Ohio Environmental Protection Agency

John R. Kasich, Governor
Mary Taylor, Lt. Governor
Craig W. Butler, Director

1/23/2018

Certified Mail

No	TOXIC REVIEW
Yes	PSD
No	SYNTHETIC MINOR TO AVOID MAJOR NSR
No	CEMS
Yes	MACT/GACT
Yes	NSPS
No	NESHAPS
No	NETTING
No	MAJOR NON-ATTAINMENT
Yes	MODELING SUBMITTED
No	MAJOR GHG
No	SYNTHETIC MINOR TO AVOID MAJOR GHG

Jim Palumbo
Harrison Power
72 Glenmaura National Blvd Suite 104A
Moosic, PA 18507

RE: DRAFT AIR POLLUTION PERMIT-TO-INSTALL
Facility ID: 0634005152
Permit Number: P0122266
Permit Type: Initial Installation
County: Harrison

Dear Permit Holder:

A draft of the Ohio Administrative Code (OAC) Chapter 3745-31 Air Pollution Permit-to-Install for the referenced facility has been issued for the emissions unit(s) listed in the Authorization section of the enclosed draft permit. This draft action is not an authorization to begin construction or modification of your emissions unit(s). The purpose of this draft is to solicit public comments on the permit. A public notice will appear in the Ohio Environmental Protection Agency (EPA) Weekly Review and the local newspaper, Harrison News Herald. A copy of the public notice and the draft permit are enclosed. This permit can be accessed electronically on the Division of Air Pollution Control (DAPC) Web page, www.epa.ohio.gov/dapc by clicking the "Search for Permits" link under the Permitting topic on the Programs tab. Comments will be accepted as a marked-up copy of the draft permit or in narrative format. Any comments must be sent to the following:

Andrew Hall
Permit Review/Development Section
Ohio EPA, DAPC
50 West Town Street, Suite 700
P.O. Box 1049
Columbus, Ohio 43216-1049

and

Ohio EPA DAPC, Southeast District Office
2195 Front Street
Logan, OH 43138

Comments and/or a request for a public hearing will be accepted within 30 days of the date the notice is published in the newspaper. You will be notified in writing if a public hearing is scheduled. A decision on issuing a final permit-to-install will be made after consideration of comments received and oral testimony if a public hearing is conducted. Any permit fee that will be due upon issuance of a final Permit-to-Install is indicated in the Authorization section. Please do not submit any payment now. If you have any questions, please contact Ohio EPA DAPC, Southeast District Office at (740)385-8501.

Sincerely,

Michael E. Hopkins, P.E.
Assistant Chief, Permitting Section, DAPC

Cc: U.S. EPA Region 5 - *Via E-Mail Notification*
Ohio EPA-SEDO; Pennsylvania; West Virginia

Permit Strategy Write-Up

1. Check all that apply:

___ Synthetic Minor Determination

___ Netting Determination

_X_ PSD (CO, NO_x, PM_{10}, $PM_{2.5}$, VOC, SO_2, H_2SO_4, Greenhouse gases)

2. Source Description:
This permit-to-install (PTI) is for the Harrison Power LLC, a 1,000 MW combined cycle turbine plant proposed to be constructed in the Harrison Industrial Park of Cadiz, Ohio (Harrison County). This facility will consist of two natural-gas fired combined cycle turbines (EUs P005-P008). The CTs being considered are General Electric (GE) Models 7HA.02 or Mitsubishi Models M501JAC. The CT model will be decided after the draft permit is issued, and the terms for the other model will be terminated. Due to variability, terms were written for each CT model and after it is decided which model will be installed, the other EU's will be invalidated in the profile. Each CT model is equipped with heat recovery steam generators (HRSGs) and duct burners. Support operations for the power plant will include: one natural gas-fired auxiliary boiler rated at 44.55 MMBtu/hr or 80 MMBtu/hr (EUs B001 and B002, the boiler size will depend on the CT chosen for installation and the terms for the alternative boiler will be terminated) used to provide steam during startups and to keep the HRSGs warm during periods of shutdown; one 1,860 kW diesel-fired emergency generator engine (EU P003); and one 320 HP diesel-fired fire pump engine (EU P004).

3. Facility Emissions and Attainment Status:

This facility is projected to be major source for HAPs. The following table identifies the facility's PTE for installing GE CTs:

Pollutant	**CCGT-1* tpy**	**CCGT-2* tpy**	**Ancillary Equipment** tpy**	**Total*** Tons per rolling, 12-month period**
$PM_{10}/PM_{2.5}$	80.2	80.2	0.297	160.7
SO_2	28.65	28.65	0.0662	57.4
NO_x	139	139	2.206	280.2
CO	112.8	112.8	1.962	227.6
VOC	49.1	49.1	0.1885	98.4
H_2SO_4	17.55	17.55	0.0102	35.1
NH_3	3671.97	3671.97	n/a	7343.95
CO_{2e}	2499820	2499820	5136.87	5004776.9

*Includes duct burners
**Ancillary equipment includes an auxiliary boiler (B002), emergency generator (P003), emergency fire pump (P004).
***ISO conditions per the permit application.

The following table identifies the facility's PTE for installing Mitsubishi CTs:

Pollutant	CCGT-1* tpy	CCGT-2* tpy	Ancillary Equipment** tpy	Total*** Tons per rolling, 12-month period
$PM_{10}/PM_{2.5}$	77.5	77.5	0.2165	155.2
SO_2	29.57	29.57	0.0132	59.2
NO_x	124	124	1.8755	249.9
CO	109.1	109.1	1.522	219.7
VOC	84.7	84.7	0.1405	169.5
H_2SO_4	31.69	31.69	0.0022	63.4
NH_3	3080.2	3080.2	n/a	6160.5
CO_{2e}	2342643	2342643	2945.47	4688231.5

*Includes duct burners
**Ancillary equipment includes an auxiliary boiler (B001), emergency generator (P003), emergency fire pump (P004).
***ISO conditions per the permit application.

Harrison County is in attainment concerning NAAQS for all criteria pollutants.

4. Source Emissions:

GE natural gas-fired combined cycle combustion turbine generator equipped with dry low NO_x (DLN) burners nominally rated at 3,459.6 MMBtu/hr at ISO conditions exhausting through a HRSG with natural gas-fired duct burners nominally rated at 570.45 MMBtu/hr controlled with selective catalytic reduction (SCR) and catalytic oxidation (P005 & P006). This table represents allowables per emissions unit:

Pollutant	Emission Rate (lb/MMBtu)	Emission Rate (ppmvdc)	Emission Rate (lb/hr)	Emission Rate (tons per rolling, 12-month period)*	BACT/BAT
NO_x CTG only CTG w/DB	n/a	2.0 2.0	25.1 29.5	139	2.0 ppmvdc NG DLN and SCR
VOC CTG only CTG w/DB	0.00132 0.00266	1.0 2.0	4.36 10.3	49.1	2.0 ppmvdc (w/DB) 1.0 ppmvdc (w/out DB) Good combustion practices and oxidation catalyst
CO CTG only CTG w/DB	n/a	2.0 2.0	15.3 17.9	112.8	2.0 ppmvdc Good combustion practices and oxidation catalyst
$PM_{10}/PM_{2.5}$ CTG only	0.00735	n/a	12.0	80.2	0.00522 lb/MMBtu (w/DB)

CTG w/DB	0.00522	n/a	18.40		0.00735 (w/out DB) Good combustion practices and pipeline quality natural gas
SO_2 CTG only CTG w/DB	0.00174 0.00174	n/a n/a	5.75 6.74	28.65	0.00174 lb/MMBtu with or without DB Good combustion practices and pipeline quality natural gas
H_2SO_4 CTG only CTG w/DB	0.00102 0.00103	n/a n/a	3.52 4.13	17.55	0.00103 lb/MMBtu with DB 0.00102 lb/MMBtu without DB Good combustion practices and pipeline quality natural gas
GHG (CO_{2e})	1012.4 lb/MW-hr (at full load ISO conditions w/out duct firing)	n/a	n/a	2,499,820	High efficient combustion technology

* Including Startup and Shutdown emissions

Mitsubishi natural gas-fired combined cycle combustion turbine generator equipped with dry low NOx (DLN) burners nominally rated at 3,231 MMBtu/hr at ISO conditions exhausting through a HRSG with natural gas-fireed duct burners nominally rated at 306 MMBtu/hr controlled with selective catalytic reduction (SCR) and catalytic oxidation (P007 & P008). This table represents allowables per emissions unit:

Pollutant	**Emission Rate (lb/MMBtu)**	**Emission Rate (ppmvdc)**	**Emission Rate (lb/hr)**	**Emission Rate (tons per rolling, 12-month period)***	**BACT/BAT**
NO_x CTG only CTG w/DB	n/a	2.0 2.0	26.7 28	124.0	2.0 ppmvdc NG DLN and SCR
VOC CTG only CTG w/DB	0.00142 0.00277	1.0 2.0	4.70 9.8	84.7	2.0 ppmvdc (w/DB) 1.0 ppmvdc (w/out DB) Good combustion

					practices and oxidation catalyst
CO CTG only CTG w/DB	n/a	2.0 2.0	16.3 17.1	109.1	2.0 ppmvdc Good combustion practices and oxidation catalyst
$PM_{10}/PM_{2.5}$ CTG only CTG w/DB	0.00444 0.005	n/a	14.10 17.7	77.5	0.00444 lb/MMBtu without DB 0.005 lb/MMBtu with DB Good combustion practices and pipeline quality natural gas
SO_2 CTG only CTG w/DB	0.0021 0.0021	n/a	6.92 7.22	29.57	0.0021 lb/MMBtu with or without DB Good combustion practices and pipeline quality natural gas
H_2SO_4 CTG only CTG w/DB	0.0022 0.0022	n/a	7.41 7.74	31.69	0.0022 lb/MMBtu with or without DB Good combustion practices and pipeline quality natural gas
GHG (CO_{2e})	976.0 lb/MW-hr (at full load ISO conditions w/out duct firing)	n/a		2,342,643	High efficient combustion technology

44.55 MMBtu/hr natural-gas fired boiler with dry low-NOx burners and flue gas recirculation (B001):

Pollutant	**Emission Rate (lb/MMBtu)**	**Maximum Emission Rate (lb/hr)**	**laximum Emission Rate (tons per rolling, 12-month period) 1080 hrs/yr**	**BACT/BAT**
NO_x	0.035	1.56	0.84	Good combustion practices and dry low

				NO_x burner
VOC	0.0036	0.16	0.086	Good combustion practices
CO	0.0375	1.67	0.90	Good combustion practices
$PM_{10}/PM_{2.5}$	0.0075	0.33	0.18	ipeline quality natural gas
SO_2	0.0005	0.022	0.012	ipeline quality natural gas
H_2SO_4	0.00008	0.004	0.002	ipeline quality natural gas
GHG	117	n/a	2817.6	Good combustion practices and pipeline quality natural gas

80 MMBtu/hr natural-gas fired boiler with dry low-NOx burners and flue gas recirculation (B002):

Pollutant	**Emission Rate (lb/MMBtu)**	**Maximum Emission Rate (lb/hr)**	**Maximum Emission Rate (tons per rolling, 12-month period) 1080 hrs/yr**	**BACT/BAT**
NO_x	0.027	2.16	1.17	Good combustion practices and dry low NO_x burner
VOC	0.0031	0.248	0.134	Good combustion practices
CO	0.031	2.48	1.34	Good combustion practices
$PM_{10}/PM_{2.5}$	0.006	0.48	0.26	peline quality natural gas
SO_2	0.0015	0.12	0.065	peline quality natural gas
H_2SO_4	0.00022	0.018	0.010	peline quality natural gas
GHG	116	n/a	5,009	Good combustion practices and pipeline quality natural gas

1,250 kW mechanical (1,8060 hp, 12.34 MMBtu/hr) emergency diesel generator (P003):

Pollutant	**Emission Rate (g/kW-hr)**	**Emission Rate (lb/hr)**	**Emissions Rate (tons per rolling, 12-month**	**BACT/BAT**

			period)	
Nonmethane hydrocarbons plus nitrogen oxides (NMHC + NO_x)	6.4	19.68	0.98 (NO_x: 0.931 VOC: 0.049)	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
CO	3.5	10.66	0.53	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
$PM_{10}/PM_{2.5}$	0.20	0.62	0.031	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
SO_2	0.0015 lb/MMbtu	0.023	0.001	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
H_2SO_4	0.00073	0.003	0.00017	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
GHG (CO_{2e})	n/a	2,184	109.2	Efficient design and proper maintenance and operation

320 hp (227 kW mechanical, 2.16 MMBtu/hr) emergency fire pump (P004):

Pollutant	**Emission Rate (g/kW-hr)**	**Emission Rate (lb/hr)**	**Emissions Rate (tons per rolling, 12-month period)**	**BACT/BAT**
Nonmethane hydrocarbons	4.0	2.12	0.11 (NO_x: 0.1045	Good combustion practices

plus nitrogen oxides (NMHC + NO_x)			VOC: 0.0055)	(ULSD) and compliance with 40 CFR Part 60, Subpart IIII
CO	3.5	1.83	0.092	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
$PM_{10}/PM_{2.5}$	0.20	0.11	0.0055	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
SO_2	0.0015 lb/MMBtu	0.004	0.0002	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
H_2SO_4	0.00073 lb/MMBtu	0.0006	0.00003	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
GHG (CO_{2e})	n/a	352	18.67	Efficient design and proper maintenance and operation

5. Conclusion:
It is recommended that this PTI be issued draft.

6. Please provide additional notes or comments as necessary:
Modeling (PSD and Toxic Air Contaminants): The permittee submitted dispersion modeling results with the permit application for PSD. Ohio EPA Central Office reviewed this modeling package prior to issuance of the draft permit.

7. Total Permit Allowable Emissions Summary (for informational purposes only):

Pollutant	Tons Per Year
NO_X	280.2
CO	227.6
$PM_{10}/PM_{2.5}$	160.7
SO_2	59.2
VOC	169.5
H_2SO_4	63.4
NH_3	7343.95
GHGs	5,004,777

STAFF DETERMINATION FOR THE APPLICATION TO CONSTRUCT
UNDER THE PREVENTION OF SIGNIFICANT DETERIORATION REGULATIONS
FOR HARRISON POWER
CADIZ, OHIO
PERMIT NUMBER P0122266

The Clean Air Act and regulations promulgated thereunder require that major air pollution sources undergoing construction or modification comply with all applicable Prevention of Significant Deterioration (PSD) provisions and nonattainment area New Source Review requirements. The federal PSD rules govern emission increases in attainment areas for major sources, which are sources with the potential to emit 250 tons per year or more of any pollutant regulated under the Clean Air Act, or 100 tons per year or more if the source is included in one of 28 source categories. In nonattainment areas, the definition of major source is one having at least 100 tons per year potential emissions. A major modification is one resulting in a contemporaneous increase in emissions which exceeds the significance level of one or more pollutants. Any changes in actual emissions within a five-year period are considered to be contemporaneous. In addition, Ohio now has incorporated the PSD and NSR requirements by rule under OAC 3745-31.

Both PSD and nonattainment rules require that certain analyses be performed before a facility can obtain a permit authorizing construction of a new source or major modification to a major source. The principal requirements of the PSD regulations are:

1. Best Available Control Technology (BACT) review - A detailed engineering review must be performed to ensure that BACT is being installed for the pollutants for which the new source is a major source.

2. Ambient Air Quality Review - An analysis must be completed to ensure the continued maintenance of the National Ambient Air Quality Standards (NAAQS) and that any increases in ambient air pollutant concentrations do not exceed the incremental values set pursuant to the Clean Air Act.

For nonattainment areas, the requirements are:

1. Lowest Achievable Emissions Rate (LAER) - New major sources must install controls that represent the lowest emission levels (highest control efficiency) that has been achieved in practice.

2. The emissions from the new major source must be offset by a reduction of existing emissions of the same pollutant by at least the same amount, and a demonstration must be made that the resulting air quality shows a net air quality benefit. This is more completely described in the Emission Offset Interpretative Ruling as found in Appendix S of 40 CFR Part 51.

3. The facility must certify that all major sources owned or operated in the state by the same entity are either in compliance with the existing State Implementation Plan (SIP) or are on an approved schedule resulting in full compliance with the SIP.

For rural ozone nonattainment areas, the requirements are:

1. LAER - New major sources must install controls that represent the lowest emissions levels (highest control efficiency) that has been achieved in practice.

2. The facility must certify that all major sources owned or operated in the state by the same entity are either in compliance with the existing SIP or are on an approved schedule resulting in full compliance with the SIP.

Finally, New Source Performance Standards (NSPS), SIP emission standards and public participation requirements must be followed in all cases.

SITE DESCRIPTION

Harrison Power LLC, a Delaware Limited Liability Company, (HP) is proposing to construct a natural gas-fired combined-cycle electric generating facility. The facility will include two combined cycle gas turbine (CCGT) units and ancillary equipment and will be located in the Harrison Industrial Park of Cadiz, Ohio. The CCGT units will have a predicted net nominal output of 1,000 megawatts (MW) at International Standards Organization (ISO) conditions with supplemental duct firing. The site will be located just off of Industrial Park Road southeast of the MarkWest Energy Partners, L.P. Cadiz Plant. The site is approximately 60 acres and consists mainly of farmland and deciduous forest. It will be a PSD/Title V major stationary source.

The area is designated as attainment/unclassifiable per the NAAQS for NSR-regulated criteria pollutants, including those triggering PSD: nitrogen oxides (NO_x); carbon monoxide (CO); PM with a diameter equal to or less than 10 micrometers (PM_{10}); PM with a diameter equal to or less than 2.5 micrometers ($PM_{2.5}$); volatile organic compounds (VOC); sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4); and greenhouse gases (GHGs). As one of the 28 named source categories, the facility will be a major stationary source at over 100 tons/year of a PSD pollutant(s) as defined under OAC 3745-31-01(NNN).

FACILITY DESCRIPTION

The Harrison Power Unit 1 and Unit 2 are identical 500 MW units, each consisting of one natural gas-fired Gas Turbine (GT), one heat recovery steam generator (HRSG), and one steam turbine generator (STG), operated in a 1 x 1 x 1 configuration. The fuel is combusted in the GTs and the expanding hot exhaust gases turn electrical generators. Hot exhaust gas exits the GTs and passes through a HRSG that consists of a superheater, an evaporator, and economizer sections that absorb the waste heat from the combustion gas stream. The HRSGs are equipped with supplemental natural gas firing, or duct burners, which allow the facility to vary the electrical output of the units and meet customer demand. Absorbed heat is used to convert incoming feed-water to steam that, in turn, drives the steam turbine generator. The cooled exhaust gas is vented to the atmosphere through the vent stack of each GT/HRSG train. GT emissions of nitrogen oxides (NO_x) will be controlled using Dry Low-NO_x Burners. NO_x emissions from the HRSG stack will be further controlled using a Selective Catalytic Reduction (SCR) system. A 19 percent solution of aqueous ammonia is vaporized and injected into the flue gas stream upstream of a catalyst bed to accomplish the NO_x reduction. Each HRSG also includes an oxidation catalyst for the control of carbon monoxide (CO) and volatile organic compound (VOC) emissions. The GT and HRSG trains will be designated as General Electric (GE) Combustion Turbines CT 1A and CT 2A and Mitsubishi Hitachi Power Systems (MHPS) CT 1B and CT 2B, respectively.

PROJECT DESCRIPTION

The Harrison Power project will consist of two CCGT units, known as Unit 1 and Unit 2, consisting of two natural gas-fired turbines each with a HRSG unit equipped with duct burners, and two steam generator turbines in a 1 x 1 x 1 CCGT configuration. Harrison Power will have a predicted net nominal output of 1,000 MW at ISO conditions with supplemental duct firing. HP is requesting a permit-to-install (PTI) that will allow two optional plant configurations. The turbines being considered for the Facility are:

- Option 1 -- Two GE Combustion Turbines CT 1A and CT 2A; or
- Option 2 – Two MHPS CT 1B and CT 2B.

The facility will include the following major and ancillary equipment:

- Two Combustion Turbines Generators (CTGs);
- Two heat recovery steam generators (HRSGs) with supplemental duct firing;
- Two steam turbine generators (STG);

- One natural gas-fired auxiliary boiler (either 80 MMBtu/hr or 44.55 MMBtu/hr;
- One 1387-kilowatt (1,860 HP) emergency diesel-fired generator; and
- One 238.6-kilowatt (320 HP) diesel-fired emergency firewater pump.

Combustion Turbine Generators and Heat Recovery Steam Generators

The Harrison Power Unit 1 and Unit 2 are identical 500 MW units, each consisting of one natural gas-fired GT, one HRSG, and one steam turbine generator, operated in a 1 x 1 x 1 configuration. The fuel is combusted in the GTs and the expanding hot exhaust gases turn electrical generators. Hot exhaust gas exits the GTs and passes through a HRSG that consists of a superheater, an evaporator, and economizer sections that absorb the waste heat from the combustion gas stream. The HRSGs are equipped with supplemental natural gas firing, or duct burners, which allow the facility to vary the electrical output of the units and meet customer demand. Absorbed heat is used to convert incoming feed-water to steam that, in turn, drives the steam turbine generator. The cooled exhaust gas is vented to the atmosphere through the vent stack of each GT/HRSG train.

If the GE combustion turbine is chosen for installation, it will be nominally rated at 3,459.6 MMBtu/hr at 100% load and -2 degrees F exhausting through a heat recovery steam generator with supplemental natural gas-fired duct burners nominally rated at 570.45 MMBtu/hr.

If the Mitsubishi combustion turbine is chosen for installation, it will be nominally rated at 3,231 MMBtu/hr at 100% load and 51 degrees F exhausting through a heat recovery steam generator with supplemental natural gas-fired duct burners nominally rated at 306 MMBtu/hr.

NO_x, CO and VOC emissions from either combustion turbine/HRSG combination will be accomplished using dry low-NO_x burners, selective catalytic reduction and catalytic oxidation.

Auxiliary Boiler

The proposed facility will include either an 80 MMBtu/hr natural gas-fired auxiliary boiler if the GE model 7HA.02 combustion turbine is installed or a 44.55 MMBtu/hr natural gas-fired auxiliary boiler if the Mitsubishi model M501JAC combustion turbine is installed. The auxiliary boiler will be utilized to warm the units to reduce equipment start times. The auxiliary boiler will operate only intermittently and only when one unit is shut down and the other unit is starting up. The boilers will be permitted as GE Auxiliary Boiler and MHPS Auxiliary Boiler. Whichever auxiliary boiler is installed, annual operation will be limited to 1,080 hours per rolling, 12-month period.

Emergency Diesel Generator

The proposed facility will include a new 1,387 KW (1,860 HP) emergency diesel engine to generate electricity to operate critical systems when power is not otherwise available. This diesel engine will be fired with ULSD and shall not operate more than 100 hours per year of non-emergency use.

Emergency Diesel Fire Pump

A new diesel-fired 238.6 KW (320 HP) fire water pump will be constructed to service the fire protection needs of the new units. This diesel engine will be fired with ULSD and shall not operate more than 100 hours per year of non-emergency use.

NEW SOURCE REVIEW (NSR)/PSD APPLICABILITY

Combined-cycle power plants with potential emissions greater than 100 tpy of one or more criteria pollutants are considered new major stationary sources under the PSD program. As shown in the table below, for Harrison Power, the potential emissions of at least one regulated criteria pollutant will exceed this threshold. As such, the proposed facility is subject to PSD New Source Review. Under the PSD regulations, once a major source threshold is triggered, PSD review must be completed for all pollutants whose potential emissions exceed their respective Significant Emission Rate.

The Project has triggered major source thresholds for PM_{10}, $PM_{2.5}$, SO_2, NO_x, CO, VOC, H_2SO_4, and GHG emissions.

PSD review requirements include application of BACT, an ambient air quality modeling analysis demonstrating compliance with NAAQS and PSD increments, and additional impacts analyses. Ohio EPA has been delegated PSD review authority by the USEPA. For an air contaminant subject to BACT, compliance with BACT requirements also represents Ohio EPA BAT.

Harrison Power is subject to MACT. The facility will satisfy the requirements of 40 CFR Part 63, Subpart ZZZZ by complying with 40 CFR Part 60, Subpart IIII.

Summary of Proposed Potential Emissions and Applicable Regulatory Thresholds

Pollutant	Annual PTE with GE Turbine (tpy)	Annual PTE with Mitsubishi Turbine (tpy)	PSD Major Source Threshold (tpy)	PSD Significant Emission Rate (tpy)	PSD Applies? (Yes/No)
PM_{10}	160.7	155.2	100	15	Yes
$PM_{2.5}$	160.7	155.2	100	10	Yes
SO_2	57.4	59.2	100	40	Yes
NO_x	280.2	249.9	100	40	Yes
CO	227.6	219.7	100	100	Yes
VOC	98.4	169.5	100	40	Yes
H_2SO_4	35.1	63.4	100	7	Yes
Pb	0.002	0.001	10	0.6	No
GHGs[a]	5,004,776.9	4,688,231.5	NA	75,000	Yes

a. GHGs are expressed as CO_{2e}. Note that as of a June 23, 2014 Supreme Court Decision, GHG emissions cannot determine major source status. USEPA issued a Policy Memo dated July 24, 2014, indicating that it intends to apply the current GHG SER threshold for requiring PSD BACT review for GHG for “anyway” sources.

PM_{10} = Particulate Matter <10 microns
$PM_{2.5}$ = Particulate Matter <2.5 microns
SO_2 = Sulfur Dioxide
NO_x = Nitrogen Oxides
CO = Carbon Monoxide

VOC = Volatile Organic Compound
H_2SO_4 = Sulfuric Acid
Pb = Lead
GHG (CO_{2e}) = Greenhouse Gases (CO_2 equivalent)

Based upon the above information, PSD review is required for PM_{10}, $PM_{2.5}$, SO_2, NO_x, CO, VOC, H_2SO_4 and GHGs.

BACT REVIEW

As part of the application for any source regulated under the PSD requirements, an analysis must be conducted that demonstrates that Best Available Control Technology will be employed by the source. In this specific case, the BACT analysis was conducted for PM_{10}, $PM_{2.5}$, SO_2, NO_x, CO, VOC, H_2SO_4 and GHGs. Each pollutant will be reviewed separately.

The application used a "top-down" approach to determine an appropriate level of control.

The basic steps to be followed are:

- Identify all available potential control options;
- Eliminate technically infeasible options;
- Rank remaining technologies by control effectiveness;
- Evaluate the feasible controls by performance and cost analysis; and
- Select BACT

CCGT - BACT Analysis for NO_x

NO_x formation, which is strongly dependent on the high temperatures developed in the combustor, is formed during the combustion of natural gas in the turbines and the duct burners. The major NO_x formation mechanism is thermal NO_x, which arise from the thermal dissociation and subsequent reaction of nitrogen (N_2) and O_2 molecules at high flame temperatures in the combustion air. Fuel NO_x, which results from the reaction of fuel-bound nitrogen compounds with O_2, is a smaller contributor to total NO_x from natural gas combustion in the GTs and the duct burners.

Identification of Technically Feasible Control Options

Potential control technologies for controlling NO_x emissions from large, natural gas-fired combined cycle turbines are listed below:

1. SCR
2. Dry Low NO_x Combustors
3. Water or Steam Injection
4. Good Operating Practices

Selective Catalytic Reduction

SCR is a widely proven technology for reducing NO_x emissions from combined cycle systems to single digit parts per million, volumetric dry (ppmvd) at 15 percent O_2 levels. SCR is a postcombustion flue gas treatment technique, treating the flue gas downstream of the gas turbine. SCR technology has been demonstrated as BACT for many combined cycle projects that along with other technologies have been permitted to NO_x limits as low as 2.5 ppmvd at 15 percent O_2.

SCR technology involves the injection of ammonia into the flue gas that then reacts with NO_x in the presence of a catalyst. NO_x is reduced into N_2 and water by lowering the activation energy of the
NO_x decomposition reaction. Small amounts of un-reacted ammonia "slip" may be emitted as a consequence of using SCR for NO_x control, and such slip represents a precursor for downwind formations of $PM_{2.5}$.

Dry Low NO_x Burners

DLNBs are standard technology for exclusively natural gas-fired combustion turbines. DLNBs are a combustion zone technology that premixes fuel and air to reduce thermal NO_x formation without the need for water or steam injection. The DLNB system also has the added advantages of limiting CO and VOC emissions to very low levels due to efficient combustion. DLNBs are inherent to each manufacturer's combustion turbine on a model by model basis. In simple cycle units, DLNBs alone have been shown to reduce NO_x emissions to 25 ppmvd at 15 percent O_2; when DLNBs are used in combination with SCR in simple cycle units, NO_x emissions are consistently reduced to under 2 ppmvd at 15 percent O_2.

Water or Steam Injection

Water or steam injection is primarily used to reduce NO_x in diffusion flame combustors such as those that burn liquid fuels. Depending on the initial NO_x levels, such rates of injection may reduce NO_x by 60 percent or more. The purpose of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel ratio of less than one. Water or steam injection is usually accompanied by a 2 to 3 percent efficiency penalty but typically results in a 5 or 6 percent increase in power output. The increased power output results from the increased mass flow required to maintain turbine inlet temperature at manufacturer's specifications. Both CO and VOC emissions are increased by water injection, with the level of CO and VOC increases dependent on the amount of water injection.

Good Operating Practices

Good operating practices can be used to minimize NO_x by controlling the air to fuel ratio. The maximum thermal NO_x formation occurs at a slightly fuel-lean mixture because of excess O_2 available for reaction. The control of stoichiometry is critical in achieving reductions in thermal NO_x. NO_x formation is strongly dependent on the high temperatures developed in the combustor. For a given stoichiometry, thermal NO_x formation rapidly drops as the temperature decreases below the adiabatic flame temperature. Maximum reduction of thermal NO_x can be achieved by control of both the combustion temperature and the stoichiometry. Gas turbines operate with high overall levels of excess air because turbines use combustion air dilution as the means to maintain the turbine inlet temperature below design limits.

Eliminate Technically Infeasible Options

A review of the RBLC database for large, natural gas-fired combined cycle turbines revealed that the most effective controls for NO_x are SCR in conjunction with DLNBs. Below are potential control technologies for NO_x that are technically infeasible.

Good Operating Practices

A review of the RBLC database for large, natural gas-fired combined cycle turbines revealed that no natural gas-fired combined cycle combustion turbine used only good operating practices as BACT during normal operations. Good operating practices can be used to minimize NO_x formation by controlling the air to fuel ratio but cannot achieve the higher NO_x control effectiveness of the remaining technologies listed above.

Rank Remaining Control Technologies by Control Effectiveness

A review of the RBLC database for large, natural gas-fired combined cycle turbines revealed that the most effective controls for NO_x are SCR in conjunction with DLNBs, which provide NO_x emission levels as low as 2 ppmvd at 15 percent O_2 and as high as 5 ppmvd at 15 percent O_2. Water injection used in combination with DLNBs in dual fuel (natural gas and fuel oil) combustion turbines has shown to provide NO_x values in the range of 2.5 ppmvd at 15 percent O_2 to 5.5 ppmvd at 15 percent O_2. Turbines approved for BACT with DLNBs alone ranged in NO_x values between 2 ppmvd at 15 percent O_2 and 50 ppmvd at 15 percent O_2. Water injection alone used as BACT on combustion turbines in combined cycle configuration had NO_x emissions of 15 ppmvd at 15 percent O_2.

Evaluation of Control Technologies

The most effective controls for NO_x emissions from large, natural gas-fired combined-cycle turbines are SCR in conjunction with DLNBs, which provide NO_x emission levels as low as 2 ppmvd at 15 percent O_2 and as high as 5 ppmvd at 15 percent O_2.

