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AIR QUALITY PROGRAM

# United States Steel Corporation

## Mon Valley Works - Clairton Plant

## Installation Permit Application
## Cogeneration Project

June 2019

Trinity Consultants

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Ms. JoAnn Truchan, P.E.
Allegheny County Health Department
Air Quality Program
301 39th Street, Building #7
Pittsburgh, PA 15201

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ALLEGHENY COUNTY HEALTH DEPT.
AIR QUALITY PROGRAM

RE: United States Steel Corporation
Mon Valley Works - Clairton Plant (TVOP No. 0052)
Installation Permit Application – Cogeneration Project Update

Dear Ms. Truchan,

United States Steel Corporation (U. S. Steel) operates the Clairton Plant in Clairton, Allegheny County. This facility is currently authorized via Title V Operating Permit (TVOP) No. 0052. On May 2, 2019, U.S. Steel submitted an Installation Permit Application for a project to install a new cogeneration process at the Clairton Plant. U. S. Steel has continued their design development of the Cogen Project and is providing ACHD with an updated permit application to reflect the changes from that process. To avoid confusion and ensure that the Department reviews the most accurate and up-to-date information, U. S. Steel is hereby submitting a complete revised Installation Permit Application which should replace the previous application in its entirety. We respectfully request that the previous application be returned at your earliest convenience.

It should be noted that the overarching intent and strategy of the project as originally communicated remains intact. The updates provided in the enclosed permit application will meet or exceed the emissions reductions included in the prior permit application. The design refinement of the project has demonstrated that to meet the project's targets, two "trains" supported by emergency boilers will better support our goals than the initial three "trains" reflected in the original renderings.

While there are other minor changes in the scope of the project, the primary design will still include the installation of the state-of-the-art, multi-pollutant control technologies that were previously specified. As noted before, this project is part of the overarching Mon Valley Works modernization and emissions reduction strategy. Employing this state of the art technology will strengthen our ability to improve air quality and reduce our carbon footprint. As a result of the proposed project, there will be no net increase in emissions of $PM_{2.5}$ and $PM_{10}$, and a significant net decrease in emissions of $SO_2$, $NO_X$, and CO. The project emissions increase will be below thresholds for triggering a major modification for all regulated New Source Review (NSR) pollutants. The overall project will result in a net decrease in emissions of air toxics and will not require further evaluation under the Department's Air Toxics Policy.

Enclosed is a complete permit application package which includes the following elements:

- Application Report;
    - Project Description
    - Emissions Calculation Methodology
    - Regulatory Applicability
    - New Source Review (NSR) Analysis
- Air Permit Application Forms;
- Compliance Review Form;
- Detailed Emission Calculations;

- Best Available Control Technology (BACT) Analysis;
- Process Flow Diagram;
- Site Map;
- Air Toxics Policy Review; and
- Application Fee.

If you have any questions on this application or need any additional information, please contact me by phone at (412) 433-5904 or by email at CWHardin@uss.com .

Sincerely,

Christopher W. Hardin
Environmental Affairs
United States Steel Corporation

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ALLEGHENY COUNTY HEALTH DEPT.
AIR QUALITY PROGRAM

# PROJECT REPORT

## United States Steel Corporation
## Mon Valley Works - Clairton Plant

**Installation Permit Application**

**Cogeneration Project**

***Updated Application***


**Prepared by:**

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June 2019

Trinity Consultants

*EHS solutions delivered uncommonly well*

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# 1. EXECUTIVE SUMMARY

United States Steel Corporation (U. S. Steel) operates the Mon Valley Works, an integrated coke and steel-making operation located in Allegheny County, Pennsylvania. The complex is comprised of three (3) main plants: the Irvin Plant, the Clairton Plant, and the Edgar Thomson Plant. The proposed project will involve the installation of new sources of air emissions at the Clairton Plant. The Clairton Plant is located in the City of Clairton, Pennsylvania and is currently authorized by Title V Operating Permit No. 0052.

The Clairton Plant is an existing major source of nitrogen oxides ($NO_X$), carbon monoxide (CO), sulfur dioxide ($SO_2$), particulate matter (PM), particulate matter less than 10 microns in diameter ($PM_{10}$), particulate matter less than 2.5 microns in diameter ($PM_{2.5}$), hazardous air pollutants (HAPs), and volatile organic compounds (VOCs), as defined in §2101.20 of Article XXI. Allegheny County, or portions of it, is currently designated as nonattainment for $SO_2$ and $PM_{2.5}$.

U. S. Steel is proposing to install a new cogeneration operation (Cogeneration Project) at the Clairton Plant. Because the new project will provide steam in the future, some existing boilers at the Clairton Plant will be permanently shut down, while others will only be needed on a limited basis. The design of the project will include the installation of state-of-the-art control technologies for multiple pollutants. This project is part of the overarching Mon Valley Works modernization and emissions reduction strategy. The addition of the Cogeneration Project will strengthen U. S. Steel's ability to improve air quality and reduce the carbon footprint of the Mon Valley Works. As a result of the proposed project, there will be no net increase in emissions of $PM_{2.5}$ and $PM_{10}$, and a significant net decrease in emissions of $SO_2$, $NO_X$, and CO.[1] The project emissions increase will be below the Significant Emission Rate (SER) thresholds for triggering a major modification for all regulated New Source Review (NSR) pollutants.

This application is for an Installation Permit requesting authorization to construct the proposed project. The required application elements are organized as follows:

- Section 2: Facility Description
- Section 3: Emission Calculations
- Section 4: Regulatory Applicability Analysis
- Section 5: New Source Review (NSR) Applicability Analysis
- Section 6: Best Available Control Technology (BACT) Summary
- Appendix A: Air Quality Permit Application Forms
- Appendix B: Compliance Review Form
- Appendix C: Emission Calculations
- Appendix D: Best Available Control Technology (BACT) Analysis
- Appendix E: Process Flow Diagrams
- Appendix F: Site Map
- Appendix G: Preliminary Emissions Specifications
- Appendix H: Air Toxics Policy Review

[1] Direct emissions of $CO_{2}e$ will increase as a result of the project. However, this is a combined heat and power process which will offset electricity that is currently being purchased from the grid as well as producing steam in a more efficient manner, resulting in a net decrease overall of $CO_{2}e$ from current levels when considering both direct and indirect sources.

# 2. PROJECT DESCRIPTION

The proposed project involves the installation of a new combined heat and power process (Cogeneration Project) at the Clairton Plant. The Cogeneration Project will be an energy efficient integrated combined heat and power process to generate electricity as well as steam to support the industrial processes of U. S. Steel's Mon Valley Works complex. The proposed Cogeneration Project will be configured with two (2) identical trains, each with a combustion turbine followed by a heat recovery steam generating (HRSG) unit (i.e., with duct burners). Each train will have a nominal heat input rating of 637 MMBtu/hr for the combustion turbine and 434 MMBtu/hr for the HRSG duct burner, with an electrical generation output capacity of approximately 47 megawatts (MW).[2,3] The units will be designed to be fired primarily with coke oven gas (COG), with the capability to fire natural gas as an alternative (e.g., for startup, shutdown, and/or malfunction events). The units may on occasion be fired with a blend of COG and natural gas. Following the installation of the new cogeneration units, some existing boilers (Boiler 1, Boiler 2, and Boiler R-1) at the Clairton Plant will not be needed and will be permanently shut down. The three remaining boilers (Boiler R-2, Boiler T-1, and Boiler T-2) will only be operated on a limited basis as needed to meet plant steam demands. In addition, the Clairton Plant is expected to be electrically independent, and/or may be a net exporter of electricity following the project, thereby significantly reducing the carbon footprint of the Mon Valley Works overall.

The Cogeneration Project will be designed to utilize multiple state-of-the-art air pollution control techniques to minimize emissions of various pollutants. The use of water injection and selective catalytic reduction (SCR) will control $NO_x$ emissions. The units will also be equipped with oxidation catalysts to minimize emissions of CO and VOC. $SO_2$ emissions will be reduced through the use of a circulating dry scrubber. Finally, the exhaust will be routed through an advanced baghouse to minimize particulate matter emissions.

New air emission sources to be installed with the proposed Cogeneration Project include the following primary and auxiliary emission units:

- Two (2) gas-fired combustion gas turbine generators, each with a heat input rating of 637 MMBtu/hr;
- Two (2) gas-fired HRSGs, each with duct burners with a heat input rating of approximately 434 MMBtu/hr;
- One (1) auxiliary package boiler, natural gas fired with a heat input rating of approximately 99 MMBtu/hr;
- Two (2) natural gas-fired dew point heaters, each with a heat input rating of 3.0 MMBtu/hr;
- One (1) diesel-fired emergency fire pump engine, rated at 55 kW;
- Two (2) lime storage silos and associated material handling systems;
- One (1) diesel storage tank to supply fuel to the emergency fire pump engine; and
- Paved haul roads for truck traffic (material receipts and waste deliveries).

As noted above, the six (6) existing boilers at the Clairton Plant will have emissions changes associated with the project. Three (3) existing boilers will be permanently shut down as part of this project, and the three (3) remaining boilers will only operate on a limited basis in the future as needed to meet plant steam demands. There will be a transition period to facilitate the initial startup and commissioning phase of the new Cogeneration units, which is expected to occur over approximately six months. As each train comes on line, it will provide electricity and steam and the existing boilers will be systematically shut down. Some existing infrastructure may be used to support the Project, but there will be no other associated emissions increases from existing units that will occur as a result of this project.

A schematic depicting the proposed equipment configuration is included in Appendix E.

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[2] Heat input rating on a high heating value (HHV) basis.

[3] Turbine rating is nominal value at 50 degrees Fahrenheit ambient temperature.

## 2.1. COGENERATION UNITS *(NEW)*

The proposed project will provide a nominal hourly power generating capacity of approximately 94 MW (nominal, 50ºF), and will consist of the installation of two (2) General Electric Frame 6B combustion turbines and two (2) HRSGs that will provide steam to drive a single steam turbine (existing). The project will supply electrical power and steam to industrial processes across the Mon Valley Works complex. Each HRSG will be equipped with duct burners which may be utilized at times of peak power demands to supplement power output by supplementing the heat from the combustion turbines. The combustion turbines will be fired primarily with COG (or a blend of COG and natural gas), but will be capable of firing on 100% natural gas during periods of startup, malfunction, or unavailability of COG if needed. The duct burners will be fired with COG only. As the project design includes some inherent redundancy, and to account for required maintenance outages, each train is expected to operate less than 8,760 hours per year.[4]

Emissions from each train will be routed through a series of air pollution control devices, including SCR for $NO_x$ reduction, oxidation catalyst for VOC/CO reduction, circulating dry scrubber for $SO_2$ control, and finally an advanced baghouse for removal of particulate matter.

Under most scenarios, the proposed cogeneration units will provide ample steam to meet the facility's needs, and therefore three (3) of the six (6) existing boilers at the Clairton Plant will be shut down as part of this project.

## 2.2. AUXILIARY PACKAGE BOILER *(NEW)*

The scope of the proposed project will include a natural gas fired package boiler (~99 MMBtu/hr) for auxiliary steam production. The boiler will be equipped with low-$NO_x$ burners and flue gas recirculation (FGR) and will be fired exclusively with natural gas. As this unit will be operated only on a limited basis to supplement plant steam when needed, it is expected to operate no more than 1,000 hours per year.

## 2.3. DIESEL EMERGENCY FIRE PUMP ENGINE & STORAGE TANK *(NEW)*

The scope of the proposed project will include a small 75-hp diesel-fired emergency fire pump engine. This engine is expected to meet EPA's Tier 3 engine standards, will burn ULSD, and will operate less than 100 hour per year based on its function. The fire pump engine will have a small dedicated fuel storage tank associated with it (~200 gallons).

## 2.4. MATERIAL HANDLING *(NEW)*

The Cogeneration Project will include equipment for storing and handling of lime for injection into the circulating dry scrubber as well as storage of waste lime. The emissions sources will include two (2) silos; one for storage of purchased lime and one for storage of waste lime. These silos will be equipped with high-efficiency bin vent filters for control of particulate matter during pneumatic transfer operations. There will be several smaller day bins installed as part of the material handling system which will be vented to the proposed Cogeneration Unit baghouses.

## 2.5. HEATERS *(NEW)*

The fuel delivery system for the Cogeneration Units will be equipped with two (2) small natural gas-fired dew point heaters, each rated at 3.0 MMBtu/hr. These heaters will serve to prevent the formation of hydrates in the fuel lines feeding the combustion units.

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[4] See detailed calculations in Appendix C for operating assumptions.

## 2.6. HAUL ROADS *(ASSOCIATED)*

**There will be new truck traffic at the facility as a result of the proposed project. Deliveries of lime and anhydrous ammonia into the facility will be expected, as well as shipments of waste lime out of the facility. All new truck traffic will occur on paved roadways.**

## 2.7. EXISTING BOILERS *(ASSOCIATED)*

**As previously noted, the Cogeneration Units will provide steam to the plant, and as a result three (3) existing boilers (Boiler #1, Boiler #2, and Boiler R-1) will no longer be needed. These boilers will be permanently removed from service following startup of the Cogeneration Units. The remaining three boilers (Boiler R-2, Boiler T-1, and Boiler T-2) will remain in operation on a limited basis only as needed to meet plant steam demands.**

# 3. EMISSION CALCULATIONS

The characteristics of air emissions from the proposed sources for the Cogeneration Project, along with the methodology used for calculating emissions, are described in narrative form below. Detailed supporting calculations are also provided in Appendix C. Note that all emission calculations that are based on published emission factors, or historical site data, have included a 15% "safety factor" consistent with ACHD's historical practices. A 10% factor has been included for greenhouse gas emissions.

Combustion-related emissions from the combustion turbines and HRSG duct burners are the primary sources associated with the project. There will also be some minimal emissions associated with the limited operation of the new package boiler and the three existing boilers that will remain, as well as other auxiliary equipment. Finally, there may be minimal fugitive particulate emissions from handling of dry sorbent materials (i.e., lime) injected into the proposed circulating dry scrubber. The methods by which emissions from each of these sources has been calculated are summarized below. A detailed analysis of the air toxics emissions and applicability of ACHD's Air Toxics Policy is included in Appendix H.

Some existing facility infrastructure may be used to support the operation of the proposed project, however, no existing sources (other than the 3 boilers that will remain) will have associated emissions increases as a result of the project.

## 3.1. COGEN - CRITERIA & GHG POLLUTANTS

Combustion in the combustion turbines and duct burners will result in emissions of criteria pollutants such as CO, $NO_X$, PM (and variants), $SO_2$, VOC, and ammonia, as well as greenhouse gas (GHG) pollutants such as carbon dioxide ($CO_2$), methane ($CH_4$), nitrogen oxides ($N_2O$). Steady-state emission rates can vary over a wide-range of operating conditions. For the purposes of determining potential emissions, the following key variables were evaluated:

- Ambient temperature;
- CTG load/duct firing configuration; and
- Fuel.

For the proposed units, there are three potential fuel scenarios: (1) coke oven gas; (2) natural gas; and (3) blend of COG and natural gas. The maximum operating schedule has been considered for each of these fuels for operational flexibility, however, the primary fuel for the system will be COG or the blend. Criteria and GHG emission rates for all operating conditions and fuel scenarios are based on preliminary engineering data (see Appendix G). Maximum expected short-term emissions are based on the worst-case short-term operating scenario (i.e., one train operating at 100% CTG load and full duct firing) from the full range of fuel scenarios and ambient temperatures. However, it is not possible for both units to operate at this worst-case scenario concurrently for extended periods of time. Therefore, maximum potential long-term emissions for each pollutant are based on the following criteria:

- Worst-case annual operating schedule (i.e., slightly less than full year operation); AND
- Maximum hourly emission rate of two units operating at average ambient conditions; OR
- One unit operating at its worst-case load at average ambient conditions.

This logic is shown for each fuel in Tables C-3a, C-3b and C-3c of Appendix C.

Steady-state emission rates take into account control efficiencies from the operation of the various proposed air pollution control equipment as follows. Note that the combination of control strategies being proposed have been optimized to prioritize reduction of priority pollutants (e.g., $SO_2$ and $PM_{2.5}$) and their precursors.

- The turbines will employ water injection and will also have the SCR system which will inject anhydrous ammonia to achieve an outlet $NO_x$ concentration of 7.5 parts per million dry volume (ppmvd) at 15% oxygen. Ammonia slip from the SCR will be 2 ppmvd or less.
- The use of an oxidation catalyst will reduce both CO and VOC emissions to approximately 3 and 5 ppmvd, respectively) for all normal operating conditions/fuel scenarios.
- The use of a circulating dry scrubber and fabric filter will reduce $SO_2$ emissions to 0.024 lb/MMBtu for operating conditions in the COG and COG blend fuel scenarios (as $SO_2$ is expected to be negligible from the natural gas only fuel scenario).[5]
- Finally, the use of the advanced baghouse will significantly reduce filterable particulate matter for all operating conditions/fuel scenarios. Condensable PM estimates include the potential formation of ammonium salts and sulfates/sulfites through the process. Total particulate emissions (filterable plus condensable) will be reduced to 0.014 lb/MMBtu.

Startup and shutdown (SU/SD) emissions are higher for certain pollutants than steady-state emissions due to two factors: (1) no or lower catalyst effectiveness; and (2) higher emitting combustion. During SU, neither catalyst is active until the end of the startup period. During SD, the SCR catalyst is inactive and the oxidation catalyst is less active. Further, during both SU and SD, the combustion turbines are not operating in the low emissions combustion mode that is achieved under steady-state operation. Planned SU/SD emissions have been calculated separately based on emission rates (on a lb/event basis) provided by the manufacturer, assuming ten (10) SU/SD events per unit per year, and conservatively added to the annual steady-state operating emissions. This approach was taken for the pollutants with higher emissions profiles during SU/SD than normal operations (i.e., $NO_x$, CO, VOC and GHGs).

## 3.2. COGEN - HAPS & AIR TOXICS

HAP emissions are regulated by U.S. EPA under Title III of the Clean Air Act Amendments of 1990 and comprise 187 compounds. In addition, Allegheny County regulates toxic air pollutants. Emissions of these constituents from the Cogeneration Units were based on the following as outlined in more detail in Table C-23a through Table C-23e of Appendix C.

- For ammonia, emissions are based on preliminary engineering data for ammonia slip from the $NO_x$ control system and assuming no conversion of the slip. This is conservative as the slip is expected to react to form ammonium salts that will be reduced by downstream controls.
- Where available, U. S. EPA AP-42 emission factors were used for natural gas combustion for the duct burners, and natural gas combustion for the combustion turbines.
- For COG combustion from the combustion turbines and duct burners, a combination of historical plant data (e.g., testing on other COG fueled combustion units as reported in annual emissions statements) and AP-42 factors were used to estimate HAP and air toxic emissions. U. S. Steel conservatively scaled each AP-42 factor for combustion stack organic HAP emissions (Tables 12.2-16 and 12.2-17) through applying a ratio of the VOC engineering estimated rate from the proposed system to the VOC emission factor from AP-42.[6] This approach was not applied to HAP metals for which the factors from Table 12.2-15 were used directly without adjustment. Also note that the proposed controls (e.g., circulating dry scrubber) will reduce emissions of hydrogen chloride and accordingly a control efficiency of 75% was applied.
- For the blended fuel scenario, the factors for natural gas and COG combustion were weighted based on the corresponding heat input of each fuel.

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[5] It should be noted that all COG fired in the Cogeneration Units will be pretreated to remove $H_2S$ with the existing system at the Clairton Plant, which consists of a vacuum carbonate scrubber followed by a 2-stage Claus sulfur removal process and Shell Claus Off-gas Treatment (SCOT).

[6] This approach aligns organic HAP emissions with total VOC emissions, taking into account the oxidation catalyst proposed for the system. Using AP-42 factors directly would result in organic HAP emissions estimates being greater than VOC.

## 3.3. AUXILIARY PACKAGE BOILER

The combustion of natural gas in the package boiler will result in emissions of CO, $NO_X$, PM, $SO_2$, and VOC as well as HAP and GHG emissions. The boiler's criteria emissions for $NO_X$ and CO are based on vendor-supplied emission factors. All other criteria pollutant and HAP emissions are based on AP-42 Chapter 1.4 emission factors for external combustion units. GHG emissions are based on emission factors from 40 CFR 98, Subpart C. Both HAP and GHG emissions factors include a 15% safety factor consistent with ACHD permitting preferences. Maximum potential emissions assume limited operation at a maximum of 1,000 hours per year given the anticipated function of the boiler. Detailed calculations are presented in Appendix C.

## 3.4. DIESEL FIRE PUMP ENGINE

The combustion of ultra-low sulfur diesel (ULSD) in the emergency fire pump engine will result in emissions of CO, $NO_X$, PM, $SO_2$, and VOC as well as HAP and GHG emissions. The engine's criteria emissions are based on meeting NSPS engine standards (g/kW hr factors) and a maximum fuel sulfur content of 15 ppm by weight (as required by NSPS Subpart IIII). HAP emissions are based on AP-42 Chapter 3.4 and Chapter 3.3 emission factors for small diesel fired internal combustion engines. GHG emissions are based on emission factors from 40 CFR 98, Subpart C. Both HAP and GHG emissions factors include a 15% safety factor consistent with ACHD permitting preferences. The maximum operating schedule is limited to 100 hours per year, which includes readiness testing and maintenance as recommended by the manufacturer. Engine calculations are presented in Appendix C.

## 3.5. DIESEL STORAGE TANK

The storage of ULSD for fuel in the emergency fire pump engine will result in small quantities of VOC and HAP emissions from working losses (when filling the tank) and breathing losses (due to ambient temperature fluctuations). Emissions are estimated using TankESP software based on the anticipated annual throughput and the latest AP-42 emission factors and calculation methods. Supporting calculations are included in Appendix C. A 15% safety factor was included on these emissions estimates.

## 3.6. DEW POINT HEATERS

The combustion of natural gas in the dew point heaters will result in emissions of CO, $NO_X$, PM, $SO_2$, and VOC as well as HAP and GHG emissions. Each heater's criteria emissions are based on vendor-supplied emission factors. HAP emissions are based on AP-42 Chapter 1.4 emission factors for external combustion units. GHG emissions are based on emission factors from 40 CFR 98, Subpart C. Both HAP and GHG emissions factors include a 15% safety factor consistent with ACHD permitting preferences. Maximum potential emissions conservatively assume full-time operation (8,760 hours per year for each heater). Detailed calculations are presented in Appendix C.

## 3.7. MATERIAL HANDLING

The handling of purchased lime and waste lime will result in emissions of filterable particulate matter from the storage silos. Each silo will be equipped with a high-efficiency bin vent filter. Emissions are estimated based on the flow rate through the bin vent (cfm) and the outlet grain loading of the filter (gr/dscf) along with the maximum expected hours of operation (12 hours per day, 5 days per week) based on operating schedule. There are smaller day bins associated with the material handling system which will be routed to the baghouse (and therefore will not have separate/individual emission points). Similarly, the loading of waste lime into trucks will be done via pneumatic transfer in a completely enclosed system, and will not have any associated emissions.

## 3.8. HAUL ROADS

Truck traffic associated with the operation of the new proposed sources will result in emissions of filterable particulate matter from certain segments of paved plant roadways. Emissions have been estimated using AP-42

Chapter 13.2 emission factors and calculations methods based on the total vehicle miles traveled and weight of the trucks associated with the project. Emissions estimates account for routine dust mitigation procedures (e.g., sweeping, applying dust suppressant, etc.) employed by the plant.

## 3.9. EXISTING BOILERS

Emissions from the three existing boilers will result from their limited operation in the future. The future projected emissions have been estimated using emission factors derived from a statistical analysis of historical stack test values along with projected annual fuel use based on limited operation.

# 4. REGULATORY APPLICABILITY ANALYSIS

This section documents the applicability determinations made for state, local and Federal air quality regulations. Applicability or non-applicability of the following regulatory programs is addressed:

- New Source Review (Prevention of Significant Deterioration/Nonattainment New Source Review);
- New Source Performance Standards (NSPS);
- National Emission Standards for Hazardous Air Pollutants (NESHAP); and
- Allegheny County Health Department air quality regulation (Article XXI).

In addition to providing a summary of applicable requirements, this section of the application also provides non-applicability determinations for certain regulations, allowing ACHD to confirm that identified regulations are not applicable. Note that explanations of non-applicability are limited to those regulations for which there may be some question of applicability to specific operations associated with the project. Regulations that are categorically non-applicable are not discussed (e.g., NSPS Subpart J, Standards of Performance for Petroleum Refineries).

## 4.1. NEW SOURCE REVIEW APPLICABILITY

The federal NSR program regulates the installation of new major sources or major modifications to existing major sources. The NSR permitting regulations are comprised of two (2) programs: 1) Prevention of Significant Deterioration for projects located in areas where specified pollutant levels have met National Ambient Air Quality Standards (NAAQS); and 2) Nonattainment New Source Review (NNSR) for projects located in areas where pollutant levels have not attained the corresponding NAAQS.

### 4.1.1. Major Source Status

The Clairton Plant is an existing major source located in the City of Clairton, Allegheny County, Pennsylvania which is currently designated as being in non-attainment with the National Ambient Air Quality Standards (NAAQS) for $SO_2$ and $PM_{2.5}$. In addition, because the county is located within the Ozone Transport Region (OTR), the area is considered non-attainment for ozone precursor pollutants ($NO_X$ and VOC). Therefore, both Non-Attainment New Source Review (NNSR) and Prevention of Significant Deterioration (PSD) permitting requirements are potentially applicable to the proposed project. As an existing major source, a major modification under NSR is triggered when a project results in a net increase in emissions for any regulated pollutant greater than the respective significant emission rate (SER).

### 4.1.2. NSR Analysis

ACHD's Article XXI regulations adopt the Federal PSD permitting procedures from 40 CFR §52.21 and the state NNSR permitting procedures from 25 PA Code §127.203. To determine the major NSR applicability for the Cogeneration Project under these two programs, the steps outlined in the U.S. EPA's NSR Workshop Manual, pages A.46-49 were generally followed. A traditional NSR applicability analysis is based on two steps: (1) determining emissions increases from the proposed project; and if increases are greater than the corresponding SER for any pollutant (2) determining the net emissions increases from the proposed project and other contemporaneous changes at the facility. These steps are discussed in detail in the following sections.

#### *Step 1 - Determine Emissions Increases from the Proposed Project*

Only project-related emissions are evaluated in this step; any contemporaneous increases or decreases are considered in Step 2.

1. Determine baseline actual emissions (BAE) from the highest 24-month average actuals over the last 10 years for PSD pollutants and the last 5 years for NNSR pollutants. The same 24-month period must be used for all sources affected by the project (existing sources that will be modified or will see an increase associated with the project). A different baseline period can be used for different pollutants, but must include all affected sources of that pollutant.

2. Determine future emissions after the project. For new sources, use potential-to-emit (PTE). For existing sources that are modified or otherwise associated with the project, use projected actual emissions (PAE).

3. Calculate project increase = PAE (or PTE) – BAE.

4. Compare project increase of each pollutant to the corresponding SER. If any pollutant exceeds the SER, then proceed to Step 2 for that pollutant.

The proposed Cogeneration Project involves the installation of new sources and the concurrent shut down of existing sources. In addition, U. S. Steel is establishing restrictions to limit the future operation of three (3) boilers at Clairton [Boiler R-2, Boiler T-1, and Boiler T-2].. Therefore, PTE from the proposed new sources, the actual emissions increases from the three (3) existing boilers that will remain, and the decreases from the shutdown of three (3) of the plant's existing boilers were used in determining the project emissions increase for comparison against the SERs. As shown in Table 4-1, project increases associated with the project do not exceed the SER for any pollutant, so it is not necessary to proceed to Step 2 netting for major modifications under NSR. A detailed analysis of NSR applicability for the project is provided in Section 5 of this report. Detailed emission calculations for all sources are included in Appendix C.

**Table 4-1. NSR Evaluation Step 1 – Project Increases**

| Pollutant | Project Increase (tpy) | NSR SER (tpy) | NSR Major Modification? |
|---|---|---|---|
| PM | -21.5 | 25 | **NO** |
| $PM_{10}$ | -1.2 | 15 | **NO** |
| $PM_{2.5}$ | -1.4 | 10 | **NO** |
| Lead | 0.00 | 0.6 | **NO** |
| $SO_2$ | -180.5 | 40 | **NO** |
| $NO_X$ | -643.4 | 40 | **NO** |
| CO | -53.4 | 100 | **NO** |
| VOC | 29.3 | 40 | **NO** |
| Ammonia | 17.2 | 40 | **NO** |
| $CO_2e$ | 642,568 | 75,000 | **NO**[7] |

## 4.2. NEW SOURCE PERFORMANCE STANDARDS

New Source Performance Standards (NSPS), located in 40 CFR 60, require new, modified, or reconstructed sources to control emissions to the level achievable by the best demonstrated technology as specified in the applicable

[7] Per 40 CFR §52.21(b)(49)(iv), as an existing major stationary source, the pollutant GHGs ($CO_2e$) is only subject to PSD if there is an emissions increase of a regulated NSR pollutant **AND** an emissions increase of 75,000 tpy $CO_2e$ or more. Since there is no emissions increase of a regulated NSR pollutant, PSD is not triggered for $CO_2e$.

provisions. Moreover, any source subject to an NSPS is also subject to the general provisions of NSPS Subpart A, except where expressly noted.

The following is a summary of applicability and non-applicability determinations for NSPS regulations of relevance to the Cogeneration Project.

### 4.2.1. NSPS Subpart A - General Provisions

All affected sources subject to source-specific NSPS are subject to the general provisions of NSPS Subpart A unless specifically excluded by the source-specific NSPS. Subpart A requires initial notification, performance testing, recordkeeping and monitoring, provides reference methods, and mandates general control device requirements for all other subparts as applicable.

### 4.2.2. NSPS Subpart D - Standards of Performance for Fossil Fuel-Fired Steam Generating Units

NSPS Subpart D applies to fossil-fuel-fired steam generating units with heat input ratings greater than 250 MMBtu/hr, which were installed after August 17, 1971. This rule provides standards for PM, $SO_2$, and $NO_X$, as well as emission monitoring and testing procedures. Per 40 CFR 60.40 (e), any facility subject to 40 CFR Subpart KKKK is not subject to Subpart D. As the turbines, duct burners, and heat recovery steam generators are subject to Subpart KKKK, this subpart does not apply to those sources. The package boiler will have a heat input rating well below 250 MMBtu/hr, and therefore will not be subject to this Subpart. Finally, the dew point heaters do not meet the definition of a steam generating unit and have heat input ratings well below 250 MMBtu/hr, and therefore are not subject to this Subpart.

### 4.2.3. NSPS Subpart Da - Standards of Performance for Electric Utility Steam Generating Units

This subpart applies to electric utility steam generating units with a heat input rating greater than 250 MMBtu/hr, which construction, modification, or reconstruction commenced after September 18, 1978. NSPS Subpart Da contains emission standards for PM, $SO_2$, and $NO_X$, as well as compliance, monitoring, and reporting requirements. 40 CFR 60.40Da (e) exempts heat recovery steam generators with duct burners that are subject to applicable requirements of NSPS Subpart KKKK. As the turbines, duct burners, and heat recovery steam generators are subject to Subpart KKKK, this subpart does not apply to those sources. The package boiler will have a heat input rating well below 250 MMBtu/hr, and therefore will not be subject to this Subpart. Finally, the dew point heaters do not meet the definition of a steam generating unit and have heat input ratings well below 250 MMBtu/hr, and therefore are not subject to this Subpart.

### 4.2.4. NSPS Subpart Db - Standards of Performance for Industrial-Commercial Steam Generating Units

NSPS Subpart Db applies to steam generating units with heat input ratings greater than 100 MMBtu/hr, which were installed after June 19, 1984. This subpart does not include stationary gas turbines in its definition of steam generating units, however duct burners do meet the definition of steam generating unit. NSPS Subpart KKKK specifically exempts heat recovery steam generators and duct burners regulated under Subpart KKKK from the requirements of NSPS Subpart Db. As the dew point heaters being installed as part of this project do not meet the definition of steam generating units, they are not subject to this Subpart. The proposed package boiler will have a heat input rating less than 100 MMBtu/hr, and will also not be subject.

### 4.2.5. NSPS Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Unit

NSPS Subpart Dc applies to a steam generating units and process heaters for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. The combustion sources (turbines and duct burners) proposed as part of the Cogeneration Project have a rated heat input greater than the maximum applicability heat input of 100 MMBtu/hr. In addition, NSPS Subpart KKKK specifically exempts heat recovery steam generators and duct burners regulated under Subpart KKKK from the requirements of NSPS Subpart Dc. The dew point heaters do not meet the definition of steam generating units and have heat input ratings below 10 MMBtu/hr. Therefore, NSPS Subpart Dc does not apply to those sources. Finally, the proposed package boiler will have a heat input rating that falls into the criteria specified for this Subpart. However, because this boiler will burn natural gas exclusively, the only applicable requirements under this Subpart will be maintaining records of the quantity and type of fuel combusted during each calendar month.

### 4.2.6. NSPS Subpart GG - Standards of Performance for Stationary Gas Turbines

40 CFR 60 Subpart GG applies to stationary gas turbines with a peak load heat input rating greater than or equal to 10 MMBtu/hr which commenced construction, modification, or reconstruction after October 3, 1977. The Cogeneration Project involves the installation of two coke oven gas-fired combustion turbines, each rated at greater than 10 MMBtu/hr. However, NSPS Subpart KKKK specifically exempts stationary combustion turbines subject to Subpart KKKK from the requirements of Subpart GG. Therefore, the requirements of NSPS Subpart GG do not apply to this project.

### 4.2.7. NSPS Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels

NSPS Subpart Kb applies to storage vessels with a capacity greater than or equal to 75 cubic meters (approximately 19,800 gallons) used to store volatile organic liquids with a maximum true vapor pressure greater than 15 kilopascals (kPa) that were constructed after July 23, 1984. The storage tank being installed to supply fuel to the emergency fire pump engine is well below the applicability threshold of 19,800 gallons, and will store diesel fuel which has a maximum true vapor pressure less than 1 kPa. Therefore, Subpart Kb is not applicable to the proposed storage tank.

### 4.2.8. NSPS Subpart IIII - Stationary Compression Ignition Internal Combustion Engines

This NSPS applies to owners and operations of stationary compression ignition (CI) internal combustion engines (ICE) that are not fire pumps and are manufactured after April 1, 2006; fire pumps that are manufactured after July 1, 2006; and CI ICEs that are modified or reconstructed after July 11, 2005. Units subject to this subpart are also subject to the provisions of 40 CFR 60 Subpart A, except where expressly noted.

NSPS Subpart IIII has specific requirements based on several criteria, including model year, engine displacement, and status as a fire pump. The emergency fire pump engine will be newer than model year 2011, and will need to be certified to meet emission standards for Tier 3 engines. No stack testing is required as a result of this regulation.

Per 40 CFR §60.4207 (b), the engine must use non-road diesel fuel with a maximum sulfur content of 15 ppm. As the fire pump engine will be fueled using ULSD, which by definition has a maximum sulfur content of 15 ppm, the unit will meet this requirement. Per 40 CFR §60.4209(a), the unit must install a non-resettable hour meter prior to startup.

### 4.2.9. NSPS Subpart KKKK - Standards of Performance for Stationary Combustion Turbines

NSPS Subpart KKKK establishes emissions standards for stationary combustion turbines with a peak load heat input greater than or equal to 10 MMBtu/hr that are constructed after February 18, 2005. The applicable heat input threshold is exclusive of fuel burned in the duct burners, though heat recovery steam generators and duct burners are subject to the requirements of this subpart when associated with a turbine that is subject to NSPS Subpart KKKK. As the turbines being installed as part of this project have a heat input greater than 10 MMBtu/hr, they and their associated HRSGs and duct burners are subject to this subpart.

This subpart has emission limits for $NO_x$ and $SO_2$, monitoring, reporting, and testing requirements which apply to these turbines and associated HRSGs and duct burners. The turbines being installed have a maximum heat input rating of approximately 637 MMBtu/hr and can burn coke oven gas, natural gas, or a blend of the two fuels.

The $NO_x$ emission limits in Table 1 of this subpart apply to the stationary combustion turbines. During operation when coke oven gas makes up greater than 50% of the heat input, a $NO_x$ limit of 74 parts per million (ppm) at 15% $O_2$ applies (new turbine firing fuels other than natural gas, rated between 50 and 850 MMBtu/hr). When operating on natural gas, a $NO_x$ limit of 25 ppm at 15% $O_2$ applies. Compliance with the $NO_x$ emission limits will be demonstrated with a continuous emissions monitoring system.

40 CFR §60.4330 (a) lists the $SO_2$ emission limit for the turbines on either a gross power output basis (0.90 lb/MWh) or a fuel sulfur concentration basis (0.06 lb/MMBtu). Compliance with the fuel input based $SO_2$ limit requires daily fuel sulfur content monitoring, unless exempted under the provisions of representative fuel sampling in 40 CFR §60.4365. Compliance with the output based $SO_2$ limit requires annual stack testing.

This subpart specifically exempts turbines regulated under this subpart from the requirements of NSPS GG, and exempts heat recovery steam generators and duct burners regulated under this subpart from the requirements of NSPS Subparts Da, Db, and Dc.

### 4.2.10. NSPS Subpart TTTT - Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

This NSPS establishes greenhouse gas emission standards and compliance schedules for stationary combustion turbines which commenced construction after January 8, 2014 and have a heat input rating greater than 250 MMBtu/hr of fossil fuel. Fossil fuel is defined as "natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat." This subpart defines natural gas as:

> *a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane)... natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable $CO_2$ content or heating value.*
> *[40 CFR §60.5580]*

As coke oven gas is not produced for the purpose of creating useful heat and specifically excluded in the definition of natural gas, it does not meet the definition of fossil fuel in this subpart. As these units combust natural gas as a startup and secondary fuel, they are considered fossil fuel-fired stationary combustion turbines. An electric generating unit is defined in this subpart as "any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (i.e. meets the applicability criteria)."

The applicability criteria in 40 CFR 60.5509 (b)(3) exempts combined heat and power units that are limited to no more than 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater, in net-electricity sales. Combined heat and power units are defined as "an electric generating unit that uses a steam generating unit or stationary combustion turbine to simultaneous produce both electric (or mechanical) and useful thermal output from the same primary energy source." As the turbines will produce both electricity and process steam, they meet the definition of combined heat and power units. The turbines will not have net electricity sales greater than 219,000 MWh, and are therefore exempt from this subpart.

### 4.2.11. Non-Applicability of All Other NSPS

NSPS standards are developed for particular industrial source categories, and the applicability of a particular NSPS to a facility can be readily ascertained based on the industrial source category covered. All other NSPS are categorically not applicable to the proposed project.

## 4.3. NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAP)

National Emission Standards for Hazardous Air Pollutants (NESHAPs), located in 40 CFR 61 and 63 are applicable to major sources of HAPs and certain designated area sources of HAPs. A major source of HAP is one with potential emissions in excess of 25 tpy for total HAPs and/or potential emissions in excess of 10 tpy for any individual HAP. The Clairton Plant is an existing major source of HAP since its potential emissions of HAP are greater than the major source thresholds. NESHAP apply to sources in specifically regulated industrial source categories (Clean Air Act Section 112(d)) or on a case-by-case basis (Section 112(g)) for facilities not regulated as a specific industrial source type.

The following is a summary of applicability and non-applicability determinations for NESHAP regulations of relevance to the proposed project.

### 4.3.1. NESHAP Subpart A - General Provisions

NESHAP Subpart A, General Provisions, contains national emissions standards for HAP defined in Section 112(b) of the Clean Air Act. All affected sources, which are subject to another NESHAP, are subject to the general provisions of NESHAP Subpart A, unless specifically excluded by the source specific NESHAP.

### 4.3.2. NESHAP Subpart L - Coke Oven Batteries

NESHAP Subpart L applies to existing and new coke oven batteries. As part of this project no changes are being made to the coke oven batteries at this facility, and thus there are no changes in regulatory applicability of this subpart.

### 4.3.3. NESHAP Subpart YYYY - Stationary Combustion Turbines

NESHAP Subpart YYYY applies to stationary combustion turbines located at major sources of HAP. This rule establishes emission and operating limits to reduce HAP emissions, and provides compliance requirements for affected units. The turbines being installed as part of this project are gas-fired stationary combustion turbines and subject to this rule; the duct burners and heat recovery steam generators are not subject to the provisions of this rule, however emission limits are allowed to be met while duct burners are in operation.

Per 40 CFR §63.6095 (d), lean premix and diffusion flame gas-fired stationary combustion turbines must comply with the Initial Notification requirements in 40 CFR 63.6145, however all other requirements of this subpart have been stayed.[8]

### 4.3.4. NESHAP Subpart ZZZZ - Stationary Reciprocating Internal Combustion Engines (RICE)

This NESHAP applies to stationary CI and spark-ignition (SI) reciprocating internal combustion engines (RICE) based on engine size, source HAP classification (major or area), and RICE status (new or existing). As the proposed emergency fire pump engine is a CI ICE that will be a new RICE located at a major source of HAP, this engine will be subject to NESHAP Subpart ZZZZ.

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[8] On April 2, 2019, U.S. EPA proposed amendments to this rule which could have applicable requirements to the proposed combustion turbines depending on the final rule. The proposal was published in the Federal Register on April 12, 2019. U. S. Steel will monitor the rule development and ensure compliance with any final applicable requirements for the proposed units.

The fire pump engine will operate for emergency purposes only. As the emergency fire pump engine will be a new CI ICE less than 250 hp, there are no additional requirements under this subpart.

### 4.3.5. NESHAP Subpart CCCCC - Coke Ovens: Pushing, Quenching, and Battery Stacks

NESHAP Subpart CCCCC establishes HAP standards for pushing, soaking, quenching, and battery stacks at coke oven batteries. No changes are being made to any of these operations as part of the Cogeneration Project. There are no changes to the regulatory applicability of this subpart.

### 4.3.6. NESHAP Subpart DDDDD - Industrial, Commercial, and Institutional Boilers (Area Source Boiler MACT)

40 CFR 63 Subpart DDDDD regulates HAP emissions from new, reconstructed and existing industrial, commercial, and institutional boilers and process heaters at major HAP sources. This subpart defines a boiler as:

> *an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in §241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.*
> *[40 CFR §63.7575]*

Waste heat boilers are specifically excluded from the definition of boilers in this subpart. Waste heat boilers are defined as follows:

> *a device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, furnace) or power (e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.*
> *[40 CFR §63.7575]*

The turbines being installed as part of this project do not meet the definition of boiler, and the associated heat recovery steam generators and duct burners are explicitly excluded from the definition of boiler. However, the proposed package boiler will meet the definition of a boiler as described above and will be subject to the rule. Because this unit will be fired exclusively with natural gas, it will be subject to annual tune-ups and associated recordkeeping and reporting requirements under the rule.

