MOUNDSVILLE POWER

www.Moundsville-Power.com

VIA HAND-DELIVERY

20 December 2013

Mr. Steve Pursley
West Virginia Department of Environmental Protection
Division of Air Quality
601 57th Street SE
Charleston, WV 25304

Dear Mr. Pursley:

On behalf of Moundsville Power, LLC enclosed are three (3) copies and a CD of a revised air permit application to construct a proposed new natural gas-fired combined-cycle combustion turbine electric power plant. The original application was submitted to the Department on October 4, 2013. This revision reflects changes in project equipment and design that have evolved since the October 2013 submittal, including:

- Change in General Electric (GE) combustion turbine model from Frame 7FA.05 to 7FA.04, and the addition of duct firing. These changes result in an overall decrease in the nominal electric generating capacity of the plant from 615 megawatts (MW) to 525 MW;

- Changes in combustion turbine startup and shutdown amounts, durations, and emissions;

- Slight changes in the sizes and emission rates for the proposed Auxiliary Boiler and Fire Water Pump, as well as a reduction in proposed annual Auxiliary Boiler operations;

- Elimination of a natural gas-fired Fuel Gas Heater;

- Minor changes in the circulating water rate and TDS concentrations for the proposed Cooling Tower.

This revision also addresses Items 1-4 of your November 4, 2013 incompleteness letter. Items 1 and 2 will be addressed in the upcoming re-publication of the legal ad pertaining to this supplemental application material. Items 3 and 4 are addressed within the enclosed revision.

The incompleteness letter also contained 17 items pertaining to air quality modeling. These items were addressed in a revised modeling protocol that was submitted to the Department on November 27, 2013.

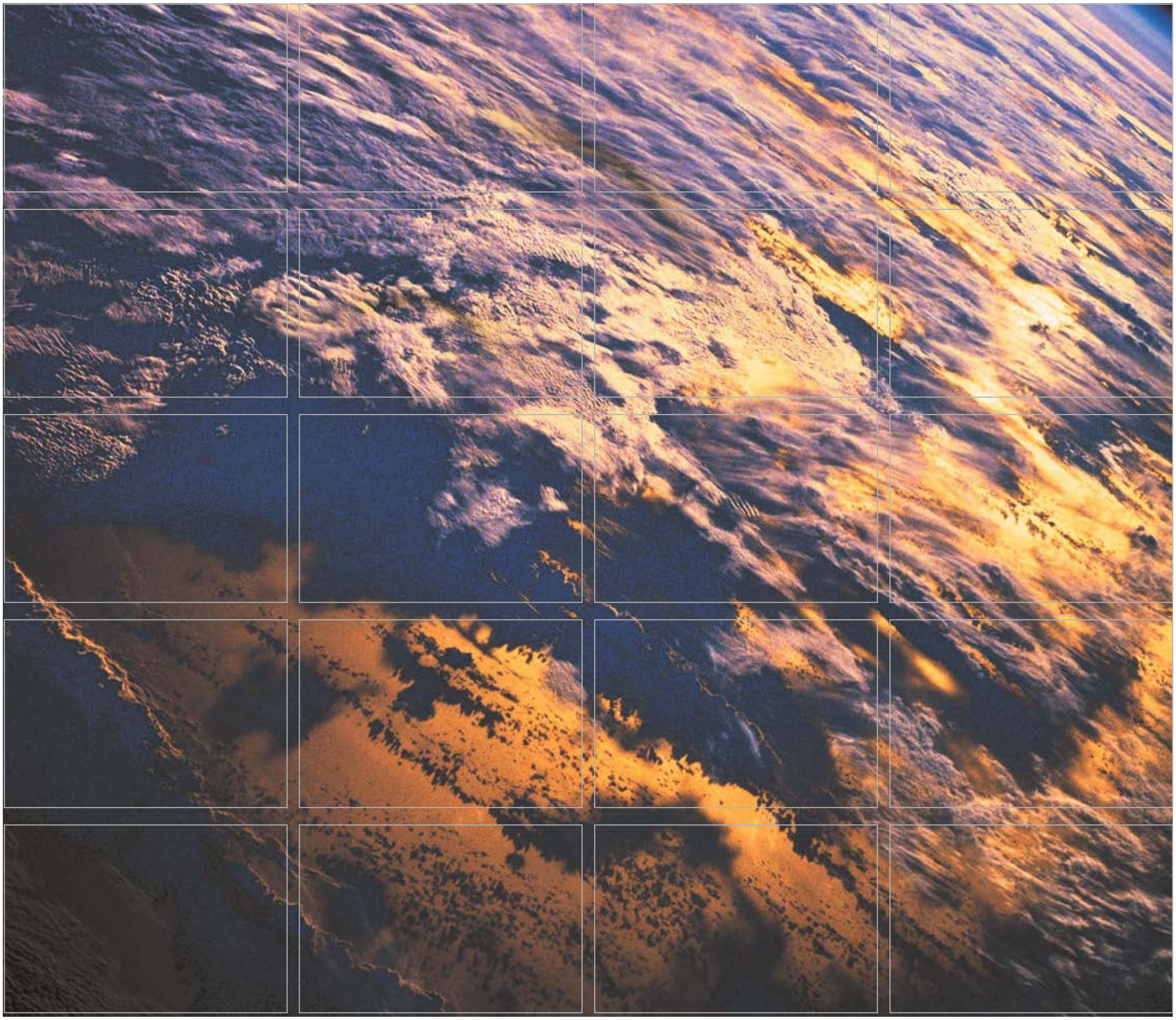
As we discussed during our November 7, 2013 meeting, Moundsville Power hopes to obtain WVDEP approval by June 2014 to allow us to maintain our project schedule. We greatly appreciate the attention you have given to this project so far, and look forward to working with you to meet this aggressive schedule.

Please call me at (716) 856-3333 or Mr. Dave Fewell of ERM at (304) 757-4777 ext. 102 if you have any questions or need any additional information.

Sincerely,

Jon M. Williams
Managing Member
Moundsville Power, LLC

Enclosures



Moundsville Power, LLC

Air Permit Application – Revision 1
Combined-Cycle Power Plant Project
Moundsville, Marshall County, West Virginia

December 2013

Environmental Resources Management
200 Princeton South, Suite 160
Ewing, NJ 08628
(609) 895-0050

www.erm.com

The world's leading sustainability consultancy

ERM

TABLE OF CONTENTS

LIST OF TABLES

LIST OF APPENDICES

1.0 INTRODUCTION

1.1 PROJECT DESCRIPTION

Moundsville Power, LLC (Moundsville Power) proposes to construct, install, and operate a proposed new combined-cycle combustion turbine (CT) electric power plant (Project).

The Project will be located at an existing Honeywell site in Moundsville, Marshall Country, West Virginia. The plant will occupy approximately 40 acres of the 280 acre site. The Project site is zoned for industrial use, and provides multiple strategic advantages that will allow the plant to produce low cost base load electricity.

The plant will tie into the American Electric Power (AEP) high voltage transmission system in the area, and sell its output into the Pennsylvania-New Jersey-Maryland Interconnection LLC (PJM) regional electric grid.

This new plant requires preconstruction approval of an air permit under the federal Prevention of Significant Deterioration (PSD) program (40 CFR 52.21) and under West Virginia Department of Environmental Protection (WVDEP or The Department) 45 CSR 13 and 14. The original air permit application for this project was submitted to the Department on October 4, 2013. This revised application reflects comments provided by WVDEP and changes in project equipment and design that have evolved since the October 2013 submittal, including:

- Change in General Electric (GE) combustion turbine model from Frame 7FA.05 to 7FA.04, and the addition of duct firing to the Heat Recovery Steam Generators (HRSGs). These changes result in an overall decrease in the nominal electric generating capacity of the plant from approximately 615 megawatts (MW) to approximately 525 MW[1];

[1] Plant output varies by several factors, including ambient temperature, relative humidity, fuel, load level, whether duct firing or evaporative cooling are in use, etc. 525.6 MW is the expected plant output at a 92 ˚F ambient temperature design condition, 45% relative humidity, at base load, firing a natural gas/ethane fuel mix, with duct firing, and with the combustion turbine evaporative cooling systems off.

- Changes in combustion turbine startup and shutdown amounts, durations, and emissions;

- Minor changes in the sizes and emission rates for the proposed Auxiliary Boiler and Fire Water Pump, as well as a reduction in proposed annual Auxiliary Boiler operations;

- Elimination of a natural gas-fired Fuel Gas Heater;

- Minor changes in the circulating water rate and Total Dissolved Solids (TDS) concentrations for the proposed Cooling Tower.

The emission sources now associated with the Project are:

- Two (2) General Electric (GE) Frame 7FA.04 advanced combined-cycle combustion turbines (CTs), each with HRSGs equipped with duct firing;

- One (1) Auxiliary Boiler with a maximum heat input of 100 million British Thermal Units per hour (MMBtu/hr);

- One (1) 1,500-kilowatt (kW) Emergency Generator;

- One (1) 251-horsepower (hp) emergency Fire Water Pump;

- One (1) wet, mechanical draft Cooling Tower consisting of ten (10) cells.

Appendix A contains conceptual plant layout drawings.

1.1.1 *Combustion Turbines*

Electricity will be generated using two (2) combined-cycle combustion turbines, each with a nominal output of approximately 197 MW and a heat input of approximately 2,087 million British Thermal Units per hour (MMBtu/hr)[2], on a Higher Heating Value (HHV) basis. Electricity generated by the combustion turbines will be routed through a local electrical substation and sold on the grid.

The highly efficient combined-cycle combustion turbines (CCGT-1 and CCGT-2) will be equipped with inlet evaporative cooling systems, which are used to increase the density of the combustion air, thereby increasing fuel and mass flow and, in turn, power output. The air density increase is accomplished by evaporating water into the inlet air, which decreases its temperature and correspondingly increases its density.

Each combustion turbine will be coupled with a HRSG to produce steam and achieve higher electric power output. The HRSGs contain a series of heat exchangers designed to recover the heat from the combustion turbine exhaust gas and produce steam, as in a boiler. The Project now includes the installation of duct burners to produce additional steam in the HRSGs for additional power output from the steam turbine generators. The maximum duct firing level for each combustion turbine/HRSG module is expected to be 65 MMBtu/hr on a Lower Heating Value (LHV) basis, which equates to 72.1 MMBtu/hr on a HHV basis. The fuel for the duct burners will be the same as for the combustion turbines: either pipeline-quality natural gas or a blend of pipeline-quality natural gas and up to 25% ethane. Steam generated in the HRSGs is routed to a steam driven

---

[2] Combustion turbine output and heat input vary by several factors, including ambient temperature, relative humidity, fuel, load level, whether duct firing or evaporative cooling are in use, etc. 196.9 MW is the expected combustion turbine output under several operating cases. 2,087 MMBtu/hr is the expected heat input for a single combustion turbine at a 10 ˚F ambient temperature design condition, 60% relative humidity, at base load, firing natural gas, with 100% duct firing, and with the evaporative cooling system off.

electric generator. This generator produces up to an additional 203 MW[3] of electricity that will also be routed through a local electrical substation and sold on the grid.

The combustion turbines will be equipped with dry low-NO_x (DLN) combustors. These combustion controls, along with Selective Catalytic Reduction (SCR) systems, will control emissions of nitrogen oxides (NO_x) from the combustion turbines. Oxidation Catalysts will be used to control carbon monoxide (CO) and volatile organic compounds (VOC) emissions from the combustion turbines. The SCRs and Oxidation Catalysts will be incorporated into the HRSGs, at locations where the emission control reactions optimally occur.

The SCRs involve the injection of aqueous ammonia (NH_3) with a concentration of less than 20% by weight into the combustion turbine exhaust gas streams. Ammonia reacts with NO_x in the combustion turbine exhaust gas streams, reducing it to elemental nitrogen (N_2) and water vapor (H_2O). The aqueous ammonia will be stored on-site in one (1) storage tank with a capacity of 20,000 gallons. The aqueous ammonia storage tank will not normally vent to the atmosphere. It will be equipped with pressure relief valves that would only vent in the event of an emergency. The Oxidation Catalysts do not require the use of reagents.

Each combustion turbine will have its own exhaust stack. Each stack is expected to be 180.5 feet above grade.

For permitting and emissions estimating purposes, this application assumes that the combustion turbines will operate 8,760 hours per year (hr/yr).

1.1.2 Auxiliary Boiler

A 100 MMBtu/hr Auxiliary Boiler will be used to produce steam for plant support. The Auxiliary Boiler will burn either pipeline-quality natural gas or a blend of pipeline-quality natural gas and up to 25% ethane. The

[3] Steam turbine generator output input varies by several factors, including ambient temperature, relative humidity, combustion turbine fuel, load level, whether duct firing or evaporative cooling are in use, etc. 203.33 MW is the expected steam turbine generator output at a at a 73.4 ˚F ambient temperature design condition, at 60% relative humidity, with the combustion turbines at base load, firing a natural gas/ethane fuel mix, with duct firing, and the evaporative cooling systems off.

Auxiliary Boiler will be equipped with ultra low-NO_x burners (ULNB) and flue gas recirculation (FGR) to control NO_x emissions.

For permitting and emissions estimating purposes, this application assumes that the Auxiliary Boiler will operate the equivalent of 2,000 hr/yr.

1.1.4 Emergency Generator

A 1,500 kW Emergency Generator (EG-1) will be used for emergency backup electric power. The fuel for the Emergency Generator will be ultra low sulfur diesel (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 ULSD fuel for the Emergency Generator will be stored in a 3,000 gallon Emergency Generator Tank (ST-2).

The Emergency Generator will operate no more than 100 hr/yr for maintenance and readiness testing. Other than maintenance and readiness testing, these engines will be used only for emergency purposes. For permitting and emissions estimating purposes, this application assumes that the Emergency Generator will operate a maximum of 500 hr/yr.

1.1.5 Fire Water Pump

A 251 hp Fire Water Pump (FP-1) will be used for plant fire protection. The fuel for the Fire Water Pump will also be ULSD, 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 ULSD fuel for the Fire Water Pump will be stored in a 500 gallon Fire Water Pump Tank (ST-1).

The Fire Water Pump will operate no more than 100 hr/yr for maintenance and readiness testing. Other than maintenance and readiness testing, the Fire Water Pump will be used only for emergency purposes. For permitting and emissions estimating purposes, this application assumes that the Fire Water Pump will operate a maximum of 500 hr/yr.

1.1.6 *Cooling Tower*

A wet, mechanical draft Cooling Tower will be used to cool the plant's steam driven electric generator. Make-up water is added to the Cooling Tower as necessary to account for water evaporated in the Cooling Tower. Air from the Cooling Tower will be vented through emission point CT-1. Steam condensate from the steam generator is routed back to the HRSGs for reuse.

The make-up cooling water for the Cooling Tower will come from the nearby Ohio River. High efficiency drift eliminators will be used to control particulate matter (PM) emissions from the Cooling Tower.

For permitting and emissions estimating purposes, this application assumes that the Cooling Tower will operate 8,760 hr/yr.

1.2 *PROJECT SCHEDULE*

As discussed during a November 7, 2013 meeting with WVDEP air permitting and modeling staff, Moundsville Power wishes to obtain WVDEP air permit approval by June 2014 to provide sufficient time for equipment ordering, fabrication, construction, and installation, and achieve commercial operation in Summer 2017.

1.3 *APPLICATION ORGANIZATION*

This application is organized into the following major sections:

- Section 2.0 provides a description of the existing site conditions;
- Section 3.0 includes the analysis of potential air quality impacts from the Project; and
- Section 4.0 summarizes conclusions;
- Section 5.0 discusses the air permit application.

2.0 EXISTING AIR QUALITY

The United States Environmental Protection Agency (USEPA) and state agencies, such as the West Virginia Department of Environmental Protection (WVDEP), monitor concentrations of the "criteria" pollutants NO_X, sulfur dioxide (SO_2), PM, ozone, CO, and lead (Pb) in ambient air at various locations throughout the United States. If monitoring data indicates that the concentration of a pollutant exceeds the National Ambient Air Quality Standard (NAAQS) in any area, then that area is classified as a "non-attainment area" for that pollutant, meaning that the area is not meeting the ambient standard. Conversely, any area in which the concentration of a criteria pollutant is below the NAAQS is classified as an "attainment area" indicating that the NAAQS is being met.

The attainment/non-attainment designations are made by states and USEPA on a pollutant-by-pollutant basis. Therefore, the air quality in an area may be designated attainment for some pollutants and non-attainment for other pollutants at the same time. For example, many cities are designated non-attainment for ozone, but are in attainment for the other criteria pollutants.

Since the late 1980s, the NAAQS for PM covered "PM_{10}," which represents PM less than 10 microns in diameter. In 1997, USEPA revised the NAAQS for PM and added a standard for a new form of PM known as $PM_{2.5}$, which is PM less than 2.5 microns in diameter. $PM_{2.5}$, or "fine particulates," is a pollutant of concern because the small size of the particles allows them to be inhaled deeply into the lungs, and the particles contribute to atmospheric haze and other air quality issues.

The entire State of West Virginia, including the Project location in Marshall County, is in attainment of the NAAQS for all criteria pollutants, except SO_2, which is discussed in more detail below.

2.1.1 $PM_{2.5}$ (1997 Annual NAAQS)

Marshall County had been designated as non-attainment for the 1997 annual $PM_{2.5}$ NAAQS. The 1997 annual $PM_{2.5}$ NAAQS is set at 15 micrograms per cubic meter ($\mu g/m^3$).

On March 8, 2012, the State of West Virginia through the West Virginia Department of Environmental Protection (WVDEP) formally submitted a request to redesignate the West Virginia portion of the Wheeling Area from nonattainment to attainment of the 1997 annual $PM_{2.5}$ NAAQS.

Concurrently, West Virginia submitted a maintenance plan for the area as a State Implementation Plan (SIP) revision to ensure continued attainment throughout the area over the next 10 years.

On December 11, 2012 (77 FR 73575), USEPA published a notice of proposed rulemaking (NPR) determining that the Wheeling Area, which includes Marshall County, has attained the 1997 annual $PM_{2.5}$ NAAQS and that the area has met the requirements for redesignation under section 107(d)(3)(E) of the Clean Air Act (CAA). In the December 11, 2012 NPR, USEPA proposed to approve WVDEP's request to change the legal definition of the West Virginia portion of the Wheeling Area from nonattainment to attainment for the 1997 annual $PM_{2.5}$ NAAQS.

On September 30, 2013 (78 FR 59841), USEPA finalized this rulemaking, approving the 1997 annual $PM_{2.5}$ NAAQS redesignation request, maintenance plan, comprehensive emissions inventory, and insignificance determination for transportation conformity for the West Virginia portion of the area, based on USEPA's determination that the area has met the criteria for redesignation to attainment specified in the Clean Air Act (CAA).

2.1.2 SO_2 (2010 1-Hour NAAQS)

Effective October 4, 2013, parts of Marshall County, specifically the Clay, Franklin, and Washington Tax Districts, are designated as non-attainment for the 2010 1-hour SO_2 NAAQS of 75 parts per billion (ppb). The proposed Project is located in the Clay Tax District. Therefore, the proposed Project area is considered non-attainment for SO_2.

2.1.3 $PM_{2.5}$ (2012 Annual NAAQS)

On December 14, 2012, USEPA adopted a revised annual $PM_{2.5}$ NAAQS of 12 $\mu g/m^3$. Attainment or non-attainment designations have not yet been made relative to this NAAQS. USEPA is scheduled to make final designations by December 2014. Historical ambient monitoring data has shown annual $PM_{2.5}$ concentrations above 12 $\mu g/m^3$. However, $PM_{2.5}$ concentrations measured at ambient monitors located in both Moundsville and Wheeling have been trending downward for over a decade. This downward trend in ambient $PM_{2.5}$ concentrations is likely to continue, as detailed in the revised air quality dispersion modeling protocol submitted on November 27, 2013. A copy of this revised protocol is provided in **Appendix B**.

3.0 AIR PERMITTING CONSIDERATIONS

3.1 OVERVIEW

Potential air pollutant emissions from the Project were evaluated to ensure that the Project will meet all applicable regulatory limits and requirements. The proposed Project was also evaluated to determine whether its emissions are predicted to have any significant impacts on the existing ambient air quality in the region. This evaluation was completed through air quality dispersion modeling studies that predict the ambient air concentrations resulting from emission sources associated with the proposed Project.

3.2 REGULATORY CONSIDERATIONS

The USEPA has defined concentration-based NAAQS for several pollutants, which are set at levels considered protective of the public health and welfare. Specifically, the NAAQS have been defined for six (6) "criteria" pollutants, including PM, SO_2, CO, nitrogen dioxide (NO_2), ozone, and Pb.

Three (3) forms of particulate matter are regulated: total suspended particulate (known as PM or TSP), PM_{10}, and $PM_{2.5}$. Emission limits and air pollution control requirements are generally more stringent for sources located in areas that do not currently attain a NAAQS for a particular pollutant (known as "non-attainment" areas). The air quality in Marshall County and the vicinity of the proposed Project is in attainment (or unclassifiable) for all pollutants, except SO_2.

Potential emissions from new and modified emission sources in non-attainment areas are evaluated through the Non-Attainment New Source Review (NA-NSR) permitting program. The goal of the NA-NSR program is to allow construction of new emission sources and modifications to existing sources, while ensuring that progress is made towards attainment of the NAAQS. Triggering NA-NSR for a given pollutant requires mitigation of adverse air quality impacts through implementation of the most stringent levels of air pollution control, known as the Lowest Achievable Emission Rate (LAER), as well as requiring emission "offsets" to be obtained for subject pollutants.

Potential emissions from new and modified sources in attainment areas are evaluated through the Prevention of Significant Deterioration (PSD) program. The goal of the PSD program is to ensure that emissions from major sources do not degrade air quality. Triggering PSD requires air pollution control known as the Best Available Control Technology (BACT) and additional impact assessments.

The proposed Moundsville Power Project has the potential to emit the criteria pollutants PM, PM_{10}, $PM_{2.5}$, CO, NO_2, SO_2, and Pb; ozone precursors; several hazardous air pollutants (HAPs); and greenhouse gases (GHGs). Because the area in which the proposed Project will be located is non-attainment for SO_2, and attainment/unclassifiable for the other criteria pollutants, applicability of both the PSD and NA-NSR regulations were assessed to ensure no adverse impacts would be caused by the Project. These evaluations are contained in Sections 3.4 (PSD) and 3.5 (NA-NSR).

Other federal and State air quality regulations apply to the proposed Project. These regulations apply either because of the type of emission source to be constructed, or because of the pollutants to be emitted from the Project. These regulations, discussed in Section 3.6, specify limits on pollutant emissions, and impose recordkeeping and reporting requirements.

3.3 AIR CONTAMINANT EMISSIONS

3.3.1 Emission Sources

The emission sources planned as part of the Moundsville Power Project include:

- Two (2) GE Frame 7FA.04 advanced combined-cycle combustion turbines, each with a nominal output of 197 MW and a heat input of 2,087 MMBtu/hr, and each with a HRSG equipped with duct burners;

- One (1) 100-MMBtu/hr Auxiliary Boiler;

- One (1) 1,500-kW Emergency Generator;

- One (1) 251-hp emergency Fire Water Pump;

- One (1) wet, mechanical draft Cooling Tower.

Table 3-1 summarizes the specifications for the proposed equipment.

Table 3-1 Moundsville Power Project - Air Contaminant Emission Sources

Component (Number of Units)	Type/Model	Size/Capacity	Fuel(s)	Proposed Maximum Operations
Combustion Turbines/Duct Burners (2)	GE Frame 7FA.04	CTs: 2,087 MMBtu/hr 197 MW Duct Burners: 72.1 MMBtu/hr	Natural gas or 0-25% ethane, 75-100% Natural gas	8,760 hr/yr per CT/duct burner
Auxiliary Boiler (1)	To be determined prior to construction	100 MMBtu/hr	Natural gas or 0-25% ethane, 75-100% Natural gas	2,000 hr/yr
Emergency Generator (1)	To be determined prior to construction	1,500-kW	ULSD	500 hr/hr (limited to emergency use and 100 hr/yr for maintenance and readiness testing)
Emergency Fire Water Pump (1)	To be determined prior to construction	251-hp	ULSD	500 hr/yr (limited to emergency use and 100 hr/yr for maintenance and readiness testing)
Cooling Tower (1)	To be determined prior to construction	159,000 gpm	N/A	8,760 hr/yr

3.3.2 Potential Emissions

Potential emissions from the Project emission sources were estimated using various calculation methodologies including vendor data, emission factors from USEPA's Compilation of Air Pollutant Emission Factors (AP-42) publication, material balances, New Source Performance Standards (NSPS) emission standards, and/or engineering calculations. Backup emission calculations are provided in Attachment N of the Air Permit Application Forms package in **Appendix D** of this application.

3.3.2.1 *Combustion Turbines*

3.3.2.1.1 Steady State Operations

Potential emissions of NO_x, CO, SO_2, PM, PM_{10}, $PM_{2.5}$, VOC, sulfuric acid (H_2SO_4), and carbon dioxide (CO_2) from the combustion turbines were based on vendor specifications provided by GE.

Potential short-term (lb/hr) emission rates were determined based on the GE data, which encompasses the expected range of combustion turbine operating loads and ambient temperatures, with and without the use of inlet air evaporative cooling, and with and without duct firing. The GE data addresses both pipeline-quality natural gas firing and the firing of a blend of pipeline-quality natural gas and up to 25% ethane. From the GE data, the potential short-term emission rates for NO_x, CO, SO_2, PM, PM_{10}, $PM_{2.5}$, VOC, H_2SO_4, and CO_2 for the combustion turbines were established by selecting the maximum lb/hr emission rates across the expected operating load and ambient temperature ranges.

Potential annual (tons/yr) emissions were then calculated by multiplying the maximum short-term emission rates by 8,760 hr/yr, then dividing by 2,000 to convert pounds to tons.

Pb emissions were estimated using AP-42 emission factors.

Maximum short-term and annual emissions from the combustion turbines during steady state operations are summarized in Table 3-2.

Table 3-2 Steady State Emissions – Combustion Turbines/Duct Burners[(1)]

Pollutant	1 CT Short Term Emissions (lb/hr)	1 CT Annual Emissions (ton/yr)	2 CTs Short Term Emissions (lb/hr)	2 CTs Annual Emissions (ton/yr)
VOC[(2)]	5.3	23.1	10.6	46.3
NO_x[(3)]	15.2	66.6	30.4	133.2
CO	9.2	40.5	18.5	80.9
SO_2	0.5	2.4	1.1	4.8
$PM/PM_{10}/PM_{2.5}$	7.6	33.1	15.1	66.2
Pb	0.001	0.004	0.002	0.01
H_2SO_4	0.351	1.5	0.7	3.1
CO_2	254,005	1,112,542	508,010	2,225,084
CH_4	6.9	30.2	13.8	60.5
N_2O	0.5	2.0	0.9	4.0
GHG (Mass Basis)	254,178	1,112,574	508,025	2,225,149
GHG (CO_2e Basis)	254,315	1,113,898	508,629	2,227, 797

(1) Emissions are post-HRSG stack emissions.
(2) VOC emissions are expressed as methane (CH_4).
(3) NO_x emissions are expressed as nitrogen dioxide (NO_2).

3.3.2.1.2 Startups and Shutdowns

After one (1) year of "continuous" operation, each combustion turbine is estimated to undergo 260 startups per year. Of these 260 startups, approximately 208 are expected to be hot startups, 48 are expected to be warm startups, and four (4) are expected to be cold startups. Accordingly, approximately 260 shutdowns per year are expected.

A hot start is defined as a start following 8 hours of shutdown or less. A warm start is defined as a start following 48 hours of shutdown. A cold start is defined as a start following 72 hours of shutdown or more. Any start following more than 8 hours of shutdown or less than 72 hours of shutdown is classified as a warm start. Table 3-3 summarizes startup and shutdown emissions and event durations for each combustion turbine, as well as the total startup and shutdown emissions from the two (2) combustion turbines.

Table 3-3 Startup and Shutdown Emissions – Combustion Turbines[(1), (2)]

Type	Pollutant	Emissions (lb/event)	Duration (min/event)	No. Events per Year	Total Duration (hr/yr)	Emissions (lb/yr)	Emissions (tons/yr) 1 CT	Emissions (tons/yr) 2 CT
	NO_x (as NO_2)							
Startups	Hot	19	25	208	86.7	3,952	2.0	4.0
	Warm	33	40	48	32.0	1,584	0.8	1.6
	Cold	47	55	4	3.7	188	0.1	0.2
Shutdowns		5	14	260	60.7	1,300	0.7	1.3
					Total	7,024	3.5	7.0
	CO							
Startups	Hot	273	25	208	86.7	56,784	28.4	56.8
	Warm	280	40	48	32.0	13,440	6.7	13.4
	Cold	1381	55	4	3.7	5,524	2.8	5.5
Shutdowns		175	14	260	60.7	45,500	22.8	45.5
					Total	121,248	60.6	121.2
	VOC (as CH_4)							
Startups	Hot	55	25	208	86.7	11,440	5.7	11.4
	Warm	56	40	48	32.0	2,688	1.3	2.7
	Cold	380	55	4	3.7	1,520	0.8	1.5
Shutdowns		46	14	260	60.7	11,960	6.0	12.0
					Total	27,608	13.8	27.6
	$PM/PM_{10}/PM_{2.5}$							
Startups	Hot	2.7	25	208	86.7	562	0.3	0.6
	Warm	4.3	40	48	32.0	206	0.1	0.2
	Cold	6	55	4	3.7	24	0.01	0.02
Shutdowns		1.5	14	260	60.7	390	0.2	0.4
					Total	1,182	0.6	1.2

(1) Startup and shutdown emission rates obtained from GE performance data.
(2) Startup and shutdown emission rates were not calculated for SO_2, Pb, H_2SO_4, or GHGs. Worst-case emissions for those pollutants were assumed to be steady-state operation.

3.3.2.1.3 *Total Combustion Turbine/Duct Burner Emissions*

Table 3-4 summarizes the total annual emissions from the combustion turbines/duct burners, including emissions from both steady state operations and combustion turbine startup and shutdown events.

Table 3-4 Total Emissions – Combustion Turbines/Duct Burners[(1)]

Pollutant	Maximum Annual Steady State Emissions: 2 CTs (tons/yr)	Startup and Shutdown Emissions: 2 CTs (tons/yr)	Total Emissions: 2 CTs (tons/yr)
VOC (as CH_4)	46.3	27.6	73.9
NO_x(as NO_2)	133.2	7.0	140.2
CO	80.9	121.2	202.2
SO_2	4.8	-- (1)	4.8
PM/PM_{10}/$PM_{2.5}$	66.2	1.18	67.4
Pb	0.01	-- (1)	0.01
H_2SO_4	3.1	-- (1)	3.1
GHG (CO_2e Basis)	2,227,797	-- (1)	2,227,797

(1) Startup and shutdown emission rates were not calculated for SO_2, Pb, H_2SO_4, or GHGs. Worst-case emissions for those pollutants were assumed to be steady-state operation.

3.3.2.2 *Auxiliary Boiler*

Auxiliary Boiler emissions were based on performance information from a potential vendor. PM_{10} and $PM_{2.5}$ emissions were assumed equal to PM emissions. Short-term SO_2 emissions were conservatively based on a sulfur content of the fuel of 2.0 grains per 100 dry standard cubic feet (gr/100 dscf). In addition, AP-42 factors were used for estimating emissions of Pb and HAPs from the boiler. HAP emissions are discussed in Section 3.3.3. The following assumptions were made to calculate Auxiliary Boiler emissions:

- Use of both pipeline-quality natural gas firing and the firing of a blend of pipeline-quality natural gas and up to 25% ethane;
- Use of low-NO_x burners with FGR; and
- Maximum annual heat input of 200,000 MMBtu per year (MMBtu/yr), which is equivalent to 2,000 hr/yr of operation at a maximum heat input of 100 MMBtu/hr.

Potential emissions of regulated pollutants from the Auxiliary Boiler are summarized in Table 3-5.

Table 3-5 Potential Emissions - Auxiliary Boiler

Pollutant	Maximum Short Term Emission Rate (lb/ hr)	Maximum Annual Emissions (tons/yr)
VOC (as CH_4)	0.6	0.6
NO_x (as NO_2)	2.0	2.0
CO	4.0	4.0
SO_2	0.06	0.06
$PM/PM_{10}/PM_{2.5}$	0.5	0.5
Pb	4.85E-05	4.85E-05
H_2SO_4	4.46E-03	4.46E-03
GHG (CO_2e Basis)	12,081	12,081

3.3.2.3 Emergency Generator and Fire Water Pump

Potential emissions of regulated pollutants from the Emergency Generator and Fire Water Pump are summarized in Tables 3-6 and 3-7, respectively. The vendor for the Emergency Generator has not yet been selected. Emissions for the Emergency Generator were estimated based on emission factors from potential vendors, and/or the applicable NSPS emission standards for stationary compression ignition (CI) reciprocating internal combustion engines (RICE) specified in 40 CFR 60, Subpart IIII.

PM_{10} and $PM_{2.5}$ emissions were assumed to equal PM emissions. The emission factors assume operation of the Emergency Generator at full load, which is reasonable given its expected use.

The vendor for the Fire Water Pump has not yet been selected. However, the Fire Water Pump emissions will not exceed the emission limits specified in NSPS Subpart IIII. As such, NO_x, PM and PM_{10}, and CO emissions from the Fire Water Pump are based on the applicable emission standards for these pollutants in NSPS Subpart IIII. Emissions of VOC, SO_2 and HAPs and were based on AP-42 emission factors.

Per 40 CFR 60, Subpart IIII, total hours for maintenance and readiness testing will not exceed 100 hr/yr. Other than maintenance and readiness testing, these units are utilized only for emergency purposes, and guidance for estimating potential emissions from emergency units is to assume maximum annual operation of 500 hr/yr.

For both the Fire Water Pump and the Emergency Generator, potential emissions were calculated based on 500 hr/yr of operation.

HAP emission estimates are discussed in Section 3.3.3.

Table 3-6 Potential Emissions - Emergency Generator

Pollutant	Emergency Generator Maximum Short Term Emissions (lb/hr)	Emergency Generator Maximum Annual Emissions (tons/yr)
VOC (as CH_4)	1.24	0.31
NO_x (as NO_2)	11.2	2.79
CO	11.53	2.88
SO_2	0.02	0.006
$PM/PM_{10}/PM_{2.5}$	0.40	0.10
Pb	---	---
H_2SO_4	---	---
GHG (CO_2e Basis)	2,416	604

Table 3-7 Potential Emissions - Fire Water Pump

Pollutant	Fire Water Pump Maximum Short Term Emissions (lb/hr)	Fire Water Pump Maximum Annual Emissions (tons/yr)
VOC (as CH_4)	0.17	0.04
NO_x (as NO_2)	1.49	0.37
CO	1.44	0.36
SO_2	0.003	7.4E-04
$PM/PM_{10}/PM_{2.5}$	0.08	0.021
Pb	---	---
H_2SO_4	---	---
GHG (CO_2e Basis)	309	77

3.3.2.5 *Cooling Tower*

Potential emissions from the proposed Cooling Tower are limited to PM emissions. The drift emissions from the Cooling Towers are limited to the particulate associated with dissolved solids in liquid droplets that become entrained in the air stream exiting the Cooling Tower. The particle size distribution is dependent on several factors including the design of the Cooling Tower, the efficiency of the drift eliminators, and the concentration of TDS in the circulating water.

PM emission estimates from the proposed Cooling Towers are based on a water circulation rate of 159,000 gallons per minute (gpm), a drift rate of 0.0005% of the circulating water rate, a maximum TDS content in the make-up cooling water of 300 mg/L, and a maximum of six (6) cycles of concentration in the circulating water.

Based on the Reisman and Frisbie method, "Calculating Realistic PM_{10} Emissions from Cooling Towers" (Reisman and Frisbie, 2002), PM_{10} emissions are estimated to be less than 50% of the PM emissions at the assumed TDS concentration (i.e. a maximum of 3,000 mg/L in the circulating water). Likewise, $PM_{2.5}$ emissions are estimated to be less than 0.2% of the PM emissions at the assumed TDS concentration.

Potential emissions from the Cooling Tower are summarized in Table 3-8.

Table 3-8 Potential Emissions – Cooling Tower

Pollutant	Maximum Short Term Emissions (lb/hr)	Maximum Annual Emissions (tons/yr)
PM	0.72	3.2
PM_{10}	0.5	2.1
$PM_{2.5}$	0.0016	0.0068

3.3.2.6 *Project Emissions Summary*

Table 3-9 summarizes the potential short-term emissions rates for the proposed Project. Potential annual emissions from the Project are summarized in Table 3-10.

Table 3-9 Short-Term Emissions Summary

Emission Unit	PM	PM_{10} and $PM_{2.5}$[6]	SO_2	NO_X (as NO_2)	CO	VOC (as CH_4)	H_2SO_4	Pb
CT/Duct Burner (each)[1]	7.6 lb/hr	7.6 lb/hr	0.5 lb/hr	15.2 lb/hr	9.2 lb/hr	5.3 lb/hr	0.35 lb/hr	0.001 lb/hr
Auxiliary Boiler [3]	0.5 lb/hr	0.5 lb/hr	0.06 lb/hr	2.00 lb/hr	4.00 lb/hr	0.60 lb/hr	---	---
Emergency Generator [4]	0.40 lb/hr	0.40 lb/hr	0.02 lb/hr	1.24 lb/hr	11.53 lb/hr	1.24 lb/hr	---	---
Fire Water Pump [4]	0.08 lb/hr	0.08 lb/hr	0.003 lb/hr	1.49 lb/hr	1.44 lb/hr	0.17 lb/hr	---	---
Cooling Tower [5]	0.72 lb/hr	0.5/0.0016 lb/hr	---	---	---	---	---	---

[1] Emissions based on GE-supplied data, except for Pb, which is based on AP-42, Section 1.4.

[2] Emissions based on emission factors in AP-42, Section 1.4.

