indicate as many rates as needed to clarify frequency of venting (e.g., 5 min/day, 2 days/wk).

[3] List all regulated air pollutants. Speciate VOCs, including all HAPs. Follow chemical name with Chemical Abstracts Service (CAS) number. **LIST** Acids, CO, CS_2, VOCs, H_2S, Inorganics, Lead, Organics, O_3, NO, NO_2, SO_2, SO_3, all applicable Greenhouse Gases (including CO_2 and methane), etc. **DO NOT LIST** H_2, H_2O, N_2, O_2, and Noble Gases.

[4] Give maximum potential emission rate with no control equipment operating. If emissions occur for less than 1 hr, then record emissions per batch in minutes (e.g. 5 lb VOC/20 minute batch).

[5] Give maximum potential emission rate with proposed control equipment operating. If emissions occur for less than 1 hr, then record emissions per batch in minutes (e.g. 5 lb VOC/20 minute batch).

[6] Indicate method used to determine emission rate as follows: MB = material balance; ST = stack test (give date of test); EE = engineering estimate; O = other (specify).

[7] Provide for all pollutant emissions. Typically, the units of parts per million by volume (ppmv) are used. If the emission is a mineral acid (sulfuric, nitric, hydrochloric or phosphoric) use units of milligram per dry cubic meter (mg/m^3) at standard conditions (68 °F and 29.92 inches Hg) (see 45CSR7). If the pollutant is SO_2, use units of ppmv (See 45CSR10).

Attachment J
EMISSION POINTS DATA SUMMARY SHEET

Table 2: Release Parameter Data

Emission Point ID No. *(Must match Emission Units Table)*	Inner Diameter (ft.)	Exit Gas			Emission Point Elevation (ft)		UTM Coordinates (km)	
		Temp. (°F)	Volumetric Flow [1] (acfm) *at operating conditions*	Velocity (fps)	Ground Level *(Height above mean sea level)*	Stack Height [2] *(Release height of emissions above ground level)*	Northing	Easting
CT-1	23	172	1,697,453	68.1	1,150	180	4,396.353	589.077
CT-2	23	172	1,697,453	68.1	1,150	180	4,396.353	589.077
FGH-1	0.6	600	1,017	60	1,150	15	4,396.353	589.077
FGH-2	0.6	600	1,017	60	1,150	15	4,396.353	589.077
EG-1	0.5	961	1,400	118.8	1,150	16	4,396.353	589.077
FWP-1	0.7	752	15,295	730.3	1,150	12	4,396.353	589.077

WCT-1	NA	Ambient	NA	NA	1,150	NA	4,396.353	589.077
DT-1	NA	Ambient	NA	NA	1,150	NA	4,396.353	589.077
DT-2	NA	Ambient	NA	NA	1,150	NA	4,396.353	589.077

[1] Give at operating conditions. Include inerts.
[2] Release height of emissions above ground level.

ATTACHMENT K
FUGITIVE EMISSIONS DATA SUMMARY SHEET

Attachment K

FUGITIVE EMISSIONS DATA SUMMARY SHEET

The FUGITIVE EMISSIONS SUMMARY SHEET provides a summation of fugitive emissions. Fugitive emissions are those emissions which could not reasonably pass through a stack, chimney, vent or other functionally equivalent opening. Note that uncaptured process emissions are not typically considered to be fugitive, and must be accounted for on the appropriate EMISSIONS UNIT DATA SHEET and on the EMISSION POINTS DATA SUMMARY SHEET.

Please note that total emissions from the source are equal to all vented emissions, all fugitive emissions, plus all other emissions (e.g. uncaptured emissions).

APPLICATION FORMS CHECKLIST - FUGITIVE EMISSIONS
1.) Will there be haul road activities? ☐ Yes ☒ No ☐ If YES, then complete the HAUL ROAD EMISSIONS UNIT DATA SHEET.
2.) Will there be Storage Piles? ☐ Yes ☒ No o ☐ If YES, complete Table 1 of the NONMETALLIC MINERALS PROCESSING EMISSIONS UNIT DATA SHEET.
3.) Will there be Liquid Loading/Unloading Operations? ☐ Yes ☒ No ☐ If YES, complete the BULK LIQUID TRANSFER OPERATIONS EMISSIONS UNIT DATA SHEET.
4.) Will there be emissions of air pollutants from Wastewater Treatment Evaporation? ☐ Yes ☒ No ☐ If YES, complete the GENERAL EMISSIONS UNIT DATA SHEET.
5.) Will there be Equipment Leaks (e.g. leaks from pumps, compressors, in-line process valves, pressure relief devices, open-ended valves, sampling connections, flanges, agitators, cooling towers, etc.)? ☒ Yes ☐ No ☐ If YES, complete the LEAK SOURCE DATA SHEET section of the CHEMICAL PROCESSES EMISSIONS UNIT DATA SHEET.
6.) Will there be General Clean-up VOC Operations? ☐ Yes ☒ No ☐ If YES, complete the GENERAL EMISSIONS UNIT DATA SHEET.
7.) Will there be any other activities that generate fugitive emissions? ☐ Yes ☒ No ☐ If YES, complete the GENERAL EMISSIONS UNIT DATA SHEET or the most appropriate form.
If you answered "NO" to all of the items above, it is not necessary to complete the following table, "Fugitive Emissions Summary."

FUGITIVE EMISSIONS SUMMARY	All Regulated Pollutants - Chemical Name/CAS [1]	Maximum Potential Uncontrolled Emissions [2]		Maximum Potential Controlled Emissions [3]		Est. Method Used [4]
		lb/hr	ton/yr	lb/hr	ton/yr	
Haul Road/Road Dust Emissions Paved Haul Roads	NA					
Unpaved Haul Roads	NA					
Storage Pile Emissions	NA					
Loading/Unloading Operations	NA					
Wastewater Treatment Evaporation & Operations	NA					
Equipment Leaks	**Some equipment leak emissions from natural gas processing and are non-regulated chemicals.**	Does not apply		Does not apply		
General Clean-up VOC Emissions	NA					
Other	NA					

[1] List all regulated air pollutants. Speciate VOCs, including all HAPs. Follow chemical name with Chemical Abstracts Service (CAS) number. LIST Acids, CO, CS_2, VOCs, H_2S, Inorganics, Lead, Organics, O_3, NO, NO_2, SO_2, SO_3, all applicable Greenhouse Gases (including CO_2 and methane), etc. DO NOT LIST H_2, H_2O, N_2, O_2, and Noble Gases.
[2] Give rate with no control equipment operating. If emissions occur for less than 1 hr, then record emissions per batch in minutes (e.g. 5 lb VOC/20 minute batch).
[3] Give rate with proposed control equipment operating. If emissions occur for less than 1 hr, then record emissions per batch in minutes (e.g. 5 lb VOC/20 minute batch).
[4] Indicate method used to determine emission rate as follows: MB = material balance; ST = stack test (give date of test); EE = engineering estimate; O = other (specify).

ATTACHMENT L
EMISSIONS UNIT DATA SHEETS

Attachment L
Emission Unit Data Sheet
(INDIRECT HEAT EXCHANGER)

Control Device ID No. (must match List Form): Combine Cycle Gas Turbine CT-1

Equipment Information

1. Manufacturer: GE or MHPS JAC	2. Model No. GE:7HA.02 /MHPS JAC 501 Serial No.
3. Number of units: 1	4. Use Electric Generation
5. Rated Boiler Horsepower: NA hp	6. Boiler Serial No.: NA
7. Date constructed: 2021	8. Date of last modification and explain: NA
9. Maximum design heat input per unit: 3,561.2 $\times10^6$ BTU/hr	10. Peak heat input per unit: 3,561 $\times10^6$ BTU/hr
11. Steam produced at maximum design output: NA LB/hr NA psig	12. Projected Operating Schedule: Hours/Day 24 Days/Week 7 Weeks/Year 52
13. Type of firing equipment to be used: ☐ Pulverized coal ☐ Spreader stoker ☐ Oil burners ☒ Natural Gas Burner ☐ Others, specify	14. Proposed type of burners and orientation: ☐ Vertical ☐ Front Wall ☐ Opposed ☐ Tangential ☒ Others, specify LNB
15. Type of draft: ☒ Forced ☐ Induced	16. Percent of ash retained in furnace: NA %
17. Will flyash be reinjected? ☐ Yes ☒ No	18. Percent of carbon in flyash: NA %

Stack or Vent Data

19. Inside diameter or dimensions: 23 ft.	20. Gas exit temperature: 172 °F
21. Height: 180 ft.	22. Stack serves: ☒ This equipment only ☐ Other equipment also (submit type and rating of all other equipment exhausted through this stack or vent)
23. Gas flow rate: 1,697,453 ft^3/min	
24. Estimated percent of moisture: NA %	

Fuel Requirements

25. Type	Fuel Oil No.	Natural Gas	Gas (other, specify)	Coal, Type:	Other:
Quantity (at Design Output)	gph@60°F	3,300,000 ft^3/hr	ft^3/hr	TPH	
Annually	×10^3 gal	28,575 ×10^6 ft^3/hr	×10^6 ft^3/hr	tons	
Sulfur	Maximum: wt. % Average: wt. %	0.4 gr/100 ft^3	gr/100 ft^3	Maximum: wt. %	
Ash (%)		NA		Maximum	
BTU Content	BTU/Gal. Lbs/Gal.@60°F	1,030 BTU/ft^3	BTU/ft^3	BTU/lb	
Source		Local Suppliers			
Supplier		Local Supplier of Pipeline Natural Gas			
Halogens (Yes/No)		NA			
List and Identify Metals		NA			

26. Gas burner mode of control:
☐ Manual ☐ Automatic hi-low
☒ Automatic full modulation ☐ Automatic on-off

27. Gas burner manufacture: GE of MHPS

28. Oil burner manufacture: NA

29. If fuel oil is used, how is it atomized? ☐ Oil Pressure ☐ Steam Pressure ☐ Compressed Air ☐ Rotary Cup ☐ Other, specify

30. Fuel oil preheated: ☒ Yes ☐ No

31. If yes, indicate temperature: °F

32. Specify the calculated theoretical air requirements for combustion of the fuel or mixture of fuels described above actual cubic feet (ACF) per unit of fuel:
NA @ NA °F, NA PSIA, NA % moisture

33. Emission rate at rated capacity: See Attachment J and Section 3 and Appendix B of the PSD Application Document lb/hr

34. Percent excess air actually required for combustion of the fuel described: NA %

Coal Characteristics

35. Seams: NA

36. Proximate analysis (dry basis): % of Fixed Carbon: % of Sulfur:
% of Moisture: % of Volatile Matter:
% of Ash:

Emissions Stream

37. What quantities of pollutants will be emitted from the boiler before controls?

Pollutant	Pounds per Hour lb/hr	grain/ACF	@ °F	PSIA
CO	See Attachment J			
Hydrocarbons				
NO_x				
Pb				
PM_{10}				
SO_2				
VOCs				
Other (specify)				

38. What quantities of pollutants will be emitted from the boiler after controls?

Pollutant	Pounds per Hour lb/hr	grain/ACF	@ °F	PSIA
CO	See Attachment J			
Hydrocarbons				
NO_x				
Pb				
PM_{10}				
SO_2				
VOCs				
Other (specify)				

39. How will waste material from the process and control equipment be disposed of?
NA

40. Have you completed an *Air Pollution Control Device Sheet(s)* for the control(s) used on this Emission Unit.

41. Have you included the ***air pollution rates*** on the Emissions Points Data Summary Sheet?

42. **Proposed Monitoring, Recordkeeping, Reporting, and Testing**
Please propose monitoring, recordkeeping, and reporting in order to demonstrate compliance with the proposed operating parameters. Please propose testing in order to demonstrate compliance with the proposed emissions limits.

MONITORING PLAN: Please list (1) describe the process parameters and how they were chosen (2) the ranges and how they were established for monitoring to demonstrate compliance with the operation of this process equipment operation or air pollution control device.
See Attachment O

TESTING PLAN: Please describe any proposed emissions testing for this process equipment or air pollution control device.
See Attachment O

RECORDKEEPING: Please describe the proposed recordkeeping that will accompany the monitoring.
See Attachment O

REPORTING: Please describe the proposed frequency of reporting of the recordkeeping.
See Attachment O

43. Describe all operating ranges and maintenance procedures required by Manufacturer to maintain warranty.
NA

Attachment L
Emission Unit Data Sheet
(INDIRECT HEAT EXCHANGER)

Control Device ID No. (must match List Form): Combine Cycle Gas Turbine CT-2

Equipment Information

1. Manufacturer: GE or MHPS JAC	2. Model No. GE:7HA.02 /MHPS JAC 501 Serial No.
3. Number of units: 1	4. Use Electric Generation
5. Rated Boiler Horsepower: NA hp	6. Boiler Serial No.: NA
7. Date constructed: 2021	8. Date of last modification and explain: NA
9. Maximum design heat input per unit: 3,561.2 $\times 10^6$ BTU/hr	10. Peak heat input per unit: 3,561 $\times 10^6$ BTU/hr
11. Steam produced at maximum design output: NA LB/hr NA psig	12. Projected Operating Schedule: Hours/Day 24 Days/Week 7 Weeks/Year 52
13. Type of firing equipment to be used: ☐ Pulverized coal ☐ Spreader stoker ☐ Oil burners ☒ Natural Gas Burner ☐ Others, specify	14. Proposed type of burners and orientation: ☐ Vertical ☐ Front Wall ☐ Opposed ☐ Tangential ☒ Others, specify LNB
15. Type of draft: ☒ Forced ☐ Induced	16. Percent of ash retained in furnace: NA %
17. Will flyash be reinjected? ☐ Yes ☒ No	18. Percent of carbon in flyash: NA %

Stack or Vent Data

19. Inside diameter or dimensions: 23 ft.	20. Gas exit temperature: 172 °F
21. Height: 180 ft.	22. Stack serves: ☒ This equipment only ☐ Other equipment also (submit type and rating of all other equipment exhausted through this stack or vent)
23. Gas flow rate: 1,697,453 ft^3/min	
24. Estimated percent of moisture: NA %	

Fuel Requirements

25. Type	Fuel Oil No.	Natural Gas	Gas (other, specify)	Coal, Type:	Other:
Quantity (at Design Output)	gph@60°F	3,300,000 ft^3/hr	ft^3/hr	TPH	
Annually	$\times 10^3$ gal	28,575 $\times 10^6$ ft^3/hr	$\times 10^6$ ft^3/hr	tons	
Sulfur	Maximum: wt. % Average: wt. %	0.4 gr/100 ft^3	gr/100 ft^3	Maximum: wt. %	
Ash (%)		NA		Maximum	
BTU Content	BTU/Gal. Lbs/Gal.@60°F	1,030 BTU/ft^3	BTU/ft^3	BTU/lb	
Source		Local Suppliers			
Supplier		Local Supplier of Pipeline Natural Gas			
Halogens (Yes/No)		NA			
List and Identify Metals		NA			

26. Gas burner mode of control:
☐ Manual ☐ Automatic hi-low
☒ Automatic full modulation ☐ Automatic on-off

27. Gas burner manufacture: GE of MHPS

28. Oil burner manufacture: NA

29. If fuel oil is used, how is it atomized? ☐ Oil Pressure ☐ Steam Pressure ☐ Compressed Air ☐ Rotary Cup ☐ Other, specify

30. Fuel oil preheated: ☒ Yes ☐ No

31. If yes, indicate temperature: °F

32. Specify the calculated theoretical air requirements for combustion of the fuel or mixture of fuels described above actual cubic feet (ACF) per unit of fuel:
NA @ NA °F, NA PSIA, NA % moisture

33. Emission rate at rated capacity: See Attachment J and Section 3 and Appendix B of the PSD Application Document lb/hr

34. Percent excess air actually required for combustion of the fuel described: NA %

Coal Characteristics

35. Seams: NA

36. Proximate analysis (dry basis): % of Fixed Carbon: % of Sulfur:
% of Moisture: % of Volatile Matter:
% of Ash:

Emissions Stream

37. What quantities of pollutants will be emitted from the boiler before controls?

Pollutant	Pounds per Hour lb/hr	grain/ACF	@ °F	PSIA
CO	See Attachment J			
Hydrocarbons				
NO_x				
Pb				
PM_{10}				
SO_2				
VOCs				
Other (specify)				

38. What quantities of pollutants will be emitted from the boiler after controls?

Pollutant	Pounds per Hour lb/hr	grain/ACF	@ °F	PSIA
CO	See Attachment J			
Hydrocarbons				
NO_x				
Pb				
PM_{10}				
SO_2				
VOCs				
Other (specify)				

39. How will waste material from the process and control equipment be disposed of?
NA

40. Have you completed an *Air Pollution Control Device Sheet(s)* for the control(s) used on this Emission Unit.

41. Have you included the ***air pollution rates*** on the Emissions Points Data Summary Sheet?

42. **Proposed Monitoring, Recordkeeping, Reporting, and Testing**
Please propose monitoring, recordkeeping, and reporting in order to demonstrate compliance with the proposed operating parameters. Please propose testing in order to demonstrate compliance with the proposed emissions limits.

MONITORING PLAN: Please list (1) describe the process parameters and how they were chosen (2) the ranges and how they were established for monitoring to demonstrate compliance with the operation of this process equipment operation or air pollution control device.
See Attachment O

TESTING PLAN: Please describe any proposed emissions testing for this process equipment or air pollution control device.
See Attachment O

RECORDKEEPING: Please describe the proposed recordkeeping that will accompany the monitoring.
See Attachment O

REPORTING: Please describe the proposed frequency of reporting of the recordkeeping.
See Attachment O

43. Describe all operating ranges and maintenance procedures required by Manufacturer to maintain warranty.
NA

Attachment L
EMISSIONS UNIT DATA SHEET
GENERAL

To be used for affected sources other than asphalt plants, foundries, incinerators, indirect heat exchangers, and quarries.

Identification Number (as assigned on *Equipment List Form*): EG-1

1. Name or type and model of proposed affected source: Emergency Electric Generator (Diesel Fuel Fired) – 1,139 kW (1,528 hp)
2. On a separate sheet(s), furnish a sketch(es) of this affected source. If a modification is to be made to this source, clearly indicated the change(s). Provide a narrative description of all features of the affected source which may affect the production of air pollutants.
3. Name(s) and maximum amount of proposed process material(s) charged per hour: NA
4. Name(s) and maximum amount of proposed material(s) produced per hour: NA
5. Give chemical reactions, if applicable, that will be involved in the generation of air pollutants: NA

* The identification number which appears here must correspond to the air pollution control device identification number appearing on the *List Form*.

6. Combustion Data (if applicable):

(a) Type and amount in appropriate units of fuel(s) to be burned:

Ultra Low Sulfur Diesel Fuel – As Required

(b) Chemical analysis of proposed fuel(s), excluding coal, including maximum percent sulfur and ash:

0.0015 % sulfur by weight

(c) Theoretical combustion air requirement (ACF/unit of fuel):

NA @ NA °F and NA psia.

(d) Percent excess air: NA

(e) Type and BTU/hr of burners and all other firing equipment planned to be used:

NA/Internal Combustion Engine

(f) If coal is proposed as a source of fuel, identify supplier and seams and give sizing of the coal as it will be fired:

NA

(g) Proposed maximum design heat input: 13.0 × 10^6 BTU/hr.

7. Projected operating schedule:

Hours/Day	0.4	Days/Week	5	Weeks/Year	50

8. Projected amount of pollutants that would be emitted from this affected source if no control devices were used:

@ NA °F and Ambient psia

a.	NO_X	See Attachment J and Section 3 and Appendix B of the PSD Application Document	lb/hr		grains/ACF
b.	SO_2		lb/hr		grains/ACF
c.	CO		lb/hr		grains/ACF
d.	PM_{10}		lb/hr		grains/ACF
e.	Hydrocarbons		lb/hr		grains/ACF
f.	VOCs		lb/hr		grains/ACF
g.	Pb		lb/hr		grains/ACF
h.	Specify other(s)				
			lb/hr		grains/ACF
			lb/hr		grains/ACF
			lb/hr		grains/ACF
			lb/hr		grains/ACF

NOTE: (1) An Air Pollution Control Device Sheet must be completed for any air pollution device(s) used to control emissions from this affected source.

(2) Complete the Emission Points Data Sheet.

9. Proposed Monitoring, Recordkeeping, Reporting, and Testing
Please propose monitoring, recordkeeping, and reporting in order to demonstrate compliance with the proposed operating parameters. Please propose testing in order to demonstrate compliance with the proposed emissions limits.

MONITORING	RECORDKEEPING
See Attachment O	See Attachment O
REPORTING	**TESTING**
See Attachment O	See Attachment O

MONITORING. PLEASE LIST AND DESCRIBE THE PROCESS PARAMETERS AND RANGES THAT ARE PROPOSED TO BE MONITORED IN ORDER TO DEMONSTRATE COMPLIANCE WITH THE OPERATION OF THIS PROCESS EQUIPMENT OPERATION/AIR POLLUTION CONTROL DEVICE.