Under the rule, process heaters are defined as follows:

> *an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials...*
> *[40 CFR §63.7575]*

The dew point heaters proposed as part of this project do meet the definition of process heaters under the rule. Because these units will be designed to burn natural gas exclusively, and will be less than 5.0 MMBtu/hr heat input, the only requirement under the rule will be to conduct a tune up once every 5 years as specified in §63.7540.

### 4.3.7. Non-Applicability of All Other NESHAP

NESHAP standards are developed for particular industrial source categories, and the applicability of a particular subpart to a facility can be readily ascertained based on the industrial source category covered. All other NESHAP subparts are categorically not applicable to the proposed project.

## 4.4. ARTICLE XXI APPLICABILITY

The Allegheny County Air Pollution Control Regulations (from Article XXI) that are applicable to the sources proposed for the Cogeneration Project are outlined below.

### 4.4.1. Article XXI §2104.01a - Visible Emissions

This regulation states that opacity shall not equal or exceed 20% for a period aggregating more than 3 minutes in any 60 minute period, or 60% at any time. The operations of the Clairton Plant, including the sources proposed as part of this project, will be subject to these general opacity requirements. Compliance will be demonstrated through the use of good combustion practices for the emission units and associated air pollution control devices.

### 4.4.2. Article XXI §2104.02.a - Particulate Emissions: Processes - Fuel Burning or Combustion Equipment

This regulation applies to fuel-burning or combustion equipment, where the actual heat input to such equipment is greater than 0.50 MMBtu/hr. This regulation will apply to the combustion turbines and HRSG duct burners proposed as part of the project. PM emissions from the combustion sources for each of the fuel scenarios will be limited to the rates shown in Table 4-2 below. These emission limits have been calculated in accordance with the formulas specified in §2104.02.a.2.B and §2104.02.a.3. Since the combustion turbines and HRSG duct burners for each train share a common stack, the allowable limit was based on a weighted average of the individual unit allowable rates and their rated heat input capacity. Compliance with these limits is based on stack test Method 5, or equivalent.

**Table 4-2. PM Emission Limits**

| Fuel Scenario | PM Limit (lb/MMBtu) | | |
|---|---|---|---|
| | Combustion Turbine | HRSG Duct Burners | Combined Flue |
| 100% Natural Gas | 0.015 | 0.008 | 0.012 |
| 100% Coke Oven Gas | 0.094 | 0.020 | 0.064 |
| Blend (COG / Natural Gas) | 0.070 | 0.020 | 0.050 |

This regulation will also apply to the emergency fire pump engine. This unit will be fired with diesel (No. 2 fuel oil) and PM emissions will be limited to 0.28 lb/MMBtu accordingly. Finally, the regulation will apply to the dew point heaters and the package boilers. These units will be fired with natural gas and PM emissions from them will be limited to 0.008 lb/MMBtu accordingly. Detailed emission calculations which demonstrate compliance with these limits for all sources are included in Appendix C.

### 4.4.3. Article XXI §2104.02.b - Particulate Emissions: Processes - General

This Subsection applies to processes not specifically listed under other sections of this regulation. This regulation will apply to the lime storage silos proposed as part of this project. The rule limits PM from these sources to less than 7 lbs per hour or 100 lbs per day. As shown in Table C-7 of Appendix C, emissions from the silo bin vents will be well below these limits. All other new sources proposed for this project will be subject to the requirements under 2104.02.a, therefore this Subsection will not apply to those sources.

## 4.4.4. Article XXI §2104.03.a - $SO_2$ Emissions

For equipment fired only with natural gas and/or liquefied petroleum gas, this regulation limits $SO_2$ emissions at a rate no greater than the potential to emit. This applies to the dew point heaters and package boiler proposed for the project. For other equipment with a heat input rating greater than 0.5 MMBtu/hr and less than 50 MMBtu/hr, $SO_2$ emissions are limited to 1.0 lb/MMBtu. This limit will apply to the emergency fire pump engine. Using ultra low sulfur diesel, the emergency engine will be compliant with this requirement. For equipment with a heat input rating greater than 50 MMBtu/hr and less than 2000 MMBtu/hr, $SO_2$ emission limits are calculated in accordance with the formula in Subsection a.2.B. Since the combustion turbines and HRSGs share a stack, the allowable rate is based on the total heat input per Subsection b.1. Based on this formula and common flue, the $SO_2$ emissions from the stack will be limited to 0.64 lb/MMBtu. As shown in the detailed calculations in Appendix C, all of the proposed new units will meet the applicable limits of this regulation.

## 4.4.5. Article XXI §2104.04 - Odor Emissions

Under this regulation, malodors are prohibited beyond the property line. U. S. Steel will ensure that the facility does not emit malodors beyond the property line through proper operation and maintenance of equipment.

## 4.4.6. Article XXI §2104.05 - Materials Handling

Emissions from materials handling shall not be visible beyond the property line. As discussed previously, lime storage silos will be equipped with high-efficiency bin vent filters with outlet grain loadings < 0.002 gr/dscf. All other handling of lime for the circulating dry scrubber will be accomplished with pneumatic systems. As such, no visible emissions from material handling activities are anticipated.

## 4.4.7. Article XXI §2104.07 - Stack Heights

This regulation specifies that the degree of emission limitation required of any source for purposes of demonstrating compliance with a NAAQS shall not be affected by that portion of any stack height that exceeds Good Engineering Practice (GEP) or any other dispersion techniques as defined by federal regulations. U. S. Steel will comply with this regulation as required.

## 4.4.8. Article XXI §2104.08 - National Emission Standards for Hazardous Air Pollutants

The federal NESHAP and MACT requirements are incorporated into ACHD regulations by reference. The potentially applicable regulations are discussed in Section 4.3 above.

## 4.4.9. Article XXI §2105.03 - Proper Operation and Maintenance of Air Pollution Equipment

All required air pollution control equipment must be properly installed, operated and maintained consistent with good air pollution control practices. The proposed project scope includes air pollution control equipment which is inherent to the design as well as add-on controls. All equipment will be operated and maintained in accordance with manufacturer's recommended emissions-related instructions.

## 4.4.10. Article XXI §2105.05 - New Source Performance Standards

The federal NSPS requirements are incorporated into ACHD regulations by reference. The potentially applicable NSPS regulations are discussed in Section 4.2 above.

### 4.4.11. Article XXI §2105.06 - Major $NO_X$ and VOC Sources

This section applies to all major sources of $NO_X$ or VOCs in existence as of November 1, 1992, for which no applicable emission limitations have been established by regulations under Article XXI. The facility is an existing major source with respect to $NO_X$ and VOC, and as such this regulation does apply. All sources proposed as part of the Cogeneration Project will emit $NO_X$ and VOC. The cogeneration units are greater than 250 MMBtu/hr, and will be equipped with continuous emissions monitoring systems (CEMS) for $NO_X$. The proposed emergency fire pump engine will operate less than 100 hours per year, and the dew point heaters will have individual rated heat input less than 20 MMBtu/hr. As such, these sources will be subject to presumptive RACT requirements under §2105.06.d.6.E. which require installation, maintenance, and operation in accordance with manufacturer's specifications. The proposed package boiler will not have any applicable requirements under this regulation. It should be noted also that all of these sources will be subject to BACT requirements as new sources.

### 4.4.12. Article XXI §2105.12.a - VOC Storage Tanks

This regulation prohibits the storage of volatile organic liquids with vapor pressures greater than 1.5 psia in above ground storage tanks between 2,000 – 40,000 gallons unless the tanks are equipped with pressure relief valves as specified. The storage tank associated with the emergency fire pump engine will be less than 2,000 gallons and therefore not subject to this rule.

### 4.4.13. Article XXI §2105.21 - Coke Ovens and Coke Oven Gas

Under §2105.21.h. of this regulation, coke oven gas supplied by the Clairton Coke Works cannot be combusted unless the concentration of hydrogen sulfide ($H_2S$) is less than or equal to 40 grains per 100 scf. The combustion units proposed as part of the Cogeneration Project will be designed to burn coke oven gas, so this limit will apply. The existing air permits for this facility specify a lower limit of 35 grains per 100 scf, which will ensure compliance with this Article XXI requirement.

### 4.4.14. Article XXI §2105.40.a - Fugitive Sources (Permitted Sources)

This section of Article XXI specifies that a permitted source may not be operated in a manner that emissions are visible beyond the property line, have opacity of more than 20% or more for a period aggregating more than 3 minutes in any 60 minute period, or 60% at any time. U. S. Steel will ensure that emissions from the proposed sources are not visible beyond the property line, and will comply with the opacity requirements.

### 4.4.15. Article XXI §2105.42 - Parking Lots & Roadways

Under this regulation, emissions from plant roadways cannot be visible beyond the property line, cannot have opacity greater than 20% for more than three minutes in any 60-minute period, or great than 60% at any time. The Clairton Plant is subject to this regulation, and routinely utilizes dust suppression techniques to comply.

### 4.4.16. Article XXI §2105.43 - Transport Emissions (Permitted Sources)

This section requires that no person transport, or allow to be transported, any solid or liquid material outside the boundary line of any source in such manner that there is any visible emission, leak, spill, or other escape of such material during transport. U. S. Steel will ensure that there are no visible emissions, leaks or spills during transporting of materials associated with the proposed project.

### 4.4.17. Article XXI §2105.45 - Construction and Land Clearing

This regulation prohibits opacity in excess of 20% for more than three minutes in any 60-minute period, or great than 60% at any time from construction or land clearing activities. U. S. Steel will ensure that all construction activities related to the proposed project meet this requirement.

### 4.4.1. Article XXI §2105.47 - Demolition

This regulation prohibits opacity in excess of 20% for more than three minutes in any 60-minute period, or great than 60% at any time from demolition activities. U. S. Steel will ensure that all demolition activities related to the proposed project meet this requirement.

### 4.4.2. Article XXI §2105.49 - Fugitive Emissions

This rule requires reasonable action must be taken to prevent fugitive emissions from becoming air-borne. U. S. Steel will employ measures to prevent fugitive emissions from becoming airborne as needed to comply with this rule.

This section presents the detailed New Source Review (NSR) applicability analysis for the proposed Cogeneration Project, with a particular focus on determining whether the project constitutes a major modification under either PSD or NNSR. As described in Section 2 of this report, the Cogeneration Project involves the installation of new equipment, associated emissions increases at existing boilers, and the shutdown of existing boilers at the Clairton Plant. Existing equipment that will be shut down as part of this project will generate emissions decreases. Some existing infrastructure may continue to be utilized in conjunction with the new sources proposed as part of the Cogeneration Project. Three existing boilers will remain, but will have limited operation in the future. There will be no other associated emissions increases at existing sources as a result of this project. Furthermore, there will be no physical changes or changes in the method of operation at upstream or downstream production operations at the facility, and thus all existing emission units that will continue to operate in the future have been excluded from the analysis in this section, with the exception of the aforementioned three boilers (Boiler R-2, Boiler T-1, and Boiler T-2).

This analysis demonstrates that the project will not result in an emissions increase that constitutes a major modification under NSR. In fact, the project will result in no net emissions increase for $PM_{2.5}$ and $PM_{10}$, and will actually result in a significant decrease in several pollutants (e.g., $NO_X$, CO, and $SO_2$).[9]

## 5.1. NSR PERMITTING APPLICABILITY

If a major source will undergo a physical or operational change, the applicant must review that project to determine if it results in a significant emissions increase (Step 1) and a significant net emissions increase of a regulated air pollutant (Step 2). If both the project's increase and the net emissions increase are significant, then PSD or NNSR permitting is required depending on the attainment status of the regulated air pollutant resulting in the significant net emissions increase. A significant net emissions increase is defined as a net emissions increase resulting from a modification at a major source that exceeds the established SER for that pollutant. Table 5-1 identifies the NSR regulated pollutants evaluated for this project and their associated SERs.

Appendix C is provided as a detailed assessment of the calculations forming the basis for the applicability determination discussed in this section. The procedures used in to make these determinations are consistent with 40 CFR §52.21 and 25 Pa Code §§127.203 – 204, which are incorporated by reference in Article XXI.

[9] Direct emissions of $CO_2e$ will increase as a result of the project. However, this is a Cogeneration Project which will offset the electricity that is currently being purchased from the grid, resulting in a net decrease overall of $CO_2e$ from both direct and indirect sources.

**Table 5-1. PSD Significant Emission Rates**

| Pollutant[10] | Significant Emission Rate (Tons/Year) | Regulated Under PSD or NNSR? |
|---|---|---|
| PM | 25 | PSD |
| $PM_{10}$ | 15 | PSD |
| $PM_{2.5}$ | 10 | NNSR |
| Lead | 0.6 | PSD |
| $SO_2$ | 40 | NNSR (and $PM_{2.5}$ precursor) |
| $NO_X$ | 40 | NNSR (ozone and $PM_{2.5}$ precursor) |
| CO | 100 | PSD |
| VOC | 40 | NNSR (ozone and $PM_{2.5}$ precursor) |
| Ammonia | 40 | NNSR ($PM_{2.5}$ precursor) |
| $CO_2e$ | 75,000 | PSD |

As previously mentioned, a detailed analysis of the project emissions is included in Appendix C. Table 5-2 summarizes the results of this analysis for NSR applicability. Future emissions from new and associated existing units as a result of the project are shown as "Project Increases" in the table, whereas the shutdown of existing equipment is represented as "Project Decreases." The scope of the proposed project involves not only the installation of the new cogeneration units and auxiliary equipment, but also the subsequent shut down of three of the plant's existing boilers and limited operation of the remaining three boilers (since the HRSGs will provide the primary source of plant steam in the future). The analysis looks at the sum of the project impacts (increases and decreases) and compares the result to the SERs. U. S. Steel has prepared this analysis for all three of the anticipated fuel scenarios, since different scenarios may result in higher emissions of some pollutants but lower emissions of others. Table 5-2 below depicts the "worst-case" annual project emissions values from all three fuel scenarios (see Table C-2 of Appendix C).

[10] PSD also has established SERs for hydrogen sulfide, total reduced sulfur, and sulfuric acid mist, which could be emitted from the sources being permitted in this action. If present at all, these compounds are expected to be at concentrations below method detection limits. Given the air pollution control devices and strategies being employed, these compounds would be expected to show up in the "back-half" of the particulate matter sampling train. The condensable particulate matter estimates for the proposed sources account for the possible presence of these compounds. The proposed project is not expected to increase emissions of any other NSR regulated pollutants (e.g., CFCs).

**Table 5-2. Project Emissions Summary**

| Pollutant | PSD /NNSR | Future Emissions from New and Associated Units (tpy) | Baseline Actual Emissions (Shutdown Units) (tpy) | Sum of Emissions Changes (tpy) | Significant Emission Rates | Trigger NSR? (Yes/No) |
|---|---|---|---|---|---|---|
| PM | PSD | 12.9 | -34.4 | -21.5 | 25 | No |
| $PM_{10}$ | PSD | 44.4 | 45.6 | -1.2 | 15 | No |
| $PM_{2.5}$ | NNSR | 44.3 | -45.6 | -1.4 | 10 | No |
| Lead | PSD | 0.0 | -0.0 | 0.0 | 0.6 | No |
| $SO_2$ | NNSR | 234.6 | -415.1 | -180.5 | 40 | No |
| $NO_X$ | NNSR | 287.9 | 931.3 | -643.4 | 40 | No |
| CO | PSD | 86.8 | -140.2 | -53.4 | 100 | No |
| VOC | NNSR | 31.9 | -2.6 | 29.3 | 40 | No |
| Ammonia | NNSR | 19.0 | -1.7 | 17.2 | 40 | No |
| $CO_2e$ | PSD | 925,401 | -282,833 | 642,568 | 75,000 | No[11] |

The following sections discuss the methodology used to assess NSR applicability. The NSR permitting program generally requires that a source obtain a permit and undertake other obligations prior to construction of any project at an industrial facility if the proposed project results in the potential to emit air pollution in excess of certain threshold levels. ACHD has incorporated by reference 40 CFR §52.21 as well as 25 Pa Code §§127.203 - 204.

### 5.1.1. Defining Existing versus New Emission Units

Different calculation methodologies are used for existing and new units; therefore, it is important to clarify whether a source affected by the proposed project is considered a new or existing emission unit.

40 CFR §52.21(b)(7)(i) and (ii), as well as 25 PA Code §121.1, define new unit and existing units:

> *(i) A new emissions unit is any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first operated.*
>
> *(ii) An existing emissions unit is any unit that does not meet the requirements in paragraph (b)(7)(i) of this section. A replacement unit, as defined in paragraph (b)(33) of this section, is an existing emissions unit.*

New sources associated with the project are the combustion turbines and HRSGs as well as the package auxiliary boiler, emergency fire pump engine and associated fuel tank, the dew point heaters, and the material handling systems. Existing sources that will be impacted by the Cogeneration Project are the six boilers and certain segments of paved roadways.

### 5.1.2. Annual Emission Increase Calculation Methodology

As the facility is classified as an existing major source for NSR, if the Cogeneration Project were classified as a *major modification*, then the full NSR permitting requirements would apply. U. S. Steel has determined the project emissions

[11] Per 40 CFR §52.21(b)(49)(iv), as an existing major stationary source, the pollutant GHGs ($CO_2e$) is only subject to PSD if there is an emissions increase of a regulated NSR pollutant **AND** an emissions increase of 75,000 tpy $CO_2e$ or more. Since there is no emissions increase of a regulated NSR pollutant, PSD is not triggered for $CO_2e$.

increase in accordance with EPA guidance to determine if the proposed project is a major modification. The methodology outlined in 25 Pa Code §127.203a(a)(1)(i) was relied upon for conducting this applicability analysis for nonattainment pollutants. For PSD, the procedures of 40 CFR §52.21 have been followed.

§127.203a(a)(1)(i)(A) provides the emission increase calculation method for existing units (i.e., the boilers in this case):

> (A) *For existing emissions units, an emissions increase of a regulated NSR pollutant is the difference between the projected actual emissions and the previous actual emissions for each unit, as determined in paragraphs (4) and (5). When calculating an increase in emissions that results from the particular project, exclude that portion of the unit's emissions following completion of the project that existing units could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions and that is also unrelated to the particular project, including all increased utilization due to product demand growth as specified in paragraph (5)(i)(C).*

§127.203a(a)(1)(i)(B) provides the emission increase calculation method for new emission units (i.e., the combustion turbines, HRSGs, package boiler, emergency fire pump engine, diesel storage tank, heaters, and material handling sources in this case):

> (B) *For new emissions units, the emissions increase of a regulated NSR pollutant will be the potential to emit from each new emissions unit.*

*Major modification* is defined by 40 CFR §52.21(b)(2)(i) and 25 Pa Code §121 as:

> *"Major Modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant emission increase ... of a regulated NSR pollutant ... and a significant net emissions increase of that pollutant ...*

As the project is classified as a physical change, the project needs to be analyzed to determine if a significant emissions increase, or a significant net emissions increase will occur. The first step (Step 1) is commonly referred to as the "project emission increases" as it accounts only for emissions changes related to the proposed project itself. If the emission increases estimated per Step 1 exceed the major modification thresholds, then the applicant may move to Step 2, commonly referred to as "netting". The netting analysis includes all projects for which emission increases or decreases have occurred or will occur during a period of time contemporaneous to the project. If the resulting net emission increases exceed the major modification threshold, then NSR permitting is required. These basic procedures are the same for both PSD and NNSR.

### 5.1.3. Baseline Actual Emissions (BAE)

For the purposes of NNSR, baseline actual emissions are defined in 25 Pa Code §127.203a(a)(4)(i) as follows:

> *For an existing emissions unit, baseline actual emissions are the average rate, in TPY, at which the unit emitted the regulated NSR pollutant during a consecutive 24-month period selected by the owner or the operator within the 5-year period immediately prior to the date a complete plan approval application is received by the Department. The Department may approve the use of a different consecutive 24-month period within the last 10 years upon a written determination that it is more representative of normal source operation....*

Per §127.203a(a)(4)(i)(D), when a project involves multiple emission units, only one consecutive 24-month period may be used to determine the baseline actual emissions for all of the emission units being changed. However, there are provisions to use a different consecutive 24-month period can be used for each pollutant.

U. S. Steel elected to use the 24 consecutive calendar months, as reported in annual emissions report (i.e., annual totals), in each of the selected baseline periods for simplicity and did not seek to evaluate each 24 calendar month period in the last 5 years. For the Cogeneration Project, a baseline period of 2014 and 2015 was selected for all non-attainment pollutants with the exception of $PM_{2.5}$.[12] These two years (2014 & 2015) reflect the maximum coke production and fuel combustion rates observed in the most recent five-year period.

ACHD adopts by reference EPA's PSD program outlined in 40 CFR §52.21. For the PSD program, baseline actual emissions for an emissions unit, other than an electric utility steam generating unit, are defined in 40 CFR §52.21(b)(48)(ii)

> *...the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the Administrator ...*

Further clarification is given that only one consecutive 24-month period may be used to determine the baseline for all the emission units being changed but that a different period can be used for each regulated pollutant. U. S. Steel computed actual baseline emissions for PSD pollutants following this procedure and selected the following as baseline periods:

- PM = 2010 and 2011;
- $PM_{10}$ = 2016 and 2017;
- CO = 2012 and 2013;
- $NO_2$ = 2014 and 2015;
- GHG = 2013 and 2014; and
- Lead = 2015 and 2016.

### 5.1.4. Potential Emissions (PTE)

Potential to emit is defined by 25 Pa Code §121.1 and §2101.20 as:

> *...The maximum capacity of a source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and limitations on hours of operation or on the type or amount of material combusted, stored or processed shall be treated as part of the design if the limitation or the effect it would have on emissions is Federally enforceable or legally and practicably enforceable by an operating permit condition. The term does not include secondary emission from an offsite facility.*

Any modification to the facility that has the potential to increase emissions of any air pollutant(s) regulated under the PSD or NNSR program must be evaluated to determine if the changes are subject to PSD or NNSR. Per §2101.20, a "modification" is defined as:

> *...A physical change in a source or a change in the method of operation of a source which would increase the amount of an air contaminant emitted by the source or which would result in the emission of an air contaminant*

[12] PM2.5 baseline years are 2016 and 2017.

*not previously emitted, except that routine maintenance, repair and replacement are not considered physical changes.*

The Cogeneration Project at the Clairton Plant qualifies as a "modification" under this definition. Therefore, the proposed process changes are identified as a potential modification requiring evaluation under the NSR permitting program.

### 5.1.5. Proposed Project Emissions Increases

The following sections summarize the methods to estimate the emissions increases from the Cogeneration Project for comparison to the NSR permitting major modification thresholds. In determining the potential emissions from the new units, U. S. Steel assumed year-round operation of the cogeneration units, taking into account redundancy and required routine maintenance outages. These details were discussed in detail in Section 3 and can be seen in Appendix C calculations. For the purposes of the NSR analysis, annual emissions were estimated based on representative average operating conditions (e.g., load, ambient temperatures, and fuels). Potential emissions from the package boiler and the emergency fire pump engine were based on the assumption that each unit would operate no more than 1,000 hours and 100 hours per year, respectively, based on their intended function.

For the three existing boilers that will remain in operation, U. S. Steel estimated their future projected emissions using emission factors derived from a statistical analysis of historical stack test data along with projected annual fuel consumption based on limited operation due to their intended function in the future (i.e., plant steam production only when needed).

### 5.1.6. Proposed Project Emissions Decreases

The sources listed below will cease to operate upon start up and commencement of normal operation of the Cogeneration Project. As such, emission decreases for this equipment will occur within the scope of the project and can be credited in the NSR applicability analysis.

- Boiler #1 – 760 MMBtu/hr (coke oven gas and/or natural gas fired)
- Boiler #2 – 481 MMBtu/hr (coke oven gas and/or natural gas fired)
- Boiler R-1 – 229 MMBtu/hr (coke oven gas and/or natural gas fired)

The methodology used to establish baseline actual emissions for these sources is discussed in Section 5.1.3. The actual emissions used in the applicability analysis are the same actual emissions that have been reported to ACHD in the Clairton Plant's Annual Emissions Inventory Statement. These actual emissions are summarized in Appendix C (Tables C-10 through C-19).

### 5.1.7. Sum of Project Emissions

U. S. Steel determined the project emissions increase by summing both the increases and the decreases in emissions as a result of the project. Because this resulting sum was below the SER for all pollutants, and GHG is not subject to regulation, there was no need to proceed to Step 2 netting to account for contemporaneous increases and decreases not associated with the project.

The calculations in Appendix C provide a detailed summary of emissions changes as a result of the project. As the sum of these changes is below the corresponding SER for all pollutants, the Cogeneration Project is not a major modification and not subject to major PSD/NNSR permitting.

## 5.1.8. Minor (De Minimis) NNSR Provisions for Ozone Precursors and $SO_2$

Since this project is considered a de minimis (non-major) emissions increase as the result of the major modification applicability review for $NO_x$, VOC and $SO_2$, then a second applicability test is performed in accordance with 25 Pa Code §127.203a(a)(2). Note that these provisions do not apply to $PM_{2.5}$ or $PM_{2.5}$ precursors.

This applicability determination is an additional netting analysis that is performed similar to the major NNSR applicability determination except for the following elements:

- All contemporaneous increases/decreases that occurred within 10 years prior to the receipt of a completed application are to be included in the analysis;
- The analysis does not apply to $PM_{2.5}$ or $PM_{2.5}$ precursors; and
- If the net emissions increase, using the above methodology, is significant, then only the requirement to obtain emissions offsets applies.

U. S. Steel has identified the following contemporaneous projects[13] at Clairton that fall within this window for $NO_x$, VOC and/or $SO_2$:

- C Battery (IP-11);
- Crude tar processing (IP-15, VOC only); and
- Truck light oil loading (IP-16, VOC only).

The final step is to sum the project increases with these contemporaneous projects to reevaluated minor NNSR applicability. Table 5-3 provides this analysis and shows that the net emissions increase is greater than the SER. Therefore, the de minimis NNSR provisions (i.e., offsets) are triggered for VOC as a result of this project. U. S. Steel will work with ACHD to satisfy this requirement. As part of this effort and per 25 Pa Code §127.206(o), U. S. Steel will evaluate potential for interpollutant trading of $NO_x$ offsets for VOC offsets given the significant quantities of $NO_x$ decreases that have occurred, or are proposed to occur at the Mon Valley Works.

Table 5-3. De Minimis NNSR Applicability Summary

| Pollutant | Sum of Emissions Changes from Project (tpy) | Contemp. Increase from IP-15 (tpy) | Contemp. Increase from IP-16 (tpy) | Contemp. Increase from IP-11 (tpy) | Net Emissions Change (tpy) | Offsets to be Applied (tpy) | Final Net Emissions after Offsets (tpy) |
|---|---|---|---|---|---|---|---|
| $SO_2$ | -180.5 | 0 | 0 | 33.3 | -147.2 | -- | -147.2 |
| $NO_x$ | -643.4 | 0 | 0 | -429.5 | -1072.5 | -- | * |
| VOC | 29.3 | 6.2 | 0.6 | 38.2 | 74.3 | -85.4 | 0 |

*The net emissions change will be adjusted after VOC offsets are applied (interpollutant trading is finalized).

[13] Note that the Quench Tower 5A/7A project (IP14) involved replacement of existing quench towers. As such, there were no actual $SO_2$, $NO_x$, or VOC emissions increases associated with this project to consider in the de minimis NNSR analysis.

# 6. BEST AVAILABLE CONTROL TECHNOLOGY SUMMARY

As part of the permit application process for the new equipment, U. S. Steel has conducted a detailed BACT review. While more details regarding the top-down review can be found in Appendix D, the following is a brief tabular summary of the technology and emission rates for the cogeneration units that were determined to satisfy BACT. Other ancillary equipment controls are discussed further in Appendix D.

**Table 6-1. Summary of BACT**

| Pollutant | BACT Summary | | |
|---|---|---|---|
| | Control Technology | Emission Rate | Emission Rate Units |
| $NO_x$ | SCR and Good Combustion Practices | 7.5 | ppmvd at 15% $O_2$ (30-day average) |
| CO | Oxidation Catalyst and Good Combustion Practices | 3 | ppmvd at 15% $O_2$ |
| $PM/PM_{10}/PM_{2.5}$ (total) | Advanced Baghouse (see other precursor controls) | 0.014 | lb/MMBtu |
| VOC | Oxidation Catalyst and Good Combustion Practices | 5.1 | ppmvd at 15% $O_2$ |
| $SO_2$ | Combustion controls, scrubber | 0.024 | lb/MMBtu |
| $NH_3$ | N/A (Limiting ammonia input, use of ammonia instead of urea in SCR) | 2 | ppmvd at 15% $O_2$ |
| $CO_2e$ | Project Design (use of COG and natural gas as fuels, efficient turbine design) | 864,096 | tpy (12-month rolling basis) |

# APPENDIX A: AIR QUALITY PERMIT APPLICATION FORMS

# ALLEGHENY COUNTY HEALTH DEPARTMENT

## AIR QUALITY PERMIT APPLICATION FORM

**SECTION 1. PERMIT DESCRIPTION**

| Check Type of Permit: | Installation | Operating |
|---|---|---|
| Initial | | |
| New Construction | X | |
| Major Modification | | |
| Minor Modification | | |
| Reactivation | | |
| Temp.Source/Multi.Loc | | |
| New Permit | | |
| Renewal | | |
| Adm. Permit Amend. | | |
| Other (Explain Below) | | |

**This permit application is for a:**

| | |
|---|---|
| Major Source | X |
| Minor Source | |
| Synthetic Minor Source (See Section 10) | |

**Amount enclosed:**

**$1,700 for IP**

**FOR ACHD USE ONLY**

**Permit Number:** 0052-I019

**Completeness:** ________

**Administration:** ________

**Engineering:** ________

**Assigned to:** ________

**Brief Description of Permit Application/Source:**
Installation of a new cogeneration process at the Clairton Plant. As part of this project, three (3) of the six (6) existing boilers at the plant will be shutdown.

**SECTION 2. APPLICANT INFORMATION**

| Applicant Type Code | Applicant Name or Registered Fictitious Name |
|---|---|
| 01 | United States Steel Corporate, Mon Valley Works |

RECEIVED
FOR ACHD USE ONLY
JUN 20 2019
ALLEGHENY COUNTY HEALTH DEPT.
AIR QUALITY PROGRAM

| First Name | M. I. | Last Name |
|---|---|---|
| Kurt | | Barshick |

Title General Manager, Mon Valley Works

Mailing Address (Street # and Name or P. O. Box #, Box #, RR #, RD #)
P.O. Box 878

Relationship of Applicant to Permitted Activity. See instructions for appropriate code.

| City | State | Zip Code + Extension |
|---|---|---|
| Dravosburg | PA | 15034 |

Telephone 412-675-2600 | FAX 412-675-5407 | E-mail kbarshick@uss.com

**SECTION 3. SITE INFORMATION**

| Facility Site Name | Federal Tax Identification Number |
|---|---|
| U. S. Steel Clairton Plant | 25-0996816 |

Address (Street #, Street Prefix, Street Name, Street Type, Street Suffix) ***P. O. BOX # IS NOT ACCEPTABLE***
400 State Street

| Municipality | State | Zip Code + Extension |
|---|---|---|
| Clairton | PA | 15025-1855 |

Telephone (Day) 412-233-1003 | Telephone (Eve.) 412-233-1035 | FAX 412-233-1004

**SECTION 3. (cont.)**

**MAP LOCATION:** Please provide the Universal Transverse Mercator (UTM) coordinates or the exact latitude and longitude of the plant. UTM coordinates are preferable to latitude and longitude and can be determined from US Geological Survey 7.5 Minute 1:24,000 scale maps.

Attach a drawing of your source showing all emission points. Number each stack S001, S002, S003, etc., and number each fugitive emission location F001, F002, etc. Identify roads as paved or unpaved, marking all parking lots (see Form E). Identify the plant boundary on the map. Include local roads and other necessary identifiers that will allow the Department to locate your source on County-wide maps.

UTM North ________ Or Latitude 40 Degrees 18 Minutes 22.72 Seconds NORTH

UTM East ________ Or Longitude 79 Degrees 52 Minutes 43.27 Seconds WEST

PLANT PROPERTY 392 Acres or ________ Square feet

BUILDING AREA ________ Acres or ________ Square feet

**GIVE TRAVEL DIRECTIONS FROM DOWNTOWN PITTSBURGH:**

From ACHD's office, turn left onto 40th St. Taken ramp left for PA_28 South toward Pittsburgh. Take ramp right for I-579 South toward Monroeville. Bear right onto Crosstown Bldg and proceed over Liberty Bridge and through Liberty Tunnel. Bear right onto W. Liberty Ave. and take ramp on right for PA_51 South toward Uniontown. Bear Right onto PA-51/Saw Mill Run Blvd and proceed approximately 13 miles. Take ramp left for PA-837 North toward Clairton and bear right onto PA-837. Proceed approximately 0.5 mile and the site will be on you right.

**DESCRIPTION OF BUSINESS**

GIVE A BRIEF DESCRIPTION OF BUSINESS OR ACTIVITY CARRIED OUT AT THIS LOCATION:
Iron and steel making – by-products coke plant

PRINCIPAL PRODUCT(S):
Coke

APPROXIMATE NUMBER OF EMPLOYEES: ~1300

If employment is seasonal, give the typical peak employment and indicate what season.

**STANDARD INDUSTRIAL CLASSIFICATION (SIC) CODE FOR THIS LOCATION:**
If there is more than one activity at this location, provide the Standard Industrial Code (SIC) for the principal activity, and other SIC codes in descending order of importance.

Primary SIC Code: 33 Primary activity: Primary Metal Industries

Secondary SIC Code: ________ Secondary activity: ________

Tertiary SIC Code: ________ Tertiary activity: ________

| SECTION 4. ENVIRONMENTAL CONTACT | | | | |
|---|---|---|---|---|
| First Name<br>Jonelle | | M. I. | Last Name<br>Scheetz | |
| Title Environmental Engineer | | | | |
| Telephone (412) 233-1015 | | | FAX (412) 233-1011 | |
| Mailing Address (Street # and Name or P. O. Box #, Box #, RR #, RD #)<br>400 State Street | | | | |
| City<br>Clairton | State<br>PA | | | Zip Code + Extension<br>15025-1855 |
| E-mail jsscheetz@uss.com | | | | |

## SECTION 5: APPLICABLE REQUIREMENTS

In this section, briefly describe all applicable federal, state, or local air rules or requirements pertaining to the facility or any part of the facility.

"Applicable requirements" can come from any of the following:

- (i.) Regulations that have been promulgated or approved by the EPA under the Clean Air Act or the regulations adopted under the Clean Air Act through rulemaking at the time of issuance but have future-effective compliance dates.
- (ii.) A regulation under Allegheny County Article XXI (Air Pollution Control), including those incorporated by reference.
- (iii.) A term or condition of any installation or operating permits issued pursuant to the County air quality regulations.
- (iv.) A standard or other requirement under Section 111 of the Clean Air Act, including subsection (d).
- (v.) A standard or other requirement under Section 112 of the Clean Air Act (42 U.S.C.A. 7412), including any requirement concerning accident prevention under subsection (r) (7).
- (vi.) A standard or other requirement of the acid rain program under Title IV of the Clean Air Act (42 U.S.C.A. 7641 - 7651o) or the regulations promulgated under the Clean Air Act.
- (vii.) Requirements established under Section 504(b) or Section 114(a)(3) of the Clean Air Act (42 U.S.C.A. 7414(a)(3).
- (viii.) A standard or other requirement governing solid waste incineration, under Section 129 of the Clean Air Act (42 U.S.C.A. 7429).
- (ix.) A standard or other requirement for consumer and commercial products, under Section 183(e) of the Clean Air Act (42 U.S.C.A. 7511b(e)).
- (x.) A standard or other requirement for tank vessels, under Section 183(f) of the Clean Air Act (42 U.S.C.A. 7511b).
- (xi.) A standard or other requirement of the program to control air pollution from outer continental shelf sources, under Section 328 of the Clean Air Act (42 U.S.C.A. 7627).
- (xii.) A standard or other requirement of the regulations promulgated to protect stratospheric ozone under Title VI of the Clean Air Act (42 U.S.C.A. 7671-7671q), unless the Administrator of the EPA has determined that such requirements need not be contained in a Title V permit.
- (xiii.) A national ambient air quality standard or increment or visibility requirement under Title I, Part C of the Clean Air Act (42 U.S.C.A. 7470-77491), but only as it would apply to temporary sources permitted pursuant to Section 504(e) of the CAA (42 U.S.C.A. 7661d).

Include any regulations that are final, but may require controls to be put on, or lower emission rates to come into effect in the future. Be as specific as necessary. For example, if you have boilers rated at 10, 70, and 100 MMBtu, then for sulfur dioxide emissions list Article XXI 2104.03 a.1, 2, and 3. When you complete the Forms for specific operations, you will be requested to repeat those requirements unique to that unit. Include general emission requirements, such as 2104.04, odor emissions, if they apply.

If there are any limitations on source operation affecting emissions or any work practice standards, provide details in this section. Include supporting documents, if necessary. If the facility is claiming any exemptions to a part of an applicable requirements stated above or any other requirements, clearly identify what section. Copy this page as needed, and attach these additional pages to this section.

An example of how Section 5.A might be completed:

| **Emission Regulation** | | **Description** |
|---|---|---|
| Art. XXI | 2104.02.a.2 | **PM** 0.40 #/$10^6$ BTU |
| Art. XXI | 2104.03.a.1 | **$SO_2$** 1.0 #/$10^6$ BTU |
| Art. XXI | 2104.01.a | **Opacity** 20% for $\leq$3 min./hr. or 60% at no time |
| Art. XXI | 2105.06.d.1 | Low **NOx** Burners w/overfire air |

List and summarize all applicable federal, state, or local air rules or requirements pertaining to the facility or any part of the facility. Also describe any regulated work practice standards that affect air emissions. Include any regulations that are in place, but have delayed deadlines for compliance. (COPY THIS PAGE AS NEEDED)

| REGULATION | DESCRIPTION |
|---|---|
| 40 CFR 60 Subpart Dc | Applies to auxiliary boiler – See Section 4.2 of attached application report |
| 40 CFR 60 Subpart IIII | Applies to emergency fire pump – See Section 4.2. of application report |
| 40 CFR 60 Subpart KKKK | Applies to cogen units - See Section 4.2. of attached application report |

| | |
|---|---|
| 40 CFR 63 Subpart YYYY | Applies to cogen unit combustion turbines – see Section 4.3 of attached application report |
| 40 CFR 63 Subpart ZZZZ | Applies to emergency fire pump – see Section 4.3 of attached application report |
| 40 CFR 63 Subpart DDDDD | Applies to auxiliary boiler and dew point heaters – see Section 4.3 of attached application report |
| 2104.02.a | Applies to cogen units, emergency fire pump engine, auxiliary boiler, and dew point heaters - See Section 4.4 of attached application report |
| 2104.02.b | Applies to storage silo bin vents – See Section 4.4 of attached application report |
| 2104.03.a | Applies to cogen units, emergency engine, auxiliary boiler, and dew point heaters - See Section 4.4 of attached application report |
| 2105.06 | Applies to cogen units, emergency engine, and dew point heaters – See Section 4.4 of attached application report |
| 2105.21 | Applies to cogen units when burning COG – See Section 4.4 of attached application report |

## SECTION 6: METHOD OF DEMONSTRATING COMPLIANCE

List the method of demonstrating compliance with each of the emission standards (these may become conditions of the Operating Permit):

**A. Compliance Method/ Monitoring Devices:**

| EMISSION UNIT # | POLLUTANT | REFERENCE TEST METHOD OR COMPLIANCE METHOD OR MONITORING DEVICE | FREQUENCY / DURATION OF SAMPLING |
|---|---|---|---|
| Each Cogen Unit | NOx | CEMS | Continuous (NSPS) |
| Each Cogen Unit | $PM_{10}/PM_{2.5}$ | Stack Test | Once every two years |
| Each Cogen Unit | CO | Stack Test | Once every two years |
| Each Cogen Unit | VOC | Stack Test | Once every two years |
| Each Cogen Unit | $SO_2$ | Stack Test | Annually |
| Each Cogen Unit | $NH_3$ | Stack Test | Initial Test to Correlate Parametric Monitoring with Compliant $NH_3$ Emissions |
| | | | |
| | | | |
| Attach any details that would further explain the method of compliance. | | | |

**B. Record keeping and Reporting:**

1. List what parameter will be recorded and the frequency of recording:

| PARAMETER | FREQUENCY |
|---|---|
| Fuel Usage in CTGs and HRSG Duct Burners, Existing Clairton Boilers R-2, T-1, T-2 | Monthly |
| Baghouse Differential Pressure | Continuous |
| Catalyst Temperature | Continuous |
| Ammonia Injection Rate | Continuous |
| Operating Hours for Emergency Engine, Auxiliary Boiler & Dew Point Heaters | Monthly |

2. Describe what is to be reported and the frequency of reporting? (Reports must be submitted at least every six (6) months)

| DESCRIPTION | FREQUENCY |
|---|---|
| Actual emissions accounted for in annual emissions inventory | Annual |
| Summary of NOx CEMS data | Semi-annual |
| Summary of control device monitoring data (e.g., dP, temperature, etc.) | Semi-annual |
| Fuel usage (quantity and type) | Semi-annual |
| | |
| | |

3. Beginning reporting date: __ /__ /__

COPY THIS PAGE AS NEEDED

## SECTION 7: COMPLIANCE PLAN

A source may apply for and receive an Operating Permit if one or more emission units are out of compliance with a regulation, provided that an adequate plan is in place to bring the unit(s) into compliance.

**A.__** 1. At the time of this permit application is your source in compliance with all applicable requirements, and do you expect your source to remain in compliance with these requirements during the permit duration (with the exception noted in item C)?

_X_ Yes __ No

2. Will your source be in compliance with all applicable requirements scheduled to take effect during the term of the permit, and will they be met by the applicable deadline?