Selection of BACT

Each GT-HRSG train will be equipped with DLNB and a SCR to control NO_x emissions to a level of 2.0 ppmvd at 15 percent O_2 (24-hour rolling average). The use of a SCR with DLNB has consistently been identified as BACT within the RLBC and is a widely accepted industry practice to control NO_x emissions from gas-fired GT and HRSG units.

CCGT - BACT Analysis for VOC

VOCs can encompass a wide spectrum of organic materials, which are discharged when some of the fuel remains unburned or is only partially burned during the combustion process—also known as "product of incomplete combustion." With natural gas, some organics are carried over as unreacted, trace constituents of the gas, while others may be pyrolysis products of heavier hydrocarbon constituents. VOC emissions are affected by the GT operating load and tend to be lower during base load operations.

Identification of Control Technologies

Potential control technologies for controlling VOC emissions from large, natural gas-fired combined cycle turbines are listed below:

1. Catalytic Oxidation
2. Good Combustion Practices
3. Flares
4. Thermal Oxidizers

Eliminate Technically Infeasible Options

Flares and thermal oxidizers have not been applied to large, natural gas-fired combined cycle turbines for control of VOC emissions and are, therefore, considered technically infeasible.

Ranking of Control Technologies

A review of the RBLC database for large, natural gas-fired combined cycle turbines revealed that the most effective control for VOCs is catalytic oxidation used in conjunction with good combustion practices.

Evaluation of Control Technologies

Utilizing good combustion practices, including proper technology selection and operating practices, will minimize the generation of VOCs in the gas turbines and duct burners. Catalytic oxidation can provide an additional means of VOC control. In some cases, there are reductions in VOC emissions claimed from oxidation catalysts installed for CO control. As VOCs can be a mix of many potential hydrocarbon chains, the potential VOC reduction across an oxidation catalyst is affected by the speciation of VOCs.

Selection of BACT

The proposed BACT for VOC emissions is the installation of an oxidation catalyst and good combustion practices for the control of VOC emissions to 2.0 ppmvd at 15 percent O_2 (3-hour rolling average) with duct burner firing and 1.0 ppmvd at 15 percent O_2 (3-hour rolling average) without duct burner firing.

BACT Analysis for CO

CO emissions result from incomplete combustion due to insufficient residence time, temperature, or mixing to complete fuel carbon oxidation. Combustion control methods used to lower NO_x emissions can result in increased CO emissions. CO emissions also tend to be lower during base load operations.

Identify Control Technologies

Potential control technologies for controlling CO emissions from large, natural gas-fired combined cycle turbines are listed below:

1. Catalytic Oxidation
2. Good Combustion Practices
3. Flares
4. Thermal Oxidizers

Eliminate Technically Infeasible Options

Utilizing good combustion practices, including proper technology selection/design and operating practices will minimize the generation of CO in the GTs and duct burners. Catalytic oxidation of CO emissions from the gas turbines and duct burners is also a technically feasible control option to further reduce CO emissions. The oxidation catalyst would be located upstream of the ammonia

injection grid for the SCR system at a temperature window similar to that of the SCR. As the combustion turbine and duct burner exhaust gases pass through the oxidation catalyst bed, CO is oxidized to carbon dioxide (CO_2).

Flares and thermal oxidizers have not been applied to GTs and are not considered technically feasible. These potential control techniques, therefore, will not be considered for the combined cycle gas turbine project.

Rank Remaining Control Technologies by Control Effectiveness

The RBLC search identified combined cycle facilities, which have utilized good combustion practices for CO control, as well as projects that have utilized both good combustion practices and oxidation catalysts for CO BACT. The range of CO emissions in the RBLC database is 0.9 ppmvd at 15 percent O_2 (without duct burner firing) to 15.0 ppmvd at 15 percent O_2.

Evaluation of Most Effective Controls

GTs have consistently demonstrated uncontrolled emissions below 9 ppmvd at base load while firing natural gas. The use of an oxidation catalyst will further lower CO emissions from the combustion turbine and duct burner to 2.0 ppmvd at 15 percent O_2. The addition of the oxidation catalyst will increase emissions of H_2SO_4 and PM_{10} due to the oxidation of SO_2 to sulfur trioxide (SO_3). These impacts have been accounted for in the emission estimates for these pollutants.

Selection of BACT

Catalytic oxidation combined with good combustion practices has been identified as BACT for control of CO emissions from the GTs and HRSGs. The proposed BACT CO emission limit for the GTs and HRSGs will be 2.0 ppmvd at 15 percent O_2 (24-hour rolling average). During SU/SD operations, good combustion practices shall be maintained as BACT to minimize CO emissions.

BACT Analysis for Particulate Matter ($PM_{10}/PM_{2.5}$)

$PM_{10}/PM_{2.5}$ emissions from GTs and duct burners primarily result from carryover of noncombustible trace constituents in the fuel. Filterable $PM_{10}/PM_{2.5}$ is that portion of the total $PM_{10}/PM_{2.5}$ that exists in the stack in either the solid or liquid state. Condensable $PM_{10}/PM_{2.5}$ exists as a gas in the stack but condenses in the cooler ambient air to form particulate matter. Condensable $PM_{10}/PM_{2.5}$ is composed of organic and inorganic compounds and is generally considered to be all less than 1 micrometer in diameter.

Identify Control Technologies

Potential control technologies for controlling PM emissions from large, natural gas-fired combined cycle turbines are listed below:

1. Fabric Filter (Baghouse)
2. Electrostatic Precipitator (ESP)
3. Clean Fuel (Low Sulfur)
4. Good Combustion Practices

Fabric Filter (Baghouse)

A fabric filter or baghouse is one of the most efficient means of separating particles from a gas stream. The advantage of bag filters is that the efficiency is largely insensitive to the physical characteristics of the gas stream and changes in the dust loading. Baghouse installations are an industry standard for particulate controls.

Both positive and negative pressure baghouses have been used in industrial applications. Positive pressure baghouses operate at an internal pressure greater than atmospheric pressure. In this configuration, the exhaust fans are located before the baghouse (i.e., “dirty side”) and pull the air from the process in order to push the air through the baghouse. Treated gas is then vented to ambient air through a stack or a continuous ridge vent. Negative pressure baghouses operate at an internal pressure less than atmospheric pressure. In this configuration, the exhaust fans are located after the baghouses (i.e., “clean side”), pull the air through the baghouse, and exhaust to the ambient air through a central stack.

Electrostatic Precipitators

ESPs use an electrostatic field to impart a charge to particles contained in the gas stream. The charged particles then migrate to a grounded collection surface. The collected particles are then periodically dislodged from the collection surface by vibrating or rapping the collection surface. The dislodged particles are then collected in a hopper at the bottom of the ESP. ESPs are very effective at removing dust from a gas stream but can be sensitive to variations in dust loading or may be ineffective on materials with certain electrical properties.

Clean Fuel (Low Sulfur)

Clean fuel (i.e., pipeline quality natural gas) contains low ash and sulfur levels, resulting in negligible PM emissions.

Good Combustion Practices

Good combustion practices refer to processes that maintain the correct air-to-fuel ratio to promote the complete combustion of VOCs. This is accomplished by monitoring the excess oxygen (O_2) concentration in the exhaust flow. If the O_2 content is too low, then the VOCs will not completely convert to CO_2 and water. Maintaining the optimal air-to-fuel ratio is necessary to drive the reaction to completion.

Eliminate Technically Infeasible Options

Post-combustion $PM_{10}/PM_{2.5}$ controls such as fabric filters and ESPs are used as controls for utility units that utilize solid fuels such as coal and pet coke, but are not technically feasible for the proposed Harrison Power units using natural gas. The extremely low grain loadings from the GT/duct-fired HRSGs flue gas resulting from burning natural gas and the large gas volumes due to high excess air levels in the flue gas preclude fabric filter and ESP technologies as viable control technologies for this application. Post-combustion $PM_{10}/PM_{2.5}$ controls for these units were not identified in the RBLC.

Rank Remaining Control Technologies by Control Effectiveness

Good combustion practices and "clean" fuels are the only technically feasible $PM_{10}/PM_{2.5}$ emission control technology for natural gas-fired units.

Evaluation of Most Effective Controls

The RBLC database search indicates that the use of good combustion practices and clean burning fuels is BACT for $PM_{10}/PM_{2.5}$. The emission limits for $PM_{10}/PM_{2.5}$ range from 11.7 pounds per hour (lb/hr) to 43.0 lb/hr and 0.005 lb/MMBtu to 0.033 lb/MMBtu in the database.

Selection of BACT

Good combustion practices and the use of pipeline quality natural gas fuel represent BACT for $PM_{10}/PM_{2.5}$. For the proposed GTs/HRSGs, the emissions of $PM_{10}/PM_{2.5}$ from the GTs and duct burners will be limited to less than or equal to 0.008 lb/MMBtu on a 3-hour average based on vendor data.

CCGT - BACT Analysis for SO_2 and H_2SO_4

Sulfur in natural gas is oxidized to SO_2 in the combustion process. A small portion of the SO_2 is oxidized to SO_3 in the combustion process. In addition, a portion of the flue gas SO_2 is oxidized to SO_3 across the oxidation catalyst and SCR catalyst. The SO_3 combines with moisture in the flue gas to form H_2SO_4.

Identification of Control Technologies

Potential control technologies for controlling SO_2/H_2SO_4 emissions from large, natural gas-fired combined cycle turbines are listed below:

1. Good Combustion Practices
2. Wet Electrostatic Precipitators
3. Dry Sorbent Injection
4. Flue Gas Desulfurization (FGD) Scrubbers

Eliminate Technically Infeasible Options

Post-combustion SO_2/H_2SO_4 reduction technologies such as Wet Electrostatic Precipitators, Dry Sorbent Injection, or FGD Scrubbers are not practical and have not been utilized in gas turbine applications.

Wet Electrostatic Precipitators

An ESP is a filtration device that removes fine particles, like dust and smoke, from a flowing gas using the force of an induced electrostatic charge minimally impeding the flow of gases through the unit. In contrast to wet scrubbers that apply energy directly to the flowing fluid medium, an ESP applies energy only to the particulate matter being collected, and therefore, is very efficient in its consumption of the energy (in the form of electricity). A wet ESP operates with water vapor saturated air streams (100 percent relative humidity) and are commonly used to remove liquid droplets such as sulfuric acid mist from industrial process gas streams. The wet ESP is also commonly used where the gases are high in moisture content, contain combustible particulate, or have particles that are sticky in nature. Wet ESPs have not been applied to large, natural gas-fired

combined cycle turbines for control of H_2SO_4 emissions and are, therefore, considered technically infeasible.

Dry Sorbent Injection

Dry Sorbent Injection (DSI) is a pollutant control technology that removes hydrogen chloride and other acid gases through two basic steps: 1) injection of a powdered sorbent into the flue gas (combustion exhaust gas exiting a power plant) where it reacts with the hydrogen chloride or other acid gases, and 2) removal of the compound by a downstream particulate matter control device such as an ESP or a fabric filter, also referred to as a baghouse. DSI is used mainly in large-scale power plants that use coal or oil containing significant amounts of sulfur as fuel, and has not been applied to large, natural gas-fired combined cycle turbines for control of H_2SO_4 emissions. Therefore, DSI is considered technically infeasible for this application.

Flue Gas Desulfurization Scrubbers

FGD is used to remove SO_2 from exhaust flue gases of fossil-fuel power plants and from the emissions of other sulfur oxide emitting processes. Most FGD systems employ two stages: one for fly ash removal and the other for SO_2 removal. In wet scrubbing systems, the flue gas normally passes first through a fly ash removal device, either an ESP or a wet scrubber, and then into the SO_2 absorber. However, in dry injection or spray drying operations, the SO_2 is first reacted with the sorbent, and then the flue gas passes through a particulate control device. FGD is used mainly in large-scale power plants that use coal or oil containing significant amounts of sulfur as fuel, and has not been applied to large, natural gas-fired combined cycle turbines for control of H_2SO_4 emissions. Therefore, FGD is considered technically infeasible for this application.

Ranking of Remaining Control Technologies

A review of the RBLC database for large, natural gas-fired combined cycle turbines revealed that the most effective control for SO_2/H_2SO_4 is good combustion practices using pipeline quality natural gas.

Evaluation of Most Effective Controls

Good combustion practices using pipeline quality natural gas is the only remaining effective control method for SO_2/H_2SO_4 from large, natural gas-fired combined cycle turbines.

Selection of BACT

The use of good combustion practices and pipeline quality natural gas is identified as BACT within the RBLC for SO_2/H_2SO_4 emissions.

BACT Analysis for Greenhouse Gases

On June 23, 2014, the U.S. Supreme Court held that the EPA exceeded its statutory authority when it interpreted the Clean Air Act to require PSD and Title V permitting for stationary sources based on their GHG emissions. Specifically, the agency may not treat GHG as a pollutant for purposes of defining a “major emitting facility” (or a “modification” thereof) in the PSD context or a “major source” in the Title V context. To the extent its regulations purport to do so, they are invalid. EPA may, however, continue to treat GHGs as a “pollutant subject to regulation under this Chapter” for

purpose of requiring BACT for "anyway sources." An "anyway source" is a site that triggers major source permitting through a pollutant besides GHGs and, therefore, triggers major source permitting "anyway." The EPA intends to continue applying BACT to GHGs at "anyway sources" and processing PSD permit applications for "anyway sources" using a 75,000 tons per year CO_{2e} threshold to determine whether a permit must include a BACT limitation for GHGs, pending further developments. Therefore, a source cannot become a major source for just GHG emissions and there cannot be a BACT-worthy significant modification by just increasing GHG emissions. If PSD is triggered for another pollutant and GHG emissions, the facility has to address major source permitting requirements (e.g., BACT analysis) for GHG emissions as well.

The main GHG pollutants of interest for the GT-HRSG units are CO_2, methane (CH_4) and nitrous oxides (N_2O). CO_2 and N_2O emissions are all produced during natural gas combustion in gas turbines. Nearly all of the fuel carbon is converted to CO_2 during the combustion process. This conversion is relatively independent of firing configuration. CH_4 is also present in the exhaust gas and is thought to be unburned fuel in the case of natural gas. Although the formation of CO acts to reduce CO_2 emissions, the amount of CO produced is insignificant compared to the amount of CO_2 produced. The majority of the fuel carbon not converted to CO_2 is due to incomplete combustion. Formation of N_2O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. However, the formation of N_2O is minimized when combustion temperatures are kept high (above 1,475 degrees Fahrenheit) and excess air is kept to a minimum (less than 1 percent).

Identification of Control Technologies

Potential control technologies for controlling CO_{2e} emissions from large, natural gas-fired combined cycle turbines are listed below:

1. Carbon Capture and Storage (CCS)
2. Thermally Efficient Turbines
3. Good Combustion Practices

Note: A review of the RBLC database did not identify control methods applicable for CH_4 and N_2O emissions related to combined cycle natural gas fired units.

Carbon Capture and Storage

CCS is typically comprised of three steps: a means to capture CO_2, a means to transport the CO_2, and a place for storage. In order to capture the CO_2 gas from the exhaust of the turbine, it must first be separated from other gases. Separation may be accomplished by using a sorbent or solvent, a membrane, or by cryogenic distillation. Once the CO_2 is separated from the flue gases, it must be transported for storage or sequestering. Storage or sequestration options include Enhanced Oil Recovery, ocean injection, algae capture, and suitable geological formations.

Separation of the CO_2 gas from the flue gas has been demonstrated in industrial applications by using an amine-based gas adsorption process. CO_2 in the gas phase dissolves into a solution of water and amine compounds. The amines react with CO_2 in solution to form protonated amine, bicarbonate, and carbamate. As these reactions occur, more CO_2 is driven from the gas phase into the solution. When the solution has reached the intended CO_2 loading, it is removed from contact with the gas stream and heated to reverse the chemical reaction and release high-purity CO_2 from the amine solvent. The amine solvent is then recycled to contact additional gas. The flue

gas must first be cooled and treated to remove reactive impurities such as sulfur, NO_x, and particulate matter.

Otherwise, these impurities may react preferentially with the amines, reducing the capacity for CO_2, or irreversibly poisoning the solvent. The resulting pure CO_2 stream is recovered at pressures near atmospheric pressure.

Membrane systems operate on the principle of selective permeation of certain gases. Selective permeation allows one component in a gas stream to pass through faster than the others. For example, CO_2 is a "fast," more permeable gas than CH_4. When a stream consisting of these two gases contacts the membrane, the CO_2 will permeate through the fiber at a faster rate than the CH_4. A successful membrane allows the desired gas molecule to adsorb to the surface on one side, often at higher pressure. The molecule then absorbs into the membrane interior, eventually reaching the other side of the membrane where it can desorb under different conditions, such as low pressure. The separated components can then be collected and transported.

Cryogenic distillation utilizes the properties of gases that have different boiling temperatures. They can be separated by cooling them until they separate into different phases. CO_2 can be frozen at 195 K and atmospheric pressure, or pressurized past its critical point at about 304 K and 74 bar to form a liquid. Water must be removed before cooling or it will form a solid, possibly disrupting the process. Another option for using cryogenics for carbon capture is the separation of O_2 from nitrogen in air for oxy-fuel combustion. Combustion reactions are performed with pure O_2, resulting in primary combustion products of CO_2 and water. This method has the advantages of simple separation of CO_2 from water later in the process to obtain a pure CO_2 stream.

After capturing the separated CO_2, transportation to a suitable sequestration or storage facility must occur. Transportation of CO_2 can occur by ship, truck, rail, or pipeline to a geological formation, CO_2 pipeline, or other sequestration site.

Storage opportunities consist of suitable geological formations such as oil and gas reservoirs, and coal bed CH_4 and saline formations. Production from an oil or natural gas reservoir can be enhanced by pumping CO_2 into the reservoir to push out the product, which is called enhanced oil recovery. Coal beds typically contain large amounts of methane-rich gas that is adsorbed onto the surface of the coal. The current practice for recovering coal bed CH_4 is to depressurize the bed, usually by pumping water out of the reservoir. An alternative approach is to inject CO_2 into the bed. Tests have shown the adsorption rate for CO_2 to be approximately twice that of CH_4, giving it the potential to efficiently displace CH_4 and remain stored in the bed. Lastly, CO_2 can be injected into saline formation. It has been estimated that deep saline formations in the U.S. could potentially store more than 12,000 billion tons of CO_2.

Thermally Efficient Turbines

Thermally efficient turbines installed in natural gas-fired power plants typically operate turbines in combined cycle configuration with an HRSG as opposed to simple cycle configuration for the most thermal efficiency.

Simple cycle configured units typically operate in the 15 to 42 percent thermal efficiency range. Simple cycle configured units are typically used for shaft horsepower applications without recovery of exhaust heat. Electrical utilities often use simple cycle configured units for generation of electricity during emergencies or during peak demand periods since they take less time to cycle on and off.

Combined cycle configured units consist of a simple cycle configured gas turbine with an HRSG. The cycle thermal efficiency can be as high as 84 percent in cases of cogeneration plants. The gas turbine drives an electric generator while the steam created utilizing the waste exhaust heat drives a steam turbine that also drives an electric generator. A supplementary-fired boiler can be used to increase the steam production. The thermal efficiency of a combined cycle unit exclusively for electricity generation is typically between 38 to 60 percent.

Good Combustion Practices

Good combustion practices, including the use of low-carbon fuel, affect resulting amounts of CO_2 through fuel efficiency. Incomplete combustion could result in higher CO emissions and lower CO_2 emissions but would also result in unburned CH_4 emissions that have a global warming potential 25 times that of CO_2, as identified by the EPA. Utilizing all available energy from the fuel input through good combustion practices would result in the lowest rate of pounds of CO_2 per megawatt hour (MWh) of energy produced.

Low-carbon fuel reduces CO_2 emissions by utilizing a fuel with greater hydrogen to carbon ratio. Natural gas is composed of CH_4 that is 25 percent hydrogen by weight. Fuel oil and coal have lower hydrogen to carbon ratios by weight, and therefore, result in higher CO_2 emissions after undergoing a redox reaction. The average emission rates in the U.S. from these three carbon-based fuels for electrical generation are: 2,249 lbs/MWh of CO_2 for coal-fired generation, 1,672 lbs/MWh of CO_2 for fuel oil, and 1,135 lbs/MWh of CO_2 for natural gas. Turbines designed to burn natural gas will result in the lowest emissions of CO_2 per MWh of electricity produced.

Feasibility of Control Technologies

Currently, there are no add-on measures that are economically feasible for the control of GHG emissions from natural gas-fired GTs. For example, carbon capture (sequestration) has been identified as a control method but it has yet to be proven economically feasible to be a required controlled measure. Although the U.S. Department of Energy (DOE) is investigating measures for feasible carbon sequestration through such activities as their Regional Carbon Sequestration Partnerships to help develop the technology, infrastructure, and regulations to implement largescale CO_2 storage, currently there are no feasible control measures for the control of GHG.

A review of the RBLC database for large, natural gas-fired combined cycle turbines revealed that the most effective controls for GHGs are good combustion practices, low carbon fuels, and thermally efficient turbines.

Carbon Capture and Storage

In order to transport CO_2, capture of the select gas must occur. Currently, fluid gas scrubbing has not been adequately met on the scale for abatement of GHGs even through acid gas removal from process streams using alkanolamines is used successfully in other industry processes such as natural gas processing. The transference of knowledge gained from other acid gas stripping processes is unclear, as there are significant differences in flue gas streams from natural gas streams as well as operational differences that must be addressed in order to facilitate widespread cost-effective deployment. The costs incurred for an unproven technology would be substantial and overly burdensome to both Harrison Power and the public at large. The DOE analyses indicate that for a new natural gas combined cycle power plant with a 550 MW equivalent net

output, postcombustion CO_2 capture capital cost would increase by $340 million or 80 percent. In terms of cost per ton of CO_2 avoided, values range from $60 per ton for integrated gasification combined cycle to $114 per ton for a natural gas combined cycle unit.

Once captured, the transport of the CO_2 gas to the pipeline would have to be implemented. The DOE reports that recent studies have shown that CO_2 pipeline transport costs for a 100-kilometer (62-mile) pipeline transporting 5 million tons per year range from approximately $1 per ton to $3 per ton. This cost is dependent on factors such as the distance between the capture and storage points, terrain the pipeline has to pass through, the anticipated flow rate of CO_2, and population and infrastructure development density.

Due to the reasons outlined above as well as the many associated challenges of separating CO_2 from the flue gas of a combined cycle gas turbine and lack of immediate storage capability in the area, CCS is considered not commercially available and not economically viable.

Ranking of Remaining Control Technologies

A review of the RBLC database for large, natural gas-fired combined cycle turbines revealed that the most effective controls for GHG emissions are good combustion practices and thermally efficient turbines.

Thermally Efficient Turbines

Thermally efficient turbines are capable of meeting the latest EPA approved GHG emission standards for power plants. The Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units approved on October 23, 2015 requires new power plants that burn fossil fuels to release no more than 1,000 pounds of CO_2 per MWh.

Good Combustion Practices

Good combustion practices result in the lowest rate of pounds of CO_2 per MWh of energy produced. Since no add-on control technologies are feasible, good combustion practices are essential to achieving the greatest amount of power produced to the lowest amount of fuel consumed and results in the least amount of CO_2 emitted.

Evaluation of Control Technologies

As stated above, the most effective controls for CO_2 are thermal efficient turbines and good combustion practices. Thermally efficient turbines operated with good combustion practices will result in the lowest amount of CO_2 produced per MWh of energy produced.

Selection of BACT

The use of good combustion practices, clean fuels, and energy efficiency have been identified as BACT in the RLBC for GHG emissions. The GT-HRSG units that will comprise Unit 1 and Unit 2 will utilize these practices to meet BACT for CO_2 emissions of 1,000 lbs/MWh.

The RBLC database did not identify control methods applicable for CH_4 emissions related to combined cycle natural gas fired units. Since good combustion practices result in the least amount

of CH_4 left uncombusted from the fuel source, EmberClear has chosen good combustion practices as the BACT for control of CH_4 emissions.

The RBLC database did not identify control methods applicable for N_2O emissions related to combined cycle natural gas fired units. The lack of available controls is due to the extremely low concentrations of N_2O in the gas stream and the cost to remove the pollutant at such low levels. Optimizing fuel combustion to minimize N_2O would result in an increase in NO_x emissions.

Combustion Turbine/Duct-Fired HRSG Startup/Shutdown BACT Evaluation

During SU/SD operations, the DLNBs operate in combustion modes, which are different than the "lean premixed" mode obtained during normal operations. During these SU/SD events, the combustion turbine NO_x concentrations are higher than the NO_x concentrations during the lean premixed mode. The equipment supplier has provided estimates of NO_x emissions during SU/SD events, which have been utilized to quantify NO_x emissions from the GT during these events.

An SCR system requires temperatures typically in the range of 575 to 750 degrees Fahrenheit to operate effectively. Ammonia injection is initiated during startup after the SCR attains the minimum operating temperature. The SCR system is designed and optimized for normal operating conditions and emission guarantees exclude operation during SU/SD periods. While there may be some NO_x reduction from the SCR system during a SU/SD event, it is difficult to quantify the level of reduction due to the transient, non-design flue gas conditions during these events. The injection of ammonia for the SCR system will be according to the manufacturer's operating procedures.

Similarly, the oxidation catalyst requires temperatures approaching 600 degrees Fahrenheit to reach their full conversion potential. As the DLNB progresses through various stages of operation during SU/SD events, both CO and VOC emissions will be at higher levels in the "lean premixed" mode of operation than obtained during normal operations.

Therefore, the most practical option to minimize emissions during SU/SD events is to progress through the event as quickly as possible, while following the manufacturer's recommended procedures. The project will use auxiliary boiler to preheat the equipment downstream of the GT and thus reduce the startup time.

Auxiliary Boiler BACT Evaluation

The auxiliary boiler will be operating only during cold startup and warm startup to reduce the startup duration. Based on estimates of annual cold and warm startups, the auxiliary boiler will be operating approximately 1,080 hours per year. Because the timing of startups is unpredictable, the operation of the auxiliary boiler is also unpredictable. The infrequent and unpredictable operations and use of natural gas fuel preclude any post-combustion controls for the auxiliary boiler for any pollutant.

The auxiliary boiler for the project will be rated at 44.55 MMBtu/hr or 80 MMBTU/hr depending on the manufacturer selected for the combustion turbines. An RBLC search for auxiliary boilers in the range of 42 MMBtu/hr to 99.8 MMBtu/hr in recent years (2014-2016) showed the following BACTs:

1. Use of clean fuel such as pipeline quality natural gas for PM, H_2SO_4, SO_2, and GHGs
2. DLNBs and good combustion practices for NO_x, GHG, and CO

Harrison Power has selected both these options as BACTs. Though VOC is not clearly mentioned in the RBLC database, good combustion is considered BACT for this pollutant also. The auxiliary boiler will be subject to the NSPS Subpart Dc; however, this NSPS does not specify any emission standards. The emissions from the auxiliary boiler after application of BACT will be based on vendor data.

Emergency Diesel Generator and Firewater Pump Engine BACT Evaluation

Both the emergency diesel generator and the firewater pump engine will be subject to the EPA Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40 CFR Parts 60, 85, et al.). This will require the manufacturer of the diesel engine to certify that the engine will meet the stringent emissions levels for $PM_{2.5}/PM_{10}$, CO, SO_2, NO_x, and VOCs for this size engine. Emergency generator sets in the size range of 500 to 2,000 kilowatts electric are required to meet Tier 2 non-road emission limits. The firewater pump engine will meet the emission limits in 40 CFR Part 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, Table 4. The engines will also be required to burn diesel fuel that meets the requirements of 40 CFR 80.510(b) for non-road diesel fuel that identifies standards for sulfur content, and cetane index or aromatic content.

The most effective way of controlling emissions of $PM_{2.5}/PM_{10}$ emissions is to utilize fuels that have low sulfur and ash contents, observe good combustion practices, and comply with the standards of NSPS Subpart IIII. Add-on controls are not practicable as the concentration of PM_{10} in emissions from the diesel engine is extremely small to begin with and not technically and economically amenable to removal by standard control devices. The proposed $PM_{2.5}/PM_{10}$ BACT emission limit for the emergency diesel generator and the firewater pump is good combustion practices and compliance with NSPS Subpart IIII.

The most effective way of controlling emissions of CO, SO_2, NO_x and VOC emissions as identified as BACT from the diesel generator is to comply with NSPS Subpart IIII (e.g., non-road diesel fuel requirements of 40 CFR 80.510(b)) and good combustion practices. The proposed CO, SO_2, NO_x and VOC BACT emission limit for the emergency diesel generator and the firewater pump is good combustion practices (use of Ultra Low Sulfur Diesel) and compliance with NSPS Subpart IIII.

SUMMARY OF BACT EVALUATIONS

The following tables summarize the proposed emission limits and associated control technology for the facility.