RECORDKEEPING. PLEASE DESCRIBE THE PROPOSED RECORDKEEPING THAT WILL ACCOMPANY THE MONITORING.

REPORTING. PLEASE DESCRIBE THE PROPOSED FREQUENCY OF REPORTING OF THE RECORDKEEPING.

TESTING. PLEASE DESCRIBE ANY PROPOSED EMISSIONS TESTING FOR THIS PROCESS EQUIPMENT/AIR POLLUTION CONTROL DEVICE.

10. Describe all operating ranges and maintenance procedures required by Manufacturer to maintain warranty
NA

Attachment L
EMISSIONS UNIT DATA SHEET
GENERAL

To be used for affected sources other than asphalt plants, foundries, incinerators, indirect heat exchangers, and quarries.

Identification Number (as assigned on *Equipment List Form*): Firewater Pump FWP-1

1. Name or type and model of proposed affected source: Firewater Pump (Diesel Fuel Fired) – 179 kW (240 hp)
2. On a separate sheet(s), furnish a sketch(es) of this affected source. If a modification is to be made to this source, clearly indicated the change(s). Provide a narrative description of all features of the affected source which may affect the production of air pollutants.
3. Name(s) and maximum amount of proposed process material(s) charged per hour: NA
4. Name(s) and maximum amount of proposed material(s) produced per hour: NA
5. Give chemical reactions, if applicable, that will be involved in the generation of air pollutants: NA

* The identification number which appears here must correspond to the air pollution control device identification number appearing on the *List Form*.

6. Combustion Data (if applicable):

(a) Type and amount in appropriate units of fuel(s) to be burned:

Ultra Low Sulfur Diesel Fuel – As Required

(b) Chemical analysis of proposed fuel(s), excluding coal, including maximum percent sulfur and ash:

0.0015 % sulfur by weight

(c) Theoretical combustion air requirement (ACF/unit of fuel):

NA @ NA °F and NA psia.

(d) Percent excess air: NA

(e) Type and BTU/hr of burners and all other firing equipment planned to be used:

NA/Internal Combustion Engine

(f) If coal is proposed as a source of fuel, identify supplier and seams and give sizing of the coal as it will be fired:

NA

(g) Proposed maximum design heat input: 2.710 $\times 10^6$ BTU/hr.

7. Projected operating schedule:

Hours/Day	0.4	Days/Week	5	Weeks/Year	50

8. Projected amount of pollutants that would be emitted from this affected source if no control devices were used:				
@ 0NA °F and Ambient psia				
a.	NO_X	See Attachment J and Section 3 and Appendix B of the PSD Application Document lb/hr		grains/ACF
b.	SO_2	lb/hr		grains/ACF
c.	CO	lb/hr		grains/ACF
d.	PM_{10}	lb/hr		grains/ACF
e.	Hydrocarbons	lb/hr		grains/ACF
f.	VOCs	lb/hr		grains/ACF
g.	Pb	lb/hr		grains/ACF
h.	Specify other(s)			
		lb/hr		grains/ACF
		lb/hr		grains/ACF
		lb/hr		grains/ACF
		lb/hr		grains/ACF

NOTE: (1) An Air Pollution Control Device Sheet must be completed for any air pollution device(s) used to control emissions from this affected source.

(2) Complete the Emission Points Data Sheet.

9. Proposed Monitoring, Recordkeeping, Reporting, and Testing
Please propose monitoring, recordkeeping, and reporting in order to demonstrate compliance with the proposed operating parameters. Please propose testing in order to demonstrate compliance with the proposed emissions limits.

MONITORING	RECORDKEEPING
See Attachment O	See Attachment O
REPORTING	**TESTING**
See Attachment O	See Attachment O

MONITORING. PLEASE LIST AND DESCRIBE THE PROCESS PARAMETERS AND RANGES THAT ARE PROPOSED TO BE MONITORED IN ORDER TO DEMONSTRATE COMPLIANCE WITH THE OPERATION OF THIS PROCESS EQUIPMENT OPERATION/AIR POLLUTION CONTROL DEVICE.

RECORDKEEPING. PLEASE DESCRIBE THE PROPOSED RECORDKEEPING THAT WILL ACCOMPANY THE MONITORING.

REPORTING. PLEASE DESCRIBE THE PROPOSED FREQUENCY OF REPORTING OF THE RECORDKEEPING.

TESTING. PLEASE DESCRIBE ANY PROPOSED EMISSIONS TESTING FOR THIS PROCESS EQUIPMENT/AIR POLLUTION CONTROL DEVICE.

10. Describe all operating ranges and maintenance procedures required by Manufacturer to maintain warranty
NA

Attachment L
EMISSIONS UNIT DATA SHEET
STORAGE TANKS

Provide the following information for <u>each</u> new or modified bulk liquid storage tank as shown on the *Equipment List Form* and other parts of this application. A tank is considered modified if the material to be stored in the tank is different from the existing stored liquid.

IF USING US EPA'S TANKS EMISSION ESTIMATION PROGRAM (AVAILABLE AT **www.epa.gov/tnn/tanks.html**), APPLICANT MAY ATTACH THE SUMMARY SHEETS IN LIEU OF COMPLETING SECTIONS III, IV, & V OF THIS FORM. HOWEVER, SECTIONS I, II, AND VI OF THIS FORM MUST BE COMPLETED. US EPA'S AP-42, SECTION 7.1, "ORGANIC LIQUID STORAGE TANKS," MAY ALSO BE USED TO ESTIMATE VOC AND HAP EMISSIONS (**http://www.epa.gov/tnn/chief/**).

I. GENERAL INFORMATION (required)

1. Bulk Storage Area Name Diesel	2. Tank Name Diesel Storage Tank DT-1
3. Tank Equipment Identification No. (as assigned on *Equipment List Form*) DT-1	4. Emission Point Identification No. (as assigned on *Equipment List Form*) DT-1
5. Date of Commencement of Construction (for existing tanks) 2021	
6. Type of change ☒ New Construction ☐ New Stored Material ☐ Other Tank Modification	
7. Description of Tank Modification (if applicable) NA	
7A. Does the tank have more than one mode of operation? ☐ Yes ☒ No (e.g. Is there more than one product stored in the tank?)	
7B. If YES, explain and identify which mode is covered by this application (Note: A separate form must be completed for each mode). NA	
7C. Provide any limitations on source operation affecting emissions, any work practice standards (e.g. production variation, etc.): NA	

II. TANK INFORMATION (required)

8. Design Capacity (specify barrels or gallons). Use the internal cross-sectional area multiplied by internal height. 300 gallons	
9A. Tank Internal Diameter (ft) 3.5	9B. Tank Internal Height (or Length) (ft) 7
10A. Maximum Liquid Height (ft) 7	10B. Average Liquid Height (ft) 3.5
11A. Maximum Vapor Space Height (ft) 6.25	11B. Average Vapor Space Height (ft) 3.5
12. Nominal Capacity (specify barrels or gallons). This is also known as "working volume" and considers design liquid levels and overflow valve heights. 500	

13A. Maximum annual throughput (gal/yr) 1,000	13B. Maximum daily throughput (gal/day) As required

14. Number of Turnovers per year (annual net throughput/maximum tank liquid volume)
2

15. Maximum tank fill rate (gal/min) 25

16. Tank fill method ☒ Submerged ☐ Splash ☐ Bottom Loading

17. Complete 17A and 17B for Variable Vapor Space Tank Systems ☒ Does Not Apply

17A. Volume Expansion Capacity of System (gal) NA	17B. Number of transfers into system per year NA

18. Type of tank (check all that apply):

☒ Fixed Roof ___ vertical ___ horizontal ___ flat roof ___ cone roof ___ dome roof
___ other (describe)

☐ External Floating Roof ___ pontoon roof ___ double deck roof

☐ Domed External (or Covered) Floating Roof

☐ Internal Floating Roof ___ vertical column support ___ self-supporting

☐ Variable Vapor Space ___ lifter roof ___ diaphragm

☐ Pressurized ___ spherical ___ cylindrical

☐ Underground

☐ Other (describe)

III. TANK CONSTRUCTION & OPERATION INFORMATION (optional if providing TANKS Summary Sheets)

19. Tank Shell Construction:
☐ Riveted ☐ Gunite lined ☐ Epoxy-coated rivets ☒ Other (describe)

20A. Shell Color White of grey	20B. Roof Color White of grey	20C. Year Last Painted NEW

21. Shell Condition (if metal and unlined):
☒ No Rust ☐ Light Rust ☐ Dense Rust ☐ Not applicable

22A. Is the tank heated? ☐ YES ☒ NO

22B. If YES, provide the operating temperature (°F) NA

22C. If YES, please describe how heat is provided to tank. NA

23. Operating Pressure Range (psig): to

24. Complete the following section for **Vertical Fixed Roof Tanks** ☒ Does Not Apply

24A. For dome roof, provide roof radius (ft) NA

24B. For cone roof, provide slope (ft/ft) NA

25. Complete the following section for **Floating Roof Tanks** ☒ Does Not Apply

25A. Year Internal Floaters Installed: NA

25B. Primary Seal Type: (check one) ☐ Metallic (Mechanical) Shoe Seal ☐ Liquid Mounted Resilient Seal ☐ Vapor Mounted Resilient Seal ☐ Other (describe):

25C. Is the Floating Roof equipped with a Secondary Seal? ☐ YES ☐ NO

25D. If YES, how is the secondary seal mounted? (check one) ☐ Shoe ☐ Rim ☐ Other (describe):

25E. Is the Floating Roof equipped with a weather shield? ☐ YES ☐ NO

25F. Describe deck fittings; indicate the number of each type of fitting:		
ACCESS HATCH		
BOLT COVER, GASKETED:	UNBOLTED COVER, GASKETED:	UNBOLTED COVER, UNGASKETED:
AUTOMATIC GAUGE FLOAT WELL		
BOLT COVER, GASKETED:	UNBOLTED COVER, GASKETED:	UNBOLTED COVER, UNGASKETED:
COLUMN WELL		
BUILT-UP COLUMN – SLIDING COVER, GASKETED:	BUILT-UP COLUMN – SLIDING COVER, UNGASKETED:	PIPE COLUMN – FLEXIBLE FABRIC SLEEVE SEAL:
LADDER WELL		
PIP COLUMN – SLIDING COVER, GASKETED:	PIPE COLUMN – SLIDING COVER, UNGASKETED:	
GAUGE-HATCH/SAMPLE PORT		
SLIDING COVER, GASKETED:	SLIDING COVER, UNGASKETED:	
ROOF LEG OR HANGER WELL		
WEIGHTED MECHANICAL ACTUATION, GASKETED:	WEIGHTED MECHANICAL ACTUATION, UNGASKETED:	SAMPLE WELL-SLIT FABRIC SEAL (10% OPEN AREA)
VACUUM BREAKER		
WEIGHTED MECHANICAL ACTUATION, GASKETED:	WEIGHTED MECHANICAL ACTUATION, UNGASKETED:	
RIM VENT		
WEIGHTED MECHANICAL ACTUATION GASKETED:	WEIGHTED MECHANICAL ACTUATION, UNGASKETED:	
DECK DRAIN (3-INCH DIAMETER)		
OPEN:	90% CLOSED:	
STUB DRAIN		
1-INCH DIAMETER:		
OTHER (DESCRIBE, ATTACH ADDITIONAL PAGES IF NECESSARY)		

26. Complete the following section for Internal Floating Roof Tanks ☐ Does Not Apply	
26A. Deck Type: ☐ Bolted ☐ Welded	
26B. For Bolted decks, provide deck construction:	
26C. Deck seam: ☐ Continuous sheet construction 5 feet wide ☐ Continuous sheet construction 6 feet wide ☐ Continuous sheet construction 7 feet wide ☐ Continuous sheet construction 5 × 7.5 feet wide ☐ Continuous sheet construction 5 × 12 feet wide ☐ Other (describe)	
26D. Deck seam length (ft)	26E. Area of deck (ft^2)
For column supported tanks: 26F. Number of columns:	26G. Diameter of each column:

IV. SITE INFORMANTION (optional if providing TANKS Summary Sheets)

27. Provide the city and state on which the data in this section are based. Morganwtown, WV
28. Daily Average Ambient Temperature (°F)
29. Annual Average Maximum Temperature (°F)
30. Annual Average Minimum Temperature (°F)
31. Average Wind Speed (miles/hr)
32. Annual Average Solar Insulation Factor (BTU/(ft^2·day))
33. Atmospheric Pressure (psia)

V. LIQUID INFORMATION (optional if providing TANKS Summary Sheets)

34. Average daily temperature range of bulk liquid:	
34A. Minimum (°F)	34B. Maximum (°F)
35. Average operating pressure range of tank:	
35A. Minimum (psig)	35B. Maximum (psig)
36A. Minimum Liquid Surface Temperature (°F)	36B. Corresponding Vapor Pressure (psia)
37A. Average Liquid Surface Temperature (°F)	37B. Corresponding Vapor Pressure (psia)
38A. Maximum Liquid Surface Temperature (°F)	38B. Corresponding Vapor Pressure (psia)

39. Provide the following for each liquid or gas to be stored in tank. Add additional pages if necessary.			
39A. Material Name or Composition			
39B. CAS Number			
39C. Liquid Density (lb/gal)			
39D. Liquid Molecular Weight (lb/lb-mole)			
39E. Vapor Molecular Weight (lb/lb-mole)			

Maximum Vapor Pressure 39F. True (psia) 39G. Reid (psia)			
Months Storage per Year 39H. From 39I. To			

VI. EMISSIONS AND CONTROL DEVICE DATA (required)

40. Emission Control Devices (check as many as apply): ☐ Does Not Apply

- ☐ Carbon Adsorption[1]
- ☐ Condenser[1]
- ☐ Conservation Vent (psig)
  - Vacuum Setting   Pressure Setting
- ☐ Emergency Relief Valve (psig)
- ☐ Inert Gas Blanket of
- ☐ Insulation of Tank with
- ☐ Liquid Absorption (scrubber)[1]
- ☐ Refrigeration of Tank
- ☐ Rupture Disc (psig)
- ☐ Vent to Incinerator[1]
- ☐ Other[1] (describe):

[1] Complete appropriate Air Pollution Control Device Sheet.

41. Expected Emission Rate (submit Test Data or Calculations here or elsewhere in the application).

Material Name & CAS No.	Breathing Loss (lb/hr)	Working Loss		Annual Loss (lb/yr)	Estimation Method[1]
		Amount	Units		

[1] EPA = EPA Emission Factor, MB = Material Balance, SS = Similar Source, ST = Similar Source Test, Throughput Data, O = Other (specify)

☐ Remember to attach emissions calculations, including TANKS Summary Sheets if applicable.

Attachment L
EMISSIONS UNIT DATA SHEET
STORAGE TANKS

Provide the following information for each new or modified bulk liquid storage tank as shown on the *Equipment List Form* and other parts of this application. A tank is considered modified if the material to be stored in the tank is different from the existing stored liquid.

IF USING US EPA'S TANKS EMISSION ESTIMATION PROGRAM (AVAILABLE AT www.epa.gov/tnn/tanks.html), APPLICANT MAY ATTACH THE SUMMARY SHEETS IN LIEU OF COMPLETING SECTIONS III, IV, & V OF THIS FORM. HOWEVER, SECTIONS I, II, AND VI OF THIS FORM MUST BE COMPLETED. US EPA'S AP-42, SECTION 7.1, "ORGANIC LIQUID STORAGE TANKS," MAY ALSO BE USED TO ESTIMATE VOC AND HAP EMISSIONS (http://www.epa.gov/tnn/chief/).

I. GENERAL INFORMATION (required)

1. Bulk Storage Area Name Diesel	2. Tank Name Diesel Storage Tank DT-2
3. Tank Equipment Identification No. (as assigned on *Equipment List Form*) DT-2	4. Emission Point Identification No. (as assigned on *Equipment List Form*) DT-2
5. Date of Commencement of Construction (for existing tanks) 2021	
6. Type of change ☒ New Construction ☐ New Stored Material ☐ Other Tank Modification	
7. Description of Tank Modification (if applicable) NA	
7A. Does the tank have more than one mode of operation? ☐ Yes ☒ No (e.g. Is there more than one product stored in the tank?)	
7B. If YES, explain and identify which mode is covered by this application (Note: A separate form must be completed for each mode). NA	
7C. Provide any limitations on source operation affecting emissions, any work practice standards (e.g. production variation, etc.): NA	

II. TANK INFORMATION (required)

8. Design Capacity (specify barrels or gallons). Use the internal cross-sectional area multiplied by internal height. 125 gallons	
9A. Tank Internal Diameter (ft) 3.5	9B. Tank Internal Height (or Length) (ft) 7
10A. Maximum Liquid Height (ft) 7	10B. Average Liquid Height (ft) 3.5
11A. Maximum Vapor Space Height (ft) 6.25	11B. Average Vapor Space Height (ft) 3.5
12. Nominal Capacity (specify barrels or gallons). This is also known as "working volume" and considers design liquid levels and overflow valve heights. 500	

13A. Maximum annual throughput (gal/yr) 1,000	13B. Maximum daily throughput (gal/day) As required

14. Number of Turnovers per year (annual net throughput/maximum tank liquid volume)
2

15. Maximum tank fill rate (gal/min) 25

16. Tank fill method ☒ Submerged ☐ Splash ☐ Bottom Loading

17. Complete 17A and 17B for Variable Vapor Space Tank Systems ☒ Does Not Apply

17A. Volume Expansion Capacity of System (gal) NA	17B. Number of transfers into system per year NA

18. Type of tank (check all that apply):

☒ Fixed Roof ___ vertical ___ horizontal ___ flat roof ___ cone roof ___ dome roof ___ other (describe)

☐ External Floating Roof ___ pontoon roof ___ double deck roof

☐ Domed External (or Covered) Floating Roof

☐ Internal Floating Roof ___ vertical column support ___ self-supporting

☐ Variable Vapor Space ___ lifter roof ___ diaphragm

☐ Pressurized ___ spherical ___ cylindrical

☐ Underground

☐ Other (describe)

III. TANK CONSTRUCTION & OPERATION INFORMATION (optional if providing TANKS Summary Sheets)

19. Tank Shell Construction:
☐ Riveted ☐ Gunite lined ☐ Epoxy-coated rivets ☒ Other (describe)

20A. Shell Color White of grey	20B. Roof Color White of grey	20C. Year Last Painted NEW

21. Shell Condition (if metal and unlined):
☒ No Rust ☐ Light Rust ☐ Dense Rust ☐ Not applicable

22A. Is the tank heated? ☐ YES ☒ NO

22B. If YES, provide the operating temperature (°F) NA

22C. If YES, please describe how heat is provided to tank. NA

23. Operating Pressure Range (psig): to

24. Complete the following section for **Vertical Fixed Roof Tanks** ☒ Does Not Apply

24A. For dome roof, provide roof radius (ft) NA

24B. For cone roof, provide slope (ft/ft) NA

25. Complete the following section for **Floating Roof Tanks** ☒ Does Not Apply

25A. Year Internal Floaters Installed: NA

25B. Primary Seal Type: (check one) ☐ Metallic (Mechanical) Shoe Seal ☐ Liquid Mounted Resilient Seal ☐ Vapor Mounted Resilient Seal ☐ Other (describe):

25C. Is the Floating Roof equipped with a Secondary Seal? ☐ YES ☐ NO

25D. If YES, how is the secondary seal mounted? (check one) ☐ Shoe ☐ Rim ☐ Other (describe):

25E. Is the Floating Roof equipped with a weather shield? ☐ YES ☐ NO

25F. Describe deck fittings; indicate the number of each type of fitting:

ACCESS HATCH

BOLT COVER, GASKETED:	UNBOLTED COVER, GASKETED:	UNBOLTED COVER, UNGASKETED:

AUTOMATIC GAUGE FLOAT WELL

BOLT COVER, GASKETED:	UNBOLTED COVER, GASKETED:	UNBOLTED COVER, UNGASKETED:

COLUMN WELL

BUILT-UP COLUMN – SLIDING COVER, GASKETED:	BUILT-UP COLUMN – SLIDING COVER, UNGASKETED:	PIPE COLUMN – FLEXIBLE FABRIC SLEEVE SEAL:

LADDER WELL

PIP COLUMN – SLIDING COVER, GASKETED:	PIPE COLUMN – SLIDING COVER, UNGASKETED:

GAUGE-HATCH/SAMPLE PORT

SLIDING COVER, GASKETED:	SLIDING COVER, UNGASKETED:

ROOF LEG OR HANGER WELL

WEIGHTED MECHANICAL ACTUATION, GASKETED:	WEIGHTED MECHANICAL ACTUATION, UNGASKETED:	SAMPLE WELL-SLIT FABRIC SEAL (10% OPEN AREA)