[3] All emissions factors from a potential boiler vendor, except for SO_2 and Pb, which are based on AP-42, Section 1.4.

[4] NO_x, CO, VOC, PM, and PM_{10} emission factors based on NSPS Subpart IIII. SO_2 emission based on sulfur content of ULSD fuel.

[5] Emissions based on a maximum TDS concentration of 3,000 mg/L in the circulating water, and the Reisman/Frisbie method to estimate the PM_{10} and $PM_{2.5}$ fractions.

[6] Assumes $PM_{2.5}$ is equivalent to PM_{10}, except for the Cooling Tower.

Table 3-10 Annual Emissions Summary (tons/yr)

Unit	VOC (as CH_4)	NO_x (as NO_2)	CO	SO_2	PM_{10}	PM	$PM_{2.5}$	Pb	H_2SO_4	CO_2e
CTs (2): Steady State	46.3	133.2	80.9	4.8	66.2	66.2	66.2	0.01	3.07	2,227,797
CTs (2): Startups & Shutdowns	27.6	7.0	121.2	--	1.2	1.2	1.2	--	--	--
Auxiliary Boiler	0.60	2.00	4.0	0.06	0.50	0.50	0.50	4.9E-05	0.004	12,081
Emergency Generator	0.3	2.8	2.9	0.01	0.10	0.10	0.10	--	--	604
Fire Water Pump	0.04	0.37	0.36	0.00	0.02	0.02	0.02	--	--	77
Cooling Tower	--	--	--	--	2.1	3.2	0.01	--	--	--
Circuit Breakers	--	--	--	--	--	--	--	--	--	58
Total	**74.8**	**145.3**	**209.4**	**4.8**	**70.1**	**71.2**	**68.0**	**0.01**	**3.1**	**2,240,618**

3.3.3 Hazardous Air Pollutant Emissions

Appropriate AP-42 sections (Section 1.4 for natural gas combustion, Section 3.3 for Gasoline and Diesel Industrial Engines, and Section 3.4 for Large Stationary Diesel and All Stationary Dual-fuel Engines) provide emission factors for organic and metal compounds resulting from combustion, some of which are HAPs. Estimated HAP emissions from the proposed Project are summarized in Table 3-11. A facility is considered a "major" source of HAPs if it has the potential to emit 10 tons/yr or more of any individual HAP, or 25 tons/yr or more of all HAPs combined. As shown in Table 3-11, maximum emissions of any single HAP are 5.54 tons/yr (formaldehyde), and estimated total HAP emissions from the Project are 12.1 tons/yr. Therefore, the Project is not a major source of HAPs.

Table 3-11 HAP Emissions Summary

Hazardous Air Pollutant (HAP)	One CT (lb/hr)	One DB (lb/hr)	Auxiliary Boiler (lb/hr)	Emergency Generator (lb/hr)	Fire Water Pump (lb/hr)	Facility Total (tons/yr)
2-Methylnaphthalene	NA	1.68E-06	2.33E-06	NA	NA	1.70E-05
Acetaldehyde	8.356E-02	NA	NA	3.72E-04	1.45E-03	7.32E-01
Acrolein	1.34E-02	NA	NA	1.16E-04	NA	1.17E-01
Arsenic	NA	1.40E-05	1.94E-05	NA	NA	1.42E-04
Benzene	2.50E-02	1.47E-04	2.04E-04	1.15E-02	1.76E-03	2.24E-01
Cadmium	NA	7.70E-05	NA	NA	NA	6.74E-04
Chromium	NA	9.80E-05	1.36E-04	NA	NA	9.94E-04
Cobalt	NA	5.88E-06	8.16E-06	NA	NA	5.97E-05
Dichlorobenzene	NA	8.40E-05	1.17E-04	NA	NA	8.52E-04
Ethylbenzene	6.68E-02	NA	NA	NA	NA	5.85E-01
Fluoranthene	NA	2.10E-07	2.91E-07	NA	NA	2.13E-06
Fluorene	NA	1.96E-07	2.72E-07	NA	NA	1.99E-06
Formaldehyde	6.26E-01	5.25E-03	7.28E-03	1.17E-03	2.23E-03	5.54E+00
Hexane	NA	1.26E-01	1.75E-01	NA	NA	1.28E+00
Manganese	NA	2.66E-05	3.69E-05	NA	NA	2.70E-04
Mercury	NA	1.82E-05	2.52E-05	NA	NA	1.85E-04
Naphthalene	2.71E-03	4.27E-05	5.92E-05	1.92E-03	1.60E-04	2.47E-02
Nickel	NA	1.47E-04	2.04E-04	NA	NA	1.49E-03
Phenanathrene	NA	1.19E-06	1.65E-06	NA	NA	1.21E-05
POM	4.59E-03	NA	NA	3.13E-03	3.18E-04	4.11E-02
Pyrene	NA	3.50E-07	4.85E-07	NA	NA	3.55E-06
Toluene	2.71E-01	2.38E-04	3.30E-04	4.15E-03	7.73E-04	2.38E+00
Xylenes	1.34E-01	NA	NA	2.85E-03	5.39E-04	1.17E+00
Maximum Individual HAP						**5.54**
Total HAPs						**12.1**

3.3.4 *Greenhouse Gas Emissions*

3.3.4.1 *Combustion Equipment*

Potential GHG emissions [i.e. CO_2, methane (CH_4) and nitrous oxide (N_2O)] were estimated for all combustion sources associated with the Project. Potential emissions of CO_2 from the combustion turbines were based on vendor specifications provided by GE. For all other pollutants and combustion equipment, the emission factors and methodology were obtained from USEPA's Mandatory Greenhouse Gas Reporting Rule at 40 CFR 98. GHG emissions on an individual and carbon dioxide equivalent (CO_2e) basis are summarized in Table 3-12. In 40 CFR 98, USEPA defines CO_2e emissions to be equivalent to CO_2 emissions plus 25 times the CH_4 emissions plus 298 times the N_2O emissions, utilizing the applicable Global Warming Potentials (GWPs).[4]

Potential GHG emissions from the combustion turbines/duct burners, Auxiliary Boiler, Emergency Generator, and Fire Water Pump are all based on their maximum annual heat inputs, the CO_2, CH_4 and N_2O emission factors listed in 40 CFR 98, Subpart C (General Stationary Fuel Combustion Sources), and the applicable GWPs.

3.3.4.2 *Circuit Breakers*

The Project includes the installation of circuit breakers that contain sulfur hexafluoride (SF_6), which is a GHG. Planned SF_6-containing circuit breakers include two (2) Generator Circuit Breakers, each with approximately 25 pounds (lbs) of SF_6, and three (3) Switchyard Breakers, each with approximately 325 lbs of SF_6.

SF_6 is a fluorinated compound with unique chemical properties that make it an efficient electrical insulator used for electrical insulation, arc quenching, and current interruption in high-voltage electrical equipment. SF_6 is used in sealed and safe systems, which under normal circumstances

---

[4] On November 15, 2013, USEPA Administrator Gina McCarthy signed rule revisions that changed the GWP for CH_4 from 21 to 25, and the GWP for N_2O from 310 to 298. The final rule revisions are expected to be published in the *Federal Register* in December 2013.

do not leak gas to the atmosphere. Hence, SF_6 leakage into the atmosphere is expected to be minimal.

Potential SF_6 fugitive emissions were calculated assuming a worst-case leak rate of 0.5% per year, which has been taken from USEPA's technical paper titled, "SF_6 Leak Rates from High Voltage Circuit Breakers - EPA Investigates Potential Greenhouse Gas Emissions Source," by J. Blackman, Program Manager, USEPA and M. Averyt, ICF Consulting, and Z. Taylor, ICF Consulting. This leak rate was applied to the number of components and anticipated SF_6 content of each component, as described above. The annual CO_2e emission rate was calculated by multiplying the mass emission rate of SF_6 by its GWP of SF_6, 22,800.[5]

Potential annual GHG emissions from the Project are summarized in Table 3-12.

Table 3-12 GHG Emissions Summary

Unit	CO_2 (tons/yr)	CH_4 (tons/yr)	N_2O (tons/yr)	SF_6 (tons/yr)	CO_2e (tons/yr)
CTs/Duct Burners	2,225,084	60.5	4.0	--	2,227,797
Auxiliary Boiler	12,058	3.3E-01	5.0E-02	--	12,081
Emergency Generator	602	2.4E-02	4.9E-03	--	604
Fire Water Pump	77	3.1E-03	6.3E-04	--	77
Circuit Breakers	--	--	--	2.56E-03	58
Total CO_2e	2,237,821	59	4	2.56E-03	2,240,618

Emissions estimated based on 40 CFR 98, Subpart C.
CO_2e = CO_2 emissions + 25(CH_4 emissions) + 298(N_2O emissions) + 22,800(SF_6 emissions)

3.3.5 Ammonia Emissions

The SCRs that will control NO_x emissions from the combustion turbines/duct burners involve the injection of aqueous ammonia with a

[5] The rule revisions signed by USEPA Administrator Gina McCarthy on November 15, 2013 changed the GWP for SF_6 from 23,900 to 22,800. The final rule revisions are expected to be published in the *Federal Register* in December 2013.

concentration of less than 20% by weight into the combustion turbine exhaust gas streams. The aqueous ammonia will be injected via injection grids located upstream of each SCR catalyst. The SCR catalyst beds provide active sites where, as the combustion turbine exhaust gases pass through the beds, the vast majority of the ammonia reacts with NO_x in the exhaust stream, reducing it to elemental nitrogen and water vapor.

Small amounts of unreacted ammonia that pass through the catalysts and emitted to the atmosphere are known as "ammonia slip". A review of recently permitted combined-cycle natural gas-fired combustion turbine projects, including those that have installed similar model GE units (Frame 7FA), indicates that many are permitted with ammonia slip limits of 5 ppmvd @ 15% O_2. Accordingly, Moundsville Power proposes an ammonia slip limit of 5 ppmvd @ 15% O_2.

3.4 PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

3.4.1 Applicability

The proposed Project was evaluated to determine whether potential emissions of PSD-regulated pollutants would classify the Project as a major source under PSD. For most PSD pollutants, the major source threshold is either 100 tons/yr or 250 tons/yr, depending on the type of source. For the proposed Project, a 250 tons/yr major source threshold applies pursuant to 40 CFR 52.21(b)(1)(i)(b) because it does not fit into one of the source categories with a 100 tons/yr major source threshold under 40 CFR 52.21(b)(1)(i)(a).

In 2010, USEPA finalized regulations, referred to as the "Tailoring Rule," governing the permitting of GHG emissions from major stationary sources under PSD. In the absence of the Tailoring Rule, any source that had the potential to emit GHG at levels greater than the major source thresholds of 100 or 250 tons/yr would be subject to PSD (similar to all the other pollutants). However, the 100/250 tons/yr threshold is extraordinarily low for GHGs given that GHGs (particularly CO_2) are emitted in much larger quantities from combustion sources than traditional pollutants such as NO_X or SO_2. As such, USEPA "tailored" PSD regulations to increase the significance threshold, and adopted a phased approach to implementing PSD requirements for GHGs.

The Tailoring Rule defines new sources that have GHG emissions greater than 100,000 tons/yr, or existing sources that have been modified and result in GHG emissions increases of greater than 75,000 tons/yr, as major sources under PSD. Regulated GHGs are defined as the aggregate sum of six (6) GHGs, including CO_2, CH_4, N_2O, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). However, combustion sources generally do not emit HFCs, PFCs, or SF_6. The proposed Project is considered a new source, and is therefore subject to a 100,000 tons/yr major source threshold for GHGs. Potential GHG emissions from the proposed Project are approximately 2.24 million tons/yr, which is above the 100,000 tons/yr major source threshold. Therefore, the proposed Project is a major source of GHGs under PSD.

With PSD, if a source emits one or more pollutants in major amounts, the source is considered major. Then, all attainment pollutants, even those emitted in non-major amounts, must be reviewed for PSD applicability by comparing their potential annual emissions to the applicable Significant Emissions Rates (SERs). Emissions greater than or equal to the applicable SER subject the pollutant to PSD.

The proposed Project emits GHGs in major amounts. Therefore, emissions of all PSD-regulated pollutants must be compared to their respective SERs. As summarized in Table 3-13, potential emissions of NO_x, CO, PM, PM_{10}, $PM_{2.5}$, VOC, and GHGs trigger PSD. For these pollutants, Moundsville Power must:

- Demonstrate use of BACT for pollutants with significant emissions (Section 3.4.2);
- Assess the ambient impact of emissions using dispersion modeling; if the impact is significant, evaluate (through refined dispersion modeling) compliance with the NAAQS and consumption of air quality increments. An air quality dispersion modeling protocol was submitted on October 4, 2013. A revised protocol was submitted on November 27, 2013. A copy of the revised protocol is provided in **Appendix B**; and
- Conduct additional impact assessments that analyze impairment to visibility, soils, and vegetation as a result of the modification, as well as impacts on Class I areas (The air quality dispersion modeling analyses will be used to conduct these assessments).

SO_2 is a non-attainment pollutant. Therefore, SO_2 emissions are not subject to PSD requirements. Rather, SO_2 emissions must be addressed under NA-NSR requirements. However, as discussed further in Section 3.5, SO_2 emissions do not trigger NA-NSR requirements.

Table 3-13 PSD and NA-NSR Applicability Summary

Pollutant	Potential Project Emissions (tons/yr)	PSD Significant Emissions Rate (tons/yr)	NA-NSR Major Threshold (tons/yr)	Triggers PSD or NA-NSR?
NO_X (as NO_2)	145.3	40	PSD	Y
CO	209.4	100	PSD	Y
PM[1]	71.2	25	PSD	Y
PM_{10}[1]	70.1	15	PSD	Y
$PM_{2.5}$[1]	68.0	10	PSD	Y
VOC (as CH_4)	74.8	40	PSD	Y
Pb	0.01	0.6	PSD	N
SO_2	4.8	NA-NSR	100	N
H_2SO_4	3.1	7	PSD	N
GHG (CO_2e)	2,240,618	100,000	PSD	Y

[1] $PM_{2.5}$ and PM_{10} assumed to be equal to total PM, except for the Cooling Tower.

3.4.2 *Best Available Control Technology*

Based on projected potential emissions, BACT is required for NO_x, CO, PM, PM_{10}, $PM_{2.5}$, VOC, and GHG emissions from all Project emissions sources (combustion turbines/duct burners, Auxiliary Boiler, Emergency Generator, Fire Water Pump, and Cooling Tower). This section summarizes the BACT determinations for these pollutants.

3.4.2.1 *BACT Analysis Process*

BACT is defined in 45 CSR 14-2.12 of the WVDEP air pollution control regulations as:

> 2.12. "Best available control technology (BACT)" means an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each regulated NSR pollutant which would be emitted from any proposed major stationary source or major modification

> which the Secretary, on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any federally enforceable emissions limitations or emissions limitations enforceable by the Secretary. If the Secretary determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

BACT analyses are conducted using USEPA's "top-down" BACT approach, as described in USEPA's *Draft New Source Review Workshop Manual*[6]. The five (5) basic steps of a top-down BACT analysis are:

Step 1: Identify potential control technologies

Step 2: Eliminate technically infeasible options

Step 3: Rank remaining control technologies by control effectiveness

Step 4: Evaluate the most effective controls and document results

Step 5: Select BACT

The first step is to identify potentially "available" control options for each emission unit triggering PSD, for each pollutant under review. Available options consist of a comprehensive list of those technologies with a

---

[6] (USEPA 1990).

potentially practical application to the emission unit in question. The list includes technologies used to satisfy BACT requirements, innovative technologies, and controls applied to similar source categories.

For this analysis, the following sources were investigated to identify potentially available control technologies:

- USEPA's RACT/BACT/LAER Clearinghouse (RBLC) database;
- USEPA's New Source Review website;
- In-house experts;
- Similar permitting projects;
- State air regulatory agency contacts;
- Technical books and articles;
- The USEPA Region 4 National Combustion Turbine Spreadsheet;[7]
- State permits issued for similar sources that have not yet been entered into the RBLC; and
- Guidance documents and personal communications with state agencies.

After identifying potential technologies, the second step is to eliminate technically infeasible options from further consideration. To be considered feasible for BACT, a technology must be both available and applicable.

The third step is to rank the technologies not eliminated in Step 2 in order of descending control effectiveness for each pollutant of concern. If the highest ranked technology is proposed as BACT, it is not necessary to perform any further technical or economic evaluation. Potential adverse impacts, however, must still be identified and evaluated.

The fourth step entails an evaluation of energy, environmental, and economic impacts for determining a final level of control. The evaluation begins with the most stringent control option and continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts. The economic or "cost-

[7] Compiled by USEPA Region 4 staff, available at: http://www.epa.gov/region4/air/permits/national_ct_list.xls.

effectiveness" analysis is conducted in a manner consistent with USEPA's *OAQPS Control Cost Manual, Fifth Edition*[8] and subsequent revisions.

The fifth and final step is to select as BACT the emission limit from application of the most effective of the remaining technologies under consideration for each pollutant of concern.

3.4.2.2 BACT Analyses

For the top-down BACT evaluation, a review was performed of the RBLC database, recent permits issued from across the U.S., the USEPA Region 4 Combustion Turbine Spreadsheet, and other available literature.

3.4.2.2.1 NO_x BACT

Combustion Turbines/Duct Burners

Step 1 - Identify Potential Control Technologies
Several combustion and post-combustion technologies are available for controlling turbine NO_x emissions. Combustion controls minimize the amount of NO_x created during the combustion process, and post-combustion controls remove NO_x from the exhaust stream after the combustion has occurred.

The three (3) basic strategies for reducing NO_x the from the combustion process are:

(1) Reduction of the peak combustion temperatures;
(2) Reduction in the amount of time the air and fuel mixture is exposed to the high combustion temperature; and
(3) Reduction in the oxygen (O_2) level in the primary combustion zone.

The following discusses potential control technologies for the proposed combined-cycle combustion turbines:

[8] (USEPA 1996)

Pre-Combustion Control Technologies

The two (2) pre-combustion control technologies that reduce NO_x emissions from combustion turbines are water or steam injection, and DLN combustors.

Water or Steam Injection

The injection of water or steam into a combustion turbine's combustors quenches the flame and absorbs heat, thus reducing combustion temperatures. The reduced temperatures in turn reduce the formation of thermal NO_x. Combined with a post-combustion control technology, water or steam injection typically can achieve NO_x emissions of 25 ppmvd @15% O_2, but with the added economic, energy, and environmental expense of producing, storing, and consuming demineralized water.

DLN Combustors

Conventional combustors are diffusion-controlled, with fuel and air are injected separately. This method of combustion results in combustion "hot spots," which produce higher levels of thermal NO_x. Lean premix and catalytic technologies are two available types of DLN combustors that are alternatives to conventional diffusion-controlled combustors. DLN combustors reduce the combustion hot spots that result in thermal NO_x formation.

With lean premix DLN combustors, the mechanisms for reducing thermal NO_x through formation are:

(1) using excess air to reduce flame temperatures (i.e., lean combustion);
(2) reducing combustor residence time to limit exposure in a high-temperature environment;
(3) mixing fuel and air in an initial "pre-combustion" stage to produce a lean and uniform fuel/air mixture that is delivered to a secondary stage where combustion takes place; and/or
(4) achieving two-stage combustion using a primary fuel-rich combustion stage to limit the amount of O_2 available to combine with elemental nitrogen (N_2) and then a secondary lean burn-stage to complete combustion in a cooler environment.

Lean premix DLN combustors have only been developed for gas fuel-fired combustion turbines. The more-advanced designs are capable of achieving 70 to 90% NO_x emission reductions, with resulting NO_x concentrations typically in the range of 9 to 25 ppmvd @15% O_2.

As the name implies, catalytic combustors use a catalyst to allow the combustion reactions to occur at lower peak flame temperatures, which reduce thermal NO_x formation. Catalytic combustors use a flameless catalytic combustion module, followed by completion of combustion at lower temperatures downstream of the catalyst.

Post-Combustion Control Technologies
The three (3) available post-combustion NO_x emission controls for combustion turbines are:

(1) SCR;
(2) $SCONO_x$™ (also known as EM_x™); and
(3) Selective Non-Catalytic Reduction (SNCR).

Both SCR and EMx™ use catalyst beds to control NO_x emissions. Combined with DLN combustors or water/steam injection, these technologies are capable of achieving NO_x emissions levels of 2 ppmvd @15% O_2 for combined-cycle combustion turbines. EM_x ™uses a hydrogen regeneration gas to convert the NO_x to elemental nitrogen (N_2) and water. Like SCR, SNCR also uses ammonia to control NO_x emissions, but without a catalyst.

Selective Catalytic Reduction
SCR is a post-combustion control technology designed to control NO_x emissions from combustion turbines. SCR systems for combined-cycle combustion turbines are typically placed inside the HRSGs, and consist of a catalyst bed with an ammonia injection grid located upstream of the catalyst. The ammonia, in this case aqueous ammonia with a concentration of less than 20% by weight, is vaporized and injected directly into the exhaust stream, where it reacts with NO_x and O_2 in the presence of the catalyst to form N_2 and water vapor.

These reactions normally occur at relatively high temperatures (e.g. 1,600 °F to 2,100 °F). However, the placement of a catalyst in the exhaust stream lowers the activation energy of the reaction, which allows the reaction to take place at lower temperatures (typically 650 °F to 850 °F).

The catalyst consists of a support system with a catalyst coating typically of titanium dioxide (TiO_2), vanadium pentoxide (V_2O_5), or zeolite. Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as "ammonia slip."

EM_x™

EM $_x$™ uses a single catalyst to remove NO_x emissions from combustion turbine exhaust gas by oxidizing nitric oxide (NO) to nitrogen dioxide (NO_2) and then absorbing the NO_2 onto a catalytic surface using a potassium carbonate (K_2CO_3) absorber coating. The potassium carbonate coating reacts with NO_2 to form potassium nitrites and nitrates, which are deposited onto the catalyst surface. The optimal temperature window for operation of the EMx™ catalyst is from 300 ˚F to 700 ˚F. EM $_x$™ does not use ammonia. Therefore, there are no ammonia emissions from this technology.

When all of the potassium carbonate absorber coating has been converted to N_2 compounds, NO_x can no longer be absorbed and the catalyst must be regenerated. Regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of O_2. Hydrogen in the gas reacts with the nitrites and nitrates to form water and N_2. Carbon dioxide (CO_2) in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst. The regeneration gas is produced by reacting natural gas with a carrier gas (such as steam) over a steam-reforming catalyst.

Selective Non-Catalytic Reduction

Like SCR, Selective Non-Catalytic Reduction (SNCR) involves injection of ammonia or urea $CO(NH_2)_2$ with proprietary conditioners into the exhaust gas stream without a catalyst. SNCR technology requires temperatures in the range of 1,600 to 2,100 °F. SNCR is not available for combustion turbines, because combustion turbine exhaust temperatures are typically 1,000 °F, significantly below the 1,600 °F minimum temperature required for effective SNCR performance.

Step 2 - Eliminate Technically Infeasible Options

Pre-Combustion Control Technologies

Water or Steam Injection

The use of water or steam injection is considered a feasible technology for reducing NO_x emissions to about 25 ppmvd @ 15% O_2 when firing gaseous fuel under most ambient conditions. Combined with SCR, water or steam injection can achieve NO_x levels of 2 ppmvd @ 15% O_2, but at slightly lower thermal efficiencies compared to DLN combustors.

DLN Combustors

DLN combustors are a feasible technology for reducing NO_x emissions from the proposed combustion turbines. DLN combustors are capable of achieving NO_x emission of 9 to 25 ppmvd @ 15% O_2 over a relatively wide operating range (e.g. 50% to 100% load). When combined with SCR, DLN combustors can achieve NO_x emissions of 2 ppmvd @ 15% O_2.

A catalytic combustion technology known as XONON™ has been demonstrated successfully in a 1.5 MW simple-cycle combustion turbine pilot facility, and is commercially available for combustion turbines rated at up to 10 MW. However, catalytic combustors such as XONON™ have not been demonstrated on industrial F Class combustion turbines such as those proposed by Moundsville Power. Therefore, the XONON™ catalytic combustion technology is not considered feasible for the proposed combustion turbines.

Post-Combustion Control Technologies

Selective Catalytic Reduction

SCR, with an ammonia slip of less than 5 ppmvd @ 15% O_2, is considered a feasible technology for reducing combustion turbine NO_x emissions to 2 ppmvd @ 15% O_2 when firing gaseous fuel. SCR has been successfully installed and used on numerous simple-cycle and combined-cycle combustion turbines.

EMx™

The demonstrated application for EMx™ is currently limited to combined-cycle combustion turbines under approximately 50 MW in size. The combustion turbines proposed for this Project are nominal 197 MW units. Therefore, EMx™ technology is not considered feasible for achieving the proposed NO_x limit of 2.0 ppmvd @ 15% O_2.

Selective Non-Catalytic Reduction

SNCR requires a temperature window that is higher than the exhaust temperatures from gaseous fuel-fired combustion turbines. Therefore, SNCR is not considered technically feasible for the proposed combustion turbines.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Based on the preceding discussions, the use of water/steam injection, DLN combustors, and SCR are the technically feasible NO_x control technologies available for the proposed combustion turbines. DLN combustors were selected because they can achieve lower NO_x emission rates from the combustion turbines over either water or steam injection, without the economic, energy, and environmental disbenefit of producing, storing, and consuming demineralized water.

Furthermore, DLN combustors result in slight improvements in thermal efficiency over water/steam injection NO_x control alternatives. When used in combination with SCR, these technologies can control NO_x emissions from the combustion turbines to 2.0 ppmvd @ 15% O_2 with and without duct firing.

There are potential environmental and energy impacts associated with the use of SCR. First, SCRs require replacement of the catalyst beds after several years. The waste catalyst must be disposed of in accordance with state and federal regulations regarding normal waste disposal. Because of the precious metal content of the catalysts, they may also be recycled to recover the precious metals. Sulfur compounds in the exhaust gas may react with the ammonia reagent, forming ammonia salts, which may increase PM, PM_{10}, and $PM_{2.5}$ emissions. SCRs also have energy impacts. Due to their location downstream of the combustion turbine exhaust, SCR catalysts increase the back pressure on the combustion turbines, which results in slightly decreased power output. This slightly decreased output leads to slightly increased pollutant emissions on a mass per unit power output basis.

Although there are potential environmental and energy impacts associated with the use of SCR, these impacts are not considered significant enough to preclude the use of SCR for NO_x emission control.

Available permits and BACT determinations were reviewed to identify NO_x emission rates that have been achieved in practice for other comparable gaseous fuel-fired combustion turbine projects. The majority of the projects had permitted NO_x emission rates equal to or greater than 2.0 ppmvd @ 15% O_2.

Only one (1) facility, for an IDC Bellingham combined-cycle plant proposed in Massachusetts, had a NO_x emission limit below the 2.0 ppmvd @ 15% O_2 level proposed as BACT by Moundsville Power. The IDC Bellingham facility was permitted with a not-to-exceed limit of 2.0 ppmvd @ 15% O_2, but the permit also required the unit to maintain emissions below 1.5 ppmvd @ 15% O_2 during normal operations. However, the IDC Bellingham facility was never built. Therefore, these emission limits were not achieved in practice. As a result, Moundsville Power's proposed emission rate of 2.0 ppmvd @ 15% O_2 with and without duct firing is the lowest NO_x emission rate achieved in practice for similar sources and, therefore, represents BACT for NO_x emissions.

Step 4 - Evaluate Most-Effective Controls and Document Results
Based on the information presented in this BACT analysis, the proposed NO_x emission rate of 2.0 ppmvd @ 15% O_2 with and without duct firing is the lowest NO_x emission rate achieved in practice at similar sources. Therefore, an assessment of the economic and environmental impacts is not necessary.

Step 5 – Select BACT
The proposed BACT for NO_x emissions from the proposed combustion turbines is the use of DLN combustors and SCR, along with good combustion practices, to control NO_x emissions to 2.0 ppmvd @ 15% O_2 with and without duct firing.

Auxiliary Boiler

There is currently no technically feasible add-on control technology to reduce NO_x emissions from gaseous fuel-fired Auxiliary Boilers of the size proposed for the Moundsville Power Project. NO_x is minimized in these units through good combustion practices, as well as flue gas recirculation (FGR) and ultra low-NO_x burners (ULNB).

FGR provides for the recycling of fuel gas into the air-fuel mixture at the burner to help cool the burner flame. ULNB may incorporate a variety of techniques including FGR, steam injection, or a combination of techniques. ULNB combines the benefits of FGR and LNB control technologies. ULNB 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 NO_x generated. Although these efficient combustion techniques are targeted to reduce NO_x emissions, they have a collateral impact of minimizing CO formation.

Moundsville Power proposes a NO_x emission level of 0.02 lb/MMBtu as BACT for the Auxiliary Boiler. Upon conducting a review of available permits and determinations for comparable boilers, Moundsville Power identified several recent permits for comparable boilers. One boiler, at the Cricket Valley Energy Center, a proposed combined-cycle power plant located in the Town of Dover, Dutchess County, New York, includes a 60

MMBtu/hr auxiliary boiler permitted NO_x emissions of 0.011 lb/MMBtu. PacifiCorp's Lake Side Power Plant in Utah County, Utah, includes two (2) 61.2 MMBtu/hr natural gas-fired auxiliary boilers that have permitted NO_x emission limits of 0.017 lb/MMBtu on a 3-hour average basis.

Both of these sites have boilers with NO_x emission limits below the 0.02 lb/MMBtu level proposed by Moundsville Power. However, the Cricket Valley facility has not been constructed. PacifiCorp's Lake Side Power Plant was commissioned in 2007, and presumably the auxiliary boilers are able to comply with their permitted NO_x emission limits of 0.017 lb/MMBtu on a 3-hour average basis.

However, given the expected limited hours of operation for the proposed Auxiliary Boiler (<2,000 hr/yr), the decrease in NO_x emissions if the boiler were required to achieve a NO_x emission level of 0.017 b/MMBtu would be no more than 0.3 tons/yr.

Therefore, Moundsville Power proposes BACT for the Auxiliary Boiler at a NO_x emission level of 0.02 lb/MMBtu. This level will be achieved using good combustion practices, along with ULNB and FGR.

Emergency Generator

Moundsville Power proposes BACT for NO_X and VOC for the 1,500-kW Emergency Generator as the applicable emission rates specified in 40 CFR 60, Subpart IIII. The Subpart IIII emission standard is 4.8 g/hp-hr for NO_X plus Non-Methane Hydrocarbons (NMHC). The level proposed for the Emergency Generator (2.8 g/hp-hr) is the same or lower than those listed in the RBLC for combined NO_x plus NMHC. Although there are several determinations that list NO_x emission rates below 4.8 g/hp-hr, when combined NO_x plus NMHC (i.e. VOC) is evaluated, none of the engines listed have limits more stringent than 4.8 g/hp-hr.

Separately, one permit, Cricket Valley has a proposed NO_x limit of 2.13 g/hp-hr, along with a VOC limit of 0.1 g/hp-hr. However, this facility has not been constructed. Therefore, the limit has not been demonstrated in practice. Therefore, Moundsville Power did not identify any engines of similar size used for emergency purposes that currently demonstrate in practice emission rates below that proposed for the Emergency Generator.

Given the intended use of the Emergency Generator only for emergency purposes, with its operations limited to emergency events and no more than 100 hr/yr for maintenance and readiness testing, the environmental benefit associated with establishing emission limits below the Subpart IIII limit of 4.8 g/hp-hr is small. However, as BACT for the Emergency Generator, Moundsville Power proposes an emission limit of 2.8 g/hp-hr for NO_x plus NMHC along with the use of ULSD fuel and good combustion practices, and limiting operations to emergency events and no more than 100 hr/yr for maintenance and readiness testing.

Fire Water Pump

Moundsville Power proposes BACT for NO_x and VOC for the 251-hp Fire Water Pump as the applicable emission rates specified in 40 CFR 60, Subpart IIII. The Subpart III emission standard is 3.0 g/hp-hr for NO_x plus NMHC. The Fire Water Pump will use ULSD fuel to ensure operation even during periods when natural gas is unavailable.

Review of the RBLC determinations and recent permits for similar equipment indicates emission limits equal to 3.0 g/hp-hr, or at less stringent levels (e.g. Live Oaks, Wolverine Power Supply Cooperative, Avenal, and Pioneer Valley). As with the Emergency Generator, although there are several determinations that list NO_x or VOC emission levels below 3.0 g/hp-hr, when combined NO_x plus NMHC is evaluated, no listings have limits more stringent than 3.0 g/hp-hr.

Although Cricket Valley lists a NO_x emission level of 2.6 g/hp-hr, it also lists a VOC emission level of 0.97 g/hp-hr. Therefore, the comparable NO_x plus NMHC value for Cricket Valley is 3.57 g/hp-hr (2.6+0.97), compared to Moundsville Power's proposed limit of 3.0 g/hp-hr.

Based on the review of existing permit limits for engines of similar size and duty as the Fire Water Pump, Moundsville Power concludes that BACT for NO_x and VOC is the use of ULSD and good combustion practices, along with limiting use to emergency events and no more than 100 hr/yr for maintenance and readiness testing. The proposed BACT is a combined NO_x plus NMHC emission rate of 3.0 g/hp-hr.

The proposed NO_x BACT for all sources is summarized in Table 3-14.

Table 3-14 Proposed NO_x BACT

Emission Source	Proposed NO_x BACT
Combustion Turbines/Duct Burners	2 ppmvd @ 15% O_2 (with and without duct firing) Use of SCR, dry low-NO_X combustor design, and efficient combustion (good combustion practices) .
Auxiliary Boiler	0.02 lb/MMBtu Use of good combustion practices, ULNB, and FGR.
Emergency Generator	2.8 g/hp-hr (NMHC+NO_X) Use of ULSD fuel and good combustion practices; operation limited to emergency use and no more than 100 hr/yr for maintenance and readiness testing.
Fire Water Pump	3.0 g/hp-hr (NMHC+NO_X) Use of ULSD fuel and good combustion practices; operation limited to emergency use and no more than 100 hr/yr for maintenance and readiness testing.

3.4.2.2.2 CO BACT

Combustion Turbines/Duct Burners

Step 1 - Identify Potential Control Technologies
CO is formed during the combustion process as a result of incomplete combustion of the carbon present in the fuel. Effective combustor design and post-combustion control using an Oxidation Catalyst are the potential technologies for controlling CO emissions from combustion turbines. As noted above in the NO_x BACT analysis, the EMx™ and XONON™ technologies were determined not to be feasible for the proposed combustion turbines, so they have not been considered further here.

Combustion Controls
CO formation is minimized by designing the combustion system to allow complete mixing of the combustion air and fuel and maximize the oxidization of fuel carbon to CO_2. Higher combustion temperatures tend to reduce CO formation, but increase NO_x formation. Water/steam injection or DLN combustors tend to lower combustion temperatures in order to reduce NO_x formation, potentially increasing CO formation.

However, using good combustor design and following best operating practices minimizes CO formation while reducing combustion temperatures and NO_x emissions.

Oxidation Catalysts
Oxidation Catalysts typically use precious metal catalyst beds. Like SCR systems for combined-cycle combustion turbines, Oxidation Catalysts are typically located within the HRSG where the temperature is in the range of 700 °F to 1,100 °F. The catalyst enhances oxidation of CO to CO_2, without the addition of any chemical reagents, because there is sufficient O_2 in the exhaust gas stream for the oxidation reactions to proceed in the presence of the catalyst alone. Catalyst volume is dependent upon the exhaust flow, temperature, and the desired removal efficiency. The catalyst material is subject to loss of activity over time due to physical deterioration or chemical deactivation. Oxidation Catalyst vendors typically guarantee catalyst life for three (3) years.

Both efficient combustion and add-on controls, such as Oxidation Catalysts, can be used alone or in combination to achieve CO emission reductions. Oxidation Catalysts have been successfully installed and used on numerous simple-cycle and combined-cycle combustion turbines.

Step 2 - Eliminate Technically Infeasible Options
Using good combustor design, following best operating practices, and using Oxidation Catalyst are technically feasible options for controlling CO emissions from the proposed combustion turbines.

There are potential environmental and energy impacts associated with the use of Oxidation Catalysts. Oxidation Catalysts require replacement of the catalyst beds after several years. The waste catalyst must be disposed of in accordance with state and federal regulations regarding normal waste disposal. Because of the precious metal content of the catalyst, they may also be recycled to recover the precious metals. Some of the SO_2 in the exhaust gas will oxidize to sulfur trioxide (SO_3). The higher the operating temperature, the higher the potential for oxidation of SO_2 to SO_3 oxidation. The SO_3 may react with moisture in the flue gas to form H_2SO_4. The increase in H_2SO_4 emission may increase PM_{10} and $PM_{2.5}$ emissions. The oxidation of CO results in increased CO_2 emissions, and CO_2 is a GHG. Oxidation Catalysts also have energy impacts. Due to their location downstream of the combustion turbine exhaust, Oxidation Catalysts increase the backpressure on the combustion turbines, which results in slightly decreased power output. This slightly decreased output leads to increased pollutant emissions on a mass per unit power output basis.

Although there are potential environmental and energy impacts associated with the use of Oxidation Catalysts, these impacts are not considered significant enough to preclude their use for CO emission control.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness
Based on the preceding discussion, good combustion practices and Oxidation Catalysts are both available and technically feasible technologies to control CO emissions from combustion turbines. Together, DLN combustors and good combustion practices, although primarily used to minimize NO_x emissions, have been effective in minimizing CO emissions from combustion turbines, including those with duct firing. These are the only practical efficient combustion alternatives currently available and used on combined-cycle combustion turbines/duct burners. Moundsville Power proposes to control CO emissions these techniques to meet a CO emission limit of 2.0 ppmvd @ 15% O_2 with and without duct firing.

Available permits and BACT determinations were reviewed to identify CO emission rates that have been achieved in practice for other comparable gaseous fuel-fired combustion turbine projects. The majority of the projects had permitted CO emission rates equal to or greater than 2.0 ppmvd @ 15% O_2. However, the following projects were identified that have CO emission rates lower than 2.0 ppmvd @ 15% O_2.