Summary of Proposed BACT/BAT Emission Limits and Associated Control Technologies for the GE Combustion Turbines (P005 and P006)

Pollutant	Emission Rate (lb/MMBtu)	Emission Rate (ppm_v) at 15% O_2	Control Technology	Represents
NO_x CTG only CTG w/ DB	n/a	2.0 2.0	DLN and SCR	BACT/BAT
VOC CTG only CTG w/ DB	0.00132 0.00266	1.0 2.0	Good combustion practices and oxidation catalyst	BACT/BAT
CO	n/a		Good combustion	BACT/BAT

CTG only CTG w/ DB		2.0 2.0	practices and oxidation catalyst	
$PM_{10}/PM_{2.5}$ CTG only CTG w/ DB	0.00735 0.00522	n/a n/a	Good combustion practices and pipeline quality natural gas	BACT/BAT
SO_2 CTG only CTG w/ DB	0.00174 0.00174	n/a n/a	Good combustion practices and pipeline quality natural gas	BACT/BAT
H_2SO_4 CTG only CTG w/ DB	0.00102 0.00103	n/a n/a	Good combustion practices and pipeline quality natural gas	BACT/BAT
GHG	1012.4 lbs CO_{2e} per MW-hr (at full load ISO conditions without duct firing)	n/a	High efficient combustion technology	BACT/BAT

Summary of Proposed BACT/BAT Emission Limits and Associated Control Technologies for the Mitsubishi Combustion Turbines (P007 and P008)

Pollutant	Emission Rate (lb/MMBtu)	Emission Rate (ppm_v) at 15% O_2	Control Technology	Represents
NO_x CTG only CTG w/ DB	n/a	2.0 2.0	DLN and SCR	BACT/BAT
VOC CTG only CTG w/ DB	0.00142 0.00277	1.0 2.0	Good combustion practices and oxidation catalyst	BACT/BAT
CO CTG only CTG w/ DB	n/a	2.0 2.0	Good combustion practices and oxidation catalyst	BACT/BAT
$PM_{10}/PM_{2.5}$ CTG only CTG w/ DB	0.00444 0.005	n/a n/a	Good combustion practices and pipeline quality natural gas	BACT/BAT
SO_2 CTG only CTG w/ DB	0.0021 0.0021	n/a n/a	Good combustion practices and pipeline	BACT/BAT

			quality natural gas	
H_2SO_4 CTG only CTG w/ DB	0.0022 0.0022	n/a n/a	Good combustion practices and pipeline quality natural gas	BACT/BAT
GHG	976.0 lbs CO_{2e} per MW-hr (at full load ISO conditions without duct firing)	n/a	High efficient combustion technology	BACT/BAT

Summary of Proposed BACT/BAT Emission Limits and Associated Control Technologies for the GE Auxiliary Boiler (B002)

Pollutant	Emission Rate (lb/MMBtu)	Control Technology	Represents
NO_x	0.027	Good combustion practices and dry low NO_x burner	BACT/BAT
VOC	0.0031	Good combustion practices	BACT/BAT
CO	0.031	Good combustion practices	BACT/BAT
$PM_{10}/PM_{2.5}$	0.006	Pipeline quality natural gas	BACT/BAT
SO_2	0.0015	Pipeline quality natural gas	BACT/BAT
H_2SO_4	0.00022	Pipeline quality natural gas	BACT/BAT
CO_{2e} (GHG)	116	Good combustion practices and Pipeline quality natural gas	BACT/BAT

Summary of Proposed BACT/BAT Emission Limits and Associated Control Technologies for the Mitsubishi Auxiliary Boiler (B001)

Pollutant	Emission Rate (lb/MMBtu)	Control Technology	Represents
NO_x	0.035	Good combustion practices and dry low NO_x burner	BACT/BAT
VOC	0.0036	Good combustion practices	BACT/BAT
CO	0.0375	Good combustion practices	BACT/BAT
$PM_{10}/PM_{2.5}$	0.0075	Pipeline quality natural gas	BACT/BAT
SO_2	0.0005	Pipeline quality natural gas	BACT/BAT
H_2SO_4	0.00008	Pipeline quality natural gas	BACT/BAT
CO_{2e} (GHG)	117	Good combustion practices and pipeline quality natural gas	BACT/BAT

Summary of Proposed BACT/BAT Emission Limits and Associated Control Technologies for the Emergency Fire Pump (P004)

Pollutant	Emission Rate (g/kW-hr)	Emission Rate (lb/hr)	Control Technology	Represents
Nonmethane hydrocarbons plus nitrogen oxides (NMHC + NO_x)	4.0	2.12	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	BACT/BAT
CO	3.5	1.83	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	BACT/BAT
$PM_{10}/PM_{2.5}$	0.20	0.11	Good combustion practices (ULSD) and compliance with 40 CFR	BACT/BAT

			Part 60, Subpart IIII	
SO_2	0.0015 lb/MMBtu	0.004	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	BACT/BAT
H_2SO_4	0.00073 lb/MMBtu	0.0006	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	BACT/BAT
GHG (CO_{2e})	n/a	352	Efficient design and proper maintenance and operation	BACT/BAT

Summary of Proposed BACT/BAT Emission Limits and Associated Control Technologies for the Emergency Diesel Generator (P003)

Pollutant	Emission Rate (g/kW-hr)	Emission Rate (lb/hr)	Control Technology	Represents
Nonmethane hydrocarbons plus nitrogen oxides (NMHC + NO_x)	6.4	19.68	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	BACT/BAT
CO	3.5	10.66	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	BACT/BAT
$PM_{10}/PM_{2.5}$	0.20	0.62	Good combustion practices (ULSD) and compliance with 40 CFR	BACT/BAT

			Part 60, Subpart IIII	
SO_2	0.0015 lb/MMBtu	0.023	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	BACT/BAT
H_2SO_4	0.00073 lb/MMBtu	0.003	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	BACT/BAT
GHG (CO_{2e})	n/a	2,184	Efficient design and proper maintenance and operation	BACT/BAT

Modeling

Air quality dispersion modeling was conducted to assess the effect of this installation on the national ambient air quality standards (NAAQS) and for the consumption of PSD increments. AERMOD (version 16216r) was used in the regulatory default, rural mode. Based on recommendations from Ohio EPA, Harrison Power used the Pittsburgh International Airport (PIT, WBAN# 94823) surface NWS observation station as a representative station, and Pittsburgh International Airport (PIT, WBAN# 94823) upper air observation data. Building downwash was incorporated into the AERMOD estimates. Harrison Power has requested a Permit-to-Install that will allow operation with either one of two potential combustion turbine manufacturers: General Electric (GE) or Mitsubishi (MHPS). Both manufacturer equipment specifications were evaluated in the air dispersion modeling.

Peak impacts of SO_2, NO_2, CO, PM_{10}, and $PM_{2.5}$ were below their PSD Class II significant impact levels (SILs). By modeling below the SILs, the project has demonstrated that it's impacts are insignificant, and will not cause or contribute to an exceedance of any PSD increment or NAAQS.

Toxics Analysis

The Ohio Air Toxics Policy requires evaluation of increases in air toxics above the one ton/year threshold. For the Harrison Power facility, an air toxics analysis was triggered for acetaldehyde ammonia, formaldehyde, hexane, toluene, xylenes, and sulfuric acid. Results compared to the Maximum Allowable Ground Level Concentration (MAGLC) are shown below.

GE Units:

Pollutant	MAGLC (□g/m^3)	Modeled Maximum 1-hr Concentration (□g/m^3)	% of MAGLC
Acetaldehyde	1071.43	0.03	<0.01%
Ammonia	416.67	179.69	43.13%
Formaldehyde	6.48	0.52	8.02%
Hexane	4202.38	0.21	<0.01%
Toluene	1795.24	0.09	0.01%
Xylenes	10333.3	0.05	<0.01%
Sulfuric Acid	4.762	0.86	18.06%

MHPS Units:

Pollutant	MAGLC (□g/m^3)	Modeled Maximum 1-hr Concentration (□g/m^3)	% of MAGLC
Acetaldehyde	1071.43	0.03	<0.01%
Ammonia	416.67	198.99	47.76%
Formaldehyde	6.48	0.61	9.41%
Hexane	4202.38	0.14	<0.01%
Toluene	1795.24	0.11	0.01%
Xylenes	10333.3	0.05	<0.01%
Sulfuric Acid	4.762	2.06	43.26%

No exceedances of the MAGLC were modeled.

Additional Impact Analysis

Harrison Power has demonstrated that the predicted pollutant concentrations throughout the study area are below the secondary NAAQS thresholds. The secondary NAAQS are designed to limit the amount of pollutants in the ambient air to levels below those which could have an adverse impact on human welfare, soils and vegetation. The modeling analyses demonstrate that no significant impacts on human welfare, soils or vegetation will occur from the proposed installation.

EPA Air Quality Criteria documents were reviewed for information on pollutants and adverse effects on the type of vegetation and soils in the area. No adverse impact upon soils or vegetation is expected. The modeled concentrations are below the secondary NAAQS limits.

Harrison Power also conducted a visibility impairment analysis at the nearest National Park. In this case, the impacts on visibility at the Wayne National Forest, located approximately 55 km distant from the project location, were assessed using VISCREEN software. This analysis demonstrated that no visibility impairment would occur.

Class I Area Considerations

The proposed installation is located greater than 100 km from any Class I area. The nearest Class I area, Otter Creek Wilderness Area, is located approximately 196 km to the southeast of the proposed installation. A Q/D screening analysis resulted in a Q/D value of 2.65 for the GE units and 2.58 for the MHPS units. Values less than 10 are generally considered to have negligible impacts on visibility in Class I areas.

Secondary Formation Impact Analysis

Pursuant to draft guidance issued by USEPA in March 2013, addressing secondarily formed $PM_{2.5}$ in a NAAQS compliance demonstration under the PSD program, Harrison Power submitted an analysis of secondary $PM_{2.5}$ formation based on the increase in SO_2 and NO_x emissions from the facility. Although no formal procedure has been promulgated for analysis of secondary $PM_{2.5}$, Ohio EPA reviewed the qualitative/quantitative results submitted by Harrison Power and is in agreement that secondary $PM_{2.5}$ formation will not consume additional PSD increments nor cause a violation of the 24-hour and Annual $PM_{2.5}$ NAAQS. Ohio EPA also conducted an additional analysis of secondarily formed $PM_{2.5}$ based on U.S. EPA's December 2, 2016 and February 23, 2017 Draft Modeled Emission Rates for Precursors (MERPs) Tier 1 assessment techniques. Using the most conservative emission rates for Annual $PM_{2.5}$ and a hypothetical source considered similar to the Harrison Power project for 24-hour $PM_{2.5}$, Ohio EPA demonstrated that secondarily-formed $PM_{2.5}$ from the project will not be significant.

Pursuant to USEPA guidance addressing secondarily formed ozone, Harrison Power submitted an analysis of secondary ozone formation based on the increase of NO_x and VOC emissions from the facility. Ohio EPA reviewed the submitted analysis, which included an analysis of current ozone monitor values in the region. Ohio EPA agrees, based on this analysis, that the Harrison Power facility will not cause a substantial increase in ozone concentrations via secondary formation. Ohio EPA also conducted an additional analysis of secondarily formed ozone based on U.S. EPA's December 2, 2016 and February 23, 2017 Draft Modeled Emission Rates for Precursors (MERPs) Tier 1 assessment techniques. Using a hypothetical source considered similar to the Harrison Power project, Ohio EPA demonstrated that secondarily-formed ozone from the project will not be significant.

Most workers associated with phases of the project/construction already reside in the region and thus would not cause growth in infrastructure/mobile sources, or emission increases and subsequent air quality impacts.

CONCLUSION

Based upon the review of the permit to install application and the supporting documentation provided by the applicant, the Ohio EPA staff has determined the proposed installation will comply with all applicable State and Federal environmental regulations and that the requirements for BACT are satisfied. Therefore, the Ohio EPA staff recommends that a permit to install be issued to Harrison Power for the proposed installation.

PUBLIC NOTICE

The following matters are the subject of this public notice by the Ohio Environmental Protection Agency. The complete public notice, including any additional instructions for submitting comments, requesting information, a public hearing, or filing an appeal may be obtained at: http://epa.ohio.gov/actions.aspx or Hearing Clerk, Ohio EPA, 50 W. Town St., Columbus, Ohio 43215. Ph: 614-644-2129 email: HClerk@epa.ohio.gov

Draft Air Pollution Permit-to-Install Initial Installation
Harrison Power
Industrial Park Road,Cadiz Industrial Park, Cadiz, OH 43907
ID#:P0122266
Date of Action: 1/23/2018
Permit Desc:Initial installation permit for a 1000 MW combined cycle electric generating facility in Harrison County that includes two (2) combustion turbines with a heat recovery stream generator (HRSG) and duct burners, auxiliary boiler, emergency diesel generator engine, and emergency fire pump engine..
The following matters are the subject of this public notice by the Ohio Environmental Protection Agency. The complete public notice, including any additional instructions for submitting comments, requesting information, a public hearing, or filing an appeal may be obtained at: http://epa.ohio.gov/actions.aspx or Hearing Clerk, Ohio EPA, 50 W. Town St., Columbus, Ohio 43215. Ph: 614-644-2129 email: HClerk@epa.ohio.gov Draft Air Pollution Permit-to-Install Initial Installation Harrison Power Industrial Park Road, Cadiz Industrial Park, Cadiz, Ohio 43907 ID#:P0122266 Date of Action: 1/23/2018 Permit Description: Initial installation permit for a 1,000 MW combined cycle electric generating facility in Harrison County. The emissions units include either two GE combustion turbines or two Mitsubishi combustion turbines each with heat recovery stream generators and duct burners, either a GE auxiliary boiler or a Mitsubishi auxiliary boiler, emergency diesel generator engine and emergency fire pump engine. A decision will be made after draft permit issuance whether to install the GE or Mitsubishi combustion turbines and boiler. This facility will generate significant levels of criteria pollutant emissions including CO, NOx, PM10, PM2.5, VOC, SO2, H2SO4 and GHG. For the purposes of Prevention of Significant Deterioration (PSD), the new facility will be a major stationary source. A PSD analysis was required for any increase in emissions of a pollutant exceeding the PSD threshold emissions level, or the significance levels. Peak impacts of SO2, NO2, CO, PM10, and PM2.5 were below their PSD Class II significant impact levels (SILs). By modeling below the SILs, the project has demonstrated that it¿s impacts are insignificant, and will not cause or contribute to an exceedance of any PSD increment or NAAQS. Impacts of toxic pollutants subject to the modeling review met the maximum ambient ground-level concentration (MAGLC). A public hearing and information session on the draft air permit is scheduled for 6 p.m., Wednesday, March 7, 2018, at Harrison Central Jr./Sr. High School, 440 E. Market St., Cadiz, OH 43907. A presiding officer will be present and may limit oral testimony to ensure that all parties are heard. All interested persons are entitled to attend or be represented and give written or oral comments on the draft permit at the hearing. Written comments must be received by Ohio EPA/Southeast District Office by March 12, 2018. Comments received after March 12, 2018 may not be considered to be a part of the official record. Written comments may be submitted at the hearing or sent to Emily Deshaies, Ohio EPA, DAPC Southeast District Office (SEDO), 2195 East Front Street, Logan, Ohio, 43138. Fax number: (740) 385-6490. Further information concerning this application, which is available for public inspection, may be secured from Emily Deshaies, Ohio EPA DAPC, SEDO at the above address during normal business hours. Telephone number: (740) 380-5263. The permit and complete instructions for requesting information or submitting comments may be obtained at: http://epa.ohio.gov/dapc/permitsonline.aspx by entering the ID # or Emily Deshaies, Ohio EPA DAPC, SEDO, 2195 Front St., Logan, OH 43138. Ph: (740)385-8501.

DRAFT

Division of Air Pollution Control
Permit-to-Install
for
Harrison Power

Facility ID:	0634005152
Permit Number:	P0122266
Permit Type:	Initial Installation
Issued:	1/23/2018
Effective:	To be entered upon final issuance

Ohio Environmental Protection Agency

Division of Air Pollution Control
Permit-to-Install
for
Harrison Power

Table of Contents

Ohio Environmental Protection Agency

Authorization

Facility ID:	0634005152
Facility Description:	1000 MW natural gas-fired combined cycle combustion turbine plant
Application Number(s):	A0057587, A0057729, A0059537
Permit Number:	P0122266
Permit Description:	Initial installation permit for a 1000 MW combined cycle electric generating facility in Harrison County that includes two (2) combustion turbines with a heat recovery stream generator (HRSG) and duct burners, auxiliary boiler, emergency diesel generator engine, and emergency fire pump engine.
Permit Type:	Initial Installation
Permit Fee:	$8,800.00 *DO NOT send payment at this time, subject to change before final issuance*
Issue Date:	1/23/2018
Effective Date:	To be entered upon final issuance

This document constitutes issuance to:

Harrison Power
Industrial Park Road
Cadiz Industrial Park
Cadiz, OH 43907

of a Permit-to-Install for the emissions unit(s) identified on the following page.

Ohio Environmental Protection Agency (EPA) District Office or local air agency responsible for processing and administering your permit:

Ohio EPA DAPC, Southeast District Office
2195 Front Street
Logan, OH 43138
(740)385-8501

The above named entity is hereby granted a Permit-to-Install for the emissions unit(s) listed in this section pursuant to Chapter 3745-31 of the Ohio Administrative Code. Issuance of this permit does not constitute expressed or implied approval or agreement that, if constructed or modified in accordance with the plans included in the application, the emissions unit(s) of environmental pollutants will operate in compliance with applicable State and Federal laws and regulations, and does not constitute expressed or implied assurance that if constructed or modified in accordance with those plans and specifications, the above described emissions unit(s) of pollutants will be granted the necessary permits to operate (air) or NPDES permits as applicable.

This permit is granted subject to the conditions attached hereto.

Ohio Environmental Protection Agency

Craig W. Butler
Director

Authorization (continued)

Permit Number: P0122266
Permit Description: Initial installation permit for a 1000 MW combined cycle electric generating facility in Harrison County that includes two (2) combustion turbines with a heat recovery stream generator (HRSG) and duct burners, auxiliary boiler, emergency diesel generator engine, and emergency fire pump engine.

Permits for the following Emissions Unit(s) or groups of Emissions Units are in this document as indicated below:

Emissions Unit ID:	**B001**
Company Equipment ID:	Auxiliary Boiler
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable
Emissions Unit ID:	**B002**
Company Equipment ID:	GE Auxiliary Boiler
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable
Emissions Unit ID:	**P003**
Company Equipment ID:	Emergency Diesel Generator
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable
Emissions Unit ID:	**P004**
Company Equipment ID:	Emergency Fire Pump
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable

Group Name: GE Combustion Turbines

Emissions Unit ID:	**P005**
Company Equipment ID:	CT 1A
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable
Emissions Unit ID:	**P006**
Company Equipment ID:	CT 2A
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable

Group Name: MHPS Combustion Turbines

Emissions Unit ID:	**P007**
Company Equipment ID:	CT 1B
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable
Emissions Unit ID:	**P008**
Company Equipment ID:	CT 2B
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable

A. Standard Terms and Conditions

1. Federally Enforceable Standard Terms and Conditions

a) All Standard Terms and Conditions are federally enforceable, with the exception of those listed below which are enforceable under State law only:

(1) Standard Term and Condition A.2.a), Severability Clause

(2) Standard Term and Condition A.3.c) through A. 3.e) General Requirements

(3) Standard Term and Condition A.6.c) and A. 6.d), Compliance Requirements

(4) Standard Term and Condition A.9., Reporting Requirements

(5) Standard Term and Condition A.10., Applicability

(6) Standard Term and Condition A.11.b) through A.11.e), Construction of New Source(s) and Authorization to Install

(7) Standard Term and Condition A.14., Public Disclosure

(8) Standard Term and Condition A.15., Additional Reporting Requirements When There Are No Deviations of Federally Enforceable Emission Limitations, Operational Restrictions, or Control Device Operating Parameter Limitations

(9) Standard Term and Condition A.16., Fees

(10) Standard Term and Condition A.17., Permit Transfers

2. Severability Clause

a) A determination that any term or condition of this permit is invalid shall not invalidate the force or effect of any other term or condition thereof, except to the extent that any other term or condition depends in whole or in part for its operation or implementation upon the term or condition declared invalid.

b) All terms and conditions designated in parts B and C of this permit are federally enforceable as a practical matter, if they are required under the Act, or any of its applicable requirements, including relevant provisions designed to limit the potential to emit of a source, are enforceable by the Administrator of the U.S. EPA and the State and by citizens (to the extent allowed by section 304 of the Act) under the Act. Terms and conditions in parts B and C of this permit shall not be federally enforceable and shall be enforceable under State law only, only if specifically identified in this permit as such.

3. General Requirements

a) Any noncompliance with the federally enforceable terms and conditions of this permit constitutes a violation of the Act, and is grounds for enforcement action or for permit revocation, revocation and re-issuance, or modification.

b) It shall not be a defense for the permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the federally enforceable terms and conditions of this permit.

c) This permit may be modified, revoked, or revoked and reissued, for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or revocation, or of a notification of planned changes or anticipated noncompliance does not stay any term and condition of this permit.

d) This permit does not convey any property rights of any sort, or any exclusive privilege.

e) The permittee shall furnish to the Director of the Ohio EPA, or an authorized representative of the Director, upon receipt of a written request and within a reasonable time, any information that may be requested to determine whether cause exists for modifying or revoking this permit or to determine compliance with this permit. Upon request, the permittee shall also furnish to the Director or an authorized representative of the Director, copies of records required to be kept by this permit. For information claimed to be confidential in the submittal to the Director, if the Administrator of the U.S. EPA requests such information, the permittee may furnish such records directly to the Administrator along with a claim of confidentiality.

4. Monitoring and Related Record Keeping and Reporting Requirements

a) Except as may otherwise be provided in the terms and conditions for a specific emissions unit, the permittee shall maintain records that include the following, where applicable, for any required monitoring under this permit:

(1) The date, place (as defined in the permit), and time of sampling or measurements.

(2) The date(s) analyses were performed.

(3) The company or entity that performed the analyses.

(4) The analytical techniques or methods used.

(5) The results of such analyses.

(6) The operating conditions existing at the time of sampling or measurement.

b) Each record of any monitoring data, testing data, and support information required pursuant to this permit shall be retained for a period of five years from the date the record was created. Support information shall include, but not be limited to all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Such records may be maintained in computerized form.

c) Except as may otherwise be provided in the terms and conditions for a specific emissions unit, the permittee shall submit required reports in the following manner:

(1) Reports of any required monitoring and/or recordkeeping of federally enforceable information shall be submitted to the Ohio EPA DAPC, Southeast District Office.

(2) Quarterly written reports of (i) any deviations from federally enforceable emission limitations, operational restrictions, and control device operating parameter limitations, excluding deviations resulting from malfunctions reported in accordance with OAC rule 3745-15-06, that have been detected by the testing, monitoring and recordkeeping requirements specified in this permit, (ii) the probable cause of such deviations, and (iii) any corrective actions or preventive measures taken, shall be made to the Ohio EPA DAPC, Southeast District Office. The written reports shall be submitted quarterly, by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters. See A.15. below if no deviations occurred during the quarter.

(3) Written reports, which identify any deviations from the federally enforceable monitoring, recordkeeping, and reporting requirements contained in this permit shall be submitted to the Ohio EPA DAPC, Southeast District Office every six months, by January 31 and July 31 of each year for the previous six calendar months. If no deviations occurred during a six-month period, the permittee shall submit a semi-annual report, which states that no deviations occurred during that period.

(4) This permit is for an emissions unit located at a Title V facility. Each written report shall be signed by a responsible official certifying that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.

d) The permittee shall report actual emissions pursuant to OAC Chapter 3745-78 for the purpose of collecting Air Pollution Control Fees.

5. Scheduled Maintenance/Malfunction Reporting

Any scheduled maintenance of air pollution control equipment shall be performed in accordance with paragraph (A) of OAC rule 3745-15-06. The malfunction, i.e., upset, of any emissions units or any associated air pollution control system(s) shall be reported to the Ohio EPA DAPC, Southeast District Office in accordance with paragraph (B) of OAC rule 3745-15-06. (The definition of an upset condition shall be the same as that used in OAC rule 3745-15-06(B)(1) for a malfunction.) The verbal and written reports shall be submitted pursuant to OAC rule 3745-15-06.

Except as provided in that rule, any scheduled maintenance or malfunction necessitating the shutdown or bypassing of any air pollution control system(s) shall be accompanied by the shutdown of the emission unit(s) that is (are) served by such control system(s).

6. Compliance Requirements

a) All applications, notifications or reports required by terms and conditions in this permit to be submitted or "reported in writing" are to be submitted to Ohio EPA through the Ohio EPA's eBusiness Center: Air Services web service ("Air Services"). Ohio EPA will accept hard copy submittals on an as-needed basis if the permittee cannot submit the required documents through the Ohio EPA eBusiness Center. In the event of an alternative hard copy submission in lieu of the eBusiness Center, the post-marked date or the date the document is delivered in person will be recognized as the date submitted. Electronic submission of applications, notifications or reports required to be submitted to Ohio EPA fulfills the requirement to submit the required information to the Director, the appropriate Ohio EPA District Office or contracted local air agency, and/or any other individual or organization specifically identified as an

additional recipient identified in this permit unless otherwise specified. Consistent with OAC rule 3745-15-03, the electronic signature date shall constitute the date that the required application, notification or report is considered to be "submitted". Any document requiring signature may be represented by entry of the personal identification number (PIN) by responsible official as part of the electronic submission process or by the scanned attestation document signed by the Authorized Representative that is attached to the electronically submitted written report.

Any document (including reports) required to be submitted and required by a federally applicable requirement in this permit shall include a certification by a Responsible Official that, based on information and belief formed after reasonable inquiry, the statements in the document are true, accurate, and complete

b) Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Director of the Ohio EPA or an authorized representative of the Director to:

(1) At reasonable times, enter upon the permittee's premises where a source is located or the emissions-related activity is conducted, or where records must be kept under the conditions of this permit.

(2) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit, subject to the protection from disclosure to the public of confidential information consistent with ORC section 3704.08.

(3) Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit.

(4) As authorized by the Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit and applicable requirements.

c) The permittee shall submit progress reports to the Ohio EPA DAPC, Southeast District Office concerning any schedule of compliance for meeting an applicable requirement. Progress reports shall be submitted semiannually or more frequently if specified in the applicable requirement or by the Director of the Ohio EPA. Progress reports shall contain the following:

(1) Dates for achieving the activities, milestones, or compliance required in any schedule of compliance, and dates when such activities, milestones, or compliance were achieved.

(2) An explanation of why any dates in any schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

7. Best Available Technology

As specified in OAC Rule 3745-31-05, new sources that must employ Best Available Technology (BAT) shall comply with the Applicable Emission Limitations/Control Measures identified as BAT for each subject emissions unit.

8. Air Pollution Nuisance

The air contaminants emitted by the emissions units covered by this permit shall not cause a public nuisance, in violation of OAC rule 3745-15-07.

9. Reporting Requirements

The permittee shall submit required reports in the following manner:

a) Reports of any required monitoring and/or recordkeeping of state-only enforceable information shall be submitted to the Ohio EPA DAPC, Southeast District Office.

b) Except as otherwise may be provided in the terms and conditions for a specific emissions unit, quarterly written reports of (a) any deviations (excursions) from state-only required emission limitations, operational restrictions, and control device operating parameter limitations that have been detected by the testing, monitoring, and recordkeeping requirements specified in this permit, (b) the probable cause of such deviations, and (c) any corrective actions or preventive measures which have been or will be taken, shall be submitted to the Ohio EPA DAPC, Southeast District Office. If no deviations occurred during a calendar quarter, the permittee shall submit a quarterly report, which states that no deviations occurred during that quarter. The reports shall be submitted quarterly, by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters. (These quarterly reports shall exclude deviations resulting from malfunctions reported in accordance with OAC rule 3745-15-06.)

10. Applicability

This Permit-to-Install is applicable only to the emissions unit(s) identified in the Permit-to-Install. Separate application must be made to the Director for the installation or modification of any other emissions unit(s) not exempt from the requirement to obtain a Permit-to-Install.

11. Construction of New Sources(s) and Authorization to Install

a) This permit does not constitute an assurance that the proposed source will operate in compliance with all Ohio laws and regulations. This permit does not constitute expressed or implied assurance that the proposed facility has been constructed in accordance with the application and terms and conditions of this permit. The action of beginning and/or completing construction prior to obtaining the Director's approval constitutes a violation of OAC rule 3745-31-02. Furthermore, issuance of this permit does not constitute an assurance that the proposed source will operate in compliance with all Ohio laws and regulations. Issuance of this permit is not to be construed as a waiver of any rights that the Ohio Environmental Protection Agency (or other persons) may have against the applicant for starting construction prior to the effective date of the permit. Additional facilities shall be installed upon orders of the Ohio Environmental Protection Agency if the proposed facilities cannot meet the requirements of this permit or cannot meet applicable standards.

b) If applicable, authorization to install any new emissions unit included in this permit shall terminate within eighteen months of the effective date of the permit if the owner or operator has not undertaken a continuing program of installation or has not entered into a binding contractual obligation to undertake and complete within a reasonable time a continuing program of installation. This deadline may be extended by up to 12 months if application is made to the

Director within a reasonable time before the termination date and the permittee shows good cause for any such extension.

c) The permittee may notify Ohio EPA of any emissions unit that is permanently shut down (i.e., the emissions unit has been physically removed from service or has been altered in such a way that it can no longer operate without a subsequent "modification" or "installation" as defined in OAC Chapter 3745-31) by submitting a certification from the authorized official that identifies the date on which the emissions unit was permanently shut down. Authorization to operate the affected emissions unit shall cease upon the date certified by the authorized official that the emissions unit was permanently shut down. At a minimum, notification of permanent shut down shall be made or confirmed by marking the affected emissions unit(s) as "permanently shut down" in "Air Services" along with the date the emissions unit(s) was permanently removed and/or disabled. Submitting the facility profile update electronically will constitute notifying the Director of the permanent shutdown of the affected emissions unit(s).

d) The provisions of this permit shall cease to be enforceable for each affected emissions unit after the date on which an emissions unit is permanently shut down (i.e., emissions unit has been physically removed from service or has been altered in such a way that it can no longer operate without a subsequent "modification" or "installation" as defined in OAC Chapter 3745-31). All records relating to any permanently shutdown emissions unit, generated while the emissions unit was in operation, must be maintained in accordance with law. All reports required by this permit must be submitted for any period an affected emissions unit operated prior to permanent shut down. At a minimum, the permit requirements must be evaluated as part of the reporting requirements identified in this permit covering the last period the emissions unit operated.

Unless otherwise exempted, no emissions unit certified by the responsible official as being permanently shut down may resume operation without first applying for and obtaining a permit pursuant to OAC Chapter 3745-31 and OAC Chapter 3745-77 if the restarted operation is subject to one or more applicable requirements.

e) The permittee shall comply with any residual requirements related to this permit, such as the requirement to submit a deviation report, air fee emission report, or other any reporting required by this permit for the period the operating provisions of this permit were enforceable, or as required by regulation or law. All reports shall be submitted in a form and manner prescribed by the Director. All records relating to this permit must be maintained in accordance with law.

12. Permit-To-Operate Application

The permittee is required to apply for a Title V permit pursuant to OAC Chapter 3745-77. The permittee shall submit a complete Title V permit application or a complete Title V permit modification application within twelve (12) months after commencing operation of the emissions units covered by this permit. However, if operation of the proposed new or modified source(s) as authorized by this permit would be prohibited by the terms and conditions of an existing Title V permit, a Title V permit modification of such new or modified source(s) pursuant to OAC rule 3745-77-04(D) and OAC rule 3745-77-08(C)(3)(d) must be obtained before operating the source in a manner that would violate the existing Title V permit requirements.

13. Construction Compliance Certification

The applicant shall identify the following dates in the "Air Services" facility profile for each new emissions unit identified in this permit.

a) Completion of initial installation date shall be entered upon completion of construction and prior to start-up.

b) Commence operation after installation or latest modification date shall be entered within 90 days after commencing operation of the applicable emissions unit.

14. Public Disclosure

The facility is hereby notified that this permit, and all agency records concerning the operation of this permitted source, are subject to public disclosure in accordance with OAC rule 3745-49-03.

15. Additional Reporting Requirements When There Are No Deviations of Federally Enforceable Emission Limitations, Operational Restrictions, or Control Device Operating Parameter Limitations

If no deviations occurred during a calendar quarter, the permittee shall submit a quarterly report, which states that no deviations occurred during that quarter. The reports shall be submitted quarterly by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters.

16. Fees

The permittee shall pay fees to the Director of the Ohio EPA in accordance with ORC section 3745.11 and OAC Chapter 3745-78. The permittee shall pay all applicable permit-to-install fees within 30 days after the issuance of any permit-to-install. The permittee shall pay all applicable permit-to-operate fees within thirty days of the issuance of the invoice.

17. Permit Transfers

Any transferee of this permit shall assume the responsibilities of the prior permit holder. The new owner must update and submit the ownership information via the "Owner/Contact Change" functionality in "Air Services" once the transfer is legally completed. The change must be submitted through "Air Services" within thirty days of the ownership transfer date.

18. Risk Management Plans

If the permittee is required to develop and register a risk management plan pursuant to section 112(r) of the Clean Air Act, as amended, 42 U.S.C. 7401 et seq. ("Act"), the permittee shall comply with the requirement to register such a plan.

19. Title IV Provisions

If the permittee is subject to the requirements of 40 CFR Part 72 concerning acid rain, the permittee shall ensure that any affected emissions unit complies with those requirements. Emissions exceeding any allowances that are lawfully held under Title IV of the Act, or any regulations adopted thereunder, are prohibited.

B. Facility-Wide Terms and Conditions

1. All the following facility-wide terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only:

   a) B.7 through B.11

2. The following emissions units contained in this permit are subject to 40 CFR Part 60, Subparts KKKK and TTTT and 40 CFR Part 63, Subpart YYYY: P005 through P008. The complete NSPS and MACT requirements, including the NSPS and MACT General Provisions, may be accessed via the internet from the Electronic Code of Federal Regulation (e-CFR) website http://www.ecfr.gov or by contacting the Ohio EPA, Southeast District Office.