VACUUM BREAKER

WEIGHTED MECHANICAL ACTUATION, GASKETED:	WEIGHTED MECHANICAL ACTUATION, UNGASKETED:

RIM VENT

WEIGHTED MECHANICAL ACTUATION GASKETED:	WEIGHTED MECHANICAL ACTUATION, UNGASKETED:

DECK DRAIN (3-INCH DIAMETER)

OPEN:	90% CLOSED:

STUB DRAIN

1-INCH DIAMETER:

OTHER (DESCRIBE, ATTACH ADDITIONAL PAGES IF NECESSARY)

26. Complete the following section for Internal Floating Roof Tanks ☐ Does Not Apply	
26A. Deck Type: ☐ Bolted ☐ Welded	
26B. For Bolted decks, provide deck construction:	
26C. Deck seam: ☐ Continuous sheet construction 5 feet wide ☐ Continuous sheet construction 6 feet wide ☐ Continuous sheet construction 7 feet wide ☐ Continuous sheet construction 5 × 7.5 feet wide ☐ Continuous sheet construction 5 × 12 feet wide ☐ Other (describe)	
26D. Deck seam length (ft)	26E. Area of deck (ft^2)
For column supported tanks: 26F. Number of columns:	26G. Diameter of each column:

IV. SITE INFORMANTION (optional if providing TANKS Summary Sheets)

27. Provide the city and state on which the data in this section are based. Morganwtown, WV
28. Daily Average Ambient Temperature (°F)
29. Annual Average Maximum Temperature (°F)
30. Annual Average Minimum Temperature (°F)
31. Average Wind Speed (miles/hr)
32. Annual Average Solar Insulation Factor (BTU/(ft^2·day))
33. Atmospheric Pressure (psia)

V. LIQUID INFORMATION (optional if providing TANKS Summary Sheets)

34. Average daily temperature range of bulk liquid:	
34A. Minimum (°F)	34B. Maximum (°F)
35. Average operating pressure range of tank:	
35A. Minimum (psig)	35B. Maximum (psig)
36A. Minimum Liquid Surface Temperature (°F)	36B. Corresponding Vapor Pressure (psia)
37A. Average Liquid Surface Temperature (°F)	37B. Corresponding Vapor Pressure (psia)
38A. Maximum Liquid Surface Temperature (°F)	38B. Corresponding Vapor Pressure (psia)

39. Provide the following for each liquid or gas to be stored in tank. Add additional pages if necessary.

39A. Material Name or Composition			
39B. CAS Number			
39C. Liquid Density (lb/gal)			
39D. Liquid Molecular Weight (lb/lb-mole)			
39E. Vapor Molecular Weight (lb/lb-mole)			

Maximum Vapor Pressure 39F. True (psia) 39G. Reid (psia)			
Months Storage per Year 39H. From 39I. To			

VI. EMISSIONS AND CONTROL DEVICE DATA (required)

40. Emission Control Devices (check as many as apply): ☐ Does Not Apply

- ☐ Carbon Adsorption[1]
- ☐ Condenser[1]
- ☐ Conservation Vent (psig)
  Vacuum Setting Pressure Setting
- ☐ Emergency Relief Valve (psig)
- ☐ Inert Gas Blanket of
- ☐ Insulation of Tank with
- ☐ Liquid Absorption (scrubber)[1]
- ☐ Refrigeration of Tank
- ☐ Rupture Disc (psig)
- ☐ Vent to Incinerator[1]
- ☐ Other[1] (describe):

[1] Complete appropriate Air Pollution Control Device Sheet.

41. Expected Emission Rate (submit Test Data or Calculations here or elsewhere in the application).

Material Name & CAS No.	Breathing Loss (lb/hr)	Working Loss		Annual Loss (lb/yr)	Estimation Method[1]
		Amount	Units		

[1] EPA = EPA Emission Factor, MB = Material Balance, SS = Similar Source, ST = Similar Source Test, Throughput Data, O = Other (specify)

☐ Remember to attach emissions calculations, including TANKS Summary Sheets if applicable.

Attachment L
Emission Unit Data Sheet
(INDIRECT HEAT EXCHANGER)

Control Device ID No. (must match List Form): FGH-1

Equipment Information

1. Manufacturer: TBD	2. Model No. NA Serial No. NA
3. Number of units: 1	4. UseSteam to preheat natural gas
5. Rated Boiler Horsepower: NA hp	6. Boiler Serial No.: NA
7. Date constructed: 2021	8. Date of last modification and explain: NA
9. Maximum design heat input per unit: 5.4 $\times 10^6$ BTU/hr	10. Peak heat input per unit: 5.4 $\times 10^6$ BTU/hr
11. Steam produced at maximum design output: NA LB/hr NA psig	12. Projected Operating Schedule: Hours/Day 24 Days/Week 7 Weeks/Year 52
13. Type of firing equipment to be used: ☐ Pulverized coal ☐ Spreader stoker ☐ Oil burners ☒ Natural Gas Burner ☐ Others, specify	14. Proposed type of burners and orientation: ☐ Vertical ☒ Front Wall ☐ Opposed ☐ Tangential ☐ Others, specify
15. Type of draft: ☒ Forced ☐ Induced	16. Percent of ash retained in furnace: NA %
17. Will flyash be reinjected? ☐ Yes ☒ No	18. Percent of carbon in flyash: NA %

Stack or Vent Data

19. Inside diameter or dimensions: 0.6 ft.	20. Gas exit temperature: 600 °F
21. Height: 15 ft.	22. Stack serves: ☒ This equipment only ☐ Other equipment also (submit type and rating of all other equipment exhausted through this stack or vent)
23. Gas flow rate: 1,017 ft^3/min	
24. Estimated percent of moisture: %	

Fuel Requirements

25. Type	Fuel Oil No.	Natural Gas	Gas (other, specify)	Coal, Type:	Other:
Quantity (at Design Output)	gph@60°F	5,250 ft^3/hr	ft^3/hr	TPH	
Annually	$\times 10^3$ gal	4.6 $\times 10^6$ ft^3/hr	$\times 10^6$ ft^3/hr	tons	
Sulfur	Maximum: wt. % Average: wt. %	0.4 gr/100 ft^3	gr/100 ft^3	Maximum: wt. %	
Ash (%)		NA		Maximum	
BTU Content	BTU/Gal. Lbs/Gal.@60°F	1,030 BTU/ft^3	BTU/ft^3	BTU/lb	
Source					
Supplier					
Halogens (Yes/No)					
List and Identify Metals					

26. Gas burner mode of control:
☐ Manual ☐ Automatic hi-low
☒ Automatic full modulation ☐ Automatic on-off

27. Gas burner manufacture: TBD

28. Oil burner manufacture: NA

29. If fuel oil is used, how is it atomized? ☐ Oil Pressure ☐ Steam Pressure ☐ Compressed Air ☐ Rotary Cup ☐ Other, specify

30. Fuel oil preheated: ☐ Yes ☐ No

31. If yes, indicate temperature: °F

32. Specify the calculated theoretical air requirements for combustion of the fuel or mixture of fuels described above actual cubic feet (ACF) per unit of fuel:
NA @ NA °F, NA PSIA, NA % moisture

33. Emission rate at rated capacity: See Attachment J and Section 3 and Appendix B of the PSD Application Document lb/hr

34. Percent excess air actually required for combustion of the fuel described: NA %

Coal Characteristics

35. Seams: NA

36. Proximate analysis (dry basis): % of Fixed Carbon: % of Sulfur:
% of Moisture: % of Volatile Matter:
% of Ash:

Emissions Stream

37. What quantities of pollutants will be emitted from the boiler before controls?

Pollutant	Pounds per Hour lb/hr	grain/ACF	@ °F	PSIA
CO	See Attachment J and Section 3 and			
Hydrocarbons				
NO_x				
Pb				
PM_{10}				
SO_2				
VOCs				
Other (specify)				

38. What quantities of pollutants will be emitted from the boiler after controls?

Pollutant	Pounds per Hour lb/hr	grain/ACF	@ °F	PSIA
CO	See Attachment J and Section 3 and			
Hydrocarbons				
NO_x				
Pb				
PM_{10}				
SO_2				
VOCs				
Other (specify)				

39. How will waste material from the process and control equipment be disposed of?
NA

40. Have you completed an *Air Pollution Control Device Sheet(s)* for the control(s) used on this Emission Unit.

41. Have you included the ***air pollution rates*** on the Emissions Points Data Summary Sheet?

42. **Proposed Monitoring, Recordkeeping, Reporting, and Testing**
Please propose monitoring, recordkeeping, and reporting in order to demonstrate compliance with the proposed operating parameters. Please propose testing in order to demonstrate compliance with the proposed emissions limits.

MONITORING PLAN: Please list (1) describe the process parameters and how they were chosen (2) the ranges and how they were established for monitoring to demonstrate compliance with the operation of this process equipment operation or air pollution control device.
See Attachment O

TESTING PLAN: Please describe any proposed emissions testing for this process equipment or air pollution control device.
See Attachment

RECORDKEEPING: Please describe the proposed recordkeeping that will accompany the monitoring.
See Attachment

REPORTING: Please describe the proposed frequency of reporting of the recordkeeping.
See Attachment

43. Describe all operating ranges and maintenance procedures required by Manufacturer to maintain warranty.
NA

Attachment L
Emission Unit Data Sheet
(INDIRECT HEAT EXCHANGER)

Control Device ID No. (must match List Form): FGH-2

Equipment Information

1. Manufacturer: TBD	2. Model No. NA Serial No. NA
3. Number of units: 1	4. UseSteam to preheat natural gas
5. Rated Boiler Horsepower: NA hp	6. Boiler Serial No.: NA
7. Date constructed: 2021	8. Date of last modification and explain: NA
9. Maximum design heat input per unit: 5.4 $\times 10^6$ BTU/hr	10. Peak heat input per unit: 5.4 $\times 10^6$ BTU/hr
11. Steam produced at maximum design output: NA LB/hr NA psig	12. Projected Operating Schedule: Hours/Day 24 Days/Week 7 Weeks/Year 52
13. Type of firing equipment to be used: ☐ Pulverized coal ☐ Spreader stoker ☐ Oil burners ☒ Natural Gas Burner ☐ Others, specify	14. Proposed type of burners and orientation: ☐ Vertical ☒ Front Wall ☐ Opposed ☐ Tangential ☐ Others, specify
15. Type of draft: ☒ Forced ☐ Induced	16. Percent of ash retained in furnace: NA %
17. Will flyash be reinjected? ☐ Yes ☒ No	18. Percent of carbon in flyash: NA %

Stack or Vent Data

19. Inside diameter or dimensions: 0.6 ft.	20. Gas exit temperature: 600 °F
21. Height: 15 ft.	22. Stack serves: ☒ This equipment only ☐ Other equipment also (submit type and rating of all other equipment exhausted through this stack or vent)
23. Gas flow rate: 1,017 ft^3/min	
24. Estimated percent of moisture: %	

Fuel Requirements

25. Type	Fuel Oil No.	Natural Gas	Gas (other, specify)	Coal, Type:	Other:
Quantity (at Design Output)	gph@60°F	5,250 ft^3/hr	ft^3/hr	TPH	
Annually	$\times 10^3$ gal	4.6 $\times 10^6$ ft^3/hr	$\times 10^6$ ft^3/hr	tons	
Sulfur	Maximum: wt. % Average: wt. %	0.4 gr/100 ft^3	gr/100 ft^3	Maximum: wt. %	
Ash (%)		NA		Maximum	
BTU Content	BTU/Gal. Lbs/Gal.@60°F	1,030 BTU/ft^3	BTU/ft^3	BTU/lb	
Source					
Supplier					
Halogens (Yes/No)					
List and Identify Metals					

26. Gas burner mode of control:
☐ Manual ☐ Automatic hi-low
☒ Automatic full modulation ☐ Automatic on-off

27. Gas burner manufacture: TBD

28. Oil burner manufacture: NA

29. If fuel oil is used, how is it atomized? ☐ Oil Pressure ☐ Steam Pressure ☐ Compressed Air ☐ Rotary Cup ☐ Other, specify

30. Fuel oil preheated: ☐ Yes ☐ No

31. If yes, indicate temperature: °F

32. Specify the calculated theoretical air requirements for combustion of the fuel or mixture of fuels described above actual cubic feet (ACF) per unit of fuel:
NA @ NA °F, NA PSIA, NA % moisture

33. Emission rate at rated capacity: See Attachment J and Section 3 and Appendix B of the PSD Application Document lb/hr

34. Percent excess air actually required for combustion of the fuel described: NA %

Coal Characteristics

35. Seams: NA

36. Proximate analysis (dry basis): % of Fixed Carbon: % of Sulfur:
% of Moisture: % of Volatile Matter:
% of Ash:

Emissions Stream

37. What quantities of pollutants will be emitted from the boiler before controls?

Pollutant	Pounds per Hour lb/hr	grain/ACF	@ °F	PSIA
CO	See Attachment J and Section 3 and			
Hydrocarbons				
NO_x				
Pb				
PM_{10}				
SO_2				
VOCs				
Other (specify)				

38. What quantities of pollutants will be emitted from the boiler after controls?

Pollutant	Pounds per Hour lb/hr	grain/ACF	@ °F	PSIA
CO	See Attachment J and Section 3 and			
Hydrocarbons				
NO_x				
Pb				
PM_{10}				
SO_2				
VOCs				
Other (specify)				

39. How will waste material from the process and control equipment be disposed of?
NA

40. Have you completed an *Air Pollution Control Device Sheet(s)* for the control(s) used on this Emission Unit.

41. Have you included the ***air pollution rates*** on the Emissions Points Data Summary Sheet?

42. **Proposed Monitoring, Recordkeeping, Reporting, and Testing**
Please propose monitoring, recordkeeping, and reporting in order to demonstrate compliance with the proposed operating parameters. Please propose testing in order to demonstrate compliance with the proposed emissions limits.

MONITORING PLAN: Please list (1) describe the process parameters and how they were chosen (2) the ranges and how they were established for monitoring to demonstrate compliance with the operation of this process equipment operation or air pollution control device.
See Attachment O

TESTING PLAN: Please describe any proposed emissions testing for this process equipment or air pollution control device.
See Attachment

RECORDKEEPING: Please describe the proposed recordkeeping that will accompany the monitoring.
See Attachment

REPORTING: Please describe the proposed frequency of reporting of the recordkeeping.
See Attachment

43. Describe all operating ranges and maintenance procedures required by Manufacturer to maintain warranty.
NA

Attachment L
EMISSIONS UNIT DATA SHEET
GENERAL

To be used for affected sources other than asphalt plants, foundries, incinerators, indirect heat exchangers, and quarries.

Identification Number (as assigned on *Equipment List Form*): WCT-1

1. Name or type and model of proposed affected source: Mechanical Draft Cooling Tower
2. On a separate sheet(s), furnish a sketch(es) of this affected source. If a modification is to be made to this source, clearly indicated the change(s). Provide a narrative description of all features of the affected source which may affect the production of air pollutants.
3. Name(s) and maximum amount of proposed process material(s) charged per hour: Process cooling water, approximately 270,000 gals/min
4. Name(s) and maximum amount of proposed material(s) produced per hour: NA
5. Give chemical reactions, if applicable, that will be involved in the generation of air pollutants: NA

* The identification number which appears here must correspond to the air pollution control device identification number appearing on the *List Form*.

6. Combustion Data (if applicable):

(a) Type and amount in appropriate units of fuel(s) to be burned:

NA

(b) Chemical analysis of proposed fuel(s), excluding coal, including maximum percent sulfur and ash:

NA

(c) Theoretical combustion air requirement (ACF/unit of fuel):

NA @ NA °F and NA psia.

(d) Percent excess air: NA

(e) Type and BTU/hr of burners and all other firing equipment planned to be used:

NA

(f) If coal is proposed as a source of fuel, identify supplier and seams and give sizing of the coal as it will be fired:

NA

(g) Proposed maximum design heat input: NA $\times 10^6$ BTU/hr.

7. Projected operating schedule:

Hours/Day 24	Days/Week 7	Weeks/Year 52

8. Projected amount of pollutants that would be emitted from this affected source if no control devices were used:

@ NA °F and Ambient psia

a.	NO_X	See Attachment J and Section 3 and Appendix B of the PSD Application Document lb/hr		grains/ACF
b.	SO_2	lb/hr		grains/ACF
c.	CO	lb/hr		grains/ACF
d.	PM_{10}	4.11 lb/hr		grains/ACF
e.	Hydrocarbons	lb/hr		grains/ACF
f.	VOCs	lb/hr		grains/ACF
g.	Pb	lb/hr		grains/ACF
h.	Specify other(s)			
		lb/hr		grains/ACF
		lb/hr		grains/ACF
		lb/hr		grains/ACF
		lb/hr		grains/ACF

NOTE: (1) An Air Pollution Control Device Sheet must be completed for any air pollution device(s) used to control emissions from this affected source.

(2) Complete the Emission Points Data Sheet.

9. Proposed Monitoring, Recordkeeping, Reporting, and Testing
Please propose monitoring, recordkeeping, and reporting in order to demonstrate compliance with the proposed operating parameters. Please propose testing in order to demonstrate compliance with the proposed emissions limits.

MONITORING	RECORDKEEPING
See Attachment O	See Attachment O
REPORTING	**TESTING**
See Attachment O	See Attachment O

MONITORING. PLEASE LIST AND DESCRIBE THE PROCESS PARAMETERS AND RANGES THAT ARE PROPOSED TO BE MONITORED IN ORDER TO DEMONSTRATE COMPLIANCE WITH THE OPERATION OF THIS PROCESS EQUIPMENT OPERATION/AIR POLLUTION CONTROL DEVICE.

RECORDKEEPING. PLEASE DESCRIBE THE PROPOSED RECORDKEEPING THAT WILL ACCOMPANY THE MONITORING.

REPORTING. PLEASE DESCRIBE THE PROPOSED FREQUENCY OF REPORTING OF THE RECORDKEEPING.

TESTING. PLEASE DESCRIBE ANY PROPOSED EMISSIONS TESTING FOR THIS PROCESS EQUIPMENT/AIR POLLUTION CONTROL DEVICE.

10. Describe all operating ranges and maintenance procedures required by Manufacturer to maintain warranty
NA

ATTACHMENT M
AIR POLLUTION CONTROL DEVICES

The Combined-Cycle Combustion Turbines and the HRSG Duct Burners will be equipped with Selective Catalytic Reduction (SCR) systems and dry low-NOx combustors (DLNC). These combustion controls along will control emissions of nitrogen oxides (NOx). Oxidation catalysts will be used to control the turbines' carbon monoxide (CO) and volatile organic compounds (VOC) emissions. The Fuel Gas Preheaters will be equipped with low- NOx burners (LNB) to control NOx emissions. The Mechanical Draft Cooling Tower will be equipped with demisters.

The proposed emission control systems including the determination of Best Available Control Technology determination are described in Section 5 of the PSD Permit Application Document.

ATTACHMENT N
SUPPORTING EMISSION CALCULATIONS

The Longview Unit 2 Project potential regulated pollutant emission from the combined cycle power train consisting of two combustion turbines, two heat recovery steam generators (HRSG) with duct burners, one diesel fuel-fired firewater pump, one diesel fired emergency generator, two gas preheaters and one mechanical draft cooling tower were estimated using some or all of the following: vendor supplied data, material balances, engineering estimates, assumptions calculations, USEPA's Compilation of Air Pollutant Emission Factors (AP-42) for combustion turbines and engines, New Source Performance Standards (NSPS) emission standards and USEPA's Mandatory Greenhouse Gas Reporting Rule (40 CFR Part 98).

The emission calculations are described and presented in Section 4 and Appendix B of the Air Permit Application document.

ATTACHMENT O
MONITORING, RECORDKEEPING, REPORTING AND TESTING PLANS

Longview Power II, LLC proposes the following as Monitoring, Recordkeeping, Reporting and Testing Plans for Unit 2:

1. Limit the annual fuel consumption for the combined-cycle Combustion Turbine (with HRSG Duct Burners) and Fuel Gas Heaters as presented in this permit application.
2. Record the amount of fuel consumed in the combined-cycle Combustion Turbine (with HRSG Duct Burners), and Fuel Gas Heaters on a daily, monthly, and 12-month rolling total.
3. Operate and maintain SCR and Oxidation Catalyst for the combined-cycle Combustion Turbines (with HRSG Duct Burners) for NOx and CO control.
4. Limit the sulfur content of the natural gas to the level indicated in the permit application.
5. Install, operate, calibrate, and maintain continuous emission monitoring systems (CEMS) on the combined-cycle Combustion Turbines as required and in accordance with applicable regulations.
6. Conduct performance testing for pollutants requiring testing in accordance with the methods, standards, and deadlines mandated by regulation.
7. Combust only ultra-low sulfur diesel (ULSD) fuel in the Emergency Generator and Fire Water Pump engines.
8. Record the annual hours of operation for the Emergency Generator and Fire Water Pump engines.
9. Maintain required records for at least five (5) years.