(1) Competitive Power Ventures (CPV) Warren;
(2) Kleen Energy Systems; and
(3) Astoria Energy LLC

These projects are discussed in more detail below.

CPV Warren
CPV Warren is a combined-cycle power plant proposed to be located in Front Royal, Warren County, Virginia. Originally developed by Competitive Power Ventures (CPV), the project was sold to Virginia Electric Power and Power Company (Dominion Virginia Power) in 2008.

A final PSD permit for a nominal 1,300 MW combined-cycle plant was issued by the Virginia Department of Environmental Quality (VDEQ) on December 21, 2010. This final PSD permit includes CO emission limits of 1.5 and 2.4 ppmvd @ 15% O_2, on a 1-hour averaging basis, for operating conditions without and with duct firing, respectively. Based on publically available information, Dominion expects commercial operation of the Warren facility to occur in late 2014 or early 2015. The plant is expected to consist of three (3) Mitsubishi Model M501GAC combustion turbines. Since the plant has not begun operation, these BACT limits for VOC have not yet been achieved in practice.

Kleen Energy Systems
The Kleen Energy Systems combined-cycle facility in Middletown, Connecticut began commercial operation in July 2011. The combustion turbines used by Kleen Energy Systems are Siemens SGT6-5000F. The permitted CO emission limits are 1.5 and 0.9 ppmvd @ 15% O_2 for operation with and without duct firing, respectively. Initial stack testing apparently demonstrated compliance with these CO emission limits. However, given the lack of long-term operation and compliance with these emission limits, these CO emission levels are not considered "achieved in practice" at this time.

Astoria Energy LLC
The Astoria Energy, LLC facility, located in the Astoria section of Queens, New York City is permitted for CO emissions of 1.5 ppmvd @ 15% O_2, with or without duct firing. The Astoria Energy plant began operation in 2011 and uses GE Frame 7FA combustion turbines. However, because the Astoria Energy plant was located in a CO non-attainment area, the 1.5 ppmvd @ 15% O_2 was a LAER, rather than BACT, limit.

Step 4 - Evaluate Most-Effective Controls and Document Results
The proposed CO emission rate of 2.0 ppmvd @ 15% O_2 with and without duct firing is the lowest CO emission rate achieved or verified with long-term compliance records for other similar facilities. Since Moundsville Power is proposing to use combustion turbines with DLN combustors and Oxidation Catalysts to reduce CO and VOC emissions (the top control alternative), an assessment of the economic and environmental impacts is not necessary.

Step 5 - Select BACT
BACT for CO emissions from the proposed combustion turbines is good combustion design and the use of Oxidation Catalysts to control CO emissions to 2.0 ppmvd @ 15% O_2 with and without duct firing.

Auxiliary Boiler

There is currently no technically feasible add-on control technology to reduce CO emissions from gaseous fuel-fired Auxiliary Boilers of the size proposed for the Moundsville Power Project. CO is minimized in these units through good combustion practices. For boilers, good combustion can include low-NO_x burners (LNB), FGR, and ULNB that each support effective combustion that minimizes CO formation.

FGR provides for the recycling of fuel gas into the air-fuel mixture at the burner to help cool the burner flame. ULNB may incorporate a variety of techniques including FGR, steam injection, or a combination of techniques. These burners combine the benefits of FGR and LNB control technologies. ULNB 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 NO_x generated. Although these efficient combustion techniques are targeted to reduce NO_x emissions, they have a collateral impact of minimizing CO formation.

There have been several auxiliary boilers permitted with CO limits between 0.02 and 0.04 lb/MMBtu. Moundsville Power proposed to equip its Auxiliary Boiler with both ULNB and FGR. The proposed CO emission level for the Auxiliary Boiler is 0.04 lb/MMBtu. This emission level is equivalent to those found in the RBLC for recently permitted units of similar design. Therefore, BACT is the use of good combustion practices to achieve an emissions limit of 0.04 lb/MMBtu for the Auxiliary Boiler.

Emergency Generator and Fire Water Pump

Moundsville Power proposes that BACT for the Emergency Generator and Fire Water Pump is the CO emission rate of 2.6 g/hp-hr specified in 40 CFR 60, Subpart IIII. This emergency equipment will be operated on ULSD fuel, with a sulfur content no greater than 0.0015% by weight.

Generally, for engines of these sizes proposed for the Project, good combustion practices are used to limit CO emissions. Review of recent permits and the RBLC for similar equipment indicates that good combustion practices are considered BACT. However, some of the BACT determinations resulted in lower emissions levels using good combustion practices.

The permits for Cricket Valley and Avenal list CO levels of 0.53 g/hp-hr and 0.447 g/hp-hr, respectively, for units similar to the proposed Fire Water Pump. Mankato Energy Center in Minnesota lists four (4) 290-hp fire water pumps with 0.25 g/hp-hr CO emission rates, and the LA County Probation Facility in California lists a 240-hp fire water pump with a CO emission rate of 0.44 g/hp-hr.

Based on the limited hours of operation for the Fire Water Pump for only emergency purposes (<< 500 hr/yr), the decrease in CO emissions should the Fire Water Pump be required to comply with a limit as low as 0.25 g/hp-hr would be no more than 0.33 tons/yr. Moundsville Power believes that there is no appreciable environmental benefit in going below the NSPS Subpart IIII limits.

For the Emergency Generator, recent permits and RBLC data reflect CO emission levels that are approximately equivalent to that proposed by Moundsville Power, with two (2) exceptions: Maidsville in West Virginia with a 1,801-hp emergency engine with a 2.23 g/hp-hr CO emission rate, and the Salt Creek Gas Plant in Texas with a 2,000-hp emergency engine and CO emission rate of 2.04 g/hp-hr. However, given the limited hours of use for emergency purposes (<< 500 hr/yr) and minimal emissions reduction (0.62 tons/yr) should the Emergency Generator be required to comply with a limit as low as 2.04 g/hp-hr, Moundsville Power believes that there is no appreciable environmental benefit to going below the NSPS Subpart IIII limit.

Based on these findings, CO BACT for the Emergency Generator and Fire Water Pump is good combustion practices and the use of ULSD fuel, in combination with limited annual operating hours, and achieving a CO emission level of 2.6 g/hp-hr.

The proposed CO BACT for all sources is summarized in Table 3-15.

Table 3-15 Proposed CO BACT

Emission Source	Proposed CO BACT
Combustion Turbines/Duct Burners	2 ppmvd @ 15% O_2 (with or without duct firing) Use of Oxidation Catalysts and efficient combustion.
Auxiliary Boiler	0.04 lb/MMBtu Good combustion practices.
Emergency Generator	2.6 g/hp-hr Use of ULSD fuel and good combustion practices.
Fire Water Pump	2.6 g/hp-hr Use of ULSD fuel and good combustion practices.

3.4.2.2.3 PM, PM_{10}, and $PM_{2.5}$ BACT

Particulate matter emissions result from each combustion source associated with the Project, as well as the mechanical draft Cooling Tower. The following summarizes the BACT evaluation conducted for each significant piece of equipment with respect to PM, PM_{10}, and $PM_{2.5}$ emissions.

Combustion Turbines/Duct Burners

PM from gaseous fuel combustion has been estimated to be less than 1 micron in equivalent aerodynamic diameter, has filterable and condensable fractions, and usually consists of hydrocarbons of larger molecular weight that are not fully combusted (USEPA, 2006). Because the particulate matter typically is less than 2.5 microns in diameter, this BACT discussion assumes the control technologies for PM, PM_{10}, and $PM_{2.5}$ are the same.

Step 1 – Identify Potential Control Technologies

Pre-Combustion Control Technologies

The major sources of PM, PM_{10}, and $PM_{2.5}$ emissions from gaseous fuel-fired combustion turbines equipped with SCR for post-combustion control of NO_x emissions are:

(1) the conversion of fuel sulfur to sulfates and ammonium sulfates;
(2) unburned hydrocarbons that can lead to the formation of PM in the exhaust stack; and
(3) PM in the ambient air entering the combustion turbines through their inlet air filtration systems, and the aqueous ammonia dilution air.

The use of clean-burning, low-sulfur fuels such as pipeline-quality natural gas or a blend of pipeline-quality natural gas and up to 25% ethane will result in minimal formation of PM, PM_{10}, and $PM_{2.5}$ during combustion. Best combustion practices will ensure proper air/fuel mixing ratios to achieve complete combustion, minimizing emissions of unburned hydrocarbons that can lead to the formation of PM emissions. In addition to good combustion practices, the use of high-efficiency filtration on the inlet air and SCR dilution air systems will minimize the entrainment of PM into the combustion turbine exhaust streams.

Post-Combustion Control Technologies

There are several post-combustion PM control systems potentially feasible to reduce PM and PM_{10} emissions from combustion turbines/duct burners including:

(1) Cyclones/centrifugal collectors;
(2) Fabric filters/baghouses;
(3) Electrostatic precipitators (ESPs); and
(4) Scrubbers.

Cyclones/centrifugal collectors are generally used in industrial applications to control large diameter particles (>10 microns). Cyclones impart a centrifugal force on the gas stream, which directs entrained particles outward. Upon contact with an outer wall, the particles slide down the cyclone wall, and are collected at the bottom of the unit. The design of a centrifugal collector provides for a means of allowing the clean gas to exit through the top of the device. Cyclones are inefficient at removing small particles.

Fabric filters/baghouses use a filter material to remove particles from a gas stream. The exhaust gas stream flows through filters/bags onto which particles are collected. Baghouses are typically employed for industrial applications to provide particulate emission control at relatively high efficiencies.

ESPs are used on a wide variety of industrial sources, including certain boilers. ESPs use electrical forces to move particles out of a flowing gas stream onto collector plates. The particles are given an electric charge by forcing them to pass through a region of gaseous ion flow called a "corona". An electrical field generated by electrodes at the center of the gas stream forces the charged particles to ESP's collecting plates.

Removal of the particles from the collecting plates is required to maintain sufficient surface area to clean the flowing gas stream. Removal must be performed in a manner to minimize re-entrainment of the collected particles. The particles are typically removed from the plates by "rapping" or knocking them loose, and collecting the fallen particles in a hopper below the plates.

Scrubber technology may also be employed to control PM in certain industrial applications. With wet scrubbers, flue gas passes through a water (or other solvent) stream, whereby particles in the gas stream are removed through inertial impaction and/or condensation of liquid droplets on the particles in the gas stream.

Step 2 - Eliminate Technically Infeasible Options
The pre-combustion control technologies identified above (i.e. clean-burning, low-sulfur fuels, good combustion practices, high-efficiency filtration of the combustion turbine inlet and SCR dilution air systems) are available and technically feasible for reducing PM emissions from the combustion turbine exhaust streams.

Each of the post-combustion control technologies described above (i.e. cyclones, baghouses, ESPs, scrubbers) are generally available. However, none of these technologies is considered practical or technically feasible for installation on gaseous fuel-fired combustion turbines.

The particles emitted from gaseous fuel-fired are typically less than 1 micron in diameter. Cyclones are not effective on particles with diameters of 10 microns or less. Therefore, a cyclone/centrifugal collection device is not a technically feasible alternative.

Baghouses, ESPs, and scrubbers have never been applied to commercial combustion turbines burning gaseous fuels. Baghouses, ESPs, and scrubbers are typically used on solid or liquid-fuel fired sources with high PM emission concentrations, and are not used in gaseous fuel-fired applications, which have inherently low PM emission concentrations. None of these control technologies is appropriate for use on gaseous fuel-fired combustion turbines because of their very low PM emissions levels, and the small aerodynamic diameter of PM from gaseous fuel combustion. Review of the RBLC, as well as USEPA and state permit databases, indicates that post-combustion controls have not been required as BACT for gaseous fuel-fired fired combined-cycle combustion turbines. Therefore, the use of baghouses, ESPs, and scrubbers is not considered technically feasible.

Moundsville Power proposes that PM, PM_{10}, and $PM_{2.5}$ BACT for the combustion turbines/duct burners is the employment of good combustion practices, along with the use of clean fuels such as pipeline-quality natural gas or a blend of pipeline-quality natural gas and up to 25% ethane, and inlet air filtration to achieve an emission limit of 7.6 lb/hr for PM, PM_{10}, and $PM_{2.5}$, with or without duct firing.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness
The use of clean-burning fuels, good combustion practices, and inlet air filtration are the technically feasible technologies to control PM, PM_{10}, and $PM_{2.5}$ emissions to no more than 7.6 lb/hr with or without duct firing. This is equivalent to an emission rate of 0.005 lb/MMBtu or less.

Review of recent permits and the RBLC for combustion turbines/duct burners indicates that the proposed PM, PM_{10}, and $PM_{2.5}$ emission rates are lower than those specified in permits for similar plants, such as the International Station Power Plant, Mankato Energy Center, Caithness Bellport Energy Center, and Cricket Valley Energy Project. These projects tend to have PM, PM_{10}, and $PM_{2.5}$ emission rates on the order of 0.012 lb/MMBtu.

Step 4 - Evaluate Most Effective Controls and Document Results
Based on the information presented in this BACT analysis, using proposed good combustion practice, pipeline quality natural gas or a blend of pipeline-quality natural gas and up to 25% ethane, and inlet air filtration to control PM, PM_{10}, and $PM_{2.5}$ emissions to no more than 7.6 lb/hr with or without duct firing. This is consistent with BACT at other similar sources. Therefore, an assessment of the economic and environmental impacts is not necessary.

Step 5 – Select BACT
The proposed BACT for PM, PM_{10}, and $PM_{2.5}$ emissions from the combustion turbines is the use of clean-burning fuels, good combustion practices, and inlet air filtration to control PM, PM_{10}, and $PM_{2.5}$ emissions to no more than 7.6 lb/hr with or without duct firing.

<u>*Auxiliary Boiler*</u>

The technologies potentially available to control PM, PM_{10}, and $PM_{2.5}$ emissions from small boilers ($\leq$100 MMBtu/hr) are the same as those described above for combustion turbines/duct burners:

(1) Cyclones/centrifugal collectors;
(2) Fabric filters/baghouses;
(3) ESPs; and
(4) Scrubbers.

However, a similar rationale eliminates the use of cyclones due to their inability to control particles smaller than 10 microns in diameter. In addition, the other add-on particulate control techniques have not been employed to remove PM from relatively small, natural gas-fired combustion units, such as the proposed Auxiliary Boiler.

A review of the RBLC, as well as USEPA and state permit databases indicates that there are no small boilers employing post-combustion control equipment to reduce PM, PM_{10}, and $PM_{2.5}$ to achieve BACT. The determinations for small boilers identify the selection of clean fuels (i.e., low-sulfur, low-ash content) and good combustion practices as BACT for PM, PM_{10}, and $PM_{2.5}$ emissions.

The proposed Auxiliary Boiler is a unit capable of firing pipeline quality natural gas or a blend of pipeline-quality natural gas and up to 25% ethane that will employ good combustion practices to minimize PM, PM_{10}, and $PM_{2.5}$ to achieve BACT emission levels.

Although BACT is a technology based standard, Moundsville Power evaluated the consistency of other relevant permits to identify the level of emissions determined as BACT. The proposed PM emission rate of 0.005 lb/MMBtu for the Auxiliary Boiler is comparable to similar units noted in the RBLC and in recently issued permits. There is one facility, the Wolverine Power Supply Cooperative, LLC with a proposed PM BACT limit of 0.11 lb/hr (0.00152 lb/MMBtu) for an Auxiliary Boiler firing diesel fuel.

The RBLC and other permits reviewed for equipment that is installed and operating identify the use of natural gas and good combustion practices as BACT for PM, PM_{10}, and $PM_{2.5}$ for small boilers ($\leq$100 MMBtu/hr). Accordingly, the proposed BACT for PM, PM_{10}, and $PM_{2.5}$ is an emission limit of 0.005 lb/MMBtu achieved using pipeline-quality natural gas or a blend of pipeline-quality natural gas and up to 25% ethane and good combustion practices.

Emergency Generator and Fire Water Pump

Moundsville Power proposes that BACT for PM, PM_{10}, and $PM_{2.5}$ for the Emergency Generator and the Fire Water Pump is an emission limit of 0.09 g/hp-hr and 0.15 g/hp-hr , respectively. The emission standard for CI RICE specified in 40 CFR 60, Subpart IIII is 0.15 g/hp-hr. Based on the definition of BACT, the facility must at a minimum meet or improve upon the limit established in the NSPS. The facility proposes to operate the emergency equipment using ULSD as fuel.

A literature review to establish a list of potential control technologies available for emergency engines concludes that there are currently no facilities employing post-combustion controls on RICE engines of these sizes to achieve BACT for PM, PM_{10}, and $PM_{2.5}$. The use of good combustion practices and clean fuels, such as ULSD, are relied upon to achieve BACT for PM, PM_{10}, and $PM_{2.5}$.

For the Emergency Generator, a review of recent permits and the RBLC includes determinations with emission levels as low as 0.03 g/hp-hr for similar sized engines, with BACT described as good combustion practices (e.g. International Station). As evidenced by the wide variety of emission levels listed in the RBLC, different engine vendors and models specify a wide range of PM, PM_{10}, and $PM_{2.5}$ emissions. Given the expected limited hours of operation for the Emergency Generator (<<500 hr/yr), the decrease in PM emissions if the engine were required to achieve an emission level of 0.03 g/hp-hr for PM, PM_{10}, and $PM_{2.5}$ would be no more than 0.067 tons/yr.

For the Fire Water Pump, a review of recent permits and the RBLC for similar equipment indicates values in line with a 0.15 g/hp-hr limit or higher (i.e., Live Oaks, Wolverine and Pioneer Valley). However, there are instances of permit limits below the NSPS Subpart IIII standard of 0.15 g/hp-hr. For example, Cricket Valley lists a PM limit of 0.0875 g/hp-hr, and the RBLC lists a limit as low as 0.07 g/hp-hr (i.e., Mankato Energy

Center) for a similar sized RICE. However, based on the expected limited hours of operation for the Fire Water Pump (<< 500 hr/yr), the net potential decrease in PM emissions if the engine were required to comply with a limit as low as 0.07 g/hp-hr would be only 0.011 tons/yr.

Given the limited operating role of the equipment to support the facility during emergency periods and for periodic maintenance and readiness testing, and the small emission reductions associated with achieving the lower PM, PM_{10}, and $PM_{2.5}$ emission rates listed in the RBLC; there is no appreciable environmental benefit associated with achieving PM, PM_{10}, and $PM_{2.5}$ emission levels below the proposed values of 0.09 g/hp-hr and 0.15 g/hp-hr for the Emergency Generator and the Fire Water Pump, respectively. Therefore, BACT for PM, PM_{10}, and $PM_{2.5}$ for the Emergency Generator and Fire Water Pump is the exclusive use of ULSD and good combustion practices to achieve an emission limit of 0.09 g/hp-hr and 0.15 g/hp-hr, respectively.

Cooling Tower

Actual drift loss rates from wet cooling systems, including those proposed for this Project, are affected by a variety of factors, including the type and design of the cooling system, capacity, velocity of air flow, density of the air in the Cooling Tower, and the TDS concentration in the circulating water. Commercially available techniques used to limit PM, PM_{10}, and $PM_{2.5}$ drift from wet Cooling Towers, with the most efficient options presented first, are discussed below.

Drift eliminators are incorporated into Cooling Tower systems to remove as many water droplets from the air leaving the system as possible. Types of drift eliminators include herringbone (blade-type), wave form, and cellular (or honeycomb) designs; system materials of construction may include ceramics, fiber reinforced cement, fiberglass, metal, plastic, or wood. Designs may include other features, such as corrugations and water removal channels, to enhance the drift removal further. Drift eliminators are considered standard in the power sector. The drift rate as a percentage of circulating water flow rates varies with the specific project, and typically ranges from 0.01 to 0.0005% of circulating water flow rates. Higher efficiency drift eliminators can achieve drift loss rates of 0.0005% of the circulating water flow rates.

Another approach to reducing PM emissions is by limiting TDS concentrations in the circulating water. In general, water droplets released as drift from wet Cooling Towers contain TDS concentrations equivalent to the solids concentrations in the circulating water. Reducing the TDS concentrations in the water, including by managing the cycles of concentrations, minimizes drift. In any particular project, TDS concentrations are defined primarily by the water source and the concentration cycles.

Maintaining low air velocities is an additional technique to reduce PM emissions from Cooling Towers. Particulate entrainment rates are influenced by air velocities in the system, so maintaining low (or optimum design) air velocities can reduce the drift.

Moundsville Power proposes to install a Cooling Tower equipped with high-efficiency drift eliminators that will achieve a minimum of a 0.0005% drift, which is the most effective technique to reduce PM, PM_{10}, and $PM_{2.5}$ emissions based on a review of RBLC determinations, recent permits, and evaluation of available literature.

A review of the RBLC data and several other recently permitted Cooling Towers throughout the U.S. conclude that the levels proposed by Moundsville Power were either equivalent to, or lower than, those for other permitted sources. Therefore, the proposed BACT for the Cooling Tower is the installation of the high efficiency mist eliminators with a drift loss of 0.0005%.

The proposed PM, PM_{10}, and $PM_{2.5}$ BACT for all sources is summarized in Table 3-16.

Table 3-16 Proposed PM, PM_{10}, and $PM_{2.5}$ BACT

Emission Source	Proposed PM, PM_{10}, and $PM_{2.5}$ BACT
Combustion Turbines/Duct Burners	7.6 lb/hr (with or without duct firing) Use of pipeline-quality natural gas or a blend of pipeline-quality natural gas and up to 25% ethane, good combustion practices, combustion turbine inlet air filtration, SCR dilution air filtration.
Auxiliary Boiler	0.005 lb/MMBtu Use of pipeline-quality natural gas or a blend of pipeline-quality natural gas and up to 25% ethane and good combustion practices
Emergency Generator	0.09 g/hp-hr Use of ULSD and good combustion practices
Fire Water Pump	0.15 g/hp-hr Use of ULSD and good combustion practices
Cooling tower	Use of high efficiency drift eliminators with a drift loss of $\leq$ 0.0005%

3.4.2.2.4 VOC BACT

Combustion Turbines/Duct Burners

Step 1 – Identify Potential Control Technologies

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 7FA industrial combustion turbines proposed by Moundsville Power 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 turbine 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 EM_x™ and XONON™ technologies were determined not to be feasible for the proposed combustion turbines, so they have not been considered further here.

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 tend to 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.

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.

Step 2 - Eliminate Technically Infeasible Options
Good combustor design and the use of Oxidation Catalysts are both technically feasible options for controlling VOC emissions from the proposed combustion turbines.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness
Based on the preceding discussions, using good combustor controls and Oxidation Catalysts are technically feasible combustion turbine VOC emission control technologies. Moundsville Power proposes to control VOC emissions using these techniques to meet VOC emission limits of 2.0 and 1.0 ppmvd @ 15% O_2 with and without duct firing, respectively.

Available permits and BACT determinations were reviewed to identify VOC emission rates that have been achieved in practice for other comparable gaseous fuel-fired combustion turbine projects. The majority of the projects had permitted VOC emission rates equal to or greater than the levels proposed by Moundsville Power (2.0 and 1.0 ppmvd @ 15% O_2 with and without duct firing, respectively).

However, the following projects were identified with VOC emission rates lower than those proposed by Moundsville Power.

(1) FPL Turkey Point Power Plant;
(2) FPL West County Energy Center;
(3) Georgia Power Plant McDonough-Atkinson;
(4) Calpine Russell City Energy Center; and
(5) CPV Warren.

These projects are discussed in more detail below.

FPL Turkey Point Power Plant
FPL's Turkey Point Power Plant Unit 5 is a combined-cycle plant located in Miami-Dade County, Florida. It has VOC permit limits of 1.9 and 1.3 ppmvd @ 15% O_2 with and without duct firing, respectively. The 1.3 ppmvd @ 15% O_2 limit without duct firing is less stringent than the 1.0 ppmvd @ 15% O_2 limit proposed by Moundsville Power. The 1.9 ppmvd @ 15% O_2 limit with duct firing is only slightly more stringent than the 2.0 ppmvd @ 15% O_2 limit proposed by Moundsville Power. Turkey Point Unit 5 consists of four (4) GE Frame 7FA combustion turbines, and began commercial operation in May 2007. The 1.9 and 2.0 ppmvd @ 15% O_2 VOC limits with duct firing are effectively equivalent.

FPL West County Energy Center
FPL's West County Energy Center Unit 3 is a combined-cycle plant located in Loxahatchee, northern Palm Beach County, Florida. It has VOC permit limits of 1.5 and 1.2 ppmvd @ 15% O_2 with and without duct firing, respectively. The 1.2 ppmvd @ 15% O_2 limit without duct firing is less stringent than the 1.0 ppmvd @ 15% O_2 limit proposed by Moundsville Power. The 1.5 ppmvd @ 15% O_2 limit with duct firing is more stringent than the 2.0 ppmvd @ 15% O_2 limit proposed by Moundsville Power. West County Energy Center Unit 3 consists of three (3) Mitsubishi Power Systems Model M501G combustion turbines, and began commercial operation in June 2011. Given the lack of long-term operation and compliance with these emission limits, these CO emission levels are not considered achieved in practice at this time.

Georgia Power Plant McDonough-Atkinson
Georgia Power's Plant McDonough-Atkinson Units 4, 5, and 6 are combined-cycle units located in Smyrna, Cobb County, Georgia. Each unit consists of two (2) Mitsubishi Heavy Industries, LTD (MHI) Model M501G combustion turbines. Each unit has VOC permit limits of 1.8 and 1.0 ppmvd @ 15% O_2 with and without duct firing, respectively. The 1.0 ppmvd @ 15% O_2 limit (1-hour basis) without duct firing matches the 1.0 ppmvd @ 15% O_2 limit proposed by Moundsville Power. The 1.8 ppmvd @ 15% O_2 limit (3-hour average) with duct firing is slightly more stringent than the 2.0 ppmvd @ 15% O_2 limit proposed by Moundsville Power. Units 4, 5, and 6 became operational in January 2012, May 2012, and October 2012, respectively. Given the lack of long-term operation and compliance with these emission limits, these CO emission levels are not considered achieved in practice at this time.

Calpine Russell City Energy Center
Calpine's Russell City Energy Center has a VOC permit limit of 1.0 ppmvd @ 15% O_2 with and without duct firing. The 1.0 ppmvd @ 15% O_2 limit without duct firing which matches the limit proposed by Moundsville Power. The 1.0 ppmvd @ 15% O_2 limit with duct firing is more stringent than the limit proposed by Moundsville Power. However, construction of the Russell City Energy Center has not been completed. Therefore, long-term demonstration of compliance with this VOC emission rate and averaging period has not been demonstrated in practice.

CPV Warren
CPV Warren is a combined-cycle power plant proposed to be located in Front Royal, Warren County, Virginia. Originally developed by Competitive Power Ventures (CPV), the project was sold to Virginia Electric Power and Power Company (Dominion Virginia Power) in 2008.

A final PSD permit for a nominal 1,300 MW combined-cycle plant was issued by the Virginia Department of Environmental Quality (VDEQ) on December 21, 2010. This final PSD permit includes VOC emission limits of 0.7 ppm and 1.6 ppmvd @ 15% O_2, on a 3-hour averaging basis, for operating conditions without and with duct firing, respectively. The CPV Warren facility was permitted with Oxidation Catalysts and good combustion practices for CO emission control. The plant has not yet been constructed. Based on publically available information, Dominion expects commercial operation of the Warren facility to occur in late 2014 or early 2015. The plant is expected to consist of three (3) Mitsubishi Model M501GAC combustion turbines. Since the plant has not begun operation, these BACT limits for VOC have not yet been achieved in practice.

Step 4 - Evaluate Most Effective Controls and Document Results
The proposed VOC emission rates of 2.0 and 1.0 ppmvd @ 15% O_2 with and without duct firing, respectively, are the lowest VOC emission rates achieved or permitted for other similar facilities. Therefore, an assessment of the economic and environmental impacts is not necessary.

Step 5 - Select BACT
Moundsville Power proposed that BACT for VOC emissions from the combustion turbines is good combustion design and the use of Oxidation Catalysts to achieve VOC emissions rates of 2.0 and 1.0 ppmvd @ 15% O_2 with and without duct firing, respectively.

The proposed VOC emission rates of 2.0 and 1.0 ppmvd @ 15% O_2 with and without duct firing, respectively, are the lowest VOC emission rates demonstrated in practice or permitted for other facilities using good combustion practices and Oxidation Catalysts.

Auxiliary Boiler

There is currently no technically feasible add-on control technology to reduce VOC emissions from gaseous fuel-fired Auxiliary Boilers of the size proposed for the Moundsville Power Project. VOC emissions are minimized in these units through good combustion practices, ULNB, and FGR, which support effective combustion that minimizes VOC formation.

Moundsville Power proposes a VOC emission level of 0.006 lb/MMBtu as BACT for the Auxiliary Boiler. A review of available permits and RBLC determinations for small boilers identified several recent permits with VOC limits. Several RBLC determinations have VOC emission levels in the 0.002 to 0.006 lb/MMBtu range. One recent permit, Cricket Valley Energy Center in New York, is the only permit reviewed with a value below 0.002 lb/MMBtu. The permitted VOC emission limit for the 60 MMBtu/hr auxiliary boiler at Cricket Valley Energy Center is 0.0015 lb/MMBtu. However, because the Cricket Valley Energy Center has not been constructed at this time, the VOC value of 0.0015 lb/MMBtu has not been achieved in practice.

Given the expected limited hours of operation for the proposed Auxiliary Boiler (<2,000 hr/yr), the decrease in VOC emissions if the boiler were required to achieve a VOC emission level of 0.002 lb/MMBtu would be no more than 0.4 tons/yr. Therefore, Moundsville Power concludes that BACT for VOC is an emission level of 0.006 lb/MMBtu. Moundsville

Power will achieve this emission level by using pipeline quality natural gas and employing good combustion practices.

Emergency Generator and Fire Water Pump

See NO_x BACT evaluations in Section 3.4.2.2.1.

The proposed VOC BACT for all sources is summarized in Table 3-17.

Table 3-17 Proposed VOC BACT

Emission Source	Proposed VOC BACT
Combustion Turbines/Duct Burners	1 ppmvd @ 15% O_2 (without duct firing) 2 ppmvd @ 15% O_2 (with duct firing) Oxidation Catalysts and good combustion practices
Auxiliary Boiler	0.006 lb/MMBtu Use of pipeline-quality natural gas or a blend of pipeline-quality natural gas and up to 25% ethane and good combustion practices
Emergency Generator	2.8 g/hp-hr NMHC+NO_X Use of ULSD and good combustion practices
Fire Water Pump	3.0 g/hp-hr NMHC+NO_X Use of ULSD and good combustion practices

3.4.2.2.5 GHG BACT

The GHG Tailoring Rule regulates emissions from six (6) covered GHGs: CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6. Typically, GHG emissions are listed in terms of CO_2e. GHG emissions associated with combustion equipment are limited to CO_2, CH_4 and N_2O. In calculating CO_2e emissions, GWPs are used to normalize emissions of pollutants such as CH_4 and N_2O, which are deemed to have a greater detrimental impact on a per pound basis than CO_2. The GWP for CO_2 is set at 1, while CH_4 and N_2O have GWPs of 25 and 298, respectively. The evaluation of technologies to minimize GHG emissions typically focuses on CO_2 emissions and mechanisms to reduce CO_2 emissions, which dominates the CO_2e emission value for combustion based equipment. As such, the BACT evaluation presented in this document refers to CO_2 as the primary GHG pollutant for proposed Project equipment.

In general, there are two strategies available to minimize GHG emissions for electric generating units (EGUs): (1) add-on control via carbon capture systems to strip CO_2 from the flue gas stream for subsequent re-use or sequestration, and (2) energy efficiency methods.

An important consideration for power plants is the source definition. USEPA permit guidance indicates that the Clean Air Act does not provide latitude for a permitting authority to redefine a source as part of a BACT evaluation. The proposed Project is a base load electric generating facility using gaseous fuel-fired combined-cycle combustion turbine technology. Only technologies that are relevant to the proposed equipment and fit within the business objectives of a facility should be considered in Step 1 of a BACT evaluation. For example, factors such as fuel type (coal versus solar or wind), or operational parameters (i.e., base load versus peak shaving) would be considered part of the "source definition" for power plants.

Combustion Turbines/Duct Burners

Step 1 – Identify Potential Control Technologies

Carbon Capture and Storage

Carbon capture and storage (CCS) is the only potentially available add-on control option at this time. In order to capture CO_2 emissions from the flue gas, CO_2 must be separated from the exhaust stream. This can be accomplished by a variety of technologies that may include:

- Pre-combustion systems designed to separate CO_2 and hydrogen in the high-pressure synthetic gas typically produced at Integrated Gasification Combined-Cycle (IGCC) power plants; and

- Post-combustion systems that separate CO_2 from flue gas such as:

    - Chemical absorption using an aqueous solution of amines as chemical solvents; or

- Physical absorption using physical absorption processes such as Rectisol or Selexol.

Separation can be facilitated using oxygen combustion, which employs oxygen instead of ambient air for make-up air supplied for combustion. Applicability of different processes to particular applications will depend on temperature, pressure, CO_2 concentrations, and the presence or absence of contaminants in the gas or exhaust stream.

After CO_2 is separated, it must be prepared for beneficial reuse or transport to a sequestration or storage facility, if a storage facility is not locally available for direct injection. In order to transport CO_2, it must be compressed and delivered via pipeline to a storage facility. Although beneficial reuse options are developing, such as the use of captured material to enhance oil or gas recovery from well fields in the petroleum industry, currently, the demand for CO_2 for such applications is well below the quantity of CO_2 that is available for capture from EGUs.

Without a market to use the recovered CO_2, the material would instead require sequestration, or permanent storage. 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. Storage facilities typically include:

1) Geologic formations;
2) Depleted oil and gas reservoirs;
3) Unmineable coal seams;
4) Saline formations;
5) Basalt formations; or
6) Terrestrial ecosystems.

Once injected, the pressurized CO_2 remains "supercritical" and behaves like a liquid. Supercritical CO_2 is denser and takes up less space than gaseous CO_2. Once injected, the CO_2 occupies pore spaces in the surrounding rock. Saline water that already resides in the pore space would be displaced by the denser CO_2. 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.

Thermal Efficiency
An emissions reduction strategy focused on energy efficiency primarily deals with increasing the thermal efficiency of a combustion turbine. Higher thermal efficiency means that less fuel is required for a given output, which results in lower GHG emissions. Maximizing EGU efficiency is an alternative available to reduce the consumption of fuel required to generate a fixed amount of output. The largest efficiency losses for a combined-cycle combustion turbine are inherent in the design of the combustion turbine and the heat recovery system. The mechanical input to the combustion turbine compressor consumes energy, and is integral to how a combustion turbine works. Therefore, there is no opportunity for efficiency gains other than the differences in design between manufacturers or models. Heat recovery in the exhaust gas is another point of efficiency loss. Heat recovery efficiency depends upon the design of the heat recovery system, and varies between manufacturers and models.

The efficiency of the combustion turbines/duct burners employed can vary widely. One alternative to reduce CO_2 emissions is to maximize combustion turbine efficiency through various design techniques. Any increase in energy efficiency within the operation of the combustion turbine yields reductions in the generation of CO_2 emissions on a per unit output basis. For example, combustion turbine suppliers typically offer several different models with a variety of efficiency ratings.

Combustion Air Cooling
A 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. Cooling the combustion air via heat exchanger systems maximizes the expansion of the air molecules and enhances the work the expanding gases perform on the turbine blades, hence producing higher amounts of electricity. A higher electric output improves the overall efficiency of the EGU. Based on general guidance available and recent analyses conducted regarding combustion air cooling, achievable reductions in fuel usage and CO_2 emissions may range from 10 – 15%[9] .

[9] (Hyperion Energy Center Best Available Control Technology (BACT) Analysis for Emissions of Carbon Dioxide, March 2009).

Cogeneration/Combined Heat & Power

Cogeneration, or Combined Heat and Power (CHP), is the operation of a combustion system to generate both heat for electric power generation and useful thermal energy for a process. The electric power is distributed for use, while the thermal energy is used locally to support heating systems or industrial processes. A CHP system allows for the use of energy in the form of heat to provide thermal energy that would otherwise be lost in cooling water for a traditional EGU. For combustion turbine systems, the more likely CHP technique would be to provide space heating for nearby buildings or to provide makeup heat to nearby coal-fired EGUs (likely application for power plants with combustion turbine and coal-fired EGUs onsite). The use of this otherwise lost heat would thereby improve the overall efficiency of the EGU or process, and subsequently reduce overall CO_2 emissions, on an equivalent basis.

The use of a CHP system provides an opportunity to extract additional energy from heat otherwise lost in a traditional EGU. However, this type of system requires the removal of steam from the steam turbine, which reduces the amount of electric power generation recognized in the CHP. This electrical energy is instead transformed to thermal energy for use on a more local basis. The advantage to a CHP system is the net improvement of overall fuel efficiency compared to a traditional EGU operation.

Lower Carbon Fuels

Carbon dioxide is produced as a combustion product of any carbon-containing fuel. All fossil fuels contain varying amounts of fuel-bound carbon that is converted during the combustion process to produce CO and CO_2. However, the use of lower carbon content gaseous fuels such as pipeline-quality natural gas or ethane, 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 and ethane combustion result in significantly lower GHG emissions than coal combustion (117.0 lb/MMBtu and 131.4 lb/MMBtu, for natural gas and ethane, respectively, versus 205.6 lb/MMBtu for bituminous coal).[10] 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.

---

[10] 40 CFR 98, Subpart C, Table C-1.

Step 2 - Eliminate Technically Infeasible Options

Carbon Capture and Storage

In general, the availability of add-on control options to remove GHGs from an EGU exhaust stream is limited. CCS is the only potentially available add-on control option at this time, and even this technology is limited and infantile in its development.