_X_ Yes __ No

**B.__** If you checked "No" for any question in Part A, please attach information identifying the requirement(s) and emission units for which compliance is not achieved, briefly describe how compliance will be achieved with the applicable requirement(s), and provide a detailed Schedule of Compliance (i.e., a schedule of remedial measures, including an enforceable sequence of actions with milestones and projected compliance dates). Title this portion of the document "Schedule M: Compliance Information". Indicate the frequency for submittal of progress reports (at least every six (6) months) and the starting date for submittal of progress reports.

**C.__** Do you have scheduled shutdown of control equipment for maintenance while the emission units are still operating?

__ Yes _X_ No

If yes, attach a description of the equipment that will be taken out of service, what pollutants and emission sources are affected, the schedule and duration of the shutdown, and what actions will be taken to minimize emissions.

## SECTION 8: OTHER PERMITS

Do you own or are you related to any other permitted company in Pennsylvania?

_X_ Yes __ No

If so, please list the company names:

U. S. Steel Mon Valley Works – Edgar Thomson Plant

U. S. Steel Mon Valley Works – Irvin Plant

U. S. Steel Mon Valley Works – Fairless Plant

## SECTION 9: COMPLIANCE CERTIFICATION

You are required to submit a certificate of compliance with all applicable requirements and a method of determining compliance with those requirements (CEMS, monitoring, tests, record keeping and other reporting). Compliance certifications are to be submitted at least on an annual basis. Please answer the following:

Schedule for Submission of Compliance Certification during the term of the permit:

_X_ We will submit a Compliance Certification annually at the same time as the submittal of the annual administrative fee. OR

___ Beginning on: __ /__ /__

### CERTIFICATION OF COMPLIANCE WITH ALL APPLICABLE REQUIREMENTS

**A "responsible official" must sign this certification. Applications without original signed certifications or necessary corporate authorizations will be returned as incomplete.**

**Except for the requirements identified in Section 7 for which compliance is not yet achieved, I hereby certify that, based on information and belief formed after reasonable inquiry, the source identified in this application is in compliance with all applicable air requirements.**

**Signature of Responsible Official**

Kurt Barshick; General Manager MVW
**Name and Title of Signer (Print or Type)**

P.O. Box 878
**Mailing Address (Street # and Name or P. O. Box #, RR #, RD #, Box #)**

Dravosburg, PA 15034
**City, State, and Zip Code + Extension**

**Date:** 6 /20/ 2019

## SECTION 10: SYNTHETIC MINOR

A Major source may, at its option, choose to place limits on its operation or emissions in order to become a "Synthetic Minor" source, and not be subject to the additional requirements of a Major source. These limits will become permit restrictions and will be federally enforceable.

Does this application include any requested restrictions?
_X_ Yes ___ No

If so, have these restrictions caused this site to go below Major source thresholds and become a Synthetic Minor?
__ Yes _X_ No

Is this facility requesting to become a Synthetic Minor source?
__ Yes _X_ No
(Please check the box on the top of page 1 as well.)

Be sure to include on each source information sheets, Forms A, B, and C, a complete description of the limitations that make this source a Synthetic Minor. Attach extra pages, if needed.

## SECTION 11: INFORMATION FOR INSTALLATION PERMITS

Is this a new Major source or Major Modification for any criteria pollutant which is in or impacting a non-attainment area?
__ Yes _X_ No

If yes, list below for which pollutant(s).

______________________________________________
______________________________________________
______________________________________________
______________________________________________
______________________________________________

Attach all required documents required under Article XXI, sections 2102.05 and 2102.06.

Is this a new Major source or Major Modification for any criteria pollutant which is in or impacting an attainment area or unclassified area?
__ Yes _X_ No

If yes, list below for which pollutant(s).

______________________________________________
______________________________________________
______________________________________________
______________________________________________
______________________________________________

Attach all required documents required under Article XXI, sections 2102.05 and 2102.07.

A source applying for a Minor Installation Permit may request public review at this time.

Are you requesting public review for a Minor Installation Permit?

__ Yes _X_ No

## SECTION 12: ALTERNATIVE OPERATING SCENARIOS

This permit allows for certain flexibility in operations. Please note the explanation of this section in the instructions. While filling out your permit application, consider all the different operating scenarios you might want to operate under during the 5-year term of your permit. This may include a change in inks or solvents, operating schedules, or other expected departures from operations that cannot be adequately described in the main body of the permit application.

Do you seek approval of any alternative operating scenario?

__ Yes _X_ No

If "Yes": Complete Form N to provide complete information for each alternative operating scenario to be employed at this location. Duplicate pages as needed.

Please note that there may be additional reporting requirements for alternative scenarios.

## SECTION 13: ADDITIONAL SUBMITTALS

A form must be submitted for each process, boiler, incinerator, etc., as indicated below. Provide the numbers of each type of unit below, and submit the designated form for each unit. Also, identify each criteria pollutant and other regulated pollutant emitted by this source (facility). See Article XXI, definition of hazardous air pollutant and section 2101.10. Include also other pollutants not regulated, but with known emission rates. Provide the total below, and submit an emissions summary for each pollutant. List below all attachments made for this application. All applicable forms must be attached to each copy of the application.

_3_ Number of Processes - Submit one Form A for each process. Number each P001, P002, etc.
_6_ Number of Boilers - Submit one Form B for each boiler. Number each B001, B002, etc.
_0_ Number of Incinerators - Submit Form C for each incinerator. Number each I001, I002, etc.
_1_ Number of storage tanks - Submit one Form D for each tank or group of tanks. Number each D001, D002, etc.
_1_ Dry bulk materials storage and handling - Submit Form E.
_1_ Roads and vehicles - Submit Form F.
_0_ Miscellaneous fugitive emissions - Submit Form G.
_1_ Number of Form F: Roads and Vehicles.
_0_ Number of Form G: Miscellaneous Fugitive Emissions.
_8_ Number of Form K: One Emissions Summary Form for Each Pollutant.
_0_ Number of Form M: One Form M for each.
_0_ Number of Form N: One Form N for each scenario.

Are map(s)/drawing(s) attached? _X_ Yes __ No

Are required documents attached pertaining to an Installation Permit? _X_ Yes __ No

Are other comments/notes attached? _X_ Yes __ No

Is a **Best Available Control Technology (BACT) analysis attached for installations?** _X_ Yes __ No

Is a **Compliance Assurance Monitoring** (CAM) **Plan** (40 CFR Part 64) attached? (applicable to Title V Operating Permit Renewals.) __ Yes _X_ No

## SECTION 14: ANNUAL APPLICATION / ADMINISTRATION FEE CALCULATION

**INSTALLATION PERMIT APPLICATION** - Check all that pertain to this application:

If this source is applicable to more than one category listed below, it is subject to the **highest** of the applicable fees, not to the total.

| | | |
|---|---|---|
| A | ☐ | Prevention of Significant Deterioration ($22,700) |
| B | ☐ | Involving ACHD Development of a MACT Standard ($8,000) |
| C | ☐ | Major new source or Major Modification ($8,000) |
| D | X | Any source subject to an existing NSPS, NESHAP, or MACT ($1,700) |
| E | ☐ | Any other Installation Permit ($1,000) |
| F | ☐ | Modification to an existing Installation Permit ($300) |

**Installation Permit Fee** $ 1,700

**Note: An administrative fee of $750.00 will be billed to the source, beginning 30 days after the Installation Permit is approved, and annually on the anniversary of the approval thereafter, until a complete Operating Permit Application has been submitted to the Department.**

**OPERATING PERMIT APPLICATION** - Check all that pertain to this application:

| | | |
|---|---|---|
| *A.* | ***Base fee*** (Minor or Synthetic Minor Source - $375.00 / Major Source - $750.00): | $ ____ |
| B. | **Hazardous Air Pollutant Source fee** - (Major Source only - if any "hazardous air pollutants" (see §2101.10) are listed on Form K, add $375.00) | +$ ______ |
| C. | **Acid Rain Source fee** (Major Source only - if any "acid rain" regulations are listed in Section 5, - add $375.00) | +$ ______ |
| D. | **Adjusted Base fee** - Add A., B., and C.: | =$ ______ |
| E. | **Noncomplying Source fee** (if "No" is checked in Section 7 Part A) Add 50% of the "Adjusted Base fee" from line D. above: | +$ ______ |
| F. | **Total Fee Due** - Add D. and E.: | =$ ____ |

***Checks are to be made payable to the "ACHD Air Pollution Control Fund."***

**All sources that apply for Operating Permits will be required to pay an annual administrative fee equal to the Operating Permit Application Fee. Major sources are also required to pay annual emissions fees. These are to be paid at the scheduled submittal of the annual emissions inventory.**

| **SECTION 14. BILLING CONTACT** | | | |
|---|---|---|---|
| First Name Kurt | M. I. | Last Name Barshick | |
| Title General Manager Mon Valley Works | | | |
| Telephone 412-675-2600 | | FAX 412-675-5407 | |
| Mailing Address (Street # and Name or P. O. Box #, Box #, RR #, RD #): P.O. Box 878 | | | |
| City Dravosburg | State PA | Zip Code + Extension 15034 | |
| E-mail kbarshick@uss.com | | | |

## SECTION 15: SIGNATURES AND CERTIFICATION

### CERTIFICATION OF COMPLETED APPLICATION

**CERTIFICATION {for corporate applicants: Attach Certificate of Corporate Authority}**

| Applicant | Preparer |
|---|---|
| Subject to the penalties of Title 18 Pa. C.S. Section 4904 relating to unsworn falsification to authorities, I certify that I have the authority to submit this Permit Application on behalf of the applicant named herein and that the information provided in this Application is true and correct to the best of my knowledge and information. | Signature of Preparer of Form (if different than applicant). |
| Signature: ______ Date: 6-20-2019 | Signature: ______ |
| Kurt Barshick<br>Name – Print or Type | Name, Mailing Address, and Phone# - Print or Type |
| General Manager, Mon Valley Works<br>Title – Print or Type | Christopher Hardin |
| P.O. Box 878<br>Mailing Address – Print or Type | 1350 Penn Ave, Suite 200 |
| Dravosburg, PA 15034<br>City, State, and Zip Code + Extension – Print or Type | Pittsburgh, PA 15222 |
| ( 412 )675-2600 Day Phone Number; ( 412 )675-5407 Fax Phone Number | |

{For corporations:
Certificate of Corporate Authority must be completed, by the Corporate Secretary, and attached}

### CERTIFICATE OF CORPORATE AUTHORITY

I, Duane Holloway, certify that I am the Secretary of the corporation named above; that Kurt Barshick, who has signed this document on behalf of the corporation was then General Manager, MVW of the said corporation; and that I know his/her signature and his/her signature is genuine; and that said Agreement was fully signed, sealed, and attested for and in behalf of said corporation by authority of its governing body.

ATTESTED TO BY: ______ DATE: 6/20/2019

{Signature}

NAME: Duane Holloway

{Print or type}

TITLE: SECRETARY

[AFFIX CORPORATE SEAL]

United States Seal Corporation CORPORATE SEAL 2001 DELAWARE

## PERMIT APPLICATION FORM A
## PROCESS OPERATIONS

**PLANT NAME AND LOCATION:** U. S. Steel Clairton Plant

**PART I - DESCRIPTION OF PROCESS** (MAKE A COPY OF SCHEDULE A FOR EACH PROCESS.)

Company Identification or Description: Cogeneration Unit 1

Installer: Unknown at this time    Installation Date: TBD, Begin ~2020

Contractor (if operated by another): N/A

Design ___ Charging or _X_ Production rate (specify units): ~47 MW/hr (nominal at 50 ºF)

Total Annual Production (specify units normally used): ____________

Raw Materials: Fuel (coke oven gas and natural gas)

Materials Produced: Steam and electricity

Process Operation Units: (Name and Previous County Permit Number, if any)

(1.) Combustion Turbine
(2.) Heat Recovery Steam Generating (HRSG) Unit
(3.) ____________
(4.) ____________
(5.) ____________
(6.) ____________

**Diagram of Process Flow:** Attach a separate sheet with a drawing of a flow diagram of this process, labeling each segment listed under Process Operation Segments. Label product intake points and product discharge points for each segment. Label emissions discharge points and the location of emissions control devices.

**PART II - PROCESS OPERATION SCHEDULE (per station)**

A. Normal schedule: (Provide information for last year. If a new unit, please estimate)

Hours/day 24    Days/week 7    Weeks/year 52    Hours/year 8,520

Start time __:__    End time __:__

Seasonal: Periods correspond to seasons instead of calendar quarters. The first season is split to include December, January, and February of the calendar year reported.

Percent of Annual Production

| | | | |
|---|---|---|---|
| December, January, & February | 25 | June, July, & August | 25 |
| March, April, & May | 25 | September, October, & November | 25 |

B. Requested limits: (Limitations on operating hours are optional.) Choose One:

_X (TPY Limits)_ 8760 hours (no limitations) or

___ I/We request the following limitation -- **This may become a federally enforceable permit condition:** Describe how this can be enforced: either list an operating schedule or downtime (e.g. only operate 8:00 to 4:00) or an operating hour reporting requirement.

_______ Total days x _______ Hours/day = _______ Hours/year

## PART III – FUELS (per station)

A. Normal operation (Provide information for last year. If a new unit, please estimate)

| ____ Year ____ or X ____ Estimate | Primary | Secondary | Other | Other |
|---|---|---|---|---|
| Type: | COG | Natural Gas | COG/NG Blend | |
| Max Amount/hour | 1,071 MMBtu /hr | 1,071 MMBtu /hr | 1,071 MMBtu /hr | |
| Sulfur Content (% wt): | 35 gr/100 scf ($H_2S$,) | Negl. | 35 gr/100 scf ($H_2S$) | |
| Ash Content (% wt): | Negl. | Negl. | Negl | |
| BTU Rating (specify units) | 1,071 MMBtu /hr | 1,071 MMBtu /hr | 1,071 MMBtu /hr | |
| Annual Fuel Consumption | ~ 7290000 MMBtu/ yr | ~ 7054600 MMBtu/ yr | ~ 7237700 MMBtu/ yr | |
| Seasonal Fuel Consumption (%): | | | | |
| December, January, and February | 25 | 25 | 25 | |
| March, April, and May | 25 | 25 | 25 | |
| June, July, and August | 25 | 25 | 25 | |
| September, October, and November | 25 | 25 | 25 | |

Fuel Mixing: If more than one fuel is used, explain usage, stating whether it is burned separately, mixed in a fixed ratio of__:__ (give units such as BTU, mmcf, gallons per ton, etc.), mixed in a variable ratio of__:__ to __:__, determined by ___ (give reason).

B. Requested limits (limitations on operations are optional, but may allow a Major source to be exempted from some requirements) **These may become permit conditions.** Please check one:

X (MMBtu/year Limits) Full use of any fuel or combination at any time (no limitations)

__ The following limitations on types of fuels or the combination of fuels are requested (describe how compliance with this method will be demonstrated)

## PART IV - OTHER LIMITATIONS

Identify any other requested limitations, such as on production rates or materials use. Describe how compliance with these restrictions will be demonstrated. **These limitations may become permit conditions.**

N/A

## PART V - APPLICABLE REQUIREMENTS

Describe all applicable requirements affecting air emissions for this unit.

| Regulation # | Requirements |
|---|---|
| 40 CFR 60.4320(a) | $NO_X$ limit when firing natural gas = 25 ppm @ 15% $O_2$<br>$NO_X$ limit when firing > 50% COG = 74 ppm @ 15% $O_2$ |
| 40 CFR 60.4330(a) | $SO_2$ limit = 0.06 lb/MMBtu (fuel sulfur input concentration) or 0.9 lb/MWh gross output |
| 2104.01.a | Opacity < 20% for 3-minutes in any 60-minute period, or < 60% at any time |
| 2104.02.a | PM filt. limits (lb/MMBtu) = 0.012 lb/MMBtu for natural gas; 0.064 lb/MMBtu for COG; 0.050for COG/NG blend |
| 2104.03.a | $SO_2$ < 0.64lb/MMBtu |
| 2105.06 | Install $NO_X$ CEMS |
| 2105.21 | H2S concentration in COG < 40 gr/100 scf |
| | |

**PART VI - EMISSION CONTROLS**

Complete the following applicable sections for each pollution control device. Attach additional sheets to provide sufficient information and engineering calculations to support the contol device performance.

On the space to the left of each device, number the device(s) by the order in which they process the waste stream(s). Fill out the requested information, then complete the table for efficiencies by pollutant for each device.

Percent Capture __100__ % (not control efficiency)
Gas flow through control units __TBD__ @ __TBD__ °F

__X__ **BAGHOUSE (fabric collector)**

Manufacturer's Name and Model __TBD, vendor selection still not finalized__
Type of bag material __TBD__
Total filter cloth area __TBD__ sq. ft., air to cloth ratio __TBD__
Bag cleaning method: __TBD__ , cycle __TBD__ min
Pressure Drop: clean __TBD__ "$H_2O$, dirty __TBD__ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|
| $PM/PM_{10}/PM_{2.5}$ (total) | N/A | Performance Expectation | 0.014 lb/MMBtu |

_____ **ELECTROSTATIC PRECIPITATOR**

Manufacturer's Name and Model: ____________
Type: __ Single Stage, __ Two Stage, __ Plate, __ Tube
Total collecting area: ________ sq. ft., cleaning cycle ______ min.
Gas Velocity: ________ ft./sec. corona power ______ kw
Bulk resistivity of dust: ______ ohm-cm Moisture content of gases: ______ vol. %

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

_____ **CYCLONE (dry gas only)**

Manufacturer's Name and Model: ____________
Gas Inlet: width ______ ft., height ______ ft.
Diameter: gas outlet ______ ft., cyclone cylinder (s) ______ ft.
Length of cyclone: ______ ft., no. of cylinder(s) ______ Pressure Drop ______ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

| PART VI - EMISSION CONTROLS (CONTINUED) | NOT APPLICABLE |
|---|---|

_____ **CONDENSER**

Manufacturer's Name and Model: ____________________

Type: surface __________ , contact ____________________

Heat transfer area: _________ sq. ft., max process pressure _________ psia

Heat duty: ________ BTU/hr. Coolant temp: inlet ____________ °F outlet _________ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

_____ **WET COLLECTOR**

Manufacturer's Name and Model: ____________________

Type: __ venturi, __ cyclone, __ spray chamber, __ packed bed

Entrainment/separator: type __________ , bed depth __________

Type & construction of chemicals added to the scrubbing liquid:

Pressure drop _________ "$H_2O$

Scrubbing liquid: flow rate _______ gpm, inlet temp. ________ °F, outlet temp. _______ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

X **AFTERBURNER (Oxidation Catalyst)**

Manufacturer's Name and Model: TBD, vendor selection still not finalized

Type: __ direct flame, X catalytic

If catalytic: inlet temp. TBD °F, outlet temp. TBD °F, catalyst life TBD

If direct flame: internal volume N/A cu. ft., average temp. N/A °F

Residence time at average temp. TBD Sec

Auxiliary fuel: max. rating N/A BTU/hr. set point N/A °F, N/A BTU/hr.

Size of Chamber N/A cu. ft., flow rate N/A

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading (gn./cu. ft.) |
|---|---|---|---|
| Carbon Monoxide | 90 | Performance Expectation | N/A |
| VOC | 40 | Performance Expectation | N/A |

_____ **ADSORPTION EQUIPMENT**

Manufacturer's Name and Model: ____________________

Type: __ Continuous, __ Fixed bed

Adsorbing material: ____________ , Bed depth ____________ in., Flow area _________ sq. ft.

Breakthrough (breakpoint) time: _________ , Pressure Drop: __________ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

**PART VI - EMISSION CONTROLS (CONTINUED)** **NOT APPLICABLE**

X **OTHER TYPES** Name and describe. Attach complete details.

| | |
|---|---|
| $NO_x$ | SCR, device outlet performance at 7.5 ppmvd |
| $SO_2$ | Scrubber |
| | |
| | |
| | |

**FUGITIVE DUST CONTROLS:** Describe below or attach a complete explanation of all controls of fugitive emissions not discussed in Form E - Roads or Form F - Storage Piles.

N/A

## PART VII - STACK DATA

Stack data must be provided for each flue, duct, pipe, stack, chimney or conduit (stacks) at which collected emissions are vented to open air through a restricted opening.

Stack Identification: COGEN1

UTM East TBD UTM North TBD or

Longitude TBD Latitude TBD

Most important stacks have been located on topographic or air navigation charts. If you know the UTM coordinates or latitude and longitude, provide this information. If there is a number of stacks close together, a common location may be used

Stack Height: TBD ft. Ground level elevation TBD ft. Diameter TBD ft.

Material Outer: TBD lining: TBD

Exit temperature (°F): TBD Exit Velocity: TBD f/s.

Exhaust Rate: TBD (ACFM) % Moisture: TBD

Nearest building to stack:

distance TBD ft. height TBD ft. length TBD ft. width TBD ft.

**Processes Sharing Stack:** If more than one process shares a stack, list them and estimate relative contribution of each.

Description TBD

Contribution to emissions from stack ______ %

Description ______

Contribution to emissions from stack ______ %

Description ______

Contribution to emissions from stack ______ %

Description ______

## PART VIII - REMARKS

**Attach calculations and reference all emission factors for Allowable, Potential to Emit, and Actual Emissions to this sheet. Reference all emission factors and efficiencies of control equipment.**

| PART IX - EMISSIONS |
|---|

**PART 9a: EMISSIONS -- SHORT TERM LB/HR (POUNDS PER HOUR) OR OTHER** **See Appendix C for Detailed Calculations**

*Operations Exclusive of Startup and Shutdown (Total Cogeneration Unit 1 Emissions – Turbine Plus HRSG)*

| Pollutant | PM | PM10 | $SO_2$ | CO | $NO_X$ | VOC | LEAD | PM2.5 |
|---|---|---|---|---|---|---|---|---|
| Allowable | 7.9 | 7.9 | 24.7 | 5.5 | 25.9 | 5.9 | 7.3E-04 | 7.9 |
| Maximum Potential | 7.9 | 7.9 | 24.7 | 5.5 | 25.9 | 5.9 | 7.3E-04 | 7.9 |
| Actual or Estimated | 7.9 | 7.9 | 24.7 | 5.5 | 25.9 | 5.9 | 7.3E-04 | 7.9 |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

**PART 9b: EMISSIONS -- ANNUAL TPY (TONS PER YEAR)**

*Operations Inclusive of Startup and Shutdown (Cogeneration UnitTotal Cogeneration Unit 1 Emissions – Turbine Plus HRSG)*

| Pollutant | PM | PM10 | $SO_2$ | CO | $NO_X$ | VOC | LEAD | PM2.5 |
|---|---|---|---|---|---|---|---|---|
| Allowable | 4.7 | 18.4 | 87.1 | 19.3 | 94.7 | 15.5 | 3.1E-03 | 18.4 |
| Maximum Potential | 4.7 | 18.4 | 87.1 | 19.3 | 94.7 | 15.5 | 3.1E-03 | 18.4 |
| Actual or Estimated | 4.7 | 18.4 | 87.1 | 19.3 | 94.7 | 15.5 | 3.1E-03 | 18.4 |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

## PERMIT APPLICATION FORM A
## PROCESS OPERATIONS

**PLANT NAME AND LOCATION:** U. S. Steel Clairton Plant

**PART I - DESCRIPTION OF PROCESS** (MAKE A COPY OF SCHEDULE A FOR EACH PROCESS.)

Company Identification or Description: Cogeneration Unit 2

Installer: Unknown at this time Installation Date: TBD, Begin ~2020

Contractor (if operated by another): N/A

Design ___ Charging or _X_ Production rate (specify units): ~47 MW/hr (nominal at 50 °F)

Total Annual Production (specify units normally used): ____________

Raw Materials: Fuel (coke oven gas and natural gas)

Materials Produced: Steam and electricity

Process Operation Units: (Name and Previous County Permit Number, if any)

(1.) Combustion Turbine
(2.) Heat Recovery Steam Generating (HRSG) Unit
(3.) ____________
(4.) ____________
(5.) ____________
(6.) ____________

**Diagram of Process Flow:** Attach a separate sheet with a drawing of a flow diagram of this process, labeling each segment listed under Process Operation Segments. Label product intake points and product discharge points for each segment. Label emissions discharge points and the location of emissions control devices.

**PART II - PROCESS OPERATION SCHEDULE (per station)**

A. Normal schedule: (Provide information for last year. If a new unit, please estimate)

Hours/day 24 Days/week 7 Weeks/year 52 Hours/year 8,520

Start time __:__ End time __:__

Seasonal: Periods correspond to seasons instead of calendar quarters. The first season is split to include December, January, and February of the calendar year reported.

Percent of Annual Production

| | | | |
|---|---|---|---|
| December, January, & February | 25 | June, July, & August | 25 |
| March, April, & May | 25 | September, October, & November | 25 |

B. Requested limits: (Limitations on operating hours are optional.) Choose One:

**X (TPY Limits)** 8760 hours (no limitations) or

___ I/We request the following limitation -- **This may become a federally enforceable permit condition:** Describe how this can be enforced: either list an operating schedule or downtime (e.g. only operate 8:00 to 4:00) or an operating hour reporting requirement.

_______ Total days x _______ Hours/day = _______ Hours/year

## PART III – FUELS (per station)

A. Normal operation (Provide information for last year. If a new unit, please estimate)

| ____ Year ____ or X Estimate | Primary | Secondary | Other | Other |
|---|---|---|---|---|
| Type: | COG | Natural Gas | COG/NG Blend | |
| Max Amount/hour | 1,071 MMBtu /hr | 1,071 MMBtu /hr | 1,071 MMBtu /hr | |
| Sulfur Content (% wt): | 35 gr/100 scf ($H_2S$) | Negl. | 35 gr/100 scf ($H_2S$) | |
| Ash Content (% wt): | Negl. | Negl. | Negl | |
| BTU Rating (specify units) | 1,071 MMBtu /hr | 1,071 MMBtu /hr | 1,071 MMBtu /hr | |
| Annual Fuel Consumption | ~ 7290000 MMBtu/ yr | ~ 7054600 MMBtu/ yr | ~ 7237700 MMBtu/ yr | |
| Seasonal Fuel Consumption (%): | | | | |
| December, January, and February | 25 | 25 | 25 | |
| March, April, and May | 25 | 25 | 25 | |
| June, July, and August | 25 | 25 | 25 | |
| September, October, and November | 25 | 25 | 25 | |

Fuel Mixing: If more than one fuel is used, explain usage, stating whether it is burned separately, mixed in a fixed ratio of__:__ (give units such as BTU, mmcf, gallons per ton, etc.), mixed in a variable ratio of__:__ to __:__, determined by ___ (give reason).

B. Requested limits (limitations on operations are optional, but may allow a Major source to be exempted from some requirements) **These may become permit conditions**. Please check one:

X (MMBtu/yr Limits) Full use of any fuel or combination at any time (no limitations)

__ The following limitations on types of fuels or the combination of fuels are requested (describe how compliance with this method will be demonstrated)

## PART IV - OTHER LIMITATIONS

Identify any other requested limitations, such as on production rates or materials use. Describe how compliance with these restrictions will be demonstrated. **These limitations may become permit conditions.**

N/A

## PART V - APPLICABLE REQUIREMENTS

Describe all applicable requirements affecting air emissions for this unit.

| Regulation # | Requirements |
|---|---|
| 40 CFR 60.4320(a) | $NO_X$ limit when firing natural gas = 25 ppm @ 15% $O_2$<br>$NO_X$ limit when firing > 50% COG = 74 ppm @ 15% $O_2$ |
| 40 CFR 60.4330(a) | $SO_2$ limit = 0.06 lb/MMBtu (fuel sulfur input concentration) or 0.9 lb/MWh gross output |
| 2104.01.a | Opacity < 20% for 3-minutes in any 60-minute period, or < 60% at any time |
| 2104.02.a | PM limits (lb/MMBtu) = 0.012 lb/MMBtu for natural gas; 0.064 lb/MMBtu for COG; 0.050for COG/NG blend |
| 2104.03.a | $SO_2$ < 0.64 lb/MMBtu |
| 2105.06 | Install $NO_X$ CEMS |

## PART VI - EMISSION CONTROLS

Complete the following applicable sections for each pollution control device. Attach additional sheets to provide sufficient information and engineering calculations to support the contol device performance.

On the space to the left of each device, number the device(s) by the order in which they process the waste stream(s). Fill out the requested information, then complete the table for efficiencies by pollutant for each device.

Percent Capture 100 % (not control efficiency)
Gas flow through control units TBD @ TBD °F

X **BAGHOUSE (fabric collector)**
Manufacturer's Name and Model TBD, vendor selection still not finalized
Type of bag material TBD
Total filter cloth area TBD sq. ft., air to cloth ratio TBD
Bag cleaning method: TBD, cycle TBD min
Pressure Drop: clean TBD "$H_2O$, dirty TBD "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|
| $PM/PM_{10}/PM_{2.5}$ (total) | N/A | Performance Expectation | 0.014 lb/MMBtu |

____ **ELECTROSTATIC PRECIPITATOR**
Manufacturer's Name and Model: ____
Type: __ Single Stage, __ Two Stage, __ Plate, __ Tube
Total collecting area: ____ sq. ft., cleaning cycle ____ min.
Gas Velocity: ____ ft./sec. corona power ____ kw
Bulk resistivity of dust: ____ ohm-cm Moisture content of gases: ____ vol. %

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

____ **CYCLONE (dry gas only)**
Manufacturer's Name and Model: ____
Gas Inlet: width ____ ft., height ____ ft.
Diameter: gas outlet ____ ft., cyclone cylinder (s) ____ ft.
Length of cyclone: ____ ft., no. of cylinder(s) ____ Pressure Drop ____ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

**PART VI - EMISSION CONTROLS (CONTINUED)** **NOT APPLICABLE**

____ **CONDENSER**

Manufacturer's Name and Model: ____________

Type: surface ________ , contact ____________

Heat transfer area: ________ sq. ft., max process pressure ________ psia

Heat duty: ________ BTU/hr. Coolant temp: inlet ____________ °F outlet ________ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
| --- | --- | --- | --- |

____ **WET COLLECTOR**

Manufacturer's Name and Model: ____________

Type: __ venturi, __ cyclone, __ spray chamber, __ packed bed

Entrainment/separator: type ________ , bed depth ________

Type & construction of chemicals added to the scrubbing liquid:

Pressure drop ________ "$H_2O$

Scrubbing liquid: flow rate ________ gpm, inlet temp. ________ °F, outlet temp. ________ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
| --- | --- | --- | --- |

X **AFTERBURNER (Oxidation Catalyst)**

Manufacturer's Name and Model: TBD, vendor selection still not finalized

Type: __ direct flame, X catalytic

If catalytic: inlet temp. TBD °F, outlet temp. TBD °F, catalyst life TBD

If direct flame: internal volume N/A cu. ft., average temp. N/A °F

Residence time at average temp. TBD Sec

Auxiliary fuel: max. rating N/A BTU/hr. set point N/A °F, N/A BTU/hr.

Size of Chamber N/A cu. ft., flow rate N/A

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading (gn./cu. ft.) |
| --- | --- | --- | --- |
| Carbon Monoxide | 90 | Performance Expectation | N/A |
| VOC | 40 | Performance Expectation | N/A |

____ **ADSORPTION EQUIPMENT**

Manufacturer's Name and Model: ____________

Type: __ Continuous, __ Fixed bed

Adsorbing material: ________ , Bed depth ________ in., Flow area ________ sq. ft.

Breakthrough (breakpoint) time: ________ , Pressure Drop: ________ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
| --- | --- | --- | --- |

| PART VI - EMISSION CONTROLS (CONTINUED) | <u>NOT APPLICABLE</u> |
|---|---|

X **OTHER TYPES** Name and describe. Attach complete details.

| | |
|---|---|
| NOx | SCR, device outlet performance at 7.5 ppmvd |
| SO2 | Scrubber |
| | |
| | |
| | |

**FUGITIVE DUST CONTROLS:** Describe below or attach a complete explanation of all controls of fugitive emissions not discussed in Form E - Roads or Form F - Storage Piles.

N/A

## PART VII - STACK DATA

Stack data must be provided for each flue, duct, pipe, stack, chimney or conduit (stacks) at which collected emissions are vented to open air through a restricted opening.

Stack Identification: COGEN2

UTM East TBD UTM North TBD or

Longitude TBD Latitude TBD

Most important stacks have been located on topographic or air navigation charts. If you know the UTM coordinates or latitude and longitude, provide this information. If there is a number of stacks close together, a common location may be used

Stack Height: TBD ft. Ground level elevation TBD ft. Diameter TBD ft.

Material Outer: TBD lining: TBD

Exit temperature (°F): TBD Exit Velocity: TBD f/s.

Exhaust Rate: TBD (ACFM) % Moisture: TBD

Nearest building to stack:

distance TBD ft. height TBD ft. length TBD ft. width TBD ft.

**Processes Sharing Stack:** If more than one process shares a stack, list them and estimate relative contribution of each.

Description TBD

Contribution to emissions from stack ______ %

Description ______

Contribution to emissions from stack ______ %

Description ______

Contribution to emissions from stack ______ %

Description ______

## PART VIII - REMARKS

**Attach calculations and reference all emission factors for Allowable, Potential to Emit, and Actual Emissions to this sheet. Reference all emission factors and efficiencies of control equipment.**

| PART IX - EMISSIONS |
|---|

**PART 9a: EMISSIONS -- SHORT TERM LB/HR (POUNDS PER HOUR) OR OTHER**   **See Appendix C for Detailed Calculations**

***Operations Exclusive of Startup and Shutdown (Cogeneration UnitTotal Cogeneration Unit 2 Emissions – Turbine Plus HRSG)***

| Pollutant | PM | PM10 | $SO_2$ | CO | $NO_X$ | VOC | LEAD | PM2.5 |
|---|---|---|---|---|---|---|---|---|
| Allowable | 7.9 | 7.9 | 24.7 | 5.5 | 25.9 | 5.9 | 7.3E-04 | 7.9 |
| Maximum Potential | 7.9 | 7.9 | 24.7 | 5.5 | 25.9 | 5.9 | 7.3E-04 | 7.9 |
| Actual or Estimated | 7.9 | 7.9 | 24.7 | 5.5 | 25.9 | 5.9 | 7.3E-04 | 7.9 |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

**PART 9b: EMISSIONS -- ANNUAL TPY (TONS PER YEAR)**

***Operations Inclusive of Startup and Shutdown (Cogeneration UnitTotal Cogeneration Unit 2 Emissions – Turbine Plus HRSG)***

| Pollutant | PM | PM10 | $SO_2$ | CO | $NO_X$ | VOC | LEAD | PM2.5 |
|---|---|---|---|---|---|---|---|---|
| Allowable | 4.7 | 18.4 | 87.1 | 19.3 | 94.7 | 15.5 | 3.1E-03 | 18.4 |
| Maximum Potential | 4.7 | 18.4 | 87.1 | 19.3 | 94.7 | 15.5 | 3.1E-03 | 18.4 |
| Actual or Estimated | 4.7 | 18.4 | 87.1 | 19.3 | 94.7 | 15.5 | 3.1E-03 | 18.4 |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

# PERMIT APPLICATION FORM A
# PROCESS OPERATIONS

**PLANT NAME AND LOCATION:** U. S. Steel Clairton Plant

**PART I - DESCRIPTION OF PROCESS** (MAKE A COPY OF SCHEDULE A FOR EACH PROCESS.)

Company Identification or Description: Diesel Emergency Fire Pump

Installer: Unknown at this time Installation Date: TBD, Begin ~2020

Contractor (if operated by another): N/A

Design ___ Charging or _X_ Production rate (specify units): 55 kW (generator)

Total Annual Production (specify units normally used): ~380 gal/yr diesel fuel

Raw Materials: Fuel

Materials Produced: Electricity

Process Operation Units: (Name and Previous County Permit Number, if any)

(1.) Fire Pump Engine
(2.) ___
(3.) ___
(4.) ___
(5.) ___
(6.) ___

**Diagram of Process Flow:** Attach a separate sheet with a drawing of a flow diagram of this process, labeling each segment listed under Process Operation Segments. Label product intake points and product discharge points for each segment. Label emissions discharge points and the location of emissions control devices.

**PART II - PROCESS OPERATION SCHEDULE (per station)**

A. Normal schedule: (Provide information for last year. If a new unit, please estimate)

Hours/day 1 Days/week 7 Weeks/year 52 Hours/year 100

Start time __:__ End time __:__

Seasonal: Periods correspond to seasons instead of calendar quarters. The first season is split to include December, January, and February of the calendar year reported.

Percent of Annual Production

| | | | |
|---|---|---|---|
| December, January, & February | 25 | June, July, & August | 25 |
| March, April, & May | 25 | September, October, & November | 25 |

B. Requested limits: (Limitations on operating hours are optional.) Choose One:

___ 8760 hours (no limitations) or

_X_ I/We request the following limitation -- **This may become a federally enforceable permit condition:** Describe how this can be enforced: either list an operating schedule or downtime (e.g. only operate 8:00 to 4:00) or an operating hour reporting requirement.

___ Total days x ___ Hours/day = 100 Hours/year

## PART III – FUELS (per station)

A. Normal operation (Provide information for last year. If a new unit, please estimate)

| ____ Year ____ or X ____ Estimate | Primary | Secondary | Other | Other |
|---|---|---|---|---|
| Type: | Diesel | | | |
| Max Amount/hour | 4 gal/hr | | | |
| Sulfur Content (% wt): | 0.0015% | | | |
| Ash Content (% wt): | Negl. | | | |
| BTU Rating (specify units) | ~ 0.5 MMBtu /hr | | | |
| Annual Fuel Consumption | ~380 gal/yr | | | |
| Seasonal Fuel Consumption (%): | | | | |
| December, January, and February | 25 | | | |
| March, April, and May | 25 | | | |
| June, July, and August | 25 | | | |
| September, October, and November | 25 | | | |

Fuel Mixing: If more than one fuel is used, explain usage, stating whether it is burned separately, mixed in a fixed ratio of__:_ (give units such as BTU, mmcf, gallons per ton, etc.), mixed in a variable ratio of__:__ to __:__, determined by__ (give reason).

B. Requested limits (limitations on operations are optional, but may allow a Major source to be exempted from some requirements) **These may become permit conditions**. Please check one:

_X_ Full use of any fuel or combination at any time (no limitations)

__ The following limitations on types of fuels or the combination of fuels are requested (describe how compliance with this method will be demonstrated)

## PART IV - OTHER LIMITATIONS

Identify any other requested limitations, such as on production rates or materials use. Describe how compliance with these restrictions will be demonstrated. **These limitations may become permit conditions.**

N/A

## PART V - APPLICABLE REQUIREMENTS

Describe all applicable requirements affecting air emissions for this unit.

| Regulation # | Requirements |
|---|---|
| 40 CFR 60.4207(b) | Maximum fuel sulfur content of 15 ppm |
| 40 CFR 60.4205(b) | Tier 3 Limits (see Section 4.2.7 of narrative) |
| 40 CFR 60.4209(a) | Install a non-resettable hour meter |
| 2104.01.a | Opacity < 20% for 3-minutes in any 60-minute period, or < 60% at any time |
| 2104.02.a | PM < 0.28 lb/MMBtu |
| 2104.03.a | $SO_2$ < 1.0 lb/MMBtu |
| 2105.06 | Presumptive RACT = installation, maintenance & operation in accordance with manufacturer's recommendations |

## PART VI - EMISSION CONTROLS - Not Applicable

Complete the following applicable sections for each pollution control device. Attach additional sheets to provide sufficient information and engineering calculations to support the contol device performance.

On the space to the left of each device, number the device(s) by the order in which they process the waste stream(s). Fill out the requested information, then complete the table for efficiencies by pollutant for each device.

Percent Capture _______ % (not control efficiency)

Gas flow through control units _________ @ _______ °F

____ **BAGHOUSE (fabric collector)**

Manufacturer's Name and Model ____________________

Type of bag material ____________________

Total filter cloth area _______ sq. ft., air to cloth ratio ____________________

Bag cleaning method: ____________________ , cycle _________ min

Pressure Drop: clean _______ "$H_2O$, dirty ________ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

____ **ELECTROSTATIC PRECIPITATOR**

Manufacturer's Name and Model: ____________________

Type: __ Single Stage, __ Two Stage, __ Plate, __ Tube

Total collecting area: _____________ sq. ft., cleaning cycle ________ min.

Gas Velocity: _____________ ft./sec. corona power ________ kw

Bulk resistivity of dust: _______ ohm-cm Moisture content of gases: _______ vol. %

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

____ **CYCLONE (dry gas only)**

Manufacturer's Name and Model: ____________________

Gas Inlet: width _______ ft., height _______ ft.

Diameter: gas outlet _______ ft., cyclone cylinder (s) _______ ft.

Length of cyclone: ______ ft., no. of cylinder(s) _______ Pressure Drop _______ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

**PART VI - EMISSION CONTROLS (CONTINUED)** **NOT APPLICABLE**

_____ **CONDENSER**

Manufacturer's Name and Model: ______________________________

Type: surface ________ , contact ______________________________

Heat transfer area: ________ sq. ft., max process pressure ________ psia

Heat duty: _______ BTU/hr. Coolant temp: inlet ______________ °F outlet ________ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

_____ **WET COLLECTOR**

Manufacturer's Name and Model: ______________________________

Type: __ venturi, __ cyclone, __ spray chamber, __ packed bed

Entrainment/separator: type __________ , bed depth __________

Type & construction of chemicals added to the scrubbing liquid:

Pressure drop _________ "$H_2O$

Scrubbing liquid: flow rate _______ gpm, inlet temp. ________ °F, outlet temp. _______ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

_____ **AFTERBURNER (Oxidation Catalyst)**

Manufacturer's Name and Model: ______________________________

Type: __ direct flame, __ catalytic

If catalytic: inlet temp. _______ °F, outlet temp. ________ °F, catalyst life ______________

If direct flame: internal volume _________ cu. ft., average temp. _________ °F

Residence time at average temp. ________ Sec

Auxiliary fuel: max. rating ________ BTU/hr. set point ________ °F, ________ BTU/hr.

Size of Chamber ________ cu. ft., flow rate ___________

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading (gn./cu. ft.) |
|---|---|---|---|

_____ **ADSORPTION EQUIPMENT**

Manufacturer's Name and Model: ______________________________

Type: __ Continuous, __ Fixed bed

Adsorbing material: ____________ , Bed depth ______________ in., Flow area _________ sq. ft.

Breakthrough (breakpoint) time: _________ , Pressure Drop: ___________ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

## PART VI - EMISSION CONTROLS (CONTINUED) <u>NOT APPLICABLE</u>

_____ **OTHER TYPES** Name and describe. Attach complete details.

**FUGITIVE DUST CONTROLS:** Describe below or attach a complete explanation of all controls of fugitive emissions not discussed in Form E - Roads or Form F - Storage Piles.