AIR QUALITY PERMIT NOTICE

Notice of Application

Notice is given that Longview Power II, LLC has applied to the West Virginia Department of Environmental Protection, Division of Air Quality, for a Prevention of Significant Deterioration (PSD) Construction Air Permit for an electric power generation facility located on Route 53 (Fort Martin Road), Maidsville, in Monongalia County, West Virginia. The latitude and longitude coordinates are: 39.7124, -79.9608

The applicant estimates the potential to discharge the following Regulated Air Pollutants: 302 tons per year of nitrogen oxides, 693 tons per year of carbon monoxide, 3,931,696 tons per year of carbon dioxide equivalent emissions, 503 tons per year of volatile organic compounds, 208 tons per year of particulate matter, 38.7 tons per year of sulfur dioxide, 0.0005 tons per year of lead, 32.5 tons of sulfuric acid, and 9.96 tons per year of hazardous air pollutants.

Startup of operation is planned to begin on or about the first quarter of 2024. Written comments will be received by the West Virginia Department of Environmental Protection, Division of Air Quality, 601 57th Street, SE, Charleston, WV 25304, for at least 30 calendar days from the date of publication of this notice.

Any questions regarding this permit application should be directed to the DAQ at (304) 926-0499, extension 1250, during normal business hours.

Dated this the 5th day of December, 2019.

By: Longview Power II, LLC
Stephen H. Nelson
Chief Operating Officer
1375 Fort Martin Road
Maidsville, WV 26541

ATTACHMENT Q
BUSINESS CONFIDENTIAL CLAIMS

The air permit application for the Longview Power Unit 2 Project is considered non-confidential since it does not contain any business confidential information.

ATTACHMENT R
AUTHORITY FORMS

No Authority Forms are required since the air permit application for the Longview Power Unit 2 Project is signed by a Responsible Official of Longview Power II, LLC.

ATTACHMENT S
TITLE V PERMIT REVISION INFORMATION

The Longview Power Unit 2 Project does not currently hold a Title V Permit since it is a new emission source. TVOP application will be prepared and submitted once the air permit has been issued.

APPENDIX B - EMISSION ESTIMATES

Longview Power Unit 2
Facility-Wide Emissions
Table B-1

PSD/NSR Pollutants	Combustion Turbine Emissions (tons/yr)	Duct Burners (tons/year)	Startup/ Shutdown Emissions (tons/yr)	Fuel Gas Preheaters (tons/yr)	Auxiliary Generator Emissions (tons/yr)	Fire Pump Emissions (tons/yr)	Cooling Tower (tons/yr)	Total Facility Emissions (tons/yr)
NOx	261.8		37.6	1.70	0.76	0.23		302.10
CO	157.1		533.9	1.83	0.44	0.06		693.35
VOC	51.4		451.5	0.33	0.05	0.02		503.36
PM/PM10/PM2.5	178.6		10.9	0.37	0.03	0.04	18.0	207.92
SO2	38.6			0.06	0.00	0.02		38.70
H2SO4	32.5			4.69E-03				32.54
GHG	3,925,364			6240.00	71.33	20.89		3,931,696
Lead		4.96E-04						0.00050
Flourides								0.00
Vinyl Chloride								0.00
Total Reduced Sulfur								0.00
Reduced Sulfur Compounds								0.00
Hazardous Air Pollutants (HAPS)								
1,3-Butadiene	6.83E-03					5.30E-06		6.84E-03
2 Methylnaphthalene		2.38E-05						2.38E-05
Acetaldehyde	6.35E-01					1.04E-04		6.36E-01
Acrolein	1.02E-01					1.25E-05		1.02E-01
Arsenic		2.38E-04						2.38E-04
Benzene	1.91E-01	2.08E-03			5.03E-04	1.27E-04		1.93E-01
Beryllium		1.19E-05						1.19E-05
Cadmium		1.09E-03						1.09E-03
Chromium		1.09E-03						1.09E-03
Cobalt		1.39E-03						1.39E-03
Dichlorobenzene		1.19E-03						1.19E-03
Ethylbenzene	5.08E-01							5.08E-01
Formaldehyde	3.38E+00	3.03E-01			5.12E-05	1.60E-04		3.69E+00
Hexane		1.25E+00						1.25E+00
Manganese		8.33E-05						8.33E-05
Mercury		3.77E-04						3.77E-04
Naphthalene	2.07E-02	6.05E-04			8.43E-05	1.15E-05		2.14E-02
Nickel		2.58E-04						2.58E-04
Phenanathrene		1.69E-05			2.65E-05	3.99E-06		4.73E-05
Propylene Oxide	4.61E-01							4.61E-01
Toluene	2.07E+00	3.37E-03			1.82E-04	5.55E-05		2.07E+00
Xylene	1.02E+00					3.87E-05		1.02E+00
Total HAPS								9.96E+00

Longview Power Unit 2
Startup Shutdown Emissions
Table B-2

Pollutant		Hot Start	Warm Start	Cold Start	Shutdown	Two CT Units
NOx	lb/event	165	528	1,848	23	
	lb/h (max)	271	441	523	45	
	tons/year	16	10	10	2	38
CO	lb/event	3,180	7,820	10,200	360	
	lb/h (max)	3,252	4,838	18,862	2,741	
	tons/year	299	141	56	38	534
VOC (w/for	lb/event	2,860	5,920	6,520	380	
	lb/h (max)	2,781	4,306	4,306	2,753	
	tons/year	269	107	36	40	452
Formaldehy	lb/event	780	1,360	1,580	120	
	lb/h (max)	860	862	862	862	
	tons/year	73	24	9	13	119
Total PM	lb/event	71	125	149	11	
	lb/h (max)	111	111	111	75	
	tons/year	7	2	1	1	11
Duration	minutes	108	196	229	12	
No of events per year		188	36	11	212	

Longview Unit 2
Fuel Gas Pre-Heaters Emissons
Table B-3

Pollutant	Maximum Short Term Emissions (1 FGH) (lb/hr)	Maximum Annual Emissions (1 FGH) (tons/yr)	Maximum Annual Emissions (2 FGHs) (tons/yr)
NOx	0.19	0.85	1.70
CO	0.21	0.92	1.83
VOC	0.04	0.17	0.33
PM10	0.04	0.18	0.37
SO2	0.01	0.03	0.06
H2SO4	5.36E-04	2.35E-03	4.69E-03
GHG	712	3,120	6,240

Longview Unit 2
Emergency Generator Emissions
Table B-4

Rated Output (kilowatts)	**1,139**	**2000**
Rated Output (horsepower)	**1,528**	**2682**
Rated input (MMBtu/hr)	**13.0**	
Hours of Operation	**100**	

Pollutant	Emission Factor (lbs/MMBtu)	Emission Factor (grams/hp hr)	Max Power Output (hp hr)	Max Fuel Input (MMBtu/hr)	Max Emission Rate (lbs/hr)	Annual Emissions (tons/yr)
NOx		4.5	1528		15.2	0.76
CO		2.6	1528		8.76	0.44
VOC		0.3	1528		1.01	0.051
PM10		0.15	1528		0.505	0.025
SO2		0.00809	1528		0.027	0.001
GHG	110			13.0	1,427	71.3
Acenapthene	4.7E-06			13.0	6.1E-05	3.0E-06
Acenaphthylene	9.2E-06			13.0	1.2E-04	6.0E-06
Acetaldehyde	2.5E-05			13.0	3.3E-04	1.6E-05
Acrolein	7.9E-06			13.0	1.0E-04	5.1E-06
Anthracene	1.2E-06			13.0	1.6E-05	8.0E-07
Benz(a)anthracene	6.2E-07			13.0	8.1E-06	4.0E-07
Benzene	7.8E-04			13.0	1.0E-02	5.0E-04
Benzo(a)pyrene	2.6E-07			13.0	3.3E-06	1.7E-07
Benzo(b)fluoroanthene	1.1E-06			13.0	1.4E-05	7.2E-07
Benzo(g,h,i)perylene	5.6E-07			13.0	7.2E-06	3.6E-07
Benzo(k)fluoranthene	2.2E-07			13.0	2.8E-06	1.4E-07
Chrysene	1.5E-06			13.0	2.0E-05	9.9E-07
Dibenzo(a,h)anthracene	3.5E-07			13.0	4.5E-06	2.2E-07
Fluoranthene	4.0E-06			13.0	5.2E-05	2.6E-06
Fluorene	1.3E-05			13.0	1.7E-04	8.3E-06
Formaldehyde	7.9E-05			13.0	1.0E-03	5.1E-05
Indeno(1,2,3-cd)pyrene	4.1E-07			13.0	5.4E-06	2.7E-07
Naphthalene	1.3E-04			13.0	1.7E-03	8.4E-05
Phenanathrene	4.1E-05			13.0	5.3E-04	2.6E-05
Pyrene	3.7E-06			13.0	4.8E-05	2.4E-06
Toluene	2.8E-04			13.0	3.6E-03	1.8E-04
Xylene	1.9E-04			13.0	2.5E-03	1.3E-04
Total Haps						1.0E-03

1. Emission rates estimated based upon AP-42 emission factors (Tables 3.4-1, 3 & 4)
2. Fuel throughput based upon similar Caterpillar diesel engine.

Longview Unit 2
Firewater Pump Emissions
Table B-5

Rated Output (kilowatts)	**179**
Rated Output (horsepower)	**240**
Rated input (MMBtu/hr)	**2.71**
Hours of Operation	**100**

Pollutant	Emission Factor (lbs/MMBtu)	Emission Factor (grams/hr)	Max Power Output (hp hr)	Max Fuel Input (MMBtu/hr)	Max Emission Rate (lb/hr)	Annual Emissions (tons/yr)
NOx		2064	240		4.55	0.228
CO		574	240		1.27	0.063
VOC		137	240		0.302	0.015
PM10	0.31		240		0.841	0.042
SO2		0.00205	240		0.492	0.025
H2SO4						
GHG	154			2.71	417.8	20.9
(1,3) Butadiene	3.9E-05			2.71	1.1E-04	5.3E-06
Acenapthene	1.4E-06			2.71	3.9E-06	1.9E-07
Acenaphthylene	5.1E-06			2.71	1.4E-05	6.9E-07
Acetaldehyde	7.7E-04			2.71	2.1E-03	1.0E-04
Acrolein	9.3E-05			2.71	2.5E-04	1.3E-05
Anthracene	1.9E-06			2.71	5.1E-06	2.5E-07
Benz(a)anthracene	1.7E-06			2.71	4.6E-06	2.3E-07
Benzene	9.3E-04			2.71	2.5E-03	1.3E-04
Benzo(a)pyrene	1.9E-07			2.71	5.1E-07	2.6E-08
Benzo(b)fluoroanthene	9.9E-08			2.71	2.7E-07	1.3E-08
Benzo(g,h,i)perylene	4.9E-07			2.71	1.3E-06	6.6E-08
Benzo(k)fluoranthene	1.6E-07			2.71	4.2E-07	2.1E-08
Chrysene	3.5E-07			2.71	9.6E-07	4.8E-08
Dibenzo(a,h)anthracene	5.8E-07			2.71	1.6E-06	7.9E-08
Fluoranthene	7.6E-06			2.71	2.1E-05	1.0E-06
Fluorene	2.9E-05			2.71	7.9E-05	4.0E-06
Formaldehyde	1.2E-03			2.71	3.2E-03	1.6E-04
Indeno(1,2,3-cd)pyrene	3.8E-07			2.71	1.0E-06	5.1E-08
Naphthalene	8.5E-05			2.71	2.3E-04	1.2E-05
Phenanathrene	2.9E-05			2.71	8.0E-05	4.0E-06
Pyrene	4.8E-06			2.71	1.3E-05	6.5E-07
Toluene	4.1E-04			2.71	1.1E-03	5.5E-05
Xylene	2.9E-04			2.71	7.7E-04	3.9E-05
Total Haps						5.2E-04

1. Emission rates estimated based upon AP-42 emission factors (Tables 3.3-1& 2)
2. Fuel throughput based upon similar Caterpillar diesel engine.

Longview Unit 2
Emergency Generator Emissions
Table B-4

Rated Output (kilowatts)	**1,139**	**2000**
Rated Output (horsepower)	**1,528**	**2682**
Rated input (MMBtu/hr)	**13.0**	
Hours of Operation	**100**	

	Emission Factor	Emission Factor	Max Power Output	Max Fuel Input	Max Emission Rate	Annual Emissions
Pollutant	**(lbs/MMBtu)**	**(grams/hp hr)**	**(hp hr)**	**(MMBtu/hr)**	**(lbs/hr)**	**(tons/yr)**
NOx		4.5	1528		15.2	0.76
CO		2.6	1528		8.76	0.44
VOC		0.3	1528		1.01	0.051
PM10		0.15	1528		0.505	0.025
SO2		0.00809	1528		0.027	0.001
GHG	110			13.0	1,427	71.3
Acenapthene	4.7E-06			13.0	6.1E-05	3.0E-06
Acenaphthylene	9.2E-06			13.0	1.2E-04	6.0E-06
Acetaldehyde	2.5E-05			13.0	3.3E-04	1.6E-05
Acrolein	7.9E-06			13.0	1.0E-04	5.1E-06
Anthracene	1.2E-06			13.0	1.6E-05	8.0E-07
Benz(a)anthracene	6.2E-07			13.0	8.1E-06	4.0E-07
Benzene	7.8E-04			13.0	1.0E-02	5.0E-04
Benzo(a)pyrene	2.6E-07			13.0	3.3E-06	1.7E-07
Benzo(b)fluoroanthene	1.1E-06			13.0	1.4E-05	7.2E-07
Benzo(g,h,i)perylene	5.6E-07			13.0	7.2E-06	3.6E-07
Benzo(k)fluoranthene	2.2E-07			13.0	2.8E-06	1.4E-07
Chrysene	1.5E-06			13.0	2.0E-05	9.9E-07
Dibenzo(a,h)anthracene	3.5E-07			13.0	4.5E-06	2.2E-07
Fluoranthene	4.0E-06			13.0	5.2E-05	2.6E-06
Fluorene	1.3E-05			13.0	1.7E-04	8.3E-06
Formaldehyde	7.9E-05			13.0	1.0E-03	5.1E-05
Indeno(1,2,3-cd)pyrene	4.1E-07			13.0	5.4E-06	2.7E-07
Naphthalene	1.3E-04			13.0	1.7E-03	8.4E-05
Phenanathrene	4.1E-05			13.0	5.3E-04	2.6E-05
Pyrene	3.7E-06			13.0	4.8E-05	2.4E-06
Toluene	2.8E-04			13.0	3.6E-03	1.8E-04
Xylene	1.9E-04			13.0	2.5E-03	1.3E-04
Total Haps						1.0E-03

1. Emission rates estimated based upon AP-42 emission factors (Tables 3.4-1, 3 & 4)
2. Fuel throughput based upon similar Caterpillar diesel engine.

Longview Unit 2
Firewater Pump Emissions
Table B-5

Rated Output (kilowatts)	**179**
Rated Output (horsepower)	**240**
Rated input (MMBtu/hr)	**2.71**
Hours of Operation	**100**

Pollutant	Emission Factor (lbs/MMBtu)	Emission Factor (grams/hr)	Max Power Output (hp hr)	Max Fuel Input (MMBtu/hr)	Max Emission Rate (lb/hr)	Annual Emissions (tons/yr)
NOx		2064	240		4.55	0.228
CO		574	240		1.27	0.063
VOC		137	240		0.302	0.015
PM10	0.31		240		0.841	0.042
SO2		0.00205	240		0.492	0.025
H2SO4						
GHG	154			2.71	417.8	20.9
(1,3) Butadiene	3.9E-05			2.71	1.1E-04	5.3E-06
Acenapthene	1.4E-06			2.71	3.9E-06	1.9E-07
Acenaphthylene	5.1E-06			2.71	1.4E-05	6.9E-07
Acetaldehyde	7.7E-04			2.71	2.1E-03	1.0E-04
Acrolein	9.3E-05			2.71	2.5E-04	1.3E-05
Anthracene	1.9E-06			2.71	5.1E-06	2.5E-07
Benz(a)anthracene	1.7E-06			2.71	4.6E-06	2.3E-07
Benzene	9.3E-04			2.71	2.5E-03	1.3E-04
Benzo(a)pyrene	1.9E-07			2.71	5.1E-07	2.6E-08
Benzo(b)fluoroanthene	9.9E-08			2.71	2.7E-07	1.3E-08
Benzo(g,h,i)perylene	4.9E-07			2.71	1.3E-06	6.6E-08
Benzo(k)fluoranthene	1.6E-07			2.71	4.2E-07	2.1E-08
Chrysene	3.5E-07			2.71	9.6E-07	4.8E-08
Dibenzo(a,h)anthracene	5.8E-07			2.71	1.6E-06	7.9E-08
Fluoranthene	7.6E-06			2.71	2.1E-05	1.0E-06
Fluorene	2.9E-05			2.71	7.9E-05	4.0E-06
Formaldehyde	1.2E-03			2.71	3.2E-03	1.6E-04
Indeno(1,2,3-cd)pyrene	3.8E-07			2.71	1.0E-06	5.1E-08
Naphthalene	8.5E-05			2.71	2.3E-04	1.2E-05
Phenanathrene	2.9E-05			2.71	8.0E-05	4.0E-06
Pyrene	4.8E-06			2.71	1.3E-05	6.5E-07
Toluene	4.1E-04			2.71	1.1E-03	5.5E-05
Xylene	2.9E-04			2.71	7.7E-04	3.9E-05
Total Haps						5.2E-04

1. Emission rates estimated based upon AP-42 emission factors (Tables 3.3-1& 2)
2. Fuel throughput based upon similar Caterpillar diesel engine.

Longview Unit 2

Mechanical Draft Coolling Tower Emissions

Table B-6

Parameter	Units	PM	PM10	PM2.5
Flow	gal/min	270000	270000	270000
Drift	%	0.002	0.002	0.002
Maxium TDS	ppm	200	200	200
Cycles of Concentration		7.6	7.6	7.6
Minutes per Hour Conversion	min/hr	60	60	60
Pound Per Gallon Conversion	lb/gal	8.34	8.34	8.34
Cooling Tower Availability	%	100%	100%	100%
PM10 to PM2.5 Conversion		1	1	0.5
lb/hr		4.11	4.11	2.05
tons/yr		18.0	18.0	8.99

APPENDIX C - VENDOR INFORMATION

7HA POWER PLANTS

290-430 MW
SIMPLE CYCLE OUTPUT

>64%
COMBINED CYCLE EFFICIENCY

CAPABILITY
55+ MW/minute ramping capability within emissions compliance

VERSATILITY
Turndown 2x1 plant load to about 15% of baseload while maintaining emissions compliance

SUSTAINABILITY
Simplified dual fuel system uses less water and eliminates recirculation

Whether your plant operates at baseload, load follows, or operates as a peaking unit, you can count on GE's 7HA gas turbine to deliver world class performance. Its industry-leading operational flexibility enables increased dispatch and ancillary revenue while fuel flexibility accommodates a wide range of gaseous fuels (shale gas, high ethane, H_2) and liquid fuels (#2 diesel, crude oils). The 7HA combined cycle plant ramps up to full load in less than 30 minutes and features a novel configuration that supports simplified installation and maintenance.

		7HA.01	7HA.02	7HA.03
SC Plant Performance	SC Net Output (MW)	290	384	430
	SC Net Heat Rate (Btu/kWh, LHV)	8,120	8,009	7,897
	SC Net Heat Rate (kJ/kWh, LHV)	8,567	8,450	8,332
	SC Net Efficiency (%, LHV)	42.0%	42.6%	43.2%
1x CC Plant Performance	CC Net Output (MW)	438	573	640
	CC Net Heat Rate (Btu/kWh, LHV)	5,481	5,381	5,342
	CC Net Heat Rate (kJ/kWh, LHV)	5,783	5,677	5,636
	CC Net Efficiency (%, LHV)	62.3%	63.4%	63.9%
	Plant Turndown – Minimum Load (%)	33.0%	33.0%	33.0%
	Ramp Rate (MW/min)	55	60	75
	Startup Time (RR Hot, Minutes)	<30	<30	<30
2x CC Plant Performance	CC Net Output (MW)	880	1,148	1,282
	CC Net Heat Rate (Btu/kWh, LHV)	5,453	5,365	5,331
	CC Net Heat Rate (kJ/kWh, LHV)	5,753	5,660	5,624
	CC Net Efficiency (%, LHV)	62.6%	63.6%	64.0%
	Plant Turndown – Minimum Load (%)	15.0%	15.0%	15.0%
	Ramp Rate (MW/min)	110	120	150
	Startup Time (RR Hot, Minutes)	<30	<30	<30

NOTE: All ratings are net plant, based on ISO conditions and natural gas fuel. Actual performance will vary with project-specific conditions and fuel.