Although numerous carbon capture, storage, and beneficial CO_2 use demonstration projects are in various stages of planning and implementation across the globe, including several in the U.S. that are funded by the Department of Energy (DOE), the technologies needed for a full-scale generating facility are not yet commercially available. In fact, President Obama formed an Interagency Task Force on Carbon Capture and Storage, co-chaired by DOE and USEPA, in early 2010 to develop a federal strategy for overcoming the barriers to the widespread, cost-effective deployment of CCS within 10 years, with an ultimate goal of bringing several commercial demonstration projects online by 2016[11].

Without a market to use the recovered CO_2, the material would instead require sequestration, or permanent storage. The geological formations near the Moundsville Power Project provide limited, if any, alternatives to adequately and permanently store recovered CO_2.

Extensive characterization studies would be needed to determine the extent and storage potential for CO_2 from Moundsville Power sources. These studies would take several years of investigation, including drilling characterization wells, and would likely require small-scale injection testing before determining their full-scale viability.

There are neither local geologic reservoirs, nor pipelines dedicated to CO_2 transport available near the proposed Project at this time. In addition, carbon capture technologies have yet to be demonstrated on a full-scale power generation facility. Therefore, options involving CCS are not currently considered feasible for this Project.

---

[10] U.S. Interagency Task Force on Carbon Capture and Storage. "Report of the Interagency Task Force on Carbon Capture and Storage." August 2010. Available online: http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf

Thermal Efficiency
The use of a combustion turbine with a higher thermal efficiency is a technically feasible alternative to one with a lower thermal efficiency rating.

Combustion Air Cooling
Although combustion air cooling is considered technically feasible, other options such as a more efficient combustion turbine are considered more effective in terms of overall net environmental benefit. The proposed combustion turbines will be equipped with inlet evaporative cooling systems, which are a form of combustion air cooling.

Cogeneration/Combined Heat & Power
For a CHP system to be beneficial, there must be a local need for thermal energy, because thermal energy cannot be effectively transported over extended distances. Given the proposed use of an extremely efficient combustion turbine operated in an efficient combined-cycle mode, there is no reasonable net environmental benefit of a CHP system for the proposed Project. Therefore, CHP is not considered technically feasible for this Project.

Lower Carbon Fuels
The use of lower carbon content gaseous fuels such as pipeline-quality natural gas or ethane, 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.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness
Moundsville Power proposes to use a high thermal efficiency combustion turbine model, GE Frame 7FA.04, operated in combined-cycle mode. The proposed combustion turbines feature an extremely low heat rate when operating in combined-cycle mode, which translates to high efficiency because a low heat rates means less fuel is combusted to produce a unit amount of electric power output.

The table in **Appendix C** of this application contains a comparison of GHG emission rate and heat rate information for various combustion turbine projects, both simple-cycle and combined-cycle. Available information is regarding size, configuration, CO_2 or GHG emission rates, and heat rates is summarized. The relevant information for the Moundsville Power combustion turbines is included in this table.

Comparisons among the various combustion turbines are somewhat complicated in that different bases can be used to establish certain parameters. For example, combustion turbine outputs can be specified on a net or gross basis, and can vary based on fuel, load, ambient temperature, whether duct firing is occurring, and other factors. GHG emission rates can be specified on a LHV or HHV basis. Nevertheless, in context, the Moundsville Power combustion turbines compare favorably with other recent combustion turbine projects in terms of output-based GHG emission rates and heat rates, which indicates that the proposed combustion turbines represent an efficient design that has been accepted as BACT for GHGs in other PSD permits.

The proposed combustion turbines will be equipped with inlet evaporative cooling systems, which are a form of combustion air cooling.

Moundsville Power proposes the use of pipeline-quality natural gas or a blend of pipeline-quality natural gas and up to 25% ethane. Natural gas and ethane are lower carbon containing fuels that yield reduced GHG emissions.

Step 4 - Evaluate Most Effective Controls and Document Results
Based on the information presented in this BACT analysis and consistent with BACT at other similar sources, Moundsville Power proposes to employ the following GHG control techniques as part of this Project:

(1) Use of a high thermal efficiency combustion turbine model, GE Frame 7FA.04, operated in combined-cycle mode;
(2) Use of inlet evaporative cooling systems, which are a form of combustion air cooling;
(3) Use of lower carbon containing fuels (pipeline-quality natural gas or a blend of pipeline-quality natural gas and up to 25% ethane);

In addition, Moundsville Power proposes a facility-wide GHG emissions limit as GHG BACT for the Project. The proposed GHG emission limit from the combustion turbines, Auxiliary Boiler, Emergency Generator, Fire Water Pump, and Circuit Breakers is 2,240,618 tons/yr, on a CO_2e basis. GHG emissions from the Project's combustion sources will be calculated in accordance with the methodology and emission factors noted in 40 CFR 98, Subparts C and D, as applicable. GHG emissions from the Project's Circuit Breakers will be calculated in accordance with the methodology and emission factors noted in 40 CFR 98, Subpart DD, as applicable.

Step 5 - Select BACT
For GHG BACT, Moundsville Power proposes to employ the following GHG control techniques:

(1) Use of a high thermal efficiency combustion turbine model, GE Frame 7FA.04, operated in combined-cycle mode;
(2) Use of inlet evaporative cooling systems, which are a form of combustion air cooling;
(3) Use of lower carbon containing fuels (pipeline-quality natural gas or a blend of pipeline-quality natural gas and up to 25% ethane);

Moundsville Power also proposes a facility-wide GHG emissions limit. The proposed GHG emission limit from the Combustion Turbines, Auxiliary Boiler, Emergency Generator, Fire Water Pump, and Circuit Breakers is 2,240,618 tons/yr, on a CO_2e basis. GHG emissions from the Project's combustion sources will be calculated in accordance with the methodology and emission factors noted in 40 CFR 98, Subparts C and D, as applicable. GHG emissions from the Project's Circuit Breakers will be calculated in accordance with the methodology and emission factors noted in 40 CFR 98, Subpart DD, as applicable.

Auxiliary Boiler

There are currently no technically feasible add-on control technologies to reduce GHG emissions from the Auxiliary Boiler. Therefore, GHG emissions from these sources will be controlled by the exclusive use of pipeline-quality natural gas and good combustion practices.

Emergency Generator and Fire Water Pump

There is currently no technically feasible add-on control technology to reduce GHG emissions from the Emergency Generator and Fire Water Pump. Therefore, Moundsville Power proposes to limit GHG emissions from these sources by using ULSD and good combustion practices.

Circuit Breakers

Sulfur hexafluoride (SF_6) gas is typically used in the circuit breakers associated with electricity generation equipment. Potential sources of SF_6 emissions include equipment leaks from SF_6 containing equipment, releases from gas cylinders used for equipment maintenance and repair operations, and SF_6 handling operations.

(1) Use of dielectric oil or compressed air circuit breakers that contain no SF_6 or other GHG pollutants; and
(2) Use of modern SF_6 circuit breakers designed to be totally enclosed systems.

Potential alternatives to SF_6 were addressed in the National Institute of Standards and Technology (NTIS) Technical Note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF6.17.* According to this document, SF_6 is a superior dielectric gas for nearly all high voltage applications. It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of SF_6-insulated equipment. The report concluded that although "…various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture… it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment." Therefore, Moundsville Power believes there are currently no technically feasible options to the use of SF_6.

Circuit breakers with insulating gases other than SF_6 are not yet commercially available, and certainly any use of less effective insulation material to control emissions of just 58 tons/yr of CO_2e would not be warranted, even if it were available. As such, non-SF_6 circuit breakers will be eliminated. The only remaining feasible control is to use a modern, totally enclosed SF_6 circuit breakers.

In comparison to older SF_6 circuit breakers, modern breakers are designed as totally enclosed pressure systems with far lower potential for SF_6 emissions. Therefore, Moundsville Power proposes to implement modern state-of-the-art, gas-tight circuit breakers with the implementation of an inspection and maintenance program to identify and repair leaks. Moundsville Power will monitor SF_6 emissions from the circuit breakers annually according to the requirements of the Mandatory Greenhouse Gas Reporting Rule for Electrical Transmission and Distribution Equipment Use (40 CFR 98, Subpart DD). Annual emissions of SF_6 will be calculated according to the mass balance approach in Equation DD-1 of Subpart DD.

The proposed GHG BACT for all sources is summarized in Table 3-18.

Table 3-18 Proposed GHG BACT

Emission Source	Proposed GHG BACT
Combustion Turbines/Duct Burners	Use of high thermal efficiency GE Frame 7FA.04 combustion turbines, use of lower carbon containing natural gas or a blend of pipeline-quality natural gas and up to 25% ethane
Auxiliary Boiler	Exclusive use of pipeline quality natural gas or a blend of pipeline-quality natural gas and up to 25% ethane
Emergency Generator	Use of ULSD fuel and good combustion practices
Fire Water Pump	Use of ULSD fuel and good combustion practices
Circuit Breakers	Totally enclosed SF_6 circuit breakers and leak detection and repair program

3.4.2.3 *Additional PSD Analyses*

The PSD regulations require additional analyses beyond BACT assessments. These additional analyses include:

- Assessment of compliance with NAAQS and PSD increments;
- An evaluation of whether the Project results in any impairment to visibility, soils, and vegetation that would occur as a result of the new source, and of general commercial, residential, industrial, and other growth associated with the new source. Furthermore, impacts on Class I areas must be analyzed to determine compliance with Class I increments and to assess the impacts of new emissions on air quality related values (AQRVs); and
- An evaluation of the Project's impacts on PSD Class I Areas.

These analyses will be addressed when the air quality dispersion modeling analyses are conducted.

3.5 NON-ATTAINMENT NEW SOURCE REVIEW (NA-NSR)

The Moundsville Power Project is located in Marshall County, which is designated as a non-attainment area for SO_2. If emissions of SO_2 from the Project are greater than 100 tons/yr, the Project will trigger the requirements of NA-NSR.

As indicated in Table 3-13, potential annual SO_2 emissions are less than the NA-NSR trigger threshold for new sources. Therefore, the proposed Project is not subject to NA-NSR for SO_2.

3.6 APPLICABLE REQUIREMENTS REVIEW

This section briefly outlines the federal and State air quality requirements to which the proposed Moundsville Power Project will be subject, in addition to the PSD and NA-NSR requirements presented previously.

3.6.1 Federal Requirements

3.6.1.1 New Source Performance Standards (NSPS)

3.6.1.1.1 Combustion Turbines

The combustion turbines are subject to 40 CFR 60 Subpart KKKK, "Standards of Performance for Stationary Combustion Turbines." All stationary gas turbines with a heat input at a peak load equal to or greater than 10.7 gigajoules per hour (10 MMBtu/hr), based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after 18 February 2005 are subject to this NSPS Subpart KKKK. Note that stationary combustion turbines regulated under Subpart KKKK are exempt from the requirements of Subpart GG.

The Subpart KKKK emission limits are:

- NO_x – 15 ppmvd @ 15% O_2 or 0.43 lb/MW-hr gross energy output; and
- SO_2 – 0.90 lb/MW-hr gross energy output or 0.060 lb/MMBtu.

Subpart KKKK includes general compliance requirements (60.4333), monitoring requirements (60.4335-60.4370), reporting requirements (60.4375-60.4395), and performance testing (60.4400-60.4415). Moundsville

Power will also be subject to applicable notification, monitoring and reporting and related applicable provisions of 40 CFR 60.7 and 60.8.

The proposed combustion turbines will meet the applicable emission limits and provisions of NSPS Subpart KKKK.

3.6.1.1.2 Auxiliary Boiler

The Auxiliary Boiler is subject to 40 CFR 60 Subpart Dc, "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units" because the rated heat input of the Auxiliary Boiler, 100 MMBtu/hr, is greater 10 MMBtu/hr and less than or equal to 100 MMBtu/hr. Subpart Dc requirements for an auxiliary boiler that only burns natural gas or other gaseous fuels include:

- Notification of the date of construction and actual startup (60.48c(a));
- Fuel and fuel use records (60.48c(f) and (g)); and
- Maintenance of required records for two (2) years from the date of the record (60.48c(i)).

The proposed Auxiliary Boiler will meet the applicable emission limits and provisions of NSPS Subpart Dc.

3.6.1.1.3 Emergency Generator and Fire Water Pump

The Emergency Generator and Fire Water Pump are subject to 40 CFR 60, Subpart IIII - *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* and the associated fuel, monitoring, compliance, testing, notification, reporting, and recordkeeping requirements (40 CFR 60.4200 *et seq*.) and related applicable provisions of 40 CFR 60.7 and 60.8. Emission limits for these engines are noted in Table 3-36. Note that both engines are not subject to the Tier 4 requirements under Subpart IIII because they both will have cylinder displacement less than 10 liters per cylinder (L/cyl.).

The emission standards in NSPS Subpart IIII applicable to the Emergency Generator and Fire Water Pump are summarized in Table 3-19 below. The proposed Emergency Generator and Fire Water Pump will meet the applicable emission limits and provisions of NSPS Subpart IIII.

Table 3-19 Emission Standards for Emergency Engines (g/hp-hr)

Emergency Engine	Model Year	$NMHC+NO_X$	CO	PM
251-hp Fire Water Pump 130<kW<225 (100<hp<300)	2006 and after	3	2.6	0.15
1,500-kW Emergency Generator <10 L/cyl. and <2,237 kW (3,000 hp)	2006 and after	4.8	2.6	0.15

3.6.1.2 NSPS for GHGs (40 CFR Part 60)

On September 20, 2013, USEPA proposed a revised Carbon Pollution Standard that would set national limits on the amount of GHG emissions allowed for new power plants. The rule will be promulgated under authority of Section 111 of the Clean Air Act (i.e., NSPS), and applies to new electric utility generating units (EGUs).

USEPA is proposing to codify the CO_2 standards of performance in the same subparts – Da and KKKK, depending on the types of units – that currently include the standards of performance for conventional pollutants. However, USEPA is co-proposing an alternative to codify the CO_2 standards in a new subpart, TTTT, as in USEPA's original April 2012 proposal.

This new proposal was issued after USEPA received and reviewed more than 2.5 million public comments on the April 2012 Carbon Pollution Standard. Concurrent with this proposal, USEPA is rescinding the original April 2012 proposed rule.

In a change from the April 2012 proposal, USEPA is now proposing a standard of performance for natural gas-fired stationary combustion turbines and for fossil fuel-fired utility boilers and integrated gasification combined-cycle (IGCC) units called the Best System of Emission Reduction (BSER). This is the most controversial part of the rule.

For affected gas turbine EGUs, the proposed limits are based on the performance of a combined-cycle design with two (1) size categories. Larger units with a heat input rating greater than 850 MMBtu/hr will be required to meet a standard of 1,000 pounds of CO_2 per gross megawatt-hour (lb-CO_2/MW-hr gross). Units rated less than or equal to 850 MMBtu/hr will be subjected to a standard of 1,100 lb-CO_2/MW-hr gross. The proposed rule specifies that compliance with these limits would be based on a 12-month rolling average basis, updated after each new operating month.

USEPA states that it considers modern and efficient natural-gas combined-cycle (NGCC) as BSER for new affected combustion turbines (Subpart KKKK sources). USEPA decided that CCS could not be considered as BSER for gas-fired combustion turbines due to: 1) the significantly lower concentration of CO_2 in the flue gas; 2) there is only one (1) CCS demonstration project on a NGCC facility; and 3) the potential of significant impacts to electricity prices and reliability of the imposition of CCS on few coal fired units.

Moundsville Power will continue to monitor this rulemaking, and will evaluate its applicability to the Project upon its promulgation. The proposed combustion turbines would meet the proposed standard of 1,000 lb-CO_2/MW-hr gross for units with a heat input rating greater than 850 MMBtu/hr.

3.6.1.3 Acid Rain Program (40 CFR Parts 72-76, 45 CSR 33)

The proposed combustion turbines meet the definition of an "affected unit" as defined in 40 CFR 72.6, and are therefore subject to the requirements of the Acid Rain Program, including emissions standards (40 CFR 72.9) and monitoring requirements (40 Part 75), among other requirements. In addition, Moundsville Power is required to apply for, and obtain, an Acid Rain permit, pursuant to 40 CFR 72.30. The terms of the Acid Rain permit will be incorporated into the facility's Title V operating permit when it is issued by WVDEP in the future. Pursuant to 40 CFR 72.30(b)(2)(ii), the Acid Rain permit application must be submitted to the permitting authority at least 24 months before the date on which a unit commences operation. With commencement of operation expected in the first or second quarter of 2017, the Acid Rain permit application must be submitted sometime in the first or second quarter of 2015.

3.6.1.4 National Emissions Standards for Hazardous Air Pollutants

National Emissions Standards for Hazardous Air Pollutants (NESHAPs) are federal HAP requirements in 40 CFR 63 that apply generally to "major" sources of HAPs, defined as facilities with the potential to emit 10 tons/yr or more of any single HAP, or 25 tons/yr or more of all HAPs. HAP standards, known as Maximum Achievable Control Technology (MACT) standards, for major HAP sources are established for classes or categories of sources. There are, at present, no source category MACT standards for combustion turbines such as those proposed by Moundsville Power. Some MACT standards, known as "area source MACT" standards, apply to minor source HAP facilities.

The total potential HAP emissions for the facility 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.

There is an area source MACT for industrial, commercial and institutional boilers and process heaters (40 CFR 63, Subpart JJJJJJ), known as "Boiler MACT". Boiler MACT does not apply to any of the proposed combustion sources because the only source considered an "affected source" under Subpart JJJJJJ is the Auxiliary Boiler and, according to 40 CFR 63.11195, a natural gas-fired boiler is not subject to Subpart JJJJJJ.

The Emergency Generator and Fire Water Pump are subject to 40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines ("RICE MACT") and the associated fuel, monitoring, compliance, testing, notification, reporting, and recordkeeping requirements.

3.6.1.5 Compliance Assurance Monitoring

Compliance Assurance Monitoring (CAM) applies to emissions units at "major" sources that are required to obtain a Title V operating permit, and that meet all three of the following criteria (40 CFR 64.2a):

> "(1) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant (or a surrogate thereof), other than an emission limitation or standard that is exempt under paragraph (b)(1) of this section;
>
> (2) The unit uses a control device to achieve compliance with any such emission limitation or standard; and
>
> (3) The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100% of the amount, in tons/yr, required for a source to be classified as a major source."

Exemptions from CAM in 40 CFR 64.2(b)(1) include:

> (i) Emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to section 111 [NSPS] or 112 [NESHAP] of the Act.
>
> (ii) Stratospheric ozone protection requirements under Title VI of the Act.
>
> (iii) Acid Rain Program requirements pursuant to sections 404, 405, 406, 407(a), 407(b), or 410 of the Act.
>
> (iv) Emission limitations or standards or other applicable requirements that apply solely under an emissions trading program approved or promulgated by the Administrator under the Act that allows for trading emissions within a source or between sources.
>
> (v) An emissions cap that meets the requirements specified in 70.4(b)(12) or 71.6(a)(13)(iii) of this chapter.
>
> (vi) Emission limitations or standards for which a Part 70 or 71 [Title V operating] permit specifies a continuous compliance determination method, as defined in 64.1…

The proposed Project was evaluated for CAM applicability. Only the combustion turbines are equipped with control devices (SCR and Oxidation Catalysts) and have pre-controlled emissions of applicable regulated air pollutants emissions (NO_x and CO) in excess of 100 tons/yr. However, the combustion turbines are subject to the NSPS Subpart KKKK, and will be equipped with Continuous Emissions Monitoring Systems (CEMS) for NO_x and CO, which are considered a continuous compliance determination method. Therefore, the combustion turbines are exempt from CAM under 40 CFR 64.2(a)(1) and (b)(1)(i).

3.6.1.6 Chemical Accident Prevention Provisions

These provisions, in 40 CFR 68, apply to a wide variety of facilities that handle, manufacture, store, or use toxic or highly flammable substances. Ammonia is one of the potentially covered substances. However, the ammonia reagent planned for the SCRs is aqueous ammonia, at a concentration of less than 20% by weight. The aqueous ammonia is planned to be stored in one (1) storage tank, with a capacity of 20,000 gallons. The use of aqueous ammonia with a concentration of less than 20% by weight ensures that the provisions of 40 CFR 68 will not apply.

3.6.1.7 Clean Air Interstate Rule and Cross-State Air Pollution Rule

The Clean Air Interstate Rule (CAIR) was a federal rule promulgated in March 2005 that implements a cap and trade program on power plant NO_X and SO_2 emissions in the eastern half of the United States. This rule was promulgated for implementation under 40 CFR 97. WVDEP has promulgated implementing regulations for CAIR under 45 CSR 39-41. According to 40 CFR 97.4, CAIR applies to any emission unit that, at any time after January 1, 1995, has a nameplate electric generating capacity of greater than 25 MWe, and sells any amount of electricity or has a maximum design heat input of greater than 250 MMBtu/hr.

On July 6, 2011, the USEPA finalized the Cross-State Air Pollution Rule (CSAPR), which replaces CAIR. The first phase of compliance begins January 1, 2012 for annual SO_2 and annual NO_X emissions, and May 1, 2012 for ozone season NO_X emissions.

However, in August 2012, the U.S. Court of Appeals for the D.C. Circuit issued a ruling that vacated CSAPR in its entirety and remanded the rule back to USEPA for reconsideration and revision. The CAIR program described above remains in place until the issues with CSAPR are resolved. At the time of this filing, the U.S. Supreme Court has agreed to review the D.C. Circuit Court's decision on CSAPR, and USEPA has filed its opening merits brief with the U.S. Supreme Court.

The CAIR program remains in place until the issues with CSAPR are resolved. Like the Acid Rain program, CAIR also requires Moundsville Power to apply for, and obtain, the applicable CAIR permits for NO_x and SO_2. Under the CAIR program, these permit applications must be submitted to the permitting authority at least 18 months prior to the date on which a unit commences operation. With commencement of operation expected in the first or second quarter of 2017, the CAIR permit applications must be submitted sometime in the third or fourth quarter of 2015.

The Moundsville Power combustion turbines are expected to be subject to CSAPR when a final rule is in place because West Virginia is an affected state, and the rule is expected to apply to any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, on or after January 1, 2005, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

3.6.1.8 *$PM_{2.5}$ Implementation Rule*

The $PM_{2.5}$ Implementation Rule[12] became effective on July 15, 2008 for non-attainment areas. Marshall County had been designated as non-attainment for the 1997 annual $PM_{2.5}$ NAAQS of 15 $\mu g/m^3$. However, on September 30, 2013, USEPA finalized rulemaking approving the area's redesignation to attainment. Therefore, this rule currently does not apply.

3.6.1.9 *Mandatory Reporting of Greenhouse Gases*

The Mandatory Greenhouse Gas Reporting Rule (40 CFR Part 98) applies to direct GHG emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO_2 underground for sequestration or other reasons. In general, the threshold for reporting is 25,000 metric tons or more of CO_{2e} per year. Reporting is at the facility level, except for certain suppliers of fossil fuels and industrial GHGs.

At the Moundsville Power facility, the Auxiliary Boiler is addressed in Subpart C (General Stationary Fuel Combustion Sources) and the combustion turbines are addressed in Subpart D (Electricity Generation). Pursuant to 40 CFR 98.30(b)(2), emergency generators and emergency equipment as defined in 40 CFR 98.6 are not included in the source category under Subpart C. Therefore, the Emergency Generator and the Fire Water Pump are exempt from reporting under the rule.

Under Subparts C and D, emissions of CO_2, CH_4 and N_2O must be determined and reported to USEPA in accordance with the following requirements:

- Procedure to estimate emissions (98.33, 98.43);
- Monitoring and QA/QC Requirements (98.34, 98.44);
- Procedures for Estimating Missing Data (98.35, 98.45);
- Data Reporting Requirements (98.36, 98.46); and
- Records that Must Be Retained (98.37, 98.47).

---

[12] See 73 FR 28321.

Moundsville Power will be required to submit an annual report of GHG emissions and data. The facility will be required to use the electronic GHG reporting tool (e-GGRT) developed by USEPA. The annual report of the previous calendar year's data is due on March 31 of each year.

3.6.2 *State Requirements*

The proposed Project will be subject to a number of WVDEP air quality requirements including, but not limited to, the following:

3.6.2.1 *45 CSR 02 (To Prevent and Control Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers)*

The Auxiliary Boiler is a natural gas-fired indirect heat exchanger with a design heat input capacity greater than 10 MMBtu/hr. The Auxiliary Boiler will comply with the applicable PM emission limits and visible emission standards in the rule.

3.6.2.2 *45 CSR 10 (To Prevent and Control Air Pollution from the Emission of Sulfur Oxides)*

The Auxiliary Boiler is a natural gas-fired indirect heat exchanger with a design heat input capacity greater than 10 MMBtu/hr. The Auxiliary Boiler will comply with the applicable SO_2 emission limits in the rule.

3.6.2.3 *45 CSR 11 (Prevention of Air Pollution Emergency Episodes)*

When requested by the WVDEP Director, Moundsville Power will prepare standby plans for reducing air pollutant emissions during Air Pollution Alerts, Air Pollution Warnings, and Air Pollution Emergencies.

3.6.2.4 *45 CSR 13 (Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Administrative Updates, Temporary Permits, General Permits, Permission to Commence Construction, and Procedures for Evaluation)*

This permit application is being submitted pursuant to 45 CSR 13 for the construction of the proposed Project.

3.6.2.5 *45 CSR 14 (Permits for Construction and Major Modification of Major Stationary Sources of Air Pollution for the Prevention of Significant Deterioration)*

As described above in Section 3.4, the proposed Project will be subject to PSD for NO_x, CO, PM, PM_{10}, $PM_{2.5}$, VOC, and GHGs.

3.6.2.6 *45 CSR 16 (Standards of Performance for New Stationary Sources)*

As described above in Section 3.6.1.1, the proposed combustion turbines will be subject to NSPS Subpart KKKK in 40 CFR 60. The proposed Auxiliary Boiler will be subject to NSPS Subpart Dc in 40 CFR 60. The proposed Emergency Generator and Fire Water Pump will be subject to NSPS Subpart IIII in 40 CFR 60.

3.6.2.7 *45 CSR 19 (Permits for Construction and Major Modification of Major Stationary Sources of Air Pollution Which Cause or Contribute to Nonattainment)*

As described above in Section 3.5, the proposed Project will not trigger NA-NSR for any non-attainment pollutants (i.e. SO_2).

3.6.2.8 *45 CSR 27 (To Prevent and Control the Emissions of Toxic Air Pollutants)*

The proposed Project will not utilize equipment that will be subject to the provisions of this rule.

3.6.2.9 *45 CSR 30 (Requirements for Operating Permits)*

The proposed Project will require a Title V Operating Permit. Pursuant to 45 CSR 30-4.1.a.2, Moundsville Power must file a complete application to obtain the Title V operating permit within 12 months after the Project commences operation, which is expected to occur in 2016.

3.6.2.10 *45 CSR 33 (Acid Rain Provisions and Permits)*

As described above in Section 3.6.1.3, the proposed combustion turbines will be subject to certain provisions of the Acid Rain program, including the permitting provisions.

3.6.2.11 *45 CSR 34 (Emission Standards for Hazardous Air Pollutants)*

As described above in Section 3.6.1.4, the Emergency Generator and Fire Water Pump are subject to 40 CFR 63, Subpart ZZZZ ("RICE MACT") and its associated fuel, monitoring, compliance, testing, notification, reporting, and recordkeeping requirements.

4.0 *SUMMARY*

The emissions sources evaluated in this application include the combustion turbines, Auxiliary Boiler, the Emergency Generator, Fire Water Pump, and Cooling Tower.

Emissions from the proposed Project trigger PSD requirements for NO_x, CO, PM, PM_{10}, $PM_{2.5}$, VOC, and GHG. No pollutants trigger NA-NSR. Emissions of all other regulated pollutants, including HAPs, will be below regulatory thresholds.

Because emissions of NO_x, CO, PM, PM_{10}, $PM_{2.5}$, VOC, and GHG trigger PSD, Moundsville Power is required to meet BACT for these pollutants, and conduct impact assessments to ensure that emissions will not adversely affect ambient air quality. BACT will be achieved using the following controls.

- NO_x emissions will be controlled using SCR and dry low-NO_x combustor technologies for the combustion turbines; ULNB and FGR for the Auxiliary Boiler; and efficient combustion and limited hours of operation for the Emergency Generator and the Fire Water Pump.

- CO emissions from the combustion turbines will be controlled using Oxidation Catalysts and good combustion practices. CO emissions from the Auxiliary Boiler will be controlled through the use of pipeline-quality natural gas or a blend of pipeline-quality natural gas and up to 25% ethane, as well as good combustion practices. CO emissions from the Emergency Generator and Fire Water Pump will be controlled using ULSD and good combustion practices.

- PM, PM_{10}, and $PM_{2.5}$ emissions from the combustion turbines will be controlled by the use of pipeline-quality natural gas or a blend of pipeline-quality natural gas and up to 25% ethane, along with filtration of the inlet air and SCR dilution air systems. PM, PM_{10}, and $PM_{2.5}$ emissions from the Auxiliary Boiler will be controlled by the use of pipeline-quality natural gas or a blend of pipeline-quality natural gas and up to 25% ethane. PM, PM_{10}, and $PM_{2.5}$ emissions from the Emergency Generator and Fire Water Pump will be controlled by use of engines with emissions less than or equal to NSPS Subpart IIII standards, the ULSD and limited annual operating hours. PM, PM_{10}, and $PM_{2.5}$ emissions from the wet mechanical draft Cooling Tower will be controlled by using high efficiency drift eliminators with a drift loss not to exceed 0.0005%.

- VOC emissions from the combustion turbines will be controlled using Oxidation Catalysts and good combustion practices. VOC emissions from the Auxiliary Boiler will be controlled by the use of pipeline-quality natural gas or a blend of pipeline-quality natural gas and up to 25% ethane, as well as good combustion practices. VOC emissions from the Emergency Generator and Fire Water Pump will be controlled using ULSD and good combustion practices.

- GHG emissions from the combustion turbines will be controlled by using high efficiency combustion turbines, and the use of lower carbon containing fuels (i.e., pipeline-quality natural gas or a blend of pipeline-quality natural gas and up to 25% ethane). GHG emissions from the Auxiliary Boiler will be minimized by the exclusive use of pipeline-quality natural gas. GHG emissions from the Emergency Generator and Fire Water Pump will be minimized by the use of ULSD and limited annual operating hours. GHG emissions from the Circuit Breakers will be controlled by using totally enclosed SF_6 circuit breakers and implementing a leak detection and repair program.

Emissions from the proposed Project are not predicted to cause any significant adverse impacts to air quality. Specifically, emissions from the proposed Project will not adversely affect ambient air quality or PSD increments. The Project's impacts on visibility in the surrounding Class I areas are likely to be minimal.

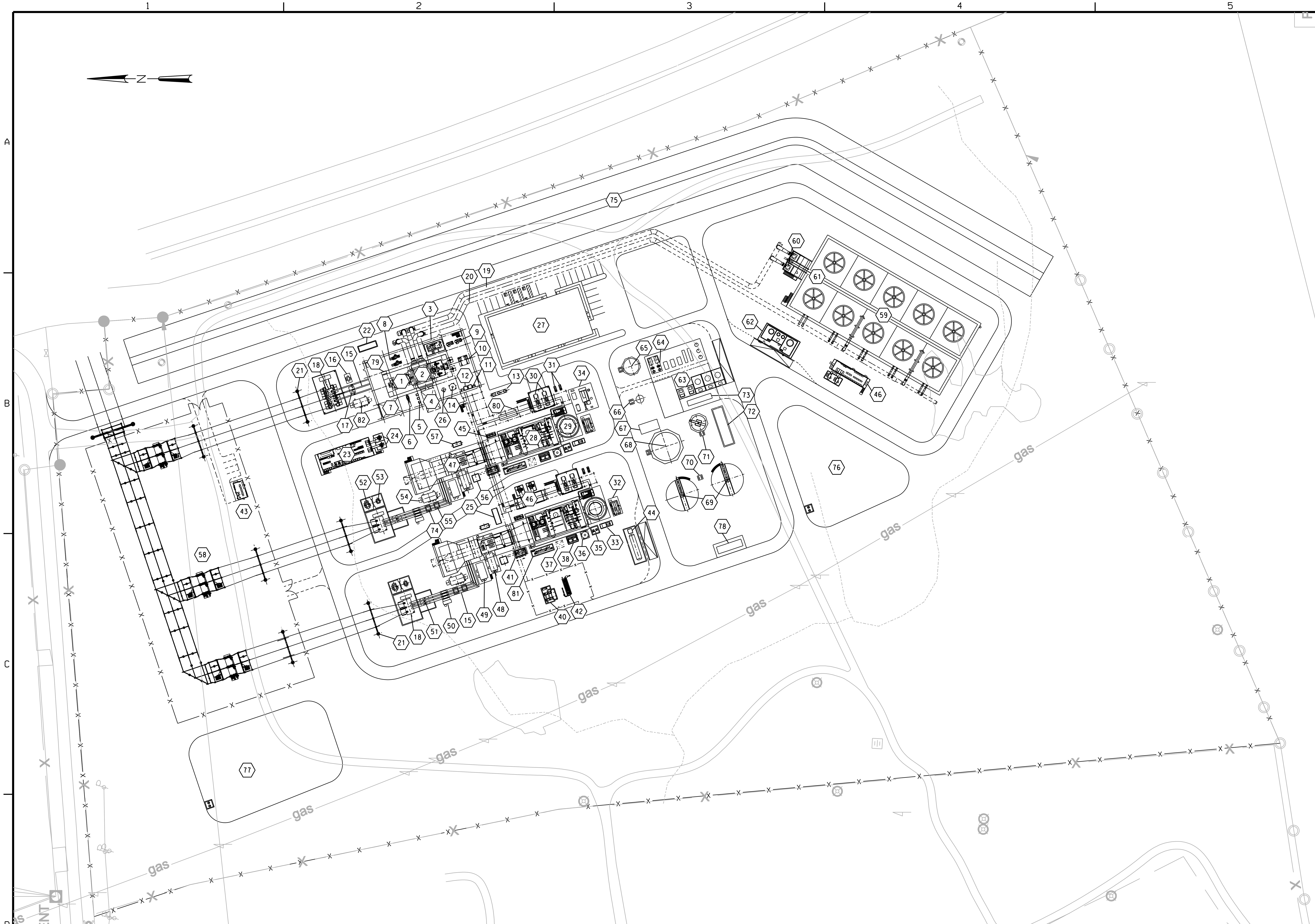
In conclusion, an evaluation of the Project and its potential emissions indicates that the Moundsville Power Project will meet all applicable State and federal air quality requirements.

5.0 AIR PERMIT APPLICATION

Appendix D contains completed and certified versions of all the relevant WVDEP Division of Air Quality application forms and attachments. In the air permit application submitted to WVDEP in October 2013, Moundsville Power provided a check for $14,500, payable to the "WVDEP Air Pollution Control Fund", for the applicable air permitting fees.

Appendices

Appendix A – Conceptual Plant Layout Drawings



EQUIPMENT LEGEND

ITEM	EQPT TAG NO	DESCRIPTION
1		STEAM TURBINE GENERATOR (STG) (TURBINE DECK)
2		STEAM SURFACE CONDENSER (GROUND FLOOR)
3		STG LUBE OIL SKID (GROUND FLOOR)
4		CONDENSER TUBE REMOVAL AREA
5		CONDENSATE PUMPS (GROUND FLOOR)
6		STG GLAND STEAM CONDENSER (MEZZANINE LEVEL)
7		TURBINE COMPONENT DROP ZONE (ALL LEVELS)
8		AIR REMOVAL VACUUM PUMPS (MEZZANINE LEVEL)
9		CLOSED COOLING WATER PUMPS (GROUND FLOOR)
10		CLOSED COOLING WATER HEAT EXCHANGERS (GROUND FLOOR)
11		AMINE FEED SKID W/ TOTE (GROUND FLOOR)
12		OXYGEN SCAVENGER FEED SKID (GROUND FLOOR)
13		OIL / WATER SEPARATOR W/ SUMP PUMPS
14		CONDENSTE RECIEVER
15		ISOLATED PHASE BUS DUCT
16		STG EXCITATION TRANSFORMER
17		STG VT & SA CABINET
18		GENERATOR STEP-UP TRANSFORMER (GSU)
19		CIRCULATING WATER SUPPLY
20		CIRCULATING WATER RETURN
21		DEAD END STRUCTURE
22		EMERGENCY DIESEL GENERATOR
23		MAIN POWER DISTRIBUTION CENTER (PDC)
24		STATION SERVICE TRANSFORMERS
25		CT WASH WATER SKID
26		CLOSED COOLING WATER EXPANSION TANK
27		ADMINISTRATION / CONTROL ROOM & MAINTENANCE BUILDING
28		HEAT RECOVERY STEAM GENERATOR (HRSG)
29		HRSG STACK
30		BOILER FEED WATER PUMPS W/ ENCLOSURE
31		LP ECONOMIZER RECIRCULATING PUMPS
32		CONTINUOUS EMISSIONS MONITORING SYSTEM (CEMS)
33		PHOSPHATE FEED SKID
34		AUXILIARY BOILER
35		HRSG BLOWDOWN SUMP W/ PUMPS
36		HRSG BLOWDOWN TANK
37		HRSG SCR REMOVAL AREA
38		HRSG AMMONIA FLOW CONTROL SKID
39		NOT USED
40		FUEL GAS COALESCING FILTERS W/ KNOCKOUT DRUM
41		FUEL GAS STARTUP HEATERS
42		FUEL GAS REGULATING STATION
43		SWITCHYARD CONTROL ROOM
44		AQUEOUS AMMONIA STORAGE TANK AND PUMPS
45		DUCT BURNER SKID
46		PDC W/ STATION SERVICE TRANSFORMERS
47		CONBUSTION TURBINE GENERATOR (CTG)
48		CT ACCESSORY MODULE
49		CT PEEC BUILDING
50		CTG GENERATOR CIRCUIT BREAKER
51		CTG UNIT AUXILIARY TRANSFORMER (UAT)
52		CTG LCI TRANSFORMER
53		CTG EXCITATION TRANSFORMER
54		CTG LCI BUILDING / EXCITER
55		DC LINK REACTOR
56		CT WASH WATER SUMP
57		CT FIRE PROTECTION CO2 SKID
58		SWITCHYARD
59		COOLING TOWER W/ INTAKE SCREENS
60		CIRCULATING WATER PUMPS
61		AUXILIARY COOLING WATER PUMP
62		CIRCULATING WATER CHEMICAL FEED BUILDING
63		WATER TREATMENT BUILDING
64		AIR COMPRESSORS, AIR DRYERS AND AIR RECEIVERS
65		DEMINERALIZED WATER STORAGE TANK AND PUMPS
66		PERMEATE STORAGE TANK AND MAKEUP PUMPS
67		FIREWATER PUMP HOUSE ENCLOSURE
68		FIREWATER / SERVICE WATER STORAGE TANK AND PUMPS
69		CLARIFIERS
70		CLARIFIER SLUDGE PUMPS
71		CLARIFIER SLUDGE THICKENER AND PUMPS
72		CLEARWELL / BACKWASH SUMP
73		FILTER PRESS
74		AC LINK REACTOR
75		DIRT BERM
76		.52 ACRE RETENTION POND W/ PUMPS
77		.68 ACRE RETENTION POND W/ PUMPS
78		HYDROGEN STORAGE TRAILER
79		CO2 BOTTLE RACK
80		STEAM / WATER SAMPLE LAB ENCLOSURE
81		FUEL GAS PERFORMANCE HEATER
82		STG EXCITATION COMPARTMENT

80 0 80 160

Scale: 1 INCH = 80 FEET

RESPONSIBLE ENGINEER

PE #

NO.	DATE	REVISION	BY	CHK
A	11/12/13	ISSUED FOR CLIENT REVIEW	JP	MM
B	11/20/13	REVISED PER CLIENT COMMENTS	JP	MM
C	11/26/13	REVISED SWITCHYARD & DELETED FG SCRUBBER	JP	MM

REVISION APPROVAL — REV — DATE / /

DISCIPLINE	REVIEWED	DISCIPLINE	REVIEWED
CIVIL	.	ELECTRICAL	.
STRUCTURAL	.	INST & CNTRL	.
MECHANICAL	.	ARCHITECTURAL	.
PROCESS	.	PLANT LAYOUTS	.
PIPING	.		