3. The following emissions units contained in this permit are subject to 40 CFR Part 60, Subpart IIII and 40 CFR Part 63, Subpart ZZZZ: P003 and P004. The complete NSPS and MACT requirements, including the NSPS and MACT General Provisions, may be accessed via the internet from the Electronic Code of Federal Regulation (e-CFR) website http://www.ecfr.gov or by contacting the Ohio EPA, Southeast District Office.

4. The following emissions units contained in this permit are subject to 40 CFR Part 60, Subpart Dc and 40 CFR Part 63, Subpart DDDDD: B001 and B002. The complete NSPS and MACT requirements, including the NSPS and MACT General Provisions, may be accessed via the internet from the Electronic Code of Federal Regulation (e-CFR) website http://www.ecfr.gov or by contacting the Ohio EPA, Southeast District Office.

5. This facility is subject to the applicable requirements specified in OAC Chapter 3745-25. In accordance with Ohio EPA Engineering Guide #64, the emission control action programs, as specified in OAC rule 3745-25-03, shall be developed and submitted within 60 days after receiving notification from the Ohio EPA.

6. The following emissions units are subject to the 40 CFR Part 97 - Cross-State Air Pollution Rule (CSAPR): P005 through P008. The applicable CSAPR requirements will be incorporated in the initial Title V operating permit terms and conditions for these emissions units based on the U.S. EPA guidance "Title V Permit Guidance and Template for the Cross-State Air Pollution Rule" available at https://www.epa.gov/sites/production/files/2016-10/documents/csapr title v permit guidance.pdf.

7. The permit-to-install (PTI) application for emissions units B001, B002 and P001 through P008 was evaluated based on the actual materials and the design parameters of the emissions units' exhaust systems, as specified by the permittee. The "Toxic Air Contaminant Statute," ORC 3704.03(F), was applied to these emissions units for each toxic air contaminant listed in OAC rule 3745-114-01, using data from the permit application; and modeling was performed for each toxic air contaminant emitted at over one ton per year using an air dispersion model such as SCREEN3, AERMOD, or ISCST3, or other Ohio EPA approved model. The predicted 1-hour maximum ground-level concentration result(s) from the approved air dispersion model, was compared to the Maximum Acceptable Ground-Level Concentration (MAGLC), calculated as described in the Ohio EPA guidance document entitled "Review of New Sources of Air Toxic Emissions, Option A," as follows:

   a) the exposure limit, expressed as a time-weighted average concentration for a conventional 8-hour workday and a 40-hour workweek, for each toxic compound(s) emitted from the emissions unit(s), (as determined from the raw materials processed and/or coatings or other materials applied) has been documented from one of the following sources and in the following order of preference (TLV was and shall be used, if the chemical is listed):

(1) threshold limit value (TLV) from the American Conference of Governmental Industrial Hygienists (ACGIH) "Threshold Limit Values for Chemical Substances and Physical Agents Biological Exposure Indices"; or

(2) STEL (short term exposure limit) or the ceiling value from the American Conference of Governmental Industrial Hygienists (ACGIH) "Threshold Limit Values for Chemical Substances and Physical Agents Biological Exposure Indices"; the STEL or ceiling value is multiplied by 0.737 to convert the 15-minute exposure limit to an equivalent 8-hour TLV.

b) The TLV is divided by 10 to adjust the standard from the working population to the general public (TLV/10).

c) This standard is/was then adjusted to account for the duration of the exposure or the operating hours of the emissions unit(s), i.e., 24 hours per day and 7 days per week, from that of 8 hours per day and 5 days per week. The resulting calculation was (and shall be) used to determine the Maximum Acceptable Ground-Level Concentration (MAGLC):

TLV/10 * 8/24 * 5/7 = 4 TLV/24 * 7 = MAGLC

d) The following summarizes the results of dispersion modeling for the "worst case" toxic contaminant (emitted at one or more tons/year) for the General Electric (GE) and Mitsubishi Hitachi Power Systems (MHPS) combustion turbines, respectively:

Toxic Contaminant: ammonia (NH_3), (sulfuric acid mist, acetaldehyde, formaldehyde, hexane, toluene and xylenes)
TLV (ppm): 25 (NH_3)
Maximum Hourly Emission Rate (lb/hr): 1676.7 (NH_3)
Predicted 1-Hour Maximum Ground-Level Concentration (ug/m^3): 179.69
MAGLC (ug/m^3): 416.67

Toxic Contaminant: ammonia (NH_3), (sulfuric acid mist, acetaldehyde, formaldehyde, hexane, toluene and xylenes)
TLV (ppm): 25 (NH_3)
Maximum Hourly Emission Rate (lb/hr): 1406.5 (NH_3)
Predicted 1-Hour Maximum Ground-Level Concentration (ug/m^3): 198.99
MAGLC (ug/m^3): 416.67

The permittee, has demonstrated that emissions of ammonia from emissions units B001, B002 and P001 through P008 are calculated to be less than 80 percent of the maximum acceptable ground level concentration (MAGLC); any new raw material or processing agent shall not be applied without evaluating each component toxic air contaminant in accordance with the "Toxic Air Contaminant Statute," ORC 3704.03(F).

8. Prior to making any physical changes to or changes in the method of operation of the emissions unit(s), that could impact the parameters or values that were used in the predicted 1-hour maximum ground-level concentration, the permittee shall re-model the change(s) to demonstrate that the MAGLC has not been exceeded. Changes that can affect the parameters/values used in determining the 1-hour maximum ground-level concentration include, but are not limited to, the following:

a) changes in the composition of the materials used or the use of new materials, that would result in the emission of a new toxic air contaminant with a lower Threshold Limit Value (TLV) than the lowest TLV previously modeled;

b) changes in the composition of the materials, or use of new materials, that would result in an increase in emissions of any toxic air contaminant listed in OAC rule 3745-114-01, that was modeled from the initial (or last) application; and

c) physical changes to the emissions unit(s) or its/their exhaust parameters (e.g., increased/ decreased exhaust flow, changes in stack height, changes in stack diameter, etc.).

If the permittee determines that the "Toxic Air Contaminant Statute" will be satisfied for the above changes, the Ohio EPA will not consider the change(s) to be a "modification" under OAC rule 3745-31-01 solely due to a non-restrictive change to a parameter or process operation, where compliance with the "Toxic Air Contaminant Statute," ORC 3704.03(F), has been documented. If the change(s) meet(s) the definition of a "modification," the permittee shall apply for and obtain a final FEPTIO prior to the change. The Director may consider any significant departure from the operations of the emissions unit, described in the permit application, as a modification that results in greater emissions than the emissions rate modeled to determine the ground level concentration; and he/she may require the permittee to submit a permit application for the increased emissions.

9. The permittee shall collect, record, and retain the following information for each toxic evaluation conducted to determine compliance with the "Toxic Air Contaminant Statute," ORC 3704.03(F):

a) a description of the parameters/values used in each compliance demonstration and the parameters or values changed for any re-evaluation of the toxic(s) modeled (the composition of materials, new toxic contaminants emitted, change in stack/exhaust parameters, etc.);

b) the Maximum Acceptable Ground-Level Concentration (MAGLC) for each significant toxic contaminant or worst-case contaminant, calculated in accordance with the "Toxic Air Contaminant Statute," ORC 3704.03(F);

c) a copy of the computer model run(s), that established the predicted 1-hour maximum ground-level concentration that demonstrated the emissions unit(s) to be in compliance with the "Toxic Air Contaminant Statute," ORC 3704.03(F), initially and for each change that requires re-evaluation of the toxic air contaminant emissions; and

d) the documentation of the initial evaluation of compliance with the "Toxic Air Contaminant Statute," ORC 3704.03(F), and documentation of any determination that was conducted to re-evaluate compliance due to a change made to the emissions unit(s) or the materials applied.

10. The permittee shall maintain a record of any change made to a parameter or value used in the dispersion model, used to demonstrate compliance with the "Toxic Air Contaminant Statute," ORC 3704.03(F), through the predicted 1-hour maximum ground-level concentration. The record shall include the date and reason(s) for the change and if the change would increase the ground-level concentration.

11. The permittee shall submit annual reports that include any changes to any parameter or value used in the dispersion model used to demonstrate compliance with the "Toxic Air Contaminate Statute", ORC 3704.03(F), through the predicted 1-hour maximum concentration. The report shall include:

    a) the original model input;

    b) the updated model input;

    c) the reason for the change(s) to the input parameter(s); and

    d) a summary of the results of the updated modeling, including the input changes; and

    e) a statement that the model results indicate that the 1-hour maximum ground-level concentration is less than 80% of the MAGLC.

    If no changes to the emissions, emissions unit(s), or the exhaust stack have been made during the reporting period, then the report shall include a statement to that effect. This report shall be postmarked or delivered no later than April 30 following the end of each calendar year.

12. This permit authorizes the installation and initial operation of only one of the two groups of combined cycle combustion turbine models in this permit: emissions units P005 and P006 (General Electric model 7HA.02) or emissions units P007 and P008 (Mitsubishi Hitachi Power Systems model 501JAC).

    This permit authorizes the installation and initial operation of only one of the two auxiliary boilers in this permit: emissions unit B001 (Mitsubishi Hatachi Power Systems 44.55 MMBtu/hr auxiliary boiler) or emissions unit B002 (General Electric 80 MMBtu/hr auxiliary boiler).

C. Emissions Unit Terms and Conditions

1. B001, Auxiliary Boiler

Operations, Property and/or Equipment Description:

44.55 MMBtu/hr natural gas-fired boiler equipped with dry low-NO_x burners

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) b)(1)c and b)(2)i

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rules 3745-31-10 through 3745-31-20 and 3745-31-34	Nitrogen oxides (NO_x) emissions shall not exceed 0.035 lb/MMBtu of actual heat input, 1.56 pounds per hour and 0.84 ton per rolling, 12-month period. Carbon monoxide (CO) emissions shall not exceed 0.0375 lb/MMBtu of actual heat input, 1.67 pounds per hour and 0.90 ton per rolling, 12-month period. Volatile organic compound (VOC) emissions shall not exceed 0.0036 lb/MMBtu of actual heat input, 0.16 pound per hour and 0.086 ton per rolling, 12-month period. Particulate emissions (PE) and emissions of particulate matter less than 10 microns (PM_{10}) and particulate matter less than 2.5 microns ($PM_{2.5}$) shall not exceed 0.0075 lb/MMBtu of actual heat input, 0.33 pound per hour and 0.18 ton per rolling, 12-month period. Sulfur dioxide (SO_2) emissions shall not exceed 0.0005 lb/MMBtu of actual heat input, 0.022 pound per hour and 0.012 ton per rolling, 12-month period.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		Sulfuric acid (H_2SO_4) emissions shall not exceed 0.00008 lb/MMBtu of actual heat input, 0.004 pound per hour and 0.002 ton per rolling, 12-month period. Carbon dioxide equivalent (CO_2e) emissions shall not exceed 2,817.6 tons per rolling, 12-month period. Visible PE from the stack serving this emissions unit shall not exceed 10% opacity as a 6-minute average. See b)(2)a through b)(2)f.
b.	OAC rule 3745-31-05(A)(3)	The emission limitations for CO, NO_x, VOC, PE/PM_{10}/$PM_{2.5}$ and SO_2 required by this rule are equivalent to the emission limitations for CO, NO_x, VOC, PE/PM_{10}/$PM_{2.5}$ and SO_2 established pursuant to OAC rules 3745-31-10 through 3745-31-20. Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3) do not apply to the CO_2e emissions from this air contaminant source pursuant to OAC rule 3745-31-34(E)(8). See b)(2)h and c)(1).
c.	OAC rule 3745-31-05(A)(3)(a)(ii)	BAT requirements under OAC rule 3745-31-05(A)(3) do not apply to the CO, NO_x, VOC, PE/PM_{10}/$PM_{2.5}$ and SO_2 emissions from this air contaminant source since the potential to emit is less than 10 tons/year. See b)(2)i.
d.	OAC rule 3745-17-10(B)(1)	The emission limitation required by this applicable rule is less stringent than the emission limitation established pursuant to OAC rules 3745-31-10 through 20.
e.	OAC rule 3745-17-07(A)	The emission limitation required by this applicable rule is less stringent than the emission limitation established pursuant to OAC rules 3745-31-10 through 20.
f.	OAC rule 3745-18-06	Exempt pursuant to OAC rule 3745-18-06(A) since only natural gas fuel is burned in this emissions unit.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
g.	OAC rule 3745-110-03(C)	Exempt pursuant to OAC rule 3745-110-03(K)(20) because this emissions unit is subject to BACT requirements for NO_x emissions.
h.	40 CFR Part 60, Subparts A and Dc (40 CFR 60.1 – 60.19 and 60.40c – 60.48c) [In accordance with 40 CFR 60.40c(a), this emissions unit is a steam generating unit commencing construction, modification, or reconstruction after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million BTU per hour (MMBtu/hr) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr).]	See b)(2)j, c)(3), d)(3) and e)(4).
i.	40 CFR Part 63, Subpart DDDDD (40 CFR 63.7480 – 63.7575) [In accordance with 40 CFR 63.7480, 63.7485, 63.7490(a)(2) and (b) and 63.7499(l), this emissions unit is a new industrial boiler located at a major source of HAP emissions in the units designed to burn gas 1 fuels subject to the emission limitations and control measures specified in this section.]	The permittee shall comply with the work practice standards in 40 CFR Part 63, Subpart DDDDD Table 3. [40 CFR 63.7500(a)(1) and Table 3 (3)] See c)(3). The permittee shall comply with the requirements of 40 CFR Part 63, Subpart DDDDD upon startup. [40 CFR 63.7495(a)]
j.	40 CFR Part 63, Subpart A (40 CFR 63.1 – 63.16)	Table 10 of 40 CFR Part 63, Subpart DDDDD specifies the provisions of Subpart A that apply to owners and operators of affected facilities subject to this subpart. [40 CFR 63.7565]

(2) Additional Terms and Conditions

a. As part of the Best Available Control Technology (BACT) determination, this emissions unit shall operate for no more than 1,080 hours per rolling, 12-month period.

b. As part of the BACT determination for NO_x, the boiler must be equipped with dry low-NO_x burners. Compliance with this requirement shall be demonstrated by compliance with the short-term NO_x emission limitations in b)(1)a.

c. As part of the BACT determination for CO, compliance with the BACT requirements shall be demonstrated by compliance with the short-term CO emission limitations in b)(1)a.

d. As part of the BACT determination for VOC, compliance with the BACT requirements shall be demonstrated by compliance with the short-term VOC emission limitation in b)(1)a.

e. As part of the BACT determination for PE/PM_{10}/$PM_{2.5}$, compliance with the BACT requirements shall be demonstrated by compliance with the short-term PE/PM_{10}/$PM_{2.5}$ emission limitations in b)(1)a.

f. As part of the BACT determination for SO_2 and H_2SO_4, the permittee shall burn only natural gas with a sulfur content of less than 0.50 grain/100 scf in this emissions unit. Compliance with this requirement shall be demonstrated by compliance with the SO_2 and H_2SO_4 emission limitations in b)(1)a and c)(1).

g. As part of the BACT determination for CO_2e, compliance with the BACT requirements shall be demonstrated by compliance with the CO_2e emission limitation in b)(1)a.

h. This BAT emission limit applies until U.S. EPA approves Ohio Administrative Code (OAC) paragraph 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) into the Ohio State Implementation Plan (SIP).

i. These requirements apply once U.S. EPA approves OAC paragraph 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) as part of the Ohio SIP.

j. See 40 CFR Part 60, Subpart Dc (40 CFR 60.40c – 60.48c).

c) Operational Restrictions

(1) The permittee shall burn only natural gas fuel with a maximum sulfur content not to exceed 0.50 grain/100 scf in this emissions unit.

(2) See 40 CFR Part 60, Subpart Dc (40 CFR 60.40c – 60.48c).

(3) See 40 CFR Part 63, Subpart DDDDD (40 CFR 63.7480 – 63.7575).

d) Monitoring and/or Recordkeeping Requirements

(1) For each day during which the permittee burns a fuel other than natural gas fuel with a maximum sulfur content of 0.50 grain/100 scf, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

(2) The permittee shall maintain monthly records of the following information:

a. the hours of operation of this emissions unit;

b. the rolling, 12-month summation of operating hours for this unit, calculated by adding the total hours of operation for the present month as recorded in d)(2)a, plus the total hours of operation for the previous 11 months;

c. the amount of natural gas consumed in this emissions unit, in MMscf;

d. the heat content of the natural gas combusted in this emissions unit, in MMBtu/MMscf;

e. the sulfur content of the natural gas combusted in this emissions unit, in grains/100 scf;

f. the total NO_x emissions from this emissions unit, in pounds, calculated by multiplying the NO_x emission factor of 0.035 lb/MMBtu, or after testing has been completed, the results of the most recent stack test, by the amount of natural gas consumed, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

g. the rolling, 12-month summation of the NO_x emissions from this emissions unit, in tons, calculated by adding the total NO_x emissions for the present month as recorded in d)(2)f, plus the total NO_x emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

h. the total CO emissions from this emissions unit, in pounds, calculated by multiplying the CO emission factor of 0.0375 lb/MMBtu, or after testing has been completed, the results of the most recent stack test, by the amount of natural gas consumed, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

i. the rolling, 12-month summation of the CO emissions from this emissions unit, in tons, calculated by adding the total CO emissions for the present month as recorded in d)(2)h, plus the total CO emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

j. the total VOC emissions from this emissions unit, in pounds, calculated by multiplying the VOC emission factor of 0.0036 lb/MMBtu, or after testing has been completed, the results of the most recent stack test, by the amount of natural gas consumed, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

k. the rolling, 12-month summation of the VOC emissions from this emissions unit, in tons, calculated by adding the total VOC emissions for the present month as recorded in d)(2)j, plus the total VOC emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

l. the total $PE/PM_{10}/PM_{2.5}$ emissions from this emissions unit, in pounds, calculated by multiplying the $PE/PM_{10}/PM_{2.5}$ emission factor of 0.0075 lb/MMBtu, or after testing has been completed, the results of the most recent stack test, by the amount of natural gas consumed, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

m. the rolling, 12-month summation of the $PE/PM_{10}/PM_{2.5}$ emissions from this emissions unit, in tons, calculated by adding the total $PE/PM_{10}/PM_{2.5}$ emissions for the present month as recorded in d)(2)l, plus the total $PE/PM_{10}/PM_{2.5}$ emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

n. the total SO_2 emissions from this emissions unit, in pounds, calculated by multiplying the SO_2 emission factor of 0.0005 lb/MMBtu, or after testing has been completed, the results of the most recent stack test, by the amount of natural gas consumed, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

o. The rolling, 12-month summation of the SO_2 emissions from this emissions unit, in tons, calculated by adding the total SO_2 emissions for the present month as recorded in d)(2)n, plus the total SO_2 emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

p. the total H_2SO_4 emissions from this emissions unit, in pounds, calculated by multiplying the H_2SO_4 emission factor of 0.00008 lb/MMBtu, or after testing has been completed, the results of the most recent stack test, by the amount of natural gas consumed, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

q. The rolling, 12-month summation of the H_2SO_4 emissions from this emissions unit, in tons, calculated by adding the total H_2SO_4 emissions for the present month as recorded in d)(2)p, plus the total H_2SO_4 emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

r. the total CO_2e emissions from this emissions unit, in pounds, calculated by multiplying the CO_2e emission factor of 117 lbs/MMBtu by the amount of natural gas consumed, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d; and

s. The rolling, 12-month summation of the CO_2e emissions from this emissions unit, in tons, calculated by adding the total CO_2e emissions for the present month as recorded in d)(2)r, plus the total CO_2e emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds.

(3) See 40 CFR Part 60, Subpart Dc (40 CFR 60.40c – 60.48c).

e) Reporting Requirements

(1) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

(2) The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than natural gas fuel with a maximum sulfur content of 0.50 grain/100 scf was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

(3) The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. any exceedances of the rolling, 12-month limitation on operating hours; and

b. any exceedances of the rolling, 12-month emission limitations for NO_x, CO, VOC, PE/PM_{10}/$PM_{2.5}$, SO_2, H_2SO_4 and CO_2e, calculated pursuant to the equations in d)(2).

(4) See 40 CFR Part 60, Subpart Dc (40 CFR 60.40c – 60.48c).

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitations:

NO_x emissions shall not exceed 0.035 lb/MMBtu of actual heat input, 1.56 pounds per hour and 0.84 ton per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the short-term emission limitations shall be demonstrated based on the emission testing requirements specified in f)(2).

Compliance with the rolling, 12-month emission limitation shall be demonstrated by the record keeping requirements specified in d)(2).

b. Emission Limitations:

CO emissions shall not exceed 0.0375 lb/MMBtu of actual heat input, 1.67 pounds per hour and 0.90 ton per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the short-term emission limitations shall be demonstrated based on the emission testing requirements specified in f)(2).

Compliance with the rolling, 12-month emission limitation shall be demonstrated by the record keeping requirements specified in d)(2).

c. Emission Limitations:

VOC emissions shall not exceed 0.0036 lb/MMBtu of actual heat input, 0.16 pound per hour and 0.086 ton per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the short-term emission limitations shall be demonstrated based on the emission testing requirements specified in f)(2).

Compliance with the rolling, 12-month emission limitation shall be demonstrated by the record keeping requirements specified in d)(2).

d. Emission Limitations:

PE and emissions of PM_{10} and $PM_{2.5}$ shall not exceed 0.0075 lb/MMBtu of actual heat input, 0.33 pounds per hour and 0.18 ton per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the short-term emission limitations shall be demonstrated based on the emission testing requirements specified in f)(2).

Compliance with the rolling, 12-month emission limitation shall be demonstrated by the record keeping requirements specified in d)(2).

e. Emission Limitations:

SO_2 emissions shall not exceed 0.0005 lb/MMBtu of actual heat input, 0.022 pound per hour and 0.012 ton per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the short-term emission limitations shall be demonstrated based on the emission testing requirements specified in f)(2).

Compliance with the rolling, 12-month emission limitation shall be demonstrated by the record keeping requirements specified in d)(2).

f. Emission Limitations:

H_2SO_4 emissions shall not exceed 0.00008 lb/MMBtu of actual heat input, 0.004 pound per hour and 0.002 ton per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the short-term emission limitations shall be demonstrated based on the emission testing requirements specified in f)(2).

Compliance with the rolling, 12-month emission limitation shall be demonstrated by the record keeping requirements specified in d)(2).

g. Emission Limitation:

CO_2e emissions shall not exceed 2,817.6 tons per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the rolling, 12-month emission limitation shall be demonstrated by the record keeping requirements specified in d)(2).

h. Emission Limitation:

Visible PE from the stack serving this emissions unit shall not exceed 10% opacity as a 6-minute average.

Applicable Compliance Method:

If required, compliance with the visible PE limitation shall be demonstrated based upon visible particulate emission observations performed in accordance with the methods and procedures specified in 40 CFR Part 60, Appendix A, Method 9.

(2) Performance testing shall be conducted as required in OAC rules 3745-31-10 through 20. The permittee shall conduct, or have conducted, emission testing for this emissions unit within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, as applicable, in accordance with the following requirements:

a. The emission testing shall be conducted to demonstrate compliance with the emission limitations specified in b)(1) for NO_x, CO, VOC, PE/PM_{10}/$PM_{2.5}$ and H_2SO_4.

b. The following test method(s) shall be employed to demonstrate compliance with the allowable mass emission rate(s):

for NO_x, Methods 1 through 4 and 7E of 40 CFR Part 60, Appendix A;

for CO, Methods 1 through 4 and 10 of 40 CFR Part 60, Appendix A;

for VOC, Methods 1 through 4 and 18 and 25 of 40 CFR Part 60, Appendix A;

for PE/PM_{10}/$PM_{2.5}$, Methods 1 through 5 of 40 CFR Part 60, Appendix A and Method 202 of 40 CFR Part 51, Appendix M;

for SO_2, 40 CFR 60.4415(a) for fuel sulfur content; and

for H_2SO_4, Methods 1 through 4 and 8 of 40 CFR Part 60, Appendix A.

Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

c. The test(s) for each pollutant shall be conducted while the emissions unit is operating at or near its maximum capacity, while burning representative fuel and/or combination of fuels, unless otherwise specified or approved by the Ohio EPA, Southeast District Office.

d. Not later than 30 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the Ohio EPA, Southeast District Office. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Ohio EPA, Southeast District Office's refusal to accept the results of the emission test(s).

e. Personnel from the Ohio EPA, Southeast District Office shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

f. A comprehensive written report on the results of the emission test(s) shall be signed by the person or persons responsible for the tests and submitted to the Ohio EPA, Southeast District Office within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Ohio EPA, Southeast District Office.

g) Miscellaneous Requirements

(1) None.

2. B002, Auxiliary Boiler

Operations, Property and/or Equipment Description:

80 MMBtu/hr natural gas-fired boiler equipped with dry low-NO_x burners

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) b)(1)c and b)(2)i

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rules 3745-31-10 through 3745-31-20 and 3745-31-34	Nitrogen oxides (NO_x) emissions shall not exceed 0.027 lb/MMBtu of actual heat input, 2.16 pounds per hour and 1.17 tons per rolling, 12-month period. Carbon monoxide (CO) emissions shall not exceed 0.031 lb/MMBtu of actual heat input, 2.48 pounds per hour and 1.34 tons per rolling, 12-month period. Volatile organic compound (VOC) emissions shall not exceed 0.0031 lb/MMBtu of actual heat input, 0.248 pound per hour and 0.134 ton per rolling, 12-month period. Particulate emissions (PE) and emissions of particulate matter less than 10 microns (PM_{10}) and particulate matter less than 2.5 microns ($PM_{2.5}$) shall not exceed 0.006 lb/MMBtu of actual heat input, 0.48 pound per hour and 0.26 ton per rolling, 12-month period. Sulfur dioxide (SO_2) emissions shall not exceed 0.0015 lb/MMBtu of actual heat input, 0.12 pound per hour and 0.065 ton per rolling, 12-month period.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		Sulfuric acid (H_2SO_4) emissions shall not exceed 0.00022 lb/MMBtu of actual heat input, 0.018 pound per hour and 0.010 ton per rolling, 12-month period. Carbon dioxide equivalent (CO_2e) emissions shall not exceed 5,009 tons per rolling, 12-month period. Visible PE from the stack serving this emissions unit shall not exceed 10% opacity as a 6-minute average. See b)(2)a through b)(2)f.
b.	OAC rule 3745-31-05(A)(3)	The emission limitations for CO, NO_x, VOC, PE/PM_{10}/$PM_{2.5}$ and SO_2 required by this rule are equivalent to the emission limitations for CO, NO_x, VOC, PE/PM_{10}/$PM_{2.5}$ and SO_2 established pursuant to OAC rules 3745-31-10 through 3745-31-20. Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3) do not apply to the CO_2e emissions from this air contaminant source pursuant to OAC rule 3745-31-34(E)(8). See b)(2)h and c)(1).
c.	OAC rule 3745-31-05(A)(3)(a)(ii)	BAT requirements under OAC rule 3745-31-05(A)(3) do not apply to the CO, NOx, VOC, PE/PM_{10}/$PM_{2.5}$ and SO_2 emissions from this air contaminant source since the potential to emit is less than 10 tons/year. See b)(2)i.
d.	OAC rule 3745-17-10(B)(1)	The emission limitation required by this applicable rule is less stringent than the emission limitation established pursuant to OAC rules 3745-31-10 through 20.
e.	OAC rule 3745-17-07(A)	The emission limitation required by this applicable rule is less stringent than the emission limitation established pursuant to OAC rules 3745-31-10 through 20.
f.	OAC rule 3745-18-06	Exempt pursuant to OAC rule 3745-18-06(A) since only natural gas fuel is burned in this emissions unit.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
g.	OAC rule 3745-110-03(C)	Exempt pursuant to OAC rule 3745-110-03(K)(20) because this emissions unit is subject to BACT requirements for NO_x emissions.
h.	40 CFR Part 60, Subparts A and Dc (40 CFR 60.1 – 60.19 and 60.40c - 60.48c) [In accordance with 40 CFR 60.40c(a), this emissions unit is a steam generating unit commencing construction, modification, or reconstruction after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million BTU per hour (MMBtu/hr) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr).]	See b)(2)j, c)(3), d)(3) and e)(4).
i.	40 CFR Part 63, Subpart DDDDD (40 CFR 63.7480 – 63.7575) [In accordance with 40 CFR 63.7480, 63.7485, 63.7490(a)(2) and (b) and 63.7499(l), this emissions unit is a new industrial boiler located at a major source of HAP emissions in the units designed to burn gas 1 fuels subject to the emission limitations and control measures specified in this section.]	The permittee shall comply with the work practice standards in 40 CFR Part 63, Subpart DDDDD Table 3. [40 CFR 63.7500(a)(1) and Table 3 (3)] See c)(3). The permittee shall comply with the requirements of 40 CFR Part 63, Subpart DDDDD upon startup. [40 CFR 63.7495(a)]
j.	40 CFR Part 63, Subpart A (40 CFR 63.1 – 63.16)	Table 10 of 40 CFR Part 63, Subpart DDDDD specifies the provisions of Subpart A that apply to owners and operators of affected facilities subject to this subpart. [40 CFR 63.7565]

(2) Additional Terms and Conditions

a. As part of the Best Available Control Technology (BACT) determination, this emissions unit shall operate for no more than 1,080 hours per rolling, 12-month period.

b. As part of the BACT determination for NO_x, the boiler must be equipped with dry low-NO_x burners. Compliance with this requirement shall be demonstrated by compliance with the short-term NO_x emission limitations in b)(1)a.

c. As part of the BACT determination for CO, compliance with the BACT requirements shall be demonstrated by compliance with the short-term CO emission limitations in b)(1)a.

d. As part of the BACT determination for VOC, compliance with the BACT requirements shall be demonstrated by compliance with the short-term VOC emission limitation in b)(1)a.

e. As part of the BACT determination for PE/PM_{10}/$PM_{2.5}$, compliance with the BACT requirements shall be demonstrated by compliance with the short-term PE/PM_{10}/$PM_{2.5}$ emission limitations in b)(1)a.

f. As part of the BACT determination for SO_2 and H_2SO_4, the permittee shall burn only natural gas with a sulfur content of less than 0.50 grain/100 scf in this emissions unit. Compliance with this requirement shall be demonstrated by compliance with the SO_2 and H_2SO_4 emission limitations in b)(1)a and c)(1).

g. As part of the BACT determination for CO_2e, compliance with the BACT requirements shall be demonstrated by compliance with the CO_2e emission limitation in b)(1)a.

h. This BAT emission limit applies until U.S. EPA approves Ohio Administrative Code (OAC) paragraph 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) into the Ohio State Implementation Plan (SIP).

i. These requirements apply once U.S. EPA approves OAC paragraph 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) as part of the Ohio SIP.

j. See 40 CFR Part 60, Subpart Dc (40 CFR 60.40c – 60.48c).

c) Operational Restrictions

(1) The permittee shall burn only natural gas fuel with a maximum sulfur content not to exceed 0.50 grain/100 scf in this emissions unit.

(2) See 40 CFR Part 60, Subpart Dc (40 CFR 60.40c – 60.48c).