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GEA34163 (09/2019)

MHPS Gas Turbine

J Series

MITSUBISHI HITACHI POWER SYSTEMS, LTD.

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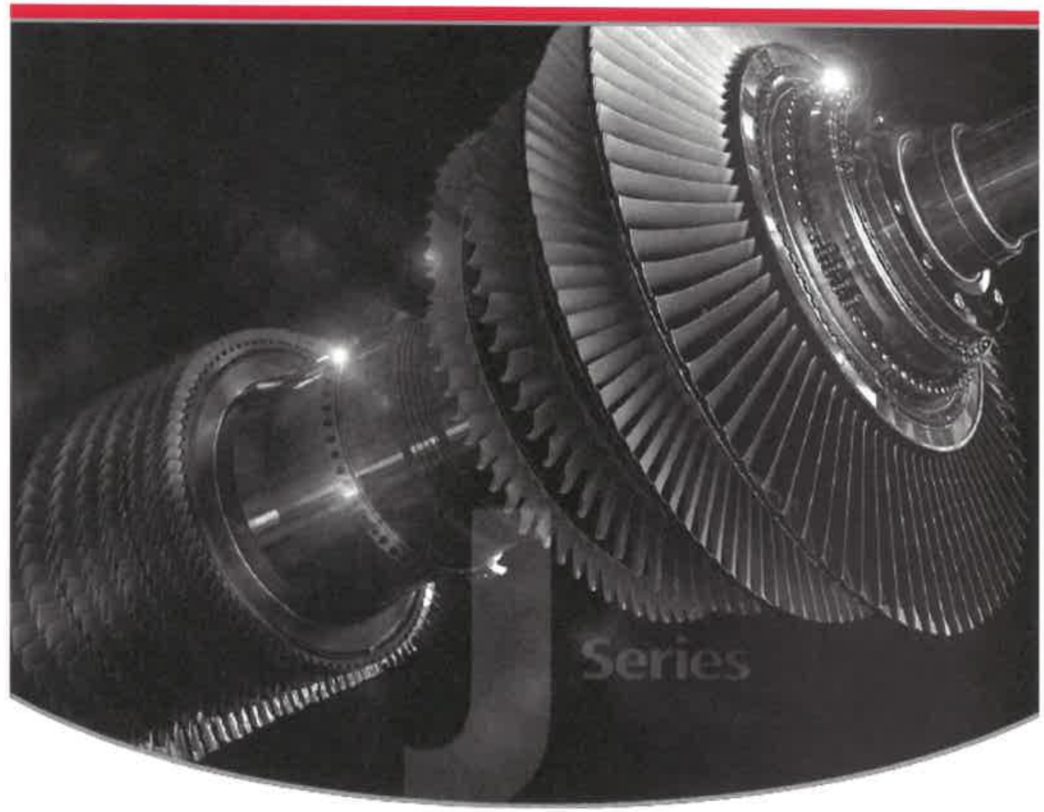
MHPS Gas Turbine
M501J / M701J



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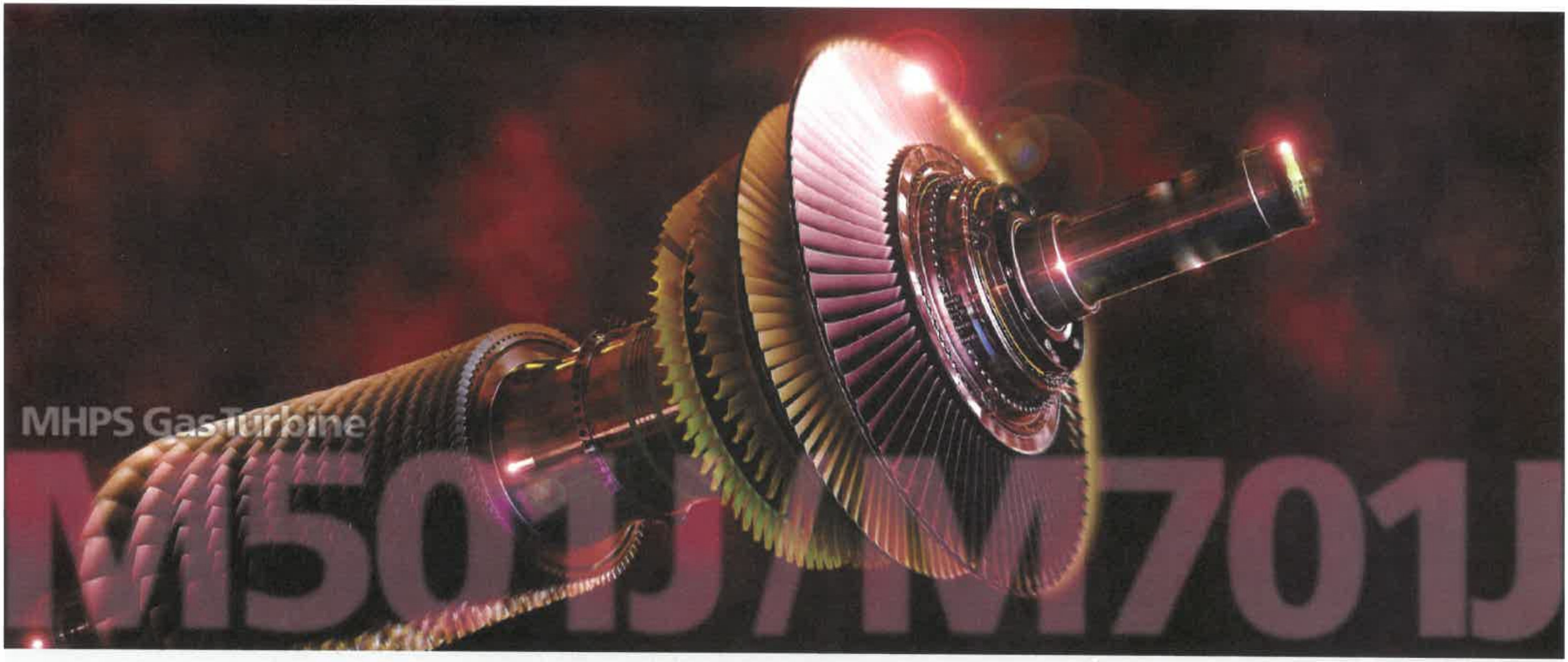


Tomorrow's Turbine Technology...Today

When developing the J-series gas turbine, the main focus was on technology that would enable a higher firing temperature and improved efficiency.
Due to the great success of these continuous efforts, the J-series gas turbine is able to operate at a turbine inlet temperature of 1,600°C (2,912°F), 100°C (180°F) higher than the G-series gas turbine.

Introducing the air cooled JAC

After validating integrated disciplines of the proven G and J-series technologies, the advanced JAC gas turbine is introduced based on air cooled combustor technology for high efficiency and operational flexibility by eliminating any need for steam cooling from the bottoming cycle.

Current production models are M501J / JAC for 60Hz and M701J / JAC for 50Hz.

Proven design based on over 40 years of experience

The J-series incorporates basic design features and concepts developed through years of experience, such as cold-end generator drive, single shaft rotor construction and axial exhaust.
These fundamental and proven features are based on our experience of more than 40 years.

Environmental protection

- Most efficient use of fossil fuel resources
- Low NO_x, CO, UHC and VOC emissions
- Reduction of CO_2 emissions is approximately 70% in combined cycle operation when compared to conventional coal plants

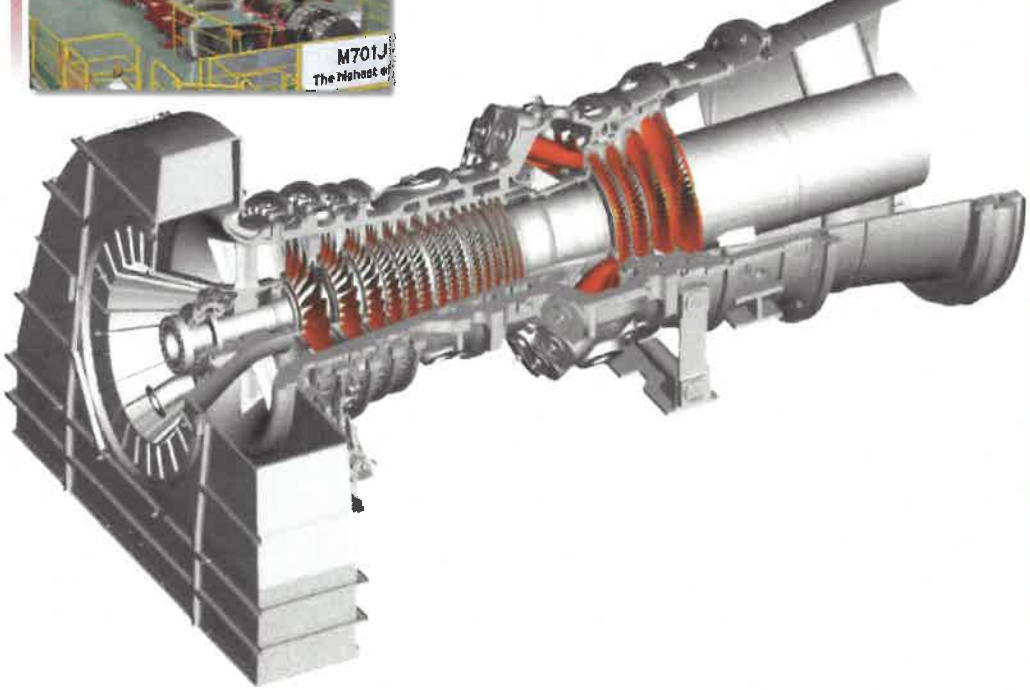
MHPS GasTurbine M501J / M701J

Longitudinal Section

Overall Design

The design of J-series gas turbine is based on proven F and G-series features.

- The compressor shaft end drive reduces the effect of thermal expansion on alignment and eliminates the need for a flexible coupling
- The rotor has a two-bearing structure to support the compressor and turbine ends
- An axial flow exhaust structure is used to optimize the combined-cycle plant layout
- The rotor structure has bolt-connected discs with the torque pins in the compressor rotor, and discs with CURVIC couplings in the turbine rotor to ensure reliable torque transmission
- Horizontally split casings that facilitate field removal of the blades with the rotor in place



Compressor

3D advanced design techniques are used to improve the performance and reduce the shockwave loss in the initial stages and frictional loss in the intermediate and final stages. This concept was evaluated by 3D computational fluid dynamics (CFD) software and verified using a full-scale high-speed research compressor.
In addition to variable inlet guide vanes used to modulate air flow, the J-series gas turbine is equipped with three variable vanes at the front stages of the compressor. The four stages operate together to modulate the gas turbine air flow in order to maintain relatively high exhaust temperatures (at part load) for improved bottoming cycle efficiency.

Combustor

The J-series combustor was based on the proven steam cooling system used in G-series gas turbines.
The turbine inlet temperature of 1,600°C (2,912°F) is 100°C (180°F) higher than the G-series. We are also able to maintain emissions to equivalent levels as that of the G-series.
This is accomplished through the use of low-NO_x technologies including optimization of the local flame temperature in the combustion zone, and by improving the combustion nozzle to produce a more homogeneous mixture of fuel and air.
The advanced JAC with the air cooled combustors adds operational flexibility by eliminating any need for steam cooling from the bottoming cycle.

Turbine

Turbine rows 1 to 4 blades are cooled by the compressor bleed air, which is cooled by the external air cooler.
Turbine rows 1 to 4 vanes are also air cooled, with row 1 vane cooled from compressor discharge air, and the remaining vane rows cooled by compressor intermediate stage bleeds respectively.
The cooling structure was improved for the G-series turbine, and again for the J-series.
Application of the high-performance film cooling developed from the Japanese National Project further offsets the temperature increase.
The metal temperature is maintained at the same level of G-series by utilizing the 1,700°C (3,092°F) class technology developed in the Japanese National Project. The 100°C (180°F) temperature increase from G-series to J-series is offset in part due to the advanced thermal barrier coating (TBC).

MHPS GasTurbine M501J/M701J

Combined Cycle Power Plant

In 1971, MHPS delivered the first combined cycle plant in Japan to a Japanese utility company.
Since then, through the experience in supplying many combined cycle plants,
we have earned an excellent reputation from our customers.
In order to satisfy customers' needs, MHPS offers its expertise
not only in supplying plants systems and equipment,
but also in providing a wide range of after-market services.

Gas Turbine Simple Cycle Performance (as of December, 2017)

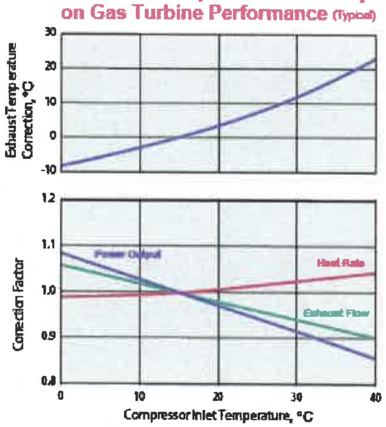
GT Model	M701J	M701JAC	M501J	M501JAC
	50Hz		60Hz	
ISO Base Rating, kW	478,000	493,000	330,000	400,000
LHV Heat Rate, kJ/kWh	8,511	8,392	8,552	8,182
Exhaust Flow, kg/s	896	896	620	694
Exhaust Temperature, °C	630	641	635	653

Combined Cycle Power Plant (as of December, 2017)

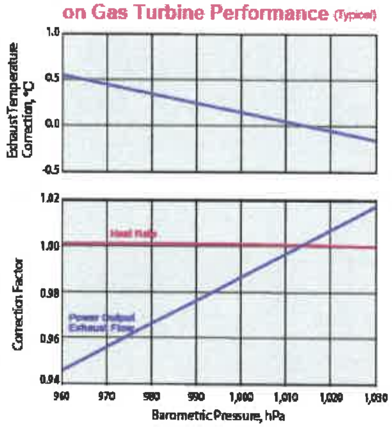
	GT Model	M701J	M701JAC	M501J	M501JAC
		50Hz		60Hz	
1on1	Plant Output, kW	701,000	717,000	484,000	575,000
	LHV Heat Rate, kJ/kWh	5,779	5,706	5,807	5,625
	Plant Efficiency, %	62.3	63.1	62.0	64.0
2on1	Plant Output, kW	—	—	971,000	1,153,000
	LHV Heat Rate, kJ/kWh	—	—	5,788	5,608
	Plant Efficiency, %	—	—	62.2	64.2

• All ratings are defined at ISO standard reference conditions: 101.3kPa, 15°C and 60%RH
• All ratings are at the generator terminals and based on the use of natural gas fuel

Effects of Compressor inlet Temperature on Gas Turbine Performance (Typical)



Effects of Barometric Pressure on Gas Turbine Performance (Typical)

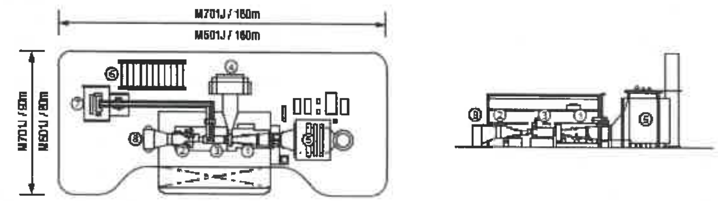


Flexible Configurations

Based on our sophisticated combined cycle plant
technology and diverse product application,
we can offer our customers not only the multi-shaft arrangement
such as 2 on 1 configuration, but also 1 on 1 configuration
having the gas turbine, steam turbine and generator
connected on the same shaft.

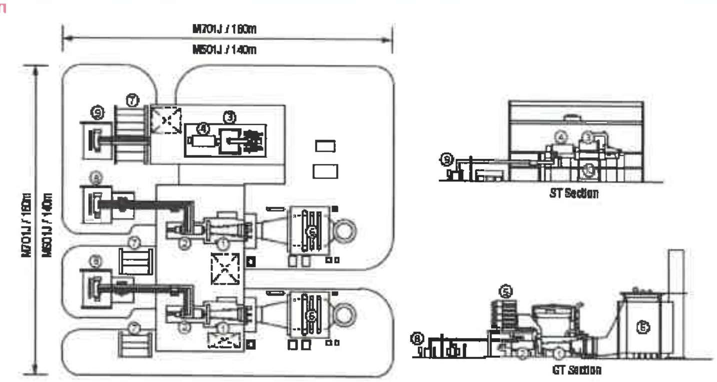
Typical Plant Layout

1 on 1 configuration, single-shaft



①Gas Turbine ②Steam Turbine ③Generator ④Inlet Air Filter ⑤Heat Recovery Steam Generator ⑥Electrical / Control Package ⑦Main Transformer ⑧Condenser

2 on 1 configuration



①Gas Turbine ②GT Generator ③Steam Turbine ④ST Generator ⑤Inlet Air Filter ⑥Heat Recovery Steam Generator ⑦Electrical / Control Package ⑧GT Main Transformer ⑨ST Main Transformer ⑩Condenser

MHPS Gas Turbine M501J / M701J

APPENDIX D - RACT/BACT/LAER CLEARINGHOUSE (RBLC) RESULTS

Table D-1 RBLC Search Results CCCT: NO_x, PM and CO BACT Limits/Technology

	RBLCID	Facility Name	State	Permit Issuance Date	NOx (PPM)	Technology	PM (LB/MMBTU)	Technology	CO (PPM)	Technology
1	IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	2	SCR w/ DLNB	0.0026	GCP	2	OC
2	MI-0441	LBWL--ERICKSON STATION	MI	12/31/2018	3	SCR w/ DLNB	6.02 lb/hr	GCP	4	OC
3	LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	2.5	SCR w/ DLNB	9.53 lb/hr	GCP	5	OC
4	WV-0032	BROOKE COUNTY POWER PLANT	WV	9/21/2018	2	SCR w/ DLNB	16.9 lb/hr	GCP	2	OC
5	PA-0319	RENAISSANCE ENERGY CENTER	PA	8/27/2018	2	SCR w/ DLNB	0.0043	GCP	2	OC
6	IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	2	SCR w/ DLNB	0.0037	GCP	2	OC
7	MI-0432	NEW COVERT GENERATING FACILITY	MI	7/30/2018	2	SCR w/ DLNB	10.7 lb/hr	GCP	2	OC
8	FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	FL	7/30/2018	2	SCR w/ DLNB	NA	GCP	4.3	OC
9	MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	2	SCR w/ DLNB	16 lb/hr	GCP	0.0045 lb/MMBtu	OC
10	MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	2	SCR w/ DLNB	19.1	GCP	4	OC
11	MI-0431	INDECK NILES LLC	MI	6/26/2018	2	SCR w/ DLNB	NA	GCP	NA	OC
12	VA-0328	C4GT, LLC	VA	4/26/2018	2	SCR w/ DLNB	0.0065	GCP	1.8	OC
13	OH-0377	HARRISON POWER	OH	4/19/2018	29.5 lb/hr	SCR w/ DLNB	0.0052	GCP	17.9 lb/hr	OC
14	MI-0439	JACKSON GENERATING STATION	MI	4/2/2018	25	SCR w/ DLNB	4.9	GCP	NA	OC
15	TX-0834	MONTGOMERY COUNTY POWER STATION	TX	3/30/2018	2	SCR w/ DLNB	125.7	GCP	2	OC
16	WV-0029	HARRISON COUNTY POWER PLANT	WV	3/26/2018	2	SCR w/ DLNB	18.2	GCP	2	OC
17	TN-0164	TVA - JOHNSONVILLE COGENERATION	TN	2/1/2018	2	SCR w/ DLNB	0.005	GCP	2	OC
18	PA-0316	RENOVO ENERGY CENTER, LLC	PA	1/26/2018	2	SCR w/ DLNB	0.00433	GCP	2	OC

Table D-2 RBLC Search Results CCCT: VOC, H_2SO_4 and CO_2e BACT Limits/Technology

	RBLCID	Facility Name	State	Permit Issuance Date	VOC (PPM)	Technology	H2SO4	Technology	CO2e (lb/MW-hr)	Technology
1	IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	NA	OC	5 lb/hr	None	4733910 TPY	GP
2	MI-0441	LBWL--ERICKSON STATION	MI	12/31/2018	3	OC	NA	NA	430349 TPY	GP
3	LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	1.1	OC	NA	NA	2602275 TPY	GP
4	WV-0032	BROOKE COUNTY POWER PLANT	WV	9/21/2018	2	OC	0.00085 lb/MMBtu, 0.4 grains/100 DSCF Sulfur	CF	829	GP
5	PA-0319	RENAISSANCE ENERGY CENTER	PA	8/27/2018	1.4	OC	2.3 lb/hr	CF	875	GP
6	IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	NA	OC	NA	None	None	None
7	MI-0432	NEW COVERT GENERATING FACILITY	MI	7/30/2018	1	OC	1 lb/hr. 0.8 grains 100 DSCF sulfur	CF	1425081 TPY	GP
8	FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	FL	7/30/2018	NA	OC	NA	CF	850	CF
9	MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	0.0026 lb/MMBtu	OC	0.0013 lb/MMBtu	CF,GCP	2042773 TPY	EF
10	MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	4	OC	2.7	CF,GCP	1978297 TPY	EF
11	MI-0431	INDECK NILES LLC	MI	6/26/2018	NA	OC	NA	NA	NA	NA
12	VA-0328	C4GT, LLC	VA	4/26/2018	0.7	OC	2.5 lb/hr	CF,GCP	883	CP, EF
13	OH-0377	HARRISON POWER	OH	4/19/2018	9.8 lb/hr	OC	0.0022	CF,GCP	1000	CP, EF
14	MI-0439	JACKSON GENERATING STATION	MI	4/2/2018	NA	OC	NA	NA	1000257 TPY	CP, EF
15	TX-0834	MONTGOMERY COUNTY POWER STATION	TX	3/30/2018	2	OC	1 grain/100 DSCF sulfur	CF	884	CP
16	WV-0029	HARRISON COUNTY POWER PLANT	WV	3/26/2018	2	OC	0.0009 lb/MMBTU, 0.4 grains/100 DSCF sulfur	CF	826	CF
17	TN-0164	TVA - JOHNSONVILLE COGENERATION	TN	2/1/2018	NA	OC	NA	NA	1800	CP
18	PA-0316	RENOVO ENERGY CENTER, LLC	PA	1/26/2018	1.4	OC	0.8 lb/hr, 0.2 grains 100 DCF sulfur	CF	875	CF,EF

Notes: CP=Good Combustion Practices; SCR = Selective Catalytic Reduction; DLNB = Dry Low NOx Burners; LNB = Low NOx, Burners;
OC = Oxidation Catalyst, CF=Clean Fuels, EF=Energy efficiency measures

APPENDIX E - MODELING INPUT/OUTPUT DATA FROM THE AIR QUALITY MODELING ANALYSIS.