STATUS

ISSUED	REV	DATE	DM	SDE	PEM
PRELIMINARY					
FOR REVIEW AND APPROVAL					
APPROVED FOR CONSTRUCTION					
REVISED & APPROVED FOR CONSTRUCTION					

SCALE 1" = 80'-0"

MOUNDSVILLE POWER, LLC
MOUNDSVILLE PROJECT
2 X 1 COMBINED CYCLE
MOUNDSVILLE, WEST VIRGINIA

PROJECT NO. 480102

CH2MHILL
CH2MHILL Engineers, Inc.

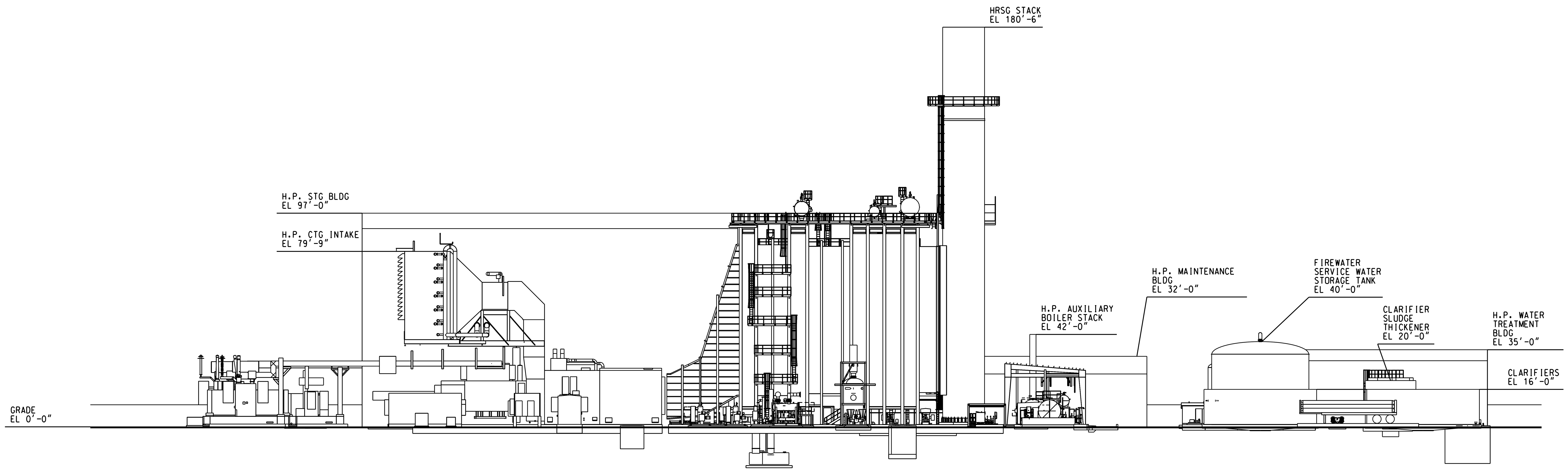
GENERAL ARRANGEMENT

PLOT PLAN

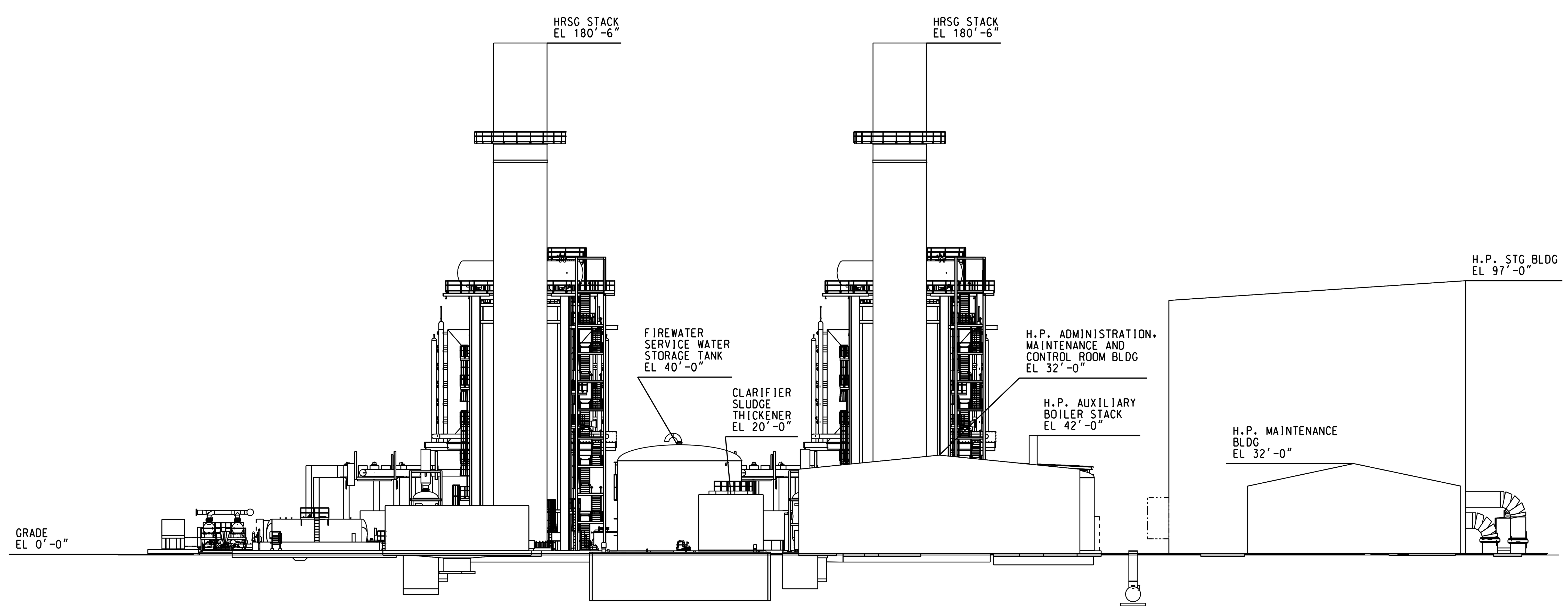
DWG. NO. SK-MP-G-1000 REV. C

FILENAME: PLOT DATE:

BAR IS ONE INCH ON ORIGINAL DRAWING.
0 1"



ELEVATION - NORTHEAST
SCALE: 1"=30'-0"



ELEVATION - NORTHWEST
SCALE: 1"=30'-0"

30 0 30 60
Scale: 1 INCH = 30 FEET

NO.	DATE	REVISION	BY	CHK
P1	/ /	ISSUED FOR INTERNAL REVIEW	JP	MM

RESPONSIBLE ENGINEER
PE #

REVISION APPROVAL		REV P1 DATE / /	
DISCIPLINE	REVIEWED	DISCIPLINE	REVIEWED
CIVIL	.	ELECTRICAL	.
STRUCTURAL	.	INST & CNTRL	.
MECHANICAL	.	ARCHITECTURAL	.
PROCESS	.	PLANT LAYOUTS	.
PIPING	.		

STATUS					
ISSUED	REV	DATE	DM	SDE	PEM
PRELIMINARY	P1				
FOR REVIEW AND APPROVAL					
APPROVED FOR CONSTRUCTION					
REVISED & APPROVED FOR CONSTRUCTION					

SCALE 1" = 30'-0"

MOUNDSVILLE POWER, LLC
MOUNDSVILLE PROJECT
2 X 1 COMBINED CYCLE
MOUNDSVILLE, WEST VIRGINIA
PROJECT NO. 480102

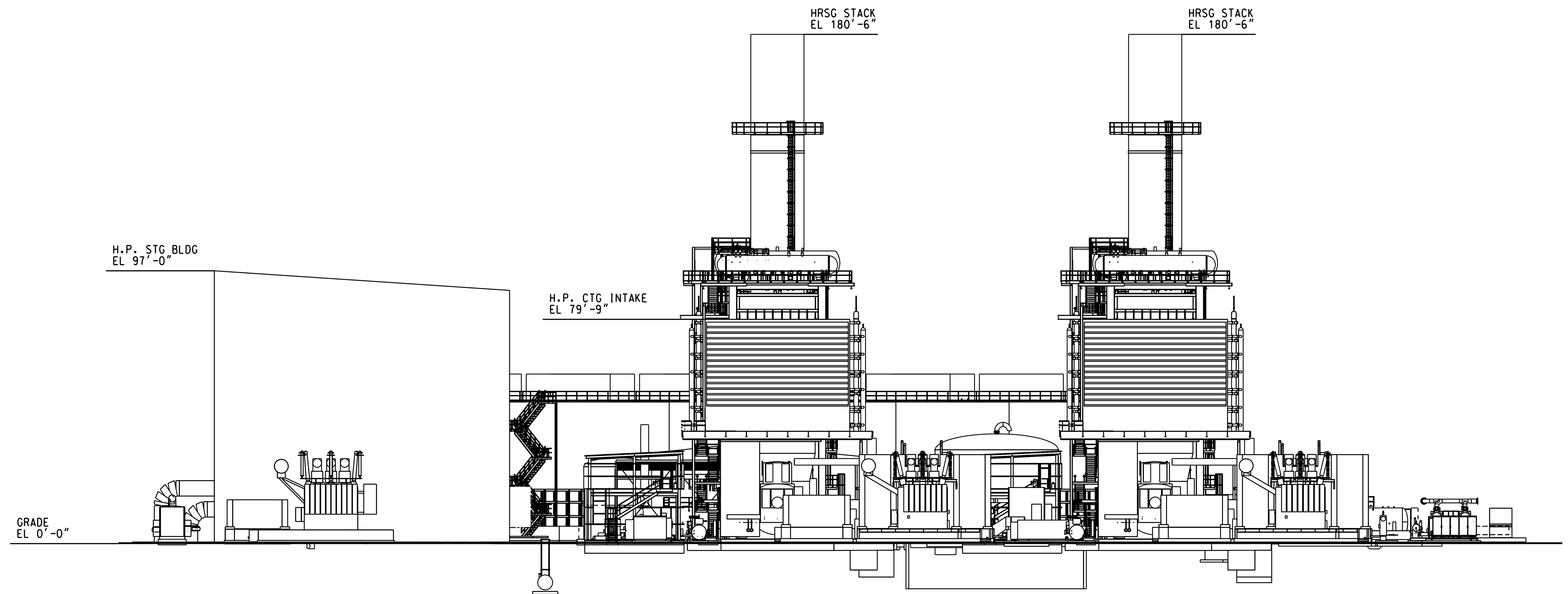
CH2MHILL
CH2MHILL Engineers, Inc.

GENERAL ARRANGEMENT
ELEVATIONS

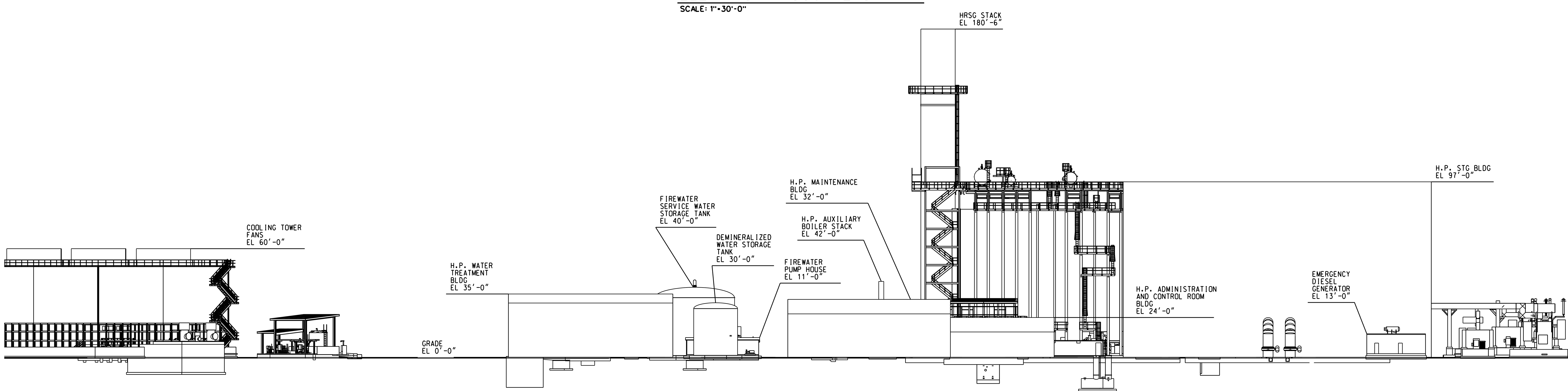
DWG. NO. SK-MP-G-1002
REV. P1

BAR IS ONE INCH ON ORIGINAL DRAWING.
0 1"

FILENAME:
PLOT DATE:



ELEVATION - SOUTHEAST
SCALE: 1"=30'-0"



ELEVATION - SOUTHWEST
SCALE: 1"=30'-0"

30 0 30 60
Scale: 1 INCH = 30 FEET

NO.	DATE	REVISION	BY	CHK
P1	/ /	ISSUED FOR INTERNAL REVIEW	JP	MM

RESPONSIBLE ENGINEER
PE #

REVISION APPROVAL		REV P1 DATE / /	
DISCIPLINE	REVIEWED	DISCIPLINE	REVIEWED
CIVIL	.	ELECTRICAL	.
STRUCTURAL	.	INST & CNTRL	.
MECHANICAL	.	ARCHITECTURAL	.
PROCESS	.	PLANT LAYOUTS	.
PIPING	.		

STATUS					
ISSUED	REV	DATE	DM	SDE	PEM
PRELIMINARY	P1				
FOR REVIEW AND APPROVAL					
APPROVED FOR CONSTRUCTION					
REVISED & APPROVED FOR CONSTRUCTION					

SCALE 1" = 30'-0"

MOUNDSVILLE POWER, LLC
MOUNDSVILLE PROJECT
2 X 1 COMBINED CYCLE
MOUNDSVILLE, WEST VIRGINIA
PROJECT NO. 480102

CH2MHILL
CH2MHILL Engineers, Inc.

GENERAL ARRANGEMENT
ELEVATIONS

DWG. NO. SK-MP-G-1003
REV. P1

FILENAME:
PLOT DATE:

BAR IS ONE INCH ON ORIGINAL DRAWING.
0 1"

Appendix B – Air Quality Dispersion Modeling Protocol (Revised November 27, 2013)

Appendix C – Comparison of GHG Emission Rates and Heat Rates for Combustion Turbines

Moundsville Power LLC

Comparison of GHG Emission Rates and Heat Rates for Combustion Turbines

Project Information		**Turbine Information**		**Other Information**	
Facility	**Location**	**Type**	**Size/Configuration**	**GHG Emission Rate**	**Heat Rate (Btu/kW-hr)**
Proposed Project (Combined-Cycle)					
Moundsville Power LLC	**Moundsville, WV**	**General Electric 7FA.04**	**182.5 MW, Gross, 59°F**	**1,211 lb CO_2/MW-hr, Gross, 59°F, NG Firing, CTG Only** **1,213 lb CO_2e/MW-hr, Gross, 59°F, NG Firing, CTG Only** **791 lb CO_2/MW-hr, Gross, 59°F, NG Firing, Combined-Cycle** **793 lb CO_2e/MW-hr, Gross, 59°F, NG Firing, Combined-Cycle**	**10,387 Btu/kW-hr HHV 59°F, NG Firing, CTG Only** **9,365 Btu/kW-hr LHV 59°F, NG Firing, CTG Only** **6,793 Btu/kW-hr HHV 59°F, NG Firing, Combined-Cycle** **6,125 Btu/kW-hr LHV 59°F, NG Firing, Combined-Cycle**
Proposed Regulations					
40 CFR Part 60 (NSPS) Subpart TTTT Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units (as proposed 9/20/2013)			New combined-cycle trains > 25 MW; existing units and simple-cycle trains are not affected	Units ≤ 850 MMBtu/hr heat input: 1,100 lb CO_2/MW-hr (gross output, 12-operating month average) Units > 850 MMBtu/hr heat input: 1,000 lb CO_2/MW-hr (gross output, 12-operating month annual average)	
Projects with Simple-Cycle Combustion Turbines					
ExTex LaPorte LP Mountain Creek SES	Dallas County, TX	Siemens SGT6-5000F(4) or equivalent	201.2 MW gross, ISO	1,169 lb CO_2e/MW-hr, 12-month rolling average	10,001 (12-month rolling average) 9,620 (Base load/ISO)
El Paso Electric Company Montana Power Station	East El Paso County, TX	General Electric LMS100	100 MW each; simple-cycle; 400 MW total	277,840 tons/yr CO_2e for each of the 4 turbines (365-day rolling average)	9,299
Cheyenne Prairie Generating Station Black Hills Corporation	Cheyenne, WY	General Electric LM6000 PF Sprint	Site-wide 220 MW	187,318 tons/yr CO_2e per turbine	N/A
			2 combined-cycle turbines	1,600 lb CO2 per MW-hr, (12-month rolling average)	
			3 simple-cycle turbines	1,100 lb CO2 per MW-hr, (12-month rolling average)	
Puget Sound Energy Fredonia Generating Station Expansion Project	Fredonia, WA	Four turbine options	Simple-cycle with number of units required to achieve about 200 MW increase	Based on "worst cased emissions"	N/A
		General Electric 7FA.05	207 MW each	1,299 lb CO_2e/MW-hr	
		General Electric 7FA.04	181 MW each	1.310 lb CO_2e/MW-hr	
		Siemens SGT6-5000F4	197 MW each	1,278 lb CO_2e/MW-hr	
		General Electric LMS100	197 MW each	1,138 lb CO_2e/MW-hr	

Moundsville Power LLC
Comparison of GHG Emission Rates and Heat Rates for Combustion Turbines

Project Information		Turbine Information		Other Information	
Facility	**Location**	**Type**	**Size/Configuration**	**GHG Emission Rate**	**Heat Rate (Btu/kW-hr)**
Projects with Combined-Cycle Combustion Turbines					
Lower Colorado River Authority Thomas G. Ferguson Plant	Llano, TX	General Electric 7FA	195 MW each; 590 MW for 2-2-1 combined-cycle configuration	0.459 ton CO_2 /net MW-hr (918 lb CO_2/net MW-hr) (365-day rolling average)	7,720 (365-day rolling average), without duct firing
Coronado Ventures La Paloma Energy Center, LLC	Harlingen, TX	Three options	Combined-cycle with 271 MW steam turbine in 2x2x1 configuration	918.5 lb CO_2/MW-hr	7,720 (365-day rolling average), without duct firing
		General Electric 7FA	183 MW each		
		Siemens SGT6-5000F(4)	205 MW each		
		Siemens SGT6-5000F(5)	232 MW each		
Calpine Corporation Channel Energy Center, LLC	Pasadena, TX	Siemens 501F (FD3)	180 MW combined-cycle with 475 MMBtu/hr duct burner	918.5 lb CO_2/MW-hr	7,730, without duct firing
Calpine/Bechtel Joint Development Russell City Energy Center	Hayward, CA	Siemens-Westinghouse 501FD3	2,038.6 MMBtu/hr each; 200 MMBtu/hr duct burners; 2 combined-cycle trains	119.0 lb CO_2e/MMBtu	7,730, without duct firing
Palmdale Hybrid Power Project	Palmdale, CA	General Electric 7FA	154 MW each; 2x2x1 combined-cycle with 267 MW steam turbine	774 lb CO_2 /net MW-hr (site-wide average) 117 lb CO_2/MMBtu (30-day average for each turbine)	6,970
Cricket Valley Energy Center	Dover, NY	General Electric 7FA.05	Three combined-cycle units with 596.8 MMBtu/hr duct burners	3,576,943 tons CO_2e maximum: emissions from 3 combined-cycle units (12-month rolling average)	7,605, without duct firing
Pioneer Valley Energy Center	Westfield, MA	Not specified	431 MW combined-cycle unit	N/A	6,840, without duct firing
PacifiCorp Energy Lake Side 2 Project	UT	Siemens 501F (FD3)	180 MW combined-cycle with 475 MMBtu/hr duct burner	950 lb CO_2e per MW-hr (12-month rolling average)	N/A
Gateway Cogeneration 1, LLC Smart Water Project	Prince George, VA	N/A	Combined-cycle	N/A	8,983
Sevier Power Company Sevier Power Project	UT	Two natural gas fired combined-cycle combustion turbines with heat recovery steam generators	580 MW (expected generating capacity)	2,019,226 tons CO2e (12-month rolling average)	N/A
Newark Energy Center Project	Newark, NJ	GE F class natural gas fired combined-cycle combustion turbines	655 MW (plant)	1,030,168 tons CO2 per turbine (12-month rolling average)	6,005, without duct firing
Old Bridge Clean Energy Center	Old Bridge, Middlesex County, NJ	700 MW natural gas-fired combined-cycle power plant	N/A	950 lb CO2e/MW-hr (12-month rolling average) 121.521 lb CO2e/MMBtu	N/A
Christian County Generation LLC	Taylorville, IL	F-class combustion turbine (either Siemens or GE); Two combined-cycle combustion turbines firing either SNG or pipeline natural gas	Two combustion turbines and the plant have nominal gross electrical generating capacity of 716 MW; Nominal net electrical generating capacity of 602 MW	2,307,110 tons/yr CO_2e (12-month rolling average) 1,201 lb CO_2/MW-hr	N/A

Appendix D – Air Permit 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):* **Moundsville Power, LLC**	2. Federal Employer ID No. ***(FEIN):*** **46-1954749**
3. Name of facility *(if different from above):* **Same**	4. The applicant is the: ☐ **OWNER** ☐ **OPERATOR** ☒ **BOTH**
5A. Applicant's mailing address: **1214 3rd Street** **Box 1138** **Moundsville, West Virginia 26041**	5B. Facility's present physical address: **NA**

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:

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: **Option to Buy**
- 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.): **Electric Power Generation Unit**	10. North American Industry Classification System **(NAICS)** code for the facility: **221112**
11A. DAQ Plant ID No. (for existing facilities only): **NA**	11B. List all current 45CSR13 and 45CSR30 (Title V) permit numbers associated with this process (for existing facilities only): **NA**

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**.

Approximately three miles south of Moundsville, West Virginia located between State Route 2 and the Ohio River and adjacent to County Highway 2/19. Former Allied Chemical Plant site.

12.B. New site address (if applicable): **Chemical Plant Access Road South** **Moundsville, West Virginia 26041**	12C. Nearest city or town: **Moundsville, West Virginia**	12D. County: **Marshall**
12.E. UTM Northing (KM): **4,417.2**	12F. UTM Easting (KM): **517.3**	12G. UTM Zone: **17**

13. Briefly describe the proposed change(s) at the facility:
Construction of an electric power generation facility.

14A. Provide the date of anticipated installation or change: **Summer 2014**
- 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:
Summer 2017

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.

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.

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
☒ General Emission Unit, specify
☒ Haul Road Emissions
☐ Hot Mix Asphalt Plant
☐ Incinerator
☒ Indirect Heat Exchanger
☐ Quarry
☐ Solid Materials Sizing, Handling and Storage Facilities
☒ Storage Tanks

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

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 Governmental Agency
☐ Authority of Partnership
☐ 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: 12/20/13 *(Please use blue ink)*
35B. Printed name of signee: **Jon M. Williams**		35C. Title: **Managing Member**
35D. E-mail: **jmwilliams@moundsville-power.com**	36E. Phone: **716-856-3333**	36F. FAX: **888-983-5443**
36A. Printed name of contact person (if different from above): **Same**		36B. Title:
36C. E-mail:	36D. Phone:	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.

<u>**Table of Contents**</u>

Attachment A

WEST VIRGINIA
STATE TAX DEPARTMENT
BUSINESS REGISTRATION CERTIFICATE

ISSUED TO:
MOUNDSVILLE POWER, LLC
CHEMICAL PLANT ACCESS RD S
MOUNDSVILLE, WV 26041-0000

BUSINESS REGISTRATION ACCOUNT NUMBER: **2280-1137**

This certificate is issued on: 09/23/2013

This certificate is issued by
the West Virginia State Tax Commissioner
in accordance with Chapter 11, Article 12, of the West Virginia Code

The person or organization identified on this certificate is registered to conduct business in the State of West Virginia at the location above.

This certificate is not transferrable and must be displayed at the location for which issued

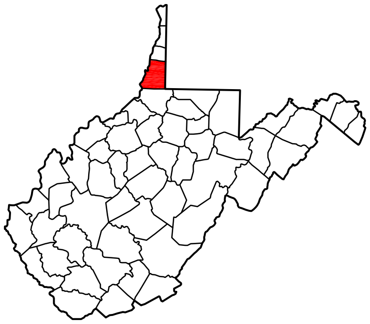
This certificate shall be permanent until cessation of the business for which the certificate of registration was granted or until it is suspended, revoked or cancelled by the Tax Commissioner.

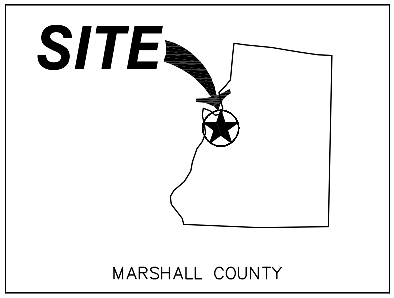
Change in name or change of location shall be considered a cessation of the business and a new certificate shall be required.

TRAVELING/STREET VENDORS: Must carry a copy of this certificate in every vehicle operated by them.
CONTRACTORS, DRILLING OPERATORS, TIMBER/LOGGING OPERATIONS: Must have a copy of this certificate displayed at every job site within West Virginia.

atL006 v.4
L0016871488

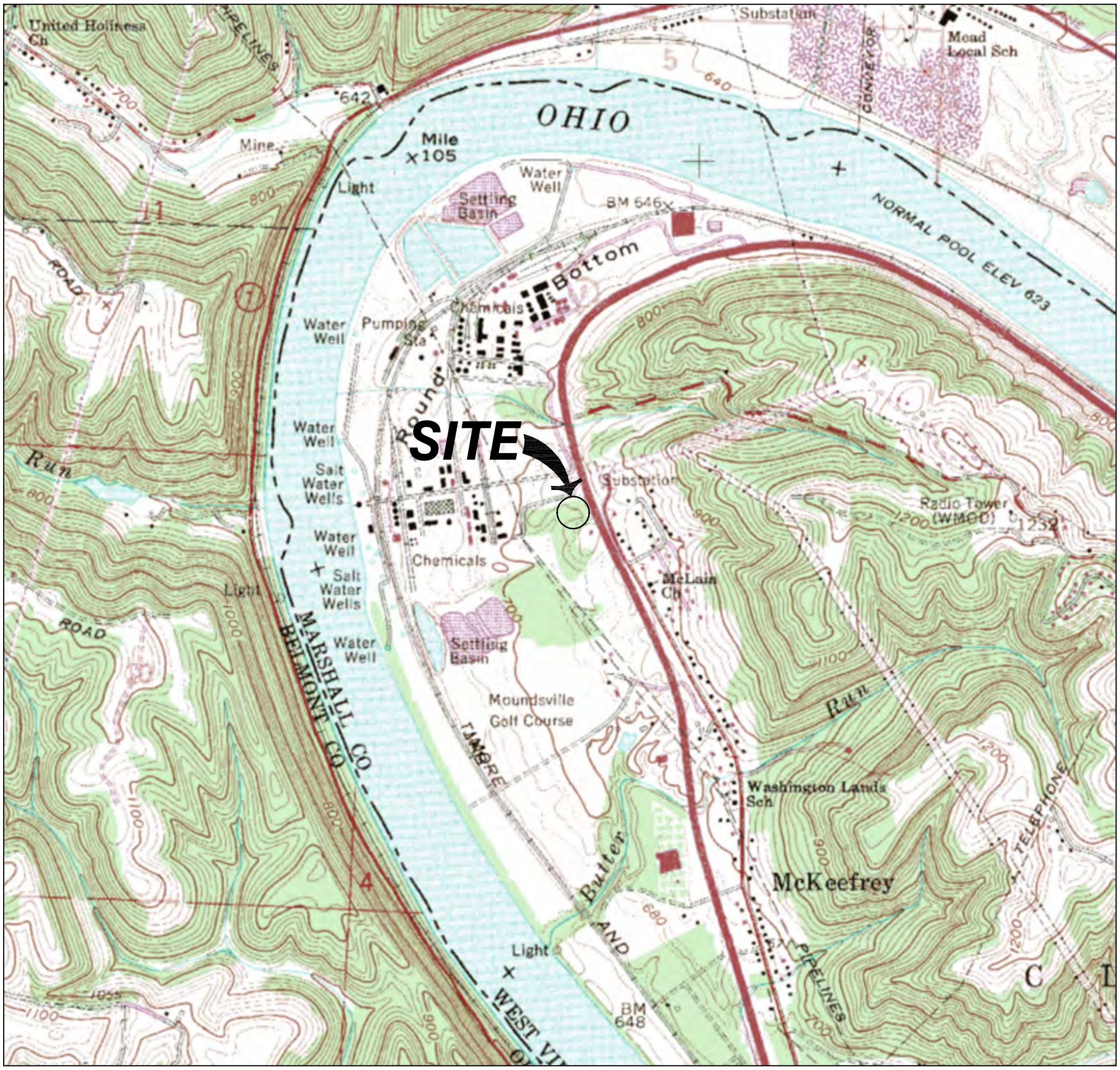
Attachment B





LAT. 39.9047 LON. −80.7973
CITY OF MOUNDSVILLE
MARSHALL COUNTY
WEST VIRGINIA

0 2000
SCALE (IN FEET)



SITE LOCATION MAP

ADAPTED FROM USGS
WEST VIRGINIA, BUSINESSBURG, 1995

REVISIONS ARE TO BE MADE ON THE CADD FILE ONLY

ERM®	**MOUNDSVILLE POWER, LLC** HANLIN–ALLIED–OLIN SUPERFUND SITE CHEMICAL PLANT ACCESS ROAD SOUTH, MOUNDSVILLE, WEST VIRGINIA	CADD Review DF CHK'D DF 0216624
Drawn By SR – 12/20/13	Environmental Resources Management	FIGURE 1

N:\Projects\H\Honeywell\Power Plant\Application Forms\Support Information\Figures\C100.dwg

Attachment C

Attachment C
Schedule of Installation and Start-up

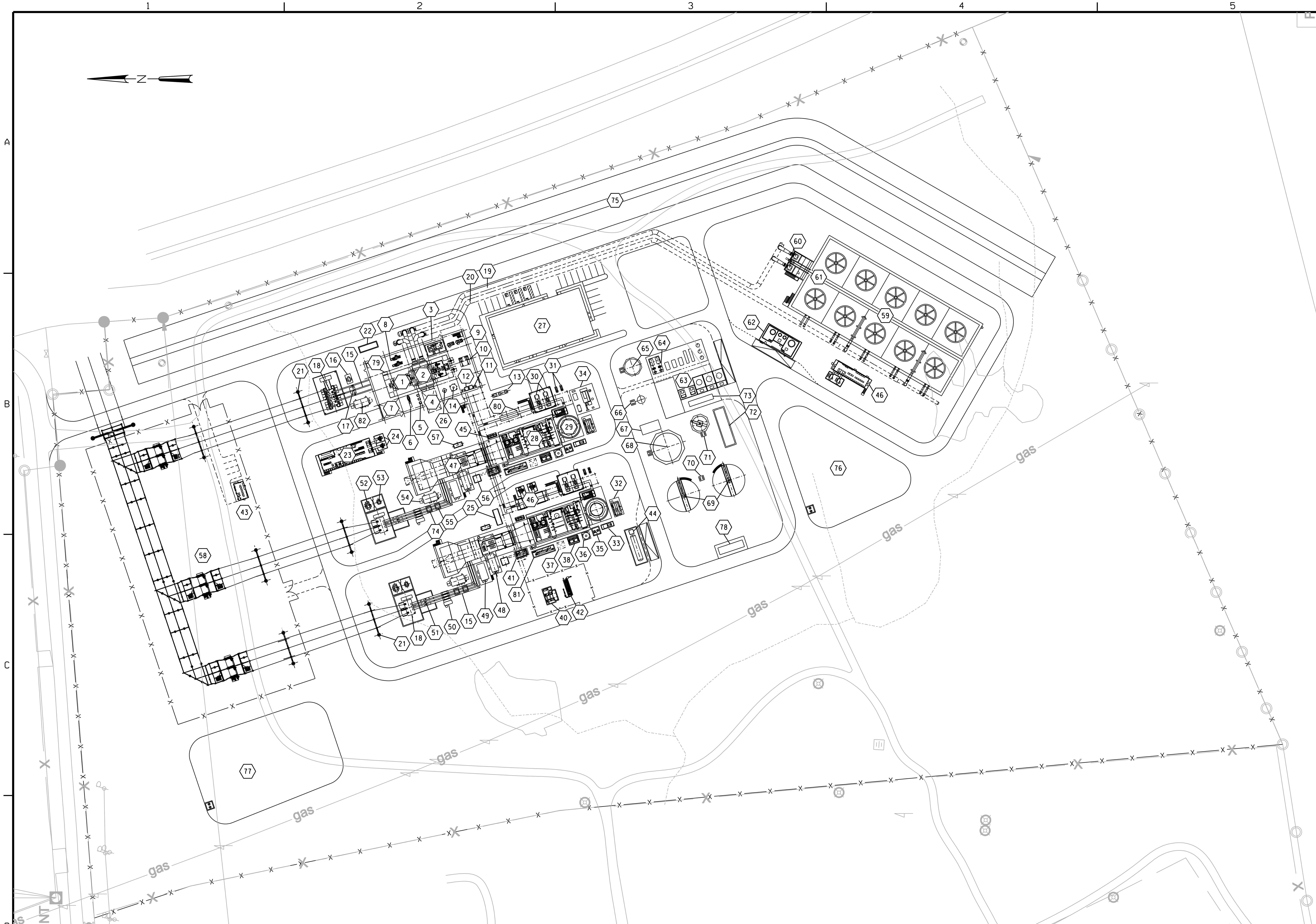
Moundsville Power has tentatively scheduled to begin construction related activities during the summer of 2014. Final installation of equipment and start-up of the facility is tentatively scheduled for the summer of 2017. This schedule may vary depending on actual delivery of equipment, unforeseen construction delays, etc.

Attachment D

Attachment D
Regulatory Discussion

The Plant will be designed and operated in accordance with applicable state and federal regulations. Regulations potentially impacting the proposed Plant are further discussed in Section 3.6 – Applicable Requirements Review of this permit application package.