(3) See 40 CFR Part 63, Subpart DDDDD (40 CFR 63.7480 – 63.7575).

d) Monitoring and/or Recordkeeping Requirements

(1) For each day during which the permittee burns a fuel other than natural gas fuel with a maximum sulfur content of 0.50 grain/100 scf, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

(2) The permittee shall maintain monthly records of the following information:

a. the hours of operation of this emissions unit;

b. the rolling, 12-month summation of operating hours for this unit, calculated by adding the total hours of operation for the present month as recorded in d)(2)a, plus the total hours of operation for the previous 11 months;

c. the amount of natural gas consumed in this emissions unit, in MMscf;

d. the heat content of the natural gas combusted in this emissions unit, in MMBtu/MMscf;

e. the sulfur content of the natural gas combusted in this emissions unit, in grains/100 scf;

f. the total NO_x emissions from this emissions unit, in pounds, calculated by multiplying the NO_x emission factor of 0.027 lb/MMBtu, or after testing has been completed, the results of the most recent stack test, by the amount of natural gas consumed, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

g. the rolling, 12-month summation of the NO_x emissions from this emissions unit, in tons, calculated by adding the total NO_x emissions for the present month as recorded in d)(2)f, plus the total NO_x emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

h. the total CO emissions from this emissions unit, in pounds, calculated by multiplying the CO emission factor of 0.031 lb/MMBtu, or after testing has been completed, the results of the most recent stack test, by the amount of natural gas consumed, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

i. the rolling, 12-month summation of the CO emissions from this emissions unit, in tons, calculated by adding the total CO emissions for the present month as recorded in d)(2)h, plus the total CO emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

j. the total VOC emissions from this emissions unit, in pounds, calculated by multiplying the VOC emission factor of 0.0031 lb/MMBtu or after testing has been completed, the results of the most recent stack test, by the amount of natural gas consumed, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

k. the rolling, 12-month summation of the VOC emissions from this emissions unit, in tons, calculated by adding the total VOC emissions for the present month as recorded in d)(2)j, plus the total VOC emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

l. the total $PE/PM_{10}/PM_{2.5}$ emissions from this emissions unit, in pounds, calculated by multiplying the $PE/PM_{10}/PM_{2.5}$ emission factor of 0.006 lb/MMBtu, or after testing has been completed, the results of the most recent stack test, by the amount of natural gas consumed, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

m. the rolling, 12-month summation of the $PE/PM_{10}/PM_{2.5}$ emissions from this emissions unit, in tons, calculated by adding the total $PE/PM_{10}/PM_{2.5}$ emissions for the present month as recorded in d)(2)l, plus the total $PE/PM_{10}/PM_{2.5}$ emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

n. the total SO_2 emissions from this emissions unit, in pounds, calculated by multiplying the SO_2 emission factor of 0.0015 lb/MMBtu, or after testing has been completed, the results of the most recent stack test, by the amount of natural gas consumed, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

o. The rolling, 12-month summation of the SO_2 emissions from this emissions unit, in tons, calculated by adding the total SO_2 emissions for the present month as recorded in d)(2)n, plus the total SO_2 emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

p. the total H_2SO_4 emissions from this emissions unit, in pounds, calculated by multiplying the H_2SO_4 emission factor of0.00022 lb/MMBtu, or after testing has been completed, the results of the most recent stack test, by the amount of natural gas consumed, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

q. The rolling, 12-month summation of the H_2SO_4 emissions from this emissions unit, in tons, calculated by adding the total H_2SO_4 emissions for the present month as recorded in d)(2)p, plus the total H_2SO_4 emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

r. the total CO_2e emissions from this emissions unit, in pounds, calculated by multiplying the CO_2e emission factor of 116 lbs/MMBtu by the amount of natural gas consumed, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d; and

s. The rolling, 12-month summation of the CO_2e emissions from this emissions unit, in tons, calculated by adding the total CO_2e emissions for the present month as recorded in d)(2)r, plus the total CO_2e emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds.

(3) See 40 CFR Part 60, Subpart Dc (40 CFR 60.40c – 60.48c).

e) Reporting Requirements

(1) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

(2) The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than natural gas fuel with a maximum sulfur content of 0.50 grain/100 scf was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

(3) The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. any exceedances of the rolling, 12-month limitation on operating hours; and

b. any exceedances of the rolling, 12-month emission limitations for NO_x, CO, VOC, PE/PM_{10}/$PM_{2.5}$, SO_2, H_2SO_4 and CO_2e, calculated pursuant to the equations in d)(2).

(4) See 40 CFR Part 60, Subpart Dc (40 CFR 60.40c – 60.48c).

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitations:

NO_x emissions shall not exceed 0.027 lb/MMBtu of actual heat input, 2.16 pounds per hour and 1.17 tons per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the short-term emission limitations shall be demonstrated based on the emission testing requirements specified in f)(2).

Compliance with the rolling, 12-month emission limitation shall be demonstrated by the record keeping requirements specified in d)(2).

b. Emission Limitations:

CO emissions shall not exceed 0.031 lb/MMBtu of actual heat input, 2.48 pounds per hour and 1.34 tons per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the short-term emission limitations shall be demonstrated based on the emission testing requirements specified in f)(2).

Compliance with the rolling, 12-month emission limitation shall be demonstrated by the record keeping requirements specified in d)(2).

c. Emission Limitations:

VOC emissions shall not exceed 0.0031 lb/MMBtu of actual heat input, 0.248 pound per hour and 0.134 ton per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the short-term emission limitations shall be demonstrated based on the emission testing requirements specified in f)(2).

Compliance with the rolling, 12-month emission limitation shall be demonstrated by the record keeping requirements specified in d)(2).

d. Emission Limitations:

PE and emissions of PM_{10} and $PM_{2.5}$ shall not exceed 0.006 lb/MMBtu of actual heat input, 0.48 pound per hour and 0.26 ton per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the short-term emission limitations shall be demonstrated based on the emission testing requirements specified in f)(2).

Compliance with the rolling, 12-month emission limitation shall be demonstrated by the record keeping requirements specified in d)(2).

e. Emission Limitations:

SO_2 emissions shall not exceed 0.0015 lb/MMBtu of actual heat input, 0.12 pound per hour and 0.065 ton per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the short-term emission limitations shall be demonstrated based on the emission testing requirements specified in f)(2).

Compliance with the rolling, 12-month emission limitation shall be demonstrated by the record keeping requirements specified in d)(2).

f. Emission Limitations:

H_2SO_4 emissions shall not exceed 0.00022 lb/MMBtu of actual heat input, 0.018 pound per hour and 0.010 ton per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the short-term emission limitations shall be demonstrated based on the emission testing requirements specified in f)(2).

Compliance with the rolling, 12-month emission limitation shall be demonstrated by the record keeping requirements specified in d)(2).

g. Emission Limitation:

CO_2e emissions shall not exceed 5,009 tons per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the rolling, 12-month emission limitation shall be demonstrated by the record keeping requirements specified in d)(2).

h. Emission Limitation:

Visible PE from the stack serving this emissions unit shall not exceed 10% opacity as a 6-minute average.

Applicable Compliance Method:

If required, compliance with the visible PE limitation shall be demonstrated based upon visible particulate emission observations performed in accordance with the methods and procedures specified in 40 CFR Part 60, Appendix A, Method 9.

(2) Performance testing shall be conducted as required in OAC rules 3745-31-10 through 20. The permittee shall conduct, or have conducted, emission testing for this emissions unit within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, as applicable, in accordance with the following requirements:

a. The emission testing shall be conducted to demonstrate compliance with the emission limitations specified in b)(1) for NO_x, CO, VOC, PE/PM_{10}/$PM_{2.5}$ and H_2SO_4.

b. The following test method(s) shall be employed to demonstrate compliance with the allowable mass emission rate(s):

for NO_x, Methods 1 through 4, and 7E of 40 CFR Part 60, Appendix A;

for CO, Methods 1 through 4 and 10 of 40 CFR Part 60, Appendix A;

for VOC, Methods 1 through 4 and 18 and 25 of 40 CFR Part 60, Appendix A;

for PE/PM_{10}/$PM_{2.5}$, Methods 1 through 5 of 40 CFR Part 60, Appendix A and Method 202 of 40 CFR Part 51, Appendix M;

for SO_2, 40 CFR 60.4415(a) for fuel sulfur content; and

for H_2SO_4, Methods 1 through 4 and 8 of 40 CFR Part 60, Appendix A.

Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

c. The test(s) for each pollutant shall be conducted while the emissions unit is operating at or near its maximum capacity, while burning representative fuel and/or combination of fuels, unless otherwise specified or approved by the Ohio EPA, Southeast District Office.

d. Not later than 30 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the Ohio EPA, Southeast District Office. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Ohio EPA, Southeast District Office's refusal to accept the results of the emission test(s).

e. Personnel from the Ohio EPA, Southeast District Office shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

f. A comprehensive written report on the results of the emission test(s) shall be signed by the person or persons responsible for the tests and submitted to the Ohio EPA, Southeast District Office within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Ohio EPA, Southeast District Office.

g) Miscellaneous Requirements

(1) None.

3. P003, Emergency Diesel Generator

Operations, Property and/or Equipment Description:

1,387 KW (1,860 HP) emergency diesel-fired generator

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) b)(1)c and b)(2)e

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rules 3745-31-10 through 20 and 3745-31-34	Non-methane hydrocarbon plus nitrogen oxides (NMHC+NO_x) emissions shall not exceed 6.40 g/kW-hour, 19.68 pounds per hour and 0.98 ton per rolling, 12-month period. Carbon monoxide (CO) emissions shall not exceed 3.5 g/kW-hour, 10.66 pounds per hour and 0.53 ton per rolling, 12-month period. Particulate emissions (PE), emissions of particulate matter less than 10 microns (PM_{10}) and emissions of particulate matter less than 2.5 microns ($PM_{2.5}$) shall not exceed 0.20 g/kW-hour, 0.62 pound per hour and 0.031 ton per rolling, 12-month period. Sulfur dioxide (SO_2) emissions shall not exceed 0.0015 pound per million Btu, 0.023 pound per hour and 0.001 ton per rolling, 12-month period. Sulfuric acid (H_2SO_4) emissions shall not exceed 0.00073 pound per million Btu, 0.003 pound per hour and 0.00017 ton per rolling, 12-month period.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		Carbon dioxide equivalent (CO_2e) emissions shall not exceed 109.2 tons per rolling, 12-month period. See b)(2)a. b)(2)b, b)(2)c and c)(1).
b.	OAC rule 3745-31-05(A)(3)	The emission limitations for NO_x, CO, volatile organic compounds (VOC), PE/PM_{10}/$PM_{2.5}$ and SO_2 required by this rule are equivalent to the emission limitations for NO_x, CO, VOC (NMHC), PE/PM_{10}/$PM_{2.5}$ and SO_2 established pursuant to OAC rules 3745-31-10 through 3745-31-20. Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3) do not apply to the CO_2e emissions from this air contaminant source pursuant to OAC rule 3745-31-34(E)(8). See b)(2)d and c)(1).
c.	OAC rule 3745-31-05(A)(3)(a)(ii)	BAT requirements under OAC rule 3745-31-05(A)(3) do not apply to the NO_x, VOC, CO, PE/PM_{10}/$PM_{2.5}$ and SO_2 emissions from this air contaminant source since the calculated annual emission rates are less than 10 tons/year taking into account the federally enforceable limits in OAC rules 3745-31-10 through 20 and 40 CFR Part 60, Subpart IIII. See b)(2)e.
d.	OAC rule 3745-17-07(A)	The emission limitation required by this applicable rule is less stringent than the emission limitation established pursuant to 40 CFR Part 60, Subpart IIII.
e.	OAC rule 3745-18-06	The emission limitation required by this applicable rule is less stringent than the emission limitations required pursuant to OAC rules 3745-31-10 through 3745-31-20 and 40 CFR Part 60, Subpart IIII.
f.	OAC rule 3745-110-03	Exempt pursuant to OAC rule 3745-110-03(K)(20) because this emissions unit is subject to BACT requirements for NO_x emissions.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
g.	40 CFR Part 60, Subpart IIII (40 CFR 60.4200 – 60.4219) [In accordance with 40 CFR 60.4200(a)(2)(i) and 60.4205(b), this emissions unit is a 1,387 kW (1,860 HP) emergency stationary compression ignition (CI) internal combustion engine (ICE) manufactured after April 1, 2006 with a displacement of less than 30 liters per cylinder subject to the emission limitations/control measures specified in this section.]	The emission limitations for NO_x+NMHC, CO, PE/PM_{10}/$PM_{2.5}$ and SO_2 required by this rule are equivalent to the emission limitations for NO_x+NMHC, CO, PE/PM_{10}/$PM_{2.5}$ and SO_2 established pursuant to OAC rules 3745-31-10 through 3745-31-20. Exhaust opacity from CI RICE must not exceed: 20 percent during the acceleration mode; 15 percent during the lugging mode; and 50 percent during the peaks in either the acceleration or lugging modes. [40 CFR 60.4205(b), 40 CFR 60.4202(a)(2), 40 CFR 89.112 and 40 CFR 89.113, and 40 CFR 60.4207(b) and 40 CFR 80.510(b)] See b)(2)f, c)(1), c)(2), d)(4) and e)(3).
h.	40 CFR 60.1 – 60.19 (40 CFR 60.4218)	Table 8 of Subpart IIII of 40 CFR Part 60 – Applicability of General Provisions to Subpart IIII, specifies the provisions of Subpart A that apply to owners and operators of affected facilities subject to this subpart.
i.	40 CFR Part 63, Subpart ZZZZ (40 CFR 63.6580 – 63.6675) [In accordance with 40 CFR 63.6585, 63.6590(a)(2)(i) and 63.6590(b)(1)(i), this emissions unit is an emergency stationary reciprocating internal combustion engine (RICE) with a site rating of more than 500 brake HP located at a major source of hazardous air pollutant (HAP) emissions for which construction commenced after December 19, 2002.]	See e)(5).
j.	40 CFR 63.1 – 63.16 (40 CFR 63.6665)	Table 8 of Subpart ZZZZ of 40 CFR Part 63 – Applicability of General Provisions to Subpart ZZZZ, specifies the provisions of Subpart A that apply to owners and operators of affected facilities subject to this subpart.

(2) Additional Terms and Conditions

a. As part of the Best Available Control Technology (BACT) determination for NMHC, NO_x, CO and $PE/PM_{10}/PM_{2.5}$, this emissions unit shall be certified to meet the emissions standards in 40 CFR 89.112 and 89.113 pursuant to 40 CFR 60.4205(b) and 60.4202(a)(2), shall employ good combustion practices per the manufacturer's operating manual, and shall not operate more than 100 hours per year of non-emergency use. Compliance with these requirements shall be demonstrated by compliance with the short-term $NMHC+NO_x$, CO and $PE/PM_{10}/PM_{2.5}$ emission limitations in b)(1)a.

b. As part of the BACT determination for SO_2 and H_2SO_4, the permittee shall burn only ultra-low sulfur diesel (ULSD) fuel with a sulfur content of less than 15 ppm (0.0015 percent by weight) in this emissions unit. Compliance with this requirement shall be demonstrated by compliance with the SO_2 and H_2SO_4 emission limitations in b)(1)a.

c. As part of the BACT determination for CO_2e, the permittee must implement good operating practices (proper maintenance and operation) and shall not operate more than 100 hours per year of non-emergency use. Compliance with this requirement shall be demonstrated by compliance with the CO_2e emission limitation in b)(1)a.

d. This BAT emission limit applies until U.S. EPA approves Ohio Administrative Code (OAC) paragraph 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) into the Ohio State Implementation Plan (SIP).

e. This rule applies once U.S. EPA approves OAC paragraph 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) as part of the Ohio SIP.

f. The permittee must comply with the applicable emission and operating limitations of 40 CFR Part 60, Subpart IIII upon startup.

c) Operational Restrictions

(1) The quality of diesel fuel burned in this emissions unit shall meet the following U.S. EPA's specifications for ULSD found in 40 CFR 80.510(b), on an 'as received' basis:

a. Sulfur content: 15 ppm maximum (0.0015% by weight).

b. Cetane index or aromatic content, as follows:

i. a minimum cetane index of 40; or

ii. a maximum aromatic content of 35 volume percent.

(2) See 40 CFR Part 60, Subpart IIII (40 CFR 60.4200 – 60.4219).

d) Monitoring and/or Recordkeeping Requirements

(1) The permittee shall maintain records of the following information each month:

a. the hours of non-emergency operation for this emissions unit; and

b. beginning after the first 12 calendar months of operation or the first 12 calendar months following the issuance of this permit, the rolling, 12-month summation of the non-emergency operating hours for this emissions unit.

(2) For each day during which the permittee burns a fuel other than USLD fuel with a sulfur content of less than 15 ppm (0.0015 percent by weight), the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

(3) The permittee shall maintain documents provided by the oil supplier for each shipment of No. 2 fuel oil to demonstrate compliance with the ULSD requirements. These documents must include the receipt or bill of lading that includes confirmation that the fuel meets the No. 2 diesel fuel ULSD standards.

(4) See 40 CFR Part 60, Subpart IIII (40 CFR 60.4200 – 60.4219).

e) Reporting Requirements

(1) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

(2) The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. any exceedances of the 100 hours per year limitation per emissions unit on non-emergency operating hours; and

b. any exceedances of the rolling, 12-month emission limitations for NMHC+NO_x, CO, PE/PM_{10}/$PM_{2.5}$, SO_2, H_2SO_4 and CO_2e, calculated pursuant to the equations in f)(1).

The quarterly deviation (excursion) reports shall be submitted in accordance with the reporting requirements of the Standard Terms and Conditions of this permit.

(3) The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than ultra-low sulfur diesel fuel with a sulfur content of less than 15 ppm (0.0015 percent by weight) was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

(4) See 40 CFR Part 60, Subpart IIII (40 CFR 60.4200 – 60.4219).

(5) See 40 CFR Part 63, Subpart ZZZZ (40 CFR 63.6580 – 63.6675).

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitations:

NMHC+NO_x emissions shall not exceed 6.40 g/kW-hour, 19.68 pounds per hour and 0.98 ton per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the short-term emission limitations shall be based on the manufacturer's certification to the standards applicable to this emissions unit and by maintaining the engine according to the manufacturer's specifications. See f)(2).

Compliance with the rolling, 12-month emission limitation shall be demonstrated based on the following calculation:

NMHC+NO_x (tons per rolling, 12-month period) =

hours of operation per rolling, 12-month period, as recorded in d)(1) x NMHC+NO_x emission limitation, in pounds per hour x 1 ton/2,000 pounds

b. Emission Limitations:

CO emissions shall not exceed 3.5 g/kW-hour, 10.66 pounds per hour and 0.53 ton per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the short-term emission limitations shall be based on the manufacturer's certification to the standards applicable to this emissions unit and by maintaining the engine according to the manufacturer's specifications. See f)(2).

Compliance with the rolling, 12-month emission limitation shall be demonstrated based on the following calculation:

CO (tons per rolling, 12-month period) =

hours of operation per rolling, 12-month period, as recorded in d)(1) X CO emission limitation, in pounds per hour X 1 ton/2,000 pounds

c. Emission Limitations:

PE and emissions of PM_{10} and $PM_{2.5}$ shall not exceed 0.20 g/kW-hour, 0.62 pound per hour and 0.031 ton per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the short-term emission limitations shall be based on the manufacturer's certification to the standards applicable to this emissions unit and by maintaining the engine according to the manufacturer's specifications. See f)(2).

Compliance with the rolling, 12-month emission limitation shall be demonstrated based on the following calculation:

$PE/PM_{10}/PM_{2.5}$ (tons per rolling, 12-month period) =

hours of operation per rolling, 12-month period, as recorded in d)(1) X $PE/PM_{10}/PM_{2.5}$ emission limitation, in pound per hour X 1 ton/2,000 pounds

d. Emission Limitations:

SO_2 emissions shall not exceed 0.0015 pound per million Btu, 0.023 pound per hour and 0.001 ton per rolling, 12-month period.

Applicable Compliance Method:

The short-term emission limitations were established based upon burning of ULSD fuel with a sulfur content of less than 15 ppm (0.0015 percent by weight).

If required, SO_2 emissions shall be demonstrated by an emission test performed in accordance with the methods and procedures specified in Methods 1 through 4 and 6 as set forth in the "Appendix on Test Methods" in 40 CFR Part 60 "Standards of Performance for New Stationary Sources". Alternative U.S. EPA-approved test methods may be used with prior approval from Ohio EPA, Southeast District Office, including fuel sulfur sampling in lieu of stack sampling.

Compliance with the rolling, 12-month emission limitation shall be demonstrated based on the following calculation:

SO_2 (tons per rolling, 12-month period) =

hours of operation per rolling, 12-month period, as recorded in d)(1) X SO_2 emission limitation, in pound per hour X 1 ton/2,000 pounds

e. Emission Limitations:

H_2SO_4 emissions shall not exceed 0.00073 lb/MMBtu, 0.003 pound per hour and 0.00017 ton per rolling, 12-month period.

Applicable Compliance Method:

The short-term emission limitations were established based upon burning of ULSD fuel with a sulfur content of less than 15 ppm (0.0015 percent by weight).

If required, H_2SO_4 emissions shall be demonstrated by an emission test performed in accordance with the methods and procedures specified in Methods 1 through 4 and 15 as set forth in the "Appendix on Test Methods" in 40 CFR Part 60 "Standards of Performance for New Stationary Sources". Alternative U.S. EPA-approved test methods may be used with prior approval from Ohio EPA, Southeast District Office, including fuel sulfur sampling in lieu of stack sampling.

Compliance with the rolling, 12-month emission limitation shall be demonstrated based on the following calculation:

H_2SO_4 (tons per rolling, 12-month period) =

hours of operation per rolling, 12-month period, as recorded in d)(1) X H_2SO_4 emission limitation, in pound per hour X 1 ton/2,000 pounds

f. Emission Limitation:

CO_2e emissions shall not exceed 109.2 tons per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the rolling, 12-month emission limitation shall be demonstrated based on the following calculation:

CO_2e (tons per rolling, 12-month period) =

hours of operation per rolling, 12-month period, as recorded in d)(1) X CO_2e emission factor of 2,184 pounds per hour, calculated from the emission factors from 40 CFR Part 98, Tables C-1 and C-2 and global warming potentials in 40 CFR Part 98, Table A-1 X 1 ton/2,000 pounds

g. Emission Limitations:

Exhaust opacity from CI RICE must not exceed:

20 percent during the acceleration mode;
15 percent during the lugging mode; and
50 percent during the peaks in either the acceleration or lugging modes.

Applicable Compliance Method:

If required, compliance shall be demonstrated based on visible particulate emission observations performed in accordance with the methods and procedures specified in 40 CFR Part 60, Appendix A, Method 9. See f)(2).

(2) Pursuant to 40 CFR 60.4211(g)(3) and 89.113(b), if the permittee does not install, configure, operate and maintain this emissions unit according to the manufacturer's emission-related written instructions, or if the permittee changes emission-related settings in a way that is not permitted by the manufacturer, compliance must be

demonstrated by conducting performance tests in accordance with the following requirements:

a. An initial performance test shall be performed to demonstrate compliance with the mass emission limitations in b)(1)a and b)(1)g for NO_X+NMHC, CO, PE/PM_{10}/$PM_{2.5}$ and exhaust opacity within one year of startup, or within one year after the emissions unit is no longer installed, configured, operated and maintained in accordance with the manufacturer's emission-related written instructions, or within one year after the permittee changes emission-related settings in a way not permitted by the manufacturer. Thereafter, subsequent performance testing must be conducted every 8,760 hours of engine operation or three years, whichever comes first.

b. The test method(s) in 40 CFR 60.4212 shall be employed to demonstrate compliance with the allowable mass emission rates. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

c. Not later than 30 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the Ohio EPA, Southeast District Office. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Ohio EPA, Southeast District Office's refusal to accept the results of the emission test(s).

d. Personnel from the Ohio EPA, Southeast District Office shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

e. A comprehensive written report on the results of the emission test(s) shall be signed by the person or persons responsible for the tests and submitted to the Ohio EPA, Southeast District Office within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Ohio EPA, Southeast District Office.

g) Miscellaneous Requirements

(1) None.

4. P004, Emergency Fire Pump

Operations, Property and/or Equipment Description:

238.6 KW (320 HP) emergency diesel-fired firewater pump

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) b)(1)c. and b)(2)e.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rules 3745-31-10 through 3745-31-20 and 3745-31-34	Nonmethane hydrocarbons plus nitrogen oxides (NMHC+NO_x) emissions shall not exceed 4.0 g/kW-hour, 2.12 pounds per hour and 0.11 ton per rolling, 12-month period. Carbon monoxide (CO) emissions shall not exceed 3.5 g/kW-hour, 1.83 pounds per hour and 0.092 ton per rolling, 12-month period. Particulate emissions (PE), emissions of particulate matter less than 10 microns (PM_{10}) and emissions of particulate matter less than 2.5 microns ($PM_{2.5}$) shall not exceed 0.20 g/kW-hour, 0.11 pound per hour and 0.0055 ton per rolling, 12-month period. Sulfur dioxide (SO_2) emissions shall not exceed 0.0015 pound per million Btu, 0.004 pound per hour and 0.0002 ton per rolling, 12-month period. Sulfuric acid (H_2SO_4) emissions shall not exceed 0.00073 lb/MMBtu, 0.0006 pound per hour and 0.00003 ton per rolling, 12-month period.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		Carbon dioxide equivalent (CO_2e) emissions shall not exceed 18.67 tons per rolling, 12-month period. See b)(2)a, b)(2)b, b)(2)c and c)(1).
b.	OAC rule 3745-31-05(A)(3)	The emission limitations for NO_x, CO, volatile organic compound (VOC), PE/PM_{10}/$PM_{2.5}$ and SO_2 required by this rule are equivalent to the emission limitations for NO_x, CO, VOC, PE/PM_{10}/$PM_{2.5}$ and SO_2 established pursuant to OAC rules 3745-31-10 through 3745-31-20. Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3) do not apply to the CO_2e emissions from this air contaminant source pursuant to OAC rule 3745-31-34(E)(8). See b)(2)d and c)(1).
c.	OAC rule 3745-31-05(A)(3)(a)(ii)	BAT requirements under OAC rule 3745-31-05(A)(3) do not apply to the NO_x, VOC, CO, PE/PM_{10}/$PM_{2.5}$ and SO_2 emissions from this air contaminant source since the calculated annual emission rates are less than 10 tons/year taking into account the federally enforceable limits in OAC rules 3745-31-10 through 20 and 40 CFR Part 60, Subpart IIII. See b)(2)e.
d.	OAC rule 3745-17-07(A)	Visible PE from any stack serving this emissions unit shall not exceed 20% opacity as a 6-minute average, except as provided by the rule.
e.	OAC rule 3745-17-11(B)	The emission limitation required by this applicable rule is less stringent than the emission limitation established pursuant to OAC rules 3745-31-10 through 20.
f.	OAC rule 3745-18-06	Exempt pursuant to OAC rule 3745-18-06(B) since the rated heat input capacity is equal to or less than 10 MMBtu/hr.
g.	OAC rule 3745-110-03	Exempt pursuant to OAC rule 3745-110-03(K)(3) because this emissions unit is a

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		stationary IC engine with an energy output capacity of less than two thousand horsepower.
h.	40 CFR Part 60, Subpart IIII (40 CFR 60.4200 – 60.4219) [In accordance with 40 CFR 60.4200(a)(2)(ii) and 60.4205(c), this emissions unit is a 320 HP certified fire pump compression ignition (CI) internal combustion engine (ICE) manufactured after July 1, 2006 with a displacement of less than 30 liters per cylinder subject to the emission limitations and control measures specified in this section.]	The emission limitations for NO_x+NMHC, CO, PE/PM_{10}/$PM_{2.5}$ and SO_2 required by this rule are equivalent to the emission limitations for NO_x+NMHC, CO, PE/PM_{10}/$PM_{2.5}$ and SO_2 established pursuant to OAC rules 3745-31-10 through 3745-31-20. [40 CFR 60.4205(c) and Table 4 to 40 CFR Part 60, Subpart IIII, and 40 CFR 60.4207(b) and 40 CFR 80.510(b)] See b)(2)f, c)(1), c)(2), d)(4) and e)(3).
i.	40 CFR 60.1 – 60.19 (40 CFR 60.4218)	Table 8 of Subpart IIII of 40 CFR Part 60 – Applicability of General Provisions to Subpart IIII, specifies the provisions of Subpart A that apply to owners and operators of affected facilities subject to this subpart.
j.	40 CFR Part 63, Subpart ZZZZ (40 CFR 63.6580 – 63.6675) [In accordance with 40 CFR 63.6585, 63.6590(a)(2)(ii) and 63.6590(c)(6), this emissions unit is an emergency stationary reciprocating internal combustion engine (RICE) with a site rating of less than 500 brake HP located at a major source of hazardous air pollutant (HAP) emissions for which construction commenced after June 12, 2006.]	New emergency stationary RICE with site rating of less than or equal to 500 HP located at a major source of HAP emissions must meet the requirements of this part by meeting the requirements of 40 CFR Part 60, Subpart IIII. No further requirements apply for such engines under this part. [40 CFR 63.6590(c)(6)]
k.	40 CFR 63.1 – 63.16 (40 CFR 63.6665)	Table 8 of Subpart ZZZZ of 40 CFR Part 63 – Applicability of General Provisions to Subpart ZZZZ, specifies the provisions of Subpart A that apply to owners and operators of affected facilities subject to this subpart.

(2) Additional Terms and Conditions

a. As part of the Best Available Control Technology (BACT) determination for NMHC+NO_x CO and PE/PM_{10}/$PM_{2.5}$, this emissions unit shall be certified to meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual, and shall not operate more than 100 hours per year of non-emergency use. Compliance with these requirements shall be demonstrated by compliance with the short-term NO_x, NMHC, CO and PE/PM_{10}/$PM_{2.5}$ emission limitations in b)(1)a.

b. As part of the BACT determination for SO_2 and H_2SO_4, the permittee shall burn only ultra-low sulfur diesel (ULSD) fuel with a sulfur content of less than 15 ppm (0.0015 percent by weight) in this emissions unit. Compliance with this requirement shall be demonstrated by compliance with the SO_2 and H_2SO_4 emission limitations in b)(1)a.

c. As part of the BACT determination for CO_2e, the permittee must implement good operating practices (proper maintenance and operation) and shall not operate more than 100 hours per year of non-emergency use. Compliance with these requirements shall be demonstrated by compliance with the CO_2e emission limitation in b)(1)a.

d. This BAT emission limit applies until U.S. EPA approves Ohio Administrative Code (OAC) paragraph 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) into the Ohio State Implementation Plan (SIP).

e. This rule applies once U.S. EPA approves OAC paragraph 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) as part of the Ohio SIP.

f. The permittee must comply with the applicable emission and operating limitations of 40 CFR Part 60, Subpart IIII upon startup.

c) Operational Restrictions

(1) The quality of diesel fuel burned in this emissions unit shall meet the following U.S. EPA's specifications for ULSD found in 40 CFR 80.510(b), on an 'as received' basis:

a. Sulfur content: 15 ppm maximum (0.0015% by weight).

b. Cetane index or aromatic content:

i. a minimum cetane index of 40; or

ii. a maximum aromatic content of 35 volume percent.

(2) See 40 CFR Part 60, Subpart IIII (40 CFR 60.4200 – 60.4219).

d) Monitoring and/or Recordkeeping Requirements

(1) The permittee shall maintain records of the following information each month:

a. the hours of non-emergency operation for this emissions unit; and

b. beginning after the first 12 calendar months of operation or the first 12 calendar months following the issuance of this permit, the rolling, 12-month summation of the non-emergency operating hours for this emissions unit.

(2) For each day during which the permittee burns a fuel other than USLD fuel with a sulfur content of less than 15 ppm (0.0015 percent by weight), the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

(3) The permittee shall maintain documents provided by the oil supplier for each shipment of No. 2 fuel oil to demonstrate compliance with the ULSD requirements. These documents must include the receipt or bill of lading that includes confirmation that the fuel meets the No. 2 diesel fuel ULSD standards.