Ambient Air Quality Services, Inc.

RECEIVED
JAN 21 2020
WV DEP / DIV OF AIR QUALITY

January 17, 2020

Edward S. Andrews, P.E.
WVDEP
Division of Air Quality
601 57th St.
Charleston, WV 25304

RE: **Section 6 and 7 of the Prevention of Significant Deterioration (PSD) Air Permit Application for the Longview Power Unit 2 Project.**

Dear Mr. Andrews:

Enclosed are one original and two (2) paper copies Sections 6-Air Quality Modeling Approach and 7-Air Quality Impact Analysis of the Prevention of Significant Deterioration (PSD) Air Application for the Longview Power Unit 2 Project.

After reviewing these sections of the PSD Application if you have any comments or questions please contact me at (484) 224 6218 ext 101 or by email at lmilitana@aaqsinc.com.

Very truly yours,
AAQS Inc.

Louis M. Militana, QEP
Partner/Principal Consultant

6. AIR QUALITY MODELING APPROACH

The air quality dispersion models used in the air quality modeling analysis of the Longview Unit 2 Project were both screening and refined U.S. EPA air dispersion models. The procedures used in conducting the modeling analysis followed the requirements outlined in 40 CFR Part 51 Appendix W "Guideline on Air Quality Models" (U.S. EPA 2017), guidance provided by West Virginia DAQ, and other state and federal regulatory agency documents. An air quality modeling protocol was submitted to WV DAQ for review and approval.

6.1 AIR QUALITY MODEL SELECTION

6.1.1 Screening Air Quality Models

A screening level air quality model was used to obtain conservative modeled estimates of the air quality impact of the proposed project based on simplified assumptions of the model inputs (e.g., preset, worst-case meteorological conditions). The screening air quality model used is the AERSCREEN model (Version 16216). AERSCREEN is the EPA's recommended screening model for simple and complex terrain for single sources including point sources, area sources, horizontal stacks, capped stacks, and flares. AERSCREEN runs AERMOD (a refined air quality model) in a screening mode using a matrix of meteorological conditions.

6.1.2 Refined Air Quality Model

A second level of more sophisticated (Refined) models was also used. The refined air quality modeling analysis used the AERMOD (**AER**MIC **MOD**el) air dispersion model as the refined air quality model. A description of this model is provided in the following subsections.

6.1.3 AERMOD Model Selection

The **A**MS/**E**PA **R**egulatory **MOD**el (AERMOD, v19191) air dispersion model was used to perform the air quality modeling analysis. The AERMOD air dispersion model is an approved U.S. EPA air dispersion model for performing refined, multi-source air quality modeling studies. The AERMOD air dispersion model contains sophisticated dispersion algorithms. A description of the AERMOD model is provided below.

The American Meteorological Society (AMS) and the U.S. Environmental Protection Agency (EPA) formed the **A**MS/**E**PA **R**egulatory **M**odel **I**mprovement **C**ommittee (AERMIC) in 1991. The goal of the committee was to introduce planetary boundary layer (PBL) concepts into a new air dispersion model. The use of PBL concepts in AERMOD represents a more sophisticated approach to predicting plume dispersion than the approach used by the ISCST3 model. The PBL concepts include using dispersion parameters (sigma y and sigma z) that are based on either measured or estimated turbulent intensities, accounting for non-homogenous conditions throughout the PBL, improving the treatment of plume rise, and enhancing the way concentrations at complex terrain receptors (i.e. terrain receptors with elevations above stack top elevation) are predicted by incorporating the concept of a critical dividing streamline.

AERMOD uses an abbreviated approach to the three-dimensional terrain feature representation and critical dividing streamline approach that is used by the Complex Terrain Dispersion Model Plus Algorithms for Unstable Situations (CTDMPLUS). The AERMOD approach determines the fraction of the plume that is below the critical dividing streamline height (Φ from 0.0 to 1.0) and then uses that number as a scaling factor. The scaling factor, Φ, is multiplied by the concentration that represents the plume flowing around the terrain feature and then 1- Φ is multiplied by the concentration that represents the plume flowing over the terrain feature. The AERMOD concentration is the sum of the two, scaled concentrations. AERMOD differs from CTDMPLUS in its treatment of flow around a terrain feature by not considering the lateral splitting of the plume that occurs as the plume flows around a terrain feature. In its present form, AERMOD uses the Schulman-Scire and Huber-Synder downwash algorithms that are contained in ISCST3.

The AERMOD modeling system consists of two pre-processors and the dispersion model. AERMET (Version 19191) is the meteorological pre-processor and AERMAP (Version 18081) is the terrain pre-processor that characterizes the terrain and generates receptor elevations. The AERMET pre-processor, which is very similar to the CTDMPLUS meteorological pre-processor (METPRO), produces a file containing an hourly, vertical profile of the atmosphere and a file that includes surface and micrometeorological data. The AERMAP pre-processor is designed to develop receptor grid height information based on United States Geological Survey (USGS) digital elevation model (DEM) data. The development of the receptor grid includes assigning receptor elevations to the receptor locations and also assigning a hill height scale to each receptor. Receptor elevations are determined by finding the four closest DEM elevation points to the receptor location and averaging the elevations to represent the receptor. Hill height scales for all receptors are determined by examining the height and proximity of all DEM points within the modeled domain area to each receptor location. The domain used in AERMAP included the area covered by the Cartesian receptors plus an additional 5,000-meter buffer in the x and y-directions. Surface elevations for all receptors were obtained from USGS 1:24,000 Level II DEM data when available and Level I when not available.

Other components of this system include AERSURFACE, a surface characteristics preprocessor, and BPIPPRIME (BPIPPRM), a multi-building dimensions program incorporating the GEP technical procedures for PRIME applications.

The AERMOD air dispersion model has various options to simulate a variety of dispersion conditions for emissions from a stack or non-stack source. The U.S. EPA has recommended various default options to be used in dispersion modeling for regulatory purposes. These recommended regulatory default options will be used in the air quality impact analysis as follows:

- Stack-tip downwash.
- Model Accounts for Elevated Terrain Effects.
- Calms Processing Routine Used.
- No Exponential Decay for Rural Mode.
- Upper bound value for "super squat" buildings.
- Missing meteorological data processing used.

6.2 LANDUSE

The land use classification for the area was based on a quantitative review of land use patterns surrounding the proposed project site and Morgantown Airport. Satellite imagery from Google Earth for current conditions (2016) was inspected and compared to 2011 satellite imagery to determine the representativeness of the 2011 land use data. The satellite imagery for the 2011 and 2016 for the project area and Morgantown Airport are shown in Figures 6-1 and 6-2,

Figure 6-1
2011 and 2016 Satellite Imagery of the Longview Power Unit 2 Area

Figure 6-2
2011 and 2016 Satellite Imagery of the Morgantown Airport Area

respectively. A qualitative visual assessment of these imageries indicates that the land use for 2011 is more than adequately representative of the current landuse conditions for both the project site and Morgantown Airport. Therefore, the 2011 National Land Cover Dataset (NLCD) was used to determine landuse for AERMOD and surface parameters for AERMET processing

The land use analysis followed the procedures recommended by the U.S. EPA (U.S. EPA 2000) and the typing scheme developed by Auer (Auer 1978). The Auer technique established four primary land use types: industrial, commercial, residential, and agricultural. Industrial, commercial, and compact residential areas are classified as urban, while agricultural and common residential areas are considered rural. For air quality modeling purposes, an area is defined as urban if more than 50 percent of the surface within 3 kilometers of the source falls under an urban land use type. Otherwise, the area is determined to be rural.

Although Morgantown, WV is in close proximity to the proposed site and represents a portion of the area that is classified as urban, a review of the gridded digital land use data and the 7.5 USGS topographic maps indicates that 98% of the area within the 3-kilometer radius is classified as rural for air quality modeling purposes (urban classifications were assumed to be category 22 (high intensity residential) and category 23 (commercial/industrial/transportation)). Based on the rural land use designation, AERMOD was used in the default (rural) mode to predict the ambient air concentrations associated with emissions from the proposed project.

6.3 RECEPTOR GRID

The AERMOD air quality modeling study used a Cartesian receptor grid network including fence line receptors. A description of the receptor grids network is provided in the following subsections.

6.3.1 AERMOD Receptor Grid

The receptor network for the AERMOD analysis minimally covered a square region 20-km on a side, centered on the proposed project site. All receptors were referenced to the UTM coordinate system (Zone 17), using the North American Datum of 1927 (NAD 27). A rectangular Cartesian coordinate receptor grid was used as the main receptor grid. The main receptor grid was centered on the CT stacks and have the following grid spacing:

- 100 meters out to ± 1 kilometer;
- 250 meters out to ± 2 kilometers;
- 500 meters out to ± 5 kilometers;
- 1,000 meters out to ± 10 kilometers.
- 2,000 meters out to ± 20 kilometers

In addition to the rectangular Cartesian coordinate receptor grid, a set of fenceline receptors were used. The fence line receptors were placed every 50 meters around the site fenced portion of the property.

Concentration contours maps were developed to determine the refined modeling grid requirements including extending the modeling domain and/or refining the resolution grid spacing. A more refined spaced receptor grid were developed and used in area of maximum predicted concentrations and the receptor grid was extended when maximum predicted concentrations occur near the edge of the receptor grid.

Terrain elevations were assigned to all receptors included in the air dispersion modeling analysis. The terrain elevations for the main receptor grid were developed using the AERMAP terrain preprocessor. The AERMAP pre-processor is designed to develop receptor grid height information based on United States Geological Survey (USGS) digital elevation model (DEM) data. The development of the receptor grid includes assigning receptor elevations to the receptor locations and also assigning a hill height scale to each receptor. Receptor elevations are determined by finding the four closest DEM elevation points to the receptor location and averaging the elevations to represent the receptor. Hill height scales for all receptors are determined by examining the height and proximity of all DEM points within the modeled domain area to each receptor location. The domain used in AERMAP included the area covered by the Cartesian receptors plus an additional 5,000-meter buffer in the x and y-direction. Terrain elevations for all receptors were obtained from the USGS 1:24,000 Level II DEM data.

The Cartesian receptor grid were further refined based on the initial modeling results. Contour plots of the predicted concentrations were developed for each pollutant and averaging time. The contour plots were used to determine if refinements to the modeling domain and/or grid resolution are necessary. When predicted maximum or high concentrations occurred in a coarse section of the grid that area of the grid was remodeled with a 50 meter spacing to determine refined maximum modeled concentrations.

6.4 METEOROLOGICAL DATA

The meteorological data for the AERMOD air dispersion model included both surface and upper air data from National Weather Service (NWS) observation stations. The representativeness and adequacy of the surface meteorological database was discussed in the Air Quality Modeling Protocol. A description of the procedures that were used to process the meteorological data is presented in the following subsections.

6.4.1 AERMOD Meteorological Data

The meteorological database for the AERMOD air dispersion model consisted of five years of surface meteorological data collected at the Morgantown Municipal Airport from 2014-2018. A wind rose for the Morgantown Airport is presented in Figure 6-3. The Morgantown meteorological data was previously used for the Longview Power Project (Unit 1) and a demonstration of the representativeness of the Morgantown Airport meteorological data for the Longview Unit project is presented the Air Quality Modeling Protocol.

The Morgantown surface meteorological data were processed using the procedures described in the U.S. EPA AERMET meteorological processor. The AERMET preprocessor produces a file containing an hourly, vertical profile of the atmosphere and a file that includes surface and micrometeorological data.

The AERMET analysis included the use of both the AERMINUTE and the draft version of AERSURFACE. The use of the draft version of AERSURFACE required approval from US. EPA Region 3. The justification for the use of the draft version of AERSURFACE is contained in Appendix A of the Air Quality Modeling Protocol.

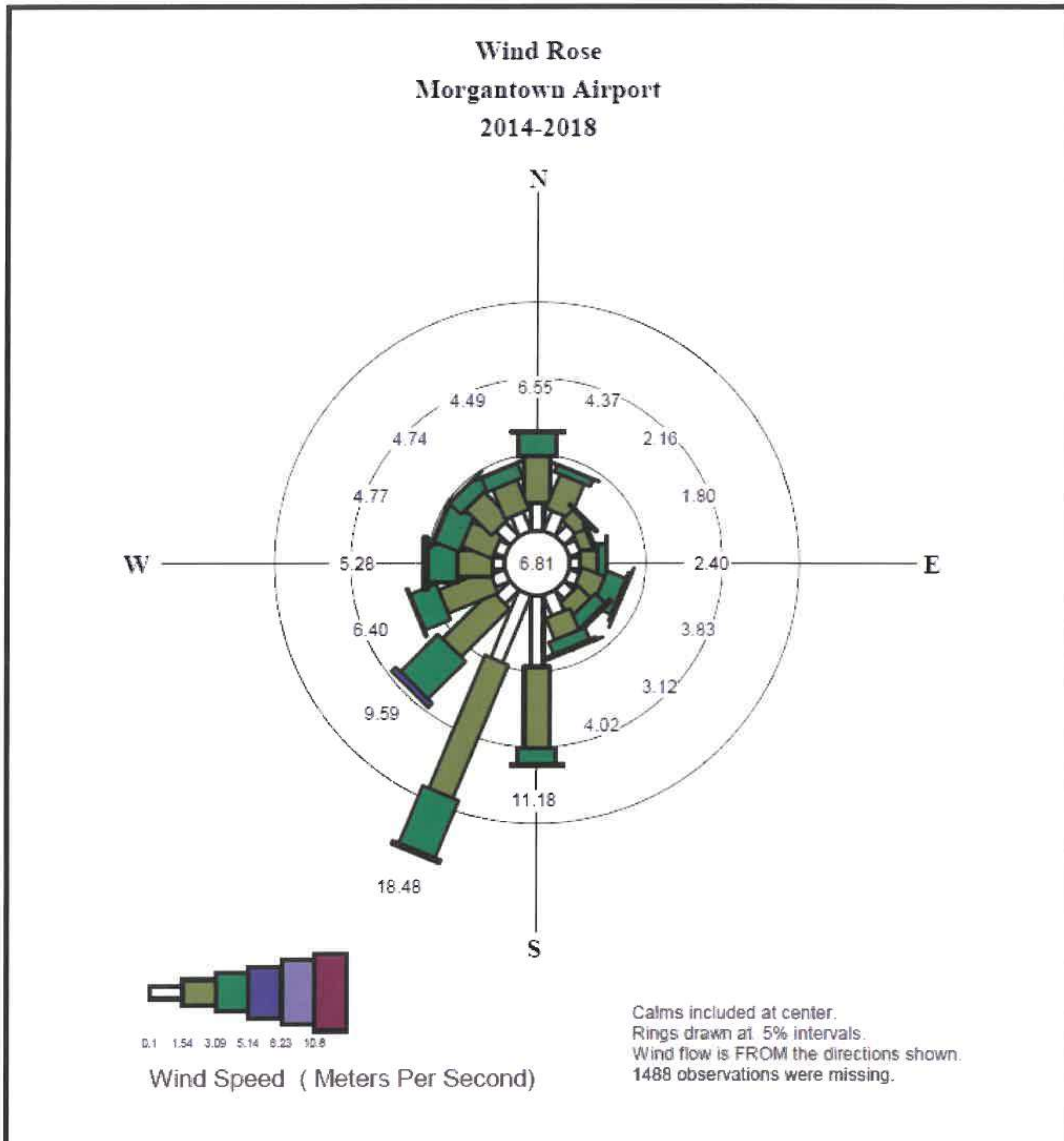


Figure 6-3
Wind Rose for Morgantown Airport (2014-2018)

The AERMINUTE (Version 15272) meteorological data processor were used to produce wind speed and direction data based on archived 1-minute and 5- minute ASOS data for Morgantown Airport, for input into AERMET Stage 2. A 0.5 m/s wind speed threshold were applied to the 1-minute ASOS derived wind speeds in AERMET.

The AERMET preprocessor also requires several micrometeorological variables for the project site area. The variables included surface roughness, Bowen ratio, and albedo. The values that were used in AERMET were determined using the draft version of the AERSURFACE pre-processor. AERSURFACE used 12 equal sectors by season.

The 2011 NLCD land use was used to develop the surface characteristics of the Morgantown Airport site and the Longview Unit 2 project site. Current satellite imagery (2016) was inspected and compared to the 2011 satellite imagery to determine the representativeness of the 2011 land use data. It was determined that the land use for 2011 is adequately representative of the current surface conditions.

A comparison of the surface characteristics of the Morgantown Airport site and the project site is presented in Table 6-1. As seen from this table the albedo and Bowen Ratios of the airport is consistent with the project site, but the surface roughness is not. Therefore, a sensitivity analysis of the impact of the difference in surface roughness on the predicted air quality concentrations of the project emission was performed. The procedure used is described in section 6.4.2.

Using the procedures described in AERMET, the surface meteorological data were combined with concurrent twice-daily rawinsonde data obtained from the NWS observation station in Pittsburgh, Pennsylvania. All NWS upper air and surface meteorological data were obtained from the National Climatic Data Center (NCDC).