Attachment E



EQUIPMENT LEGEND

ITEM	EQPT TAG NO	DESCRIPTION
1		STEAM TURBINE GENERATOR (STG) (TURBINE DECK)
2		STEAM SURFACE CONDENSER (GROUND FLOOR)
3		STG LUBE OIL SKID (GROUND FLOOR)
4		CONDENSER TUBE REMOVAL AREA
5		CONDENSATE PUMPS (GROUND FLOOR)
6		STG GLAND STEAM CONDENSER (MEZZANINE LEVEL)
7		TURBINE COMPONENT DROP ZONE (ALL LEVELS)
8		AIR REMOVAL VACUUM PUMPS (MEZZANINE LEVEL)
9		CLOSED COOLING WATER PUMPS (GROUND FLOOR)
10		CLOSED COOLING WATER HEAT EXCHANGERS (GROUND FLOOR)
11		AMINE FEED SKID W/ TOTE (GROUND FLOOR)
12		OXYGEN SCAVENGER FEED SKID (GROUND FLOOR)
13		OIL / WATER SEPARATOR W/ SUMP PUMPS
14		CONDENSTE RECIEVER
15		ISOLATED PHASE BUS DUCT
16		STG EXCITATION TRANSFORMER
17		STG VT & SA CABINET
18		GENERATOR STEP-UP TRANSFORMER (GSU)
19		CIRCULATING WATER SUPPLY
20		CIRCULATING WATER RETURN
21		DEAD END STRUCTURE
22		EMERGENCY DIESEL GENERATOR
23		MAIN POWER DISTRIBUTION CENTER (PDC)
24		STATION SERVICE TRANSFORMERS
25		CT WASH WATER SKID
26		CLOSED COOLING WATER EXPANSION TANK
27		ADMINISTRATION / CONTROL ROOM & MAINTENANCE BUILDING
28		HEAT RECOVERY STEAM GENERATOR (HRSG)
29		HRSG STACK
30		BOILER FEED WATER PUMPS W/ ENCLOSURE
31		LP ECONOMIZER RECIRCULATING PUMPS
32		CONTINUOUS EMISSIONS MONITORING SYSTEM (CEMS)
33		PHOSPHATE FEED SKID
34		AUXILIARY BOILER
35		HRSG BLOWDOWN SUMP W/ PUMPS
36		HRSG BLOWDOWN TANK
37		HRSG SCR REMOVAL AREA
38		HRSG AMMONIA FLOW CONTROL SKID
39		NOT USED
40		FUEL GAS COALESCING FILTERS W/ KNOCKOUT DRUM
41		FUEL GAS STARTUP HEATERS
42		FUEL GAS REGULATING STATION
43		SWITCHYARD CONTROL ROOM
44		AQUEOUS AMMONIA STORAGE TANK AND PUMPS
45		DUCT BURNER SKID
46		PDC W/ STATION SERVICE TRANSFORMERS
47		CONBUSTION TURBINE GENERATOR (CTG)
48		CT ACCESSORY MODULE
49		CT PEEC BUILDING
50		CTG GENERATOR CIRCUIT BREAKER
51		CTG UNIT AUXILIARY TRANSFORMER (UAT)
52		CTG LCI TRANSFORMER
53		CTG EXCITATION TRANSFORMER
54		CTG LCI BUILDING / EXCITER
55		DC LINK REACTOR
56		CT WASH WATER SUMP
57		CT FIRE PROTECTION CO2 SKID
58		SWITCHYARD
59		COOLING TOWER W/ INTAKE SCREENS
60		CIRCULATING WATER PUMPS
61		AUXILIARY COOLING WATER PUMP
62		CIRCULATING WATER CHEMICAL FEED BUILDING
63		WATER TREATMENT BUILDING
64		AIR COMPRESSORS, AIR DRYERS AND AIR RECEIVERS
65		DEMINERALIZED WATER STORAGE TANK AND PUMPS
66		PERMEATE STORAGE TANK AND MAKEUP PUMPS
67		FIREWATER PUMP HOUSE ENCLOSURE
68		FIREWATER / SERVICE WATER STORAGE TANK AND PUMPS
69		CLARIFIERS
70		CLARIFIER SLUDGE PUMPS
71		CLARIFIER SLUDGE THICKENER AND PUMPS
72		CLEARWELL / BACKWASH SUMP
73		FILTER PRESS
74		AC LINK REACTOR
75		DIRT BERM
76		.52 ACRE RETENTION POND W/ PUMPS
77		.68 ACRE RETENTION POND W/ PUMPS
78		HYDROGEN STORAGE TRAILER
79		CO2 BOTTLE RACK
80		STEAM / WATER SAMPLE LAB ENCLOSURE
81		FUEL GAS PERFORMANCE HEATER
82		STG EXCITATION COMPARTMENT

80 0 80 160
Scale: 1 INCH = 80 FEET

RESPONSIBLE ENGINEER
PE #

NO.	DATE	REVISION	BY	CHK
A	11/12/13	ISSUED FOR CLIENT REVIEW	JP	MM
B	11/20/13	REVISED PER CLIENT COMMENTS	JP	MM
C	11/26/13	REVISED SWITCHYARD & DELETED FG SCRUBBER	JP	MM

REVISION APPROVAL — REV — DATE / /

DISCIPLINE	REVIEWED	DISCIPLINE	REVIEWED
CIVIL	.	ELECTRICAL	.
STRUCTURAL	.	INST & CNTRL	.
MECHANICAL	.	ARCHITECTURAL	.
PROCESS	.	PLANT LAYOUTS	.
PIPING	.		

STATUS

ISSUED	REV	DATE	DM	SDE	PEM
PRELIMINARY					
FOR REVIEW AND APPROVAL					
APPROVED FOR CONSTRUCTION					
REVISED & APPROVED FOR CONSTRUCTION					

SCALE 1" = 80'-0"

MOUNDSVILLE POWER, LLC
MOUNDSVILLE PROJECT
2 X 1 COMBINED CYCLE
MOUNDSVILLE, WEST VIRGINIA

PROJECT NO. 480102

CH2MHILL
CH2MHILL Engineers, Inc.

GENERAL ARRANGEMENT

PLOT PLAN

DWG. NO. SK-MP-G-1000

REV. C

FILENAME:

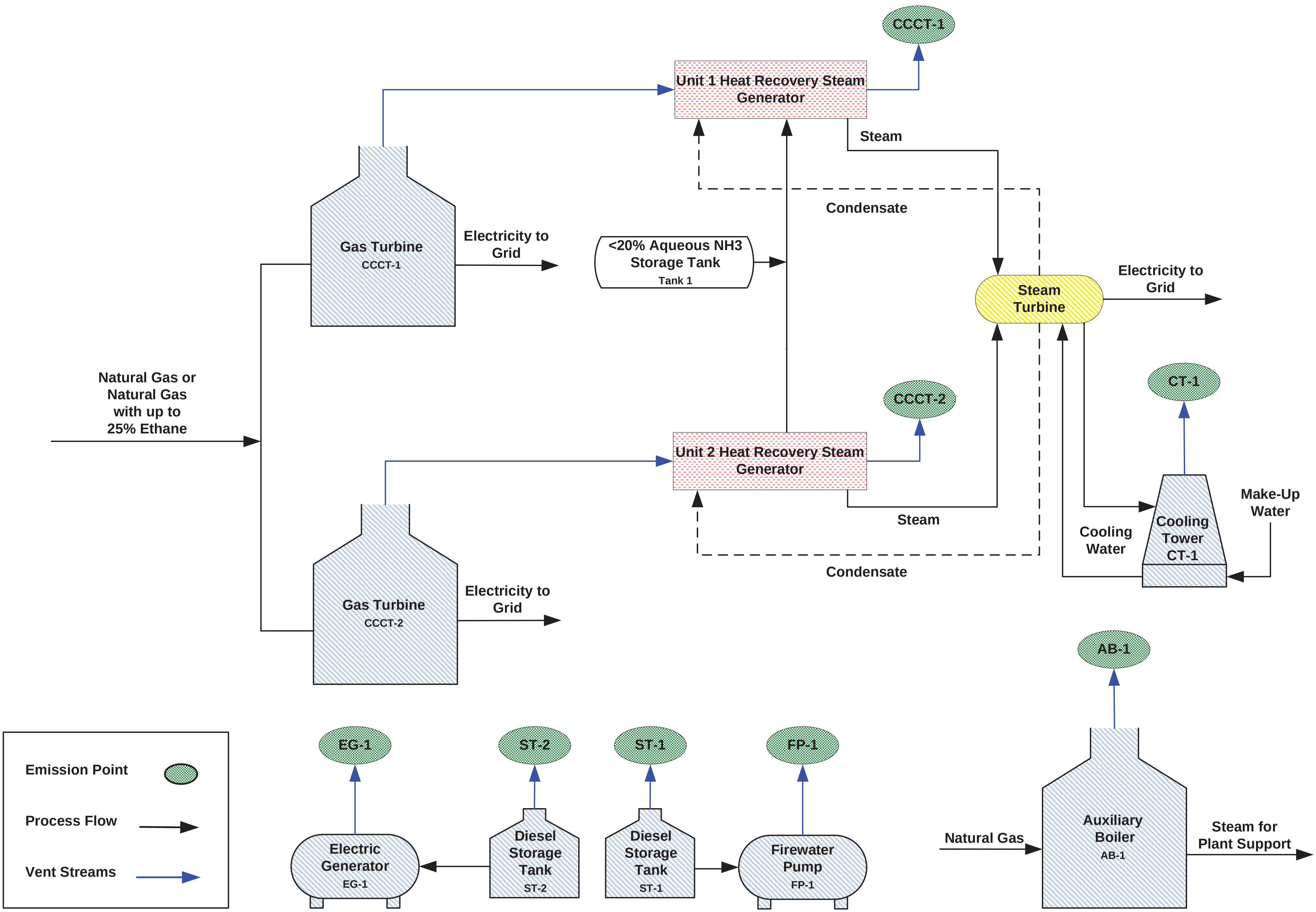
PLOT DATE:

BAR IS ONE INCH ON ORIGINAL DRAWING.
0 1"

Attachment F

Attachment F

Process Flow Diagram



Attachment G

Attachment G
Process Description

The Moundsville Power Plant will generate approximately 525 megawatts (MW)[1] of electricity that will be sold on the Pennsylvania-New Jersey-Maryland Interconnection LLC (PJM) regional electric grid. Pipeline-quality natural gas used by the plant's combustion turbines will be purchased from local suppliers, and will take advantage of the gas produced in nearby natural gas shale plays. In addition, the combustion turbines may fire a blend of pipeline-quality natural gas with up to 25% ethane.

Electricity will be generated using two (2) combined-cycle combustion turbines (CCGT-1 and CCGT-2), each rated at 197 MW (at various ambient temperature design conditions) and 2,087 million Btu per hour (MMBtu/hr)[2]. Electricity generated by the combustion turbines will be routed through a local electrical substation and sold on the grid.

To enhance the plant's overall efficiency and increase the amount of electric generated by the plant, the hot exhaust gases from the combustion turbines is routed to downstream Heat Recovery Steam Generators (HRSGs). The HRSGs contain a series of heat exchangers designed to recover the heat from the turbines' exhaust gas and produce steam, as in a boiler. Each combustion turbine will have its own HRSG. Cooled exhaust gas passing through the HRSGs is vented to the atmosphere through emission points CCGT-1 and CCGT-2. The Selective Catalytic Reduction (SCR) and Oxidation Catalyst control devices used to reduce NO_x and CO emissions from the combustion turbines will be incorporated into the HRSGs, at locations where the emission control reactions optimally occur.

[1] Plant output varies by several factors, including ambient temperature, relative humidity, fuel, load level, whether duct firing or evaporative cooling are in use, etc. 525.6 MW is the expected plant output at a 92 ˚F ambient temperature design condition, 45% relative humidity, at base load, firing a natural gas/ethane fuel mix, with duct firing, and with the combustion turbine evaporative cooling systems off.

[2] Combustion turbine output and heat input vary by several factors, including ambient temperature, relative humidity, fuel, load level, whether duct firing or evaporative cooling are in use, etc. 196.9 MW is the expected combustion turbine output under several operating cases. 2,087 MMBtu/hr is the expected heat input for a single combustion turbine at a 10 ˚F ambient temperature design condition, 60% relative humidity, at base load, firing natural gas, with 100% duct firing, and with the evaporative cooling system off.

The SCRs involve the injection of aqueous ammonia (NH_3) with a concentration of less than 20% by weight into the combustion turbine exhaust gas streams. Ammonia reacts with NO_x in the exhaust gas stream, reducing it to elemental nitrogen (N_2) and water vapor (H_2O). The aqueous ammonia will be stored on-site in one (1) storage tank, with a capacity of 20,000 gallons. The aqueous ammonia storage tank will not normally vent to the atmosphere. It will be equipped with pressure relief valves that would only vent in the event of an emergency. The Oxidation Catalysts do not require the use of chemical reagents.

Steam generated in the HRSGs is routed to a steam driven electric generator. This generator produces up to an additional 203 MW[3] of electricity that is also sold on the grid. Electricity generated by the two (2) combustion turbines and the single steam generator represent the plant's total electrical output.

Water from the plant's wet, mechanical draft Cooling Tower is used to cool the steam driven electric generator. Make-up water is added to the Cooling Tower as necessary to account for water evaporated in the Cooling Tower. Exhaust from the Cooling Tower is vented through emission point CT-1. Steam condensate from the steam generator is routed back to the HRSGs for reuse in the steam cycle.

Support equipment will also be used by the plant to assist with facility operations. A 100 MMBtu/hr Auxiliary Boiler is used to produce steam for plant support. In addition, a 1,500 kW (approximately 2,000 hp) Emergency Generator (EG-1) is used for emergency backup electric power, and a 251 hp Fire Water Pump (FP-1) will be used for plant fire protection. Both the Emergency Generator and the Fire Water Pump will run on ultra low sulfur diesel (USLD) fuel, and will be periodically operated for short periods per manufacturer's maintenance instructions to ensure operational readiness in the event of an emergency. The ULSD fuel will be stored in two (2) small storage tanks; the 500 gallon Fire Water Pump Tank (ST-1), and the 3,000 gallon Emergency Generator Tank (ST-2).

[3] Steam turbine generator output input varies by several factors, including ambient temperature, relative humidity, combustion turbine fuel, load level, whether duct firing or evaporative cooling are in use, etc. 203.33 MW is the expected steam turbine generator output at a at a 73.4 ˚F ambient temperature design condition, at 60% relative humidity, with the combustion turbines at base load, firing a natural gas/ethane fuel mix, with duct firing, and the evaporative cooling systems off.

Attachment H

Attachment H
MSDS

For informational purposes, attached is a typical MSDS for natural gas. Chemical compositions included in this MSDS may vary depending on vendor supply and were not used in determining maximum emission rates.

Material Safety Data Sheet

SECTION 1 PRODUCT AND COMPANY IDENTIFICATION

NATURAL GAS - SWEET

Company Identification
Appalachian/Michigan Business Unit
Chevron North America Exploration and Production Company (a division of Chevron U.S.A. Inc.)
1550 Coraopolis Heights Road
Moon Township, PA 15108
United States of America

Transportation Emergency Response
CHEMTREC: (800) 424-9300 or (703) 527-3887
Health Emergency
Chevron Emergency Information Center: Located in the USA. International collect calls accepted. (800) 231-0623 or (510) 231-0623
Product Information
Product Information: (412) 865-3408

SECTION 2 COMPOSITION/ INFORMATION ON INGREDIENTS

COMPONENTS	CAS NUMBER	AMOUNT
Methane	74-82-8	< 88 %weight
Ethane	74-84-0	< 31 %weight
Propane	74-98-6	< 18 %weight
Butane	106-97-8	< 6 %weight
Carbon dioxide	124-38-9	< 6 %weight
Nitrogen	7727-37-9	< 3 %weight
Benzene	71-43-2	< 2.5 %weight

SECTION 3 HAZARDS IDENTIFICATION

****
EMERGENCY OVERVIEW

- FLAMMABLE GAS. MAY CAUSE FLASH FIRE
- CONTENTS UNDER PRESSURE
- NO ODORANT ADDED; DETECTION OF LEAK VIA SENSE OF SMELL MAY NOT BE POSSIBLE
- MAY CAUSE DIZZINESS, DROWSINESS AND REDUCED ALERTNESS
- MAY CAUSE CANCER
- CONTAINS MATERIAL THAT MAY CAUSE DAMAGE TO:
- BLOOD/BLOOD FORMING ORGANS

- REDUCES OXYGEN AVAILABLE FOR BREATHING
****

IMMEDIATE HEALTH EFFECTS
Eye: Not expected to cause prolonged or significant eye irritation.
Skin: Contact with the skin is not expected to cause prolonged or significant irritation. Contact with the skin is not expected to cause an allergic skin response. Not expected to be harmful to internal organs if absorbed through the skin.
Ingestion: Material is a gas and cannot usually be swallowed.
Inhalation: This material can act as a simple asphyxiant by displacement of air. Symptoms of asphyxiation may include rapid breathing, incoordination, rapid fatigue, excessive salivation, disorientation, headache, nausea, and vomiting. Convulsions, loss of consciousness, coma, and/or death may occur if exposure to high concentrations continues. Excessive or prolonged breathing of this material may cause central nervous system effects. Central nervous system effects may include headache, dizziness, nausea, vomiting, weakness, loss of coordination, blurred vision, drowsiness, confusion, or disorientation. At extreme exposures, central nervous system effects may include respiratory depression, tremors or convulsions, loss of consciousness, coma or death. If this material is heated, fumes may be unpleasant and produce nausea and irritation of the eye and upper respiratory tract.

DELAYED OR OTHER HEALTH EFFECTS:
Reproduction and Birth Defects: This material is not expected to cause adverse reproductive effects based on animal data.This material is not expected to cause harm to the unborn child based on animal data.
Cancer: Prolonged or repeated exposure to this material may cause cancer. Contains benzene, which has been classified as a carcinogen by the National Toxicology Program (NTP) and a Group 1 carcinogen (carcinogenic to humans) by the International Agency for Research on Cancer (IARC).

Target Organs: Contains material that may cause damage to the following organ(s) following repeated inhalation at concentrations above the recommended exposure limit: Blood/Blood Forming Organs
See Section 11 for additional information. Risk depends on duration and level of exposure.

SECTION 4 FIRST AID MEASURES

Eye: No specific first aid measures are required. As a precaution, remove contact lenses, if worn, and flush eyes with water.
Skin: No specific first aid measures are required. As a precaution, remove clothing and shoes if contaminated. To remove the material from skin, use soap and water. Discard contaminated clothing and shoes or thoroughly clean before reuse.
Ingestion: No specific first aid measures are required because this material is a gas.
Inhalation: During an emergency, wear an approved, positive pressure air-supplying respirator. Move the exposed person to fresh air. If not breathing, give artificial respiration. If breathing is difficult, give oxygen. Get immediate medical attention.

SECTION 5 FIRE FIGHTING MEASURES

SPECIAL NOTES: In case of fire do not extinguish. Stop flow of fuel and allow fire to burn out.

FIRE CLASSIFICATION:
OSHA Classification (29 CFR 1910.1200): Flammable gas.

NFPA RATINGS: Health: 1 Flammability: 4 Reactivity: 0

FLAMMABLE PROPERTIES:

Flashpoint: -162 °C (-260 °F) (Typical)
Autoignition: 482 °C - 632 °C (900 °F - 1170 °F)
Flammability (Explosive) Limits (% by volume in air): Lower: 3.8 Upper: 17

EXTINGUISHING MEDIA: Allow gas to burn if flow cannot be shut off safely. Apply water from a safe distance to cool container, surrounding equipment and structures. Container areas exposed to direct flame contact should be cooled with large quantities of water (500 gallons water per minute flame impingement exposure) to prevent weakening of container structure.

PROTECTION OF FIRE FIGHTERS:
Fire Fighting Instructions: Do not extinguish. Stop flow of fuel and allow fire to burn out. If flames are accidentally extinguished, explosive reignition may occur. Eliminate ignition sources. Keep people away. Isolate fire area and deny unnecessary entry. Immediately withdraw all personnel from area in case of rising sound from venting safety device or discoloration of the container. For unignited vapor cloud, use water spray to knock down and control dispersion of vapors. Use water spray to cool fire-exposed containers and fire-affected zone until fire is out and danger of reignition has passed. See Section 7 for proper handling and storage. For fires involving this material, do not enter any enclosed or confined fire space without proper protective equipment, including self-contained breathing apparatus.
Combustion Products: Highly dependent on combustion conditions. A complex mixture of airborne solids, liquids, and gases including carbon monoxide, carbon dioxide, and unidentified organic compounds will be evolved when this material undergoes combustion.

SECTION 6 ACCIDENTAL RELEASE MEASURES

Protective Measures: Eliminate all sources of ignition in vicinity of released gas. If this material is released into the work area, evacuate the area immediately. Monitor area with combustible gas indicator. For large releases, warn public of downwind explosion hazard.
Spill Management: Stop the source of the release if you can do it without risk. Observe precautions in Exposure Controls/Personal Protection section of the MSDS. All equipment used when handling the product must be grounded. If possible, turn leaking containers so that gas escapes rather than liquid. Use water spray to reduce vapors or divert vapor cloud drift. Do not direct water at spill or source of leak. Prevent spreading of vapors through sewers, ventilation systems and confined areas. Isolate area until gas has dispersed.
Reporting: Report spills to local authorities and/or the U.S. Coast Guard's National Response Center at (800) 424-8802 as appropriate or required.

SECTION 7 HANDLING AND STORAGE

Precautionary Measures: This material presents a fire hazard. Gas can catch fire and burn with explosive force. Invisible gas spreads easily and can be set on fire by many sources such as pilot lights, welding equipment, and electrical motors and switches. Gases are heavier than air and may travel along the ground or into drains to possible distant ignition sources that may cause an explosive flashback. Do not breathe gas. Wash thoroughly after handling.
Unusual Handling Hazards: This product does not contain an odorant. Detection of leak via sense of smell, therefore, may not be possible.
Static Hazard: Electrostatic charge may accumulate and create a hazardous condition when handling this material. To minimize this hazard, bonding and grounding may be necessary but may not, by themselves, be sufficient. Review all operations which have the potential of generating and accumulating an electrostatic charge and/or a flammable atmosphere (including tank and container filling, splash filling, tank cleaning, sampling, gauging, switch loading, filtering, mixing, agitation, and vacuum truck operations) and use appropriate mitigating procedures. For more information, refer to OSHA Standard 29 CFR 1910.106, 'Flammable and Combustible Liquids', National Fire Protection Association (NFPA 77, 'Recommended Practice on Static Electricity', and/or the American Petroleum Institute (API)

Recommended Practice 2003, 'Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents'.
General Storage Information: DO NOT USE OR STORE near heat, sparks, flames, or hot surfaces . USE AND STORE ONLY IN WELL VENTILATED AREA. Keep container closed when not in use. When working with this material, the minimal oxygen content should be 19.5% by volume under normal atmospheric pressure.

SECTION 8 EXPOSURE CONTROLS/PERSONAL PROTECTION

GENERAL CONSIDERATIONS:
Consider the potential hazards of this material (see Section 3), applicable exposure limits, job activities, and other substances in the work place when designing engineering controls and selecting personal protective equipment. If engineering controls or work practices are not adequate to prevent exposure to harmful levels of this material, the personal protective equipment listed below is recommended. The user should read and understand all instructions and limitations supplied with the equipment since protection is usually provided for a limited time or under certain circumstances.

ENGINEERING CONTROLS:
Use process enclosures, local exhaust ventilation, or other engineering controls to control airborne levels below the recommended exposure limits. Use in a well-ventilated area. Use explosion-proof ventilation equipment.

PERSONAL PROTECTIVE EQUIPMENT
Eye/Face Protection: No special eye protection is normally required. Where splashing is possible, wear safety glasses with side shields as a good safety practice.
Skin Protection: No special protective clothing is normally required. Where splashing is possible, select protective clothing depending on operations conducted, physical requirements and other substances in the workplace. Suggested materials for protective gloves include: Nitrile Rubber, Viton.
Respiratory Protection: Determine if airborne concentrations are below the recommended occupational exposure limits for jurisdiction of use. If airborne concentrations are above the acceptable limits, wear an approved respirator that provides adequate protection from this material, such as: Supplied-Air Respirator, or Air-Purifying Respirator for Organic Vapors.
Wear an approved positive pressure air-supplying respirator unless ventilation or other engineering controls are adequate to maintain a minimal oxygen content of 19.5% by volume under normal atmospheric pressure.
Use a positive pressure air-supplying respirator in circumstances where air-purifying respirators may not provide adequate protection.

Occupational Exposure Limits:

Component	Agency	TWA	STEL	Ceiling	Notation
Benzene	ACGIH	.5 ppm (weight)	2.5 ppm (weight)	--	Skin A1 Skin
Benzene	CVX	1 ppm (weight)	5 ppm (weight)	--	--
Benzene	OSHA SRS	1 ppm (weight)	5 ppm (weight)	--	--
Benzene	OSHA Z-2	10 ppm (weight)	--	25 ppm (weight)	--
Butane	ACGIH	1000 ppm (weight)	--	--	--
Carbon dioxide	ACGIH	5000 ppm (weight)	30000 ppm (weight)	--	--
Carbon dioxide	OSHA Z-1	9000 mg/m3	--	--	--

Ethane	ACGIH	1000 ppm (weight)	--	--	--
Methane	ACGIH	1000 ppm (weight)	--	--	--
Nitrogen	ACGIH	--	--	--	Simple asphyxiant.
Propane	ACGIH	1000 ppm (weight)	--	--	--
Propane	OSHA Z-1	1800 mg/m3	--	--	--

Consult local authorities for appropriate values.

SECTION 9 PHYSICAL AND CHEMICAL PROPERTIES

Attention: the data below are typical values and do not constitute a specification.

Color: Colorless
Physical State: Gas
Odor: Odorless
pH: Not Applicable
Vapor Pressure: 760 mmHg
Vapor Density (Air = 1): No data available
Boiling Point: -162°C (-259.6°F)
Solubility: Insoluble in water.
Freezing Point: No data available
Melting Point: -184°C (-299.2°F)
Specific Gravity: 0.57
Density: No data available
Viscosity: No data available

SECTION 10 STABILITY AND REACTIVITY

Chemical Stability: This material is considered stable under normal ambient and anticipated storage and handling conditions of temperature and pressure.
Incompatibility With Other Materials: May react with strong acids or strong oxidizing agents, such as chlorates, nitrates, peroxides, etc.
Hazardous Decomposition Products: Carbon Dioxide (Elevated temperatures), Carbon Monoxide (Elevated temperatures)
Hazardous Polymerization: Hazardous polymerization will not occur.

SECTION 11 TOXICOLOGICAL INFORMATION

IMMEDIATE HEALTH EFFECTS
Eye Irritation: The eye irritation hazard is based on evaluation of data for similar materials or product components.
Skin Irritation: The skin irritation hazard is based on evaluation of data for similar materials or product components.
Skin Sensitization: The skin sensitization hazard is based on evaluation of data for similar materials or product components.
Acute Dermal Toxicity: The acute dermal toxicity hazard is based on evaluation of data for similar materials or product components.

Acute Oral Toxicity: The acute oral toxicity hazard is based on evaluation of data for similar materials or product components.

Acute Inhalation Toxicity: The acute inhalation toxicity hazard is based on evaluation of data for similar materials or product components.

ADDITIONAL TOXICOLOGY INFORMATION:

This product contains butane. An atmospheric concentration of 100,000 ppm (10%) butane is not noticeably irritating to the eyes, nose or respiratory tract, but will produce slight dizziness in a few minutes of exposure. No chronic systemic effect has been reported from occupational exposure.

This product contains benzene.
GENETIC TOXICITY/CANCER: Repeated or prolonged breathing of benzene vapor has been associated with the development of chromosomal damage in experimental animals and various blood diseases in humans ranging from aplastic anemia to leukemia (a form of cancer). All of these diseases can be fatal. In some individuals, benzene exposure can sensitize cardiac tissue to epinephrine which may precipitate fatal ventricular fibrillation.
REPRODUCTIVE/DEVELOPMENTAL TOXICITY: No birth defects have been shown to occur in pregnant laboratory animals exposed to doses not toxic to the mother. However, some evidence of fetal toxicity such as delayed physical development has been seen at such levels. The available information on the effects of benzene on human pregnancies is inadequate but it has been established that benzene can cross the human placenta.
OCCUPATIONAL: The OSHA Benzene Standard (29 CFR 1910.1028) contains detailed requirements for training, exposure monitoring, respiratory protection and medical surveillance triggered by the exposure level. Refer to the OSHA Standard before using this product.

This product may contain detectable but varying quantities of the naturally occurring radioactive substance radon 222. The amount in the gas itself is not hazardous, but since radon rapidly decays (t1/2 = 3.82days) to form other radioactive elements including lead 210, polonium 210, and bismuth 210, equipment may contain radioactivity. The radon decay products are solids and therefore may attach to dust particles or form films and sludges in equipment. Inhalation, ingestion or skin contact with radon decay products can lead to the deposit (or presence) of radioactive material in the respiratory tract, bone, blood forming organs, intestinal tract, and kidney, which may lead to certain cancers. The International Agency for Research on Cancer (IARC) has classified radon as a Group 1 carcinogen. Some studies of people occupationally exposed to radiation indicate an increased incidence of chromosomal aberrations; the clinical significance of this increase is unknown. Risks can be minimized by following good industrial and personal hygiene practices noted in the section on storage and handling.

SECTION 12 ECOLOGICAL INFORMATION

ECOTOXICITY

This material is not expected to be harmful to aquatic organisms. The ecotoxicity hazard is based on an evaluation of data for the components or a similar material.

ENVIRONMENTAL FATE

Ready Biodegradability: This material is expected to be readily biodegradable. The biodegradability of this material is based on an evaluation of data for the components or a similar material.

SECTION 13 DISPOSAL CONSIDERATIONS

Use material for its intended purpose or recycle if possible. This material, if it must be discarded, may meet the criteria of a hazardous waste as defined by US EPA under RCRA (40 CFR 261) or other State and local regulations. Measurement of certain physical properties and analysis for regulated components may be necessary to make a correct determination. If this material is classified as a hazardous waste, federal law requires disposal at a licensed hazardous waste disposal facility.

SECTION 14 TRANSPORT INFORMATION

The description shown may not apply to all shipping situations. Consult 49CFR, or appropriate Dangerous Goods Regulations, for additional description requirements (e.g., technical name) and mode-specific or quantity-specific shipping requirements.

DOT Shipping Description: UN1971, NATURAL GAS, COMPRESSED, 2.1 ADDITIONAL INFORMATION - RQ (BENZENE) FOR SINGLE PACKAGES CONTAINING GREATER THAN OR EQUAL TO 10 LBS AND CONCENTRATION OF 200 PPM

IMO/IMDG Shipping Description: UN1971, NATURAL GAS, COMPRESSED, 2.1

ICAO/IATA Shipping Description: UN1971, NATURAL GAS, COMPRESSED, 2.1

SECTION 15 REGULATORY INFORMATION

EPCRA 311/312 CATEGORIES:

1. Immediate (Acute) Health Effects: YES
2. Delayed (Chronic) Health Effects: YES
3. Fire Hazard: YES
4. Sudden Release of Pressure Hazard: YES
5. Reactivity Hazard: NO

REGULATORY LISTS SEARCHED:

01-1=IARC Group 1	03=EPCRA 313
01-2A=IARC Group 2A	04=CA Proposition 65
01-2B=IARC Group 2B	05=MA RTK
02=NTP Carcinogen	06=NJ RTK
	07=PA RTK

The following components of this material are found on the regulatory lists indicated.

Benzene	01-1, 02, 04, 05, 06, 07
Butane	05, 06, 07
Carbon dioxide	05, 06, 07
Ethane	05, 06, 07
Methane	05, 06, 07
Nitrogen	05, 06, 07
Propane	05, 06, 07

CERCLA REPORTABLE QUANTITIES(RQ)/EPCRA 302 THRESHOLD PLANNING QUANTITIES(TPQ):

Component	Component RQ	Component TPQ	Product RQ
Benzene	10 lbs	None	400 lbs

CHEMICAL INVENTORIES:
All components comply with the following chemical inventory requirements: AICS (Australia), DSL (Canada), EINECS (European Union), IECSC (China), KECI (Korea), PICCS (Philippines), TSCA (United States).

SECTION 16 OTHER INFORMATION

NFPA RATINGS: Health: 1 Flammability: 4 Reactivity: 0

HMIS RATINGS: Health: 1* Flammability: 4 Reactivity: 0
(0-Least, 1-Slight, 2-Moderate, 3-High, 4-Extreme, PPE:- Personal Protection Equipment Index recommendation, *- Chronic Effect Indicator). These values are obtained using the guidelines or published evaluations prepared by the National Fire Protection Association (NFPA) or the National Paint and Coating Association (for HMIS ratings).

REVISION STATEMENT: This revision updates the following sections of this Material Safety Data Sheet: 2, 3, 4, 5, 6, 7, 8, 12, 15
Revision Date: NOVEMBER 01, 2011

ABBREVIATIONS THAT MAY HAVE BEEN USED IN THIS DOCUMENT:

TLV - Threshold Limit Value	TWA - Time Weighted Average
STEL - Short-term Exposure Limit	PEL - Permissible Exposure Limit
	CAS - Chemical Abstract Service Number
ACGIH - American Conference of Governmental Industrial Hygienists	IMO/IMDG - International Maritime Dangerous Goods Code
API - American Petroleum Institute	MSDS - Material Safety Data Sheet
CVX - Chevron	NFPA - National Fire Protection Association (USA)
DOT - Department of Transportation (USA)	NTP - National Toxicology Program (USA)
IARC - International Agency for Research on Cancer	OSHA - Occupational Safety and Health Administration

Prepared according to the OSHA Hazard Communication Standard (29 CFR 1910.1200) and the ANSI MSDS Standard (Z400.1) by the Chevron Energy Technology Company, 100 Chevron Way, Richmond, California 94802.

The above information is based on the data of which we are aware and is believed to be correct as of the date hereof. Since this information may be applied under conditions beyond our control and with which we may be unfamiliar and since data made available subsequent to the date hereof may suggest modifications of the information, we do not assume any responsibility for the results of its use. This information is furnished upon condition that the person receiving it shall make his own determination of the suitability of the material for his particular purpose.