N/A

## PART VII - STACK DATA

Stack data must be provided for each flue, duct, pipe, stack, chimney or conduit (stacks) at which collected emissions are vented to open air through a restricted opening.

***All Parameters are preliminary design values still under evaluation***

Stack Identification: FPUMP

UTM East TBD UTM North TBD or

Longitude TBD Latitude TBD

Most important stacks have been located on topographic or air navigation charts. If you know the UTM coordinates or latitude and longitude, provide this information. If there is a number of stacks close together, a common location may be used

***All Parameters are preliminary design values still under evaluation***

Stack Height: TBD ft. Ground level elevation TBD ft. Diameter TBD ft.

Material Outer: TBD lining: TBD

Exit temperature (°F): TBD Exit Velocity: TBD f/s.

Exhaust Rate: TBD (ACFM) % Moisture: TBD

Nearest building to stack:

distance TBD ft. height TBD ft. length TBD ft. width TBD ft.

**Processes Sharing Stack:** If more than one process shares a stack, list them and estimate relative contribution of each.

Description N/A, Dedicated Stack

Contribution to emissions from stack ________ %

Description ________

Contribution to emissions from stack ________ %

Description ________

Contribution to emissions from stack ________ %

Description ________

## PART VIII - REMARKS

**Attach calculations and reference all emission factors for Allowable, Potential to Emit, and Actual Emissions to this sheet. Reference all emission factors and efficiencies of control equipment.**

| PART IX - EMISSIONS |
|---|

PART 9a: EMISSIONS -- SHORT TERM LB/HR (POUNDS PER HOUR) OR OTHER

See Appendix C for Detailed Calculations

| Pollutant | PM | PM10 | $SO_2$ | CO | $NO_x$ | VOC | LEAD | PM2.5 |
|---|---|---|---|---|---|---|---|---|
| Allowable | 0.03 | 0.03 | 0.2 | 0.1 | 0.5 | 0.05 | -- | 0.03 |
| Maximum Potential | 0.03 | 0.03 | 0.2 | 0.1 | 0.5 | 0.05 | -- | 0.03 |
| Actual or Estimated | 0.03 | 0.03 | 0.2 | 0.1 | 0.5 | 0.05 | -- | 0.03 |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

PART 9b: EMISSIONS -- ANNUAL TPY (TONS PER YEAR)

| Pollutant | PM | PM10 | $SO_2$ | CO | $NO_x$ | VOC | LEAD | PM2.5 |
|---|---|---|---|---|---|---|---|---|
| Allowable | <0.01 | <0.01 | 0.01 | 0.01 | 0.03 | <0.01 | -- | <0.01 |
| Maximum Potential | <0.01 | <0.01 | 0.01 | 0.01 | 0.03 | <0.01 | -- | <0.01 |
| Actual or Estimated | <0.01 | <0.01 | 0.01 | 0.01 | 0.03 | <0.01 | -- | <0.01 |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

## PERMIT APPLICATION FORM B
## FUEL BURNING OR COMBUSTION EQUIPMENT

**PLANT NAME AND LOCATION:** U. S. Steel Clairton Plant

Schedule B requires information on boilers, heaters, and other combustion units. Complete one form for each unit, making copies of this form as needed.

**PART I - DESCRIPTION OF COMBUSTION UNIT** (MAKE A COPY OF SCHEDULE B FOR EACH UNIT)

Company Identification or Description: Dew Point Heater 1
Unit Make: TBD Unit Model: TBD
Description of Unit and Type of Firing (e.g. spreader stoker, traveling grate, etc.)

Installer: Unknown at this time Installation Date: __ /__ / 2020 (begin)_
Contractor (if operated by another): N/A
Installation Date: __ /__ /__ Your Identification: DPHTR-1
Previous County Air Pollution Permit Number (if any): N/A
Rated Capacity (BTU/hr) 3,000,000 Maximum Capacity (BTU/hr): 3,000,000
Normal Use (BTU/hr) 3,000,000
Percent of Heat Used for:
Power Generation _______ % process 100 % space heating _______ % (Annual average)

**PART II - OPERATION SCHEDULE**

A. Normal schedule: (Provide information for last year. If a new unit, please estimate)
Hours/day 7 Days/week 52 Weeks/year _______ Hours/year 8,760
Start time __:__ End time __:__
Seasonal: (Periods correspond to seasons instead of calendar quarters. The first season is split to include December, January, and February of the calendar year reported.)

Percent of Annual Production

| | | | |
|---|---|---|---|
| December, January, & February | 25 | June, July, & August | 25 |
| March, April, & May | 25 | September, October, & November | 25 |

B. Requested limits: (limitations on operating hours are optional) Choose One:
_X_ 8760 hours (no limitations) or
__ I/We request the following limitation -- **This may become a federally enforceable permit condition:** Describe how this can be enforced: Either list an operating schedule or downtime (e.g. only operate 8:00 to 4:00) or an operating hour reporting requirement.

_________ Total days x _________ Hours/day = _________ Hours/year

## PART III - FUELS

A. Normal operation (Provide information for last year. If a new unit, please estimate)

_____ Year _______ or X Estimate

| | Primary | Secondary | Other | Other |
|---|---|---|---|---|
| Type: | N. Gas | | | |
| Max Amount/hour | ~2,900 scf/hr | | | |
| Sulfur Content (% wt): | Negl. | | | |
| Ash Content (% wt): | Negl. | | | |
| BTU Rating (specify units) | 3 MMBtu/hr | | | |
| Annual Fuel Consumption | 26,280 MMBtu/yr | | | |
| Seasonal Fuel Consumption (%): | | | | |
| December, January & February | 25 | | | |
| March, April, and May | 25 | | | |
| June, July, and August | 25 | | | |
| September, October, & November | 25 | | | |

Fuel Mixing: If more than one fuel is used, explain usage, stating whether it is burned separately, mixed in a fixed ratio of__:__ (give units such as BTU, mmcf, gallons per ton, etc.), mixed in a variable ratio of__:__ to __:__, determined by __ (give reason).

B. Requested limits (limitations on operations are optional, but may allow a Major source to be exempted from some requirements) **These may become permit conditions**. Please check one:

X Full use of any fuel or combination at any time (no limitations) OR

__ The following limitations on types of fuels or the combination of fuels (describe how compliance with this method will be demonstrated):

## PART IV - OTHER LIMITATIONS

Identify any other requested limitations, such as on production rates or materials use. Describe how compliance with these restrictions will be demonstrated. **These limitations may become permit conditions.**

N/A

## PART V - APPLICABLE REQUIREMENTS

Describe all applicable air requirements for this source.

| Regulation # | Requirements |
|---|---|
| 40 CFR 63.7540 | Tune up every 5 years |
| 2104.01.a | Opacity < 20% for 3-minutes in any 60-minute period, or < 60% at any time |
| 2104.02.a | PM < 0.008 lb/MMBtu |
| 2104.03.a | $SO_2$ < PTE |

| | |
|---|---|
| 2105.06 | Presumptive RACT = installation, maintenance & operation in accordance with manufacturer's recommendations |
| | |

| PART VI - EMISSION CONTROLS | NOT APPLICABLE |
|---|---|

Complete the following applicable sections for each pollution control device. Attach additional sheets to provide sufficient information and engineering calculations to support the contol device performance.

On the space to the left of each device, number the device(s) by the order in which they process the waste stream(s). Fill out the requested information, then complete the table for efficiencies by pollutant for each device.

Percent Capture _______ % (not control efficiency)

Gas flow through control units _________ @ _______ °F

_____ **BAGHOUSE (fabric collector)**

Manufacturer's Name and Model: ______________________

Type of bag material: ______________________

Total filter cloth area: _______ sq. ft. air to cloth ratio ______________

Bag cleaning method: ______________ cycle ________ minute(s)

Pressure Drop: clean _______ "$H_2O$, dirty _______ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|
| | | | |

_____ **ELECTROSTATIC PRECIPITATOR**

Manufacturer's Name and Model: ______________________

Type: __ single stage, __ two stage, __ plate, __ tube

Total collecting area: _________ sq. ft. cleaning cycle _______ min

Gas Velocity: _____________ ft./sec. corona power _______ kw

Bulk resistivity of Dust: ________ ohm-cm Moisture content of gases _______ vol. %

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|
| | | | |

_____ **CYCLONE (dry gas only)**

Manufacturer's Name and Model: ______________________

Gas Inlet: width _______ ft., height _______ ft.

Diameter: gas outlet _______ ft., cyclone cylinder (s) _______ ft.

Length of cyclone: ______ ft., no. of cylinder(s) _______ Pressure Drop _______ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|
| | | | |

| PART VI - EMISSION CONTROLS (CONTINUED) | NOT APPLICABLE |
|---|---|

____ **CONDENSER**

Manufacturer's Name and Model: ____________________

Type: surface ________ , contact ____________________

Heat transfer area: ________ sq. ft., max process pressure ________ psia

Heat duty: ________ BTU/hr. Coolant temp: inlet ____________ °F outlet __________ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

____ **WET COLLECTOR**

Manufacturer's Name and Model: ____________________

Type: __ venturi, __ cyclone, __ spray chamber, __ packed bed

Entrainment/separator: type __________ , bed depth: __________

Type & construction of chemicals added to the scrubbing liquid:

Pressure drop ________ "$H_2O$

Scrubbing liquid: flow rate ________ gpm, inlet temp. ________ °F, outlet temp. ________ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

____ **AFTERBURNER**

Manufacturer's Name and Model: ____________________

Type: __ direct flame, __ catalytic

If catalytic: inlet temp. ________ °F, outlet temp. ________ °F, catalyst life ____________

If direct flame: Internal volume ________ cu. ft., average temp. ________ °F

Residence time at average temp. ________ sec

Auxiliary fuel: max. rating ________ BTU/hr. set point ________ °F, ________ BTU/hr.

Size of Chamber ________ cu. ft. flow rate __________

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading (gn./cu. ft.) |
|---|---|---|---|

____ **ADSORPTION EQUIPMENT**

Manufacturer's Name and Model: ____________________

Type: __ continuous, __ fixed bed

Adsorbing material: __________ bed depth __________ in., flow area ________ sq. ft.

Breakthrough (breakpoint) time: ________ Pressure drop: __________ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

## PART VI - EMISSION CONTROLS (CONTINUED)

X **OTHER TYPES:** Name and describe. Attach complete details.

| | |
|---|---|
| NOx | Low NOx Burners |
| | |
| | |
| | |
| | |

**FUGITIVE DUST CONTROLS:** Describe below or attach a complete explanation of all controls of fugitive emissions not discussed in Form E - Roads or Form F - Storage Piles.

N/A

## PART VII - STACK DATA

Stack data must be provided for each flue, duct, pipe, stack, chimney or conduit (stacks) at which collected emissions are vented to open air through a restricted opening.

Stack Identification: DPHTR-1

UTM East TBD    UTM North TBD    or

Longitude TBD    Latitude TBD

Most important stacks have been located on topographic or air navigation charts. If you know the UTM coordinates or latitude and longitude, provide this information. If there is a number of stacks close together, a common location may be used

Stack Height: TBD ft.    Ground level elevation TBD ft.    Diameter TBD ft.

Material Outer: TBD    Lining: TBD

Exit temperature (F): TBD    Exit Velocity: TBD (f/s).

Exhaust rate: TBD (ACFM)    % Moisture: TBD

Nearest building to stack:

Distance TBD ft.  height TBD ft.  length TBD ft.  width TBD ft.

**Processes Sharing Stack:** If more than one process shares a stack, list them and estimate relative contribution of each.

Description N/A, Dedicated Stack

Contribution to emissions from stack ________ %

Description ________

Contribution to emissions from stack ________ %

Description ________

Contribution to emissions from stack ________ %

Description ________

## PART VIII - REMARKS

**Attach calculations and reference all emission factors for Allowable, Potential to Emit, and Actual Emissions to this sheet. Reference all emission factors and efficiencies of control equipment.**

| PART IX - EMISSIONS |
|---|

## PART 9a: EMISSIONS -- SHORT TERM LB/HR (POUNDS PER HOUR) OR OTHER

See Appendix C for Detailed Calculations

| Pollutant | Particulate | PM10 | SO2 | CO | NOx | VOC | LEAD | PM2.5 |
|---|---|---|---|---|---|---|---|---|
| Allowable | 0.01 | 0.01 | <0.01 | 0.1 | 0.1 | 0.01 | 1.7E-6 | 0.01 |
| Maximum Potential | 0.01 | 0.01 | <0.01 | 0.1 | 0.1 | 0.01 | 1.7E-6 | 0.01 |
| Actual or Estimated | 0.01 | 0.01 | <0.01 | 0.1 | 0.1 | 0.01 | 1.7E-6 | 0.01 |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

## PART 9b: EMISSIONS -- ANNUAL TPY (TONS PER YEAR)

| Pollutant | Particulate | PM10 | SO2 | CO | NOX | VOC | LEAD | PM2.5 |
|---|---|---|---|---|---|---|---|---|
| Allowable | 0.06 | 0.06 | 0.01 | 0.5 | 0.4 | 0.04 | 7.3E-6 | 0.06 |
| Maximum Potential | 0.06 | 0.06 | 0.01 | 0.5 | 0.4 | 0.04 | 7.3E-6 | 0.06 |
| Actual or Estimated | 0.06 | 0.06 | 0.01 | 0.5 | 0.4 | 0.04 | 7.3E-6 | 0.06 |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

## PART IX - EMISSIONS (CONTINUED)

**List all known pollutants, including, but not limited to those found under Article XXI section 2101.20 in the definition of Hazardous Air Pollutants.**

Transfer this information to the summary emissions sheets.

See Appendix C

## PERMIT APPLICATION FORM B
## FUEL BURNING OR COMBUSTION EQUIPMENT

**PLANT NAME AND LOCATION:** U. S. Steel Clairton Plant

Schedule B requires information on boilers, heaters, and other combustion units. Complete one form for each unit, making copies of this form as needed.

**PART I - DESCRIPTION OF COMBUSTION UNIT** (MAKE A COPY OF SCHEDULE B FOR EACH UNIT)

Company Identification or Description: Dew Point Heater 2

Unit Make: TBD Unit Model: TBD

Description of Unit and Type of Firing (e.g. spreader stoker, traveling grate, etc.)

Installer: Unknown at this time Installation Date: __ /__ / 2020 (begin)_

Contractor (if operated by another): N/A

Installation Date: __ /__ /__ Your Identification: DPHTR-2

Previous County Air Pollution Permit Number (if any): N/A

Rated Capacity (BTU/hr) 3,000,000 Maximum Capacity (BTU/hr): 3,000,000

Normal Use (BTU/hr) 3,000,000

Percent of Heat Used for:

Power Generation ______ % process 100 % space heating ______ % (Annual average)

**PART II - OPERATION SCHEDULE**

A. Normal schedule: (Provide information for last year. If a new unit, please estimate)

Hours/day 7 Days/week 52 Weeks/year ______ Hours/year 8,760

Start time __:__ End time __:__

Seasonal: (Periods correspond to seasons instead of calendar quarters. The first season is split to include December, January, and February of the calendar year reported.)

Percent of Annual Production

| | | | |
|---|---|---|---|
| December, January, & February | 25 | June, July, & August | 25 |
| March, April, & May | 25 | September, October, & November | 25 |

B. Requested limits: (limitations on operating hours are optional) Choose One:

_X_ 8760 hours (no limitations) or

__ I/We request the following limitation – **This may become a federally enforceable permit condition:** Describe how this can be enforced: Either list an operating schedule or downtime (e.g. only operate 8:00 to 4:00) or an operating hour reporting requirement.

________ Total days x ________ Hours/day = ________ Hours/year

## PART III - FUELS

A. Normal operation (Provide information for last year. If a new unit, please estimate)

| ___ Year ___ or X Estimate | Primary | Secondary | Other | Other |
|---|---|---|---|---|
| Type: | N. Gas | | | |
| Max Amount/hour | ~2,900 scf/hr | | | |
| Sulfur Content (% wt): | Negl. | | | |
| Ash Content (% wt): | Negl. | | | |
| BTU Rating (specify units) | 3 MMBtu/hr | | | |
| Annual Fuel Consumption | 26,280 MMBtu/yr | | | |
| Seasonal Fuel Consumption (%): | | | | |
| December, January & February | 25 | | | |
| March, April, and May | 25 | | | |
| June, July, and August | 25 | | | |
| September, October, & November | 25 | | | |

Fuel Mixing: If more than one fuel is used, explain usage, stating whether it is burned separately, mixed in a fixed ratio of__:__ (give units such as BTU, mmcf, gallons per ton, etc.), mixed in a variable ratio of__:__ to __:__, determined by __ (give reason).

B. Requested limits (limitations on operations are optional, but may allow a Major source to be exempted from some requirements) **These may become permit conditions**. Please check one:

_X_ Full use of any fuel or combination at any time (no limitations) OR

__ The following limitations on types of fuels or the combination of fuels (describe how compliance with this method will be demonstrated):

## PART IV - OTHER LIMITATIONS

Identify any other requested limitations, such as on production rates or materials use. Describe how compliance with these restrictions will be demonstrated. **These limitations may become permit conditions.**

N/A

## PART V - APPLICABLE REQUIREMENTS

Describe all applicable air requirements for this source.

| Regulation # | Requirements |
|---|---|
| 40 CFR 63.7540 | Tune up every 5 years |
| 2104.01.a | Opacity < 20% for 3-minutes in any 60-minute period, or < 60% at any time |
| 2104.02.a | PM < 0.008 lb/MMBtu |
| 2104.03.a | $SO_2$ < PTE |

| | |
|---|---|
| 2105.06 | Presumptive RACT = installation, maintenance & operation in accordance with manufacturer's recommendations |

**PART VI - EMISSION CONTROLS** **NOT APPLICABLE**

Complete the following applicable sections for each pollution control device. Attach additional sheets to provide sufficient information and engineering calculations to support the contol device performance.

On the space to the left of each device, number the device(s) by the order in which they process the waste stream(s). Fill out the requested information, then complete the table for efficiencies by pollutant for each device.

Percent Capture ______ % (not control efficiency)

Gas flow through control units ________ @ ______ °F

_____ **BAGHOUSE (fabric collector)**

Manufacturer's Name and Model: ______________________________

Type of bag material: ______________________________

Total filter cloth area: ______ sq. ft. air to cloth ratio ______________

Bag cleaning method: ______________ cycle ________ minute(s)

Pressure Drop: clean ______ "$H_2O$, dirty ______ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

_____ **ELECTROSTATIC PRECIPITATOR**

Manufacturer's Name and Model: ______________________________

Type: __ single stage, __ two stage, __ plate, __ tube

Total collecting area: ________ sq. ft. cleaning cycle ______ min

Gas Velocity: __________ ft./sec. corona power ______ kw

Bulk resistivity of Dust: ______ ohm-cm Moisture content of gases ______ vol. %

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

_____ **CYCLONE (dry gas only)**

Manufacturer's Name and Model: ______________________________

Gas Inlet: width ______ ft., height ______ ft.

Diameter: gas outlet ______ ft., cyclone cylinder (s) ______ ft.

Length of cyclone: ______ ft., no. of cylinder(s) ______ Pressure Drop ______ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

| PART VI - EMISSION CONTROLS (CONTINUED) | NOT APPLICABLE |
|---|---|

_____ **CONDENSER**

Manufacturer's Name and Model: ______________________

Type: surface ________ , contact ______________________

Heat transfer area: ________ sq. ft., max process pressure ________ psia

Heat duty: ________ BTU/hr. Coolant temp: inlet ____________ °F outlet __________ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

_____ **WET COLLECTOR**

Manufacturer's Name and Model: ______________________

Type: __ venturi, __ cyclone, __ spray chamber, __ packed bed

Entrainment/separator: type __________ , bed depth: __________

Type & construction of chemicals added to the scrubbing liquid:

Pressure drop ________ "$H_2O$

Scrubbing liquid: flow rate ________ gpm, inlet temp. ________ °F, outlet temp. ________ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

_____ **AFTERBURNER**

Manufacturer's Name and Model: ______________________

Type: __ direct flame, __ catalytic

If catalytic: inlet temp. ________ °F, outlet temp. ________ °F, catalyst life ______________

If direct flame: Internal volume ________ cu. ft., average temp. ________ °F

Residence time at average temp. ________ sec

Auxiliary fuel: max. rating ________ BTU/hr. set point ________ °F, ________ BTU/hr.

Size of Chamber ________ cu. ft. flow rate __________

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading (gn./cu. ft.) |
|---|---|---|---|

_____ **ADSORPTION EQUIPMENT**

Manufacturer's Name and Model: ______________________

Type: __ continuous, __ fixed bed

Adsorbing material: __________ bed depth __________ in., flow area ________ sq. ft.

Breakthrough (breakpoint) time: ________ Pressure drop: __________ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

## PART VI - EMISSION CONTROLS (CONTINUED)

X **OTHER TYPES:** Name and describe. Attach complete details.

| | |
|---|---|
| NOx | Low NOx Burners |
| | |
| | |
| | |
| | |

**FUGITIVE DUST CONTROLS:** Describe below or attach a complete explanation of all controls of fugitive emissions not discussed in Form E - Roads or Form F - Storage Piles.

N/A

## PART VII - STACK DATA

Stack data must be provided for each flue, duct, pipe, stack, chimney or conduit (stacks) at which collected emissions are vented to open air through a restricted opening.

Stack Identification: DPHTR-2

UTM East TBD UTM North TBD or

Longitude TBD Latitude TBD

Most important stacks have been located on topographic or air navigation charts. If you know the UTM coordinates or latitude and longitude, provide this information. If there is a number of stacks close together, a common location may be used

Stack Height: TBD ft. Ground level elevation TBD ft. Diameter TBD ft.

Material Outer: TBD Lining: TBD

Exit temperature (F): TBD Exit Velocity: TBD (f/s).

Exhaust rate: TBD (ACFM) % Moisture: TBD

Nearest building to stack:

Distance TBD ft. height TBD ft. length TBD ft. width TBD ft.

**Processes Sharing Stack:** If more than one process shares a stack, list them and estimate relative contribution of each.

Description N/A, Dedicated Stack

Contribution to emissions from stack ______ %

Description ______

Contribution to emissions from stack ______ %

Description ______

Contribution to emissions from stack ______ %

Description ______

## PART VIII - REMARKS

**Attach calculations and reference all emission factors for Allowable, Potential to Emit, and Actual Emissions to this sheet. Reference all emission factors and efficiencies of control equipment.**

## PART IX - EMISSIONS

### PART 9a: EMISSIONS -- SHORT TERM LB/HR (POUNDS PER HOUR) OR OTHER

See Appendix C for Detailed Calculations

| Pollutant | Particulate | PM10 | SO2 | CO | NOx | VOC | LEAD | PM2.5 |
|---|---|---|---|---|---|---|---|---|
| Allowable | 0.01 | 0.01 | <0.01 | 0.1 | 0.1 | 0.01 | 1.7E-6 | 0.01 |
| Maximum Potential | 0.01 | 0.01 | <0.01 | 0.1 | 0.1 | 0.01 | 1.7E-6 | 0.01 |
| Actual or Estimated | 0.01 | 0.01 | <0.01 | 0.1 | 0.1 | 0.01 | 1.7E-6 | 0.01 |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

### PART 9b: EMISSIONS -- ANNUAL TPY (TONS PER YEAR)

| Pollutant | Particulate | PM10 | SO2 | CO | NOX | VOC | LEAD | PM2.5 |
|---|---|---|---|---|---|---|---|---|
| Allowable | 0.06 | 0.06 | 0.01 | 0.5 | 0.4 | 0.04 | 7.3E-6 | 0.06 |
| Maximum Potential | 0.06 | 0.06 | 0.01 | 0.5 | 0.4 | 0.04 | 7.3E-6 | 0.06 |
| Actual or Estimated | 0.06 | 0.06 | 0.01 | 0.5 | 0.4 | 0.04 | 7.3E-6 | 0.06 |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

## PART IX - EMISSIONS (CONTINUED)

**List all known pollutants, including, but not limited to those found under Article XXI section 2101.20 in the definition of Hazardous Air Pollutants.**

Transfer this information to the summary emissions sheets.

See Appendix C

## PERMIT APPLICATION FORM B
## FUEL BURNING OR COMBUSTION EQUIPMENT

**PLANT NAME AND LOCATION:** U. S. Steel Clairton Plant

Schedule B requires information on boilers, heaters, and other combustion units. Complete one form for each unit, making copies of this form as needed.

**PART I - DESCRIPTION OF COMBUSTION UNIT** (MAKE A COPY OF SCHEDULE B FOR EACH UNIT)

Company Identification or Description: Auxiliary Boiler

Unit Make: TBD Unit Model: TBD

Description of Unit and Type of Firing (e.g. spreader stoker, traveling grate, etc.)

Installer: Unknown at this time Installation Date: __ /__ / 2020 (begin)_

Contractor (if operated by another): N/A

Installation Date: __ /__ /__ Your Identification: AUXBLR

Previous County Air Pollution Permit Number (if any): N/A

Rated Capacity (BTU/hr) 99,000,000 Maximum Capacity (BTU/hr): 99,000,000

Normal Use (BTU/hr) 99,000,000

Percent of Heat Used for:

Power Generation ______ % process 100 % space heating ______ % (Annual average)

**PART II - OPERATION SCHEDULE**

A. Normal schedule: (Provide information for last year. If a new unit, please estimate)

Hours/day 7 Days/week 52 Weeks/year ______ Hours/year 1,000

Start time __:__ End time __:__

Seasonal: (Periods correspond to seasons instead of calendar quarters. The first season is split to include December, January, and February of the calendar year reported.)

Percent of Annual Production

| | | | |
|---|---|---|---|
| December, January, & February | 25 | June, July, & August | 25 |
| March, April, & May | 25 | September, October, & November | 25 |

B. Requested limits: (limitations on operating hours are optional) Choose One:

__ 8760 hours (no limitations) or

_X_ I/We request the following limitation -- **This may become a federally enforceable permit condition:** Describe how this can be enforced: Either list an operating schedule or downtime (e.g. only operate 8:00 to 4:00) or an operating hour reporting requirement.

______ Total days x ______ Hours/day = 1,000 Hours/year

## PART III - FUELS

A. Normal operation (Provide information for last year. If a new unit, please estimate)

| ____ Year ______ or X Estimate | Primary | Secondary | Other | Other |
|---|---|---|---|---|
| Type: | N. Gas | | | |
| Max Amount/hour | ~95780 scf/hr | | | |
| Sulfur Content (% wt): | Negl. | | | |
| Ash Content (% wt): | Negl. | | | |
| BTU Rating (specify units) | 99 MMBtu/hr | | | |
| Annual Fuel Consumption | 99,000 MMBtu/yr | | | |
| Seasonal Fuel Consumption (%): | | | | |
| December, January & February | 25 | | | |
| March, April, and May | 25 | | | |
| June, July, and August | 25 | | | |
| September, October, & November | 25 | | | |

Fuel Mixing: If more than one fuel is used, explain usage, stating whether it is burned separately, mixed in a fixed ratio of__:__(give units such as BTU, mmcf, gallons per ton, etc.), mixed in a variable ratio of__:__ to __:__, determined by __ (give reason).

B. Requested limits (limitations on operations are optional, but may allow a Major source to be exempted from some requirements) **These may become permit conditions.** Please check one:

_X_ Full use of any fuel or combination at any time (no limitations) OR

__ The following limitations on types of fuels or the combination of fuels (describe how compliance with this method will be demonstrated):

## PART IV - OTHER LIMITATIONS

Identify any other requested limitations, such as on production rates or materials use. Describe how compliance with these restrictions will be demonstrated. **These limitations may become permit conditions.**

N/A

## PART V - APPLICABLE REQUIREMENTS

Describe all applicable air requirements for this source.

| Regulation # | Requirements |
|---|---|
| | |
| 40 CFR 60.48c | Maintain records of monthly fuel use |
| 40 CFR 63.7540 | Annual tune up |
| 2104.01.a | Opacity < 20% for 3-minutes in any 60-minute period, or < 60% at any time |
| 2104.02.a | PM < 0.008 lb/MMBtu |

## PART VI - EMISSION CONTROLS NOT APPLICABLE

Complete the following applicable sections for each pollution control device. Attach additional sheets to provide sufficient information and engineering calculations to support the contol device performance.

On the space to the left of each device, number the device(s) by the order in which they process the waste stream(s). Fill out the requested information, then complete the table for efficiencies by pollutant for each device.

Percent Capture ________ % (not control efficiency)

Gas flow through control units __________ @ ________ °F

_____ **BAGHOUSE (fabric collector)**

Manufacturer's Name and Model: ______________________________

Type of bag material: ______________________________

Total filter cloth area: ________ sq. ft. air to cloth ratio ______________

Bag cleaning method: ______________ cycle _________ minute(s)

Pressure Drop: clean ________ "$H_2O$, dirty ________ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

_____ **ELECTROSTATIC PRECIPITATOR**

Manufacturer's Name and Model: ______________________________

Type: __ single stage, __ two stage, __ plate, __ tube

Total collecting area: _________ sq. ft. cleaning cycle ________ min

Gas Velocity: _____________ ft./sec. corona power ________ kw

Bulk resistivity of Dust: ________ ohm-cm Moisture content of gases ________ vol. %

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

_____ **CYCLONE (dry gas only)**

Manufacturer's Name and Model: ______________________________

Gas Inlet: width ________ ft., height ________ ft.

Diameter: gas outlet ________ ft., cyclone cylinder (s) ________ ft.

Length of cyclone: ______ ft., no. of cylinder(s) ________ Pressure Drop ________ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

**PART VI - EMISSION CONTROLS (CONTINUED)** **NOT APPLICABLE**

_____ **CONDENSER**

Manufacturer's Name and Model: ______________________________

Type: surface __________ , contact ______________________________

Heat transfer area: __________ sq. ft., max process pressure __________ psia

Heat duty: ________ BTU/hr. Coolant temp: inlet ______________ °F outlet ____________ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
| --- | --- | --- | --- |

_____ **WET COLLECTOR**

Manufacturer's Name and Model: ______________________________

Type: __ venturi, __ cyclone, __ spray chamber, __ packed bed

Entrainment/separator: type ___________ , bed depth: ____________

Type & construction of chemicals added to the scrubbing liquid:

Pressure drop __________ "$H_2O$

Scrubbing liquid: flow rate ________ gpm, inlet temp. _________ °F, outlet temp. ________ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
| --- | --- | --- | --- |

_____ **AFTERBURNER**

Manufacturer's Name and Model: ______________________________

Type: __ direct flame, __ catalytic

If catalytic: inlet temp. ________ °F, outlet temp. _________ °F, catalyst life ______________

If direct flame: Internal volume __________ cu. ft., average temp. __________ °F

Residence time at average temp. _________ sec

Auxiliary fuel: max. rating _________ BTU/hr. set point _________ °F, _________ BTU/hr.

Size of Chamber ________ cu. ft. flow rate _____________

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading (gn./cu. ft.) |
| --- | --- | --- | --- |

_____ **ADSORPTION EQUIPMENT**

Manufacturer's Name and Model: ______________________________

Type: __ continuous, __ fixed bed

Adsorbing material: _____________ bed depth _______________ in., flow area _________ sq. ft.

Breakthrough (breakpoint) time: __________ Pressure drop: ____________ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
| --- | --- | --- | --- |

**PART VI - EMISSION CONTROLS (CONTINUED)**

X **OTHER TYPES:** Name and describe. Attach complete details.

| | |
|---|---|
| NOx | Low NOx Burners with FGR |

**FUGITIVE DUST CONTROLS:** Describe below or attach a complete explanation of all controls of fugitive emissions not discussed in Form E - Roads or Form F - Storage Piles.

N/A

## PART VII - STACK DATA

Stack data must be provided for each flue, duct, pipe, stack, chimney or conduit (stacks) at which collected emissions are vented to open air through a restricted opening.

Stack Identification: AUXBLR

UTM East TBD UTM North TBD or

Longitude TBD Latitude TBD

Most important stacks have been located on topographic or air navigation charts. If you know the UTM coordinates or latitude and longitude, provide this information. If there is a number of stacks close together, a common location may be used

Stack Height: TBD ft. Ground level elevation TBD ft. Diameter TBD ft.

Material Outer: TBD Lining: TBD

Exit temperature (F): TBD Exit Velocity: TBD (f/s).

Exhaust rate: TBD (ACFM) % Moisture: TBD

Nearest building to stack:

Distance TBD ft. height TBD ft. length TBD ft. width TBD ft.

**Processes Sharing Stack:** If more than one process shares a stack, list them and estimate relative contribution of each.

Description N/A, Dedicated Stack

Contribution to emissions from stack ______ %

Description ______

Contribution to emissions from stack ______ %

Description ______

Contribution to emissions from stack ______ %

Description ______

## PART VIII - REMARKS

**Attach calculations and reference all emission factors for Allowable, Potential to Emit, and Actual Emissions to this sheet. Reference all emission factors and efficiencies of control equipment.**

## PART IX - EMISSIONS

### PART 9a: EMISSIONS -- SHORT TERM LB/HR (POUNDS PER HOUR) OR OTHER

See Appendix C for Detailed Calculations

| Pollutant | Particulate | PM10 | SO2 | CO | NOx | VOC | LEAD | PM2.5 |
|---|---|---|---|---|---|---|---|---|
| Allowable | 0.2 | 0.8 | 0.1 | 5.4 | 2.0 | 0.6 | 5.5E-5 | 0.8 |
| Maximum Potential | 0.2 | 0.8 | 0.1 | 5.4 | 2.0 | 0.6 | 5.5E-5 | 0.8 |
| Actual or Estimated | 0.2 | 0.8 | 0.1 | 5.4 | 2.0 | 0.6 | 5.5E-5 | 0.8 |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

### PART 9b: EMISSIONS -- ANNUAL TPY (TONS PER YEAR)

| Pollutant | Particulate | PM10 | SO2 | CO | NOX | VOC | LEAD | PM2.5 |
|---|---|---|---|---|---|---|---|---|
| Allowable | 0.1 | 0.4 | 0.03 | 2.7 | 1.0 | 0.3 | 2.8E-5 | 0.4 |
| Maximum Potential | 0.1 | 0.4 | 0.03 | 2.7 | 1.0 | 0.3 | 2.8E-5 | 0.4 |
| Actual or Estimated | 0.1 | 0.4 | 0.03 | 2.7 | 1.0 | 0.3 | 2.8E-5 | 0.4 |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

**PART IX - EMISSIONS (CONTINUED)**

**List all known pollutants, including, but not limited to those found under Article XXI section 2101.20 in the definition of Hazardous Air Pollutants.**

Transfer this information to the summary emissions sheets.

See Appendix C

## PERMIT APPLICATION FORM B
## FUEL BURNING OR COMBUSTION EQUIPMENT

**PLANT NAME AND LOCATION:** U. S. Steel Clairton Plant

Schedule B requires information on boilers, heaters, and other combustion units. Complete one form for each unit, making copies of this form as needed.

**PART I - DESCRIPTION OF COMBUSTION UNIT** (MAKE A COPY OF SCHEDULE B FOR EACH UNIT)

Company Identification or Description: Existing Boiler R-2 (B006)
Unit Make: Riley Unit Model: Stoker
Description of Unit and Type of Firing (e.g. spreader stoker, traveling grate, etc.)

Installer: N/A Installation Date: N/A
Contractor (if operated by another): N/A
Installation Date: __ /__ /__ Your Identification: B006 (current permit ID)
Previous County Air Pollution Permit Number (if any): N/A
Rated Capacity (BTU/hr) 229,000,000 Maximum Capacity (BTU/hr): 229,000,000
Normal Use (BTU/hr) 229,000,000
Percent of Heat Used for:
Power Generation ______ % process 100 % space heating ______ % (Annual average)

**PART II - OPERATION SCHEDULE**

A. Normal schedule: (Provide information for last year. If a new unit, please estimate)

Hours/day 7 Days/week 52 Weeks/year ______ Hours/year 1,200 (future use)

Start time __:__ End time __:__

Seasonal: (Periods correspond to seasons instead of calendar quarters. The first season is split to include December, January, and February of the calendar year reported.)

Percent of Annual Production

| | | | |
|---|---|---|---|
| December, January, & February | 25 | June, July, & August | 25 |
| March, April, & May | 25 | September, October, & November | 25 |

B. Requested limits: (limitations on operating hours are optional) Choose One:

X 8760 hours (no limitations) or **(See Fuel Limits in Part III)**

__ I/We request the following limitation -- **This may become a federally enforceable permit condition:** Describe how this can be enforced: Either list an operating schedule or downtime (e.g. only operate 8:00 to 4:00) or an operating hour reporting requirement.

______ Total days x ______ Hours/day = ______ Hours/year

## PART III - FUELS

A. Normal operation (Provide information for last year. If a new unit, please estimate)

| ___ Year 2018 or X Estimate | Primary | Secondary | Other | Other |
|---|---|---|---|---|
| Type: | COG | | | |
| Max Amount/hour | ~0.5 MMcf/hr | | | |
| Sulfur Content (% wt): | 35 gr/100 scf ($H_2S$) | | | |
| Ash Content (% wt): | Negl. | | | |
| BTU Rating (specify units) | 229 MMBtu/hr | | | |
| Annual Fuel Consumption | 280727 MMBtu/yr | | | |
| Seasonal Fuel Consumption (%): | | | | |
| December, January & February | 25 | | | |
| March, April, and May | 25 | | | |
| June, July, and August | 25 | | | |
| September, October, & November | 25 | | | |

Fuel Mixing: If more than one fuel is used, explain usage, stating whether it is burned separately, mixed in a fixed ratio of__:__(give units such as BTU, mmcf, gallons per ton, etc.), mixed in a variable ratio of__:__ to __:__, determined by __ (give reason).

B. Requested limits (limitations on operations are optional, but may allow a Major source to be exempted from some requirements) **These may become permit conditions**. Please check one:

___ Full use of any fuel or combination at any time (no limitations) OR

_X_ The following limitations on types of fuels or the combination of fuels (describe how compliance with this method will be demonstrated): **Limited to 274,800 MMBtu/yr. Monitor fuel usage on a monthly basis.**

## PART IV - OTHER LIMITATIONS

Identify any other requested limitations, such as on production rates or materials use. Describe how compliance with these restrictions will be demonstrated. **These limitations may become permit conditions.**

N/A

## PART V - APPLICABLE REQUIREMENTS

Describe all applicable air requirements for this source.

| Regulation # | Requirements |
|---|---|
| | No Changes to Applicability |
| | |
| | |
| | |

**PART VI - EMISSION CONTROLS** **NOT APPLICABLE – No Changes**

Complete the following applicable sections for each pollution control device. Attach additional sheets to provide sufficient information and engineering calculations to support the contol device performance.

On the space to the left of each device, number the device(s) by the order in which they process the waste stream(s). Fill out the requested information, then complete the table for efficiencies by pollutant for each device.

Percent Capture _______ % (not control efficiency)
Gas flow through control units _________ @ _______ °F

_____ **BAGHOUSE (fabric collector)**

Manufacturer's Name and Model: ______________________________
Type of bag material: ______________________________
Total filter cloth area: _______ sq. ft. air to cloth ratio ______________
Bag cleaning method: ______________ cycle ________ minute(s)
Pressure Drop: clean _______ "$H_2O$, dirty ________ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

_____ **ELECTROSTATIC PRECIPITATOR**

Manufacturer's Name and Model: ______________________________
Type: __ single stage, __ two stage, __ plate, __ tube
Total collecting area: _________ sq. ft. cleaning cycle _______ min
Gas Velocity: _____________ ft./sec. corona power _______ kw
Bulk resistivity of Dust: _______ ohm-cm Moisture content of gases _______ vol. %

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

_____ **CYCLONE (dry gas only)**

Manufacturer's Name and Model: ______________________________
Gas Inlet: width _______ ft., height _______ ft.
Diameter: gas outlet _______ ft., cyclone cylinder (s) _______ ft.
Length of cyclone: ______ ft., no. of cylinder(s) _______ Pressure Drop _______ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

**PART VI - EMISSION CONTROLS (CONTINUED)** **NOT APPLICABLE**

____ **CONDENSER**

Manufacturer's Name and Model: ____________________

Type: surface ________ , contact ____________________

Heat transfer area: ________ sq. ft., max process pressure ________ psia

Heat duty: ________ BTU/hr. Coolant temp: inlet ____________ °F outlet ________ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

____ **WET COLLECTOR**

Manufacturer's Name and Model: ____________________

Type: __ venturi, __ cyclone, __ spray chamber, __ packed bed

Entrainment/separator: type ________ , bed depth: ________

Type & construction of chemicals added to the scrubbing liquid:

Pressure drop ________ "$H_2O$

Scrubbing liquid: flow rate ________ gpm, inlet temp. ________ °F, outlet temp. ________ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

____ **AFTERBURNER**

Manufacturer's Name and Model: ____________________

Type: __ direct flame, __ catalytic

If catalytic: inlet temp. ________ °F, outlet temp. ________ °F, catalyst life ________

If direct flame: Internal volume ________ cu. ft., average temp. ________ °F

Residence time at average temp. ________ sec

Auxiliary fuel: max. rating ________ BTU/hr. set point ________ °F, ________ BTU/hr.

Size of Chamber ________ cu. ft. flow rate ________

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading (gn./cu. ft.) |
|---|---|---|---|

____ **ADSORPTION EQUIPMENT**

Manufacturer's Name and Model: ____________________

Type: __ continuous, __ fixed bed

Adsorbing material: ________ bed depth ________ in., flow area ________ sq. ft.

Breakthrough (breakpoint) time: ________ Pressure drop: ________ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

**PART VI - EMISSION CONTROLS (CONTINUED)**

____ **OTHER TYPES:** Name and describe. Attach complete details.

**FUGITIVE DUST CONTROLS:** Describe below or attach a complete explanation of all controls of fugitive emissions not discussed in Form E - Roads or Form F - Storage Piles.

N/A

## PART VII - STACK DATA

Stack data must be provided for each flue, duct, pipe, stack, chimney or conduit (stacks) at which collected emissions are vented to open air through a restricted opening.

Stack Identification: S028 (No Stack Changes)

UTM East ____________ UTM North ____________ or

Longitude ____________ Latitude ____________

Most important stacks have been located on topographic or air navigation charts. If you know the UTM coordinates or latitude and longitude, provide this information. If there is a number of stacks close together, a common location may be used

Stack Height: ______ ft. Ground level elevation ______ ft. Diameter ______ ft.