(4) See 40 CFR Part 60, Subpart IIII (40 CFR 60.4200 – 60.4219).

e) Reporting Requirements

(1) The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. any exceedances of the 100 hours per year limitation per emissions unit on non-emergency operating hours; and

b. any exceedances of the rolling, 12-month emission limitations for NMHC+NO_x, CO, PE/PM_{10}/$PM_{2.5}$, H_2SO_4 and CO_2e, calculated pursuant to the equations in f)(1).

The quarterly deviation (excursion) reports shall be submitted in accordance with the reporting requirements of the Standard Terms and Conditions of this permit.

(2) The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than ultra-low sulfur diesel fuel with a sulfur content of less than 15 ppm (0.0015 percent by weight) was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

(3) See 40 CFR Part 60, Subpart IIII (40 CFR 60.4200 – 60.4219).

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitations:

NMHC+NO_x emissions shall not exceed 4.0 g/kW-hour, 2.12 pounds per hour and 0.11 ton per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the short-term emission limitations shall be based on the manufacturer's certification to the standards applicable to this emissions unit and by maintaining the engine according to the manufacturer's specifications. See f)(2).

Compliance with the rolling, 12-month emission limitation shall be demonstrated based on the following calculation:

NMHC+NO_x (tons per rolling, 12-month period) =

hours of operation per rolling, 12-month period, as recorded in d)(1)(b) X NMHC+ NO_x emission limitation, in pounds per hour X 1 ton/2,000 pounds

b. Emission Limitations:

CO emissions shall not exceed shall not exceed 3.5 g/kW-hour (2.6 g/HP-hour), 1.83 pounds per hour and 0.092 ton per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the short-term emission limitations shall be based on the manufacturer's certification to the standards applicable to this emissions unit and by maintaining the engine according to the manufacturer's specifications. See f)(2).

Compliance with the rolling, 12-month emission limitation shall be demonstrated based on the following calculation:

CO (tons per rolling, 12-month period) =

hours of operation per rolling, 12-month period, as recorded in d)(1)(b) X CO emission limitation, in pounds per hour X 1 ton/2,000 pounds

c. Emission Limitations:

PE and emissions of PM_{10} and $PM_{2.5}$ shall not exceed 0.20 g/kW-hour, 0.11 pound per hour and 0.0055 ton per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the short-term emission limitations shall be based on the manufacturer's certification to the standards applicable to this emissions unit and by maintaining the engine according to the manufacturer's specifications. See f)(2).

Compliance with the rolling, 12-month emission limitation shall be demonstrated based on the following calculation:

PE/PM_{10}/$PM_{2.5}$ (tons per rolling, 12-month period) =

hours of operation per rolling, 12-month period, as recorded in d)(1)(b) X $PE/PM_{10}/PM_{2.5}$ emission limitation, in pounds per hour X 1 ton/2,000 pounds

d. Emission Limitations:

SO_2 emissions shall not exceed 0.0015 pound per million Btu, 0.004 pound per hour and 0.0002 ton per rolling, 12-month period.

Applicable Compliance Method:

The short-term emission limitations were established based upon burning of ULSD fuel with a sulfur content of less than 15 ppm (0.0015 percent by weight).

If required, SO_2 emissions shall be demonstrated by an emission test performed in accordance with the methods and procedures specified in Methods 1 through 4 and 6 as set forth in the "Appendix on Test Methods" in 40 CFR Part 60 "Standards of Performance for New Stationary Sources". Alternative U.S. EPA-approved test methods may be used with prior approval from Ohio EPA, Southeast District Office, including fuel sulfur sampling in lieu of stack sampling.

Compliance with the rolling, 12-month emission limitation shall be demonstrated based on the following calculation:

SO_2 (tons per rolling, 12-month period) =

hours of operation per rolling, 12-month period, as recorded in d)(1)(b) X SO_2 emission limitation, in pound per hour X 1 ton/2,000 pounds

e. Emission Limitations:

H_2SO_4 emissions shall not exceed 0.00073 pound per million Btu, 0.0006 pound per hour and 0.00003 ton per rolling, 12-month period.

Applicable Compliance Method:

The short-term emission limitations were established based upon burning of ULSD fuel with a sulfur content of less than 15 ppm (0.0015 percent by weight).

If required, H_2SO_4 emissions shall be demonstrated by an emission test performed in accordance with the methods and procedures specified in Methods 1 through 4 and 15 as set forth in the "Appendix on Test Methods" in 40 CFR Part 60 "Standards of Performance for New Stationary Sources". Alternative U.S. EPA-approved test methods may be used with prior approval from Ohio EPA, Southeast District Office, including fuel sulfur sampling in lieu of stack sampling.

Compliance with the rolling, 12-month emission limitation shall be demonstrated based on the following calculation:

H_2SO_4 (tons per rolling, 12-month period) =

hours of operation per rolling, 12-month period, as recorded in d)(1)(b) X H_2SO_4 emission limitation, in pound per hour X 1 ton/2,000 pounds

f. Emission Limitation:

CO_2e emissions shall not exceed 18.67 tons per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the rolling, 12-month emission limitation shall be demonstrated based on the following calculation:

CO_2e (tons per rolling, 12-month period) =

hours of operation per rolling, 12-month period, as recorded in d)(1)(b) X CO_2e emission factor of 352 pounds per hour, calculated from the emission factors from 40 CFR Part 98, Tables C-1 and C-2 and global warming potentials in 40 CFR Part 98, Table A-1 X 1 ton/2,000 pounds

g. Emission Limitation:

Visible PE from any stack serving this emissions unit shall not exceed 20% opacity as a 6-minute average, except as provided by the rule.

Applicable Compliance Method:

If required, compliance shall be demonstrated based on visible particulate emission observations performed in accordance with the methods and procedures specified in 40 CFR Part 60, Appendix A, Method 9.

(2) Pursuant to 40 CFR 60.4211(g)(2), if the permittee does not install, configure, operate and maintain this emissions unit according to the manufacturer's emission-related written instructions, or if the permittee changes emission-related settings in a way that is not permitted by the manufacturer, compliance must be demonstrated by conducting the initial performance test in accordance with the following requirements:

a. An initial performance test shall be performed to demonstrate compliance with the mass emission limitations in b)(1)a and b)(1)g for NMHC+NO_X, CO and PE/PM_{10}/$PM_{2.5}$, within one year of startup, or within one year after the emissions unit is no longer installed, configured, operated and maintained in accordance with the manufacturer's emission-related written instructions, or within one year after the permittee changes emission-related settings in a way not permitted by the manufacturer.

b. The test method(s) in 40 CFR 60.4212 shall be employed to demonstrate compliance with the allowable mass emission rates. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

c. Not later than 30 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the Ohio EPA, Southeast District Office. The "Intent to Test" notification shall describe in detail the proposed test methods

and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Ohio EPA, Southeast District Office's refusal to accept the results of the emission test(s).

d. Personnel from the Ohio EPA, Southeast District Office shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

e. A comprehensive written report on the results of the emission test(s) shall be signed by the person or persons responsible for the tests and submitted to the Ohio EPA, Southeast District Office within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Ohio EPA, Southeast District Office.

g) Miscellaneous Requirements

(1) None.

5. Emissions Unit Group – General Electric (GE) Combustion Turbines: P005 and P006

EU ID	Operations, Property and/or Equipment Description
P005	GE Combustion Turbine 1; GE model 7HA.02 natural gas-fired combined cycle combustion turbine generator equipped with dry low-NO_x (DLN) burners nominally rated at 3,459.6 MMBtu/hr at 100% load and -2° F exhausting through a heat recovery steam generator (HRSG) with supplemental natural gas-fired duct burners nominally rated at 570.45 MMBtu/hr controlled with catalytic oxidation and selective catalytic reduction (SCR) used to generate additional electricity
P006	GE Combustion Turbine 2; GE model 7HA.02 natural gas-fired combined cycle combustion turbine generator equipped with dry low-NO_x (DLN) burners nominally rated at 3,459.6 MMBtu/hr at 100% load and -2° F exhausting through a heat recovery steam generator (HRSG) with supplemental natural gas-fired duct burners nominally rated at 570.45 MMBtu/hr controlled with catalytic oxidation and selective catalytic reduction (SCR) used to generate additional electricity

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only:

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rules 3745-31-10 through 3745-31-20 and 3745-31-34	**Emission Limits without Duct Burner Firing** Nitrogen oxides (NO_x) emissions shall not exceed 2.0 ppmvd at 15% oxygen (O_2) based on a 24-hour block averaging period and 25.1 pounds per hour, excluding periods of startup and shutdown. Carbon monoxide (CO) emissions shall not exceed 2.0 ppmvd at 15% O_2 based on a 24-hour block averaging period and 15.3 pounds per hour, excluding periods of startup and shutdown. Volatile organic compound (VOC)

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		emissions shall not exceed 1.0 ppmvd at 15% O_2 and 4.36 pounds per hour, excluding periods of startup and shutdown. Particulate emissions (PE) and emissions of particulate matter with a diameter less than 10 microns (PM_{10}) and particulate matter less than 2.5 microns ($PM_{2.5}$) shall not exceed 0.00735 lb/MMBtu and 12.00 pounds per hour. Sulfur dioxide (SO_2) emissions shall not exceed 0.00174 lb/MMBtu and 5.75 pounds per hour. Sulfuric acid (H_2SO_4) emissions shall not exceed 0.00102 lb/MMBtu and 3.52 pounds per hour. Carbon dioxide equivalent (CO_2e) emissions shall not exceed 1,012.4 lbs/MW-hr gross energy output at full load ISO conditions when firing natural gas. Gross energy output is defined as the gross power output of the generators before accounting for any balance of plant loads. Visible PE from the stack serving this emissions unit shall not exceed 10% opacity as a 6-minute average. **Emission Limits with Duct Burner Firing** NO_x emissions shall not exceed 2.0 ppmvd at 15% O_2 based on a 24-hour block averaging period and 29.5 pounds per hour, excluding periods of startup and shutdown. CO emissions shall not exceed 2.0 ppmvd at 15% O_2 based on a 24-hour block averaging period and 17.9 pounds per hour, excluding periods of startup and shutdown.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		VOC emissions shall not exceed 2.0 ppmvd at 15% O_2 and 10.3 pounds per hour, excluding periods of startup and shutdown. $PE/PM_{10}/PM_{2.5}$ emissions shall not exceed 0.00522 lb/MMBtu and 18.40 pounds per hour. SO_2 emissions shall not exceed 0.00174 lb/MMBtu and 6.74 pounds per hour. H_2SO_4 emissions shall not exceed 0.00103 lb/MMBtu and 4.13 pounds per hour. The emission limitation specified by this rule for CO_2e emissions is equivalent to the requirements in 40 CFR Part 60, Subpart TTTT. Visible PE from the stack serving this emissions unit shall not exceed 10% opacity as a 6-minute average. **Rolling, 12-Month Emission Limitations:** 139 tons of NO_x emissions per rolling, 12-month period, including start-up and shutdown emissions. 112.8 tons of CO emissions per rolling, 12-month period, including start-up and shutdown emissions. 49.1 tons of VOC emissions per rolling, 12-month period, including start-up and shutdown emissions. 80.2 tons of $PE/PM_{10}/PM_{2.5}$ emissions per rolling, 12-month period. 28.65 tons of SO_2 emissions per rolling, 12-month period.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		17.55 tons of H_2SO_4 emissions per rolling, 12-month period. 2,499,820 tons of CO_2e emissions per rolling, 12-month period. See b)(2)a through b)(2)e.
b.	ORC 3704.03(T) and OAC rule 3745-31-05(A)(3)	The emission limitations for NO_x, CO, VOC and PE/PM_{10}/$PM_{2.5}$ required by this rule are equivalent to the emission limitations for NO_x, CO, VOC and PE/PM_{10}/$PM_{2.5}$ established pursuant to OAC rules 3745-31-10 through 3745-31-20. See c)(1).
c.	OAC rules 3745-17-07(A), 3745-17-10 (HRSG duct burners) and 3745-17-11(B)(4) (Turbine)	The PE limitations required by these rules applicable are less stringent than the emission limitations established pursuant to OAC rules 3745-31-10 through 20.
d.	OAC rule 3745-18-06(F)	Exempt pursuant to OAC rule 3745-18-06(A) since only natural gas is burned in this emissions unit.
e.	40 CFR Part 75 and OAC chapter 3745-103	See b)(2)f.
f.	OAC rule 3745-110-03	Exempt pursuant to OAC rule 3745-110-03(K)(20) because this emissions unit is subject to BACT requirements for NO_x emissions.
g.	40 CFR Part 60, Subpart KKKK (40 CFR 60.4300 – 60.4420) [In accordance with 40 CFR 60.4300 and 60.4305(a), this emissions unit is a stationary combustion turbine with a heat input at peak load (HHV) equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, and associated heat recovery steam generator with duct burners that commenced construction, modification, or reconstruction after February 18, 2005, subject to the emission limitations and control measures specified in this section.]	NO_x emissions from new combustion turbines firing natural gas with heat input capacities at peak load (HHV) greater than 850 MMBtu/hr shall not exceed 15 ppm at 15% O_2 or 54 ng/J of useful output (0.43 lb/MWh). [40 CFR 60.4320(a) and Table 1 of 40 CFR Part 60, Subpart KKKK] SO_2 emissions from the turbine must not exceed 0.90 lb/MWh of gross output, or, fuels burned in the turbine must not contain sulfur in concentrations which would result in potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input. [40 CFR 60.4330(a)] See b)(2)g.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
h.	40 CFR Part 60, Subpart TTTT (40 CFR 60.5508 – 60.5580) [In accordance with 40 CFR 60.5508 and 60.5509(a), this emissions unit is a stationary combustion turbine (EGU) that commenced construction after June 18, 2014 and has a base load rating greater than 250 MMBtu/hr and serving a generator capable of selling greater than 25 MW of electricity to a utility power distribution system, subject to the emission limitations and control measures specified in this section.]	Carbon dioxide (CO_2) emissions shall not exceed 450 kg per MW-h of gross energy output (1,000 lbs/MW-h) on a 12-operating-month rolling average basis, or, if a petition is granted, CO_2 emissions shall not exceed 470 kg per MW-h of net energy output (1,030 lbs/MW-h) on a 12-operating-month rolling average basis. [40 CFR 60.5520(a)-(c) and Table 2 of 40 CFR Part 60, Subpart TTTT]
i.	40 CFR Part 60, Subpart A (40 CFR 60.1 – 60.19)	General Provisions Table 3 of 40 CFR Part 60, Subpart TTTT shows which parts of the General Provisions in 40 CFR 63.1 through 63.19 do not apply. [40 CFR 60.5570 and Table 3 of 40 CFR Part 60, Subpart TTTT]
j.	40 CFR Part 63, Subpart YYYY (40 CFR 63.6080 – 63.6175) [In accordance with 40 CFR 63.6080, 63.6085 and 63.6090(a)(2), this emissions unit is a new stationary combustion turbine for which construction commenced after January 14, 2003 located at a major source of HAP emissions subject to the emission limitations/control measures specified in this section.]	See b)(2)h.
k.	40 CFR Part 63, Subpart A (40 CFR 63.1 – 63.16)	Table 7 of 40 CFR Part 63, Subpart YYYY shows which parts of the General Provisions in 40 CFR 63.1 through 63.16 apply.

(2) Additional Terms and Conditions

a. As part of the Best Available Control Technology (BACT) determination for NO_x, the permittee shall install and maintain dry low NO_x burners and an SCR system

on this emissions unit. Operation of these control systems shall reduce NO_x emissions to the limitations specified in b)(1)a.

b. As part of the BACT determination for CO and VOC, the permittee shall install and operate an oxidation catalyst and shall operate the emissions unit in accordance with good combustion practices as recommended by the manufacturer to ensure compliance with the CO and VOC limitations specified in b)(1)a.

c. As part of the BACT determination for visible PE, $PM/PM_{10}/PM_{2.5}$, SO_2 and H_2SO_4 emissions, the permittee shall burn only natural gas (as specified in b)(1)) in this emissions unit to ensure compliance with the $PM/PM_{10}/PM_{2.5}$, SO_2 and H_2SO_4 limitations specified in b)(1)a.

d. As part of the BACT determination for CO_2e, the permittee shall operate the emissions unit using good combustion practices as recommended by the manufacturer to ensure compliance with the CO_2e limitations specified in b)(1)a.

e. The permittee shall comply with the following requirements during periods of startup and shutdown.

	Emission Limitations During Startup and Shutdown (pounds per hour)[a]			
	Cold Startup	Warm Startup	Hot Startup	Shutdown
NO_x	262.46	155.83	89.67	31.6
CO	771.49	155.97	131.93	139.32
VOC	55.86	13.43	15.87	34.24

[a] Pound per hour emissions rates as presented are the maximum rates during any hour during the event from each unit.

Operating modes of the combined cycle combustion turbine are defined as follows:

Operating Mode	**Definition**
Cold Startup	When the combustion turbine has been shut down for more than 72 hours
Warm Startup	When the combustion turbine has been shut down for a period from 8 to 72 hours
Hot Startup	When the combustion turbine has been shut down for less than 8 hours
Steady-state	When the load is between the minimum environmental compliance load (MECL) and 100%. The duct burners

	may operate when the combustion turbine is in steady-state.
Shutdown	Begins when the first CEM data point out of compliance with either the CO or NO_x ppmvd emission limit that occurs after load is reduced below Steady-state in conjunction with the process of ceasing operation of the unit, and ends when fuel flow to the turbine ceases.

f. The permittee is subject to the requirements of OAC chapter 3745-103 and 40 CFR Parts 72 and 75 concerning acid rain, so the permittee shall ensure that any affected emissions unit complies with those requirements. Emissions exceeding any allowances that are lawfully held under Title IV of the Act, or any regulations adopted thereunder, are prohibited.

g. Only heat input to the combustion turbine should be included when determining whether or not 40 CFR Part 60, Subpart KKKK is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

h. The continuous emission monitoring system consists of all the equipment used to acquire data to provide a record of emissions and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data recording/processing hardware and software.

i. Each continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system) shall be certified to meet the requirements of 40 CFR Part 60 and 40 CFR Part 75, Appendix B and Performance Specifications 2, 3 and 6. At least 45 days before commencing certification testing of the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system), the permittee shall develop and maintain a written quality assurance/quality control plan designed to ensure continuous valid and representative readings of NO_x and CO_2 or O_2 emissions from the continuous monitor(s), in units of the applicable standard(s). The fuel flow monitor/meter shall be maintained as required in 40 CFR Part 75, Appendix D. Except as allowed below, the plan shall follow the requirements of 40 CFR Part 60, Appendix F and 40 CFR Part 75, Appendix B. The quality assurance/quality control plan and a logbook dedicated to the continuous NO_x monitoring system must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct relative accuracy test audits for the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system) in accordance with the frequencies required pursuant to 40 CFR Part 60 and 40 CFR Part 75; or may follow relative accuracy test audit frequency requirements for monitoring systems subject to 40 CFR Part 75, Appendix B, in lieu of frequencies required in 40 CFR Part 60. In either case, results shall be recorded and reported in units of the applicable standard(s) in accordance with 40 CFR Part 60.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits pursuant to 40 CFR Part 60, and linearity checks pursuant to 40 CFR Part 75; however, linearity checks completed pursuant to 40 CFR Part 75, Appendix B, may be substituted for the quarterly cylinder gas or relative accuracy audits required per 40 CFR Part 60.

j. Each continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system) shall be certified to meet the requirements of 40 CFR Part 60, Appendix B, Performance Specifications 3, 4 or 4a and 6. At least 45 days before commencing certification testing of the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system), the permittee shall develop and maintain a written quality assurance/quality control plan designed to ensure continuous valid and representative readings of CO and CO_2 or O_2 emissions from the continuous monitor(s), in units of the applicable standard(s). The fuel flow monitor/meter shall be maintained as required in 40 CFR Part 75, Appendix D. Except as allowed below, the plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook dedicated to the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system) must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct relative accuracy test audits for the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system) in accordance with the frequencies required for monitoring systems subject to 40 CFR 60, or may follow relative accuracy test audit frequency requirements for monitoring systems subject to 40 CFR Part 75, Appendix B. In either case, results shall be recorded and reported in units of the applicable standard(s) in accordance with 40 CFR Part 60.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits as required in 40 CFR Part 60; however, the quarterly cylinder gas audit and relative accuracy audit frequency requirements may be adjusted to coincide with linearity checks completed for continuous emissions monitoring systems subject to 40 CFR Part 75, Appendix B requirements.

k. See 40 CFR Part 60, Subpart TTTT (40 CFR 60.5508 – 60.5580).

c) Operational Restrictions

(1) The permittee shall burn only pipeline quality natural gas with a maximum sulfur content not to exceed 0.50 grain/100 scf in this emissions unit.

(2) Except during periods of startup, the SCR system for this emissions unit shall be in operation at all times, including during the shutdown of the unit.

(3) In accordance with good engineering practices, the SCR unit shall be operated and maintained in accordance with the manufacturer's recommendations, with any modifications deemed necessary by the permittee. The permittee shall maintain on site a copy of the operation and maintenance manual, as provided by the manufacturer.

(4) See 40 CFR Part 60, Subpart KKKK (40 CFR 60.4300 – 60.4420).

(5) See 40 CFR Part 60, Subpart TTTT (40 CFR 60.5508 – 60.5580).

(6) See 40 CFR Part 63, Subpart YYYY (40 CFR 63.6080 – 63.6175).

d) Monitoring and/or Recordkeeping Requirements

(1) For each day during which the permittee burns a fuel other than pipeline quality natural gas with a maximum sulfur content of 0.5 grain/100 scf, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

(2) The permittee shall maintain monthly records of the following information for this emissions unit:

a. the hours of operation of the combustion turbine in each operating mode;

b. the hours of operation of the duct burners;

c. the amount of gaseous fuel consumed in this emissions unit, in MMscf;

d. the heat content of the gaseous fuel combusted in this emissions unit, in MMBtu/MMscf;

e. the sulfur content of the gaseous fuel combusted in this emissions unit, in gr/dscf;

f. the total NO_x emissions, in pounds, including startup/shutdown emissions, as recorded in d)(4)b.;

g. the total CO emissions, in pounds, including startup/shutdown emissions, as recorded in d)(7)b.;

h. the total VOC emissions, in pounds, including startup/shutdown emissions, calculated by multiplying the VOC emission factor of 0.00132 lb/MMBtu (w/o duct burner firing) or 0.00266 lb/MMBtu (w/ duct burner firing), or after testing has been completed, the results of the most recent stack test, by the amount of gaseous fuel consumed during steady-state operation, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d, plus the hours of operation of the combustion turbine in each startup and shutdown operating mode as recorded in d(2)a. multiplied by the pounds per hour emission limitations for the corresponding modes of operation in b)(2)e;

i. the total $PE/PM_{10}/PM_{2.5}$ emissions, in pounds, including startup/shutdown emissions, calculated by multiplying the emission factor of 0.00735 lb/MMBtu (w/o duct burner firing) or 0.00522 lb/MMBtu (w/ duct burner firing), or after testing has been completed, the results of the most recent stack test, by the amount of gaseous fuel consumed, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

j. the total SO_2 emissions, in pounds, including startup/shutdown emissions, for this emissions unit, calculated by multiplying the emission factor of 0.00174 lb/MMBtu

or after testing has been completed, the results of the most recent stack test, by the amount of gaseous fuel consumed, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

k. the total H_2SO_4 emissions, in pounds, including startup/shutdown emissions, calculated by multiplying the emission factor of 0.00102 lb/MMBtu (w/o duct burner firing) or 0.00103 lb/MMBtu (w/duct burner firing), or after testing has been completed, the results of the most recent stack test by the amount of gaseous fuel consumed, including periods of startup/shutdown, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

l. the total CO_2e emissions, in pounds, including startup/shutdown emissions, calculated by multiplying the CO_2e emission factor of 117.10 lbs/MMBtu by the amount of gaseous fuel consumed, including periods of startup/shutdown, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

m. the rolling, 12-month summation of the NO_x emissions, in tons, including start-up/shutdown emissions, calculated by adding the total NO_x emissions for the present month as recorded in d)(2)f, plus the total NO_x emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

n. the rolling, 12-month summation of the CO emissions, in tons, including startup/shutdown emissions, calculated by adding the total CO emissions for the present month as recorded in d)(2)g, plus the total CO emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

o. the rolling, 12-month summation of the VOC emissions, in tons, including startup/shutdown emissions, calculated by adding the total VOC emissions for the present month as recorded in d)(2)h, plus the total VOC emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

p. the rolling, 12-month summation of the PE/PM_{10}/$PM_{2.5}$ emissions, in tons, including startup/shutdown emissions, calculated by adding the total PE/PM_{10}/$PM_{2.5}$ emissions for the present month as recorded in d)(2)i, plus the total PE/PM_{10}/$PM_{2.5}$ emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

q. the rolling, 12-month summation of the SO_2 emissions, in tons, including startup/shutdown emissions, calculated by adding the total SO_2 emissions for the present month as recorded in d)(2)j, plus the total SO_2 emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

r. the rolling, 12-month summation of the H_2SO_4 emissions, in tons, including startup/shutdown emissions, calculated by adding the total H_2SO_4 emissions for the present month as recorded in d)(2)k, plus the total H_2SO_4 emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds; and

s. the rolling, 12-month summation of the CO_2e emissions, in tons, including startup/shutdown emissions, calculated by adding the total CO_2e emissions for

the present month as recorded in d)(2)l, plus the total CO_2e emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds.

(3) Prior to the installation of the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system), the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specifications 2 and 3. The Ohio EPA, Central Office shall approve the proposed sampling site and certify that the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system) meets the requirements of Performance Specifications 2 and 3 and the accuracy requirements of Performance Specification 6.

Following installation, the permittee shall document that the fuel flow monitor/meter meets 40 CFR Part 75 certification requirements prior to the performance specification test, and shall demonstrate how the pound per hour emissions of NO_x is being calculated stoichiometrically. The U.S. EPA shall certify that the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system) meets the requirements under 40 CFR Part 75, which may be approved through the recommendation for certification by Ohio EPA to U.S. EPA. Once received, the letter(s)/document(s) of certification under 40 CFR Part 60 and certification or recommendation for certification under 40 CFR Part 75 shall be maintain on site and made available to the Director (the appropriate Ohio EPA District Office or local air agency) upon request.

(4) The permittee shall install, operate and maintain equipment to continuously monitor and record NO_x and CO_2 or O_2 emissions from this emissions unit in units of the applicable standard(s). The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60 and/or Part 75.

The permittee shall maintain records of all data obtained by the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system) including, but not limited to:

a. emissions of NO_x in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. emissions of NO_x in pounds per hour and in units of the applicable standard(s) in the appropriate averaging period;

c. the percent CO_2 or O_2 with each cycle time of the analyzer, with no resolution less than one data point per minute required;

d. results of quarterly cylinder gas audits or linearity checks;

e. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

f. results of required relative accuracy test audit(s), including results in units of the applicable standard(s);

g. hours of operation of the emissions unit, continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system), and control equipment;

h. the date, time, and hours of operation of the emissions unit without the control equipment and/or the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system);

i. the date, time, and hours of operation of the emissions unit during any malfunction of the control equipment and/or the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system); as well as,

j. the reason (if known) and the corrective actions taken (if any) for each such event in d)(4)h and d)(4)i.

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(5) The permittee may operate and maintain equipment to continuously monitor and record the fuel flow rate in order to stoichiometrically calculate emissions of NO_x, in pounds per hour, as an alternative to conducting Performance Specification 6. Fuel heat content values for each fuel burned, as applied in the stoichiometric calculations, shall also be recorded. The permittee shall maintain records of data obtained by the fuel flow monitor/meter, including the dates and results of each calibration check and the magnitude of calibration adjustments; periods of downtime and malfunction of the fuel flow monitor/meter; as well as, the reason (if known) and the corrective actions taken (if any) for each such event.

(6) Prior to the installation of the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system), the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specifications 3 and 4 or 4a (as appropriate). The Ohio EPA, Central Office shall approve the proposed sampling site and certify that the continuous CO monitoring system meets the requirements of Performance Specifications 3 and 4 or 4a and the accuracy requirements of Performance Specification 6.

Following installation, the permittee shall document that the fuel flow monitor/meter meets 40 CFR Part 75 certification requirements prior to the performance specification test, and shall demonstrate how the pound per hour emissions of CO is being calculated stoichiometrically. Once received, the letter(s)/document(s) of certification shall be maintained on site and shall be made available to the Director (the appropriate Ohio EPA District Office or local air agency) upon request.

(7) The permittee shall operate and maintain equipment to continuously monitor and record CO and CO_2 or O_2 emissions from this emissions unit in units of the applicable standard(s). The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

The permittee shall maintain records of all data obtained by the continuous CO monitoring system including, but not limited to:

a. emissions of CO in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. emissions of CO in pounds per month;

c. the percent CO_2 or O_2 with each cycle time of the analyzer, with no resolution less than one data point per minute required;

d. results of quarterly cylinder gas audits;

e. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

f. results of required relative accuracy test audit(s), including results in units of the applicable standard(s);

g. hours of operation of the emissions unit, continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system), and control equipment;

h. the date, time, and hours of operation of the emissions unit without the control equipment and/or the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system);

i. the date, time, and hours of operation of the emissions unit during any malfunction of the control equipment and/or the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system); as well as,

j. the reason (if known) and the corrective actions taken (if any) for each such event in d)(7)h and d)(7)i.

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(8) The permittee may operate and maintain equipment to continuously monitor and record the fuel flow rate in order to stoichiometrically calculate emissions of CO in pounds per hour, as an alternative to conducting Performance Specification 6. Fuel heat content values for each fuel burned, as applied in the stoichiometric calculations, shall also be recorded. The permittee shall maintain records of data obtained by the fuel flow monitor/meter, including the dates and results of each calibration check and the magnitude of calibration adjustments; periods of downtime and malfunction of the fuel flow monitor/meter; as well as, the reason (if known) and the corrective actions taken (if any) for each such event.

(9) The permittee shall collect, record, and maintain measurements, data, records, and reports required per 40 CFR Part 75; and shall submit certification, recertification,

notifications, applications, monitoring plans, petitions for alternative monitoring systems, electronic quarterly reports, and any other pertinent record and/or report to the Administrator (U.S. EPA), as required by 40 CFR Part 75.

(10) The permittee shall operate and maintain equipment to continuously monitor and record the actual fuel flow to this emissions unit when the emissions unit is in operation. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 75. If the fuel flow monitoring and/or recording equipment is (are) not in service when the emissions unit is in operation, the permittee shall comply with the approved data substitution protocol.

Fuel flow data that is substituted in accordance with 40 CFR Part 75, Appendix D, is not to be used when verifying compliance with the hourly NO_x and CO pounds per hour emission limits. Hours in which fuel flow is substituted should be included as NO_x and CO monitoring system downtime.

(11) The permittee shall monitor the sulfur content and gross caloric value of the fuel being fired in the combustion turbine and duct burners, representative fuel sampling shall be conducted which shows that the sulfur content of the fuel does not exceed 1.5E-03 lb SO_2/MMBtu heat input. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to 40 CFR Part 75 is required.

(12) The permittee shall determine the hourly heat input rate to the combustion turbine and duct burner, in MMBtu, from the fuel flow rate and gross calorific value as determined in d)(8). The heat input rate shall be calculated in accordance with the procedures in section 5 of 40 CFR Part 75, Appendix F.

(13) See 40 CFR Part 60, Subpart KKKK (40 CFR 60.4300 – 60.4420).

(14) See 40 CFR Part 60, Subpart TTTT (40 CFR 60.5508 – 60.5580).