6.4.2 Sensitivity Analysis

A site specific sensitivity analysis was performed following the AERMOD Implementation Guide (August 2019). The meteorological data (2014-2018) from Morgantown Airport (MGW) were processed through AERMET using both the micrometeorological variables (2011 NLCD data for albedo, Bowen ratio, and surface roughness length) associated with MGW as well as the

Table 6-1
Comparison of the Surface Characteristics of the Project Site and Meteorological Data Collection Site (Morgantown Airport)

		Morgantown Airport			Project Site					Morgantown Airport			Project Site		
Season	Sector	Albedo	Bowen Ratio	Zo	Albedo	Bowen Ratio	Zo	Season	Sector	Albedo	Bowen Ratio	Zo	Albedo	Bowen Ratio	Zo
1	1	0.17	0.86	0.254	0.17	0.85	0.063	3	1	0.16	0.46	0.65	0.16	0.37	0.3
1	2	0.17	0.86	0.308	0.17	0.85	0.034	3	2	0.16	0.46	0.64	0.16	0.37	0.211
1	3	0.17	0.86	0.151	0.17	0.85	0.035	3	3	0.16	0.46	0.301	0.16	0.37	0.214
1	4	0.17	0.86	0.148	0.17	0.85	0.041	3	4	0.16	0.46	0.323	0.16	0.37	0.183
1	5	0.17	0.86	0.14	0.17	0.85	0.12	3	5	0.16	0.46	0.329	0.16	0.37	0.293
1	6	0.17	0.86	0.128	0.17	0.85	0.035	3	6	0.16	0.46	0.289	0.16	0.37	0.16
1	7	0.17	0.86	0.08	0.17	0.85	0.019	3	7	0.16	0.46	0.145	0.16	0.37	0.108
1	8	0.17	0.86	0.07	0.17	0.85	0.05	3	8	0.16	0.46	0.159	0.16	0.37	0.175
1	9	0.17	0.86	0.159	0.17	0.85	0.071	3	9	0.16	0.46	0.227	0.16	0.37	0.256
1	10	0.17	0.86	0.092	0.17	0.85	0.123	3	10	0.16	0.46	0.143	0.16	0.37	0.401
1	11	0.17	0.86	0.093	0.17	0.85	0.05	3	11	0.16	0.46	0.131	0.16	0.37	0.238
1	12	0.17	0.86	0.052	0.17	0.85	0.039	3	12	0.16	0.46	0.111	0.16	0.37	0.22
2	1	0.15	0.58	0.406	0.15	0.54	0.099	4	1	0.16	0.86	0.634	0.16	0.85	0.3
2	2	0.15	0.58	0.471	0.15	0.54	0.051	4	2	0.16	0.86	0.614	0.16	0.85	0.211
2	3	0.15	0.58	0.228	0.15	0.54	0.053	4	3	0.16	0.86	0.271	0.16	0.85	0.214
2	4	0.15	0.58	0.226	0.15	0.54	0.061	4	4	0.16	0.86	0.299	0.16	0.85	0.179
2	5	0.15	0.58	0.221	0.15	0.54	0.164	4	5	0.16	0.86	0.306	0.16	0.85	0.288
2	6	0.15	0.58	0.204	0.15	0.54	0.079	4	6	0.16	0.86	0.267	0.16	0.85	0.157
2	7	0.15	0.58	0.106	0.15	0.54	0.055	4	7	0.16	0.86	0.129	0.16	0.85	0.108
2	8	0.15	0.58	0.093	0.15	0.54	0.078	4	8	0.16	0.86	0.146	0.16	0.85	0.174
2	9	0.15	0.58	0.199	0.15	0.54	0.112	4	9	0.16	0.86	0.211	0.16	0.85	0.256
2	10	0.15	0.58	0.115	0.15	0.54	0.19	4	10	0.16	0.86	0.127	0.16	0.85	0.401
2	11	0.15	0.58	0.115	0.15	0.54	0.075	4	11	0.16	0.86	0.115	0.16	0.85	0.238
2	12	0.15	0.58	0.072	0.15	0.54	0.066	4	12	0.16	0.86	0.096	0.16	0.85	0.219

micrometeorological variables associated with the Longview Power Unit 2 (LVP2) site using the draft version of AERSURFACE. The results of the CT/HRSG load analyses for all compounds and averaging periods using both meteorological data sets were compared to determine the meteorological data set (either MGW/MGW surface or MGW/LVP2 surface) producing the maximum short-term concentrations. The meteorological dataset and CT/HRSG load identified as producing the maximum short-term concentrations were used for all further refined air quality modeling analyses.

6.5 GOOD ENGINEERING PRACTICE STACK HEIGHT ANALYSIS

Following U.S. EPA guidance contained in the "Guideline for Determination of Good Engineering Practice (GEP) Stack Height (Revised)" (U.S. EPA 1985), a GEP analysis was performed to evaluate the potential for building downwash on the stacks. The following procedures were used to analyze the stacks for downwash effects. The stacks and influencing buildings were located on a plant map and the coordinates were manually digitized. The stack height and relevant building dimensions were evaluated using the U.S. EPA Building Profile Input Program Prime (BPIPPRM, Date 04274). BPIPPRM determines, in each of the 36 wind directions (10° sectors), which building may produce the greatest downwash effects for a stack. The direction-specific dimensions produced by BPIPPRM were included in the AERMOD air quality modeling studies. Table 6-2 and Figures 6-2 summarizes and displays the building dimensions and structures that influence each stack. The BPIPPRM analysis indicated that the GEP height for all stacks is 250 ft., based on the preliminary height of the HRSG Drum Building. The CT, emergency generator, fire water pump and gas preheater stacks are within 500 ft. (the area of influence) of HRSG Drum Building which produced the controlling GEP heights for all sources. The stack height for the CT, gas preheater, emergency generators and fire water pumps are 180, 15, 16 and 12 ft , respectively which are not GEP height and therefore do not avoid building downwash effects. Therefore, direction-specific building downwash dimensions were included in the AERMOD dispersion modeling analyses.

6.6 MODELED EMISSION RATES

All loads and operating scenarios for normal operating conditions (38 operating scenarios, for winter, summer, average conditions, with and without duct burners and one and two combustion.

Table 6-2
Building Dimensions for GEP Height Analysis

Building/Structure	Height (ft.)	Maximum Projected Width (ft.)	Formula GEP height (ft.)	Radius of Influence (ft.)	Controlling Structure for Source(s)
Steam Turbine Building	96	444	240	480	No
HRSG Drum Platform North	100	276	250	500	Yes
HRSG Drum Platform South	100	276	250	500	Yes

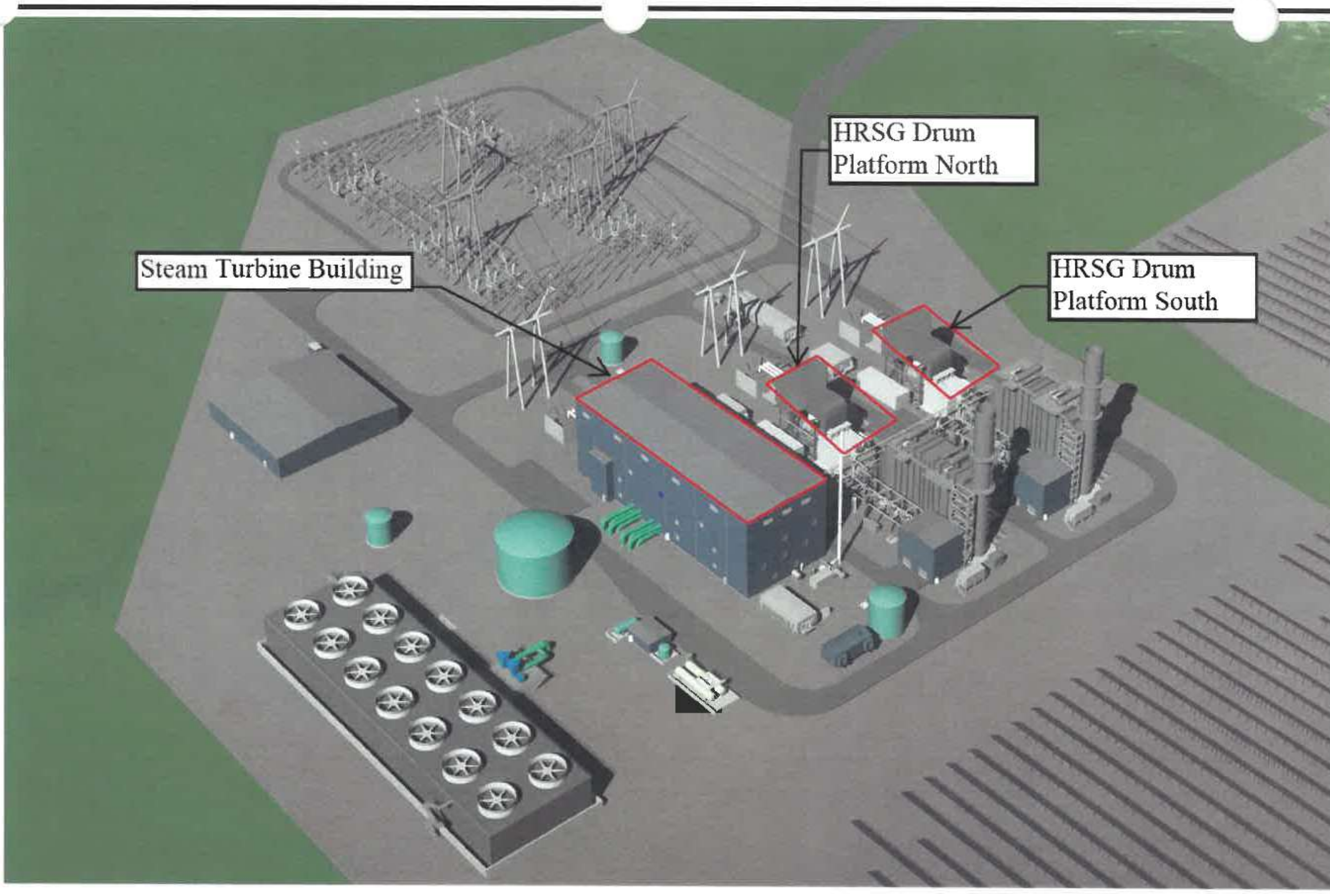


Figure 6-4
Structural Downwash Analysis

turbines operating) identified in Section 3 were initially modeled using meteorological data processed with the Longview Unit 2 site and the Morgantown Airport surface conditions. The results are summarized in Table 6-3. As seen from this table operating conditions No 22 and 33 for the GE turbine (with Morgantown Airport surface conditions) produced the overall highest $PM_{2.5}$ concentrations (24-hr and annual), condition No. 34 for the Mitsubishi turbine (with Longview Unit 2 site surface conditions) produced the overall highest 1-hr NO_x and CO concentrations, and conditions No. 34 for the Mitsubishi turbine (with Morgantown Airport surface conditions) produced the overall highest annual NO_x and 8-hr CO concentrations.

These operating conditions and hourly emissions were used for all further pollutant and time period specific refined modeling including short-term and long-term averaging periods including SIL, cumulative multi-source and visibility analysis.

The proposed Longview Power Unit 2 Project is considered a base load power plant and thus is planned to operate 24 hrs/day, 7 days/week and 365 days/year with very infrequent startup and shutdown events. The emissions expected for the startup and shutdown conditions were not modeled as they are considered to be infrequent to effect the design concentrations or produce enough events to satisfy the statistical form of the NAAQS.

Table 6-3
Load Analysis

Turbine: GE 7HA.03						**Turbine: MHPS JAC**					
GE/ MGW SFC		**Max**	**GE/ Longview SFC**		**Max**	**Mit/ MGW SFC**		**Max**	**Mit/ Longview SFC**		**Max**
Overall Max	**Load No**	**$\mu g/m^3$**	**Overall Max**	**Load No**	**$\mu g/m^3$**	**Overall Max**	**Load No**	**$\mu g/m^3$**	**Overall Max**	**Load No**	**$\mu g/m^3$**
NO_x 1hr	27	7.92	NO_x 1hr	29	10.53	NO_x 1hr	34	8.58	**NO_x 1hr**	**34**	12.98
NO_x Annual	29	0.161	NO_x Annual	29	0.153	**NO_x Annual**	**34**	0.194	NO_x Annual	34	0.185
CO 1hr	27	4.80	CO 1hr	29	6.40	CO 1hr	37	5.72	**CO 1hr**	**37**	9.14
CO 8hr	29	2.05	CO 8hr	29	2.03	**CO 8hr**	**37**	2.74	CO 8hr	37	2.62
$PM_{2.5}$ 24hr	**22**	1.38	$PM_{2.5}$ 24hr	22	1.35	$PM_{2.5}$ 24hr	34	1.25	$PM_{2.5}$ 24hr	34	1.24
$PM_{2.5}$ Annual	**33**	0.149	$PM_{2.5}$ Annual	33	0.148	$PM_{2.5}$ Annual	34	0.131	$PM_{2.5}$ Annual	34	0.124

7. AIR QUALITY IMPACTS ANALYSIS

The air quality modeling analysis was used to determine the predicted ambient air concentrations resulting from emissions from the Longview Unit 2 Project following the procedures and data described in Section 6 and the Air Quality Modeling Protocol. The air quality modeling analyses were used to determine the significant impact area (SIA), the amount of PSD increment consumed, and the level of compliance with the National Ambient Air Quality Standards (NAAQS) and other air quality related values (AQRVs).

7.1 SIGNIFICANCE ANALYSIS

The air quality impact analysis initially evaluated emissions of CO, $PM/PM_{10}/PM_{2.5}$, and NO_x from the project to determine the significant area of impact. These were the only pollutant exceeding the PSD significant emission levels which required an air quality modeling analysis.

The Significant Impact Levels (SILs) are shown in Table 7-1. The EPA has historically cautioned states that the use of a SIL may not be appropriate when a substantial portion of any NAAQS or PSD increment is known to be consumed. Therefore, justification of the use of SILs is recommended in support of the PSD review record. To provide justification with respect to use of SILs in the significance and NAAQS analyses, the differences between the NAAQS and background concentrations determined to be representative of the Project impact area for applicable pollutant and averaging periods were compared to the applicable values. As shown in Table 7-2, the differences between the NAAQS and background concentrations are much higher than the corresponding SILs. Therefore, it is sufficient for WVDEP to conclude that an air quality modeled impact less than the SIL for each of the applicable compounds will not cause or contribute to a modeled violation of the NAAQS.

The Significant Impact Area (SIA) is defined as a circle with a radius extending from the reference origin of the proposed Longview Unit 2 project out to the greatest radius where a receptor has a maximum concentration equal to the significance levels. The SIA with the largest

Table 7-1
Significance Impact Levels ($\mu g/m^3$)

Pollutant	Averaging Time	Class II	Class I EPA	Class I FLM
Sulfur Dioxide	Annual	1	0.1	0.03
	24-hour	5	0.2	0.07
	3-hour	25	1	0.48
	1-hour	7.8		
PM_{10}	Annual	1		
	24-hour	5	0.3	0.27
$PM_{2.5}$	Annual	0.3 0.2 proposed	0.27	
	24-hour	1.2	0.05	
Nitrogen Dioxide	Annual	1	0.1	0.03
	1-hr	7.5	NA	NA
Carbon Monoxide	8-hour	500	NA	NA
	1-hour	2,000	NA	NA

Table 7-2
Comparison of NAAQS, Representative Background Concentrations, and SILs

Pollutant and Averaging Period	Background	Background	NAAQS	NAAQS	SIL	Difference	Greater than SIL?
SO_2	**(ppb)**	**(μg/m^3)**	**(ppb)**	**(μg/m^3)**	**(μg/m^3)**	**(μg/m^3)**	
3-hour	20.6	53.8	75	195.8	5	142	YES
1-hour	35	91.4	500	1,305	1	1214	YES
NO_2							
Annual	6.21	11.7	53	99.6	1	88.0	YES
1-hour	45	84.6	100	188	7.5	103	YES
$PM_{2.5}$							
Annual		7.4		12	0.2	4.6	YES
24-hour		23.4		35	1.2	11.6	YES
PM_{10}							
24-hour		135		150	5	15	YES
CO							
8-hour	0.7	798	35	39,900	2,000	39,102	YES
1-hour	0.8	912	9	10,260	5,00	9,348	YES

radial distance among the CO, $PM/PM_{10}/PM_{2.5}$, and NO_x was used for all further modeling as described in Section 7.2. The further analysis was performed to determine compliance with the NAAQS and Class I and II PSD increments shown in Tables 7-3 and 7-4, respectively.

The air quality modeling analysis for the determination of the PSD pollutants with concentrations above the SIA used the maximum predicted concentrations (i.e. highest short-term and annual average concentrations) and NOT the statistical form of the NAAQS (i.e., 98th percentile, averaged over 3 years). As seen in Table 7-5 only the 1-hr NO_x and 24-hr $PM_{2.5}$ had predicted concentrations above the SIL. Therefore, since only the 1-hr NO_x and 24-hr $PM_{2.5}$ had predicted concentrations above the SIL, these were the only pollutants and averaging periods requiring further analysis to demonstrate compliance with the NAAQS and PSD increments.

7.2 CLASS II AREA- MULTI-SOURCE IMPACT ANALYSIS

A discussion of the Class II area air quality impact analysis for NAAQS and PSD increment consumption is presented in the following sections.

7.2.1 NAAQS Analysis

Since the initial significance analysis indicated that the proposed project has significant impacts for 1-hr NO_x and 24-hr $PM_{2.5}$, a multi-source impact analysis was conducted. The multi-source impact analysis included all sources at the Longview Unit 2 that emit $PM_{2.5}$ and NO_x. In addition, other major sources of these PSD pollutants located within 30 km of proposed project were included in the offsite emission inventory.

The offsite emission inventory for West Virginia sources was obtained from a Freedom of Information Request (FOIA Request #2019-10-038) to WVDEP to obtain all major sources in the following counties: Marion, Monongalia, and Preston Counties. The inventory provided by WVDEP was actual emissions. The inventory was converted to maximum permitted emissions through a review of the Title V permit for each source. The offsite emission inventory for Pennsylvania sources was obtained based on a review of Title V permits in the following counties: Greene and Fayette Counties and the most recent PSD permit application (APV Renaissance Energy Center, Monongahela Township, PA). The offsite emission inventory for the NAAQS and PSD increment analysis is presented in Table 7-6.

Table 7-3
National Ambient Air Quality Standards

Pollutant		Primary/Secondary	Averaging Time	Level	Form
Carbon Monoxide (CO)		primary	8 hours	9 ppm	Not to be exceeded more than once per year
			1 hour	35 ppm	
Lead (Pb)		primary and Secondary	Rolling 3 month average	0.15 µg/m3(1)	Not to be exceeded
Nitrogen Dioxide (NO2)		Primary	1 hour	100 ppb	98th percentile of 1-hour daily maximum concentrations, averaged over 3 years
		primary and Secondary	1 year	53 ppb (2)	Annual Mean
Ozone (O3)		primary and Secondary	8 hours	0.070 ppm (3)	Annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years
Particle Pollution (PM)	$PM_{2.5}$	Primary	1 year	12.0 $\mu g/m^3$	annual mean, averaged over 3 years
		Secondary	1 year	15.0 $\mu g/m^3$	annual mean, averaged over 3 years
		primary and Secondary	24 hours	35 $\mu g/m^3$	98th percentile, averaged over 3 years
	PM_{10}	primary and Secondary	24 hours	150 $\mu g/m^3$	Not to be exceeded more than once per year on average over 3 years
Sulfur Dioxide (SO2)		Primary	1 hour	75 ppb (4)	99th percentile of 1-hour daily maximum concentrations, averaged over 3 years
		Secondary	3 hours	0.5 ppm	Not to be exceeded more than once per year

(1) In areas designated nonattainment for the Pb standards prior to the promulgation of the current (2008) standards, and for which implementation plans to attain or maintain the current (2008) standards have not been submitted and approved, the previous standards (1.5 µg/m3 as a calendar quarter average) also remain in effect.

(2) The level of the annual NO2 standard is 0.053 ppm. It is shown here in terms of ppb for the purposes of clearer comparison to the 1-hour standard level.

(3) Final rule signed October 1, 2015, and effective December 28, 2015. The previous (2008) O3 standards additionally remain in effect in some areas. Revocation of the previous (2008) O3 standards and transitioning to the current (2015) standards will be addressed in the implementation rule for the current standards.

(4) The previous SO2 standards (0.14 ppm 24-hour and 0.03 ppm annual) will additionally remain in effect in certain areas: (1) any area for which it is not yet 1 year since the effective date of designation under the current (2010) standards, and (2)any area for which implementation plans providing for attainment of the current (2010) standard have not been submitted and approved and which is designated nonattainment under the previous SO2 standards or is not meeting the requirements of a SIP call under the previous SO2 standards (40 CFR 50.4(3)), A SIP call is an EPA action requiring a state to resubmit all or part of its State Implementation Plan to demonstrate attainment of the require NAAQS.