Material Outer: ____________ Lining: ____________

Exit temperature (F): ______ Exit Velocity: ______ (f/s).

Exhaust rate: ______ (ACFM) % Moisture: ______

Nearest building to stack:

Distance ______ ft. height ______ ft. length ______ ft. width ______ ft.

**Processes Sharing Stack:** If more than one process shares a stack, list them and estimate relative contribution of each.

Description ____________

Contribution to emissions from stack ______ %

Description ____________

Contribution to emissions from stack ______ %

Description ____________

Contribution to emissions from stack ______ %

Description ____________

## PART VIII - REMARKS

**Attach calculations and reference all emission factors for Allowable, Potential to Emit, and Actual Emissions to this sheet. Reference all emission factors and efficiencies of control equipment.**

| PART IX - EMISSIONS |
|---|

PART 9a: EMISSIONS -- SHORT TERM LB/HR (POUNDS PER HOUR) OR OTHER      See Appendix C for Detailed Calculations

| Pollutant | Particulate | PM10 | SO2 | CO | NOx | VOC | LEAD | PM2.5 |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | 49.25 | | | | | |
| Actual or Estimated | | | | | | | | |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

PART 9b: EMISSIONS -- ANNUAL TPY (TONS PER YEAR)      *Projected Actual Emissions (see Appendix C)

| Pollutant | Particulate | PM10 | SO2 | CO | NOX | VOC | LEAD | PM2.5 |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | 1.1 | 2.3 | 20.2 | 27.1 | 28.4 | 0.02 | 1.2E-4 | 2.0 |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

## PART IX - EMISSIONS (CONTINUED)

**List all known pollutants, including, but not limited to those found under Article XXI section 2101.20 in the definition of Hazardous Air Pollutants.**

Transfer this information to the summary emissions sheets.

See Appendix C

# PERMIT APPLICATION FORM B
# FUEL BURNING OR COMBUSTION EQUIPMENT

**PLANT NAME AND LOCATION:** U. S. Steel Clairton Plant

Schedule B requires information on boilers, heaters, and other combustion units. Complete one form for each unit, making copies of this form as needed.

## PART I - DESCRIPTION OF COMBUSTION UNIT (MAKE A COPY OF SCHEDULE B FOR EACH UNIT)

Company Identification or Description: Existing Boiler T-1 (B007)

Unit Make: Erie City Unit Model: N/A

Description of Unit and Type of Firing (e.g. spreader stoker, traveling grate, etc.)

Installer: N/A Installation Date: N/A

Contractor (if operated by another): N/A

Installation Date: __ /__ /__ Your Identification: B007 (current permit ID)

Previous County Air Pollution Permit Number (if any): N/A

Rated Capacity (BTU/hr) 156,000,000 Maximum Capacity (BTU/hr): 156,000,000

Normal Use (BTU/hr) 156,000,000

Percent of Heat Used for:

Power Generation _____ % process 100 % space heating _____ % (Annual average)

## PART II - OPERATION SCHEDULE

A. Normal schedule: (Provide information for last year. If a new unit, please estimate)

Hours/day 7 Days/week 52 Weeks/year Hours/year 2,200 (future use)

Start time __:__ End time __:__

Seasonal: (Periods correspond to seasons instead of calendar quarters. The first season is split to include December, January, and February of the calendar year reported.)

Percent of Annual Production

| | | | |
|---|---|---|---|
| December, January, & February | 25 | June, July, & August | 25 |
| March, April, & May | 25 | September, October, & November | 25 |

B. Requested limits: (limitations on operating hours are optional) Choose One:

_X_ 8760 hours (no limitations) or **(See Fuel Limits in Part III)**

__ I/We request the following limitation -- **This may become a federally enforceable permit condition:** Describe how this can be enforced: Either list an operating schedule or downtime (e.g. only operate 8:00 to 4:00) or an operating hour reporting requirement.

_____ Total days x _____ Hours/day = _____ Hours/year

## PART III - FUELS

A. Normal operation (Provide information for last year. If a new unit, please estimate)

| ___ Year 2018 or X Estimate | Primary | Secondary | Other | Other |
|---|---|---|---|---|
| Type: | COG | N. Gas | | |
| Max Amount/hour | ~0.3 MMcf/hr | ~0.2 MMcf/hr | | |
| Sulfur Content (% wt): | 35 gr/100 scf ($H_2S$) | Negl. | | |
| Ash Content (% wt): | Negl. | Negl. | | |
| BTU Rating (specify units) | 156 MMBtu/hr | 156 MMBtu/hr | | |
| Annual Fuel Consumption | 272700 MMBtu/yr | 0 MMBtu/yr | | |
| Seasonal Fuel Consumption (%): | | | | |
| December, January & February | 25 | 25 | | |
| March, April, and May | 25 | 25 | | |
| June, July, and August | 25 | 25 | | |
| September, October, & November | 25 | 25 | | |

Fuel Mixing: If more than one fuel is used, explain usage, stating whether it is burned separately, mixed in a fixed ratio of__:__ (give units such as BTU, mmcf, gallons per ton, etc.), mixed in a variable ratio of__:__ to __:__, determined by__ (give reason). **Fuel can, but is not required, to be burned simultaneously. Emissions estimates assume up to 70% of rated heat input (on an hourly basis) is from COG, with the balance from natural gas.**

B. Requested limits (limitations on operations are optional, but may allow a Major source to be exempted from some requirements) **These may become permit conditions**. Please check one:

___ Full use of any fuel or combination at any time (no limitations) OR

_X_ The following limitations on types of fuels or the combination of fuels (describe how compliance with this method will be demonstrated): **Combined limit of 480,480 MMBtu/yr (aggregate) on COG for Boilers T-1 and T-2 and up to 205,920 MMBtu/yr (aggregate) on N. Gas for Boilers T-1 and T-2. Monitor fuel usage on a monthly basis.**

## PART IV - OTHER LIMITATIONS

Identify any other requested limitations, such as on production rates or materials use. Describe how compliance with these restrictions will be demonstrated. **These limitations may become permit conditions.**

N/A

## PART V - APPLICABLE REQUIREMENTS

Describe all applicable air requirements for this source.

| Regulation # | Requirements |
|---|---|
| | No Changes to Applicability |

| PART VI - EMISSION CONTROLS | NOT APPLICABLE – No Changes |
|---|---|

Complete the following applicable sections for each pollution control device. Attach additional sheets to provide sufficient information and engineering calculations to support the contol device performance.

On the space to the left of each device, number the device(s) by the order in which they process the waste stream(s). Fill out the requested information, then complete the table for efficiencies by pollutant for each device.

Percent Capture _______ % (not control efficiency)

Gas flow through control units ________ @ _______ °F

_____ **BAGHOUSE (fabric collector)**

Manufacturer's Name and Model: ______________________________

Type of bag material: ______________________________

Total filter cloth area: _______ sq. ft. air to cloth ratio ______________

Bag cleaning method: ______________ cycle ________ minute(s)

Pressure Drop: clean _______ "$H_2O$, dirty ________ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

_____ **ELECTROSTATIC PRECIPITATOR**

Manufacturer's Name and Model: ______________________________

Type: __ single stage, __ two stage, __ plate, __ tube

Total collecting area: ________ sq. ft. cleaning cycle _______ min

Gas Velocity: ____________ ft./sec. corona power _______ kw

Bulk resistivity of Dust: _______ ohm-cm Moisture content of gases _______ vol. %

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

_____ **CYCLONE (dry gas only)**

Manufacturer's Name and Model: ______________________________

Gas Inlet: width _______ ft., height _______ ft.

Diameter: gas outlet _______ ft., cyclone cylinder (s) _______ ft.

Length of cyclone: ______ ft., no. of cylinder(s) _______ Pressure Drop _______ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

## PART VI - EMISSION CONTROLS (CONTINUED) NOT APPLICABLE

### _____ CONDENSER

Manufacturer's Name and Model: ____________________

Type: surface ________ , contact ____________________

Heat transfer area: ________ sq. ft., max process pressure ________ psia

Heat duty: ________ BTU/hr. Coolant temp: inlet ____________ °F outlet __________ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
| --- | --- | --- | --- |

### _____ WET COLLECTOR

Manufacturer's Name and Model: ____________________

Type: __ venturi, __ cyclone, __ spray chamber, __ packed bed

Entrainment/separator: type __________ , bed depth: __________

Type & construction of chemicals added to the scrubbing liquid:

Pressure drop ________ "$H_2O$

Scrubbing liquid: flow rate ________ gpm, inlet temp. ________ °F, outlet temp. ________ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
| --- | --- | --- | --- |

### _____ AFTERBURNER

Manufacturer's Name and Model: ____________________

Type: __ direct flame, __ catalytic

If catalytic: inlet temp. ________ °F, outlet temp. ________ °F, catalyst life ____________

If direct flame: Internal volume ________ cu. ft., average temp. ________ °F

Residence time at average temp. ________ sec

Auxiliary fuel: max. rating ________ BTU/hr. set point ________ °F, ________ BTU/hr.

Size of Chamber ________ cu. ft. flow rate ________

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading (gn./cu. ft.) |
| --- | --- | --- | --- |

### _____ ADSORPTION EQUIPMENT

Manufacturer's Name and Model: ____________________

Type: __ continuous, __ fixed bed

Adsorbing material: __________ bed depth __________ in., flow area ________ sq. ft.

Breakthrough (breakpoint) time: ________ Pressure drop: __________ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
| --- | --- | --- | --- |

## PART VI - EMISSION CONTROLS (CONTINUED)

_____ **OTHER TYPES:** Name and describe. Attach complete details.

| | |
|---|---|
| | |
| | |
| | |
| | |
| | |

**FUGITIVE DUST CONTROLS:** Describe below or attach a complete explanation of all controls of fugitive emissions not discussed in Form E - Roads or Form F - Storage Piles.

N/A

## PART VII - STACK DATA

Stack data must be provided for each flue, duct, pipe, stack, chimney or conduit (stacks) at which collected emissions are vented to open air through a restricted opening.

Stack Identification: S030 (No Stack Changes)

UTM East ______________ UTM North ______________ or

Longitude ______________ Latitude ______________

Most important stacks have been located on topographic or air navigation charts. If you know the UTM coordinates or latitude and longitude, provide this information. If there is a number of stacks close together, a common location may be used

Stack Height: ______ ft. Ground level elevation ______ ft. Diameter ______ ft.

Material Outer: ______________ Lining: ______________

Exit temperature (F): ______ Exit Velocity: ______ (f/s).

Exhaust rate: ______ (ACFM) % Moisture: ______

Nearest building to stack:

Distance ______ ft. height ______ ft. length ______ ft. width ______ ft.

**Processes Sharing Stack:** If more than one process shares a stack, list them and estimate relative contribution of each.

Description ______________

Contribution to emissions from stack ______ %

Description ______________

Contribution to emissions from stack ______ %

Description ______________

Contribution to emissions from stack ______ %

Description ______________

## PART VIII - REMARKS

**Attach calculations and reference all emission factors for Allowable, Potential to Emit, and Actual Emissions to this sheet. Reference all emission factors and efficiencies of control equipment.**

| PART IX - EMISSIONS |
|---|

**PART 9a: EMISSIONS -- SHORT TERM LB/HR (POUNDS PER HOUR) OR OTHER** **See Appendix C for Detailed Calculations**

| Pollutant | Particulate | PM10 | SO2 | CO | NOx | VOC | LEAD | PM2.5 |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | 23.49 | | | | | |
| Actual or Estimated | | | | | | | | |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

**PART 9b: EMISSIONS -- ANNUAL TPY (TONS PER YEAR)** ***Projected Actual Emissions (see Appendix C)**

| Pollutant | Particulate | PM10 | SO2 | CO | NOX | VOC | LEAD | PM2.5 |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | 1.0 | 2.4 | 20.0 | 8.7 | 34.1 | 0.2 | 1.3E-4 | 2.4 |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

## PART IX - EMISSIONS (CONTINUED)

**List all known pollutants, including, but not limited to those found under Article XXI section 2101.20 in the definition of Hazardous Air Pollutants.**

Transfer this information to the summary emissions sheets.

See Appendix C

# PERMIT APPLICATION FORM B
# FUEL BURNING OR COMBUSTION EQUIPMENT

**PLANT NAME AND LOCATION:** U. S. Steel Clairton Plant

Schedule B requires information on boilers, heaters, and other combustion units. Complete one form for each unit, making copies of this form as needed.

## PART I - DESCRIPTION OF COMBUSTION UNIT (MAKE A COPY OF SCHEDULE B FOR EACH UNIT)

Company Identification or Description: Existing Boiler T-2 (B008)

Unit Make: Erie City Unit Model: N/A

Description of Unit and Type of Firing (e.g. spreader stoker, traveling grate, etc.)

Installer: N/A Installation Date: N/A

Contractor (if operated by another): N/A

Installation Date: __ /__ /__ Your Identification: B008 (current permit ID)

Previous County Air Pollution Permit Number (if any): N/A

Rated Capacity (BTU/hr) 156,000,000 Maximum Capacity (BTU/hr): 156,000,000

Normal Use (BTU/hr) 156,000,000

Percent of Heat Used for:

Power Generation ______ % process 100 % space heating ______ % (Annual average)

## PART II - OPERATION SCHEDULE

A. Normal schedule: (Provide information for last year. If a new unit, please estimate)

Hours/day 7 Days/week 52 Weeks/year Hours/year 2,200 (future use)

Start time __:__ End time __:__

Seasonal: (Periods correspond to seasons instead of calendar quarters. The first season is split to include December, January, and February of the calendar year reported.)

Percent of Annual Production

| | | | |
|---|---|---|---|
| December, January, & February | 25 | June, July, & August | 25 |
| March, April, & May | 25 | September, October, & November | 25 |

B. Requested limits: (limitations on operating hours are optional) Choose One:

X 8760 hours (no limitations) or **(See Fuel Limits in Part III)**

__ I/We request the following limitation -- **This may become a federally enforceable permit condition:** Describe how this can be enforced: Either list an operating schedule or downtime (e.g. only operate 8:00 to 4:00) or an operating hour reporting requirement.

______ Total days x ______ Hours/day = ______ Hours/year

## PART III - FUELS

A. Normal operation (Provide information for last year. If a new unit, please estimate)

| _____ Year 2018 or X Estimate | Primary | Secondary | Other | Other |
|---|---|---|---|---|
| Type: | COG | N. Gas | | |
| Max Amount/hour | ~0.3 MMcf/hr | ~0.2 MMcf/hr | | |
| Sulfur Content (% wt): | 35 gr/100 scf ($H_2S$) | Negl. | | |
| Ash Content (% wt): | Negl. | Negl. | | |
| BTU Rating (specify units) | 156 MMBtu/hr | 156 MMBtu/hr | | |
| Annual Fuel Consumption | 272700 MMBtu/yr | 0 MMBtu/yr | | |
| Seasonal Fuel Consumption (%): | | | | |
| December, January & February | 25 | 25 | | |
| March, April, and May | 25 | 25 | | |
| June, July, and August | 25 | 25 | | |
| September, October, & November | 25 | 25 | | |

Fuel Mixing: If more than one fuel is used, explain usage, stating whether it is burned separately, mixed in a fixed ratio of__:__(give units such as BTU, mmcf, gallons per ton, etc.), mixed in a variable ratio of__:__ to __:__, determined by__ (give reason). **Fuel can, but is not required, to be burned simultaneously. Emissions estimates assume up to 70% of rated heat input (on an hourly basis) is from COG, with the balance from natural gas.**

B. Requested limits (limitations on operations are optional, but may allow a Major source to be exempted from some requirements) **These may become permit conditions.** Please check one:

___ Full use of any fuel or combination at any time (no limitations) OR

_X_ The following limitations on types of fuels or the combination of fuels (describe how compliance with this method will be demonstrated): **Combined limit of 480,480 MMBtu/yr (aggregate) on COG for Boilers T-1 and T-2 and up to 205,920 MMBtu/yr (aggregate) on N. Gas for Boilers T-1 and T-2. Monitor fuel usage on a monthly basis.**

## PART IV - OTHER LIMITATIONS

Identify any other requested limitations, such as on production rates or materials use. Describe how compliance with these restrictions will be demonstrated. **These limitations may become permit conditions.**

N/A

## PART V - APPLICABLE REQUIREMENTS

Describe all applicable air requirements for this source.

| Regulation # | Requirements |
|---|---|
| | No Changes to Applicability |
| | |

**PART VI - EMISSION CONTROLS** **NOT APPLICABLE – No Changes**

Complete the following applicable sections for each pollution control device. Attach additional sheets to provide sufficient information and engineering calculations to support the contol device performance.

On the space to the left of each device, number the device(s) by the order in which they process the waste stream(s). Fill out the requested information, then complete the table for efficiencies by pollutant for each device.

Percent Capture _______ % (not control efficiency)

Gas flow through control units _________ @ _______ °F

_____ **BAGHOUSE (fabric collector)**

Manufacturer's Name and Model: ____________________

Type of bag material: ____________________

Total filter cloth area: _______ sq. ft. air to cloth ratio ____________

Bag cleaning method: ____________ cycle ________ minute(s)

Pressure Drop: clean _______ "$H_2O$, dirty ________ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

_____ **ELECTROSTATIC PRECIPITATOR**

Manufacturer's Name and Model: ____________________

Type: __ single stage, __ two stage, __ plate, __ tube

Total collecting area: _________ sq. ft. cleaning cycle _______ min

Gas Velocity: ____________ ft./sec. corona power _______ kw

Bulk resistivity of Dust: ________ ohm-cm Moisture content of gases _______ vol. %

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

_____ **CYCLONE (dry gas only)**

Manufacturer's Name and Model: ____________________

Gas Inlet: width _______ ft., height _______ ft.

Diameter: gas outlet _______ ft., cyclone cylinder (s) _______ ft.

Length of cyclone: ______ ft., no. of cylinder(s) _______ Pressure Drop _______ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading |
|---|---|---|---|

| PART VI - EMISSION CONTROLS (CONTINUED) | NOT APPLICABLE |
|---|---|

____ **CONDENSER**

Manufacturer's Name and Model: ____________________

Type: surface ________ , contact ____________________

Heat transfer area: ________ sq. ft., max process pressure ________ psia

Heat duty: ________ BTU/hr. Coolant temp: inlet ____________ °F outlet __________ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

____ **WET COLLECTOR**

Manufacturer's Name and Model: ____________________

Type: __ venturi, __ cyclone, __ spray chamber, __ packed bed

Entrainment/separator: type __________ , bed depth: __________

Type & construction of chemicals added to the scrubbing liquid:

Pressure drop ________ "$H_2O$

Scrubbing liquid: flow rate _______ gpm, inlet temp. ________ °F, outlet temp. _______ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

____ **AFTERBURNER**

Manufacturer's Name and Model: ____________________

Type: __ direct flame, __ catalytic

If catalytic: inlet temp. _______ °F, outlet temp. ________ °F, catalyst life ____________

If direct flame: Internal volume ________ cu. ft., average temp. ________ °F

Residence time at average temp. ________ sec

Auxiliary fuel: max. rating ________ BTU/hr. set point ________ °F, ________ BTU/hr.

Size of Chamber ________ cu. ft. flow rate ________

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading (gn./cu. ft.) |
|---|---|---|---|

____ **ADSORPTION EQUIPMENT**

Manufacturer's Name and Model: ____________________

Type: __ continuous, __ fixed bed

Adsorbing material: __________ bed depth __________ in., flow area ________ sq. ft.

Breakthrough (breakpoint) time: ________ Pressure drop: __________ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

## PART VI - EMISSION CONTROLS (CONTINUED)

_____ **OTHER TYPES:** Name and describe. Attach complete details.

**FUGITIVE DUST CONTROLS:** Describe below or attach a complete explanation of all controls of fugitive emissions not discussed in Form E - Roads or Form F - Storage Piles.

N/A

## PART VII - STACK DATA

Stack data must be provided for each flue, duct, pipe, stack, chimney or conduit (stacks) at which collected emissions are vented to open air through a restricted opening.

Stack Identification: S031 (No Stack Changes)

UTM East ____________ UTM North ____________ or

Longitude ____________ Latitude ____________

Most important stacks have been located on topographic or air navigation charts. If you know the UTM coordinates or latitude and longitude, provide this information. If there is a number of stacks close together, a common location may be used

Stack Height: ______ ft. Ground level elevation ______ ft. Diameter ______ ft.

Material Outer: ____________ Lining: ____________

Exit temperature (F): ______ Exit Velocity: ______ (f/s).

Exhaust rate: ______ (ACFM) % Moisture: ______

Nearest building to stack:

Distance ______ ft. height ______ ft. length ______ ft. width ______ ft.

**Processes Sharing Stack:** If more than one process shares a stack, list them and estimate relative contribution of each.

Description ____________

Contribution to emissions from stack ______ %

Description ____________

Contribution to emissions from stack ______ %

Description ____________

Contribution to emissions from stack ______ %

Description ____________

## PART VIII - REMARKS

**Attach calculations and reference all emission factors for Allowable, Potential to Emit, and Actual Emissions to this sheet. Reference all emission factors and efficiencies of control equipment.**

| PART IX - EMISSIONS |
|---|

PART 9a: EMISSIONS -- SHORT TERM LB/HR (POUNDS PER HOUR) OR OTHER    See Appendix C for Detailed Calculations

| Pollutant | Particulate | PM10 | SO2 | CO | NOx | VOC | LEAD | PM2.5 |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | 23.49 | | | | | |
| Actual or Estimated | | | | | | | | |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

PART 9b: EMISSIONS -- ANNUAL TPY (TONS PER YEAR)    *Projected Actual Emissions (see Appendix C)

| Pollutant | Particulate | PM10 | SO2 | CO | NOX | VOC | LEAD | PM2.5 |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | 1.0 | 2.4 | 20.0 | 8.7 | 34.1 | 0.2 | 1.3E-4 | 2.4 |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

**PART IX - EMISSIONS (CONTINUED)**

**List all known pollutants, including, but not limited to those found under Article XXI section 2101.20 in the definition of Hazardous Air Pollutants.**

Transfer this information to the summary emissions sheets.

See Appendix C

## PERMIT APPLICATION FORM C
## SOLID WASTE INCINERATOR

**PLANT NAME AND LOCATION:** NOT APPLICABLE

Schedule C requires information on incinerators. Complete one form for each unit, making copies of this form as needed. Do not use this form for afterburners used as control devices.

### PART I - DESCRIPTION OF COMBUSTION UNIT (MAKE A COPY OF SCHEDULE C FOR EACH UNIT)

Company Identification or Description: ____________________

Unit Make: ____________________ Model and Class: ____________________

American Incinerator Association Class of Waste __________ @ __________ BTU/lb as fired

Daily Amount Waste __________ Lbs. (__) Estimated, (__) Actual

Installer: ____________________ Installation Date: __/__/__

Contractor (if operated by another): ____________________

Installation Date: __/__/__ Your Identification: ____________________

Previous County Air Pollution Permit Number (if any): ____________________

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Primary Combustion Chamber: | Length | ____ ft. | ____ in. | Grate Area | ____ | sq. ft. |
| | Width | ____ ft. | ____ in. | Burner capacity | ____ | BTU/hr |
| | Height | ____ ft. | ____ in. | Hearth area | ____ | sq. ft. |
| | Volume | ____ cu. ft. | | Heat release | ____ | BTU/hr/cu ft |
| Secondary Combustion Chamber: | Length | ____ ft. | ____ in. | Smallest Area | ____ | sq. ft. |
| | Width | ____ ft. | ____ in. | Burner capacity | ____ | BTU/hr |
| | Height | ____ ft. | ____ in. | Max velocity | ____ | ft/sec |
| | Volume | ____ cu. ft. | | | | |
| | Flue Gas Flow | ____ acfm@ | ____ °F | ____ % | | % excess air |

**Attach a flow diagram of all waste and fuel streams**

### PART II - OPERATION SCHEDULE

A. Normal schedule: (Provide information for last year. If a new unit, please estimate)

Hours/day ______ Days/week ______ Weeks/year ______ Hours/year ______

Start time __:__ End time __:__

Seasonal: (Periods correspond to seasons instead of calendar quarters. The first season is split to include December, January, and February of the calendar year reported.)

Percent of Annual Production

| | | | |
|---|---|---|---|
| December, January, & February | ______ | June, July, & August | ______ |
| March, April, & May | ______ | September, October, & November | ______ |

B. Requested limits: (limitations on operating hours are optional) Choose One:

__ 8760 hours (no limitations) or

__ I/We request the following limitation – **This may become a federally enforceable permit condition:** Describe how this can be enforced: Either list an operating schedule or downtime (e.g. only operate 8:00 to 4:00) or an operating hour reporting requirement.

__________ Total days x __________ Hours/day = __________ Hours/year

## PART III - FUELS

A. Normal operation (Provide information for last year. If a new unit, please estimate)

| ____ Year ______ or _____ Estimate | Primary | Secondary | Other | Other |
|---|---|---|---|---|
| Type: | ________ | ________ | ________ | ________ |
| Max amount/hour | ________ | ________ | ________ | ________ |
| Sulfur content (% wt): | ________ | ________ | ________ | ________ |
| Ash content (% wt): | ________ | ________ | ________ | ________ |
| BTU Rating (specify units) | ________ | ________ | ________ | ________ |
| Annual Fuel Consumption | ________ | ________ | ________ | ________ |
| Seasonal Fuel Consumption (%): | | | | |
| December, January and February | ________ | ________ | ________ | ________ |
| March, April, and May | ________ | ________ | ________ | ________ |
| June, July, and August | ________ | ________ | ________ | ________ |
| September, October, and November | ________ | ________ | ________ | ________ |

Fuel Mixing: If more than one fuel is used, explain usage, stating whether it is burned separately, mixed in a fixed ratio of__:__(give units such as BTU, mmcf, gallons per ton, etc.), mixed in a variable ratio of__:__ to __:__, determined by __ (give reason).

B. Requested limits (limitations on operations are optional, but may allow a Major source to be exempted from some requirements) **These may become permit conditions.** Please check one:

____ Full use of any fuel or combination at any time (no limitations) OR

____ The following limitations on individual fuels or the combination of fuels (describe how compliance with this method will be demonstrated):

## PART IV - OTHER LIMITATIONS

Identify any other requested limitations, such as on production rates or materials use. Describe how compliance with these restrictions will be demonstrated. **These limitations may become permit conditions.**

**PART V - APPLICABLE REQUIREMENTS**

Describe all applicable air requirements for this source.

| Regulation # | Requirements |
|---|---|
| | |
| | |
| | |

**PART VI - EMISSION CONTROLS**

Complete the following applicable sections for each pollution control device. Attach additional sheets to provide sufficient information and engineering calculations to support the contol device performance.

On the space to the left of each device, number the device(s) by the order in which they process the waste stream(s). Fill out the requested information, then complete the table for efficiencies by pollutant for each device.

Percent Capture _______ % (not control efficiency)

Gas flow through control units _________ @ _______ °F

_____ **BAGHOUSE (fabric collector)**

Manufacturer's Name and Model: ______________________________

Type of bag material: ______________________________

Total filter cloth area: _______ sq. ft. air to cloth ratio ______________

Bag cleaning method: ______________ cycle ________ min

Pressure Drop: clean _______ "$H_2O$, dirty _______ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading Corr. To 7% $O_2$ (gn/cu. ft) |
|---|---|---|---|

_____ **ELECTROSTATIC PRECIPITATOR**

Manufacturer's Name and Model: ______________________________

Type: __ single stage, __ two stage, __ plate, __ tube

Total collecting area: _________ sq. ft. cleaning cycle ________ min

Gas Velocity: _____________ ft./sec. corona power ________ kw

Bulk resistivity of Dust: _______ ohm-cm Moisture Content of gases _______ vol. %

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading Corr. To 7% $O_2$ (gn/cu. ft) |
|---|---|---|---|

_____ **CYCLONE (dry gas only)**

Manufacturer's Name and Model: ______________________________

Gas inlet: width _______ ft., height _______ ft.

Diameter: gas outlet _______ ft., cyclone cylinder (s) _______ ft.

Length of cyclone: ______ ft., no. of cylinder(s) _______ Pressure Drop _______ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading Corr. To 7% $O_2$ (gn/cu. ft) |
|---|---|---|---|

## PART VI - EMISSION CONTROLS (CONTINUED)

_____ **CONDENSER**

Manufacturer's Name and Model: ______________________________

Type: surface __________ , contact ______________________________

Heat transfer area: ________ sq. ft., Max process pressure _________ psia

Heat duty: ________ BTU/hr. Coolant temp: inlet ______________ °F, outlet _________ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

_____ **WET COLLECTOR**

Manufacturer's Name and Model: ______________________________

Type: __ venturi, __ cyclone, __ spray chamber, __ packed bed

Entrainment/separator: type __________ , bed depth: __________

Type & construction of chemicals added to the scrubbing liquid:

Pressure drop _________ "$H_2O$

Scrubbing liquid: flow rate _______ gpm, inlet temp. ________ °F, outlet temp. _______ °F

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

_____ **AFTERBURNER**

Manufacturer's Name and Model: ______________________________

Type: __ direct flame, __ catalytic

If catalytic: inlet temp. _______ °F, outlet temp. ________ °F, catalyst life ______________

If direct flame: internal volume _________ cu. ft., average temp. _________ °F

Residence time at average temp. ________ sec

Auxiliary fuel: max. rating ________ BTU/hr. set point _________ °F, ________ BTU/hr.

Size of Chamber _______ cu. ft. flow rate ___________

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Grain Loading Corr. To 7% $O_2$ (gn/cu. ft) |
|---|---|---|---|

_____ **ADSORPTION EQUIPMENT**

Manufacturer's Name and Model: ______________________________

Type: __ continuous, __ fixed bed

Adsorbing material: ____________ bed depth _____________ in., flow area _________ sq. ft.

Breakthrough (breakpoint) time: ___________ Pressure drop: ___________ "$H_2O$

| Pollutant | Efficiency (%) | Basis for Efficiency | Outlet Concentration (ppm) |
|---|---|---|---|

## PART VI - EMISSION CONTROLS (CONTINUED)

_____ **OTHER TYPES** Name and describe. Attach complete details.

**FUGITIVE DUST CONTROLS:** Describe below or attach a complete explanation of all controls of fugitive emissions not discussed in Form E - Roads or Form F - Storage Piles.

## PART VII - STACK DATA

Stack data must be provided for each flue, duct, pipe, stack, chimney or conduit (stacks) at which collected emissions are vented to open air through a restricted opening.

Stack Identification: ____________________
UTM East ____________________ UTM North ____________________ or
Longitude ____________________ Latitude ____________________

Most important stacks have been located on topographic or air navigation charts. If you know the UTM coordinates or latitude and longitude, provide this information. If there is a number of stacks close together, a common location may be used

Stack Height: ________ Ft. Ground level elevation ________ Ft. Diameter ________ Ft.
Material Outer: ____________________ Lining: ____________________
Exit temperature (F): ____________ Exit Velocity: ____________ (f/s)
Exhaust Rate: ________ (ACFM) % Moisture: ________
Nearest building to stack:
distance ________ ft. height ________ ft. length ________ ft. width ________ Ft.

**Processes Sharing Stack:** If more than one process shares a stack, list them and estimate relative contribution of each.

Description ____________________
Contribution to emissions from stack ________ %
Description ____________________
Contribution to emissions from stack ________ %
Description ____________________
Contribution to emissions from stack ________ %
Description ____________________

## PART VIII - REMARKS

**Attach calculations and reference all emission factors for Allowable, Potential to Emit, and Actual Emissions to this sheet. Reference all emission factors and efficiencies of control equipment.**

PART IX - EMISSIONS

PART 9a: EMISSIONS -- SHORT TERM LB/HR (POUNDS PER HOUR) OR OTHER ____________

| Pollutant | PM | PM10 | $SO_2$ | CO | $NO_x$ | VOC | LEAD | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

PART 9b: EMISSIONS -- ANNUAL TPY (TONS PER YEAR)

| Pollutant | PM | PM10 | $SO_2$ | CO | $NO_x$ | VOC | LEAD | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

## PART IX - EMISSIONS (CONTINUED)

**List all known pollutants, including, but not limited to those found under Article XXI section 2101.20 in the definition of Hazardous Air Pollutants.**

Transfer this information to the summary emissions sheets.

# PERMIT APPLICATION FORM D
# STORAGE TANKS

Tanks situated at a common location in the facility and storing the same materials, or vented through a common control device may be grouped together for reporting purposes if the emissions from individual tanks are small. A diagram should be attached showing the locations of grouped tanks. A separate listing should be provided for Part I for each tank. Part II and estimates of emissions should be for the group. Emissions from liquid or gas storage tanks that condense to form solids in ambient air should be included in emissions estimates as particulate TSP and/or PM10.

## PART I - DESCRIPTION OF STORAGE TANKS (MAKE A COPY OF SCHEDULE E FOR EACH STORAGE TANK)

Company Identification or Description: Cogeneration Plant Emergency Engine Fuel Tank (Exempt)

Installer: TBD Installation Date: TBD, Begin ~2020

Prior Allegheny County Air Pollution Permit No. N/A

Capacity 200 gal (fire pump) (specify units) Age: New (years)

Diameter TBD (ft) Height TBD (ft)

Paint Color TBD Loading Type TBD

**Materials Normally Used**

Common Name Diesel Oil Chemical Name Distillate Oil

Chemical Abstract Service # N/A Liquid Molecular Weight N/A

Vapor Pressure <0.01 psia at 52 F (temperature)

**Type of tank (check appropriate spaces):**

Underground _____ Pressure Tank _____ Surface X

If the tank is a surface tank:

_____ No Roof

TBD Fixed Roof

Roof Paint Color TBD Shell Paint Color TBD

Paint Condition TBD Average Vapor Space Height TBD (ft)

Pressure Relief Valve Setting: Pressure TBD psia

Vacuum TBD

Vapor Recovery System (Description)

Control Efficiency N/A %

Gas Blanketing System Gas N/A Amt Used N/A

_____ Floating Roof (specify internal or external floating roof.)

_____ External Floating Roof

Primary Seal Type _____

Secondary Seal Type _____

_____ Internal Floating Roof

Primary Seal Type _____

Deck Construction Type _____

Tank Construction Type _____

## PART II - OPERATING SCHEDULE

Throughput (specify units):

Annual ~378 gal (fire pump) Daily ~1 gal (fire pump)

Maximum turnovers per year: ~2 gal (fire pump)

Seasonal: Periods correspond to seasons instead of calendar quarters. The first season is split to include December, January, and February.

Seasonal Percentage of Total Throughput:

| | | | |
|---|---|---|---|
| December, January, & February | 25 % | June, July, & August | 25 % |
| March, April, & May | 25 % | September, October, & November | 25 % |

Dates tank is not normally in use: from __/__/__ TO __/__/__

## PART III - CONTROL DEVICES

Describe any control devices, including any gas blanketing system noted above.

N/A

## PART IV - EMISSIONS - ANNUAL TPY

| Pollutant | PM | PM10 | $SO_2$ | CO | $NO_x$ | VOC | LEAD | |
|---|---|---|---|---|---|---|---|---|
| Allowable | N/A | N/A | N/A | N/A | N/A | <0.01 | N/A | |
| Maximum Potential | N/A | N/A | N/A | N/A | N/A | <0.01 | N/A | |
| Actual or Estimated | N/A | N/A | N/A | N/A | N/A | <0.01 | N/A | |

| Pollutant | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Allowable | | | | | | | | |
| Maximum Potential | | | | | | | | |
| Actual or Estimated | | | | | | | | |

List all known pollutants, including, but not limited to those found under Article XXI section 2101.20 in the definition of Hazardous Air Pollutants.

Transfer this information to the summary emissions sheets.

## PERMIT APPLICATION FORM E
## DRY BULK MATERIALS STORAGE AND HANDLING

This form reports particulate emissions from wind erosion of bulk materials stockpiles, from additions and retrievals of material, and from stockpile maintenance. It includes materials stored under cover and in silos. Storage piles including hazardous materials such as lead compounds or asbestos should be reported here. A separate form should be prepared for each stockpile. Mining, excavation, crushing, and other materials processing should be treated as processes and reported on Form A.

**PART I - DESCRIPTION OF STORAGE PILE** (MAKE A COPY OF SCHEDULE E FOR EACH STORAGE PILE)

Open and enclosed stockpiles of raw materials, intermediate products, and finished products should be reported. Include silos in reporting types of stockpile covering.

**Company Identification or Description:** Lime Silo, Waste Lime Silo, Lime Day Bins (1 and 2)

UTM East: TBD (Silos/Bins) UTM North: TBD (Silos/Bins) (center of pile)

Type of Material Stored (Generic Name): Hydrated Lime

Major Chemical Components (list, with percentages of each):

Hydrated Lime (100%)

Moisture Content: N/A % Silt Content: N/A %

Height of Pile (give units): N/Aa

Uncovered: N/A acres or N/A square feet

If covered or enclosed:

Type of cover: See bin/silo details in Part III of Form E

Estimated Control Efficiency: N/A %

**PART II - STORAGE PILE TRANSFERS**

For the purpose of this schedule, stockpile transfers include either adding material onto a pile and removal of material from a pile. This schedule does not include loading or unloading from barges, rail cars or other transport, or transportation and marketing of dry materials, which should be reported as processes on Form A.

Normal Inventory: N/A (Tons)

| Estimated | Additions (tons) | Retrievals |
|---|---|---|
| December, January, and February | | |
| March, April, and May | | |
| June, July, and August | | |
| September, October, and November | | |
| Annual storage losses (tons) | | |

**PART III - EQUIPMENT**
Immobile equipment or equipment that is dedicated to the particular stockpile should be reported as fixed or dedicated units. Mobile equipment or equipment that may be moved to another area of the plant should be reported as transient or mobile units. This may include bulldozers, backhoes, or other large, mobile equipment that works on or around a stockpile. Percent utilization is the percentage of operating time (hours divided by annual hours) that equipment is in operation on the storage pile.

Fixed or Dedicated Units

| | Name | Size (Capacity) | % Utilization |
|---|---|---|---|
| (1.) | Hydrated Lime Storage Silo | 37.5 tons | ~36 |
| (2.) | Waste Lime Storage Silo | 37.5 tons | ~36 |
| (3.) | Hydrated Lime Day Bins (2 bins) | 3 tons (each) | 100% |
| (4.) | | | |
| (5.) | | | |
| (6.) | | | |

Transient or Mobile Units

| | Name | Size (Capacity) | % Utilization |
|---|---|---|---|
| (1.) | N/A | | |
| (2.) | | | |
| (3.) | | | |
| (4.) | | | |
| (5.) | | | |
| (6.) | | | |

**PART IV - DUST CONTROL MEASURES (describe):**

**PART V - EMISSION ESTIMATES**

**A. Wind Erosion** Not Applicable

| | PM10 | | TSP | |
|---|---|---|---|---|
| | Lb./hr. | TPY | Lb./hr. | TPY |
| Uncontrolled | | | | |
| Controlled | | | | |

**B. Stockpile Activity (Storage and Retrieval)** **FROM SILO BIN VENTS (Emissions are total for the two bin vents combined)**

| | PM10 | | TSP | |
|---|---|---|---|---|
| | Lb./hr. | TPY | Lb./hr. | TPY |
| Uncontrolled | N/A | N/A | N/A | N/A |
| Controlled | 0.04 | 0.04 | 0.07 | 0.07 |

**C. Stockpile Activity Maintenance** Not Applicable

| | PM10 | | TSP | |
|---|---|---|---|---|
| | Lb./hr. | TPY | Lb./hr. | TPY |
| Uncontrolled | | | | |
| Controlled | | | | |

**Attach calculations and reference all emission factors for Allowable, Potential to Emit, and Actual emissions for this sheet. Reference all emission factors and efficiencies of control equipment.**

# PERMIT APPLICATION FORM F
# ROADS AND VEHICLES

This form covers fugitive emissions from vehicles and vehicle travel on paved and unpaved roads and parking lots within the plant property. Plants with only normal business traffic of light duty vehicles and paved parking lots with capacity less than one hundred cars are not required to submit Form F.

## PART I – ROADS

Paved Roads: 1.33 (lime) / 1.96 ($NH_3$) (miles) Unpaved Roads: N/A (miles)

Parking Lots (area): None impacted by project (specify units)

## PART II - VEHICLES

**Light-Duty Gasoline Vehicles (LDGV)** N/A (average weekly number)

Estimated Total Vehicle Miles Traveled ______

| Seasonal Usage (%) | Paved Areas | Unpaved Areas |
|---|---|---|
| December, January, and February | | |
| March, April, and May | | |
| June, July, and August | | |
| September, October, and November | | |
| Annual Storage Losses (tons) | | |

**Heavy-Duty Gasoline Vehicles (HDGV)** Estimated Annual Fuel Consumption N/A (gal)

Estimated Total Vehicle Miles Traveled ______ Ave. Wgt. ______

| Seasonal Usage (%) | Paved Areas | Unpaved Areas |
|---|---|---|
| December, January, and February | | |
| March, April, and May | | |
| June, July, and August | | |
| September, October, and November | | |
| Annual Storage Losses (tons) | | |

**Heavy-Duty Diesel Vehicles (HDDV)** Estimated Annual Fuel Consumption Unknown (gal)

Estimated Total Vehicle Miles Traveled ~2,742 Ave. Wgt. 18 tons

| Seasonal Usage (%) | Paved Areas | Unpaved Areas |
|---|---|---|
| December, January, and February | 25 | 25 |
| March, April, and May | 25 | 25 |
| June, July, and August | 25 | 25 |
| September, October, and November | 25 | 25 |
| Annual Storage Losses (tons) | | |

**Road Dust Emissions** See Appendix C Table 8a, 8b and 8c for details

| | TSP | PM10 |
|---|---|---|
| Uncontrolled Emissions | 1.75 | 0.35 |
| Control Efficiency | 95% | 95% |
| Controlled (Actual) Emissions | 0.09 | 0.02 |

Dust Control Measures (Describe):

Roadway fugitive dust is controlled using a combination of periodic vacuum sweeping, use of water sprays and/or chemical dust suppressants and/or proper maintenance.

Transfer this information to the summary emissions sheets.

## PERMIT APPLICATION FORM G
## MISCELLANEOUS FUGITIVE EMISSIONS

This form is for reporting miscellaneous fugitive emissions which are not reported in forms A-F. Fugitives are emissions which escape into the plant air or outdoor air by means other than a flue or duct. Fugitives associated with a particular process should be reported on the form for that process. For example, fugitives from a paper coating line would be reported for that line. Fugitives from several segments may be grouped together. Fugitives not associated with any one process should be reported here as "Plant Fugitives." Examples are dust (TSP) and fine particulates ($PM_{10}$) from abrasive blasting or construction/demolition, VOC and/or air toxics from cleanup, painting or maintenance, or chemicals from laboratory experiments or hoods. A separate form G should be completed for each type or category of activity. Additional forms may be attached if there are more than four (4) pollutants for the activity.