(15) See 40 CFR Part 63, Subpart YYYY (40 CFR 63.6080 – 63.6175).

e) Reporting Requirements

(1) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

(2) The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than pipeline quality natural gas with a maximum sulfur content of the natural gas of 0.5 grain/100 standard cubic feet was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurred.

(3) The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. all exceedances of the NO_x, CO, and/or VOC start-up/shutdown limitations; and

b. all exceedances of the rolling, 12-month NO_x, CO, VOC, PE/PM_{10}/$PM_{2.5}$, SO_2 and/or H_2SO_4 emission limitations.

These quarterly reports shall be submitted in accordance with the reporting requirements of the Standard Terms and Conditions of this permit.

(4) The permittee shall comply with the following quarterly reporting requirements for the emissions unit and its continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system):

a. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency, documenting all instances of NO_x emissions in excess of any applicable limit specified in this permit, 40 CFR Part 60, OAC Chapters 3745-14 and 3745-23, and any other applicable rules or regulations. The report shall document the date, commencement and completion times, duration, and magnitude of each exceedance, as well as the reason (if known) and the corrective actions taken (if any) for each exceedance. Excess emissions shall be reported in units of the applicable standard(s).

b. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR Parts 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency, documenting all instances of continuous CO_2 or O_2 monitoring system downtime and malfunction while the emissions unit was in operation.

c. These quarterly reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous NO_x and CO_2 or O_2 and other associated monitors;

iii. a description of any change in the equipment that comprises the continuous emission monitoring system (CEMS), including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the excess emissions report (EER)*, i.e., a summary of any exceedances during the calendar quarter, as specified above;

v. the total NO_x emissions for the calendar quarter (tons);

vi. the total operating time (hours) of the emissions unit;

vii. the total operating time of the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system) while the emissions unit was in operation;

viii. results and date of quarterly cylinder gas audits or linearity checks;

ix. unless previously submitted, results and date of the relative accuracy test audit(s), including results in units of the applicable standard(s), (during appropriate quarter(s));

x. unless previously submitted, the results of any relative accuracy test audit showing the continuous NO_x and CO_2 or O_2 monitor out-of-control and the compliant results following any corrective actions;

xi. the date, time, and duration of any/each malfunction** of the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system), emissions unit, and/or control equipment;

xii. the date, time, and duration of any downtime** of the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system) and/or control equipment while the emissions unit was in operation; and

xiii. the reason (if known) and the corrective actions taken (if any) for each event in e)(4)c.xi. and e)(4)c.xii.

Each report shall address the operations conducted and data obtained during the previous calendar quarter.

* where no excess emissions have occurred or the continuous monitoring system(s) has/have not been inoperative, repaired, or adjusted during the calendar quarter, such information shall be documented in the EER quarterly report

** each downtime and malfunction event shall be reported regardless if there is an exceedance of any applicable limit

(5) If using the fuel flow rate to stoichiometrically calculate the pound per hour emissions of NO_x in place of Performance Specification 6 requirements, the permittee shall submit quarterly reports, to the appropriate Ohio EPA District Office or local air agency, that document the date, time, and duration of each malfunction and/or period of downtime of the continuous fuel flow monitoring system, while the emissions unit was in operation, and the reason (if known) and the corrective actions taken (if any) for each such event. If there was no downtime or malfunction of the continuous fuel flow monitoring system during any calendar quarter, the report shall be submitted so stating it. These quarterly reports shall be submitted by January 30, April 30, July 30, and October 30 of each year.

(6) The permittee shall comply with the following quarterly reporting requirements for the emissions unit and its continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system):

a. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA

District Office or local air agency, documenting all instances of CO emissions in excess of any applicable limit specified in this permit, 40 CFR Part 60, OAC Chapter 3745-21, and any other applicable rules or regulations. The report shall document the date, commencement and completion times, duration, and magnitude of each exceedance, as well as, the reason (if known) and the corrective actions taken (if any) for each exceedance. Excess emissions shall be reported in units of the applicable standard(s).

b. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR Parts 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency, documenting all instances of continuous CO_2 or O_2 monitoring system downtime and malfunction while the emissions unit was in operation.

c. These quarterly reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous CO and CO_2 or O_2 and other associated monitors;

iii. a description of any change in the equipment that comprises the continuous emission monitoring system (CEMS), including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the excess emissions report (EER)*, i.e., a summary of any exceedances during the calendar quarter, as specified above;

v. the total CO emissions for the calendar quarter (tons);

vi. the total operating time (hours) of the emissions unit;

vii. the total operating time of the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system) while the emissions unit was in operation;

viii. results and dates of quarterly cylinder gas audits;

ix. unless previously submitted, results and dates of the relative accuracy test audit(s), including results in units of the applicable standard(s), (during appropriate quarter(s));

x. unless previously submitted, the results of any relative accuracy test audit showing the continuous CO and CO_2 or O_2 monitor out-of-control and the compliant results following any corrective actions;

xi. the date, time, and duration of any/each malfunction** of the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system), and/or emissions unit;

xii. the date, time, and duration of any downtime** of the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system) while the emissions unit was in operation; and

xiii. the reason (if known) and the corrective actions taken (if any) for each event in e)(6)c.xi. and e)(6)c.xii.

Each report shall address the operations conducted and data obtained during the previous calendar quarter.

* where no excess emissions have occurred or the continuous monitoring system(s) has/have not been inoperative, repaired, or adjusted during the calendar quarter, such information shall be documented in the EER quarterly report

** each downtime and malfunction event shall be reported regardless of whether there is an exceedance of any applicable limit

(7) If using the fuel flow rate to stoichiometrically calculate the pound per hour emissions of CO, in place of Performance Specification 6 requirements, the permittee shall submit quarterly reports, to the appropriate Ohio EPA District Office or local air agency, that document the date, time, and duration of each malfunction and/or period of downtime of the continuous fuel flow monitoring system, while the emissions unit was in operation, and the reason (if known) and the corrective actions taken (if any) for each such event. If there was no downtime or malfunction of the continuous fuel flow monitoring system during any calendar quarter, the report shall be submitted so stating it. These quarterly reports shall be submitted by January 30, April 30, July 30, and October 30 of each year.

(8) See 40 CFR Part 60, Subpart KKKK (40 CFR 60.4300 – 60.4420).

(9) See 40 CFR Part 60, Subpart TTTT (40 CFR 60.5508 – 60.5580).

(10) See 40 CFR Part 63, Subpart YYYY (40 CFR 63.6080 – 63.6175).

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods for this emissions unit:

a. Emission Limitations:

NO_x emissions without duct burner firing shall not exceed 2.0 ppmvd at 15% O_2 based on a 24-hour block averaging period and 25.1 pounds per hour, excluding periods of startup and shutdown.

NO_x emissions with duct burner firing shall not exceed 2.0 ppmvd at 15% O_2 based on a 24-hour block averaging period and 29.5 pounds per hour, excluding periods of startup and shutdown.

NO_x emissions from new combustion turbines firing natural gas with heat input capacities greater than 850 MMBtu/hr shall not exceed 15 ppm at 15% O_2 calculated on a 30-day rolling average or 54 ng/J of useful output (0.43 lb/MWh).

Applicable Compliance Method:

Initial compliance with the allowable outlet concentration and the pounds per hour emission limitations shall be demonstrated through emission testing performed as described in f)(4).

Ongoing compliance with the short-term NO_x emission limitations shall be demonstrated through the data collected as required in the monitoring and record keeping section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the testing and recertification requirements of 40 CFR Part 60 and 40 CFR Part 75.

Ongoing compliance with the CO_2 or O_2 monitoring requirements contained in this permit, 40 CFR Parts 60 and 75, and any other applicable standard(s) shall be demonstrated through the data collected as required in the monitoring and record keeping section of this permit; and demonstration of compliance with the quality assurance/quality control plan, which shall meet all of the testing and recertification requirements of 40 CFR Part 60 and 40 CFR Part 75.

b. Emission Limitations:

CO emissions without duct burner firing shall not exceed 2.0 ppmvd at 15% O_2 based on a 24-hour block averaging period and 15.3 pounds per hour, excluding periods of startup and shutdown.

CO emissions with duct burner firing shall not exceed 2.0 ppmvd at 15% O_2 based on a 24-hour block averaging period and 17.9 pounds per hour, excluding periods of startup and shutdown.

Applicable Compliance Method:

Initial compliance with the allowable outlet concentration and the pounds per hour emission limitations shall be demonstrated through emission testing performed as described in f)(4) below.

Ongoing compliance with the short-term CO emission limitations shall be demonstrated through the data collected as required in the monitoring and record keeping section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60.

Ongoing compliance with the CO_2 or O_2 monitoring requirements contained in this permit, 40 CFR Parts 60 and 75, and any other applicable standard(s) shall be demonstrated through the data collected as required in the monitoring and record keeping section of this permit; and demonstration of compliance with the quality assurance/quality control plan, which shall meet all of the testing and recertification requirements of 40 CFR Part 60 and 40 CFR Part 75.

c. Emission Limitations:

VOC emissions without duct burner firing shall not exceed 1.0 ppmvd at 15% O_2 and 4.36 pounds per hour, excluding periods of startup and shutdown.

VOC emissions with duct burner firing shall not exceed 2.0 ppmvd at 15% O_2 and 10.3 pounds per hour, excluding periods of startup and shutdown.

Applicable Compliance Method:

Compliance with the short-term VOC emission limitations shall be demonstrated by the emission testing requirements specified in f)(4).

d. Emission Limitations:

PE/PM_{10}/$PM_{2.5}$ emissions without duct burner firing shall not exceed 0.00735 lb/MMBtu and 12.00 pounds per hour.

PE/PM_{10}/$PM_{2.5}$ emissions with duct burner firing shall not exceed 0.00522 lb/MMBtu and 18.40 pounds per hour.

Applicable Compliance Method:

Compliance with the short-term PE/PM_{10}/$PM_{2.5}$ emission limitations shall be demonstrated by the emission testing requirements specified in f)(4).

e. Emission Limitations:

SO_2 emissions without duct burner firing shall not exceed 0.00174 lb/MMBtu and 5.75 pounds per hour.

SO_2 emissions with duct burner firing shall not exceed 0.00174 lb/MMBtu and 6.74 pounds per hour.

SO_2 emissions from the turbine must not exceed 0.90 lb/MWh of gross output, or, fuels burned in the turbine must not contain sulfur in concentrations which would result in potential sulfur emissions in excess of 0.060 lb SO_2 MMBtu heat input.

Applicable Compliance Methods:

Compliance with the short-term SO_2 emission limitations shall be demonstrated by the monitoring requirements specified in d)(11) and the emission testing requirements specified in f)(4).

f. Emission Limitations:

H_2SO_4 emissions without duct burner firing shall not exceed 0.00102 lb/MMBtu and 3.52 pounds per hour.

H_2SO_4 emissions with duct burner firing shall not exceed 0.0.00103 lb/MMBtu and 4.13 pounds per hour.

Applicable Compliance Method:

Compliance with the short-term H_2SO_4 emission limitations shall be demonstrated by the emission testing requirements specified in f)(4).

g. Emission Limitation:

Visible PE from the stack serving this emissions unit shall not exceed 10% opacity as a 6-minute average.

Applicable Compliance Method:

Compliance with the visible PE limitation shall be demonstrated by the emission testing requirements specified in f)(4).

h. Emission Limitations:

Emissions shall not exceed:

139 tons of NO_x per rolling, 12-month period, including start-up and shutdown emissions;

112.8 tons of CO emissions per rolling, 12-month period, including start-up and shutdown emissions;

49.1 tons of VOC emissions per rolling, 12-month period, including start-up and shutdown emissions;

80.2 tons of PE/PM_{10}/$PM_{2.5}$ emissions per rolling, 12-month period;

28.65 tons of SO_2 emissions per rolling, 12-month period;

17.55 tons of H_2SO_4 emissions per rolling, 12-month period; and

2,499,820 tons of CO_2e emissions per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the rolling, 12-month emission limitations shall be demonstrated by the record keeping requirements specified in d)(2).

i. Emission Limitation:

CO_2e emissions shall not exceed 1,012.4 lbs/MW-hr gross energy output (at full load ISO conditions when firing natural gas without duct burner firing).

Applicable Compliance Method:

Since more than 99% of the CO_2e emissions result from CO_2 emissions, compliance with the 1,012.4 lbs/MW-hr gross energy output limitation will be assumed if the CO_2 emissions determined during the emission testing conducted per f)(4) are determined to not exceed 1,012.4 lbs/MW-hr gross energy output.

j. Emission Limitation:

CO_2 emissions shall not exceed 450 kg per MW-hr of gross energy output (1,000 lbs/MW-hr) on a 12-operating-month rolling average basis, or, if a petition is granted, CO_2 emissions shall not exceed 470 kg per MW-hr of net energy output (1,030 lbs/MW-hr) on a 12-operating-month rolling average basis.

Applicable Compliance Method:

Compliance with the output based emission limitation shall be demonstrated by the procedures specified in 40 CFR 60.5535 and 60.5540.

k. Emission Limitation:

The permittee shall burn only pipeline quality natural gas with a maximum sulfur content not to exceed 0.5 grain/100 scf in this emissions unit.

Applicable Compliance Method:

Compliance with the fuel sulfur content limitation shall be demonstrated by the testing requirements specified in f)(4) and the record keeping requirements specified in d)(11).

l. Emission Limitations:

NO_x emissions during startup and shutdown shall not exceed 262.46 pounds per hour during cold startup, 155.83 pounds per hour during warm startup, 89.67 pounds per hour during hot startup and 31.6 pounds per hour during shutdown.

CO emissions during startup and shutdown shall not exceed 771.49 pounds per hour during cold startup, 155.97 pounds per hour during warm startup, 131.93 pounds per hour during hot startup and 139.32 pounds per hour during shutdown.

VOC emissions during startup and shutdown shall not exceed 55.86 pounds per hour during cold startup, 13.43 pounds per hour during warm startup, 15.87 pounds per hour during hot startup and 34.24 pounds per hour during shutdown.

Applicable Compliance Method:

These emission limitations are based on manufacturer's data.

Compliance with the CO and NO_x pounds per hour startup and shutdown emission limitations shall be demonstrated using the continuous emission monitoring system based on a 1-hour block average.

Compliance with the VOC pounds per hour startup and shutdown emission limitations shall be demonstrated through the record keeping requirements specified in d)(2) of this permit.

(2) Within 60 days of achieving the maximum production rate at which the emissions unit(s) will be operated, but not later than 180 days after initial startup, the permittee shall conduct certification tests of the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system), in units of the applicable standard(s), to demonstrate compliance with 40 CFR Part 60, Appendix B, Performance Specifications 2 and 3, Performance Specification 6 relative accuracy requirements, ORC section 3704.03(I) and 40 CFR Part 75.

The permittee shall certify that the fuel flow monitor/meter meets 40 CFR Part 75 certification requirements prior to the performance specification test and shall demonstrate how the pound per hour emissions of NO_x and CO_2 or O_2 will be calculated stoichiometrically from the fuel flow rate.

Personnel from the Ohio EPA Central Office and the appropriate Ohio EPA District Office or local air agency shall be notified 45 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. Two copies of the test results shall be submitted to Ohio EPA, one copy to the appropriate Ohio EPA District Office or local air agency and one copy to Ohio EPA Central Office, and pursuant to OAC rule 3745-15-04, within 30 days after the test is completed.

Certification, or recommendation for certification by Ohio EPA to U.S. EPA, of the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system) shall be granted upon determination by the Ohio EPA, Central Office that the system meets the requirements of 40 CFR Part 60, Appendix B, Performance Specifications 2 and 3; Performance Specification 6 relative accuracy requirements; ORC section 3704.03(I); and 40 CFR Part 75.

(3) Within 60 days of achieving the maximum production rate at which the emissions unit(s) will be operated, but not later than 180 days after initial startup, the permittee shall conduct certification tests of the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system) in units of the applicable standard(s), to demonstrate compliance with 40 CFR Part 60, Appendix B, Performance Specifications 3 and 4 or 4a (as appropriate) and 6; and ORC section 3704.03(I).

Personnel from the Ohio EPA Central Office and the appropriate Ohio EPA District Office or local air agency shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests.

Two copies of the test results shall be submitted to Ohio EPA, one copy to the appropriate Ohio EPA District Office or local air agency and one copy to Ohio EPA Central Office, and pursuant to OAC rule 3745-15-04, within 30 days after the test is completed.

Certification of the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system) shall be granted upon determination by the Ohio EPA Central Office that the system meets the requirements of 40 CFR Part 60, Appendix B, Performance Specifications 3 and 4 or 4a (as appropriate) and 6 and ORC section 3704.03(I).

(4) The permittee shall conduct, or have conducted, emission testing for this emissions unit in accordance with OAC rules 3745-31-10 through 3745-31-20, 40 CFR 60.8, 60.4405 and 60.4415 and the following requirements:

a. The emission testing shall be conducted within 60 days after achieving the maximum production rate at which the modified facility will be operated, but not later than 180 days after initial startup of the modified unit. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test) using one of the three methodologies in 40 CFR 60.4415(a).

b. The emission testing shall be conducted to demonstrate initial compliance with the NO_x and CO outlet concentrations, the lb/hr emission limitations for NO_x, CO, VOC, and PE and $PM_{10}/PM_{2.5}$, the visible PE limit and the fuel sulfur content after modification.

c. The following test method(s) shall be employed to demonstrate compliance with the above emission limitations:

NO_x	Method 7E or 20 of 40 CFR Part 60, Appendix A
CO	Methods 1 through 4 and 10 of 40 CFR Part 60, Appendix A
VOC	Methods 1 through 4, 18 and 25A of 40 CFR Part 60, Appendix A
PE	Methods 1 through 5 of 40 CFR Part 60, Appendix A
$PM_{10}/PM_{2.5}$	Methods 1 through 4 of 40 CFR Part 60, Appendix A and Methods 201/201A and 202 as set forth in 40 CFR Part 51, Appendix M
CO_2	Methods 1 through 4 of 40 CFR Part 60, Appendix A, mass balance calculations using ASTM D1945-03 (Standard Test Method for Analysis of Natural Gas by Gas Chromatography) and/or ASTM D1826-94 (Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter).
VEs	Method 9 of 40 CFR Part 60, Appendix A
SO_2 (fuel sulfur content)	40 CFR 60.4415(a)

H_2SO_4	Methods 1 through 4 and 8 of 40 CFR Part 60, Appendix A

Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA Southeast District Office.

d. The test(s) shall be conducted under those representative conditions that challenge to the fullest extent possible a facility's ability to meet the applicable emissions limits and/or control requirements, unless otherwise specified or approved by the Ohio EPA Southeast District Office. Although this generally consists of operating the emissions unit at its maximum material input/production rates and results in the highest emission rate of the tested pollutant, there may be circumstances where a lower emissions loading is deemed the most challenging control scenario. Failure to test under these conditions is justification for not accepting the test results as a demonstration of compliance.

e. Not later than 30 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the Ohio EPA Southeast District Office. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Ohio EPA Southeast District Office's refusal to accept the results of the emission test(s).

f. Personnel from the Ohio EPA Southeast District Office shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

g. A comprehensive written report on the results of the emissions test(s) shall be signed by the person or persons responsible for the tests and submitted to the Ohio EPA Southeast District Office within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Ohio EPA Southeast District Office.

g) Miscellaneous Requirements

(1) None.

6. Emissions Unit Group – Mitsubishi Hitachi Power Systems (MHPS) Combustion Turbines: P007 and P008

EU ID	Operations, Property and/or Equipment Description
P007	MHPS Combustion Turbine 1; Mitsubishi Model M501JAC natural gas-fired combined cycle combustion turbine generator equipped with dry low-NO_x (DLN) burners nominally rated at 3,231 MMBtu/hr at 100% load and 51° F exhausting through a heat recovery steam generator (HRSG) with supplemental natural gas-fired duct burners nominally rated at 306 MMBtu/hr controlled with catalytic oxidation and selective catalytic reduction (SCR) used to generate electricity
P008	MHPS Combustion Turbine 2; Mitsubishi Model M501JAC natural gas-fired combined cycle combustion turbine generator equipped with DLN burners nominally rated at 3,231 MMBtu/hr at 100% load and 51° F exhausting through a HRSG with supplemental natural gas-fired duct burners nominally rated at 306 MMBtu/hr controlled with catalytic oxidation and SCR used to generate electricity

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only:

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rules 3745-31-10 through 3745-31-20 and 3745-31-34	**Emission Limits without Duct Burner Firing** Nitrogen oxides (NO_x) emissions shall not exceed 2.0 ppmvd at 15% oxygen (O_2) based on a 24-hour block averaging period and 26.7 pounds per hour, excluding periods of startup and shutdown. Carbon monoxide (CO) emissions shall not exceed 2.0 ppmvd at 15% O_2 based on a 24-hour block averaging period and 16.3 pounds per hour, excluding periods of startup and shutdown. Volatile organic compound (VOC)

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		emissions shall not exceed 1.0 ppmvd at 15% O_2 and 4.70 pounds per hour, excluding periods of startup and shutdown. Particulate emissions (PE) and emissions of particulate matter with a diameter less than 10 microns (PM_{10}) and particulate matter less than 2.5 microns ($PM_{2.5}$) shall not exceed 0.00444 lb/MMBtu and 14.10 pounds per hour. Sulfur dioxide (SO_2) emissions shall not exceed 0.0021 lb/MMBtu and 6.92 pounds per hour. Sulfuric acid (H_2SO_4) emissions shall not exceed 0.0022 lb/MMBtu and 7.41 pounds per hour. Carbon dioxide equivalent (CO_2e) emissions shall not exceed 976.0 lbs/MW-hr gross energy output at full load ISO conditions when firing natural gas. Gross energy output is defined as the gross power output of the generators before accounting for any balance of plant loads. Visible PE from the stack serving this emissions unit shall not exceed 10% opacity as a 6-minute average. **Emission Limits with Duct Burner Firing** NO_x emissions shall not exceed 2.0 ppmvd at 15% O_2 based on a 24-hour block averaging period and 28 pounds per hour, excluding periods of startup and shutdown. CO emissions shall not exceed 2.0 ppmvd at 15% O_2 based on a 24-hour block averaging period and 17.1 pounds per hour, excluding periods of startup and shutdown.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		VOC emissions shall not exceed 2.0 ppmvd at 15% O_2 and 9.8 pounds per hour, excluding periods of startup and shutdown. $PE/PM_{10}/PM_{2.5}$ emissions shall not exceed 0.005 lb/MMBtu and 17.7 pounds per hour. SO_2 emissions shall not exceed 0.0021 lb/MMBtu and 7.22 pounds per hour. H_2SO_4 emissions shall not exceed 0.0022 lb/MMBtu and 7.74 pounds per hour. The emission limitation specified by this rule for CO_2e emissions is equivalent to the requirements in 40 CFR Part 60, Subpart TTTT. Visible PE from the stack serving this emissions unit shall not exceed 10% opacity as a 6-minute average. **Rolling, 12-Month Emission Limitations:** 124.0 tons of NO_x emissions per rolling, 12-month period, including start-up and shutdown emissions. 109.1 tons of CO emissions per rolling, 12-month period, including start-up and shutdown emissions. 84.7 tons of VOC emissions per rolling, 12-month period, including start-up and shutdown emissions. 77.5 tons of $PE/PM_{10}/PM_{2.5}$ emissions per rolling, 12-month period. 29.57 tons of SO_2 emissions per rolling, 12-month period. 31.69 tons of H_2SO_4 emissions per

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		rolling, 12-month period. 2,342,643 tons of CO_2e emissions per rolling, 12-month period. See b)(2)a through b)(2)e.
b.	ORC 3704.03(T) and OAC rule 3745-31-05(A)(3)	The emission limitations for NO_x, CO, VOC, SO_2 and PE/PM_{10}/$PM_{2.5}$ required by this rule are equivalent to the emission limitations for NO_x, CO, VOC, SO_2 and PE/PM_{10}/$PM_{2.5}$ established pursuant to OAC rules 3745-31-10 through 3745-31-20. See c)(1).
c.	OAC rules 3745-17-07(A), 3745-17-10 (HRSG duct burners) and 3745-17-11(B)(4) (Turbine)	The PE limitations specified by these rules are less stringent than the emission limitations established pursuant to OAC rules 3745-31-10 through 3745-31-20.
d.	OAC rule 3745-18-06(F)	Exempt pursuant to OAC rule 3745-18-06(A) since only natural gas is burned in this emissions unit.
e.	40 CFR Part 75 and OAC Chapter 3745-103	See b)(2)f.
f.	OAC rule 3745-110-03	Exempt pursuant to OAC rule 3745-110-03(K)(20) because this emissions unit is subject to BACT requirements for NO_x emissions.
g.	40 CFR Part 60, Subpart KKKK (40 CFR 60.4300 – 60.4420) [In accordance with 40 CFR 60.4300 and 60.4305(a), this emissions unit is a stationary combustion turbine with a heat input at peak load (HHV) equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, and associated heat recovery steam generator with duct burners that commenced construction, modification, or reconstruction after February 18, 2005, subject to the emission limitations and control measures specified in this section.]	NO_x emissions from new combustion turbines firing natural gas with heat input capacities at peak load (HHV) greater than 850 MMBtu/hr shall not exceed 15 ppm at 15% O_2 or 54 ng/J of useful output (0.43 lb/MWh). [40 CFR 60.4320(a) and Table 1 of 40 CFR Part 60, Subpart KKKK] SO_2 emissions from the turbine must not exceed 0.90 lb/MWh of gross output, or, fuels burned in the turbine must not contain sulfur in concentrations which would result in potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input. [40 CFR 60.4330(a)] See b)(2)g.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
h.	40 CFR Part 60, Subpart TTTT (40 CFR 60.5508 – 60.5580) [In accordance with 40 CFR 60.5508 and 60.5509(a), this emissions unit is a stationary combustion turbine (EGU) that commenced construction after June 18, 2014 and has a base load rating greater than 250 MMBtu/hr and serving a generator capable of selling greater than 25 MW of electricity to a utility power distribution system, subject to the emission limitations and control measures specified in this section.]	Carbon dioxide (CO_2) emissions shall not exceed 450 kg per MW-h of gross energy output (1,000 lbs/MW-h) on a 12-operating-month rolling average basis, or, if a petition is granted, CO_2 emissions shall not exceed 470 kg per MW-h of net energy output (1,030 lbs/MW-h) on a 12-operating-month rolling average basis. [40 CFR 60.5520(a)-(c) and Table 2 of 40 CFR Part 60, Subpart TTTT]
i.	40 CFR Part 60, Subpart A (40 CFR 60.1 – 60.19)	General Provisions Table 3 of 40 CFR Part 60, Subpart TTTT shows which parts of the General Provisions in 40 CFR 63.1 through 63.19 do not apply. [40 CFR 60.5570 and Table 3 of 40 CFR Part 60, Subpart TTTT)
j.	40 CFR Part 63, Subpart YYYY (40 CFR 63.6080 – 63.6175) [In accordance with 40 CFR 63.6080, 63.6085 and 63.6090(a)(2), this emissions unit is a new stationary combustion turbine for which construction commenced after January 14, 2003 located at a major source of HAP emissions subject to the emission limitations/control measures specified in this section.]	See b)(2)h.
k.	40 CFR Part 63, Subpart A (40 CFR 63.1 – 63.16)	Table 7 of 40 CFR Part 63, Subpart YYYY shows which parts of the General Provisions in 40 CFR 63.1 through 63.16 apply.

(2) Additional Terms and Conditions

a. As part of the Best Available Control Technology (BACT) determination for NO_x, the permittee shall install and maintain dry low NO_x burners and an SCR system

on this emissions unit. Operation of these control systems shall reduce NO_x emissions to the limitations specified in b)(1)a.

b. As part of the BACT determination for CO and VOC, the permittee shall install and operate an oxidation catalyst and shall operate the emissions unit in accordance with good combustion practices as recommended by the manufacturer to ensure compliance with the CO and VOC limitations specified in b)(1)a.

c. As part of the BACT determination for visible PE, $PM/PM_{10}/PM_{2.5}$, SO_2 and H_2SO_4 emissions, the permittee shall burn only natural gas (as specified in b)(1)) in this emissions unit to ensure compliance with the $PM/PM_{10}/PM_{2.5}$, SO_2 and H_2SO_4 limitations specified in b)(1)a.

d. As part of the BACT determination for CO_2e, the permittee shall operate the emissions unit using good combustion practices as recommended by the manufacturer to ensure compliance with the CO_2e limitations specified in b)(1)a.

e. The permittee shall comply with the following requirements during periods of startup and shutdown.

	Emission Limitations During Startup and Shutdown (pounds per hour)[a]			
	Cold Startup	Warm Startup	Hot Startup	Shutdown
NO_x	42.67	42.67	31.67	32.17
CO	371.4	331.4	111.4	133.54
VOC	176.53	176.53	146.53	187.76

[a] Pound per hour emissions rates as presented are the maximum rates during any hour during the event from each unit.

Operating modes of the combined cycle combustion turbine are defined as follows:

Operating Mode	**Definition**
Cold Startup	When the combustion turbine has been shut down for more than 72 hours
Warm Startup	When the combustion turbine has been shut down for a period from 8 to 72 hours
Hot Startup	When the combustion turbine has been shut down for less than 8 hours
Steady-state	When the load is between the minimum environmental compliance load (MECL) and 100%. The duct burners

	may operate when the combustion turbine is in steady-state.
Shutdown	Begins when the first CEM data point out of compliance with either the CO or NO_x ppmvd emission limit that occurs after load is reduced below Steady-state in conjunction with the process of ceasing operation of the unit, and ends when fuel flow to the turbine ceases.

f. The permittee is subject to the requirements of OAC chapter 3745-103 and 40 CFR Parts 72 and 75 concerning acid rain, so the permittee shall ensure that any affected emissions unit complies with those requirements. Emissions exceeding any allowances that are lawfully held under Title IV of the Act, or any regulations adopted thereunder, are prohibited.

g. Only heat input to the combustion turbine should be included when determining whether or not 40 CFR Part 60, Subpart KKKK is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

h. The continuous emission monitoring system consists of all the equipment used to acquire data to provide a record of emissions and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data recording/processing hardware and software.

i. Each continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system) shall be certified to meet the requirements of 40 CFR Part 60 and 40 CFR Part 75, Appendix B and Performance Specifications 2, 3 and 6. At least 45 days before commencing certification testing of the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system), the permittee shall develop and maintain a written quality assurance/quality control plan designed to ensure continuous valid and representative readings of NO_x and CO_2 or O_2 emissions from the continuous monitor(s), in units of the applicable standard(s). The fuel flow monitor/meter shall be maintained as required in 40 CFR Part 75, Appendix D. Except as allowed below, the plan shall follow the requirements of 40 CFR Part 60, Appendix F and 40 CFR Part 75, Appendix B. The quality assurance/quality control plan and a logbook dedicated to the continuous NO_x monitoring system must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct relative accuracy test audits for the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system) in accordance with the frequencies required pursuant to 40 CFR Part 60 and 40 CFR Part 75; or may follow relative accuracy test audit frequency requirements for monitoring systems subject to 40 CFR Part 75, Appendix B, in lieu of frequencies required in 40 CFR Part 60. In either case, results shall be recorded and reported in units of the applicable standard(s) in accordance with 40 CFR Part 60.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits pursuant to 40 CFR Part 60, and linearity checks pursuant to 40 CFR Part 75; however, linearity checks completed pursuant to 40 CFR Part 75, Appendix B, may be substituted for the quarterly cylinder gas or relative accuracy audits required per 40 CFR Part 60.

j. Each continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system) shall be certified to meet the requirements of 40 CFR Part 60, Appendix B, Performance Specifications 3, 4 or 4a and 6. At least 45 days before commencing certification testing of the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system), the permittee shall develop and maintain a written quality assurance/quality control plan designed to ensure continuous valid and representative readings of CO and CO_2 or O_2 emissions from the continuous monitor(s), in units of the applicable standard(s). The fuel flow monitor/meter shall be maintained as required in 40 CFR Part 75, Appendix D. Except as allowed below, the plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook dedicated to the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system) must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct relative accuracy test audits for the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system) in accordance with the frequencies required for monitoring systems subject to 40 CFR 60, or may follow relative accuracy test audit frequency requirements for monitoring systems subject to 40 CFR Part 75, Appendix B. In either case, results shall be recorded and reported in units of the applicable standard(s) in accordance with 40 CFR Part 60.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits as required in 40 CFR Part 60; however, the quarterly cylinder gas audit and relative accuracy audit frequency requirements may be adjusted to coincide with linearity checks completed for continuous emissions monitoring systems subject to 40 CFR Part 75, Appendix B requirements.

k. See 40 CFR Part 60, Subpart TTTT (40 CFR 60.5508 – 60.5580).

c) Operational Restrictions

(1) The permittee shall burn only pipeline quality natural gas with a maximum sulfur content not to exceed 0.50 grain/100 scf in this emissions unit.