Table 7-4
Class I and II Areas
PSD Increments (µg/m^3)

Pollutant	Averaging Period	Class I	Class II
SO_2	Annual	2	20
	24-hour	5	91
	3-hour	25	512
PM_{10}	Annual	4	17
	24-hr	8	30
$PM_{2.5}$	Annual	1	4
	24-hour	2	9
NO_2	Annual	2.5	25

Table 7-5
Comparison of Maximum Predicted Concentrations (µg/m^3)
from the Longview Power Unit 2 Emissions to SILs

Averaging Period	**NO_x**	**PM_{10}**	**$PM_{2.5}$**	**CO**
1-hr	**13.80**			12.36
8-hr				3.90
24-hr		1.47	**1.47**	
Annual	0.45		0.21	
Significant Impact Levels (SILs)				
Short-term (1-,3-,-8, or 24-hr)	7.5	5	1.2	2,000
Long-term (Annual)	1	NA	0.2	500

Table 7-6
Offsite Emission Inventory
NAAQS and PSD Increment Sources

Plant Name	Plant East	Plant North	Latitude	Longitude	Emission Unit	NOx lb/hr	PM lb/hr	Stack Height ft	Diameter ft	Temperature Deg F	Exit Velocit fps
American Bituminous Power-Grant Town Plant	572000	4379000	39.5577	-80.1619	Fluidized Bed Comb. Boil.	442	33.1	327	13.0	325	4.(
Allegheny Gans Energy LLC	599451	4400391	39.7476	-79.8392	Comb. Gas Turbine Unit 8&9	82	26.0	75.0	9.0	816	1
Dynegy Fayette II, LLC	592566	4412644	39.8588	-79.9178	Combined Cycle Turbines	43.2	69.6	200	20.0	200	56
Longview Power Unit 1	589200	4395700	39.7065	-79.9595	Pc Boiler	324	0.00	554	25.8	125	49
Monongahela Power Co.- Fort Martin Power	591934	4396198	39.7107	-79.9275	Fort Martin Unit 1	3494	1062	550	24.8	126	57
Morgantown Energy Facility	589107	4388311	39.6399	-79.9615	Boilers	300	22.5	338	8.0	335	79
Mylan Pharmaceuticals Inc. - Chestnut Ridge Road Facility	589000	4390269	39.6575	-79.9625	Boilers	6.16	0.48	20	1	0	63
Novelis	576700	4371500	39.4896	-80.1080	#4 FCE Comb #4,5,6,7 Purge	0.69	0.04	200	1.5	175	0.1
ND Fairmont LLC	575300	4375100	39.5222	-80.1239	Boiler	18.55	0.33	60	6	325	21
APV Renaissance Partners	591713	4412738	39.8597	-79.9277	Combined Cycle Turbines	28.70	16.80	180	23	173	53

An analysis of the location of minor sources and background air quality selected for the NAAQS analysis was performed to determine if the minor sources should be included in the multi-source modeling analysis or whether the existing background air quality data is conservatively high enough to represent the impact of the minor sources. It was determined that the minor sources were generally internal combustion engines and other small source of emissions and were already included in the maximum measured concentrations from ambient air monitoring stations over the previous 3 years (2016-2018). The background air quality selected for the NAAQS analysis is further discussed in Section 7.3. The NAAQS analysis was based on the form of the ambient standard either, maximum concentration or statistical analysis (i.e., highest second highest, annual maximum, 99th percentile or 98th percentile).

7.2.1.1 NAAQS Results

The NAAQS compliance assessment included the Longview Unit 2 Project emissions; the offsite facilities including Longview Unit 1 (Table 7-6) and representative background concentrations (Table 7-8). The results of NAAQS modeling analysis are shown in Table 7-7. As seen from this table, the Longview Unit 2 emission did not produce ambient impacts above the SIL for either 1-hr NO_x or 24-HR $PM_{2.5}$ using the statistical form of the NAAQS. Therefore, the project is not causing or contributing to an exceedance of the NAAQS for NO_x or $PM_{2.5}$.

7.2.2 PSD Increment Analysis

The PSD increment analysis included all PSD increment consuming sources identified in the offsite emission inventory for West Virginia and Pennsylvania and was used to assess PSD increment consumption. The PSD increment analysis was based on the maximum concentration for the form of the PSD increment.

Air quality increment consumption is tracked by tabulating the actual emissions changes at a stationary source, area source or mobile source since the minor source baseline date and changes in actual emissions at major stationary sources after the major source baseline date. To determine the air quality increment consumed in a region the net actual emissions changes are modeled to obtain an air quality increment consumption concentrations. The changes in emissions from existing sources and increases from proposed new sources since the baseline date are modeled together to determine

Table 7-7
Comparison of Predicted Multi-Source Concentration to SIL, NAAQS and PSD Increment

	NO_x ($\mu g/m^3$)	$PM_{2.5}$ ($\mu g/m^3$)
NAAQS	**1-hr average H8H 5-yr Average (2014-2018)**	**24-hr average H8H 5-yr Average (2014-2018)**
All sources	157.5	9.33
Background	84.9	23.4
Total	242.4	32.7
NAAQS	188	35
Longview Power Unit 2 contribution	5.58	0.88
SIL	7.5	1.2
PSD Increment		**24-hr average H2H (2014)**
All sources		1.27
Increment		8
Longview Power Unit 2 contribution		1.24
SIL		1.2

the incremental change in air quality levels. These incremental changes in air quality levels are compared to the PSD increment.

The PSD major source baseline dates for NO_2, PM_{10}, and SO_2 have been triggered by the Morgantown Energy Associates (MEA) project. This facility is located within the same air quality control region of that the Longview Unit 2 Project is located. The major source baseline year for NO_2, PM_{10}, and SO_2 is 1989.

The results of PSD increment modeling analysis are shown in Table 7-7. As seen from this table, the Longview Power Project Unit 2 emissions did not produce ambient impacts above the SIL for 1-hr NO_x or 24-HR $PM_{2.5}$. Therefore, the project is not causing or contributing to an exceedance of the PSD increment for NO_x or $PM_{2.5}$ and no further modeling analysis is required.

7.2.3 Visibility Analysis

A screening level visibility assessment using VISCREEN (Version: 13190) was performed to assess potential visibility impact from the project. The model calculates the change in the color difference index (ΔE) and contrast between the plume and the viewing background. The selected sites for the Class II visibility analysis using VISCREEN are Mylan Park and the Morgantown Airport. Both represent areas where visibility is important for either recreational or commercial purposes. Mylan Park and the Morgantown Airport are approximately 10 km southwest and 9 km southeast of the Longview Power Unit 2 site.

The results of the VISCREEN Level 1 analysis for Myland Park and Morgantown Airport are shown in Table 7-8. As seen from this table, the plume perceptibility and contrast calculated by VISCREEN are less than the Class I plume visibility screening criteria for Myland Park and Morgantown Airport.

7.2.4 Secondary Aerosol Formation

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 (USEPA, 2019) was used to demonstrate the effects of NO_x and VOC emissions from the proposed project on ozone and secondary formation of $PM_{2.5}$. A representative hypothetical source was identified from the Appendix Table A-1 of the guidance document. The hypothetical source selected was

Table 7-8
Plume Visual Impact Analysis

Pollutant	Emission Rate (lb/hr)	Transport Parameter	km	Meteorological Parameter	
Total NOx as NO_2	19	Background visual range	20	Plume-Source-Observer Angle (degrees)	11.25
Primary NO_2	28	Source-observer distance	9	Stability	6
PM_{10}	0	Minimum source distance	9	Wind Speed (mps)	1
Soot (elemental C)	0	Maximum source distance	10	Background Ozone (ppm)	0.04
Primary SO_4	0				

Visual Impact

Background	Theta [a] (degrees)	Azimuth [b] (degrees)	Distance (km)	Alpha [c] (degrees)	Plume Perceptibility [d] (ΔE)		Contrast (|C|) [e]	
					Criteria	Plume	Criteria	Plume
Sky	10	112	10	56	2.16	1.303	0.05	0.01
Sky	140	112	10	56	2.00	0.148	0.05	-0.008
Terrain	10	84	9	84	2.00	1.812	0.05	0.018
Terrain	140	84	9	84	2.00	0.277	0.05	0.009

a Theta is the vertical angle subtended by the plume
b Azimuth is the angle between the line connecting the source, observer and the line of sight
c Alpha is the angle between the line of sight and the plume centerline
d Plume perceptibility parameter (dimensionless)
e Visual contrast against background parameter (dimensionless)

Doddridge in West Virginia. This source was selected due to its proximity, similar air shed to the Longview Power Unit 2 project and it is the only hypothetical source located in West Virginia. The method of including the MERP results into the modeling results included:

1. Comparing the predicted NO_x 1-hr average, high 8th highest, 5-yr average concentration for the project to the NO_x SIL (as a percentage of the SIL).
2. Comparing the predicted $PM_{2.5}$ 24-hr average, high 8th highest, 5-yr average concentration for the project to the $PM_{2.5}$ SIL (as a percentage of the SIL).
3. Comparing the project's NO_x emission rate to the MERP for Doddridge for $PM_{2.5}$ from NO_x (as a percentage of the MERP).
4. Adding the items 2 and 3 above and comparing resultant to 100%.
5. Comparing the Comparing the project's NO_x emission rate to the MERP for Doddridge for Ozone (as a percentage).
6. Comparing the Comparing the project's VOC emission rate to MERP (tons/year) Doddridge O_3 from VOC (as a percentage).\
7. Adding items 5 and 6 above and comparing resultant to 100%.

The results of the MERP analysis is shown in Table 7-9. As seen from this table the predicted concentrations of ozone and secondary formation of $PM_{2.5}$ due to the NO_x and VOC emissions from the proposed project are not significant.

7.3 BACKGROUND AMBIENT AIR DATA

Background ambient air quality values are required as part of the NAAQS analysis. The background values should be representative of the background pollutant concentration levels that could be expected to occur in the vicinity of the Longview Unit 2 Project. Therefore, ambient air data from a West Virginia DAQ monitoring station in Morgantown, WV, Ohio EPA monitoring station in Shadyside, OH and Pennsylvania DEP monitoring station in Charleroi, PA were reviewed in order to select representative background pollutant concentration data. A summary of the air quality data from monitoring stations in Morgantown, WV, Shadyside, OH and Charleroi, PA are presented in Table 7-10. The maximum measured concentrations from these monitoring stations over the previous 3 years (2016-2018) were used to establish the existing ambient air quality levels for NAAQS compliance evaluation.

Table 7-9
MERP Analysis for $PM_{2.5}$ and O_3 NAAQS

NAAQS $PM_{2.5}$ and O_3	**NO_x 1-hr high 8th highest 5-yr Average**	**$PM_{2.5}$ 24-hr high 8th highest 5-yr Average**	**8 hr O_3**
	$PM_{2.5}$ Impact		
Longview Power Unit 2 ($\mu g/m^3$)	3.30	0.50	
SIL ($\mu g/m^3$)	7.5	1.2	
Primary Impact of SIL	44%	42%	
Below SIL	Yes	Yes	
MERP (tons/year) Doddridge $PM_{2.5}$ from NO_x		31,798	340[a]
Longview Power Unit 2 NO_x Emissions (tons/year)		302	302
Secondary Impact		1%	83%
Total NO_x Impact		43%	
Total NO_x Impact (direct and indirect) below 100%		Yes	
	O_3 Impact		
MERP (tons/year) Doddridge **O_3** from VOC			5,170
Longview Power Unit 2 VOC Emissions (tons/year)			503
Secondary Impact			11%
Total **O_3** Impact			94%
Total **O_3** Impact (direct and indirect) below 100%			Yes

Table 7-10
Proposed Background
Ambient Air Data for NAAQS Analysis

Pollutant and Averaging Period	2016	2017	2018	Site Location
SO_2 (ppb)				
3-hour	10.6	6	20.6	Morgantown Airport US 119 & Airport Blvd. (AQS Site ID 54-061-0003)
1-hour	23	9	35	
NO_2 (ppb)				
Annual	6.21	5.35	5.29	220 Meddings Road Charleroi, PA (AQS Site ID 42-125-0005)
1-hour	44	43	45	
$PM_{2.5}$ (µg/m3)				
Annual	7.40	7.3	7.2	Morgantown Airport US 119 & Airport Blvd. (AQS Site ID 54-061-0003)
24-hour	20.6	23.4	18.9	
PM_{10} (µg/m3)				
24-hour	135	61	73	2 Ball Park Rd Shadyside, OH (AQS Site ID 39-013-0006)
CO (ppm)				
8-hour	0.7	0.5	0.6	2 Ball Park Rd Shadyside, OH (AQS Site ID 39-013-0006)
1-hour	0.8	0.8	0.8	

A demonstration of the representativeness of these monitoring stations for the Longview Unit 2 Project was discussed in the Air Quality Modeling Protocol submitted to WV DEP.

7.4 CLASS I AREA ASSESSMENT

An assessment of potential project impacts on increment consumption, visibility and other air quality related values (AQRVs) in Class I areas is a requirement for PSD projects. Air quality impacts at Class I areas must be assessed under PSD regulations if they are within 100 km of the PSD source, or if the PSD source is judged to have a potential effect at Class I areas at distances beyond 100 km

There are four (4) Class I areas within 250 km of the proposed site of the Longview Unit 2 Project. These areas are the Dolly Sods, Otter Creek and James River Face National Wilderness Areas and the Shenandoah National Park. The Dolly Sods, Otter Creek, James River Face and Shenandoah areas are approximately 91 km southeast, 78 km south-southeast, 237 south-southeast, and 173 km southeast respectively, of the proposed project site. The locations of the Class I areas relative to the proposed plant site are shown in Figure 7-1.

The initial screening method described in Section 3.2 of the FLAG (2010) document was used to evaluate the impacts of the proposed Longview Unit 2 Project on the Class I areas. The FLAG member agencies that administer Federal Class I areas (U.S. Forest Service (USFS) the National Park Service (NPS) and U.S. Fish and Wildlife Service (FWS)) will consider a source locating greater than 50 km from a Class I area to have negligible impacts with respect to Class I AQRVs if its total SO_2, NO_x, PM_{10}, and H_2SO_4 annual emissions (in tons per year, based on 24-hour maximum allowable emissions), divided by the distance (in km) from the Class I area (Q/D) is 10 or less. The Agencies would not request any further Class I AQRV impact analyses from such sources. The Q/D calculation for the proposed project is shown in Table 7-11. As seen from this table the Q/D calculation is less than ten for all four Class I Areas, therefore, no further Class I impact analysis is required for AQRV.

A Class I NAAQS and PSD increment screening level assessment following the procedure described in Section 4.2 of Appendix W was also performed. Preliminary modeling using the preferred near field refined air quality model (AERMOD) was used to determine the significance

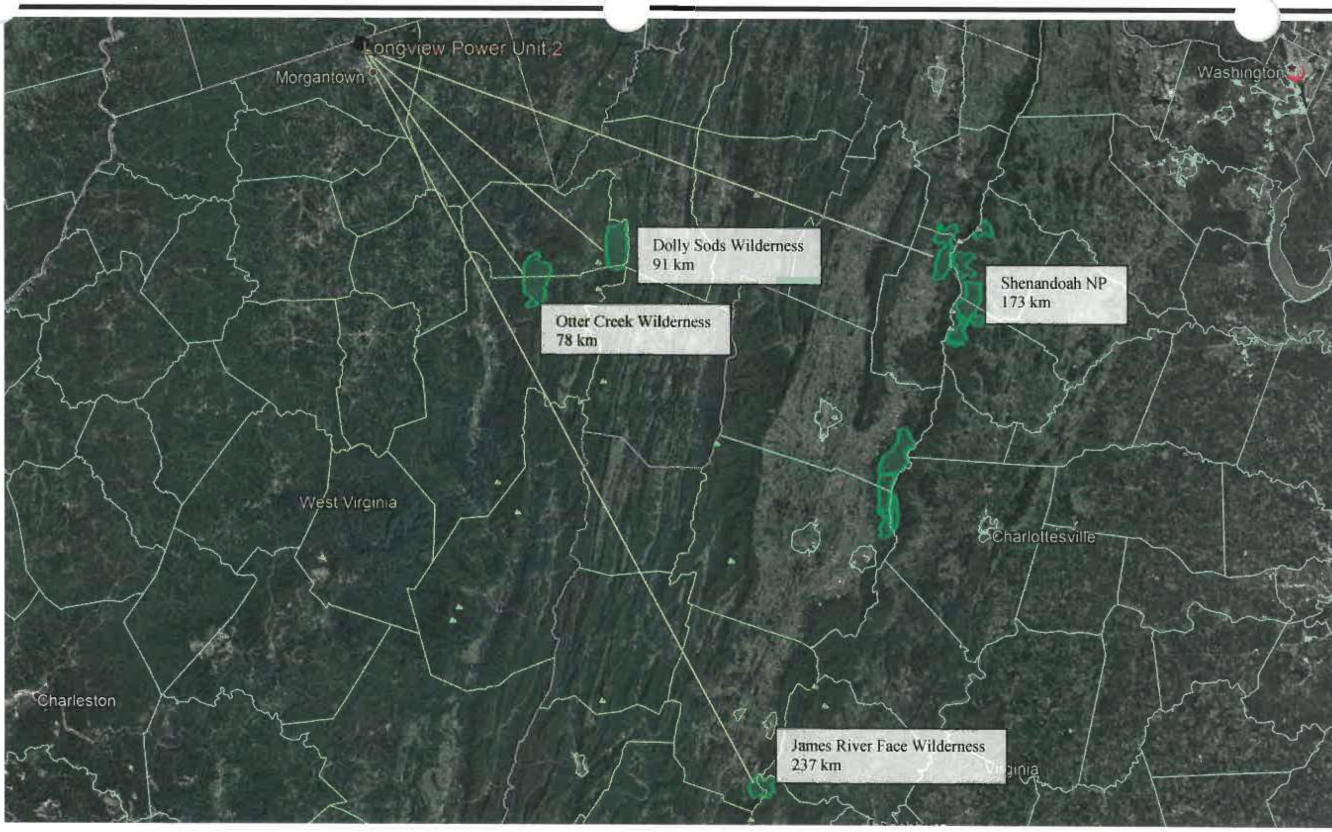


Figure 7-1
Location of Class I Areas

Table 7-11
Q/D Calculations for Class I Areas

Total Project Emissions	**Q (tpy)**		
SO_2, NO_x, PM_{10}, and H_2SO_4	581		
Class I Area	**D (km)**	**Q/D**	**Q/D < 10?**
Shenandoah National Park	173	3.36	Yes
Dolly Sods	91	6.39	Yes
Otter Creek	78	7.45	Yes
James River Face	237	2.45	Yes

of the ambient impacts at 50 km from the proposed Longview Power Unit 2 project. These results are shown in Table 7-12. As seen from this table all of the impacts are less than significance levels for Class I areas.

Since the predicted concentrations are less than the significance levels at 50 km, no further analysis was performed for the screening Class I NAAQS/PSD increment screening analysis. The nearest Class I area is Otter Creek Wilderness which 78 km south-southeast of the project site.

7.5 OTHER AIR QUALITY RELATED VALUES ANALYSIS

PSD regulations also require an analysis of the effects of the proposed project on AQRVs in areas surrounding the project. These AQRVs include effects of other growth (residential, commercial, or industrial) associated with the project and possible impacts on sensitive flora, fauna, and soils. Growth-related AQRVs, such as influxes of additional population or increases in vehicular traffic, will not be significantly affected by the proposed project. The electricity produced by the project will be transmitted over a multi-state power grid and will not directly enable or support any additional local commercial, industrial, or residential development. The labor force required to operate the facility will be small and will be drawn from the local communities. Therefore, there are no anticipated effects on growth.

Evaluation of potential impacts on vegetation and soils were performed by comparison of maximum modeled impacts from the Project to Air Quality Related Value (AQRV) screening concentrations provided in the EPA document "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals" and to NAAQS secondary standards. The screening levels represent the minimum concentrations in either plant tissue or soils at which adverse growth effects or tissue injury was reported in the literature. The NAAQS secondary standards were set to protect public welfare, including protection against damage to crops and vegetation. Therefore, comparing maximum predicted concentration due to the project to the AQRVs and the secondary NAAQS provides an indication as to whether potential impacts are likely to be significant. A comparison of the predicted concentrations to the screening AQRV is presented in Table 7-13. As seen from this table, maximum predicted concentration due to the project are well below the AQRVs and the secondary NAAQS.

Table 7-12
Maximum Predicted Impact from the Longview Power Unit 2 at 50km Distance

Averaging Period	NO_x	PM_{10}	$PM_{2.5}$	CO
1-hr	0.69			0.62
8-hr				0.22
24-hr		0.10	0.1	
Annual	0.02	0.012	0.012	
Significant Impact Levels (SILs)				
Short-term (1-,3-,-8, or 24-hr)	NA	0.3	0.27	NA
Long-term (Annual)	0.1	0.2	0.05	NA

Table 7-13
Comparison of the Maximum Predicted Air Quality Concentrations (μg/m^3) to the Screening Level AQRVs and the NAAQS Secondary Standards

Pollutant	Averaging Period	AQRV Screening Levels	Secondary NAAQS	Maximum Predicted Concentration
PM_{10}	24-hour	NA	150	1.47
	Annual	NA	50	0.21
$PM_{2.5}$	24-hour	NA	35	1.47
	Annual	NA	15	0.21
NO_2	4-hour	3,760	NA	13.8 (1-hr)
	8-hour	3,760	NA	13.8 (1-hr)
	1-month	564	NA	13.8 (1-hr)
	Annual	100	100	0.45
CO	Weekly	1,800,000	NA	3.90 (8-hr)

As further analysis of the potential impact of the proposed project on air quality related values a screening level visibility assessment using VISCREEN (Version: 13190) was performed for the Class I areas. between the plume and the viewing background. If the hourly estimates of ΔE is less than to 2.0 or the absolute value of the contrast values ($|C|$) is less than 0.05, then no further visibility analysis is required. The results indicate that the potential emission of NO_x and $PM_{2.5}$ would produce a change in color difference of 1.43 and a contrast of 0.02 in the nearest Class I area, Otter Creek Wilderness.