**Process Description or Miscellaneous Activity (describe):**

Give a verbal description of the activity reported, such as construction projects, abrasive blasting, painting, cleaning, or other activity that has no relation to regular plant processes. State the type of abrasives, cleaners, or paints used, and other information that would be helpful in estimating dust or evaporative emissions.

**GASES AND LIQUIDS** NOT APPLICABLE

| | | | | |
|---|---|---|---|---|
| Common Name: | ______ | ______ | ______ | ______ |
| Chemical Name: | ______ | ______ | ______ | ______ |
| CAS #: | ______ | ______ | ______ | ______ |
| Use: | ______ | ______ | ______ | ______ |
| Quantity Purchased (units): | | | | |
| Annually: | ______ | ______ | ______ | ______ |
| Daily: | ______ | ______ | ______ | ______ |
| Seasonal Use: (%) | | | | |
| December, January, and February: | ______ | ______ | ______ | ______ |
| March, April, and May: | ______ | ______ | ______ | ______ |
| June, July, and August: | ______ | ______ | ______ | ______ |
| September, October, and November: | ______ | ______ | ______ | ______ |
| Volatiles Wgt % or lb./gal. OR | ______ | ______ | ______ | ______ |
| Total Volatiles | ______ | ______ | ______ | ______ |
| Amt Volatiles Recovered and Shipped Off Site | ______ | ______ | ______ | ______ |
| Amount Emitted | ______ | ______ | ______ | ______ |

**PARTICULATE EMISSIONS**

| | **TSP** | **PM10** |
|---|---|---|
| Estimated amount of particulates generated per unit of activity | ______ | ______ |
| Estimated total amount of particulates | ______ | ______ |
| Seasonal Distribution (%) | | |
| December, January, and February: | ______ | ______ |
| March, April, and May: | ______ | ______ |
| June, July, and August: | ______ | ______ |
| September, October, and November: | ______ | ______ |
| Controls (describe): | | |
| Efficiency (%) | ______ | ______ |
| Net Emissions | ______ | ______ |

**Allegheny County Health Department**
**Air Quality Program**

## PERMIT APPLICATION FORM K

## SUMMARY OF EMISSIONS

Name of Owner/Operator U. S. Steel Mon Valley Works Plant Name Clairton Plant

Pollutant NOx CAS No. ______ Year for actual emissions ______ or X estimated

| POINT | UNITS DISCHARGING TO THIS STACK | EMISSION SOURCE DESCRIPTION | ANNUAL THROUGHOUT UNITS | ALLOWABLE UNITS (tpy) | POTENTIAL (tpy) | ACTUAL (tpy) |
|---|---|---|---|---|---|---|
| COGEN1 | Cogeneration Unit 1 | Cogeneration Unit 1 (Turbine + HRSG) | N/A | 94.7 | 94.7 | 94.7 |
| COGEN2 | Cogeneration Unit 2 | Cogeneration Unit 2 (Turbine + HRSG) | N/A | 94.7 | 94.7 | 94.7 |
| FPUMP | Fire Pump | Diesel Emergency Fire Pump | 100 hrs/yr | 0.03 | 0.03 | 0.03 |
| AUXBLR | Aux. Boiler | Auxiliary Boiler | 1,000 hrs/yr | 1.0 | 1.0 | 1.0 |
| DPHTR-1 | Heater 1 | Dew Point Heater 1 | N/A | 0.4 | 0.4 | 0.4 |
| DPHTR-2 | Heater 2 | Dew Point Heater 2 | N/A | 0.4 | 0.4 | 0.4 |
| BV1 | Lime Silo | Hydrated Lime Silo Bin Vent | 3,120 hrs/yr | N/A | N/A | N/A |
| BV2 | Waste Lime Silo | Waste Lime Silo Bin Vent | 3,120 hrs/yr | N/A | N/A | N/A |
| FUG. | Paved Roads | Paved Roads | N/A | N/A | N/A | N/A |
| FUG | Oil Storage Tank | Oil Storage Tank | N/A | N/A | N/A | N/A |
| *New Equipment only. See Appendix C for projected actual emission from existing boilers. | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| TOTAL EMISSIONS FOR THIS SOURCE (FACILITY) | | | | 191.2 | 191.2 | 191.2 |

**If this is a NON-CRITERIA POLLUTANT, include the CAS number. For the fields "Point" and "Units discharging to this stack," use the identifying numbers from your plant drawing. For a more complete explanation of emissions, see definitions in Article XXI.**

**Allowable emissions are the maximum allowable by regulation. Calculate using the capacity of the unit unless restricted by operation limits, and the most strict regulation pertaining to that unit. Calculate for the shortest term regulated (one hour, one day....). Reflect the time period when defining the units.**

**Potential to emit (Potential on the chart) is the maximum capacity to emit contaminants, including fugitive emissions, under the physical and operational design of the unit. Include any permitted or regulated restrictions to operate. The Potential to Emit values should be less than or equal to the Allowable emissions.**

**Actual emissions are the best estimate of the latest year of emissions from each unit. For those that are new, actual emissions would be an estimate of a normal annual operation. Please note that sources will be required to submit an annual emissions report and may be required to pay an annual emissions fee. This report and fee payment will be made under a separate document.**

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**Allegheny County Health Department**
**Air Quality Program**

## PERMIT APPLICATION FORM K

## SUMMARY OF EMISSIONS

Name of Owner/Operator U. S. Steel Mon Valley Works Plant Name Clairton Plant

Pollutant CO CAS No. ______ Year for actual emissions ______ or X estimated

| POINT | UNITS DISCHARGING TO THIS STACK | EMISSION SOURCE DESCRIPTION | ANNUAL THROUGHOUT UNITS | ALLOWABLE UNITS (tpy) | POTENTIAL (tpy) | ACTUAL (tpy) |
|---|---|---|---|---|---|---|
| COGEN1 | Cogeneration Unit 1 | Cogeneration Unit 1 (Turbine + HRSG) | N/A | 19.3 | 19.3 | 19.3 |
| COGEN2 | Cogeneration Unit 2 | Cogeneration Unit 2 (Turbine + HRSG) | N/A | 19.3 | 19.3 | 19.3 |
| FPUMP | Fire Pump | Diesel Emergency Fire Pump | 100 hrs/yr | 0.01 | 0.01 | 0.01 |
| AUXBLR | Aux. Boiler | Auxiliary Boiler | 1,000 hrs/yr | 2.7 | 2.7 | 2.7 |
| DPHTR-1 | Heater 1 | Dew Point Heater 1 | N/A | 0.5 | 0.5 | 0.5 |
| DPHTR-2 | Heater 2 | Dew Point Heater 2 | N/A | 0.5 | 0.5 | 0.5 |
| BV1 | Lime Silo | Hydrated Lime Silo Bin Vent | 3,120 hrs/yr | N/A | N/A | N/A |
| BV2 | Waste Lime Silo | Waste Lime Silo Bin Vent | 3,120 hrs/yr | N/A | N/A | N/A |
| FUG. | Paved Roads | Paved Roads | N/A | N/A | N/A | N/A |
| FUG | Oil Storage Tank | Oil Storage Tank | N/A | N/A | N/A | N/A |
| *New Equipment only. See Appendix C for projected actual emission from existing boilers. | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| TOTAL EMISSIONS FOR THIS SOURCE (FACILITY) | | | | 42.4 | 42.4 | 42.4 |

**If this is a NON-CRITERIA POLLUTANT, include the CAS number. For the fields "Point" and "Units discharging to this stack," use the identifying numbers from your plant drawing. For a more complete explanation of emissions, see definitions in Article XXI.**

**Allowable emissions are the maximum allowable by regulation. Calculate using the capacity of the unit unless restricted by operation limits, and the most strict regulation pertaining to that unit. Calculate for the shortest term regulated (one hour, one day....). Reflect the time period when defining the units.**

**Potential to emit (Potential on the chart) is the maximum capacity to emit contaminants, including fugitive emissions, under the physical and operational design of the unit. Include any permitted or regulated restrictions to operate. The Potential to Emit values should be less than or equal to the Allowable emissions.**

**Actual emissions are the best estimate of the latest year of emissions from each unit. For those that are new, actual emissions would be an estimate of a normal annual operation. Please note that sources will be required to submit an annual emissions report and may be required to pay an annual emissions fee. This report and fee payment will be made under a separate document.**

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## Allegheny County Health Department
## Air Quality Program

# PERMIT APPLICATION FORM K

## SUMMARY OF EMISSIONS

Name of Owner/Operator U. S. Steel Mon Valley Works Plant Name Clairton Plant

Pollutant $SO_2$ CAS No. ______ Year for actual emissions ______ or X estimated

| POINT | UNITS DISCHARGING TO THIS STACK | EMISSION SOURCE DESCRIPTION | ANNUAL THROUGHOUT UNITS | ALLOWABLE UNITS (tpy) | POTENTIAL (tpy) | ACTUAL (tpy) |
|---|---|---|---|---|---|---|
| COGEN1 | Cogeneration Unit 1 | Cogeneration Unit 1 (Turbine + HRSG) | N/A | 87.1 | 87.1 | 87.1 |
| COGEN2 | Cogeneration Unit 2 | Cogeneration Unit 2 (Turbine + HRSG) | N/A | 87.1 | 87.1 | 87.1 |
| FPUMP | Fire Pump | Diesel Emergency Fire Pump | 100 hrs/yr | <0.01 | <0.01 | <0.01 |
| AUXBLR | Aux. Boiler | Auxiliary Boiler | 1,000 hrs/yr | 0.03 | 0.03 | 0.03 |
| DPHTR-1 | Heater 1 | Dew Point Heater 1 | N/A | <0.01 | <0.01 | <0.01 |
| DPHTR-2 | Heater 2 | Dew Point Heater 2 | N/A | <0.01 | <0.01 | <0.01 |
| BV1 | Lime Silo | Hydrated Lime Silo Bin Vent | 3,120 hrs/yr | N/A | N/A | N/A |
| BV2 | Waste Lime Silo | Waste Lime Silo Bin Vent | 3,120 hrs/yr | N/A | N/A | N/A |
| FUG. | Paved Roads | Paved Roads | N/A | N/A | N/A | N/A |
| FUG | Oil Storage Tank | Oil Storage Tank | N/A | N/A | N/A | N/A |
| *New Equipment only. See Appendix C for projected actual emission from existing boilers. | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| TOTAL EMISSIONS FOR THIS SOURCE (FACILITY) | | | | 174.3 | 174.3 | 174.3 |

**If this is a NON-CRITERIA POLLUTANT, include the CAS number. For the fields "Point" and "Units discharging to this stack," use the identifying numbers from your plant drawing. For a more complete explanation of emissions, see definitions in Article XXI.**

**Allowable emissions are the maximum allowable by regulation. Calculate using the capacity of the unit unless restricted by operation limits, and the most strict regulation pertaining to that unit. Calculate for the shortest term regulated (one hour, one day....). Reflect the time period when defining the units.**

**Potential to emit (Potential on the chart) is the maximum capacity to emit contaminants, including fugitive emissions, under the physical and operational design of the unit. Include any permitted or regulated restrictions to operate. The Potential to Emit values should be less than or equal to the Allowable emissions.**

**Actual emissions are the best estimate of the latest year of emissions from each unit. For those that are new, actual emissions would be an estimate of a normal annual operation. Please note that sources will be required to submit an annual emissions report and may be required to pay an annual emissions fee. This report and fee payment will be made under a separate document.**

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**Allegheny County Health Department**
**Air Quality Program**

# PERMIT APPLICATION FORM K

## SUMMARY OF EMISSIONS

Name of Owner/Operator U. S. Steel Mon Valley Works  Plant Name Clairton Plant

Pollutant VOC  CAS No. ____  Year for actual emissions ____ or X estimated

| POINT | UNITS DISCHARGING TO THIS STACK | EMISSION SOURCE DESCRIPTION | ANNUAL THROUGHOUT UNITS | ALLOWABLE UNITS (tpy) | POTENTIAL (tpy) | ACTUAL (tpy) |
|---|---|---|---|---|---|---|
| COGEN1 | Cogeneration Unit 1 | Cogeneration Unit 1 (Turbine + HRSG) | N/A | 15.5 | 15.5 | 15.5 |
| COGEN2 | Cogeneration Unit 2 | Cogeneration Unit 2 (Turbine + HRSG) | N/A | 15.5 | 15.5 | 15.5 |
| FPUMP | Fire Pump | Diesel Emergency Fire Pump | 100 hrs/yr | <0.01 | <0.01 | <0.01 |
| AUXBLR | Aux. Boiler | Auxiliary Boiler | 1,000 hrs/yr | 0.3 | 0.3 | 0.3 |
| DPHTR-1 | Heater 1 | Dew Point Heater 1 | N/A | 0.04 | 0.04 | 0.04 |
| DPHTR-2 | Heater 2 | Dew Point Heater 2 | N/A | 0.04 | 0.04 | 0.04 |
| BV1 | Lime Silo | Hydrated Lime Silo Bin Vent | 3,120 hrs/yr | N/A | N/A | N/A |
| BV2 | Waste Lime Silo | Waste Lime Silo Bin Vent | 3,120 hrs/yr | N/A | N/A | N/A |
| FUG. | Paved Roads | Paved Roads | N/A | N/A | N/A | N/A |
| FUG | Oil Storage Tank | Oil Storage Tank | N/A | <0.01 | <0.01 | <0.01 |
| *New Equipment only. See Appendix C for projected actual emission from existing boilers. | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| TOTAL EMISSIONS FOR THIS SOURCE (FACILITY) | | | | 31.4 | 31.4 | 31.4 |

**If this is a NON-CRITERIA POLLUTANT, include the CAS number. For the fields "Point" and "Units discharging to this stack," use the identifying numbers from your plant drawing. For a more complete explanation of emissions, see definitions in Article XXI.**

**Allowable emissions are the maximum allowable by regulation. Calculate using the capacity of the unit unless restricted by operation limits, and the most strict regulation pertaining to that unit. Calculate for the shortest term regulated (one hour, one day....). Reflect the time period when defining the units.**

**Potential to emit (Potential on the chart) is the maximum capacity to emit contaminants, including fugitive emissions, under the physical and operational design of the unit. Include any permitted or regulated restrictions to operate. The Potential to Emit values should be less than or equal to the Allowable emissions.**

**Actual emissions are the best estimate of the latest year of emissions from each unit. For those that are new, actual emissions would be an estimate of a normal annual operation. Please note that sources will be required to submit an annual emissions report and may be required to pay an annual emissions fee. This report and fee payment will be made under a separate document.**

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**Allegheny County Health Department**
**Air Quality Program**

## PERMIT APPLICATION FORM K

## SUMMARY OF EMISSIONS

Name of Owner/Operator U. S. Steel Mon Valley Works  Plant Name Clairton Plant

Pollutant $PM_{10}$  CAS No. ____  Year for actual emissions ____ or X estimated

| POINT | UNITS DISCHARGING TO THIS STACK | EMISSION SOURCE DESCRIPTION | ANNUAL THROUGHOUT UNITS | ALLOWABLE UNITS (tpy) | POTENTIAL (tpy) | ACTUAL (tpy) |
|---|---|---|---|---|---|---|
| COGEN1 | Cogeneration Unit 1 | Cogeneration Unit 1 (Turbine + HRSG) | N/A | 18.4 | 18.4 | 18.4 |
| COGEN2 | Cogeneration Unit 2 | Cogeneration Unit 2 (Turbine + HRSG) | N/A | 18.4 | 18.4 | 18.4 |
| FPUMP | Fire Pump | Diesel Emergency Fire Pump | 100 hrs/yr | <0.01 | <0.01 | <0.01 |
| AUXBLR | Aux. Boiler | Auxiliary Boiler | 1,000 hrs/yr | 0.4 | 0.4 | 0.4 |
| DPHTR-1 | Heater 1 | Dew Point Heater 1 | N/A | 0.1 | 0.1 | 0.1 |
| DPHTR-2 | Heater 2 | Dew Point Heater 2 | N/A | 0.1 | 0.1 | 0.1 |
| BV1 | Lime Silo | Hydrated Lime Silo Bin Vent | 3,120 hrs/yr | 0.04 | 0.04 | 0.04 |
| BV2 | Waste Lime Silo | Waste Lime Silo Bin Vent | 3,120 hrs/yr | 0.03 | 0.03 | 0.03 |
| FUG. | Paved Roads | Paved Roads | N/A | 0.02 | 0.02 | 0.02 |
| FUG | Oil Storage Tank | Oil Storage Tank | N/A | N/A | N/A | N/A |
| *New Equipment only. See Appendix C for projected actual emission from existing boilers. | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| TOTAL EMISSIONS FOR THIS SOURCE (FACILITY) | | | | 37.4 | 37.4 | 37.4 |

**If this is a NON-CRITERIA POLLUTANT, include the CAS number. For the fields "Point" and "Units discharging to this stack," use the identifying numbers from your plant drawing. For a more complete explanation of emissions, see definitions in Article XXI.**

**Allowable emissions are the maximum allowable by regulation. Calculate using the capacity of the unit unless restricted by operation limits, and the most strict regulation pertaining to that unit. Calculate for the shortest term regulated (one hour, one day....). Reflect the time period when defining the units.**

**Potential to emit (Potential on the chart) is the maximum capacity to emit contaminants, including fugitive emissions, under the physical and operational design of the unit. Include any permitted or regulated restrictions to operate. The Potential to Emit values should be less than or equal to the Allowable emissions.**

**Actual emissions are the best estimate of the latest year of emissions from each unit. For those that are new, actual emissions would be an estimate of a normal annual operation. Please note that sources will be required to submit an annual emissions report and may be required to pay an annual emissions fee. This report and fee payment will be made under a separate document.**

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# Allegheny County Health Department
# Air Quality Program

## PERMIT APPLICATION FORM K

## SUMMARY OF EMISSIONS

Name of Owner/Operator U. S. Steel Mon Valley Works  Plant Name Clairton Plant

Pollutant $PM_{2.5}$  CAS No. ______  Year for actual emissions ______ or X estimated

| POINT | UNITS DISCHARGING TO THIS STACK | EMISSION SOURCE DESCRIPTION | ANNUAL THROUGHOUT UNITS | ALLOWABLE UNITS (tpy) | POTENTIAL (tpy) | ACTUAL (tpy) |
|---|---|---|---|---|---|---|
| COGEN1 | Cogeneration Unit 1 | Cogeneration Unit 1 (Turbine + HRSG) | N/A | 18.4 | 18.4 | 18.4 |
| COGEN2 | Cogeneration Unit 2 | Cogeneration Unit 2 (Turbine + HRSG) | N/A | 18.4 | 18.4 | 18.4 |
| FPUMP | Fire Pump | Diesel Emergency Fire Pump | 100 hrs/yr | <0.01 | <0.01 | <0.01 |
| AUXBLR | Aux. Boiler | Auxiliary Boiler | 1,000 hrs/yr | 0.4 | 0.4 | 0.4 |
| DPHTR-1 | Heater 1 | Dew Point Heater 1 | N/A | 0.1 | 0.1 | 0.1 |
| DPHTR-2 | Heater 2 | Dew Point Heater 2 | N/A | 0.1 | 0.1 | 0.1 |
| BV1 | Lime Silo | Hydrated Lime Silo Bin Vent | 3,120 hrs/yr | 0.04 | 0.04 | 0.04 |
| BV2 | Waste Lime Silo | Waste Lime Silo Bin Vent | 3,120 hrs/yr | 0.03 | 0.03 | 0.03 |
| FUG. | Paved Roads | Paved Roads | N/A | <0.01 | <0.01 | <0.01 |
| FUG | Oil Storage Tank | Oil Storage Tank | N/A | N/A | N/A | N/A |
| *New Equipment only. See Appendix C for projected actual emission from existing boilers. | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| TOTAL EMISSIONS FOR THIS SOURCE (FACILITY) | | | | 37.4 | 37.4 | 37.4 |

**If this is a NON-CRITERIA POLLUTANT, include the CAS number. For the fields "Point" and "Units discharging to this stack," use the identifying numbers from your plant drawing. For a more complete explanation of emissions, see definitions in Article XXI.**

**Allowable emissions are the maximum allowable by regulation. Calculate using the capacity of the unit unless restricted by operation limits, and the most strict regulation pertaining to that unit. Calculate for the shortest term regulated (one hour, one day....). Reflect the time period when defining the units.**

**Potential to emit (Potential on the chart) is the maximum capacity to emit contaminants, including fugitive emissions, under the physical and operational design of the unit. Include any permitted or regulated restrictions to operate. The Potential to Emit values should be less than or equal to the Allowable emissions.**

**Actual emissions are the best estimate of the latest year of emissions from each unit. For those that are new, actual emissions would be an estimate of a normal annual operation. Please note that sources will be required to submit an annual emissions report and may be required to pay an annual emissions fee. This report and fee payment will be made under a separate document.**

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# Allegheny County Health Department
# Air Quality Program

## PERMIT APPLICATION FORM K

## SUMMARY OF EMISSIONS

Name of Owner/Operator U. S. Steel Mon Valley Works Plant Name Clairton Plant

Pollutant NH3 CAS No. ______ Year for actual emissions ______ or X Estimated

| POINT | UNITS DISCHARGING TO THIS STACK | EMISSION SOURCE DESCRIPTION | ANNUAL THROUGHOUT UNITS | ALLOWABLE UNITS (tpy) | POTENTIAL (tpy) | ACTUAL (tpy) |
|---|---|---|---|---|---|---|
| COGEN1 | Cogeneration Unit 1 | Cogeneration Unit 1 (Turbine + HRSG) | N/A | 9.3 | 9.3 | 9.3 |
| COGEN2 | Cogeneration Unit 2 | Cogeneration Unit 2 (Turbine + HRSG) | N/A | 9.3 | 9.3 | 9.3 |
| FPUMP | Fire Pump | Diesel Emergency Fire Pump | 100 hrs/yr | N/A | N/A | N/A |
| AUXBLR | Aux. Boiler | Auxiliary Boiler | 1,000 hrs/yr | N/A | N/A | N/A |
| DPHTR-1 | Heater 1 | Dew Point Heater 1 | N/A | N/A | N/A | N/A |
| DPHTR-2 | Heater 2 | Dew Point Heater 2 | N/A | N/A | N/A | N/A |
| BV1 | Lime Silo | Hydrated Lime Silo Bin Vent | 3,120 hrs/yr | N/A | N/A | N/A |
| BV2 | Waste Lime Silo | Waste Lime Silo Bin Vent | 3,120 hrs/yr | N/A | N/A | N/A |
| FUG. | Paved Roads | Paved Roads | N/A | N/A | N/A | N/A |
| FUG | Oil Storage Tank | Oil Storage Tank | N/A | N/A | N/A | N/A |
| *New Equipment only. See Appendix C for projected actual emission from existing boilers. | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| TOTAL EMISSIONS FOR THIS SOURCE (FACILITY) | | | | 18.5 | 18.5 | 18.5 |

**If this is a NON-CRITERIA POLLUTANT, include the CAS number. For the fields "Point" and "Units discharging to this stack," use the identifying numbers from your plant drawing. For a more complete explanation of emissions, see definitions in Article XXI.**

**Allowable emissions are the maximum allowable by regulation. Calculate using the capacity of the unit unless restricted by operation limits, and the most strict regulation pertaining to that unit. Calculate for the shortest term regulated (one hour, one day....). Reflect the time period when defining the units.**

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**Allegheny County Health Department**
**Air Quality Program**

# PERMIT APPLICATION FORM K

## SUMMARY OF EMISSIONS

Name of Owner/Operator U. S. Steel Mon Valley Works    Plant Name Clairton Plant

Pollutant GHG    CAS No. ____    Year for actual emissions ____ or X estimated

| POINT | UNITS DISCHARGING TO THIS STACK | EMISSION SOURCE DESCRIPTION | ANNUAL THROUGHOUT UNITS | ALLOWABLE UNITS (tpy) | POTENTIAL (tpy) | ACTUAL (tpy) |
|---|---|---|---|---|---|---|
| COGEN1 | Cogeneration Unit 1 | Cogeneration Unit 1 (Turbine + HRSG) | N/A | 432,048 | 432,048 | 432,048 |
| COGEN2 | Cogeneration Unit 2 | Cogeneration Unit 2 (Turbine + HRSG) | N/A | 432,048 | 432,048 | 432,048 |
| FPUMP | Fire Pump | Diesel Emergency Fire Pump | 100 hrs/yr | 5 | 5 | 5 |
| AUXBLR | Aux. Boiler | Auxiliary Boiler | 1,000 hrs/yr | 6,666 | 6,666 | 6,666 |
| DPHTR-1 | Heater 1 | Dew Point Heater 1 | N/A | 1,769 | 1,769 | 1,769 |
| DPHTR-2 | Heater 2 | Dew Point Heater 2 | N/A | 1,769 | 1,769 | 1,769 |
| BV1 | Lime Silo | Hydrated Lime Silo Bin Vent | 3,120 hrs/yr | N/A | N/A | N/A |
| BV2 | Waste Lime Silo | Waste Lime Silo Bin Vent | 3,120 hrs/yr | N/A | N/A | N/A |
| FUG. | Paved Roads | Paved Roads | N/A | N/A | N/A | N/A |
| FUG | Oil Storage Tank | Oil Storage Tank | N/A | N/A | N/A | N/A |
| *New Equipment only. See Appendix C for projected actual emission from existing boilers. | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| TOTAL EMISSIONS FOR THIS SOURCE (FACILITY) | | | | 874,306 | 874,306 | 874,306 |

**If this is a NON-CRITERIA POLLUTANT, include the CAS number. For the fields "Point" and "Units discharging to this stack," use the identifying numbers from your plant drawing. For a more complete explanation of emissions, see definitions in Article XXI.**

**Allowable emissions are the maximum allowable by regulation. Calculate using the capacity of the unit unless restricted by operation limits, and the most strict regulation pertaining to that unit. Calculate for the shortest term regulated (one hour, one day....). Reflect the time period when defining the units.**

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## PERMIT APPLICATION FORM M
## SOURCE OUT OF COMPLIANCE

**FORM M** Sources Out of Compliance

There is no Form M included in this application form. Strategies for bringing non-complying sources into compliance will vary so widely from source to source that it would not be useful to provide a form for completion. Provide your own description and label it Form M. Include enough detail that it is clear what emission units are not in compliance and of what regulations they are not in compliance. Provide a detailed schedule of compliance. This would include an installation schedule, changes in operations, a leak detection program schedule – whatever it will require to bring the emission unit into compliance. Make sure that the dates are manageable; they may be included in the permit, and become enforceable. Regular reports on the progress of reaching compliance are required every six months (they may be more frequent if desired).

# PERMIT APPLICATION FORM N
# ALTERNATIVE OPERATING SCENARIO

**A: GENERAL INFORMATION NOT APPLICABLE**

1. Alternative Scenario Number (Plan #): ______________
2. Give a general description of the changes involved in this alternative scenario:
3. Please Identify the emissions units affected in the Table below:

| Emission Unit # | Type of Emission Unit | Changes in the Process / Changes in the Project / Other Changes | SIC/SCC Associated with Scenario |
|---|---|---|---|
| | | | |
| | | | |
| | | | |

4. Describe and cite all applicable requirements pertaining to this alternative scenario:

**B: COMPLIANCE METHOD**

| Emission Unit # | Pollutant | Compliance Method | Reference Test Method | Monitoring Device | Frequency / Duration of Sampling |
|---|---|---|---|---|---|
| | | | | | |
| | | | | | |
| | | | | | |

Attach any other related information which would further explain the method of compliance.

**C: RECORDKEEPING AND REPORTING**

1. List what parameter will be recorded and the frequency of recording:
2. Describe what is to be reported and the frequency of reporting? (Reports must be submitted at least every six (6) months
3. Beginning reporting date: __ /__ /__

# APPENDIX B: COMPLIANCE REVIEW FORM

2700-PM-AQ0004 Rev. 6/2006

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

# AIR POLLUTION CONTROL ACT COMPLIANCE REVIEW FORM

Fully and accurately provide the following information, as specified. Attach additional sheets as necessary.

**Type of Compliance Review Form Submittal (check all that apply)**

☐ Original Filing
☒ Amended Filing

Date of Last Compliance Review Form Filing: 3/29/2017

**Type of Submittal**

☐ New Plan Approval ☐ New Operating Permit ☐ Renewal of Operating Permit
☐ Extension of Plan Approval ☐ Change of Ownership ☐ Periodic Submission (@ 6 mos)
☒ Other: Minor permit application for Clairton Plant

## SECTION A. GENERAL APPLICATION INFORMATION

**Name of Applicant/Permittee/("applicant")**
**(non-corporations-attach documentation of legal name)**
United States Steel Corporation (Mon Valley Works - Clairton Plant)

**Address** 400 State Street
Clairton, PA 15025
c/o Jonelle Scheetz, C-71

**Telephone** (412) 233-1015 **Taxpayer ID#** 25-1897152

**Permit, Plan Approval or Application ID#** Operating Permit #0052

**Identify the form of management under which the applicant conducts its business (check appropriate box)**

☐ Individual ☐ Syndicate ☐ Government Agency
☐ Municipality ☐ Municipal Authority ☐ Joint Venture
☐ Proprietorship ☐ Fictitious Name ☐ Association
☒ Public Corporation ☐ Partnership ☐ Other Type of Business, specify below:
☐ Private Corporation ☐ Limited Partnership

**Describe below the type(s) of business activities performed.**

United States Steel Corporation, a publicly traded corporation, manufactures and sells a wide variety of steel sheet, tubular, and tin products; coke and taconite pellets; and coal chemicals. The Mon Valley Works - Clairton Plant manufactures coke.

## SECTION B. GENERAL INFORMATION REGARDING "APPLICANT"

**If applicant is a corporation or a division or other unit of a corporation, provide the names, principal places of business, state of incorporation, and taxpayer ID numbers of all domestic and foreign parent corporations (including the ultimate parent corporation), and all domestic and foreign subsidiary corporations of the ultimate parent corporation with operations in Pennsylvania. Please include all corporate divisions or units, (whether incorporated or unincorporated) and privately held corporations. (A diagram of corporate relationships may be provided to illustrate corporate relationships.) Attach additional sheets as necessary.**

| Unit Name | Principal Places of Business | State of Incorporation | Taxpayer ID | Relationship to Applicant |
|---|---|---|---|---|
| United States Steel Corporation (U. S. Steel) | USA | Delaware | 25-1897152 | Self |
| Transtar, Inc. | USA | Delaware | 51-0313339 | Subsidiary of U. S. Steel |
| Union Railroad Company | USA | Delaware | 25-1589128 | Subsidiary of Transtar, Inc. |
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## SECTION C. SPECIFIC INFORMATION REGARDING APPLICANT AND ITS "RELATED PARTIES"

**Pennsylvania Facilities. List the name and location (mailing address, municipality, county), telephone number, and relationship to applicant (parent, subsidiary or general partner) of applicant and all Related Parties' places of business, and facilities in Pennsylvania. Attach additional sheets as necessary.**

| Unit Name | Street Address | County and Municipality | Telephone No. | Relationship to Applicant |
|---|---|---|---|---|
| Clairton Plant | 400 State Street | Allegheny/Clairton | (412) 233-1015 | Self |
| Edgar Thomson Plant | 1300 Braddock Avenue | Allegheny/Braddock | (412) 273-4730 | Self |
| Irvin Plant | Camp Hollow Road | Allegheny/West Mifflin | (412) 675-7382 | Self |
| Fairless Plant | Pennsylvania Avenue | Bucks/Fairless Hills | (412) 675-7382 | Self |
| Transtar, Inc. | 200 Penn Avenue, Suite 300 | Allegheny/Pittsburgh | (412) 433-7090 | Subsidiary of U. S. Steel |
| Union Railroad Company | 200 Penn Avenue, Suite 300 | Allegheny/Pittsburgh | (412) 433-7090 | Subsidiary of Transtar, Inc. |
| | | | ( | |
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**Provide the names and business addresses of all general partners of the applicant and parent and subsidiary corporations, if any.**

| Name | Business Address |
|---|---|
| Not Applicable | |
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**List the names and business address of persons with overall management responsibility for the process being permitted (i.e. plant manager).**

| Name | Business Address |
|---|---|
| Kurt Barshick | P. O. Box 878, Dravosburg, PA 15034 |
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**Plan Approvals or Operating Permits. List all plan approvals or operating permits issued by the Department or an approved local air pollution control agency under the APCA to the applicant or related parties that are currently in effect or have been in effect at any time 5 years prior to the date on which this form is notarized. This list shall include the plan approval and operating permit numbers, locations, issuance and expiration dates. Attach additional sheets as necessary.**

| Air Contamination Source | Plan Approval/ Operating Permit# | Location | Issuance Date | Expiration Date |
|---|---|---|---|---|
| Fairless Plant | 09-00006 | Fairless Plant, Fairless Hills, PA | 11/19/2012; 12/22/2016 | 11/19/2017 |
| Edgar Thomson Plant: See Attached List | See Attached List | Edgar Thomson Plant, Braddock, PA | See Attached List | See Attached List |
| Irvin Plant: See Attached List | See Attached List | Irvin Plant, West Mifflin, PA | See Attached List | See Attached List |
| Clairton Plant: See Attached List | See Attached List | Clairton Plant, Clairton, PA | See Attached List | See Attached List |
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**Compliance Background. (Note: Copies of specific documents, if applicable, must be made available to the Department upon its request.) List all documented conduct of violations or enforcement actions identified by the Department pursuant to the APCA, regulations, terms and conditions of an operating permit or plan approval or order by applicant or any related party, using the following format grouped by source and location in reverse chronological order. Attach additional sheets as necessary. See the definition of "documented conduct" for further clarification. Unless specifically directed by the Department, deviations which have been previously reported to the Department in writing, relating to monitoring and reporting, need not be reported.**

| Date | Location | Plan Approval/ Operating Permit# | Nature of Documented Conduct | Type of Department Action | Status: Litigation Existing/Continuing or Corrected/Date | Dollar Amount Penalty |
|---|---|---|---|---|---|---|
| See Attached List | | | | | | $ |
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**List all incidents of deviations of the APCA, regulations, terms and conditions of an operating permit or plan approval or order by applicant or any related party, using the following format grouped by source and location in reverse chronological order. This list must include items both currently known and unknown to the Department. Attach additional sheets as necessary. See the definition of "deviations" for further clarification.**

| Date | Location | Plan Approval/ Operating Permit# | Nature of Deviation | Incident Status: Litigation Existing/Continuing Or Corrected/Date |
|---|---|---|---|---|
| See Attached List | | | | |
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**<u>CONTINUING OBLIGATION</u>. Applicant is under a continuing obligation to update this form using the Compliance Review Supplemental Form if any additional deviations occur between the date of submission and Department action on the application.**

| VERIFICATION STATEMENT | |
|---|---|
| **Subject to the penalties of Title 18 Pa.C.S. Section 4904 and 35 P.S. Section 4009(b)(2), I verify under penalty of law that I am authorized to make this verification on behalf of the Applicant/Permittee. I further verify that the information contained in this Compliance Review Form is true and complete to the best of my belief formed after reasonable inquiry. I further verify that reasonable procedures are in place to ensure that "documented conduct" and "deviations" as defined in 25 Pa Code Section 121.1 are identified and included in the information set forth in this Compliance Review Form.** | |
| Signature | 4-26-2019<br>Date |
| Kurt Barshick<br>Name (Print or Type) | |
| Mon Valley Works - General Manager<br>Title | |

**United States Steel Corporation**
**Allegheny County Health Department Permits**

Clairton Works

| | |
|---|---|
| 7035003-010-26320 | Coke Battery No. 1 |
| 7035003-010-26318 | Coke Battery No. 2 |
| 7035003-010-26317 | Coke Battery No. 3 |
| 7035003-010-26312 | Coke Battery No. 7 |
| 7035003-010-26313 | Coke Battery No. 8 |
| 7035003-010-26319 | Coke Battery No. 9 |
| 7035003-010-26309 | Coke Battery No. 13 |
| 7035003-010-26307 | Coke Battery No. 14 |
| 7035003-010-25306 | Coke Battery No. 15 |
| 7035003-010-26304 | Coke Battery No. 19 |
| 7035003-010-53800 | Coke Battery No. 20 |
| 78-I-0083-P | Coke Battery B and B Quench Tower |
| 7035003-010-25101 | Quench Tower #1 |
| 7035003-010-25102 | Quench Tower #3 |
| 7035003-010-25104 | Quench Tower #5 |
| 7035003-010-25106 | Quench Tower #7 |
| 91-I-0021-P | Coke By-Products Recovery Plant |
| 7035003-010-00801 | Boiler No. 1 |
| 7035003-010-00800 | Boiler No. 2 |
| 7035003-010-99100 | Boiler Nos. 13 and 14 |
| 7035003-010-01300 | Boiler Nos. R1 and R2 |
| 7035003-010-00600 | Boiler Nos. T1 and T2 |
| 7035003-010-25001 | Coke Screening No. 1 |
| 7035003-010-25002 | Coke Screening No. 2 |
| 0052-I003 | Coke Screening No. 3 |
| 0052-I006 | Fan Upgrade 1-3 PEC |
| 0052-I007 | Fan Upgrade 7-9 PEC |
| 0052-I008 | Fan Upgrade 13-15 PEC |
| 0052-I005a | Fan Upgrade 19/20 PEC |
| 0052-I002b | Ammonia Flare |
| 0052-I004 | Methanol/MEA Tanks |
| 73-O-01138-P | Coke Battery 1 |
| 73-O-01136-P | Coke Battery 2 |
| 73-I-1135-P | Coke Battery 3 |
| 73-O-1130-P | Coke Battery 7 |
| 73-O-1131-P | Coke Battery 8 |
| 73-O-1137-P | Coke Battery 9 |
| 73-O-1127-P | Coke Battery 13 |
| 78-I-009 | Coke Batteries 13-15 Rebuild |
| 73-O-1126-P | Coke Battery 14 |
| 93-I-0010-P | Coke Battery 15 |
| 77-I-0019-P | Coke Battery 20 |
| 87-I-0031-P | PEC for 1-3 |
| 87-I-0032-P | PEC for 7-9 |
| 87-I-0037-P | PEC for 13-15 |
| 87-I-0033-P | PEC for 19/20 |
| 78-I-0083-P | Coke Battery B and Quench Tower |
| 90-I-0031-P | Igniters for 1-3, 7-9, and 13-15 |
| 90-I-0032-P | Igniters for 19/20 |
| 90-I-0033-P | Igniters for B |
| 73-O-1139-P | Quench Tower #1 |

| | |
|---|---|
| 73-O-1140-P | Quench Tower #3 |
| 73-O-1142-P | Quench Tower #5 |
| 73-O-1144-P | Quench Tower #7 |
| 73-O-1148-P | Coke Screening #1 |
| 73-O-1149-P | Coke Screening #2 |
| GC-80-62 | COG Desulfurization |
| 73-I-3784-P | COG Desulfurization |
| 7035003-010-8400 | Sulfur Production (Claus Carbonate) |
| 73-O-1153-P | Sulfur Production (Claus Carbonate) |
| 7035003-010-25600 | Gas Processing |
| 73-O-1155-P | Gas Processing |
| 91-I-0021-P | Benzene NESHAP By-Product Plant Emission Control |
| 73-O-1161-P | Coal Chemical Recovery #1 Unit |
| 7035003-010-25501 | Coal Chemical Recovery #1 Unit |
| 73-I-4035-P | Tanks |
| 73-O-1162-P | Coal Chemical Recovery #2 Unit |
| 7035003-010-25502 | Coal Chemical Recovery #2 Unit |
| 73-I-4036-C | Tanks |
| 94-I-0096-C | Boiler #1 |
| 75-I-0019-C | Boiler #1 |
| 94-I-0019-C | Boiler #2 |
| 75-I-0020-C | Boiler #2 |
| 94-I-0091-C | Boilers R1 and R2 |
| 74-O-6090-C | Boilers R1 and R2 |
| 94-I-0093-C | Boilers T1 and T2 |
| 89-I-0003-C | Boilers T1 and T2 |
| 76-I-0067-C | Boilers T1 and T2 |
| 73-I-4034-P | No. 1 Tar Acid Tanks |
| 73-I-4030-P | Tar Refining Tanks V-100 & V-101 |
| 73-I-4029-P | Tar Refining Tanks 3-A & 4-A |
| 73-I-4028-P | Tar Refining Tanks 10, 11, & V-113 |
| 73-I-4027-P | Tar Refining Tanks 3 to 8 & T |
| 73-I-4026-P | Road Tar Terminal V-200 to V-208 inclusive |
| 0052-I011 | C Battery |
| 0052-I011b | Revised C Battery |
| 0052-I013 | Coke Screening #4 |
| 0052-I014a | Quench Towers 5A and 7A |
| 0052-I015 | Truck/ Railcar Loading and Process Tanks |
| 0052-I016 | Light Oil Loading Facility |
| 0052-I017 | 1-Hour SO2 NAAQS |
| 0052 | Title V Operating Permit |

Edgar Thomson

| | |
|---|---|
| 7035003-002-93800 | BOP |
| 7035003-002-32300 | BOP Slag Processing |
| 92-I006-P | BOP Slag Processing |
| 92-I0088-P | BOP Slag Processing |
| 92-I066-P | BOP Slag Processing |
| 7035003-002-90105 | #1 Blast Furnace |
| 7035003-002-31400 | #1 Blast Furnace Hard Slag Pit |
| 94-I-0026-P | #1 Blast Furnace Hard Slag Pit |
| 4-1-0026-P | #1 Blast Furnace Hard Slag Pit |
| 7035003-002-90107 | #3 Blast Furnace |
| 7035003-002-31401 | #3 Blast Furnace Hard Slag Pit |
| 94-I-0027-P | #3 Blast Furnace Hard Slag Pit |

| | |
|---|---|
| 7035003-002-93900 | Dual Slab Caster and Ladle Metallurgy Facility |
| 90-I-003-P | Dual Slab Caster and Ladle Metallurgy Facility |
| 95-I-006-P | RH Vacuum Degasser |
| 94-I-006-P | RH Vacuum Degasser |
| 7035003-004-99200 | #2 Power House Riley Boilers #1, 2, & 3 |
| 7035003-002-99200 | #2 Power House Riley Boilers #1, 2, & 3 |
| 0061559-000-73800 | Waste Product Recycle & Briquetting Process |
| 93-I-0039-P | Waste Product Recycle & Briquetting Process |
| 0051-I004a | BOP Emission Control Upgrade |
| 0051-I005 | LMF Emission Control Upgrade |
| 0051-I006 | 1-Hour SO2 NAAQS |
| 0051 | Title V Operating Permit |