Attachment I

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]
CCCT-1	**CCCT-1**	**Combined-Cycle Combustion Turbine**	**2017**	**2,087 MMBtu/hr**	**New**	**DLNC & SCR, Oxidation Catalyst**
CCCT-2	**CCCT-2**	**Combined-Cycle Combustion Turbine**	**2017**	**2,087 MMBtu/hr**	**New**	**DLNC & SCR, Oxidation Catalyst**
NA	**NA**	**CCCT-1 Heat Recovery Steam Generator with Duct Burners**	**2017**	**72.1 MMBtu/hr**	**New**	**NA**
NA	**NA**	**CCCT-2 Heat Recovery Steam Generator with Duct Burners**	**2017**	**72.1 MMBtu/hr**	**New**	**NA**
NA	**NA**	**Steam Turbine Electric Generator**	**2017**	**197 MW**	**New**	**NA**
CT-1	**CT-1**	**Cooling Tower**	**2017**	**159,000 gpm**	**New**	**NA**
AB-1	**AB-1**	**Auxiliary Boiler**	**2017**	**100 MMBtu/hr**	**New**	**ULNB, FGR**
FP-1	**FP-1**	**Firewater Pump**	**2017**	**251 hp**	**New**	**NA**
EG-1	**EG-1**	**Emergency Electric Generator**	**2017**	**1,500 kW**	**New**	**NA**
ST-1	**ST-1**	**Fire Water Pump Tank (ULSD)**	**2017**	**500 gallons**	**New**	**NA**
ST-2	**ST-2**	**Emergency Generator Tank (ULSD)**	**2017**	**3,000 gallons**	**New**	**NA**
NA	**NA**	**Aqueous Ammonia Storage Tank 1**	**2017**	**20,000 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 J

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] (mg/m^3)
		ID No.	Source	ID No.	Device Type	Short Term[2]	Max (hr/yr)		lb/hr	ton/yr	lb/hr	ton/yr			
CCCT-1	**Upward Vertical Stack**	**CCCT- 1**	**Comb. Cycle Combust . Turbine**	**NA**	**Low NOx Burners & SCR, Oxidation Catalyst**	**C**	**8,760**	**NO_x**	**113.4**	**523.1**	**15.20**	**70.10**	**Gas**	**EE**	**4.2**
								CO	**33.72**	**369.0**	**9.24**	**101.1**	**Gas**	**EE**	**2.6**
								Total VOC	**5.28**	**26.95**	**5.28**	**36.95**	**Gas**	**EE**	**1.5**
								PM/PPM_{10}/PM2.5	**7.56**	**33.70**	**7.56**	**33.70**	**Solid**	**EE**	**2.1**
								SO_2	**0.55**	**2.39**	**0.55**	**2.39**	**Gas**	**EE**	**0.2**
								Sulfur Acid Mist	**0.35**	**1.55**	**0.35**	**1.55**	**Solid**	**EE**	**0.1**
								Lead	**0.001**	**0.005**	**0.001**	**0.005**	**Solid**	**AP-42**	**<0.001**
								Acetaldehyde	**0.08**	**0.35**	**0.08**	**0.35**	**Gas**	**AP-42**	**0.02**
								Acrolein	**0.01**	**0.05**	**0.01**	**0.05**	**Gas**	**AP-42**	**0.004**
								Benzene	**0.02**	**0.10**	**0.02**	**0.10**	**Gas**	**AP-42**	**0.007**
								Ethylbenzene	**0.06**	**0.28**	**0.06**	**0.28**	**Gas**	**AP-42**	**0.02**
								Formaldehyde	**0.60**	**2.65**	**0.60**	**2.65**	**Gas**	**AP-42**	**0.2**
								Hexane	**0.13**	**0.55**	**0.13**	**0.55**	**Gas**	**AP-42**	**0.03**
								Naphthalene	**0.003**	**0.01**	**0.003**	**0.01**	**Gas**	**AP-42**	**0.001**
								POM	**0.004**	**0.02**	**0.004**	**0.02**	**Gas**	**AP-42**	**0.001**
								Toluene	**0.26**	**1.15**	**0.26**	**1.15**	**Gas**	**AP-42**	**0.08**
								Xylenes	**0.13**	**0.56**	**0.13**	**0.56**	**Gas**	**AP-42**	**0.04**
								Total HAP	**1.30**	**5.95**	**1.30**	**5.95**	**Gas**	**AP-42**	**0.4**
								CO_{2e}	**254,315**	**1,113,898**	**254,315**	**1,113,898**	**Gas**	**Sub. C**	**70,410**
CCCT-2	**Upward Vertical Stack**	**CCCT-2**	**Comb. Cycle Combust . Turbine**	**NA**	**Low NOx Burners & SCR, Oxidation Catalyst**	**C**	**8,760**	**NO_x**	**113.4**	**523.1**	**15.20**	**70.10**	**Gas**	**EE**	**4.2**
								CO	**33.72**	**369.0**	**9.24**	**101.1**	**Gas**	**EE**	**2.6**
								Total VOC	**5.28**	**26.95**	**5.28**	**36.95**	**Gas**	**EE**	**1.5**
								PM/PPM_{10}/PM2.5	**7.56**	**33.70**	**7.56**	**33.70**	**Solid**	**EE**	**2.1**
								SO_2	**0.55**	**2.39**	**0.55**	**2.39**	**Gas**	**EE**	**0.2**
								Sulfur Acid Mist	**0.35**	**1.55**	**0.35**	**1.55**	**Solid**	**EE**	**0.1**
								Lead	**0.001**	**0.005**	**0.001**	**0.005**	**Solid**	**AP-42**	**<0.001**
								Acetaldehyde	**0.08**	**0.35**	**0.08**	**0.35**	**Gas**	**AP-42**	**0.02**
								Acrolein	**0.01**	**0.05**	**0.01**	**0.05**	**Gas**	**AP-42**	**0.004**
								Benzene	**0.02**	**0.10**	**0.02**	**0.10**	**Gas**	**AP-42**	**0.007**
								Ethylbenzene	**0.06**	**0.28**	**0.06**	**0.28**	**Gas**	**AP-42**	**0.02**
								Formaldehyde	**0.60**	**2.65**	**0.60**	**2.65**	**Gas**	**AP-42**	**0.2**
								Hexane	**0.13**	**0.55**	**0.13**	**0.55**	**Gas**	**AP-42**	**0.03**
								Naphthalene	**0.003**	**0.01**	**0.003**	**0.01**	**Gas**	**AP-42**	**0.001**
								POM	**0.004**	**0.02**	**0.004**	**0.02**	**Gas**	**AP-42**	**0.001**
								Toluene	**0.26**	**1.15**	**0.26**	**1.15**	**Gas**	**AP-42**	**0.08**
								Xylenes	**0.13**	**0.56**	**0.13**	**0.56**	**Gas**	**AP-42**	**0.04**
								Total HAP	**1.30**	**5.95**	**1.30**	**5.95**	**Gas**	**AP-42**	**0.4**
								CO_{2e}	**254,315**	**1,113,898**	**254,315**	**1,113,898**	**Gas**	**Sub. C**	**70,410**

- **For turbines CCCT-1 and CCCT-2, annual NOx, CO, VOC, and PM represents combined steady state, start-up, and shutdown emission rates.**

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] (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	**NA**	**CT-1**	**Cooling Tower**	**NA**	**NA**	**C**	**8,760**	**PM** **PM_{10}** **$PM_{2.5}$**	**0.72** **0.48** **0.002**	**3.15** **2.51** **0.007**	**0.72** **0.48** **0.002**	**3.15** **2.51** **0.007**	**Solid** **Solid** **Solid**	**EE** **EE** **EE**	**0.13** **0.1** **<0.001**
ST-1	**Upward Vertical Stack**	**ST-1**	**Diesel Storage Tank**	**NA**	**NA**	**C**	**8,760**	**Total VOC**	**<0.001**	**<0.001**	**<0.001**	**<0.001**	**Gas**	**AP-42**	**NA**
ST-2	**Upward Vertical Stack**	**ST-2**	**Diesel Storage Tank**	**NA**	**NA**	**C**	**8,760**	**Total VOC**	**<0.001**	**<0.001**	**<0.001**	**<0.001**	**Gas**	**AP-42**	**NA**

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] (mg/m^3)
		ID No.	Source	ID No.	Device Type	Short Term[2]	Max (hr/yr)		lb/hr	ton/yr	lb/hr	ton/yr			
AB-1	**Upward Vertical Stack**	**AB-1**	**Aux. Boiler**	**NA**	**Ultra Low NOx Burners & FGR**	**As Required**	**2,000**	**NO_x**	**4.00**	**4.00**	**2.00**	**2.00**	**Gas**	**EE**	**5.3**
								CO	**4.00**	**4.00**	**4.00**	**4.00**	**Gas**	**EE**	**11**
								Total VOC	**0.60**	**0.60**	**0.60**	**0.60**	**Gas**	**EE**	**1.6**
								PM/PPM_{10}/PM2.5	**0.50**	**0.50**	**0.50**	**0.50**	**Gas**	**EE**	**1.3**
								SO_2	**0.06**	**0.06**	**0.06**	**0.06**	**Gas**	**AP-42**	**0.2**
								Sulfuric Acid Mist	**0.005**	**0.005**	**0.005**	**0.005**	**Solid**	**EE**	**0.01**
								Lead	**<0.001**	**<0.001**	**<0.001**	**<0.001**	**Solid**	**AP-42**	**0.003**
								Benzene	**<0.001**	**<0.001**	**<0.001**	**<0.001**	**Gas**	**AP-42**	**0.003**
								Formaldehyde	**0.007**	**0.007**	**0.007**	**0.007**	**Gas**	**AP-42**	**0.02**
								Hexane	**0.18**	**0.18**	**0.18**	**0.18**	**Gas**	**AP-42**	**0.5**
								Toluene	**<0.001**	**<0.001**	**<0.001**	**<0.001**	**Gas**	**AP-42**	**0.003**
								Total HAP	**0.18**	**0.18**	**0.18**	**0.18**	**Gas**	**AP-42**	**0.5**
								CO_{2e}	**12,081**	**12,081**	**12,081**	**12,081**	**Gas**	**Sub. C**	**32,247**
FP-1	**Exhaust**	**FP-1**	**Fire Water Pump**	**NA**	**NA**	**As Required**	**500**	**NO_x**	**1.49**	**0.37**	**1.49**	**0.37**	**Gas**	**O- NSPS**	**320**
								CO	**1.44**	**0.36**	**1.44**	**0.36**	**Gas**	**O- NSPS**	**309**
								Total VOC	**0.17**	**0.04**	**0.17**	**0.04**	**Gas**	**O- NSPS**	**37**
								PM/PPM_{10}/PM2.5	**0.08**	**0.02**	**0.08**	**0.02**	**Gas**	**O- NSPS**	**17**
								SO_2	**0.003**	**<0.001**	**0.003**	**<0.001**	**Gas**	**MB**	**0.6**
								Acetaldehyde	**0.002**	**<0.001**	**0.002**	**<0.001**	**Gas**	**AP-42**	**0.4**
								Benzene	**0.002**	**<0.001**	**0.002**	**<0.001**	**Gas**	**AP-42**	**0.4**
								Formaldehyde	**0.002**	**<0.001**	**0.002**	**<0.001**	**Gas**	**AP-42**	**0.4**
								Toluene	**<0.001**	**<0.001**	**<0.001**	**<0.001**	**Gas**	**AP-42**	**0.2**
								Total HAP	**0.007**	**0.002**	**0.007**	**0.002**	**Gas**	**AP-42**	**1.5**
								CO_{2e}	**309**	**77.3**	**309**	**77.3**	**Gas**	**Sub. C**	**66,369**

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] (mg/m^3)
		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**	**Emerg. Electric Gen.**	**NA**	**NA**	**As Required**	**500**	**NO_x**	**11.18**	**2.79**	**11.18**	**2.79**	**Gas**	**O- NSPS**	**298**
								CO	**11.53**	**2.88**	**11.53**	**2.88**	**Gas**	**O- NSPS**	**308**
								Total VOC	**1.24**	**0.31**	**1.24**	**0.31**	**Gas**	**O- NSPS**	**33**
								PM/PPM_{10}/PM2.5	**0.40**	**0.10**	**0.40**	**0.10**	**Gas**	**O- NSPS**	**11**
								SO_2	**0.02**	**0.006**	**0.02**	**0.006**	**Gas**	**MB**	**0.5**
								Benzene	**0.01**	**0.003**	**0.01**	**0.003**	**Gas**	**AP-42**	**0.3**
								Formaldehyde	**0.001**	**<0.001**	**0.001**	**<0.001**	**Gas**	**AP-42**	**0.03**
								Toluene	**0.004**	**0.001**	**0.004**	**0.001**	**Gas**	**AP-42**	**0.1**
								Xylenes	**0.003**	**<0.001**	**0.003**	**<0.001**	**Gas**	**AP-42**	**0.08**
								Total HAP	**0.03**	**0.006**	**0.03**	**0.006**	**Gas**	**AP-42**	**0.8**
								CO_{2e}	**2,416**	**604**	**2,416**	**604**	**Gas**	**Sub. C**	**64,488**

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
CCGT-1	**18.5**	**180.6**	**964,083**	**60**	**720**	**180.5**	**4,417.2**	**517.3**
CCGT-2	**18.5**	**180.6**	**964,083**	**60**	**720**	**180.5**	**4,417.2**	**517.3**
CT-1(1)	**30**	**66**	**1,800,000**	**42**	**720**	**60**	**4,417.2**	**517.3**
AB-1	**3.5**	**300**	**100,000**	**173**	**720**	**42**	**4,417.2**	**517.3**
FP-1	**0.5**	**900**	**1,243**	**106**	**720**	**11**	**4,417.2**	**517.3**
EG-1	**1.5**	**900**	**10,000**	**94**	**720**	**13**	**4,417.2**	**517.3**
ST-1	**NA**	**Ambient**	**NA**	**NA**	**720**	**NA**	**4,417.2**	**517.3**
ST-2	**NA**	**Ambient**	**NA**	**NA**	**720**	**NA**	**4,417.2**	**517.3**

(1) Cooling tower diameter, flow, and velocity are per individual cell.

Attachment K

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 ☐ 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	**No Haul of Bulk Raw Materials or Products**	--	--	--	--	--
Storage Pile Emissions	**NA**	--	--	--	--	--
Loading/Unloading Operations	**NA**	--	--	--	--	--
Wastewater Treatment Evaporation & Operations	**NA**	--	--	--	--	--
Equipment Leaks	**Most equipment leak emissions will be natural gas consisting most of non-regulated chemicals.**	--	--	--	--	--
General Clean-up VOC Emissions	**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

Attachment L
Emission Unit Data Sheet
(INDIRECT HEAT EXCHANGER)

Control Device ID No. (must match List Form):

Equipment Information: Combined Cycle Gas Turbine CCCT-1

1. Manufacturer: **GE or equivalent**	2. Model No. **7FA.04** Serial No. **NA**
3. Number of units: **1**	4. Use – **Electric Generation**
5. Rated Boiler Horsepower: **NA** hp	6. Boiler Serial No.: **NA**
7. Date constructed: **2017**	8. Date of last modification and explain: **NA**
9. Maximum design heat input per unit: **2,087** $\times 10^6$ BTU/hr	10. Peak heat input per unit: **2,087** $\times 10^6$ 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 **Dry Low NO_x Burners**
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: **18.5** ft.	20. Gas exit temperature: **163-188** °F
21. Height: **180.5** 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: **673,600-1,116,483** ft^3/min	
24. Estimated percent of moisture: **NA** %	

Fuel Requirements

25. Type	Fuel Oil No.	Natural Gas or Natural Gas With up to 25% Ethane	Gas (other, specify)	Coal, Type:	Other:
Quantity (at Design Output)	**NA** gph@60°F	**2,026207** ft^3/hr	**NA** ft^3/hr	**NA** TPH	
Annually	$\times 10^3$ gal	**17,750** $\times 10^6$ ft^3/yr	$\times 10^6$ ft^3/yr	tons	
Sulfur	Maximum: wt. % Average: wt. %	**2.56** ppmw	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		**Evaluating Suppliers**			
Supplier		**Evaluating Suppliers**			
Halogens (Yes/No)		**No**			
List and Identify Metals		**NA**			

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

27. Gas burner manufacturer: **GE**

28. Oil burner manufacturer: **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** 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	**33.72**	**NA**	**NA**	**NA**
Hydrocarbons	**NA**	**NA**	**NA**	**NA**
NO_x	**113.4**	**NA**	**NA**	**NA**
Pb	**0.001**	**NA**	**NA**	**NA**
$PM/PM_{10}/PM_{2.5}$	**7.56**	**NA**	**NA**	**NA**
SO_2	**0.55**	**NA**	**NA**	**NA**
VOCs	**5.28**	**NA**	**NA**	**NA**
Total HAPs	**1.36**	**NA**	**NA**	**NA**
CO_{2e}	**254,315**	**NA**	**NA**	**NA**
Sulfuric Acid Mist	**0.35**	**NA**	**NA**	**NA**

Emissions represent hourly steady state emission rates only.

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

Pollutant	Pounds per Hour lb/hr	grain/ACF	@ °F	PSIA
CO	**9.24**	**NA**	**NA**	**NA**
Hydrocarbons	**NA**	**NA**	**NA**	**NA**
NO_x	**15.20**	**NA**	**NA**	**NA**
Pb	**0.001**	**NA**	**NA**	**NA**
$PM/PM_{10}/PM_{2.5}$	**7.56**	**NA**	**NA**	**NA**
SO_2	**0.55**	**NA**	**NA**	**NA**
VOCs	**5.28**	**NA**	**NA**	**NA**
Total HAPs	**1.36**	**NA**	**NA**	**NA**
CO_{2e}	**254,315**	**NA**	**NA**	**NA**
Sulfuric Acid Mist	**0.35**	**NA**	**NA**	**NA**

Emissions represent hourly steady state emission rates only.

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):

Equipment Information: Combined Cycle Gas Turbine CCCT-2

1. Manufacturer: **GE or equivalent**	2. Model No. **7FA.04** Serial No. **NA**
3. Number of units: **1**	4. Use – **Electric Generation**
5. Rated Boiler Horsepower: **NA** hp	6. Boiler Serial No.: **NA**
7. Date constructed: **2017**	8. Date of last modification and explain: **NA**
9. Maximum design heat input per unit: **2,087** $\times 10^6$ BTU/hr	10. Peak heat input per unit: **2,087** $\times 10^6$ 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 **Dry Low NO_x Burners**
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: **18.5** ft.	20. Gas exit temperature: **163-188** °F
21. Height: **180.5** 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: **673,600-1,116,483** ft^3/min	
24. Estimated percent of moisture: **NA** %	

Fuel Requirements

25. Type	Fuel Oil No.	Natural Gas or Natural Gas With up to 25% Ethane	Gas (other, specify)	Coal, Type:	Other:
Quantity (at Design Output)	**NA** gph@60°F	**2,026207** ft^3/hr	**NA** ft^3/hr	**NA** TPH	
Annually	$\times 10^3$ gal	**17,750** $\times 10^6\ ft^3/yr$	$\times 10^6\ ft^3/yr$	tons	
Sulfur	Maximum: wt. % Average: wt. %	**2.56** ppmw	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		**Evaluating Suppliers**			
Supplier		**Evaluating Suppliers**			
Halogens (Yes/No)		**No**			
List and Identify Metals		**NA**			

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

27. Gas burner manufacturer: **GE**

28. Oil burner manufacturer: **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** 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	**33.72**	**NA**	**NA**	**NA**
Hydrocarbons	**NA**	**NA**	**NA**	**NA**
NO_x	**113.4**	**NA**	**NA**	**NA**
Pb	**0.001**	**NA**	**NA**	**NA**
$PM/PM_{10}/PM_{2.5}$	**7.56**	**NA**	**NA**	**NA**
SO_2	**0.55**	**NA**	**NA**	**NA**
VOCs	**5.28**	**NA**	**NA**	**NA**
Total HAPs	**1.356**	**NA**	**NA**	**NA**
CO_{2e}	**254,315**	**NA**	**NA**	**NA**
Sulfuric Acid Mist	**0.35**	**NA**	**NA**	**NA**

Emissions represent hourly steady state emission rates only.

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

Pollutant	Pounds per Hour lb/hr	grain/ACF	@ °F	PSIA
CO	**9.24**	**NA**	**NA**	**NA**
Hydrocarbons	**NA**	**NA**	**NA**	**NA**
NO_x	**15.20**	**NA**	**NA**	**NA**
Pb	**0.001**	**NA**	**NA**	**NA**
$PM/PM_{10}/PM_{2.5}$	**7.56**	**NA**	**NA**	**NA**
SO_2	**0.55**	**NA**	**NA**	**NA**
VOCs	**5.28**	**NA**	**NA**	**NA**
Total HAPs	**1.36**	**NA**	**NA**	**NA**
CO_{2e}	**254,315**	**NA**	**NA**	**NA**
Sulfuric Acid Mist	**0.35**	**NA**	**NA**	**NA**

Emissions represent hourly steady state emission rates only.

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):

Equipment Information: Auxiliary Boiler AB-1

1. Manufacturer: **TBD**	2. Model No. **NA** Serial No. **NA**
3. Number of units: **1**	4. Use – **Steam Production**
5. Rated Boiler Horsepower: **NA** hp	6. Boiler Serial No.: **NA**
7. Date constructed: **2017**	8. Date of last modification and explain: **NA**
9. Maximum design heat input per unit: **100** $\times 10^6$ BTU/hr	10. Peak heat input per unit: **100** $\times 10^6$ 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: **3.5** ft.	20. Gas exit temperature: **300** °F
21. Height: **42** 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: **100,000** ft^3/min	
24. Estimated percent of moisture: **NA** %	

Fuel Requirements

25. Type	Fuel Oil No.	Natural Gas or Natural Gas With up to 25% Ethane	Gas (other, specify)	Coal, Type:	Other:
Quantity (at Design Output)	**NA** gph@60°F	**97,087** ft^3/hr	**NA** ft^3/hr	**NA** TPH	
Annually	$\times 10^3$ gal	**194.2** $\times 10^6$ ft^3/yr	$\times 10^6$ ft^3/yr	tons	
Sulfur	Maximum: wt. % Average: wt. %	**2.0** 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		**Evaluating Suppliers**			
Supplier		**Evaluating Suppliers**			
Halogens (Yes/No)		**No**			
List and Identify Metals		**NA**			

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

27. Gas burner manufacturer: **TBD**

28. Oil burner manufacturer: **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** 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	**4.00**	**NA**	**NA**	**NA**
Hydrocarbons	**NA**	**NA**	**NA**	**NA**
NO_x	**2.00**	**NA**	**NA**	**NA**
Pb	**<0.001**	**NA**	**NA**	**NA**
$PM/PM_{10}/PM_{2.5}$	**0.50**	**NA**	**NA**	**NA**
SO_2	**0.06**	**NA**	**NA**	**NA**
VOCs	**0.60**	**NA**	**NA**	**NA**
Total HAPs	**0.18**	**NA**	**NA**	**NA**
CO_{2e}	**11,701**	**NA**	**NA**	**NA**
Sulfuric Acid Mist	**0.005**	**NA**	**NA**	**NA**

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

Pollutant	Pounds per Hour lb/hr	grain/ACF	@ °F	PSIA
CO	**4.00**	**NA**	**NA**	**NA**
Hydrocarbons	**NA**	**NA**	**NA**	**NA**
NO_x	**2.00**	**NA**	**NA**	**NA**
Pb	**<0.001**	**NA**	**NA**	**NA**
$PM/PM_{10}/PM_{2.5}$	**0.50**	**NA**	**NA**	**NA**
SO_2	**0.06**	**NA**	**NA**	**NA**
VOCs	**0.60**	**NA**	**NA**	**NA**
Total HAPs	**0.18**	**NA**	**NA**	**NA**
CO_{2e}	**11,701**	**NA**	**NA**	**NA**
Sulfuric Acid Mist	**0.005**	**NA**	**NA**	**NA**

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*): **Cooling Tower CT-1**

1.	Name or type and model of proposed affected source: **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: **Cooling Water:** **Circulating Water – 159,000 gpm** **Make-up Water – 185,500 gph**
4.	Name(s) and maximum amount of proposed material(s) produced per hour: **Cooling Water:** **Circulating Water – 159,000 gpm** **Make-up Water – 185,500 gph**
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): **NA**

(a) Type and amount in appropriate units of fuel(s) to be burned:

(b) Chemical analysis of proposed fuel(s), excluding coal, including maximum percent sulfur and ash:

(c) Theoretical combustion air requirement (ACF/unit of fuel):

@ °F and psia.

(d) Percent excess air:

(e) Type and BTU/hr of burners and all other firing equipment planned to be used:

(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:

(g) Proposed maximum design heat input: $\times 10^6$ 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 **NA** psia

a.	NO_X	**NA** lb/hr	**NA** grains/ACF
b.	SO_2	**NA** lb/hr	**NA** grains/ACF
c.	CO	**NA** lb/hr	**NA** grains/ACF
d.	PM_{10}	**0.48** lb/hr	**NA** grains/ACF
e.	Hydrocarbons	**NA** lb/hr	**NA** grains/ACF
f.	VOCs	**NA** lb/hr	**NA** grains/ACF
g.	Pb	**NA** lb/hr	**NA** grains/ACF
h.	Specify other(s)		
	PM	**0.72** lb/hr	**NA** grains/ACF
	$PM_{2.5}$	**0.002** lb/hr	**NA** grains/ACF
		lb/hr	**NA** grains/ACF
		lb/hr	**NA** 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
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*): **Emergency Electric Generator EG-1**

1.	Name or type and model of proposed affected source: **Emergency Electric Generator – 1,500 kW (~2,000 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

(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	**11.18** lb/hr		**NA** grains/ACF	
b.	SO_2	**0.02** lb/hr		**NA** grains/ACF	
c.	CO	**11.53** lb/hr		**NA** grains/ACF	
d.	$PM/PM_{10}/PM_{2.5}$	**0.40** lb/hr		**NA** grains/ACF	
e.	Hydrocarbons	**NA** lb/hr		**NA** grains/ACF	
f.	VOCs	**1.24** lb/hr		**NA** grains/ACF	
g.	Pb	**NA** lb/hr		**NA** grains/ACF	
h.	Specify other(s)				
	CO_{2e}	**2,416** lb/hr		**NA** grains/ACF	
	Total HAPs	**0.03** lb/hr		**NA** grains/ACF	
		lb/hr		**NA** grains/ACF	
		lb/hr		**NA** 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 FP-1**

1. Name or type and model of proposed affected source: **Firewater Pump – 251 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: **Firewater – As Required**
4. Name(s) and maximum amount of proposed material(s) produced per hour: **Firewater – As Required**
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

(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	**1.49**	lb/hr	**NA**	grains/ACF
b.	SO_2	**0.003**	lb/hr	**NA**	grains/ACF
c.	CO	**1.44**	lb/hr	**NA**	grains/ACF
d.	$PM/PM_{10}/PM_{2.5}$	**0.08**	lb/hr	**NA**	grains/ACF
e.	Hydrocarbons	**NA**	lb/hr	**NA**	grains/ACF
f.	VOCs	**0.17**	lb/hr	**NA**	grains/ACF
g.	Pb	**NA**	lb/hr	**NA**	grains/ACF
h.	Specify other(s)				
	CO_{2e}	**309**	lb/hr	**NA**	grains/ACF
	Total HAPs	**0.007**	lb/hr	**NA**	grains/ACF
			lb/hr	**NA**	grains/ACF
			lb/hr	**NA**	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 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 ST-1**
3. Tank Equipment Identification No. (as assigned on *Equipment List Form*) **ST-1**	4. Emission Point Identification No. (as assigned on *Equipment List Form*) **ST-1**

5. Date of Commencement of Construction (for existing tanks) **2017**

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.
500 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)	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 gallons

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 X 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) Welded		
20A. Shell Color **Light Gray**	20B. Roof Color **Light Gray**	20C. Year Last Painted **2016**
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): **Ambient** to **Ambient**		
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:		
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		

<table>
<tr><td colspan="6">25F. Describe deck fittings; indicate the number of each type of fitting:</td></tr>
<tr><td colspan="6">ACCESS HATCH</td></tr>
<tr><td colspan="2">BOLT COVER, GASKETED:</td><td colspan="2">UNBOLTED COVER, GASKETED:</td><td colspan="2">UNBOLTED COVER, UNGASKETED:</td></tr>
<tr><td colspan="6">AUTOMATIC GAUGE FLOAT WELL</td></tr>
<tr><td colspan="2">BOLT COVER, GASKETED:</td><td colspan="2">UNBOLTED COVER, GASKETED:</td><td colspan="2">UNBOLTED COVER, UNGASKETED:</td></tr>
<tr><td colspan="6">COLUMN WELL</td></tr>
<tr><td colspan="2">BUILT-UP COLUMN – SLIDING COVER, GASKETED:</td><td colspan="2">BUILT-UP COLUMN – SLIDING COVER, UNGASKETED:</td><td colspan="2">PIPE COLUMN – FLEXIBLE FABRIC SLEEVE SEAL:</td></tr>
<tr><td colspan="6">LADDER WELL</td></tr>
<tr><td colspan="3">PIP COLUMN – SLIDING COVER, GASKETED:</td><td colspan="3">PIPE COLUMN – SLIDING COVER, UNGASKETED:</td></tr>
<tr><td colspan="6">GAUGE-HATCH/SAMPLE PORT</td></tr>
<tr><td colspan="3">SLIDING COVER, GASKETED:</td><td colspan="3">SLIDING COVER, UNGASKETED:</td></tr>
<tr><td colspan="6">ROOF LEG OR HANGER WELL</td></tr>
<tr><td colspan="2">WEIGHTED MECHANICAL ACTUATION, GASKETED:</td><td colspan="2">WEIGHTED MECHANICAL ACTUATION, UNGASKETED:</td><td colspan="2">SAMPLE WELL-SLIT FABRIC SEAL (10% OPEN AREA)</td></tr>
<tr><td colspan="6">VACUUM BREAKER</td></tr>
<tr><td colspan="3">WEIGHTED MECHANICAL ACTUATION, GASKETED:</td><td colspan="3">WEIGHTED MECHANICAL ACTUATION, UNGASKETED:</td></tr>
<tr><td colspan="6">RIM VENT</td></tr>
<tr><td colspan="3">WEIGHTED MECHANICAL ACTUATION GASKETED:</td><td colspan="3">WEIGHTED MECHANICAL ACTUATION, UNGASKETED:</td></tr>
<tr><td colspan="6">DECK DRAIN (3-INCH DIAMETER)</td></tr>
<tr><td colspan="3">OPEN:</td><td colspan="3">90% CLOSED:</td></tr>
<tr><td colspan="6">STUB DRAIN</td></tr>
<tr><td colspan="6">1-INCH DIAMETER:</td></tr>
<tr><td colspan="6">OTHER (DESCRIBE, ATTACH ADDITIONAL PAGES IF NECESSARY)</td></tr>
</table>

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. **See TANKS Summary Sheet**
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: **See TANKS Summary Sheet**	
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	**Diesel Fuel**		
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/yr)	Working Loss		Annual Loss (lb/yr)	Estimation Method[1]
		Amount	Units		
Diesel Fuel	**0.10**	**0.02**	**lb/yr**	**0.12**	**TANKS 4.0.9d**

[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 ST-2**
3. Tank Equipment Identification No. (as assigned on *Equipment List Form*) **ST-2**	4. Emission Point Identification No. (as assigned on *Equipment List Form*) **ST-2**
5. Date of Commencement of Construction (for existing tanks) **2017**	
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. **3,000 gallons**	
9A. Tank Internal Diameter (ft) **7**	9B. Tank Internal Height (or Length) (ft) **10.5**
10A. Maximum Liquid Height (ft) **10.5**	10B. Average Liquid Height (ft) **5.25**
11A. Maximum Vapor Space Height (ft) **10.25**	11B. Average Vapor Space Height (ft) **5.25**
12. Nominal Capacity (specify barrels or gallons). This is also known as "working volume" and considers design liquid levels and overflow valve heights. **3,000 gallons**	

13A. Maximum annual throughput (gal/yr) **6,000**	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) **100**	
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 X 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) Welded		
20A. Shell Color **Light Gray**	20B. Roof Color **Light Gray**	20C. Year Last Painted **2016**
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): **Ambient** to **Ambient**		
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:		
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. **See TANKS Summary Sheet**
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: **See TANKS Summary Sheet**	
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	**Diesel Fuel**		
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/yr)**	**Working Loss**		**Annual Loss (lb/yr)**	**Estimation Method[1]**
		Amount	**Units**		
Diesel Fuel	**0.64**	**0.11**	**lb/yr**	**0.75**	**TANKS 4.0.9.d**

[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

Attachment M
Air Pollution Control Devices

The Combined-Cycle Combustion Turbines will be equipped with dry low-NO_x combustors (DLNC). These combustion controls along with Selective Catalytic Reduction (SCR) systems will control emissions of nitrogen oxides (NO_x). Oxidation catalysts will be used to control the turbines' carbon monoxide (CO) and volatile organic compounds (VOC) emissions. The Auxiliary Boiler will be equipped with ultra low-NO_x burners (ULNB) and flue gas recirculation (FGR) to control NO_x emissions.

The proposed emission control systems and association regulatory implications are further discussed in **Section 3.4 – Prevention of Significant Deterioration (PSD)** of this permit application package.

Attachment N

Attachment N
Calculation Explanation

Potential emissions from the Project's emission sources were estimated using various calculation methodologies including vendor data, emission factors from USEPA's Compilation of Air Pollutant Emission Factors (AP-42) publication, material balances, New Source Performance Standards (NSPS) emission standards, and/or engineering calculations.

Moundsville Power
Facility Emissions Summary Tables

Combustion Turbines

Pollutant	Maximum Short Term Emissions: 1 CT (lb/ hr)	Maximum Annual Steady State Emissions: 2 CTs (tons/yr)	Startup and Shutdown Emissions: 2 CTs (tons/yr)	Total Annual Emissions: 2 CTs (tons/yr)
VOC	5.3	46.3	27.6	73.9
NO_x	15.2	133.2	7.0	140.2
CO	9.2	80.9	121.2	202.2
SO_2	0.5	4.8	-- [1]	4.8
$PM_{10}/PM_{2.5}$	7.6	66.2	1.18	67.4
PM	7.6	66.2	1.18	67.4
Pb	0.001	0.01	-- [1]	0.01
H_2SO_4	0.4	3.1	-- [1]	3.1

[1] *Worst-case annual emissions are addressed by steady-state operation.*

Auxiliary Boiler

Pollutant	Maximum Short Term Emissions (lb/ hr)	Maximum Annual Emissions (tons/yr)
VOC	0.60	0.60
NO_x	2.00	2.00
CO	4.00	4.00
SO_2	0.06	0.06
$PM_{10}/PM_{2.5}$	0.50	0.50
PM	0.50	0.50
Pb	4.85E-05	4.85E-05
H_2SO_4	4.46E-03	4.46E-03

Moundsville Power

Facility Emissions Summary Tables

Emergency Generator and Fire Water Pump

Pollutant	Emergency Generator Maximum Short Term Emissions (lb/hr)	Emergency Generator Maximum Annual Emissions (tons/yr)	Fire Water Pump Maximum Short Term Emissions (lb/hr)	Fire Water Pump Maximum Annual Emissions (tons/yr)
VOC	1.24	0.31	0.17	0.04
NO_x	11.18	2.79	1.49	0.37
CO	11.53	2.88	1.44	0.36
SO_2	2.31E-02	5.78E-03	2.96E-03	7.40E-04
$PM_{10}/PM_{2.5}$	0.40	0.10	0.08	0.02
PM	0.40	0.10	0.08	0.02
Pb	--	--	--	--
H_2SO_4	--	--	--	--

Cooling Tower

Pollutant	Cooling Tower Maximum Short Term Emissions (lb/hr)	Cooling Tower Maximum Annual Emissions (tons/yr)
PM	0.72	3.15
PM_{10}	0.48	2.12
$PM_{2.5}$	0.0016	0.01

Moundsville Power
Facility Emissions Summary Tables

Facility-Wide Emissions Summary

Unit	Annual Emissions (tons/yr)									
	VOC	NO_x	CO	SO_2	PM_{10}	PM	$PM_{2.5}$	Pb	H_2SO_4	CO_2e
CTs (2) - Steady State	46.3	133.2	80.9	4.8	66.2	66.2	66.2	0.0	3.1	2,227,797
CTs - Startups & Shutdowns	27.6	7.0	121.2	--	1.2	1.2	1.2	-- (1)	--	--
Auxiliary Boiler	0.60	2.00	4.00	0.06	0.50	0.50	0.50	4.9E-05	0.004	12,081
Emergency Generator	0.31	2.79	2.88	0.01	0.10	0.10	0.10	--	--	604
Fire Water Pump	0.04	0.37	0.36	0.00	0.02	0.02	0.02	--	--	77
Cooling Tower	--	--	--	--	2.12	3.15	0.01	--	--	--
Circuit Breakers	--	--	--	--	--	--	--	--	--	58
Total	**74.8**	**145.3**	**209.4**	**4.8**	**70.1**	**71.2**	**68.0**	**0.01**	**3.1**	**2,240,618**

Emission Calculations - GHGs

Source	CO_2		CH_4		N_2O		SF_6		CO_2e	
	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)
Combustion Turbines (2)	508,010	2,225,084	13.8	60.5	0.9	4.0	--	--	508,629.4	2,227,797
Auxiliary Boiler	12,058	12,058	3.3E-01	3.3E-01	5.0E-02	5.0E-02	--	--	12,081.2	12,081
Emergency Generator	2,408	602	9.8E-02	2.4E-02	2.0E-02	4.9E-03	--	--	2,416.4	604
Fire Water Pump	308	77	1.3E-02	3.1E-03	2.5E-03	6.3E-04	--	--	309.2	77
Circuit Breakers	--	--	--	--	--	--	5.85E-04	2.56E-03	13.3	58
Total CO_2e	**522,785**	**2,237,821**	**14**	**61**	**1**	**4**	**5.85E-04**	**2.56E-03**	**523,450**	**2,240,618**

Moundsville Power
Facility Emissions Summary Tables

Hazardous Air Pollutant (HAP)	One CT (lb/hr)	One DB (lb/hr)	Auxiliary Boiler (lb/hr)	Emergency Generator (lb/hr)	Fire Water Pump (lb/hr)	Facility Total (tons/yr)
2-Methylnaphthalene	NA	1.68E-06	2.33E-06	NA	NA	1.70E-05
Acetaldehyde	8.35E-02	NA	NA	3.72E-04	1.45E-03	7.32E-01
Acrolein	1.34E-02	NA	NA	1.16E-04	NA	1.17E-01
Arsenic	NA	1.40E-05	1.94E-05	NA	NA	1.42E-04
Benzene	2.50E-02	1.47E-04	2.04E-04	1.15E-02	1.76E-03	2.24E-01
Cadmium	NA	7.70E-05	NA	NA	NA	6.74E-04
Chromium	NA	9.80E-05	1.36E-04	NA	NA	9.94E-04
Cobalt	NA	5.88E-06	8.16E-06	NA	NA	5.97E-05
Dichlorobenzene	NA	8.40E-05	1.17E-04	NA	NA	8.52E-04
Ethylbenzene	6.68E-02	NA	NA	NA	NA	5.85E-01
Fluoranthene	NA	2.10E-07	2.91E-07	NA	NA	2.13E-06
Fluorene	NA	1.96E-07	2.72E-07	NA	NA	1.99E-06
Formaldehyde	6.26E-01	5.25E-03	7.28E-03	1.17E-03	2.23E-03	5.54E+00
Hexane	NA	1.26E-01	1.75E-01	NA	NA	1.28E+00
Manganese	NA	2.66E-05	3.69E-05	NA	NA	2.70E-04
Mercury	NA	1.82E-05	2.52E-05	NA	NA	1.85E-04
Naphthalene	2.71E-03	4.27E-05	5.92E-05	1.92E-03	1.60E-04	2.47E-02
Nickel	NA	1.47E-04	2.04E-04	NA	NA	1.49E-03
Phenanathrene	NA	1.19E-06	1.65E-06	NA	NA	1.21E-05
POM	4.59E-03	NA	NA	3.13E-03	3.18E-04	4.11E-02
Pyrene	NA	3.50E-07	4.85E-07	NA	NA	3.55E-06
Toluene	2.71E-01	2.38E-04	3.30E-04	4.15E-03	7.73E-04	2.38E+00
Xylenes	1.34E-01	NA	NA	2.85E-03	5.39E-04	1.17E+00
	Maximum Emissions (Single HAP)					**5.54**
	Total HAPs					**12.10**

NA = No Emission Factor Available.

Moundsville Power

Emission Calculations - Combustion Turbines

Input Data	
No. of Combustion Turbines	2
Natural Gas Heating Value (Btu/lb - HHV)	23,524
Natural Gas Heating Value (Btu/lb - LHV)	21,210
LHV-HHV Conversion Factor (Natural Gas)	1.11
Ethane Heating Value (Btu/lb - HHV)	23,075
Ethane Heating Value (Btu/lb - LHV)	20,918
LHV-HHV Conversion Factor (Ethane)	1.10
Natural Gas Percentage of Fuel Blend	75%
Ethane Percentage of Fuel Blend	25%
CT Annual Capacity Factor (%)	100%
CT Annual Operating Hours (hr/yr)	8,760
Max. Heat Input (MMBtu/hr) per CT (HHV, all conditions)	2,087
Max. Heat Input (MMBtu/yr) per CT (HHV, all conditions)	1.828E+07
Pb Emission Factor (lb/MMscf)	0.0005
Global Warming Potential - CO_2	1
Global Warming Potential - CH_4	25
Global Warming Potential - N_2O	298

40 CFR Part 98 Subpart C Emission Factors for GHG Pollutants [4]		
	Natural Gas	**Ethane**
Conversion Factor (kg to lb)	2.2046	2.2046
CO_2 Emission Factor (kg/MMBtu)	53.06	59.60
CO_2 Emission Factor (lb/MMBtu)	116.98	131.40
CH_4 Emission Factor (kg/MMBtu)	1.00E-03	3.00E-03
CH_4 Emission Factor (lb/MMBtu)	2.20E-03	6.61E-03
N_2O Emission Factor (kg/MMBtu)	1.00E-04	6.00E-04
N_2O Emission Factor (lb/MMBtu)	2.20E-04	1.32E-03

Pollutant	1 CT		2 CTs	
	lb/hr	**ton/yr [1]**	**lb/hr**	**ton/yr**
VOC	5.3	23.1	10.6	46.3
NO_x	15.2	66.6	30.4	133.2
CO	9.2	40.5	18.5	80.9
SO_2	0.5	2.4	1.1	4.8
$PM/PM_{10}/PM_{2.5}$	7.6	33.1	15.1	66.2
Pb [2]	0.001	0.004	0.002	0.01
H_2SO_4 [3]	0.351	1.5	0.7	3.1
CO_2 [3]	254,005	1,112,542	508,010	2,225,084
CH_4 [4]	6.9	30.2	13.8	60.5
N_2O [4]	0.5	2.0	0.9	4.0
GHG (Mass Basis) [5]	254,178	1,112,574	508,025	2,225,149
GHG (CO_2e Basis) [6], [7]	254,315	1,113,898	508,629	2,227,797

[1] Tons/yr = (Maximum lb/hr) x (8,760 hr/yr) x (1 ton/2000 lb).