(2) Except during periods of startup, the SCR system for this emissions unit shall be in operation at all times, including during the shutdown of the unit.

(3) In accordance with good engineering practices, the SCR unit shall be operated and maintained in accordance with the manufacturer's recommendations, with any modifications deemed necessary by the permittee. The permittee shall maintain on site a copy of the operation and maintenance manual, as provided by the manufacturer.

(4) See 40 CFR Part 60, Subpart KKKK (40 CFR 60.4300 – 60.4420).

(5) See 40 CFR Part 60, Subpart TTTT (40 CFR 60.5508 – 60.5580).

(6) See 40 CFR Part 63, Subpart YYYY (40 CFR 63.6080 – 63.6175).

d) Monitoring and/or Recordkeeping Requirements

(1) For each day during which the permittee burns a fuel other than pipeline quality natural gas with a maximum sulfur content of 0.5 grain/100 scf, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

(2) The permittee shall maintain monthly records of the following information for this emissions unit:

a. the hours of operation of the combustion turbine in each operating mode;

b. the hours of operation of the duct burners;

c. the amount of gaseous fuel consumed in this emissions unit, in MMscf;

d. the heat content of the gaseous fuel combusted in this emissions unit, in MMBtu/MMscf;

e. the sulfur content of the gaseous fuel combusted in this emissions unit, in gr/dscf;

f. the total NO_x emissions, in pounds, including startup/shutdown emissions, as recorded in d)(4)b.;

g. the total CO emissions, in pounds, including startup/shutdown emissions, as recorded in d)(7)b.;

h. the total VOC emissions, in pounds, including startup/shutdown emissions, calculated by multiplying the VOC emission factor of 0.00142 lb/MMBtu (w/o duct burner firing) or 0.00277 lb/MMBtu (w/ duct burner firing), or after testing has been completed, the results of the most recent stack test, by the amount of gaseous fuel consumed during steady-state operation, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d plus the hours of operation of the combustion turbine in each startup and shutdown operating mode as recorded in d(2)a. multiplied by the pounds per hour emission limitations for the corresponding modes of operation in b)(2)e;

i. the total $PE/PM_{10}/PM_{2.5}$ emissions, in pounds, including startup/shutdown emissions, calculated by multiplying the emission factor of 0.00444 lb/MMBtu (w/o duct burner firing) or 0.005 lb/MMBtu (w/ duct burner firing) or after testing has been completed, the results of the most recent stack test, by the amount of gaseous fuel consumed, including periods of startup/shutdown, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

j. the total SO_2 emissions, in pounds, including startup/shutdown emissions, for this emissions unit, calculated by multiplying the emission factor of 0.0021 lb/MMBtu,

or after testing has been completed, or the results of the most recent stack test, by the amount of gaseous fuel consumed, including periods of startup/shutdown, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

k. the total H_2SO_4 emissions, in pounds, including startup/shutdown emissions, calculated by multiplying the emission factor of 0.0022 lb/MMBtu, or after testing has been completed, the results of the most recent stack test, by the amount of gaseous fuel consumed, including periods of startup/shutdown, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

l. the total CO_2e emissions, in pounds, including startup/shutdown emissions, calculated by multiplying the CO_2e emission factor of 117.1 lbs/MMBtu by the amount of gaseous fuel consumed, including periods of startup/shutdown, as recorded in d)(2)c and the heat content of the natural gas consumed, as recorded in d)(2)d;

m. the rolling, 12-month summation of the NO_x, in tons, including start-up/shutdown emissions, calculated by adding the total NO_x emissions for the present month as recorded in d)(2)f, plus the total NO_x emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

n. The rolling, 12-month summation of the CO, in tons, including startup/shutdown emissions, calculated by adding the total CO emissions for the present month as recorded in d)(2)g, plus the total CO emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

o. The rolling, 12-month summation of the VOC, in tons, including startup/shutdown emissions, calculated by adding the total VOC emissions for the present month as recorded in d)(2)h, plus the total VOC emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

p. The rolling, 12-month summation of the PE/PM_{10}/$PM_{2.5}$, in tons, including startup/shutdown emissions, calculated by adding the total PE/PM_{10}/$PM_{2.5}$ emissions for the present month as recorded in d)(2)i, plus the total PE/PM_{10}/$PM_{2.5}$ emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

q. The rolling, 12-month summation of the SO_2 emissions, in tons, including startup/shutdown emissions, calculated by adding the total SO_2 emissions for the present month as recorded in d)(2)j, plus the total SO_2 emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds;

r. The rolling, 12-month summation of the H_2SO_4, in tons, including startup/shutdown emissions, calculated by adding the total H_2SO_4 emissions for the present month as recorded in d)(2)k, plus the total H_2SO_4 emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds; and

s. The rolling, 12-month summation of the CO_2e, in tons, including startup/shutdown emissions, calculated by adding the total CO_2e emissions for the present month

as recorded in d)(2)l, plus the total CO_2e emissions for the previous 11 months, and multiplying by 1 ton/2,000 pounds.

(3) Prior to the installation of the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system), the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specifications 2 and 3. The Ohio EPA, Central Office shall approve the proposed sampling site and certify that the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system) meets the requirements of Performance Specifications 2 and 3 and the accuracy requirements of Performance Specification 6.

Following installation, the permittee shall document that the fuel flow monitor/meter meets 40 CFR Part 75 certification requirements prior to the performance specification test, and shall demonstrate how the pound per hour emissions of NO_x is being calculated stoichiometrically. The U.S. EPA shall certify that the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system) meets the requirements under 40 CFR Part 75, which may be approved through the recommendation for certification by Ohio EPA to U.S. EPA. Once received, the letter(s)/document(s) of certification under 40 CFR Part 60 and certification or recommendation for certification under 40 CFR Part 75 shall be maintain on site and made available to the Director (the appropriate Ohio EPA District Office or local air agency) upon request.

(4) The permittee shall install, operate and maintain equipment to continuously monitor and record NO_x and CO_2 or O_2 emissions from this emissions unit in units of the applicable standard(s). The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60 and/or Part 75.

The permittee shall maintain records of all data obtained by the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system) including, but not limited to:

a. emissions of NO_x in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. emissions of NO_x in pounds per hour and in units of the applicable standard(s) in the appropriate averaging period;

c. the percent CO_2 or O_2 with each cycle time of the analyzer, with no resolution less than one data point per minute required;

d. results of quarterly cylinder gas audits or linearity checks;

e. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

f. results of required relative accuracy test audit(s), including results in units of the applicable standard(s);

g. hours of operation of the emissions unit, continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system), and control equipment;

h. the date, time, and hours of operation of the emissions unit without the control equipment and/or the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system);

i. the date, time, and hours of operation of the emissions unit during any malfunction of the control equipment and/or the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system); as well as,

j. the reason (if known) and the corrective actions taken (if any) for each such event in d)(4)h and d)(4)i.

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(5) The permittee may operate and maintain equipment to continuously monitor and record the fuel flow rate in order to stoichiometrically calculate emissions of NO_x, in pounds per hour, as an alternative to conducting Performance Specification 6. Fuel heat content values for each fuel burned, as applied in the stoichiometric calculations, shall also be recorded. The permittee shall maintain records of data obtained by the fuel flow monitor/meter, including the dates and results of each calibration check and the magnitude of calibration adjustments; periods of downtime and malfunction of the fuel flow monitor/meter; as well as, the reason (if known) and the corrective actions taken (if any) for each such event.

(6) Prior to the installation of the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system), the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specifications 3 and 4 or 4a (as appropriate). The Ohio EPA, Central Office shall approve the proposed sampling site and certify that the continuous CO monitoring system meets the requirements of Performance Specifications 3 and 4 or 4a and the accuracy requirements of Performance Specification 6.

Following installation, the permittee shall document that the fuel flow monitor/meter meets 40 CFR Part 75 certification requirements prior to the performance specification test, and shall demonstrate how the pound per hour emissions of CO is being calculated stoichiometrically. Once received, the letter(s)/document(s) of certification shall be maintained on site and shall be made available to the Director (the appropriate Ohio EPA District Office or local air agency) upon request.

(7) The permittee shall operate and maintain equipment to continuously monitor and record CO and CO_2 or O_2 emissions from this emissions unit in units of the applicable standard(s). The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

The permittee shall maintain records of all data obtained by the continuous CO monitoring system including, but not limited to:

a. emissions of CO in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. emissions of CO in pounds per month;

c. the percent CO_2 or O_2 with each cycle time of the analyzer, with no resolution less than one data point per minute required;

d. results of quarterly cylinder gas audits;

e. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

f. results of required relative accuracy test audit(s), including results in units of the applicable standard(s);

g. hours of operation of the emissions unit, continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system), and control equipment;

h. the date, time, and hours of operation of the emissions unit without the control equipment and/or the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system);

i. the date, time, and hours of operation of the emissions unit during any malfunction of the control equipment and/or the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system); as well as,

j. the reason (if known) and the corrective actions taken (if any) for each such event in d)(7)h and d)(7)i.

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(8) The permittee may operate and maintain equipment to continuously monitor and record the fuel flow rate in order to stoichiometrically calculate emissions of CO in pounds per hour, as an alternative to conducting Performance Specification 6. Fuel heat content values for each fuel burned, as applied in the stoichiometric calculations, shall also be recorded. The permittee shall maintain records of data obtained by the fuel flow monitor/meter, including the dates and results of each calibration check and the magnitude of calibration adjustments; periods of downtime and malfunction of the fuel flow monitor/meter; as well as, the reason (if known) and the corrective actions taken (if any) for each such event.

(9) The permittee shall collect, record, and maintain measurements, data, records, and reports required per 40 CFR Part 75; and shall submit certification, recertification,

notifications, applications, monitoring plans, petitions for alternative monitoring systems, electronic quarterly reports, and any other pertinent record and/or report to the Administrator (U.S. EPA), as required by 40 CFR Part 75.

(10) The permittee shall operate and maintain equipment to continuously monitor and record the actual fuel flow to this emissions unit when the emissions unit is in operation. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 75. If the fuel flow monitoring and/or recording equipment is (are) not in service when the emissions unit is in operation, the permittee shall comply with the approved data substitution protocol.

Fuel flow data that is substituted in accordance with 40 CFR Part 75, Appendix D, is not to be used when verifying compliance with the hourly NO_x and CO pounds per hour emission limits. Hours in which fuel flow is substituted should be included as NO_x and CO monitoring system downtime.

(11) The permittee shall monitor the sulfur content and gross caloric value of the fuel being fired in the combustion turbine and duct burners, representative fuel sampling shall be conducted which shows that the sulfur content of the fuel does not exceed 1.5E-03 lb SO_2/MMBtu heat input. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to 40 CFR Part 75 is required.

(12) The permittee shall determine the hourly heat input rate to the combustion turbine and duct burner, in MMBtu, from the fuel flow rate and gross calorific value as determined in d)(8). The heat input rate shall be calculated in accordance with the procedures in section 5 of 40 CFR Part 75, Appendix F.

(13) See 40 CFR Part 60, Subpart KKKK (40 CFR 60.4300 – 60.4420).

(14) See 40 CFR Part 60, Subpart TTTT (40 CFR 60.5508 – 60.5580).

(15) See 40 CFR Part 63, Subpart YYYY (40 CFR 63.6080 – 63.6175).

e) Reporting Requirements

(1) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

(2) The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than pipeline quality natural gas with a maximum sulfur content of 0.5 grain/100 standard cubic feet was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurred.

(3) The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. all exceedances of the NO_x, CO, and/or VOC start-up/shutdown limitations; and

b. all exceedances of the rolling, 12-month NO_x, CO, VOC, PE/PM_{10}/$PM_{2.5}$, SO_2 and/or H_2SO_4 emission limitations.

These quarterly reports shall be submitted in accordance with the reporting requirements of the Standard Terms and Conditions of this permit.

(4) The permittee shall comply with the following quarterly reporting requirements for the emissions unit and its continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system):

a. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency, documenting all instances of NO_x emissions in excess of any applicable limit specified in this permit, 40 CFR Part 60, OAC Chapters 3745-14 and 3745-23, and any other applicable rules or regulations. The report shall document the date, commencement and completion times, duration, and magnitude of each exceedance, as well as the reason (if known) and the corrective actions taken (if any) for each exceedance. Excess emissions shall be reported in units of the applicable standard(s).

b. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR Parts 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency, documenting all instances of continuous CO_2 or O_2 monitoring system downtime and malfunction while the emissions unit was in operation.

c. These quarterly reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous NO_x and CO_2 or O_2 and other associated monitors;

iii. a description of any change in the equipment that comprises the continuous emission monitoring system (CEMS), including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the excess emissions report (EER)*, i.e., a summary of any exceedances during the calendar quarter, as specified above;

v. the total NO_x emissions for the calendar quarter (tons);

vi. the total operating time (hours) of the emissions unit;

vii. the total operating time of the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system) while the emissions unit was in operation;

viii. results and date of quarterly cylinder gas audits or linearity checks;

ix. unless previously submitted, results and date of the relative accuracy test audit(s), including results in units of the applicable standard(s), (during appropriate quarter(s));

x. unless previously submitted, the results of any relative accuracy test audit showing the continuous NO_x and CO_2 or O_2 monitor out-of-control and the compliant results following any corrective actions;

xi. the date, time, and duration of any/each malfunction** of the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system), emissions unit, and/or control equipment;

xii. the date, time, and duration of any downtime** of the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system) and/or control equipment while the emissions unit was in operation; and

xiii. the reason (if known) and the corrective actions taken (if any) for each event in e)(4)c.xi. and e)(4)c.xii.

Each report shall address the operations conducted and data obtained during the previous calendar quarter.

* where no excess emissions have occurred or the continuous monitoring system(s) has/have not been inoperative, repaired, or adjusted during the calendar quarter, such information shall be documented in the EER quarterly report

** each downtime and malfunction event shall be reported regardless if there is an exceedance of any applicable limit

(5) If using the fuel flow rate to stoichiometrically calculate the pound per hour emissions of NO_x in place of Performance Specification 6 requirements, the permittee shall submit quarterly reports, to the appropriate Ohio EPA District Office or local air agency, that document the date, time, and duration of each malfunction and/or period of downtime of the continuous fuel flow monitoring system, while the emissions unit was in operation, and the reason (if known) and the corrective actions taken (if any) for each such event. If there was no downtime or malfunction of the continuous fuel flow monitoring system during any calendar quarter, the report shall be submitted so stating it. These quarterly reports shall be submitted by January 30, April 30, July 30, and October 30 of each year.

(6) The permittee shall comply with the following quarterly reporting requirements for the emissions unit and its continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system):

a. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA

District Office or local air agency, documenting all instances of CO emissions in excess of any applicable limit specified in this permit, 40 CFR Part 60, OAC Chapter 3745-21, and any other applicable rules or regulations. The report shall document the date, commencement and completion times, duration, and magnitude of each exceedance, as well as, the reason (if known) and the corrective actions taken (if any) for each exceedance. Excess emissions shall be reported in units of the applicable standard(s).

b. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR Parts 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency, documenting all instances of continuous CO_2 or O_2 monitoring system downtime and malfunction while the emissions unit was in operation.

c. These quarterly reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous CO and CO_2 or O_2 and other associated monitors;

iii. a description of any change in the equipment that comprises the continuous emission monitoring system (CEMS), including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the excess emissions report (EER)*, i.e., a summary of any exceedances during the calendar quarter, as specified above;

v. the total CO emissions for the calendar quarter (tons);

vi. the total operating time (hours) of the emissions unit;

vii. the total operating time of the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system) while the emissions unit was in operation;

viii. results and dates of quarterly cylinder gas audits;

ix. unless previously submitted, results and dates of the relative accuracy test audit(s), including results in units of the applicable standard(s), (during appropriate quarter(s));

x. unless previously submitted, the results of any relative accuracy test audit showing the continuous CO and CO_2 or O_2 monitor out-of-control and the compliant results following any corrective actions;

xi. the date, time, and duration of any/each malfunction** of the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system), and/or emissions unit;

xii. the date, time, and duration of any downtime** of the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system) while the emissions unit was in operation; and

xiii. the reason (if known) and the corrective actions taken (if any) for each event in e)(6)c.xi. and e)(6)c.xii.

Each report shall address the operations conducted and data obtained during the previous calendar quarter.

*where no excess emissions have occurred or the continuous monitoring system(s) has/have not been inoperative, repaired, or adjusted during the calendar quarter, such information shall be documented in the EER quarterly report

**each downtime and malfunction event shall be reported regardless of whether there is an exceedance of any applicable limit

(7) If using the fuel flow rate to stoichiometrically calculate the pound per hour emissions of CO, in place of Performance Specification 6 requirements, the permittee shall submit quarterly reports, to the appropriate Ohio EPA District Office or local air agency, that document the date, time, and duration of each malfunction and/or period of downtime of the continuous fuel flow monitoring system, while the emissions unit was in operation, and the reason (if known) and the corrective actions taken (if any) for each such event. If there was no downtime or malfunction of the continuous fuel flow monitoring system during any calendar quarter, the report shall be submitted so stating it. These quarterly reports shall be submitted by January 30, April 30, July 30, and October 30 of each year.

(8) See 40 CFR Part 60, Subpart KKKK (40 CFR 60.4300 – 60.4420).

(9) See 40 CFR Part 60, Subpart TTTT (40 CFR 60.5508 – 60.5580).

(10) See 40 CFR Part 63, Subpart YYYY (40 CFR 63.6080 – 63.6175).

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods for this emissions unit:

a. Emission Limitations:

NO_x emissions without duct burner firing shall not exceed 2.0 ppmvd at 15% O_2 based on a 24-hour block averaging period and 26.7 pounds per hour, excluding periods of startup and shutdown.

NO_x emissions with duct burner firing shall not exceed 2.0 ppmvd at 15% O_2 based on a 24-hour block averaging period and 28 pounds per hour, excluding periods of startup and shutdown.

NO_x emissions from new combustion turbines firing natural gas with heat input capacities greater than 850 MMBtu/hr shall not exceed 15 ppm at 15% O_2 calculated on a 30-day rolling average or 54 ng/J of useful output (0.43 lb/MWh).

Applicable Compliance Method:

Initial compliance with the allowable outlet concentration and the pounds per hour emission limitations shall be demonstrated through emission testing performed as described in f)(4).

Ongoing compliance with the short-term NO_x emission limitations shall be demonstrated through the data collected as required in the monitoring and record keeping section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the testing and recertification requirements of 40 CFR Part 60 and 40 CFR Part 75.

Ongoing compliance with the CO_2 or O_2 monitoring requirements contained in this permit, 40 CFR Parts 60 and 75, and any other applicable standard(s) shall be demonstrated through the data collected as required in the monitoring and record keeping section of this permit; and demonstration of compliance with the quality assurance/quality control plan, which shall meet all of the testing and recertification requirements of 40 CFR Part 60 and 40 CFR Part 75.

b. Emission Limitations:

CO emissions without duct burner firing shall not exceed 2.0 ppmvd at 15% O_2 based on a 24-hour block averaging period and 16.3 pounds per hour, excluding periods of startup and shutdown.

CO emissions with duct burner firing shall not exceed 2.0 ppmvd at 15% O_2 based on a 24-hour block averaging period and 17.1 pounds per hour, excluding periods of startup and shutdown.

Applicable Compliance Method:

Initial compliance with the allowable outlet concentration and the pounds per hour emission limitations shall be demonstrated through emission testing performed as described in f)(4).

Ongoing compliance with the short-term CO emission limitations shall be demonstrated through the data collected as required in the monitoring and record keeping section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60.

Ongoing compliance with the CO_2 or O_2 monitoring requirements contained in this permit, 40 CFR Parts 60 and 75, and any other applicable standard(s) shall be demonstrated through the data collected as required in the monitoring and record keeping section of this permit; and demonstration of compliance with the quality assurance/quality control plan, which shall meet all of the testing and recertification requirements of 40 CFR Part 60 and 40 CFR Part 75.

c. Emission Limitations:

VOC emissions without duct burner firing shall not exceed 1.0 ppmvd at 15% O_2 and 4.7 pounds per hour, excluding periods of startup and shutdown.

VOC emissions with duct burner firing shall not exceed 2.0 ppmvd at 15% O_2 and 9.8 pounds per hour, excluding periods of startup and shutdown.

Applicable Compliance Method:

Compliance with the short-term VOC emission limitations shall be demonstrated by the emission testing requirements specified in f)(4).

d. Emission Limitations:

PE/PM_{10}/$PM_{2.5}$ emissions without duct burner firing shall not exceed 0.00444 lb/MMBtu and 14.1 pounds per hour.

PE/PM_{10}/$PM_{2.5}$ emissions with duct burner firing shall not exceed 0.005 lb/MMBtu and 17.7 pounds per hour.

Applicable Compliance Method:

Compliance with the short-term PE/PM_{10}/$PM_{2.5}$ emission limitations shall be demonstrated by the emission testing requirements specified in f)(4).

e. Emission Limitations:

SO_2 emissions without duct burner firing shall not exceed 0.0021 pound/MMBtu and 6.92 pounds per hour.

SO_2 emissions with duct burner firing shall not exceed 0.0021 lb/MMBtu and 7.22 pounds per hour.

SO_2 emissions from the turbine must not exceed 0.90 lb/MWh of gross output, or, fuels burned in the turbine must not contain sulfur in concentrations which would result in potential sulfur emissions in excess of 0.060 lb SO_2 MMBtu heat input.

Applicable Compliance Methods:

Compliance with the short-term SO_2 emission limitations shall be demonstrated by the monitoring requirements specified in d)(11) and the emission testing requirements specified in f)(4).

f. Emission Limitations:

H_2SO_4 emissions without duct burner firing shall not exceed 0.0022 lb/MMBtu and 7.41 pounds per hour.

H_2SO_4 emissions with duct burner firing shall not exceed 0.0022 lb/MMBtu and 7.74 pounds per hour.

Applicable Compliance Method:

Compliance with the short-term H_2SO_4 emission limitations shall be demonstrated by the emission testing requirements specified in f)(4).

g. Emission Limitation:

Visible PE from the stack serving this emissions unit shall not exceed 10% opacity as a 6-minute average.

Applicable Compliance Method:

Compliance with the visible PE limitation shall be demonstrated by the emission testing requirements specified in f)(4).

h. Emission Limitations:

Emissions shall not exceed:

124.0 tons of NO_x per rolling, 12-month period, including start-up and shutdown emissions;

109.1 tons of CO emissions per rolling, 12-month period, including start-up and shutdown emissions;

84.7 tons of VOC emissions per rolling, 12-month period, including start-up and shutdown emissions;

77.5 tons of PE/PM_{10}/$PM_{2.5}$ emissions per rolling, 12-month period;

29.57 tons of SO_2 emissions per rolling, 12-month period;

31.69 tons of H_2SO_4 emissions per rolling, 12-month period; and

2,342,643 tons of CO_2e emissions per rolling, 12-month period.

Applicable Compliance Method:

Compliance with the rolling, 12-month emission limitations shall be demonstrated by the record keeping requirements specified in d)(2).

i. Emission Limitation:

CO_2e emissions shall not exceed 976.0 lbs/MW-hr gross energy output (at full load ISO conditions when firing natural gas without duct burner firing).

Applicable Compliance Method:

Since more than 99% of the CO_2e emissions result from CO_2 emissions, compliance with the 976.0 lbs/MW-hr gross energy output limitation will be assumed if the CO_2 emissions determined during the emission testing conducted per f)(4) are determined to not exceed 976.0 lbs/MW-hr gross energy output.

j. Emission Limitation:

CO_2 emissions shall not exceed 450 kg per MW-hr of gross energy output (1,000 lbs/MW-hr) on a 12-operating-month rolling average basis, or, if a petition is granted, CO_2 emissions shall not exceed 470 kg per MW-hr of net energy output (1,030 lbs/MW-hr) on a 12-operating-month rolling average basis.

Applicable Compliance Method:

Compliance with the output based emission limitation shall be demonstrated by the procedures specified in 40 CFR 60.5535 and 60.5540.

k. Emission Limitation:

The permittee shall burn only pipeline quality natural gas with a maximum sulfur content not to exceed 0.5 grain per 100 scf in this emissions unit.

Applicable Compliance Method:

Compliance with the fuel sulfur content limitation shall be demonstrated by the testing requirements specified in f)(4) and the record keeping requirements specified in d)(11).

l. Emission Limitations:

NO_x emissions during startup and shutdown shall not exceed 42.67 pounds per hour during cold startup, 42.67 pounds per hour during warm startup, 31.67 pounds per hour during hot startup and 32.17 pounds per hour during shutdown.

CO emissions during startup and shutdown shall not exceed 371.4 pounds per hour during cold startup, 331.4 pounds per hour during warm startup, 111.4 pounds per hour during hot startup and 133.54 pounds per hour during shutdown.

VOC emissions during startup and shutdown shall not exceed 176.53 pounds per hour during cold startup, 176.53 pounds per hour during warm startup, 146.53 pounds per hour during hot startup and 187.76 pounds per hour during shutdown.

Applicable Compliance Method:

These emission limitations are based on manufacturer's data.

Compliance with the CO and NO_x pounds per hour startup and shutdown emission limitations shall be demonstrated using the continuous emission monitoring system based on a 1-hour block average.

Compliance with the VOC pounds per hour startup and shutdown emission limitations shall be demonstrated through the record keeping requirements specified in d)(2) of this permit.

(2) Within 60 days of achieving the maximum production rate at which the emissions unit(s) will be operated, but not later than 180 days after initial startup, the permittee shall conduct certification tests of the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system), in units of the applicable standard(s), to demonstrate compliance with 40 CFR Part 60, Appendix B, Performance Specifications 2 and 3; Performance Specification 6 relative accuracy requirements; ORC section 3704.03(I); and 40 CFR Part 75.

The permittee shall certify that the fuel flow monitor/meter meets 40 CFR Part 75 certification requirements prior to the performance specification test and shall demonstrate how the pound per hour emissions of NO_x and CO_2 or O_2 will be calculated stoichiometrically from the fuel flow rate.

Personnel from the Ohio EPA Central Office and the appropriate Ohio EPA District Office or local air agency shall be notified 45 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. Two copies of the test results shall be submitted to Ohio EPA, one copy to the appropriate Ohio EPA District Office or local air agency and one copy to Ohio EPA Central Office, and pursuant to OAC rule 3745-15-04, within 30 days after the test is completed.

Certification, or recommendation for certification by Ohio EPA to U.S. EPA, of the continuous NO_x monitoring system (including the associated continuous CO_2 or O_2 monitoring system) shall be granted upon determination by the Ohio EPA, Central Office that the system meets the requirements of 40 CFR Part 60, Appendix B, Performance Specifications 2 and 3; Performance Specification 6 relative accuracy requirements; ORC section 3704.03(I); and 40 CFR Part 75.

(3) Within 60 days of achieving the maximum production rate at which the emissions unit(s) will be operated, but not later than 180 days after initial startup, the permittee shall conduct certification tests of the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system) in units of the applicable standard(s), to demonstrate compliance with 40 CFR Part 60, Appendix B, Performance Specifications 3 and 4 or 4a (as appropriate) and 6; and ORC section 3704.03(I).

Personnel from the Ohio EPA Central Office and the appropriate Ohio EPA District Office or local air agency shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests.

Two copies of the test results shall be submitted to Ohio EPA, one copy to the appropriate Ohio EPA District Office or local air agency and one copy to Ohio EPA Central Office, and pursuant to OAC rule 3745-15-04, within 30 days after the test is completed.

Certification of the continuous CO monitoring system (including the associated continuous CO_2 or O_2 monitoring system) shall be granted upon determination by the Ohio EPA Central Office that the system meets the requirements of 40 CFR Part 60, Appendix B, Performance Specifications 3 and 4 or 4a (as appropriate) and 6 and ORC section 3704.03(I).

(4) The permittee shall conduct, or have conducted, emission testing for this emissions unit in accordance with OAC rules 3745-31-10 through 3745-31-20, 40 CFR 60.8, 60.4405 and 60.4415 and the following requirements:

a. The emission testing shall be conducted within 60 days after achieving the maximum production rate at which the modified facility will be operated, but not later than 180 days after initial startup of the modified unit. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test) using one of the three methodologies in 40 CFR 60.4415(a).

b. The emission testing shall be conducted to demonstrate initial compliance with the NO_x and CO outlet concentrations, the lb/hr emission limitations for NO_x, CO, VOC, and PE and $PM_{10}/PM_{2.5}$, the visible PE limit and the fuel sulfur content after modification.

c. The following test method(s) shall be employed to demonstrate compliance with the above emission limitations:

NO_x	Method 7E or 20 of 40 CFR Part 60, Appendix A
CO	Methods 1 through 4 and 10 of 40 CFR Part 60, Appendix A
VOC	Methods 1 through 4, 18 and 25A of 40 CFR Part 60, Appendix A
PE	Methods 1 through 5 of 40 CFR Part 60, Appendix A
$PM_{10}/PM_{2.5}$	Methods 1 through 4 of 40 CFR Part 60, Appendix A and Methods 201/201A and 202 as set forth in 40 CFR Part 51, Appendix M
CO_2	Methods 1 through 4 of 40 CFR Part 60, Appendix A, mass balance calculations using ASTM D1945-03 (Standard Test Method for Analysis of Natural Gas by Gas Chromatography) and/or ASTM D1826-94 (Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter).
VEs	Method 9 of 40 CFR Part 60, Appendix A
SO_2 (fuel sulfur content)	40 CFR 60.4415(a)

H_2SO_4	Methods 1 through 4 and 8 of 40 CFR Part 60, Appendix A

Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA Southeast District Office.

d. The test(s) shall be conducted under those representative conditions that challenge to the fullest extent possible a facility's ability to meet the applicable emissions limits and/or control requirements, unless otherwise specified or approved by the Ohio EPA Southeast District Office. Although this generally consists of operating the emissions unit at its maximum material input/production rates and results in the highest emission rate of the tested pollutant, there may be circumstances where a lower emissions loading is deemed the most challenging control scenario. Failure to test under these conditions is justification for not accepting the test results as a demonstration of compliance.

e. Not later than 30 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the Ohio EPA Southeast District Office. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Ohio EPA Southeast District Office's refusal to accept the results of the emission test(s).

f. Personnel from the Ohio EPA Southeast District Office shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

g. A comprehensive written report on the results of the emissions test(s) shall be signed by the person or persons responsible for the tests and submitted to the Ohio EPA Southeast District Office within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Ohio EPA Southeast District Office.

g) Miscellaneous Requirements

(1) None.