<u>Irvin Plant</u>

| | |
|---|---|
| 0050-I002a | Cold Reduction Mill |
| 0050-I001b | 64" Pickle Line |
| 0050-I003 | OCA Furnace #14 |
| 0050-I006 | OCA Furnaces #15 and #16 |
| 0050-I007 | Continuous Terne Line Molten Lead Pot Baghouse |
| 0050-I008 | 1-Hour SO2 NAAQS |
| 0050 | Title V Operating Permit |

**U. S. Steel – Mon Valley Works – Clairton Plant**
**Compliance Background – May 2, 2019**

| Date | Location | Plan Approval/ Operating Permit# | Nature of Documented Conduct | Type of Department Action | Status: Litigation Existing/Continuing Or Corrected/Date | Dollar Amount Penalty |
|---|---|---|---|---|---|---|
| 4/11/19 | Fairless Plant | Permit #09-00006 | Galv Line Tune-ups | Notice of Violation | In progress | NA |
| 3/29/19 | Clairton | Article XXI/ Permit #0052-I011b | Battery Emissions – 3Q and 4Q 2018 | Enforcement Order #190305 | Appealed | $707,568 |
| 3/25/19 | Clairton | Article XXI/ Permit #0052-I017 | B Battery Quench Tower stack test exceedance | Enforcement Order #190304 | Final | $1.980 |
| 3/25/19 | Clairton | Article XXI/ Permit #0052 | Battery 13 Combustion Stack exceedance | Enforcement Order #190303 | In progress | NA |
| 3/6/19 | Clairton | Article XXI | Coke Oven Regulations – Request for Reports and Info | Administrative Order | Final | NA |
| 3/12/19 | Clairton, Irvin, Edgar Thomson | Article XXI | SO2 Emissions – No. 2 Control Room Fire | Enforcement Order #190202A | In progress | NA |
| 10/31/18 | Clairton | Article XXI/ Permit #0052-I011b | Battery Emissions – 2Q 2018 | Administrative Order #181002 Revised | Appealed | $613,716 |
| 7/25/18 | Edgar Thomson | Article XXI | Visible Emissions during BF CH BH stack testing | Administrative Order #180706 | Final | NA |
| 6/28/18 | Clairton | Article XXI/ Permit #0052-I011 | Article XXI Exceedances, C Quench Tower, B Battery Door Standard, Compliance Rate Percentages | Enforcement Order #180601 | Appealed/ Hearing Held | $1,091,950 |
| 6/13/18 | Irvin | Article XXI | Asbestos Quarterly Reporting | Enforcement Order #180506 | Appealed | NA |
| 6/13/18 | Edgar Thomson | Article XXI | Asbestos Quarterly Reporting | Enforcement Order #180505 | Appealed | NA |
| 6/13/18 | Clairton | Article XXI | Asbestos Quarterly Reporting | Enforcement Order #180504 | Appealed | NA |
| 3/30/18 | Clairton | Article XXI | 2016 Asbestos Removal Project | Enforcement Order #180303A | Final | $198,625 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 3/6/18 | Clairton | Article XXI/ Permit #0052-I011 | Battery Emissions | Administrative Order #180301 | Final | $392,100 |
| 2/27/18 | Clairton | Article XXI/ Permit #0052-I011 | C Battery Combustion Stack PM stack test exceedance | Administrative Order #180203 | Final | $5,500 |
| 2/27/18 | Clairton | Article XXI/ Permit #0052-I017 | C Battery Quench Tower SO2 stack test exceedance | Administrative Order #180202 | Final | NA |
| 11/9/17 | Edgar Thomson Plant | Article XXI | Visible Emissions at BOP scrubber stack, BOP shop, Blast Furnaces, and LMF | Notice of Violation/Notice of Noncompliance from ACHD and EPA | Awaiting EPA Response for Meeting in June 2019 | NA |
| 2/8/17 | Edgar Thomson Plant | Article XXI | Visible Emissions, Operation and Maintenance Blast Furnace No.1 | Notice of Violation/Settlement Offer #170201 | Final | $13,350 |
| 1/25/17 | Clairton Plant | Article XXI/ Permit No. 0052-I011 | Battery Emissions | Notice of Violation/ Settlement Offer #170101 | Final | $253,425 |
| 11/17/16 | Clairton Plant | Article XXI/ Permit No. 0052-I011 | Battery Emissions | Notice of Violation/ Settlement Offer #161003 | Final | $142,950 |
| 8/31/16 | Edgar Thomson Plant | Article XXI | Alleged violations of opacity from BOP Scrubber Stacks and Operations and Maintenance of Air Pollution Control Equipment | Notice of Violation #160802 | Corrected | NA |
| 7/18/16 | Clairton Plant | Article XXI | Battery Emissions | Notice of Violation/ Settlement Offer #160701 | Final | $1,575 |
| 4/22/16 | Edgar Thomson Plant | Article XXI | Blast Furnace Emissions (Goggle Valve) | Notice of Violation | Final | NA |
| 4/12/16 | Edgar Thomson Plant | DEP Continuous Source Monitoring System (CSMS) Data Availability Requirements | Insufficient NOx CEMS data availability on Boiler 2 | Letter | Final | NA |
| 3/24/16 | Clairton | Consent | Civil Complaint | Complaint Filed by | Existing/In Effect | $25,000 |

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|---|---|---|---|---|---|---|
| | Plant | Judgment | in Equity; and Consent Judgment | ACHD; and Consent Judgment entered by the Court of Common Pleas, Allegheny County | | |
| 10/30/15 | Clairton Plant | Article XXI and Installation Permit #0052-I011 | Battery Emissions | Statement of Violation | Final | $12,275 |
| 6/2/15 | Fairless Plant | Permit #09-00006 | Gasoline Storage Tank Pressure Relief Valve | Notice of Violation | NA | NA |
| 5/11/15 | Clairton Plant | Article XXI and Installation Permit #0052-I011 | Battery Emissions | Statement of Violation | Final | $5,500 |
| 3/17/15 | Clairton Plant | Article XXI and Installation Permit #0052-I011 | Battery Emissions | Statement of Violation | Final | $4,575 |
| 11/18/14 | Clairton Plant | Article XXI and Installation Permit #0052-I011 | Battery Emissions | Statement of Violation | Final | $17,650 |
| 10/31/14 | Clairton Plant | Article XXI and Installation Permit #0052-I011 | Battery Emissions | Statement of Violation | Final | $7,125 |
| 8/7/14 | Clairton Plant | Article XXI | Failure to complete testing/excessive emissions | Consent Order and Agreement between ACHD and USS | Superseded by Consent Judgment Entered on 3/24/2016 | $300,000 |
| 5/8/14 | Clairton Plant | Article XXI and Installation Permit #0052-I011 | Battery Emissions | Statement of Violation | Final | $3,425 |

**U. S. Steel Mon Valley Works – Clairton Plant**
**Incidents of Deviations – May 2, 2019**

| Date | Location | Plan Approval/ Operating Permit# | Nature of Deviation | Status: Litigation Existing/Continuing Or Corrected/Date |
|---|---|---|---|---|
| 5/2014 – | Clairton | Article XXI & | Refer to semi- | NA |

| | | | | |
|---|---|---|---|---|
| 5/2019 | Plant | Permit #0052 | annual deviation reports/ annual certifications | |
| 5/2014 – 5/2019 | Fairless | Permit #09-00006 | Refer to deviation reports | NA |
| 5/2014 – 5/2019 | Edgar Thomson | Article XXI & Permit #0051 | Refer to semi-annual deviation report | NA |
| 5/2014 – 5/2019 | Irvin | Article XXI & Permit #0050 | Refer to deviation reports | NA |

# APPENDIX C: EMISSION CALCULATIONS

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-1. Cogen Project Emissions Summary**

| Pollutant[1] | PSD/NA NSR | Significant Emission Rate (tpy) | *Project Increase* Future Emissions from New and Associated Units[2] (tpy) | *Project Decrease* Baseline Actual Emissions (Shutdown Units)[3] (tpy) | Total Project Emissions Increase (tpy) | Increase > SER?[4] |
|---|---|---|---|---|---|---|
| PM (filt.) | PSD | 25 | 12.9 | 34.4 | -21.5 | NO |
| $PM_{10}$ (filt. + cond.) | PSD | 15 | 44.4 | 45.6 | -1.2 | NO |
| $PM_{2.5}$ (filt. + cond.) | NA NSR | 10 | 44.3 | 45.6 | -1.4 | NO |
| Lead | PSD | 1 | 6.6E-03 | 3.5E-04 | 6.3E-03 | NO |
| $SO_2$ | NA NSR | 40 | 234.6 | 415.1 | -180.5 | NO |
| $NO_x$ | NA NSR (precursor) | 40 | 287.9 | 931.3 | -643.4 | NO |
| CO | PSD | 100 | 86.8 | 140.2 | -53.4 | NO |
| VOC | NA NSR (precursor) | 40 | 31.9 | 2.6 | 29.3 | NO |
| Ammonia | NA NSR (precursor) | 40 | 19.0 | 1.7 | 17.2 | NO |
| $CO_2e$ | PSD | 75,000 | 925,401.4 | 282,833.0 | 642,568.4 | YES |

1. PSD also has established SERs for hydrogen sulfide, total reduced sulfur, and sulfuric acid mist, which could be emitted from the sources being permitted in this action. If present at all, these compounds are expected to be at concentrations below method detection limits. Given the air pollution control devices and strategies being employed, these compounds would be expected to show up in the "back-half" of the particulate matter sampling train. The condensable particulate matter estimates for the proposed sources account for the possible presence of these compounds. The proposed project is not expected to increase emissions of any other NSR regulated pollutants (e.g., CFCs).

2. Future emissions from new units is potential to emit. Future emissions from associated units is projected actuals.

3. Baseline emissions are based on emissions reported by U. S. Steel as part of annual emissions inventories.

4. Per 40 CFR §52.21(b)(49)(iv), as an existing major stationary source, the pollutant GHGs (CO2e) is only subject to PSD if there is an emissions increase of a regulated NSR pollutant AND an emissions increase of 75,000 tpy $CO_2e$ or more. Since there is no emissions increase of a regulated NSR pollutant, PSD is not triggered for $CO_2e$.

**Company Name:** **U. S. Steel**
**Facility Name:** **Clairton**
**Project Description:** **Cogeneration Project**

**Table C-2. Summary of Future Criteria Pollutant Emissions from Cogeneration Project (New and Associated Emission Units)**

| Emission Unit Description | Fuel/Material | CO | $NO_x$ | PM | $PM_{10}$ | $PM_{2.5}$ | $SO_2$ | VOC | Lead | $NH_3$ | $CO_2e$ |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | tpy | tpy | tpy | tpy | tpy | tpy | tpy | tpy | tpy | tpy |
| Cogen Unit 1 | COG | 16.6 | 91.3 | 4.7 | 18.4 | 18.4 | 87.1 | 14.0 | 3.1E-03 | 9.0 | 390,691 |
| Cogen Unit 1 | Natural Gas | 13.5 | 93.8 | 4.6 | 18.2 | 18.2 | 18.6 | 13.9 | 7.9E-04 | 9.3 | 431,929 |
| Cogen Unit 1 | Blend | 15.1 | 92.3 | 4.7 | 18.3 | 18.3 | 60.7 | 13.8 | 2.4E-03 | 9.1 | 404,500 |
| Cogen Unit 1 Planned SUSD | | 2.8 | 0.9 | | | | | 1.6 | | | 119.4 |
| *Cogen Unit 1 - Max. Scenario* | | *19.3* | *94.7* | *4.7* | *18.4* | *18.4* | *87.1* | *15.5* | *3.1E-03* | *9.3* | *432,048* |
| Cogen Unit 2 | COG | 16.6 | 91.3 | 4.7 | 18.4 | 18.4 | 87.1 | 14.0 | 3.1E-03 | 9.0 | 390,691 |
| Cogen Unit 2 | Natural Gas | 13.5 | 93.8 | 4.6 | 18.2 | 18.2 | 18.6 | 13.9 | 7.9E-04 | 9.3 | 431,929 |
| Cogen Unit 2 | Blend | 15.1 | 92.3 | 4.7 | 18.3 | 18.3 | 60.7 | 13.8 | 2.4E-03 | 9.1 | 404,500 |
| Cogen Unit 2 Planned SUSD | | 2.8 | 0.9 | | | | | 1.6 | | | 119.4 |
| *Cogen Unit 2 - Max. Scenario* | | *19.3* | *94.7* | *4.7* | *18.4* | *18.4* | *87.1* | *15.5* | *3.1E-03* | *9.3* | *432,048* |
| Diesel Emergency Fire Pump | Diesel | 0.01 | 0.03 | 1.5E-03 | 1.7E-03 | 1.7E-03 | 8.7E-03 | 2.4E-03 | 0.0E+00 | 0.0 | 4.9 |
| Package Boiler | Natural Gas | 2.7 | 1.0 | 0.1 | 0.4 | 0.4 | 0.03 | 0.3 | 2.8E-05 | 0.0 | 6,666 |
| Heater 1 | Natural Gas | 0.5 | 0.4 | 0.1 | 0.1 | 0.1 | 6.6E-03 | 3.9E-02 | 7.3E-06 | 0.0 | 1,769.5 |
| Heater 2 | Natural Gas | 0.5 | 0.4 | 0.1 | 0.1 | 0.1 | 6.6E-03 | 3.9E-02 | 7.3E-06 | 0.0 | 1,769.5 |
| Hydrated Lime Bin Vent | Material Handling | 0.0 | 0.0 | 4.0E-02 | 4.0E-02 | 4.0E-02 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Waste Lime Silo Bin Vent | Material Handling | 0.0 | 0.0 | 2.7E-02 | 2.7E-02 | 2.7E-02 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Paved Roads | Hydrated Lime | 0.0 | 0.0 | 3.3E-02 | 6.7E-03 | 1.6E-03 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Paved Roads | Baghouse/CDS Material | 0.0 | 0.0 | 5.0E-02 | 1.0E-02 | 2.5E-03 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Paved Roads | Anhydrous NH3 | 0.0 | 0.0 | 4.1E-03 | 8.2E-04 | 2.0E-04 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Fire Pump Diesel Tank | Diesel | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.5E-06 | 0.0 | 0.0 | 0.0 |
| Boiler R-2 | Projected Actual- COG | 27.1 | 28.4 | 1.1 | 2.3 | 2.0 | 20.2 | 1.8E-02 | 1.2E-04 | 0.0 | 14,204.1 |
| Boiler R-2 | Projected Actual- NG | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0E+00 | 0.0E+00 | 0.0 | 0.0 |
| *Boiler R-2* | *Projected Actual Total* | *27.1* | *28.4* | *1.1* | *2.3* | *2.0* | *20.2* | *1.8E-02* | *1.2E-04* | *0.0* | *14204.1* |
| Boiler T-1 | Projected Actual- COG | 4.5 | 20.2 | 0.9 | 2.0 | 2.1 | 20.0 | 0.2 | 1.0E-04 | 0.0 | 12,417.7 |
| Boiler T-1 | Projected Actual- NG | 4.2 | 13.9 | 0.1 | 0.4 | 0.4 | 0.0 | 2.5E-02 | 2.9E-05 | 0.2 | 6,028.1 |
| *Boiler T-1* | *Projected Actual Total* | *8.7* | *34.1* | *1.0* | *2.4* | *2.4* | *20.0* | *0.2* | *1.3E-04* | *0.2* | *18445.9* |
| Boiler T-2 | Projected Actual- COG | 4.5 | 20.2 | 0.9 | 2.0 | 2.1 | 20.0 | 0.2 | 1.0E-04 | 0.0 | 12,417.7 |
| Boiler T-2 | Projected Actual- NG | 4.2 | 13.9 | 0.1 | 0.4 | 0.4 | 0.0 | 2.5E-02 | 2.9E-05 | 0.2 | 6,028.1 |
| *Boiler T-2* | *Projected Actual Total* | *8.7* | *34.1* | *1.0* | *2.4* | *2.4* | *20.0* | *0.2* | *1.3E-04* | *0.2* | *18445.9* |
| **Total** | | **86.8** | **287.9** | **12.9** | **44.4** | **44.3** | **234.6** | **31.9** | **6.6E-03** | **19.0** | **925,401** |

Company Name: **U. S. Steel**
Facility Name: **Clairton**
Project Description: **Cogeneration Project**

Table C-3a. Summary of Cogeneration Plant Emissions (Turbines + Duct Burners) - Coke Oven Gas Fuel Cases

| | NOx | | CO | | PM (filterable) | | PM10/PM2.5 (filt. + conden.) | | VOC | | SO2 | | NH3 | | CO2 | | CH4 (CO2e) | | N2O (CO2e) | | CO2e | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | *lb/hr* | *Case* | *lb/hr* | *Case* | *lb/hr* | *Case* | *lb/hr* | *Case* | *lb/hr* | *Case* | *lb/hr* | *Case* | *lb/hr* | *Case* | *lb/hr* | *Case* | *lb/hr* | *Case* | *lb/hr* | *Case* | *lb/hr* | *Case* |
| Case w/ 1 Unit[1] (per unit) | 25.7 | 18 | 5.4 | 18 | 1.1 | 18 | 4.3 | 18 | 5.3 | 18 | 24.5 | 18 | 2.5 | 18 | 109,884 | 18 | 62.2 | 18 | 74.2 | 18 | 110,020 | 18 |
| Case w/ 2 Units[2] (per unit) | 21.4 | 17 | 3.9 | 17 | 1.1 | 17 | 4.3 | 19 | 3.3 | 17 | 20.4 | 17 | 2.1 | 17 | 91,598 | 17 | 51.9 | 17 | 61.8 | 17 | 91,711 | 17 |
| Worst Case Emissions[3] (lb/hr) | 42.9 | 17 | 7.8 | 17 | 2.2 | 17 | 8.6 | 19 | 6.6 | 17 | 40.9 | 17 | 4.2 | 17 | 183195.5 | 17 | 103.7 | 17 | 123.7 | 17 | 183422.9 | 17 |
| **Worst Case Emissions (tpy)[4]** | **182.6** | **tpy** | **33.1** | **tpy** | **9.4** | **tpy** | **36.8** | **tpy** | **27.9** | **tpy** | **174.2** | **tpy** | **18.0** | **tpy** | **780,413** | **tpy** | **442.0** | **tpy** | **526.8** | **tpy** | **781,381** | **tpy** |

1 Highest hourly emissions from all "100% GTG Load, Full Duct Firing." Only one unit is expected to operate at a time in this mode.
2 Highest hourly emissions for all other operating case descriptions.
3 Hourly emissions calculated as the greater of Case with 1 unit or 2 x Case with 2 units.
4 Annual worst case emissions calculated based on 8,520 hr/yr of operation per unit.
* No SUSD emissions considered in this table.

Company Name: U. S. Steel
Facility Name: Clairton
Project Description: Cogeneration Project

Table C-3b. Summary of Cogeneration Plant Emissions (Turbines + Duct Burners) for Natural Gas Cases

| | NOx | | CO | | PM (filterable) | | PM10/PM2.5 (filt. + conden.) | | VOC | | SO2 | | NH3 | | CO2 | | CH4 (CO2e) | | N2O (CO2e) | | CO2e | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | lb/hr | Case | lb/hr | Case | lb/hr | Case | lb/hr | Case | lb/hr | Case | lb/hr | Case | lb/hr | Case | lb/hr | Case | lb/hr | Case | lb/hr | Case | lb/hr | Case |
| Case w/ 1 Unit[1] (per unit) | 25.9 | 42 | 4.6 | 42 | 1.1 | 42 | 4.2 | 42 | 5.1 | 42 | 7.1 | 42 | 2.6 | 42 | 118,077 | 42 | 59.7 | 42 | 71.2 | 42 | 118,208 | 42 |
| Case w/ 2 Units[2] (per unit) | 22.0 | 41 | 3.2 | 41 | 1.1 | 41 | 4.3 | 43 | 3.3 | 41 | 4.4 | 41 | 2.2 | 41 | 101,282 | 41 | 50.2 | 41 | 59.8 | 41 | 101,392 | 41 |
| Worst Case Emissions[3] (lb/hr) | 44.0 | 41 | 6.3 | 41 | 2.1 | 41 | 8.5 | 43 | 6.5 | 41 | 8.7 | 41 | 4.3 | 41 | 202563.3 | 41 | 100.4 | 41 | 119.7 | 41 | 202783.4 | 41 |
| **Worst Case Emissions (tpy)[4]** | **187.5** | **tpy** | **27.0** | **tpy** | **9.1** | **tpy** | **36.4** | **tpy** | **27.8** | **tpy** | **37.2** | **tpy** | **18.5** | **tpy** | **862,920** | **tpy** | **427.7** | **tpy** | **509.8** | **tpy** | **863,857** | **tpy** |

1 Highest hourly emissions from all "100% GTG Load, Full Duct Firing." Only one unit is expected to operate at a time in this mode.
2 Highest hourly emissions for all other operating case descriptions.
3 Hourly emissions calculated as the greater of Case with 1 unit or 2 x Case with 2 units.
4 Annual worst case emissions calculated based on 8,520 hr/yr of operation per unit.
* No SUSD emissions considered in this table.

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

Table C-3c. Summary of Cogeneration Plant Emissions (Turbines + Duct Burners) for Blended Fuel Cases

| | NOx | | CO | | PM (filterable) | | PM10/PM2.5 (filt. + conden.) | | VOC | | SO2 | | NH3 | | CO2 | | CH4 (CO2e) | | N2O (CO2e) | | CO2e | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | *lb/hr* | *Case* | *lb/hr* | *Case* | *lb/hr* | *Case* | *lb/hr* | *Case* | *lb/hr* | *Case* | *lb/hr* | *Case* | *lb/hr* | *Case* | *lb/hr* | *Case* | *lb/hr* | *Case* | *lb/hr* | *Case* | *lb/hr* | *Case* |
| Case w/ 1 Unit[1] (per unit) | 25.9 | 46 | 5.0 | 46 | 1.1 | 46 | 4.3 | 46 | 5.3 | 46 | 18.0 | 46 | 2.6 | 46 | 112,732 | 46 | 61.6 | 46 | 73.5 | 46 | 112,867 | 46 |
| Case w/ 2 Units[2] (per unit) | 21.7 | 45 | 3.5 | 45 | 1.1 | 45 | 4.3 | 47 | 3.2 | 45 | 14.2 | 45 | 2.1 | 45 | 94,840 | 45 | 51.5 | 45 | 61.4 | 45 | 94,953 | 45 |
| Worst Case Emissions[3] (lb/hr) | 43.3 | 45 | 7.1 | 45 | 2.2 | 45 | 8.6 | 47 | 6.5 | 45 | 28.5 | 45 | 4.3 | 45 | 189680.3 | 45 | 103.0 | 45 | 122.8 | 45 | 189906.1 | 45 |
| **Worst Case Emissions (tpy)[4]** | **184.6** | **tpy** | **30.2** | **tpy** | **9.3** | **tpy** | **36.7** | **tpy** | **27.7** | **tpy** | **121.3** | **tpy** | **18.2** | **tpy** | **808,038** | **tpy** | **438.8** | **tpy** | **523.1** | **tpy** | **809,000** | **tpy** |

1 Highest hourly emissions from all "100% GTG Load, Full Duct Firing." Only one unit is expected to operate at a time in this mode.
2 Highest hourly emissions for all other operating case descriptions.
3 Hourly emissions calculated as the greater of Case with 1 unit or 2 x Case with 2 units.
4 Annual worst case emissions calculated based on 8,520 hr/yr of operation per unit.
* No SUSD emissions considered in this table.

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-4. Summary of Planned Turbine Startup Shutdown Emissions**

| Event | NOx | CO | UHC (as $CH_4$) | $CO_2$ | GHG ($CO_2$ + UHC) |
|---|---|---|---|---|---|
| | *lb/event* | *lb/event* | *lb/event* | *lb/event* | *lb/event* |
| Startup | 99.4 | 344.1 | 194.5 | 12,334 | 12,529 |
| Shutdown | 81.5 | 210.8 | 116.3 | 11,227 | 11,343 |
| Event | *tpy (per unit)* | *tpy (per unit)* | *tpy (per unit)* | *tpy (per unit)* | *tpy (per unit)* |
| Startup | 0.5 | 1.7 | 1.0 | 61.7 | 62.6 |
| Shutdown | 0.4 | 1.1 | 0.6 | 56.1 | 56.7 |

# of Planned Startup Events per Unit per Year: 10
# of Planned Shutodwn Events per Unit Per Year: 10

**Company Name:** **U. S. Steel**
**Facility Name:** **Clairton**
**Project Description:** **Cogeneration Project**

## Table C-5. Summary of Emissions from Proposed Emergency Diesel Fire Pump

**Emergency Fire Pump Emissions - Diesel < 600 hp**

| | | | |
|---|---|---|---|
| Potential Annual Hours of Operation: | 100 | hr/yr | |
| Maximum Engine Rating: | 55 | kW | |
| Maximum Engine Rating: | 74 | hp | |
| Average Brake Specific Fuel Consumption: | 7,000 | Btu/hp-hr | [AP-42, Table 3.4-1, note (e)] |
| Engine Heat Input: | 0.52 | MMBtu/hr | |
| Diesel Fuel Sulfur Content: | 0.0015 | % | Based on use of ultra low sulfur diesel |

**Criteria Pollutant Emissions**

| Pollutant | Diesel Emission Factor (lb/hp-hr) | Diesel Emission Factor (g/kW-hr) | Potential Emissions (lb/hr) | Potential Emissions (tpy) | Emission Factor Source |
|---|---|---|---|---|---|
| $NO_x$ | -- | 4.21 | 0.51 | 0.03 | Vendor Data |
| CO | -- | 1.2 | 0.15 | 0.01 | Vendor Data |
| $PM/PM_{10}/PM_{2.5}$[2] | -- | 0.250 | 0.03 | 1.52E-03 | Vendor Data |
| PM (cond.) | 6.20E-05 | -- | 4.59E-03 | 2.29E-04 | AP-42, Table 3.4-2 (10/96)[1] |
| $SO_2$ | 2.36E-03 | -- | 0.17 | 0.01 | AP-42, Table 3.3-1 (10/96)[1] |
| VOC | -- | 0.39 | 0.05 | 2.36E-03 | Vendor Data |

1. An additional 15% is added to all AP-42 emission factors for the purpose of permitting. Condensable factor from AP-42 for large diesel engines used for this engine in lieu of better data.
2. PM emission rate is equivalent to: 0.059 lb/MMBtu

**HAP Emissions**

| Pollutant | Diesel Emission Factor (lb/MMBtu) | Potential Emissions (lb/hr) | Potential Emissions (tpy) | Emission Factor Source | Air Toxic? (Category) |
|---|---|---|---|---|---|
| Benzene | 1.1E-03 | 5.56E-04 | 2.8E-05 | AP-42, Table 3.3-2 (10/96)[1] | Other Toxics |
| Toluene | 4.7E-04 | 2.44E-04 | 1.2E-05 | AP-42, Table 3.3-2 (10/96)[1] | Other Toxics |
| Xylenes | 3.3E-04 | 1.70E-04 | 8.5E-06 | AP-42, Table 3.3-2 (10/96)[1] | Other Toxics |
| 1,3-Butadiene | 4.5E-05 | 2.33E-05 | 1.2E-06 | AP-42, Table 3.3-2 (10/96)[1] | Other Toxics |
| Formaldehyde | 1.4E-03 | 7.03E-04 | 3.5E-05 | AP-42, Table 3.3-2 (10/96)[1] | Other Toxics |
| Acetaldehyde | 8.8E-04 | 4.57E-04 | 2.3E-05 | AP-42, Table 3.3-2 (10/96)[1] | Other Toxics |
| Acrolein | 1.1E-04 | 5.51E-05 | 2.8E-06 | AP-42, Table 3.3-2 (10/96)[1] | Other Toxics |
| Total HAP | | | 1.1E-04 | | |

1. An additional 15% is added to all AP-42 emission factors.

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

## Table C-5. Summary of Emissions from Proposed Emergency Diesel Fire Pump

### Other Air Toxics

| Pollutant | Diesel Emission Factor (lb/MMBtu) | Potential Emissions (lb/hr) | Potential Emissions (tpy) | Emission Factor Source | Air Toxic? (Category) |
|---|---|---|---|---|---|
| Total PAH | 1.93E-04 | 1.0E-04 | 5.0E-06 | AP-42, Table 3.3-2 (10/96)[1] | POM |
| Propylene | 2.97E-03 | 1.5E-03 | 7.7E-05 | AP-42, Table 3.3-2 (10/96)[1] | Other Toxics |

1. An additional 15% is added to all AP-42 emission factors.

### GHG Emissions

| Pollutant | Diesel Emission Factor (lb/MMBtu) | Potential Emissions (lb/hr) | Potential Emissions (tpy) | Emission Factor Source |
|---|---|---|---|---|
| $CO_2$ | 187.5 | 97.1 | 4.9 | 40 CFR 98, Subpart C |
| $CH_4$ | 7.6E-03 | 3.9E-03 | 2.0E-04 | 40 CFR 98, Subpart C |
| $N_2O$ | 1.5E-03 | 7.9E-04 | 3.9E-05 | 40 CFR 98, Subpart C |
| $CO_2e$ | | 97.46 | 4.9 | 40 CFR 98, Subpart A |

1. An additional 15% is added to published factors (e.g., Subpart C).

### Emergency Generator Fuel Consumption

| Item | Value | Unit | Note |
|---|---|---|---|
| Diesel Heating Value | 19,300 | Btu/lb | Source: AP-42, Table 3.4-1 (10/96), Note (e) |
| Diesel Heating Value | 0.02 | MMBtu/lb | |
| Diesel Density | 7.1 | lb/gal | Source: AP-42, Table 3.4-1 (10/96), Note (a) |
| Fuel Consumption | 27 | lb/hr | |
| Fuel Consumption | 4 | gal/hr | |
| Fuel Consumption | 378 | gal/yr | |

Company Name: **U. S. Steel**
Facility Name: **Clairton**
Project Description: **Cogeneration Project**

Table C-6a. Summary of Emissions from Proposed Package Boiler

**New Unit Information :**

| | |
|---|---|
| Fuel Type: | Natural Gas |
| Higher Heating Value (HHV) (Btu/scf): | 1,034 |
| Heat Input per Unit (MMBtu/hr): | 99.0 |
| Potential Fuel Consumption (MMBtu/yr): | 99,000 |
| Max. Fuel Consumption at 100% (scf/hr): | 95,782 |
| Max. Fuel Consumption (MMscf/yr): | 95.78 |
| Max. Annual Hours of Operation (hr/yr): | 1,000 |
| Number of Units to be Installed: | 1 |

**Criteria Pollutant Emission Rates**

| Pollutant | Emission Factor | Potential Emissions (Per Unit) | |
|---|---|---|---|
| | (lb/MMBtu)[1] | (lb/hr)[2] | (ton/yr) |
| $NO_X$ | 0.020 | 1.98 | 0.99 |
| CO | 0.055 | 5.45 | 2.72 |
| VOC | 0.0061 | 0.61 | 0.30 |
| $SO_2$ | 0.0007 | 0.07 | 0.03 |
| $PM_{filt.}$ | 0.0021 | 0.21 | 0.10 |
| $PM_{10}$ /$PM_{2.5}$ (Total) | 0.0085 | 0.84 | 0.42 |

**GHG Pollutant Emission Rates**

| Pollutant | Emission Factor | Potential Emissions | |
|---|---|---|---|
| | (lb/MMBtu)[2] | (lb/hr) | (ton/yr) |
| $CO_2$ | 116.98 | 13,317.73 | 6,659 |
| $CH_4$ | 2.2E-03 | 0.25 | 1.3E-01 |
| $N_2O$ | 2.2E-04 | 2.51E-02 | 1.3E-02 |
| $CO_2e$[3] | | 13,331.48 | 6,666 |

Global Warming Potential (GWP) 25 $CH_4$
298 $N_2O$

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

Table C-6a. Summary of Emissions from Proposed Package Boiler

**Hazardous Air Pollutant (HAP) Potential Emissions**

| Pollutant | Emission Factor (lb/MMscf)[4] | Potential Emissions (lb/hr) | Potential Emissions (ton/yr) | Emission Factor Source | Air Toxic? (Category) |
|---|---|---|---|---|---|
| 2-Methylnaphthalene | 2.8E-05 | 2.6E-06 | 1.3E-06 | AP-42 Table 1.4-3, July 1998 | N/A |
| 3-Methylchloranthrene | 2.1E-06 | 2.0E-07 | 9.9E-08 | AP-42 Table 1.4-3, July 1998 | N/A |
| 7,12-Dimethylbenz(a)anthracene | 1.8E-05 | 1.8E-06 | 8.8E-07 | AP-42 Table 1.4-3, July 1998 | POM |
| Acenaphthene | 2.1E-06 | 2.0E-07 | 9.9E-08 | AP-42 Table 1.4-3, July 1998 | N/A |
| Acenaphthylene | 2.1E-06 | 2.0E-07 | 9.9E-08 | AP-42 Table 1.4-3, July 1998 | N/A |
| Anthracene | 2.8E-06 | 2.6E-07 | 1.3E-07 | AP-42 Table 1.4-3, July 1998 | N/A |
| Benz(a)anthracene | 2.1E-06 | 2.0E-07 | 9.9E-08 | AP-42 Table 1.4-3, July 1998 | POM |
| Benzene | 2.4E-03 | 2.3E-04 | 1.2E-04 | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Benzo(a)pyrene | 1.4E-06 | 1.3E-07 | 6.6E-08 | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(b)fluoranthene | 2.1E-06 | 2.0E-07 | 9.9E-08 | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(g,h,i)perylene | 1.4E-06 | 1.3E-07 | 6.6E-08 | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(k)fluoranthene | 2.1E-06 | 2.0E-07 | 9.9E-08 | AP-42 Table 1.4-3, July 1998 | POM |
| Chrysene | 2.1E-06 | 2.0E-07 | 9.9E-08 | AP-42 Table 1.4-3, July 1998 | POM |
| Dibenzo(a,h) anthracene | 1.4E-06 | 1.3E-07 | 6.6E-08 | AP-42 Table 1.4-3, July 1998 | POM |
| Dichlorobenzene | 1.4E-03 | 1.3E-04 | 6.6E-05 | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Fluoranthene | 3.5E-06 | 3.3E-07 | 1.7E-07 | AP-42 Table 1.4-3, July 1998 | N/A |
| Fluorene | 3.2E-06 | 3.1E-07 | 1.5E-07 | AP-42 Table 1.4-3, July 1998 | N/A |
| Formaldehyde | 8.6E-02 | 8.3E-03 | 4.1E-03 | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Hexane | 2.1E+00 | 2.0E-01 | 9.9E-02 | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Indo(1,2,3-cd)pyrene | 2.1E-06 | 2.0E-07 | 9.9E-08 | AP-42 Table 1.4-3, July 1998 | POM |
| Naphthalene | 7.0E-04 | 6.7E-05 | 3.4E-05 | AP-42 Table 1.4-3, July 1998 | POM |
| Phenanthrene | 2.0E-05 | 1.9E-06 | 9.4E-07 | AP-42 Table 1.4-3, July 1998 | N/A |
| Pyrene | 5.8E-06 | 5.5E-07 | 2.8E-07 | AP-42 Table 1.4-3, July 1998 | N/A |
| Toluene | 3.9E-03 | 3.7E-04 | 1.9E-04 | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Arsenic | 2.3E-04 | 2.2E-05 | 1.1E-05 | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Beryllium | 1.4E-05 | 1.3E-06 | 6.6E-07 | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Cadmium | 1.3E-03 | 1.2E-04 | 6.1E-05 | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Chromium | 1.6E-03 | 1.5E-04 | 7.7E-05 | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Cobalt | 9.7E-05 | 9.3E-06 | 4.6E-06 | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Lead | 5.8E-04 | 5.5E-05 | 2.8E-05 | AP-42 Table 1.4-2, July 1998 | HAP Metals |
| Manganese | 4.4E-04 | 4.2E-05 | 2.1E-05 | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Mercury | 3.0E-04 | 2.9E-05 | 1.4E-05 | AP-42 Table 1.4-4, July 1998 | Mercury |
| Nickel | 2.4E-03 | 2.3E-04 | 1.2E-04 | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Selenium | 2.8E-05 | 2.6E-06 | 1.3E-06 | AP-42 Table 1.4-4, July 1998 | N/A |
| **Total HAP (including Lead)** | | **0.21** | **0.10** | AP-42 Table 1.4-4, July 1998 | |

**Company Name:** **U. S. Steel**
**Facility Name:** **Clairton**
**Project Description:** **Cogeneration Project**

Table C-6a. Summary of Emissions from Proposed Package Boiler

**Other Air Toxics**

| Pollutant | Emission Factor (lb/MMscf)[1] | Potential Emissions (lb/hr) | Potential Emissions (ton/yr) | Emission Factor Source | Air Toxic? (Category) |
|---|---|---|---|---|---|
| Barium | 5.1E-03 | 4.8E-04 | 2.4E-04 | AP-42 Table 1.4-4, July 1998 | HAP Metals |

[1] Emission factor based on BACT/vendor data for NOx and CO and AP-42 Table 1.4-2 for PM, SO2 and VOC. 15% addition included for AP-42 factors to account for variability.

[2] GHG Emission factors from Tables C-1 and C-2, 40 CFR 98, Subpart C. 15% addition included to account for variability.

[3] GWP from Table A-1, 40 CFR 98, Subpart A.

[4] All emission rates based on AP-42 emission factors include a 15% addition to account for variability in AP-42 emission factors.

Company Name: **U. S. Steel**
Facility Name: **Clairton**
Project Description: **Cogeneration Project**

Table C-6b. Summary of Emissions from Proposed Heaters (Each)

**New Heater Information (Per Heater):**

| | |
|---|---|
| Fuel Type: | Natural Gas |
| Higher Heating Value (HHV) (Btu/scf): | 1,034 |
| Heat Input per Unit (MMBtu/hr): | 3.0 |
| Potential Fuel Consumption (MMBtu/yr): | 26,280 |
| Max. Fuel Consumption at 100% (scf/hr): | 2,902 |
| Max. Fuel Consumption (MMscf/yr): | 25.43 |
| Max. Annual Hours of Operation (hr/yr): | 8,760 |
| Number of Units to be Installed: | 2 |

**Criteria Pollutant Emission Rates (Per Heater)**

| Pollutant | Emission Factor | Potential Emissions (Per Unit) | |
|---|---|---|---|
| | (lb/MMBtu)[1] | (lb/hr)[2] | (ton/yr) |
| $NO_X$ | 0.033 | 0.10 | 0.43 |
| CO | 0.037 | 0.11 | 0.49 |
| VOC | 0.003 | 0.01 | 0.04 |
| $SO_2$ | 0.0005 | 0.00 | 0.01 |
| $PM/PM_{10}/PM_{2.5}$ | 0.0048 | 0.01 | 0.06 |

**GHG Pollutant Emission Rates (Per Heater)**

| Pollutant | Emission Factor | Potential Emissions | |
|---|---|---|---|
| | (lb/MMBtu)[2] | (lb/hr) | (ton/yr) |
| $CO_2$ | 116.98 | 403.57 | 1,768 |
| $CH_4$ | 2.2E-03 | 0.01 | 3.3E-02 |
| $N_2O$ | 2.2E-04 | 7.61E-04 | 3.3E-03 |
| $CO_2e$[3] | | 403.98 | 1,769 |

Global Warming Potential (GWP) 25 $CH_4$
298 $N_2O$

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

Table C-6b. Summary of Emissions from Proposed Heaters (Each)

**Hazardous Air Pollutant (HAP) Potential Emissions (Per Heater)**

| Pollutant | Emission Factor | Potential Emissions | Potential Emissions | Emission Factor Source | Air Toxic? (Category) |
|---|---|---|---|---|---|
| | (lb/MMscf)[4] | (lb/hr) | (ton/yr) | | |
| 2-Methylnaphthalene | 2.8E-05 | 8.0E-08 | 3.5E-07 | AP-42 Table 1.4-3, July 1998 | N/A |
| 3-Methylchloranthrene | 2.1E-06 | 6.0E-09 | 2.6E-08 | AP-42 Table 1.4-3, July 1998 | N/A |
| 7,12-Dimethylbenz(a)anthracene | 1.8E-05 | 5.3E-08 | 2.3E-07 | AP-42 Table 1.4-3, July 1998 | POM |
| Acenaphthene | 2.1E-06 | 6.0E-09 | 2.6E-08 | AP-42 Table 1.4-3, July 1998 | N/A |
| Acenaphthylene | 2.1E-06 | 6.0E-09 | 2.6E-08 | AP-42 Table 1.4-3, July 1998 | N/A |
| Anthracene | 2.8E-06 | 8.0E-09 | 3.5E-08 | AP-42 Table 1.4-3, July 1998 | N/A |
| Benz(a)anthracene | 2.1E-06 | 6.0E-09 | 2.6E-08 | AP-42 Table 1.4-3, July 1998 | POM |
| Benzene | 2.4E-03 | 7.0E-06 | 3.1E-05 | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Benzo(a)pyrene | 1.4E-06 | 4.0E-09 | 1.8E-08 | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(b)fluoranthene | 2.1E-06 | 6.0E-09 | 2.6E-08 | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(g,h,i)perylene | 1.4E-06 | 4.0E-09 | 1.8E-08 | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(k)fluoranthene | 2.1E-06 | 6.0E-09 | 2.6E-08 | AP-42 Table 1.4-3, July 1998 | POM |
| Chrysene | 2.1E-06 | 6.0E-09 | 2.6E-08 | AP-42 Table 1.4-3, July 1998 | POM |
| Dibenzo(a,h) anthracene | 1.4E-06 | 4.0E-09 | 1.8E-08 | AP-42 Table 1.4-3, July 1998 | POM |
| Dichlorobenzene | 1.4E-03 | 4.0E-06 | 1.8E-05 | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Fluoranthene | 3.5E-06 | 1.0E-08 | 4.4E-08 | AP-42 Table 1.4-3, July 1998 | N/A |
| Fluorene | 3.2E-06 | 9.3E-09 | 4.1E-08 | AP-42 Table 1.4-3, July 1998 | N/A |
| Formaldehyde | 8.6E-02 | 2.5E-04 | 1.1E-03 | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Hexane | 2.1E+00 | 6.0E-03 | 2.6E-02 | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Indo(1,2,3-cd)pyrene | 2.1E-06 | 6.0E-09 | 2.6E-08 | AP-42 Table 1.4-3, July 1998 | POM |
| Naphthalene | 7.0E-04 | 2.0E-06 | 8.9E-06 | AP-42 Table 1.4-3, July 1998 | POM |
| Phenanthrene | 2.0E-05 | 5.7E-08 | 2.5E-07 | AP-42 Table 1.4-3, July 1998 | N/A |
| Pyrene | 5.8E-06 | 1.7E-08 | 7.3E-08 | AP-42 Table 1.4-3, July 1998 | N/A |
| Toluene | 3.9E-03 | 1.1E-05 | 5.0E-05 | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Arsenic | 2.3E-04 | 6.7E-07 | 2.9E-06 | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Beryllium | 1.4E-05 | 4.0E-08 | 1.8E-07 | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Cadmium | 1.3E-03 | 3.7E-06 | 1.6E-05 | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Chromium | 1.6E-03 | 4.7E-06 | 2.0E-05 | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Cobalt | 9.7E-05 | 2.8E-07 | 1.2E-06 | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Lead | 5.8E-04 | 1.7E-06 | 7.3E-06 | AP-42 Table 1.4-2, July 1998 | HAP Metals |
| Manganese | 4.4E-04 | 1.3E-06 | 5.6E-06 | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Mercury | 3.0E-04 | 8.7E-07 | 3.8E-06 | AP-42 Table 1.4-4, July 1998 | Mercury |
| Nickel | 2.4E-03 | 7.0E-06 | 3.1E-05 | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Selenium | 2.8E-05 | 8.0E-08 | 3.5E-07 | AP-42 Table 1.4-4, July 1998 | N/A |
| **Total HAP (including Lead)** | | **0.01** | **0.03** | AP-42 Table 1.4-4, July 1998 | |

Company Name: **U. S. Steel**
Facility Name: **Clairton**
Project Description: **Cogeneration Project**

Table C-6b. Summary of Emissions from Proposed Heaters (Each)

**Other Air Toxics (Per Heater)**

| Pollutant | Emission Factor | Potential Emissions | Potential Emissions | Emission Factor Source | Air Toxic? (Category) |
|---|---|---|---|---|---|
| | (lb/MMscf)[1] | (lb/hr) | (ton/yr) | | |
| Barium | 5.1E-03 | 1.5E-05 | 6.4E-05 | AP-42 Table 1.4-4, July 1998 | HAP Metals |

[1] Emission factor provided by vendor for criteria pollutants (PM, NOx, CO, SO2 and VOC).
[2] GHG Emission factors from Tables C-1 and C-2, 40 CFR 98, Subpart C. 15% addition included to account for variability.
[3] GWP from Table A-1, 40 CFR 98, Subpart A.
[4] All emission rates based on AP-42 emission factors include a 15% addition to account for variability in AP-42 emission factors.