[2] Pb emission factor from USEPA's AP-42, Section 1.4.

[3] Based on the emissions and performance data provided by GE.

[4] Default emission factors obtained from 40 CFR Part 98, Subpart C: General Stationary Fuel Combustion Sources, Tables C-1 and C-2 for natural gas firing.

[5] The sum of potential annual GHG emissions on a mass basis (i.e., no GWP applied).

[6] For each GHG, emissions are normalized to a CO_2e basis by multiplying the mass emissions of each individual GHG pollutant by its respective Global warming potentials (GWP). GWP of each pollutant established by 40 CFR Part 98, Subpart A: General Provisions, Table A-1.

[7] The sum of potential annual GHG emissions on a CO_2e basis.

Moundsville Power
Emission Calculations - Combustion Turbine Startups and Shutdowns

Type	Pollutant	Emissions (lb/event)[1]	Duration (min/event)[1]	No. of Events per Year[1]	Total Duration (hr/yr)	Emissions (lb/yr)	Emissions from 1 CT (tons/yr)	Emissions from 2 CTs (tons/yr)
	NOx							
Startups	Hot	19	25	208	86.7	3,952	2.0	4.0
	Warm	33	40	48	32.0	1,584	0.8	1.6
	Cold	47	55	4	3.7	188	0.1	0.2
Shutdowns		5	14	260	60.7	1,300	0.7	1.3
					Total	7,024	3.5	7.0
	CO							
Startups	Hot	273	25	208	86.7	56,784	28.4	56.8
	Warm	280	40	48	32.0	13,440	6.7	13.4
	Cold	1381	55	4	3.7	5,524	2.8	5.5
Shutdowns		175	14	260	60.7	45,500	22.8	45.5
					Total	121,248	60.6	121.2
	VOC							
Startups	Hot	55	25	208	86.7	11,440	5.7	11.4
	Warm	56	40	48	32.0	2,688	1.3	2.7
	Cold	380	55	4	3.7	1,520	0.8	1.5
Shutdowns		46	14	260	60.7	11,960	6.0	12.0
					Total	27,608	13.8	27.6
	$PM/PM_{10}/PM_{2.5}$							
Startups	Hot	2.7	25	208	86.7	562	0.3	0.6
	Warm	4.3	40	48	32.0	206	0.1	0.2
	Cold	6	55	4	3.7	24	0.01	0.02
Shutdowns		1.5	14	260	60.7	390	0.2	0.4
					Total	1,182	0.6	1.2

(1) Startup and shutdown emission rates obtained from GE performance data.

(2) Startup and shutdown emission rates were not calculated for SO_2, Pb, H_2SO_4, or GHGs. Worst-case emissions for those pollutants were assumed to be steady-state operation.

Moundsville Power

Emission Calculations - Auxiliary Boiler

Parameter	Value	
Natural Gas Heating Value (Btu/scf)	1,030	
Maximum Heat Input (MMBtu/hr):	100	
Maximum Heat Input (Btu/hr)	100,000,000	
Maximum Annual Fuel Use (scf/hr)	97,087	
Maximum Annual Fuel Use (MMscf/hr)	0.0971	
Maximum Annual Fuel Use (MMscf/yr)	194	
Maximum Annual Operation (hr/yr)	2,000	
Natural Gas Percentage of Fuel Blend	75%	
Ethane Percentage of Fuel Blend	25%	
Conversion Factor SO_2 to SO_3	5%	
Conversion Factor SO_3 to H_2SO_4	100%	
Molecular weight of SO2	64	
Molecular weight of SO3	80	
Molecular weight of H2SO4	98	
Global Warming Potential - CO2	1	
Global Warming Potential - CH4	25	
Global Warming Potential - N2O	298	
40 CFR Part 98 Subpart C Emission Factors for GHG Pollutants[5]		
	Natural Gas	**Ethane**
Conversion Factor (kg to lb)	2.2046	2.2046
CO_2 Emission Factor (kg/MMBtu)	53.06	59.60
CO_2 Emission Factor (lb/MMBtu)	116.98	131.40
CH_4 Emission Factor (kg/MMBtu)	1.00E-03	3.00E-03
CH_4 Emission Factor (lb/MMBtu)	2.20E-03	6.61E-03
N_2O Emission Factor (kg/MMBtu)	1.00E-04	6.00E-04
N_2O Emission Factor (lb/MMBtu)	2.20E-04	1.32E-03

Pollutant	Emission Factor (lb/MMBtu)[2, 5]	Emissions (lb/hr)	Emissions (tons/yr)
VOC	0.006	0.60	0.60
NOx	0.02	2.00	2.00
CO	0.04	4.00	4.00
SO_2 [3]	0.0006	0.06	0.06
PM [1]/PM_{10}/$PM_{2.5}$	0.005	0.50	0.50
Pb	4.85E-07	4.85E-05	4.85E-05
H_2SO_4[4]	4.46E-05	4.46E-03	4.46E-03
CO_2 [5]	120.58	12,058	12,058
CH_4 [5]	0.00	0.33	0.33
N_2O [5]	0.00	0.05	0.050
GHG (Mass Basis) [6]	--	12,059	12,059
GHG (CO_2e Basis) [7, 8]	--	12,081	12,081

(1) PM emission factor includes filterable and condensable fractions.

(2) Emission factors obtained from potential vendor.

(3) Emission rate obtained from US EPA AP-42 Section 1.4, Table 1.4-2.

(4) Exhaust emissions are based on 95% fuel sulfur conversion to SO_2 and 5% fuel sulfur conversion to SO_3. Sulfuric acid mist (H_2SO_4) emission calculations conservatively assume that all SO_3 combines with water to form sulfur mist.
SO_3 = SO_2 emissions (lb/hr) * 5% * MW SO_3/MW SO_2
H_2SO_4 = SO_3 emissions (lb/hr) * 100% * MW H_2SO_4/MW SO_3

(5) Default emission factors obtained from 40 CFR Part 98, Subpart C: General Stationary Fuel Combustion Sources, Tables C-1 and C-2 for natural gas firing and ethane combustion. Per Table C-2, the default CH_4 and N_2O factors for ethane combustion are those for "Petroleum".

(6) The sum of potential annual GHG emissions on a mass basis (i.e., no GWP applied).

(7) For each GHG, emissions are normalized to a CO_2e basis by multiplying the mass emissions of each individual GHG pollutant by its respective Global warming potentials (GWP). GWP of each pollutant established by 40 CFR Part 98, Subpart A: General Provisions, Table A-1.

(8) The sum of potential annual GHG emissions on a CO_2e basis.

Hazardous Air Pollutants

Pollutant	Emission Factor (lb/MMscf) [1]	Emissions (lb/hr)	Emissions (tons/yr)
2-Methylnaphthalene	2.4E-05	2.33E-06	2.33E-06
Arsenic	2.0E-04	1.94E-05	1.94E-05
Benzene	2.1E-03	2.04E-04	2.04E-04
Cadmium	1.1E-03	1.07E-04	1.07E-04
Chromium	1.4E-03	1.36E-04	1.36E-04
Cobalt	8.4E-05	8.16E-06	8.16E-06
Dichlorobenzene	1.2E-03	1.17E-04	1.17E-04
Fluoranthene	3.0E-06	2.91E-07	2.91E-07
Fluorene	2.8E-06	2.72E-07	2.72E-07
Formaldehyde	7.5E-02	7.28E-03	7.28E-03
Hexane	1.8E+00	1.75E-01	1.75E-01
Manganese	3.8E-04	3.69E-05	3.69E-05
Mercury	2.6E-04	2.52E-05	2.52E-05
Naphthalene	6.1E-04	5.92E-05	5.92E-05
Nickel	2.1E-03	2.04E-04	2.04E-04
Phenanathrene	1.7E-05	1.65E-06	1.65E-06
Pyrene	5.0E-06	4.85E-07	4.85E-07
Toluene	3.4E-03	3.30E-04	3.30E-04

(1) Emission factors obtained from AP-42, Ch. 1.4, Tables 1.4-3 and 1.4-4. Emission factors were not included for pollutants at or below the method detection limits, designated as "less than (<)" in AP-42 emission factor tables.

Moundsville Power
Emission Calculations - Emergency Generator

Parameter	Value
Heating Value of ULSD (Btu/gal):	135,000
ULSD Sulfur Content (wt. %):	0.0015
Rated Output (kW):	1,500
Rated Output (hp):	2,012
Fuel Consumption (gal/hr):	109.4
Heat Input (MMBtu/hr):	14.8
Maximum Annual Operation (hr/yr)	500
NOx + NMHC Emission Factor (g/hp-hr)	2.8
Concentration of NOx	90%
Concentration of NMHC	10%
Molecular weight of S	32
Molecular weight of SO2	64
Fuel Oil Density (lb/gal)	7.05
kg-lb Conversion Factor	2.20
CO2 Emission Factor (kg/MMBtu)	73.96
CO2 Emission Factor (lb/MMBtu)	163.05
CH4 Emission Factor (kg/MMBtu)	3.00E-03
CH4 Emission Factor (lb/MMBtu)	6.61E-03
N2O Emission Factor (kg/MMBtu)	6.00E-04
N2O Emission Factor (lb/MMBtu)	1.32E-03
Global Warming Potential - CO2	1
Global Warming Potential - CH4	25
Global Warming Potential - N2O	298

Criteria Pollutants

Pollutant	Emission Factor (g/hp-hr) [1]	Emission Factor (lb/MMBtu)	Emissions (lb/hr)	Emissions (tons/yr)
VOC	0.28	--	1.24	0.31
NOx	2.52	--	11.18	2.79
CO	2.6	--	11.53	2.88
SO_2	--	--	0.02	0.006
$PM/PM_{10}/PM_{2.5}$	0.09	--	0.40	0.10
CO_2	--	163	2,408	602
CH_4	--	6.61E-03	9.77E-02	0.02
N_2O	--	1.32E-03	1.95E-02	0.00
GHG (Mass Basis)	--	--	2,408	602
GHG (CO_2e Basis)	--	--	2,416	604

(1) Emission factor for CO from 40 CFR Part 60, Subpart IIII: Standards Of Performance For Stationary Compression Ignition Internal Combustion Engines. NO_x + NMHC factor of 2.8 g/hp-hr is provided by vendor. NO_x and VOC emissions are conservatively estimated to be 90% and 10% of this factor, respectively. PM emission factor of 0.09 g/hp-hr is provided by vendor. SO_2 lb/hr emission rate calculated as a mass balance and based on fuel consumption and fuel oil sulfur content.

(2) Default emission factors obtained from 40 CFR Part 98, Subpart C: General Stationary Fuel Combustion Sources, Tables C-1 and C-2 for distillate fuel oil No. 2 firing.

(3) Global warming potentials (GWP) of each pollutant established by 40 CFR Part 98, Subpart A: General Provisions, Table A-1.

(4) For each GHG, emissions are normalized to a CO_2e basis by multiplying the mass emissions of each individual GHG pollutant by its respective GWP.

(5) The sum of potential annual GHG emissions on a mass basis (i.e., no GWP applied).

(6) The sum of potential annual GHG emissions on a CO_2e basis.

Hazardous Air Pollutants

Pollutant	Emission Factor (lb/MMBtu) [(1), (2)]	Emissions (lb/hr)	Emissions (tons/yr)
Acetaldehyde	2.52E-05	3.72E-04	9.30E-05
Acrolein	7.88E-06	1.16E-04	2.91E-05
Benzene	7.76E-04	1.15E-02	2.87E-03
Formaldehyde	7.89E-05	1.17E-03	2.91E-04
Naphthalene	1.30E-04	1.92E-03	4.80E-04
POM	2.12E-04	3.13E-03	7.83E-04
Toluene	2.81E-04	4.15E-03	1.04E-03
Xylenes	1.93E-04	2.85E-03	7.13E-04

(1) Emission factors provided AP-42, Tables 3.4-3 and 3.4-4 Emission factors were not included for pollutants at or below the method detection limits, designated as "less than (<)" in AP-42 emission factor tables.

(2) Polycyclic Organic Matter (listed as "Total PAH" in AP-42)

Moundsville Power

Emission Calculations - Fire Water Pump

Parameter	Value
Heating Value of ULSD (Btu/gal):	135,000
ULSD Sulfur Content (wt. %):	0.0015
Rated Output (hp):	251
Fuel Consumption (gal/hr):	14.0
Heat Input (MMBtu/hr):	1.89
Maximum Annual Operation (hr/yr):	500
NOx + NMHC Emission Factor (g/hp-hr)	3.0
Concentration of NOx	90%
Concentration of NMHC	10%
Molecular weight of S	32
Molecular weight of SO2	64
Fuel Oil Density (lb/gal)	7.05
kg-lb Conversion Factor	2.20
CO2 Emission Factor (kg/MMBtu)	73.96
CO2 Emission Factor (lb/MMBtu)	163.05
CH4 Emission Factor (kg/MMBtu)	3.00E-03
CH4 Emission Factor (lb/MMBtu)	6.61E-03
N2O Emission Factor (kg/MMBtu)	6.00E-04
N2O Emission Factor (lb/MMBtu)	1.32E-03
Global Warming Potential - CO2	1
Global Warming Potential - CH4	25
Global Warming Potential - N2O	298

Criteria Pollutants

Pollutant	Emission Factor (g/hp-hr)[1]	Emission Factor (lb/MMBtu)	Emissions (lb/hr)	Emissions (tons/yr)
VOC	0.30	--	0.17	0.04
NO_x	2.70	--	1.49	0.37
CO	2.6	--	1.44	0.36
SO_2	--	--	0.003	7.4E-04
$PM/PM_{10}/PM_{2.5}$	0.15	--	0.08	0.021
CO_2	--	163	308	77
CH_4	--	6.61E-03	1.25E-02	3.13E-03
N_2O	--	1.32E-03	2.50E-03	6.25E-04
GHG (Mass Basis)	--	--	308	77
GHG (CO_2e Basis)	--	--	309	77

[1] Emission factors from 40 CFR Part 60, Subpart IIII: Standards Of Performance For Stationary Compression Ignition Internal Combustion Engines. NO_x + NMHC factor is 3.0 g/hp-hr. NO_x and VOC emissions are conservatively estimated to be 90% and 10% of this factor, respectively. SO_2 lb/hr emission rate calculated as a mass balance and based on fuel consumption and fuel oil sulfur content.

[2] Default emission factors obtained from 40 CFR Part 98, Subpart C: General Stationary Fuel Combustion Sources, Tables C-1 and C-2 for distillate fuel oil No. 2 firing.

[3] Global warming potentials (GWP) of each pollutant established by 40 CFR Part 98, Subpart A: General Provisions, Table A-1.

[4] For each GHG, emissions are normalized to a CO_2e basis by multiplying the mass emissions of each individual GHG pollutant by its respective GWP.

[5] The sum of potential annual GHG emissions on a mass basis (i.e., no GWP applied).

[6] The sum of potential annual GHG emissions on a CO_2e basis.

Hazardous Air Pollutants

Pollutant	Emission Factor (lb/MMBtu)[1], [2]	Emissions (lb/hr)	Emissions (tons/yr)
Acetaldehyde	7.67E-04	1.45E-03	3.62E-04
Benzene	9.33E-04	1.76E-03	4.41E-04
Formaldehyde	1.18E-03	2.23E-03	5.58E-04
Naphthalene	8.48E-05	1.60E-04	4.01E-05
POM	1.68E-04	3.18E-04	7.94E-05
Toluene	4.09E-04	7.73E-04	1.93E-04
Xylenes	2.85E-04	5.39E-04	1.35E-04

[1] Emission factors obtained from AP-42, Ch. 3.3, Table 3.3-2. Emission factors were not included for pollutants at or below the method detection limits, designated as "less than (<)" in AP-42 emission factor tables.

[2] Polycyclic Organic Matter (listed as "Total PAH" in AP-42)

Moundsville Power

Emission Calculations - Cooling Tower

Parameter	
Number of Units	1
Number of Cells per Tower	10
Design Circulating Water Flow Rate (gpm)	159,000
Cooling Tower Drift Rate (% of circulating water flow rate)	0.0005
Total Dissolved Solids in Make-up Water (mg/L)	300
Cycles of Concentration	6
Maximum TDS in Circulating Water (mg/L)	1,800
PI	3.1415927
Specific Gravity of Water	1
Specific Gravity of TDS	2.2
PM_{10} Fraction	67.3%
$PM_{2.5}$ Fraction	0.22%
Conversion Factor (min/hr)	60
Grams/lb	453.59
Water Density (L/gal)	3.8
Maximum Annual Operations (hr/yr)	8,760
Conversion Factor (lb/ton)	2,000

Pollutant	**PM**	**PM_{10}**	**$PM_{2.5}$**
Maximum Hourly Emissions (lb/hr)	0.72	0.48	1.56E-03
Maximum Annual Emissions (tons/yr)	3.2	2.1	6.81E-03

Reisman/Frisbie Particle Sizing

EPRI Droplet Diameter (um)	Droplet Volume (μm^3)	Droplet Mass (µg)	Particle Mass (Solids) (µg)	Solid Particle Volume (µm3)	Solid Particle Diameter (µm)	EPRI % Mass Smaller	EPRI % Mass Smaller
10	524	5.24E-04	9.42E-07	0.43	0.935	0.000	
20	4189	4.19E-03	7.54E-06	3.43	1.871	0.196	**0.22**
30	14137	1.41E-02	2.54E-05	11.57	2.806	0.226	
40	33510	3.35E-02	6.03E-05	27.42	3.741	0.514	
50	65450	6.54E-02	1.18E-04	53.55	4.676	1.816	
60	113097	1.13E-01	2.04E-04	92.53	5.612	5.702	
70	179594	1.80E-01	3.23E-04	146.94	6.547	21.348	
90	381704	3.82E-01	6.87E-04	312.30	8.418	49.812	**67.3**
110	696910	6.97E-01	1.25E-03	570.20	10.288	70.509	
130	1150347	1.15E+00	2.07E-03	941.19	12.159	82.023	
150	1767146	1.77E+00	3.18E-03	1445.85	14.029	88.012	
180	3053628	3.05E+00	5.50E-03	2498.42	16.835	91.032	
210	4849048	4.85E+00	8.73E-03	3967.40	19.641	92.468	
240	7238229	7.24E+00	1.30E-02	5922.19	22.447	94.091	
270	10305995	1.03E+01	1.86E-02	8432.18	25.253	94.689	
300	14137167	1.41E+01	2.54E-02	11566.77	28.059	96.288	
350	22449298	2.24E+01	4.04E-02	18367.61	32.735	97.011	
400	33510322	3.35E+01	6.03E-02	27417.54	37.412	98.340	
450	47712938	4.77E+01	8.59E-02	39037.86	42.088	99.071	
500	65449847	6.54E+01	1.18E-01	53549.87	46.765	99.071	
600	113097336	1.13E+02	2.04E-01	92534.18	56.118	100.000	

Moundsville Power

Emission Calculations - HAPs

Parameters	Units	CT[1]	DB	Auxiliary Boiler	Emergency Generator	Fire Water Pump
Maximum Heat Input	MMBtu/hr	2,087	72	100	14.8	1.89
Maximum Annual Operation	hr/yr	8,760	8,760	2,000	500	500

[1] Expected heat input at an ambient temperature of 10 °F.

HAP	CT Emission Factor[1] (lb/MMBtu)	DB Emission Factor [2] (lb/MMscf)	One CT (lb/hr)	One DB (lb/hr)	Two CT (lb/hr)	Two DB (lb/hr)	One CT (tons/yr)	Two CT (tons/yr)	One DB (tons/yr)	Two DB (tons/yr)	One CT + One DB (tons/yr)	Two CT + Two DB (tons/yr)
2-Methylnaphthalene	NA	2.4E-05	NA	1.68E-06	NA	3.36E-06	NA	NA	7.36E-06	1.47E-05	7.36E-06	1.47E-05
Acetaldehyde	4.0E-05	NA	0.0835	NA	1.67E-01	NA	3.66E-01	0.731	NA	NA	3.66E-01	7.31E-01
Acrolein	6.4E-06	NA	0.0134	NA	2.67E-02	NA	5.85E-02	0.117	NA	NA	5.85E-02	1.17E-01
Arsenic	NA	2.0E-04	NA	1.40E-05	NA	2.80E-05	NA	NA	6.13E-05	1.23E-04	6.13E-05	1.23E-04
Benzene	1.2E-05	2.1E-03	0.0250	1.47E-04	5.01E-02	2.94E-04	1.10E-01	0.219	6.44E-04	1.29E-03	1.10E-01	2.21E-01
Cadmium	NA	1.1E-03	NA	7.70E-05	NA	1.54E-04	NA	NA	3.37E-04	6.74E-04	3.37E-04	6.74E-04
Chromium	NA	1.4E-03	NA	9.80E-05	NA	1.96E-04	NA	NA	4.29E-04	8.58E-04	4.29E-04	8.58E-04
Cobalt	NA	8.4E-05	NA	5.88E-06	NA	1.18E-05	NA	NA	2.58E-05	5.15E-05	2.58E-05	5.15E-05
Dichlorobenzene	NA	1.2E-03	NA	8.40E-05	NA	1.68E-04	NA	NA	3.68E-04	7.36E-04	3.68E-04	7.36E-04
Ethylbenzene	3.2E-05	NA	0.0668	NA	1.34E-01	NA	2.93E-01	0.585	NA	NA	2.93E-01	5.85E-01
Fluoranthene	NA	3.0E-06	NA	2.10E-07	NA	4.20E-07	NA	NA	9.20E-07	1.84E-06	9.20E-07	1.84E-06
Fluorene	NA	2.8E-06	NA	1.96E-07	NA	3.92E-07	NA	NA	8.58E-07	1.72E-06	8.58E-07	1.72E-06
Formaldehyde	3.0E-04	7.5E-02	0.6261	5.25E-03	1.25E+00	1.05E-02	2.74E+00	5.485	2.30E-02	4.60E-02	2.77E+00	5.53E+00
Hexane	NA	1.8E+00	NA	1.26E-01	NA	2.52E-01	NA	NA	5.52E-01	1.10E+00	5.52E-01	1.10E+00
Manganese	NA	3.8E-04	NA	2.66E-05	NA	5.32E-05	NA	NA	1.16E-04	2.33E-04	1.16E-04	2.33E-04
Mercury	NA	2.6E-04	NA	1.82E-05	NA	3.64E-05	NA	NA	7.97E-05	1.59E-04	7.97E-05	1.59E-04
Naphthalene	1.3E-06	6.1E-04	0.0027	4.27E-05	5.43E-03	8.54E-05	1.19E-02	0.024	1.87E-04	3.74E-04	1.21E-02	2.41E-02
Nickel	NA	2.1E-03	NA	1.47E-04	NA	2.94E-04	NA	NA	6.44E-04	1.29E-03	6.44E-04	1.29E-03
Phenanathrene	NA	1.7E-05	NA	1.19E-06	NA	2.38E-06	NA	NA	5.21E-06	1.04E-05	5.21E-06	1.04E-05
POM	2.2E-06	NA	0.0046	NA	9.18E-03	NA	2.01E-02	0.040	NA	NA	2.01E-02	4.02E-02
Pyrene	NA	5.0E-06	NA	3.50E-07	NA	7.00E-07	NA	NA	1.53E-06	3.07E-06	1.53E-06	3.07E-06
Toluene	1.3E-04	3.4E-03	0.2713	2.38E-04	5.43E-01	4.76E-04	1.19E+00	2.377	1.04E-03	2.08E-03	1.19E+00	2.38E+00
Xylenes	6.4E-05	NA	0.1336	NA	2.67E-01	NA	5.85E-01	1.170	NA	NA	5.85E-01	1.17E+00

NA = No Emission Factor Available.

[1] AP-42 Chapter 3.1, Table 3.1-3.

[2] AP-42 Chapter 1.4, Tables 1.4-3 and 1.4-4.

Hazardous Air Pollutant (HAP)	One CT (lb/hr)	One DB (lb/hr)	Auxiliary Boiler (lb/hr)	Emergency Generator (lb/hr)	Fire Water Pump (lb/hr)	Two CT + Two DB (tons/yr)	Auxiliary Boiler (tons/yr)	Emergency Generator (tons/yr)	Fire Water Pump (tons/yr)	Facility Total (tons/yr)
2-Methylnaphthalene	NA	1.68E-06	2.33E-06	NA	NA	1.47E-05	2.33E-06	NA	NA	1.70E-05
Acetaldehyde	8.35E-02	NA	NA	3.72E-04	1.45E-03	7.31E-01	NA	9.30E-05	3.62E-04	7.32E-01
Acrolein	1.34E-02	NA	NA	1.16E-04	NA	1.17E-01	NA	2.91E-05	NA	1.17E-01
Arsenic	NA	1.40E-05	1.94E-05	NA	NA	1.23E-04	1.94E-05	NA	NA	1.42E-04
Benzene	2.50E-02	1.47E-04	2.04E-04	1.15E-02	1.76E-03	2.21E-01	2.04E-04	2.87E-03	4.41E-04	2.24E-01
Cadmium	NA	7.70E-05	NA	NA	NA	6.74E-04	NA	NA	NA	6.74E-04
Chromium	NA	9.80E-05	1.36E-04	NA	NA	8.58E-04	1.36E-04	NA	NA	9.94E-04
Cobalt	NA	5.88E-06	8.16E-06	NA	NA	5.15E-05	8.16E-06	NA	NA	5.97E-05
Dichlorobenzene	NA	8.40E-05	1.17E-04	NA	NA	7.36E-04	1.17E-04	NA	NA	8.52E-04
Ethylbenzene	6.68E-02	NA	NA	NA	NA	5.85E-01	NA	NA	NA	5.85E-01
Fluoranthene	NA	2.10E-07	2.91E-07	NA	NA	1.84E-06	2.91E-07	NA	NA	2.13E-06
Fluorene	NA	1.96E-07	2.72E-07	NA	NA	1.72E-06	2.72E-07	NA	NA	1.99E-06
Formaldehyde	6.26E-01	5.25E-03	7.28E-03	1.17E-03	2.23E-03	5.53E+00	7.28E-03	2.91E-04	5.58E-04	5.54E+00
Hexane	NA	1.26E-01	1.75E-01	NA	NA	1.10E+00	1.75E-01	NA	NA	1.28E+00
Manganese	NA	2.66E-05	3.69E-05	NA	NA	2.33E-04	3.69E-05	NA	NA	2.70E-04
Mercury	NA	1.82E-05	2.52E-05	NA	NA	1.59E-04	2.52E-05	NA	NA	1.85E-04
Naphthalene	2.71E-03	4.27E-05	5.92E-05	1.92E-03	1.60E-04	2.41E-02	5.92E-05	4.80E-04	4.01E-05	2.47E-02
Nickel	NA	1.47E-04	2.04E-04	NA	NA	1.29E-03	2.04E-04	NA	NA	1.49E-03
Phenanathrene	NA	1.19E-06	1.65E-06	NA	NA	1.04E-05	1.65E-06	NA	NA	1.21E-05
POM	4.59E-03	NA	NA	3.13E-03	3.18E-04	4.02E-02	NA	7.83E-04	7.94E-05	4.11E-02
Pyrene	NA	3.50E-07	4.85E-07	NA	NA	3.07E-06	4.85E-07	NA	NA	3.55E-06
Toluene	2.71E-01	2.38E-04	3.30E-04	4.15E-03	7.73E-04	2.38E+00	3.30E-04	1.04E-03	1.93E-04	2.38E+00
Xylenes	1.34E-01	NA	NA	2.85E-03	5.39E-04	1.17E+00	NA	7.13E-04	1.35E-04	1.17E+00
Maximum Emissions (Single HAP)										**5.54**
Total HAPs										**12.1**

NA = No Emission Factor Available.

Moundsville Power
Emission Calculations - GHGs (SF_6) from Circuit Breakers

Pollutant	Emission Source	Count (Breakers)	Mass of SF_6 per Breaker (lb/Breaker/year)	Annual SF_6 Leak Rate (% by weight)	SF_6 Mass Emissions (tons/yr)	Global Warming Potential	CO_2e (tons/yr)
SF_6	Generator Breakers	2	25	0.50%	1.25E-04	22,800	2.85
SF_6	Switchyard Circuit Breakers	3	325	0.50%	2.44E-03	22,800	55.58
	Total	**5**	**350**		**0.0026**		**58.43**

(1) The annual mass emissions of SF_6 from electrical breakers are calculated using the number of breakers, mass of SF_6 per breaker, and annual leak rate as follows:

SF_6 for Breakers (tons/yr) = Number of Breakers x Mass of SF_6 per Breaker (lb) x Annual SF_6 Leak Rate (%) x 1 ton/2000 lb

(2) The Global Warming Potential factor for SF_6 was obtained from 40 CFR Part 98, Subpart A, Table A-1.

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification	
User Identification:	Diesel Storage Tank ST-1
City:	Moundsville
State:	West Virginia
Company:	Moundsville Power, LLC
Type of Tank:	Vertical Fixed Roof Tank
Description:	
Tank Dimensions	
Shell Height (ft):	7.00
Diameter (ft):	3.50
Liquid Height (ft) :	7.00
Avg. Liquid Height (ft):	3.50
Volume (gallons):	500.00
Turnovers:	2.00
Net Throughput(gal/yr):	1,000.00
Is Tank Heated (y/n):	N
Paint Characteristics	
Shell Color/Shade:	Gray/Light
Shell Condition	Good
Roof Color/Shade:	Gray/Light
Roof Condition:	Good
Roof Characteristics	
Type:	Dome
Height (ft)	0.00
Radius (ft) (Dome Roof)	0.00
Breather Vent Settings	
Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Pittsburgh, Pennsylvania (Avg Atmospheric Pressure = 14.11 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Diesel Storage Tank ST-1 - Vertical Fixed Roof Tank
Moundsville, West Virginia

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	56.69	48.70	64.69	52.55	0.0058	0.0043	0.0077	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

Diesel Storage Tank ST-1 - Vertical Fixed Roof Tank
Moundsville, West Virginia

Annual Emission Calcaulations	
Standing Losses (lb):	0.1041
Vapor Space Volume (cu ft):	35.9837
Vapor Density (lb/cu ft):	0.0001
Vapor Space Expansion Factor:	0.0579
Vented Vapor Saturation Factor:	0.9988
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	35.9837
Tank Diameter (ft):	3.5000
Vapor Space Outage (ft):	3.7401
Tank Shell Height (ft):	7.0000
Average Liquid Height (ft):	3.5000
Roof Outage (ft):	0.2401
Roof Outage (Dome Roof)	
Roof Outage (ft):	0.2401
Dome Radius (ft):	3.5000
Shell Radius (ft):	1.7500
Vapor Density	
Vapor Density (lb/cu ft):	0.0001
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0058
Daily Avg. Liquid Surface Temp. (deg. R):	516.3645
Daily Average Ambient Temp. (deg. F):	50.3083
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	512.2183
Tank Paint Solar Absorptance (Shell):	0.5400
Tank Paint Solar Absorptance (Roof):	0.5400
Daily Total Solar Insulation Factor (Btu/sqft day):	1,202.9556
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0579
Daily Vapor Temperature Range (deg. R):	31.9767
Daily Vapor Pressure Range (psia):	0.0034
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0058
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0043
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0077
Daily Avg. Liquid Surface Temp. (deg R):	516.3645
Daily Min. Liquid Surface Temp. (deg R):	508.3704
Daily Max. Liquid Surface Temp. (deg R):	524.3587
Daily Ambient Temp. Range (deg. R):	19.1500
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9988
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0058
Vapor Space Outage (ft):	3.7401
Working Losses (lb):	0.0181
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0058
Annual Net Throughput (gal/yr.):	1,000.0000
Annual Turnovers:	2.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	500.0000
Maximum Liquid Height (ft):	7.0000
Tank Diameter (ft):	3.5000
Working Loss Product Factor:	1.0000
Total Losses (lb):	0.1221

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

Diesel Storage Tank ST-1 - Vertical Fixed Roof Tank
Moundsville, West Virginia

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	0.02	0.10	0.12

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Diesel Storage Tank ST-2
City:	Moundsville
State:	West Virginia
Company:	Moundsville Power, LLC
Type of Tank:	Vertical Fixed Roof Tank
Description:	

Tank Dimensions

Shell Height (ft):		10.50
Diameter (ft):		7.00
Liquid Height (ft) :		10.50
Avg. Liquid Height (ft):		5.25
Volume (gallons):		3,000.00
Turnovers:		2.00
Net Throughput(gal/yr):		6,000.00
Is Tank Heated (y/n):	N	

Paint Characteristics

Shell Color/Shade:	Gray/Light
Shell Condition	Good
Roof Color/Shade:	Gray/Light
Roof Condition:	Good

Roof Characteristics

Type:	Dome	
Height (ft)		0.00
Radius (ft) (Dome Roof)		0.00

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Pittsburgh, Pennsylvania (Avg Atmospheric Pressure = 14.11 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Diesel Storage Tank ST-2 - Vertical Fixed Roof Tank
Moundsville, West Virginia

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	56.69	48.70	64.69	52.55	0.0058	0.0043	0.0077	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

Diesel Storage Tank ST-2 - Vertical Fixed Roof Tank
Moundsville, West Virginia

Annual Emission Calcaulations	
Standing Losses (lb):	0.6374
Vapor Space Volume (cu ft):	220.5214
Vapor Density (lb/cu ft):	0.0001
Vapor Space Expansion Factor:	0.0579
Vented Vapor Saturation Factor:	0.9982
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	220.5214
Tank Diameter (ft):	7.0000
Vapor Space Outage (ft):	5.7301
Tank Shell Height (ft):	10.5000
Average Liquid Height (ft):	5.2500
Roof Outage (ft):	0.4801
Roof Outage (Dome Roof)	
Roof Outage (ft):	0.4801
Dome Radius (ft):	7.0000
Shell Radius (ft):	3.5000
Vapor Density	
Vapor Density (lb/cu ft):	0.0001
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0058
Daily Avg. Liquid Surface Temp. (deg. R):	516.3645
Daily Average Ambient Temp. (deg. F):	50.3083
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	512.2183
Tank Paint Solar Absorptance (Shell):	0.5400
Tank Paint Solar Absorptance (Roof):	0.5400
Daily Total Solar Insulation Factor (Btu/sqft day):	1,202.9556
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0579
Daily Vapor Temperature Range (deg. R):	31.9767
Daily Vapor Pressure Range (psia):	0.0034
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0058
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0043
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0077
Daily Avg. Liquid Surface Temp. (deg R):	516.3645
Daily Min. Liquid Surface Temp. (deg R):	508.3704
Daily Max. Liquid Surface Temp. (deg R):	524.3587
Daily Ambient Temp. Range (deg. R):	19.1500
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9982
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0058
Vapor Space Outage (ft):	5.7301
Working Losses (lb):	0.1084
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0058
Annual Net Throughput (gal/yr.):	6,000.0000
Annual Turnovers:	2.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	3,000.0000
Maximum Liquid Height (ft):	10.5000
Tank Diameter (ft):	7.0000
Working Loss Product Factor:	1.0000
Total Losses (lb):	0.7458

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

Diesel Storage Tank ST-2 - Vertical Fixed Roof Tank
Moundsville, West Virginia

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	0.11	0.64	0.75

Attachment O

Attachment O

Monitoring, Recordkeeping, Reporting and Testing Plans

Moundsville Power suggests the following:

- Limit the annual gas consumption for the combined-cycle combustion turbines and auxiliary boiler as presented in this permit application.
- Record the amount of natural gas consumed in the combined-cycle combustion turbines and auxiliary boiler on a daily, monthly, and 12-month rolling total.
- Operate and maintain SCR and Oxidation Catalyst for the combined-cycle combustion turbines for NOx and CO control.
- Limit the sulfur content of the natural gas as required by regulation.
- Install, operate, calibrate, and maintain continuous emission monitoring systems (CEMS) on the combined-cycle combustion turbines as required and in accordance with applicability regulations.
- Conduct performance testing for each pollutant in accordance with the methods, standards, and deadlines mandated by regulation.
- Combust only ultra low sulfur diesel (ULSD) fuel in the emergency electrical generator and firewater pump engines.
- Record the annual hours of operation for the emergency electrical generator and firewater pump engines.
- Maintain required records for at least five (5) years.

Attachment P

Attachment P

AIR QUALITY PERMIT NOTICE
Notice of Application

Notice is given that Moundsville Power, LLC has applied to the West Virginia Department of Environmental Protection, Division of Air Quality, for a PSD permit application, for an electric power generation facility located on State Route 2, south of Moundsville, in Marshall County, West Virginia. The latitude and longitude coordinates are: 39.9047 and -80.7973. The applicant estimates the potential to discharge the following Regulated Air Pollutants will 145 tons per year nitrogen oxides, 209 tons per year carbon monoxide, 2,240,618 tons per year carbon dioxide equivalent emissions, 75 tons per year volatile organic compounds, 71 tons per year particulate matter, 4.8 tons per year sulfur dioxide, 0.01 tons per year lead, and 12.1 tons per year hazardous air pollutants. Startup of operation began the 1st day of July, 2017. 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 1227, during normal business hours.

Dated this the **(day)** day of December, 2013.

By: Moundsville Power, LLC
Jon M. Williams
Managing Member
1214 3rd Street
Box 1138
Moundsville, West Virginia 26041

Attachment Q

Attachment Q
Business Confidential Claims

This permit application does not contain business confidential information; therefore, this application is considered non-confidential.

Attachment R

Attachment R
Authority Forms

Since this application is signed by the “Responsible Official”, this section is not applicable.

Attachment S

Attachment S
Title V Permit Revision Information

Since the site does not currently possess a Title V Permit, Attachment S is not being provided with this permit application.