**Company Name:** **U. S. Steel**
**Facility Name:** **Clairton**
**Project Description:** **Cogeneration Project**

**Table C-7. Summary of Emissions from Proposed Material Handling Systems**

| Equipment[1,2] | Flow Rate (acfm/dscfm) | $PM/PM_{10}/PM_{2.5}$ Outlet Rate (gr/dscf) | Potential Emissions (lb/hr) | Maximum Hours of Operation (hrs/yr)[1] | Potential Emissions (tpy) |
|---|---|---|---|---|---|
| Hydrated Lime Silo Bin Vent | 1,500 | 0.002 | 0.03 | 3,120 | 0.04 |
| Waste Lime Silo Bin Vent | 1,000 | 0.002 | 0.02 | 3,120 | 0.03 |
| **Total** | | | 0.04 | | **0.07** |

1. Hours of operation are reflect of maximum schedule for the bin vents. Assumes 12 hours per day, 5 days a week for the entire

2. All other material handling components (e.g., day bins) will either be tied into the baghouse and/or will be a pneumatic/enclosed design and will not have emissions under normal operating conditions.

**Company Name:** **U. S. Steel**
**Facility Name:** **Clairton**
**Project Description:** **Cogeneration Project**

**Table C-8a. Paved Haul Road Emissions - Proposed Lime Transfers**

AP-42 13.2.1.3 (January, 2011) - Eq 2
$E= [k(sL)^{0.91} \times (W)^{1.02}]$

| | | | Reference |
|---|---|---|---|
| k (PM) | 0.011 | lb/VMT | Table 13.2.1-1 (January, 2011) |
| k ($PM_{10}$) | 0.0022 | lb/VMT | Table 13.2.1-1 (January, 2011) |
| k ($PM_{2.5}$) | 0.00054 | lb/VMT | Table 13.2.1-1 (January, 2011) |
| sL | 7.4 | $g/m^2$ | Annual Emission Reporting Practice |
| W | 18 | tons | Average weight of vehicle |
| E (PM) | 1.26 | lb/VMT | AP-42 13.2.1.3 (January, 2011) - Eq 2 |
| E ($PM_{10}$) | 0.25 | lb/VMT | AP-42 13.2.1.3 (January, 2011) - Eq 2 |
| E ($PM_{2.5}$) | 0.06 | lb/VMT | AP-42 13.2.1.3 (January, 2011) - Eq 2 |

| | | |
|---|---|---|
| Hydrate Lime: | 2,000 | tons |
| Empty Truck: | 15 | tons |
| Hydrate Weight Added: | 5 | tons |
| Trips/Year: | 400 | |

Vehicle Miles Traveled (VMT):

| | | | | |
|---|---|---|---|---|
| Length of Roadway: | 7,000 | ft | 1.33 | miles |
| Round trip length: | 14,000 | ft | 2.65 | miles |
| VMT per day: | 2.9 | miles/day | | |
| VMT per year: | 1,061 | miles/year | | |
| Control Efficiency: | 95 | % | | |

| Pollutant | Emissions - Uncontrolled | | | Emissions - Controlled | | |
|---|---|---|---|---|---|---|
| | lb/hr[1] | lb/yr | tpy | lb/hr[1] | lb/yr | tpy |
| PM | 0.15 | 1,336 | 0.67 | 0.01 | 66.81 | 0.03 |
| $PM_{10}$ | 0.03 | 267.22 | 0.13 | 0.00 | 13.36 | 0.01 |
| $PM_{2.5}$ | 0.01 | 65.59 | 0.03 | 0.00 | 3.28 | 0.002 |

**Notes:**
1. Short-term emissions are averaged based on 8,760 hours of operation per year.

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-8b. Paved Haul Road Emissions - Proposed Waste Lime Transfers**

AP-42 13.2.1.3 (January, 2011) - Eq 2
$E= [k(sL)^{0.91} \times (W)^{1.02}]$

| | | | Reference |
|---|---|---|---|
| k (PM) | 0.011 | lb/VMT | Table 13.2.1-1 (January, 2011) |
| k ($PM_{10}$) | 0.0022 | lb/VMT | Table 13.2.1-1 (January, 2011) |
| k ($PM_{2.5}$) | 0.00054 | lb/VMT | Table 13.2.1-1 (January, 2011) |
| sL | 7.4 | $g/m^2$ | Annual Emission Reporting Practice |
| W | 18 | tons | Average weight of vehicle |
| E (PM) | 1.26 | lb/VMT | AP-42 13.2.1.3 (January, 2011) - Eq 2 |
| E ($PM_{10}$) | 0.25 | lb/VMT | AP-42 13.2.1.3 (January, 2011) - Eq 2 |
| E ($PM_{2.5}$) | 0.06 | lb/VMT | AP-42 13.2.1.3 (January, 2011) - Eq 2 |

| | | |
|---|---|---|
| Waste Lime: | 3,000 | tons |
| Empty Truck: | 15 | tons |
| Waste Lime Weight Added: | 5 | tons |
| Trips/Year: | 600 | |

Vehicle Miles Traveled (VMT):

| | | | | |
|---|---|---|---|---|
| Length of Roadway: | 7,000 | ft | 1.33 | miles |
| Round trip length: | 14,000 | ft | 2.65 | miles |
| VMT per day: | 4.4 | miles/day | | |
| VMT per year: | 1,591 | miles/year | | |
| Control Efficiency: | 95 | % | | |

| | Emissions - Uncontrolled | | | Emissions - Controlled | | |
|---|---|---|---|---|---|---|
| Pollutant | lb/hr[1] | lb/yr | tpy | lb/hr[1] | lb/yr | tpy |
| PM | 0.23 | 2,004 | 1.00 | 0.01 | 100.21 | 0.05 |
| $PM_{10}$ | 0.05 | 400.84 | 0.20 | 0.00 | 20.04 | 0.01 |
| $PM_{2.5}$ | 0.01 | 98.39 | 0.05 | 0.00 | 4.92 | 0.002 |

**Notes:**
1. Short-term emissions are averaged based on 8,760 hours of operation per year.

**Company Name:** **U. S. Steel**
**Facility Name:** **Clairton**
**Project Description:** **Cogeneration Project**

**Table C-8c. Paved Haul Road Emissions - Proposed Anhydrous Ammonia Transfers**

AP-42 13.2.1.3 (January, 2011) - Eq 2
$E= [k(sL)^{0.91} \times (W)^{1.02}]$

| | | | Reference |
|---|---|---|---|
| k (PM) | **0.011** | lb/VMT | Table 13.2.1-1 (January, 2011) |
| k ($PM_{10}$) | **0.0022** | lb/VMT | Table 13.2.1-1 (January, 2011) |
| k ($PM_{2.5}$) | **0.00054** | lb/VMT | Table 13.2.1-1 (January, 2011) |
| sL | 7.4 | $g/m^2$ | Annual Emission Reporting Practice |
| W | 25 | tons | Average weight of vehicle |
| E (PM) | 1.81 | lb/VMT | AP-42 13.2.1.3 (January, 2011) - Eq 2 |
| E ($PM_{10}$) | 0.36 | lb/VMT | AP-42 13.2.1.3 (January, 2011) - Eq 2 |
| E ($PM_{2.5}$) | 0.09 | lb/VMT | AP-42 13.2.1.3 (January, 2011) - Eq 2 |

| | | |
|---|---|---|
| Anhydrous NH3: | 922,475 | lbs/yr |
| Anhydrous NH3: | 184,495 | gals/yr |
| Empty Truck: | 15 | tons |
| Ammonia Load: | 8,000 | gals/truck |
| Density of Anhydrous NH3: | 5 | lb/gal (at 60F) |
| Ammonia Added: | 20 | tons |
| Trips/Year: | 23 | |

Vehicle Miles Traveled (VMT):

| | | | | |
|---|---|---|---|---|
| Length of Roadway: | 10,350 | ft | 1.96 | miles |
| Round trip length: | 20,700 | ft | 3.92 | miles |
| VMT per day: | 0.25 | miles/day | | |
| VMT per year: | 90 | miles/year | | |
| Control Efficiency: | 95 | % | | |

| | Emissions - Uncontrolled | | | Emissions - Controlled | | |
|---|---|---|---|---|---|---|
| **Pollutant** | **lb/hr[1]** | **lb/yr** | **tpy** | **lb/hr[1]** | **lb/yr** | **tpy** |
| PM | 0.02 | 163.88 | 0.08 | 0.00 | 8.19 | 0.004 |
| $PM_{10}$ | 0.00 | 32.78 | 0.02 | 0.00 | 1.64 | 0.001 |
| $PM_{2.5}$ | 0.00 | 8.04 | 0.00 | 0.00 | 0.40 | 0.0002 |

**Notes:**
1. Short-term emissions are averaged based on 8,760 hours of operation per year.

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

## Table C-9. Proposed Fuel Oil Storage Tank Emissions

**Process Section:** Ancillary
**Process Name:** Storage Tanks
**Emission Unit:** Fuel Oil Storage Tank

| Tank | Capacity (gal) | Throughput (gal) | VOC Emissions - Uncontrolled lb/hr[1] | VOC Emissions - Uncontrolled tpy | VOC Emissions - Controlled lb/hr[1] | VOC Emissions - Controlled tpy |
|---|---|---|---|---|---|---|
| Fire Pump Tank | 200 | 378 | 5.77E-07 | 2.53E-06 | 5.77E-07 | 2.53E-06 |
| **Total** | | | **5.77E-07** | **2.53E-06** | **5.77E-07** | **2.53E-06** |

**Notes:**
1. Working and breathing losses estimated using TankESP calculation software based on diesel.
2. Emissions shown above include a 15% "safety factor" since the software uses AP-42 Chapter 7 emission factors & calculation methods.

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-10. Past Actual Emissions Summary - PM filterable**

| Plant | Unit Description | Emission Unit ID | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | tpy | tpy | tpy | tpy | tpy | tpy | tpy | tpy | tpy |
| Clairton | Boiler #1 - COG | 031 | 19.45 | 21.53 | 7.18 | 8.11 | 1.74 | 1.26 | 12.85 | 15.59 | 7.31 |
| Clairton | Boiler #1 - NG | 032 | 0.56 | 0.60 | 0.46 | 0.15 | 0.20 | 0.55 | 1.10 | 0.39 | 0.48 |
| Clairton | Boiler #2 - COG | 033 | 8.29 | 9.50 | 5.81 | 8.47 | 1.06 | 0.95 | 5.43 | 6.09 | 5.85 |
| Clairton | Boiler #2 - NG | 034 | 0.30 | 0.25 | 0.21 | 0.09 | 0.12 | 0.35 | 0.64 | 0.26 | 0.32 |
| Clairton | Boiler R-1 - COG | 035 | 1.09 | 0.42 | 0.18 | 0.16 | 0.24 | 0.41 | 0.17 | 0.02 | 0.00 |
| Clairton | Boiler R-1 - NG | 035 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler R-2 - COG | 036 | 1.63 | 0.28 | 0.10 | 0.13 | 0.17 | 0.25 | 0.35 | 0.61 | 0.61 |
| Clairton | Boiler R-2 - NG | 036 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-1 - COG | 037 | 1.23 | 1.16 | 0.08 | 0.13 | 0.14 | 0.15 | 0.26 | 0.58 | 0.59 |
| Clairton | Boiler T-1 - NG | 037 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-2 - COG | 038 | 1.23 | 1.16 | 0.16 | 0.26 | 0.12 | 0.13 | 0.26 | 0.58 | 0.59 |
| Clairton | Boiler T-2 - NG | 038 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Years | | | 2010 / 2011 | 2011 / 2012 | 2012 / 2013 | 2013 / 2014 | 2014 / 2015 | 2015 / 2016 | 2016 / 2017 | 2017/ 2018 |
| *Clairton Decreases* | *Annual* | | *33.81* | *34.89* | *14.18* | *17.50* | *3.78* | *4.05* | *21.04* | *24.12* | *15.75* |
| *Clairton Decreases* | *2-Yr Average* | | | ***34.35*** | *24.54* | *15.84* | *10.64* | *3.91* | *12.54* | *22.58* | *19.94* |

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-11a. Past Actual Emissions Summary - PM10 (Filterable)**

| Plant | Unit Description | Emission Unit ID | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | tpy | tpy | tpy | tpy | tpy | tpy | tpy | tpy | tpy |
| Clairton | Boiler #1 - COG | 031 | 13.64 | 15.11 | 7.18 | 8.11 | 1.74 | 1.26 | 12.85 | 15.59 | 7.31 |
| Clairton | Boiler #1 - NG | 032 | 0.56 | 0.60 | 0.46 | 0.15 | 0.20 | 0.55 | 1.10 | 0.39 | 0.48 |
| Clairton | Boiler #2 - COG | 033 | 5.81 | 6.67 | 5.81 | 8.47 | 1.06 | 0.95 | 5.43 | 6.09 | 5.85 |
| Clairton | Boiler #2 - NG | 034 | 0.30 | 0.25 | 0.21 | 0.09 | 0.12 | 0.35 | 0.64 | 0.26 | 0.32 |
| Clairton | Boiler R-1 - COG | 035 | 0.77 | 0.29 | 0.18 | 0.16 | 0.24 | 0.41 | 0.17 | 0.02 | 0.00 |
| Clairton | Boiler R-1 - NG | 035 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler R-2 - COG | 036 | 1.14 | 0.20 | 0.10 | 0.13 | 0.17 | 0.25 | 0.35 | 0.61 | 0.61 |
| Clairton | Boiler R-2 - NG | 036 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-1 - COG | 037 | 0.87 | 0.81 | 0.08 | 0.13 | 0.14 | 0.15 | 0.26 | 0.58 | 0.59 |
| Clairton | Boiler T-1 - NG | 037 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-2 - COG | 038 | 0.87 | 0.81 | 0.16 | 0.26 | 0.12 | 0.13 | 0.26 | 0.58 | 0.59 |
| Clairton | Boiler T-2 - NG | 038 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-11b. Past Actual Emissions Summary - PM10 (Condensable)**

| Plant | Unit Description | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| | | tpy | tpy | tpy | tpy | tpy | tpy | tpy | tpy | tpy |
| Clairton | Boiler #1 - COG | 10.19 | 11.29 | 0.61 | 5.18 | 13.93 | 10.08 | 11.38 | 13.80 | 4.73 |
| Clairton | Boiler #1 - NG | 1.68 | 1.79 | 1.38 | 0.45 | 0.59 | 1.65 | 3.29 | 1.16 | 1.44 |
| Clairton | Boiler #2 - COG | 4.34 | 4.98 | 0.35 | 2.53 | 12.12 | 10.87 | 5.59 | 6.27 | 7.94 |
| Clairton | Boiler #2 - NG | 0.91 | 0.74 | 0.63 | 0.27 | 0.36 | 1.06 | 1.90 | 0.78 | 0.94 |
| Clairton | Boiler R-1 - COG | 0.57 | 0.22 | 0.10 | 0.58 | 0.94 | 1.56 | 0.11 | 0.02 | 0.00 |
| Clairton | Boiler R-1 - NG | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler R-2 - COG | 0.85 | 0.15 | 0.08 | 0.69 | 1.13 | 1.68 | 0.19 | 0.34 | 0.72 |
| Clairton | Boiler R-2 - NG | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-1 - COG | 0.65 | 0.61 | 0.06 | 0.65 | 2.51 | 2.75 | 0.18 | 0.42 | 0.88 |
| Clairton | Boiler T-1 - NG | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-2 - COG | 0.65 | 0.61 | 0.05 | 0.59 | 2.01 | 2.20 | 0.19 | 0.44 | 1.40 |
| Clairton | Boiler T-2 - NG | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-11c. Past Actual Emissions Summary - PM10 total**

| Plant | Unit Description | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| | | tpy | tpy | tpy | tpy | tpy | tpy | tpy | tpy | tpy |
| Clairton | Boiler #1 - COG | 23.84 | 26.39 | 7.78 | 13.29 | 15.67 | 11.34 | 24.23 | 29.40 | 12.05 |
| Clairton | Boiler #1 - NG | 2.24 | 2.39 | 1.84 | 0.59 | 0.78 | 2.20 | 4.39 | 1.55 | 1.93 |
| Clairton | Boiler #2 - COG | 10.16 | 11.65 | 6.17 | 11.00 | 13.18 | 11.82 | 11.02 | 12.36 | 13.79 |
| Clairton | Boiler #2 - NG | 1.22 | 0.99 | 0.84 | 0.36 | 0.48 | 1.41 | 2.54 | 1.04 | 1.26 |
| Clairton | Boiler R-1 - COG | 1.34 | 0.51 | 0.28 | 0.75 | 1.19 | 1.97 | 0.28 | 0.04 | 0.00 |
| Clairton | Boiler R-1 - NG | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler R-2 - COG | 2.00 | 0.34 | 0.18 | 0.82 | 1.30 | 1.92 | 0.55 | 0.94 | 1.33 |
| Clairton | Boiler R-2 - NG | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-1 - COG | 1.51 | 1.42 | 0.15 | 0.77 | 2.65 | 2.90 | 0.44 | 1.00 | 1.47 |
| Clairton | Boiler T-1 - NG | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-2 - COG | 1.51 | 1.42 | 0.22 | 0.84 | 2.12 | 2.33 | 0.45 | 1.02 | 1.99 |
| Clairton | Boiler T-2 - NG | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Plant | Years | | 2010 / 2011 | 2011 / 2012 | 2012 / 2013 | 2013 / 2014 | 2014 / 2015 | 2015 / 2016 | 2016 / 2017 | 2017 / 2018 |
| *Clairton Decreases* | *Annual* | *43.88* | *45.12* | *17.45* | *28.43* | *37.37* | *35.89* | *43.89* | *47.34* | *33.82* |
| *Clairton Decreases* | *2-Yr Average* | | *44.50* | *31.29* | *22.94* | *32.90* | *36.63* | *39.89* | ***45.62*** | *40.58* |

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-12a. Past Actual Emissions Summary - PM2.5 (Filterable)**

| Plant | Unit Description | Emission Unit ID | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|
| | | | tpy | tpy | tpy | tpy | tpy |
| Clairton | Boiler #1 - COG | 031 | 1.74 | 1.26 | 12.85 | 15.59 | 7.31 |
| Clairton | Boiler #1 - NG | 032 | 0.20 | 0.55 | 1.10 | 0.39 | 0.48 |
| Clairton | Boiler #2 - COG | 033 | 0.92 | 0.83 | 5.43 | 6.09 | 5.85 |
| Clairton | Boiler #2 - NG | 034 | 0.12 | 0.35 | 0.64 | 0.26 | 0.32 |
| Clairton | Boiler R-1 - COG | 035 | 0.05 | 0.08 | 0.17 | 0.02 | 0.00 |
| Clairton | Boiler R-1 - NG | 035 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler R-2 - COG | 036 | 0.07 | 0.10 | 0.35 | 0.61 | 0.61 |
| Clairton | Boiler R-2 - NG | 036 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-1 - COG | 037 | 0.11 | 0.12 | 0.26 | 0.58 | 0.59 |
| Clairton | Boiler T-1 - NG | 037 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-2 - COG | 038 | 0.11 | 0.12 | 0.26 | 0.58 | 0.59 |
| Clairton | Boiler T-2 - NG | 038 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-12b. Past Actual Emissions Summary - PM2.5 (Condensable)**

| Plant | Unit Description | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|
| | | tpy | tpy | tpy | tpy | tpy |
| Clairton | Boiler #1 - COG | 13.93 | 10.08 | 11.38 | 13.80 | 4.73 |
| Clairton | Boiler #1 - NG | 0.59 | 1.65 | 3.29 | 1.16 | 1.44 |
| Clairton | Boiler #2 - COG | 12.12 | 10.87 | 5.59 | 6.27 | 7.94 |
| Clairton | Boiler #2 - NG | 0.36 | 1.06 | 1.90 | 0.78 | 0.94 |
| Clairton | Boiler R-1 - COG | 0.94 | 1.56 | 0.11 | 0.02 | 0.00 |
| Clairton | Boiler R-1 - NG | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler R-2 - COG | 1.13 | 1.68 | 0.19 | 0.34 | 0.72 |
| Clairton | Boiler R-2 - NG | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-1 - COG | 2.51 | 2.75 | 0.18 | 0.42 | 0.88 |
| Clairton | Boiler T-1 - NG | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-2 - COG | 2.01 | 2.20 | 0.19 | 0.44 | 1.40 |
| Clairton | Boiler T-2 - NG | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

## Table C-12c. Past Actual Emissions Summary - PM2.5 total

| Plant | Unit Description | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|
| | | tpy | tpy | tpy | tpy | tpy |
| Clairton | Boiler #1 - COG | 15.67 | 11.34 | 24.23 | 29.40 | 12.05 |
| Clairton | Boiler #1 - NG | 0.78 | 2.20 | 4.39 | 1.55 | 1.93 |
| Clairton | Boiler #2 - COG | 13.05 | 11.70 | 11.02 | 12.36 | 13.79 |
| Clairton | Boiler #2 - NG | 0.48 | 1.41 | 2.54 | 1.04 | 1.26 |
| Clairton | Boiler R-1 - COG | 0.99 | 1.64 | 0.28 | 0.04 | 0.00 |
| Clairton | Boiler R-1 - NG | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler R-2 - COG | 1.20 | 1.78 | 0.55 | 0.94 | 1.33 |
| Clairton | Boiler R-2 - NG | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-1 - COG | 2.62 | 2.87 | 0.44 | 1.00 | 1.47 |
| Clairton | Boiler T-1 - NG | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-2 - COG | 2.11 | 2.31 | 0.45 | 1.02 | 1.99 |
| Clairton | Boiler T-2 - NG | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Plant | Years | | 2014 / 2015 | 2015 / 2016 | 2016 / 2017 | 2017 / 2018 |
| *Clairton Decreases* | *Annual* | *36.90* | *35.25* | *43.89* | *47.34* | *33.82* |
| *Clairton Decreases* | *2-Yr Average* | | *36.07* | *39.57* | ***45.62*** | *40.58* |

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-13. Past Actual Emissions Summary - NOx**

| Plant | Unit Description | Emission Unit ID | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|
| | | | tpy | tpy | tpy | tpy | tpy |
| Clairton | Boiler #1 - COG | 031 | 630.49 | 604.41 | 379.08 | 497.58 | 531.55 |
| Clairton | Boiler #1 - NG | 032 | 14.41 | 40.49 | 80.91 | 64.82 | 80.81 |
| Clairton | Boiler #2 - COG | 033 | 202.70 | 185.57 | 153.35 | 163.59 | 267.96 |
| Clairton | Boiler #2 - NG | 034 | 8.80 | 25.93 | 46.75 | 25.33 | 30.64 |
| Clairton | Boiler R-1 - COG | 035 | 11.96 | 19.84 | 3.22 | 0.47 | 0.00 |
| Clairton | Boiler R-1 - NG | 035 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler R-2 - COG | 036 | 13.74 | 20.37 | 8.00 | 13.85 | 29.45 |
| Clairton | Boiler R-2 - NG | 036 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-1 - COG | 037 | 22.56 | 24.71 | 5.30 | 12.04 | 22.95 |
| Clairton | Boiler T-1 - NG | 037 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-2 - COG | 038 | 17.44 | 19.09 | 4.42 | 10.03 | 20.82 |
| Clairton | Boiler T-2 - NG | 038 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Years | | | 2014 / 2015 | 2015 / 2016 | 2016 / 2017 | 2017/ 2018 |
| *Clairton Decreases* | *Annual* | | *922.09* | *940.41* | *681.03* | *787.72* | *984.18* |
| *Clairton Decreases* | *2-Yr Average* | | | ***931.25*** | *810.72* | *734.38* | *885.95* |

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-14. Past Actual Emissions Summary - CO**

| Plant | Unit Description | Emission Unit ID | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | tpy | tpy | tpy | tpy | tpy | tpy | tpy | tpy | tpy |
| Clairton | Boiler #1 - COG | 031 | 57.71 | 63.90 | 65.09 | 75.11 | 0.65 | 0.47 | 0.45 | 0.54 | 0.55 |
| Clairton | Boiler #1 - NG | 032 | 24.78 | 26.43 | 20.32 | 6.56 | 8.64 | 24.28 | 48.51 | 17.06 | 21.27 |
| Clairton | Boiler #2 - COG | 033 | 24.60 | 28.21 | 30.14 | 46.07 | 0.30 | 0.27 | 0.21 | 0.24 | 0.30 |
| Clairton | Boiler #2 - NG | 034 | 13.42 | 10.94 | 9.25 | 4.02 | 5.28 | 15.55 | 28.03 | 11.50 | 13.90 |
| Clairton | Boiler R-1 - COG | 035 | 3.24 | 1.25 | 2.14 | 2.03 | 1.89 | 3.13 | 0.68 | 0.10 | 0.00 |
| Clairton | Boiler R-1 - NG | 035 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler R-2 - COG | 036 | 4.84 | 0.83 | 1.81 | 2.24 | 17.43 | 25.85 | 9.95 | 17.20 | 29.89 |
| Clairton | Boiler R-2 - NG | 036 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-1 - COG | 037 | 3.66 | 3.43 | 2.95 | 4.82 | 1.44 | 1.57 | 0.37 | 0.85 | 1.50 |
| Clairton | Boiler T-1 - NG | 037 | 0.23 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-2 - COG | 038 | 3.66 | 3.43 | 2.95 | 4.82 | 3.31 | 3.63 | 0.86 | 1.96 | 3.47 |
| Clairton | Boiler T-2 - NG | 038 | 0.23 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Years | | | 2010 / 2011 | 2011 / 2012 | 2012 / 2013 | 2013 / 2014 | 2014 / 2015 | 2015 / 2016 | 2016 / 2017 | 2017/ 2018 |
| *Clairton Decreases* | *Annual* | | *136.50* | *138.42* | *134.66* | *145.68* | *38.94* | *74.75* | *89.08* | *49.46* | *70.89* |
| *Clairton Decreases* | *2-Yr Average* | | | *137.46* | *136.54* | ***140.17*** | *92.31* | *56.85* | *81.91* | *69.27* | *60.17* |

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-15. Past Actual Emissions Summary - VOC**

| Plant | Unit Description | Emission Unit ID | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|
| | | | tpy | tpy | tpy | tpy | tpy |
| Clairton | Boiler #1 - COG | 031 | 1.94 | 1.41 | 1.34 | 1.63 | 1.66 |
| Clairton | Boiler #1 - NG | 032 | 0.19 | 0.52 | 1.31 | 1.14 | 1.16 |
| Clairton | Boiler #2 - COG | 033 | 0.19 | 0.17 | 0.13 | 0.15 | 0.19 |
| Clairton | Boiler #2 - NG | 034 | 0.11 | 0.33 | 0.76 | 0.67 | 0.68 |
| Clairton | Boiler R-1 - COG | 035 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler R-1 - NG | 035 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler R-2 - COG | 036 | 0.01 | 0.01 | 0.00 | 0.01 | 0.01 |
| Clairton | Boiler R-2 - NG | 036 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-1 - COG | 037 | 0.01 | 0.01 | 0.00 | 0.00 | 0.01 |
| Clairton | Boiler T-1 - NG | 037 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-2 - COG | 038 | 0.11 | 0.12 | 0.03 | 0.06 | 0.11 |
| Clairton | Boiler T-2 - NG | 038 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Years | | | 2014 / 2015 | 2015 / 2016 | 2016 / 2017 | 2017/ 2018 |
| *Clairton Decreases* | *Annual* | | *2.56* | *2.58* | *3.58* | *3.65* | *3.82* |
| *Clairton Decreases* | *2-Yr Average* | | | ***2.57*** | *3.08* | *3.62* | *3.74* |

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-16. Past Actual Emissions Summary - SO2**

| Plant | Unit Description | Emission Unit ID | 2014 tpy | 2015 tpy | 2016 tpy | 2017 tpy | 2018 tpy |
|---|---|---|---|---|---|---|---|
| Clairton | Boiler #1 - COG | 031 | 266.20 | 192.65 | 90.44 | 109.75 | 222.69 |
| Clairton | Boiler #1 - NG | 032 | 0.06 | 0.17 | 0.35 | 0.12 | 0.15 |
| Clairton | Boiler #2 - COG | 033 | 132.00 | 118.40 | 108.17 | 121.35 | 243.16 |
| Clairton | Boiler #2 - NG | 034 | 0.04 | 0.11 | 0.20 | 0.08 | 0.10 |
| Clairton | Boiler R-1 - COG | 035 | 6.24 | 10.35 | 1.86 | 0.27 | 0.00 |
| Clairton | Boiler R-1 - NG | 035 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler R-2 - COG | 036 | 11.18 | 16.58 | 3.83 | 6.63 | 18.37 |
| Clairton | Boiler R-2 - NG | 036 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-1 - COG | 037 | 18.94 | 20.74 | 2.54 | 5.78 | 20.48 |
| Clairton | Boiler T-1 - NG | 037 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-2 - COG | 038 | 17.40 | 19.05 | 2.51 | 5.70 | 24.29 |
| Clairton | Boiler T-2 - NG | 038 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Years | | | 2014 / 2015 | 2015 / 2016 | 2016 / 2017 | 2017/ 2018 |
| *Clairton Decreases* | *Annual* | | *452.05* | *378.05* | *209.90* | *249.69* | *529.25* |
| *Clairton Decreases* | *2-Yr Average* | | | ***415.05*** | *293.98* | *229.79* | *389.47* |

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-17. Past Actual Emissions Summary - CO2e**

| Plant | Unit Description | Emission Unit ID | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | tpy | tpy | tpy | tpy | tpy | tpy | tpy | tpy | tpy |
| Clairton | Boiler #1 - COG | 031 | 113,182.2 | 124,908.9 | 126,441.6 | 145,711.1 | 147,792.4 | 95,659.6 | 100,138.5 | 121,517.8 | 122,966.5 |
| Clairton | Boiler #1 - NG | 032 | 35,728.8 | 38,113.2 | 29,772.4 | 9,689.1 | 12,617.6 | 31,897.4 | 70,350.3 | 24,735.4 | 30,716.8 |
| Clairton | Boiler #2 - COG | 033 | 51,993.7 | 58,270.3 | 58,318.2 | 89,397.3 | 91,423.2 | 73,809.9 | 62,588.7 | 70,219.6 | 90,086.4 |
| Clairton | Boiler #2 - NG | 034 | 19,353.1 | 15,770.5 | 13,545.8 | 5,936.0 | 7,708.3 | 20,426.0 | 40,652.1 | 16,670.2 | 20,079.2 |
| Clairton | Boiler R-1 - COG | 035 | 3,880.4 | 1,886.9 | 4,146.2 | 3,878.1 | 4,295.8 | 6,372.1 | 1,561.9 | 228.1 | 0.4 |
| Clairton | Boiler R-1 - NG | 035 | 12.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Clairton | Boiler R-2 - COG | 036 | 5,789.8 | 1,250.5 | 3,514.9 | 4,275.0 | 5,751.2 | 7,622.6 | 3,294.0 | 5,697.8 | 9,985.9 |
| Clairton | Boiler R-2 - NG | 036 | 157.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Clairton | Boiler T-1 - COG | 037 | 15,815.8 | 6,067.9 | 5,731.4 | 9,289.2 | 9,306.2 | 9,044.1 | 2,435.7 | 5,533.5 | 9,705.3 |
| Clairton | Boiler T-1 - NG | 037 | 326.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Clairton | Boiler T-2 - COG | 038 | 15,815.8 | 6,067.9 | 5,731.4 | 9,289.2 | 9,306.2 | 9,044.1 | 2,435.7 | 5,533.5 | 9,705.3 |
| Clairton | Boiler T-2 - NG | 038 | 326.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | Years | | | 2010 / 2011 | 2011 / 2012 | 2012 / 2013 | 2013 / 2014 | 2014 / 2015 | 2015 / 2016 | 2016 / 2017 | 2017 / 2018 |
| *Clairton Decreases* | *Annual* | | *262,383* | *252,336* | *247,202* | *277,465* | *288,201* | *253,876* | *283,457* | *250,136* | *293,246* |
| *Clairton Decreases* | *2-Yr Average* | | | *257,359* | *249,769* | *262,333* | *282,833* | *271,038* | *268,666* | *266,796* | *271,691* |

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Entire tab revised**

**Table C-18. Past Actual Emissions Summary - Lead**

| Plant | Unit Description | Emission Unit ID | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | tpy | tpy | tpy | tpy | tpy | tpy | tpy | tpy | tpy |
| Clairton | Boiler #1 - COG | 031 | | | | | | | | | |
| Clairton | Boiler #1 - NG | 032 | 1.5E-04 | 1.6E-04 | 1.2E-04 | 3.9E-05 | 5.2E-05 | 1.4E-04 | 2.9E-04 | 1.0E-04 | 1.27E-04 |
| Clairton | Boiler #2 - COG | 033 | | | | | | | | | |
| Clairton | Boiler #2 - NG | 034 | 8.0E-05 | 6.5E-05 | 5.5E-05 | 2.4E-05 | 3.2E-05 | 9.3E-05 | 1.7E-04 | 6.9E-05 | 8.28E-05 |
| Clairton | Boiler R-1 - COG | 035 | | | | | | | | | |
| Clairton | Boiler R-1 - NG | 035 | 5.0E-08 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.00E+00 |
| Clairton | Boiler R-2 - COG | 036 | | | | | | | | | |
| Clairton | Boiler R-2 - NG | 036 | 6.5E-07 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.00E+00 |
| Clairton | Boiler T-1 - COG | 037 | | | | | | | | | |
| Clairton | Boiler T-1 - NG | 037 | 1.4E-06 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.00E+00 |
| Clairton | Boiler T-2 - COG | 038 | | | | | | | | | |
| Clairton | Boiler T-2 - NG | 038 | 1.4E-06 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 0.00E+00 |
| | Years | | | 2010 / 2011 | 2011 / 2012 | 2012 / 2013 | 2013 / 2014 | 2014 / 2015 | 2015 / 2016 | 2016 / 2017 | 2017/ 2018 |
| *Clairton Decreases* | *Annual* | | *2.3E-04* | *2.2E-04* | *1.8E-04* | *6.3E-05* | *8.3E-05* | *2.4E-04* | *4.56E-04* | *1.7E-04* | *2.09E-04* |
| *Clairton Decreases* | *2-Yr Average* | | | *2.3E-04* | *2.0E-04* | *1.2E-04* | *7.3E-05* | *1.6E-04* | ***3.46E-04*** | *3.1E-04* | *1.90E-04* |

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-19. Past Actual Emissions Summary - NH3**

| Plant | Unit Description | Emission Unit ID | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|
| | | | tpy | tpy | tpy | tpy | tpy |
| Clairton | Boiler #1 - COG | 031 | 0.43 | 0.31 | 0.29 | 0.36 | 0.36 |
| Clairton | Boiler #1 - NG | 032 | 0.33 | 0.93 | 1.85 | 0.65 | 0.81 |
| Clairton | Boiler #2 - COG | 033 | 0.26 | 0.24 | 0.18 | 0.21 | 0.26 |
| Clairton | Boiler #2 - NG | 034 | 0.20 | 0.59 | 1.07 | 0.44 | 0.53 |
| Clairton | Boiler R-1 - COG | 035 | 0.01 | 0.02 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler R-1 - NG | 035 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler R-2 - COG | 036 | 0.02 | 0.02 | 0.01 | 0.02 | 0.03 |
| Clairton | Boiler R-2 - NG | 036 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-1 - COG | 037 | 0.03 | 0.03 | 0.01 | 0.02 | 0.03 |
| Clairton | Boiler T-1 - NG | 037 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Clairton | Boiler T-2 - COG | 038 | 0.03 | 0.03 | 0.01 | 0.02 | 0.03 |
| Clairton | Boiler T-2 - NG | 038 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Plant | Years | | | 2014 / 2015 | 2015 / 2016 | 2016 / 2017 | 2017 / 2018 |
| *Clairton Decreases* | *Annual* | | *1.30* | *2.17* | *3.42* | *1.70* | *2.05* |
| *Clairton Decreases* | *2-Yr Average* | | | ***1.74*** | *2.80* | *2.56* | *1.88* |

**Company Name:** **U. S. Steel**
**Facility Name:** **Clairton**
**Project Description:** **Cogeneration Project**

**Table C-20. Aggregation of De Minimis Increases for NNSR Pollutants**

| Description | C Battery | Crude Tar Processing | Truck Light Oil Loading |
|---|---|---|---|
| Permit | IP11 | IP15 | IP16 |
| Site | Clairton | Clairton | Clairton |
| Pollutant | tpy | tpy | tpy |
| VOC | 38.2 | 6.17 | 0.6 |
| NOx | -429.5 | 0.0 | 0.0 |
| SO2 | 33.3 | 0.0 | 0.0 |

1. This data, which are potential emissions from these projects are used in the minor NNSR netting calculation.

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-21. Summary of Projected Actual Emissions from Existing Boilers**

**Existing Unit Information:**

| Unit: | Boiler R-2 | Boiler T-1 | Boiler T-2 | |
|---|---|---|---|---|
| Fuel Type: | COG | COG & Natural Gas | COG & Natural Gas | |
| Nominal COG Higher Heating Value (HHV) (Btu/scf): | 500 | 500 | 500 | |
| Nominal Natural Gas Higher Heating Value (HHV) (Btu/scf): | 1,034 | 1,034 | 1,034 | |
| Heat Input per Unit (MMBtu/hr): | 229.0 | 156.0 | 156.00 | |
| Max. Annual Hours of Operation at Full Load (hr/yr): | 1,200 | 2,200 | 2,200 | ***Combined Boiler T-1 & T-2*** |
| Potential Fuel Consumption (MMBtu/yr): | 274,800 | 343,200 | 343,200 | ***686,400*** |
| Projected COG Consumption (% of fuel): | 100% | 70% | 70% | |
| Projected Natural Gas Consumption (% of fuel): | 0% | 30% | 30% | |
| Max. COG Consumption (MMBtu/yr): | 274,800 | 240,240 | 240,240 | ***480,480*** |
| Max. NG Consumption (MMBtu/yr): | 0 | 102,960 | 102,960 | ***205,920*** |
| Max. Approximate COG Consumption (MMscf/yr): | 550 | 480 | 480 | |
| Max. Approximate NG Consumption (MMscf/yr): | 0 | 100 | 100 | |

**Criteria Pollutant Projected Actual Emission Rates (COG Combustion)**

| Pollutant | Boiler R-2 | | Boiler T-1 | | Boiler T-2 | |
|---|---|---|---|---|---|---|
| | Emission Factor | Emissions | Emission Factor | Emissions | Emission Factor | Emissions |
| | (lb/MMcf)[1] | (ton/yr) | (lb/MMcf)[1] | (ton/yr) | (lb/MMcf)[1] | (ton/yr) |
| $NO_X$ | 103.37 | 28.41 | 84.01 | 20.18 | 84.01 | 20.18 |
| CO | 98.51 | 27.07 | 18.67 | 4.48 | 18.67 | 4.48 |
| VOC | 0.07 | 0.02 | 0.84 | 0.20 | 0.84 | 0.20 |
| $SO_2$ | 73.53 | 20.21 | 83.26 | 20.00 | 83.26 | 20.00 |
| Ammonia | 0.12 | 0.03 | 0.12 | 0.03 | 0.12 | 0.03 |
| Lead | 4.26E-04 | 1.17E-04 | 4.26E-04 | 1.02E-04 | 4.26E-04 | 1.02E-04 |
| $PM_{filt.}$ | 4.02 | 1.10 | 3.74 | 0.90 | 3.74 | 0.90 |
| $PM_{10}$ (Total) | 8.28 | 2.27 | 8.21 | 1.97 | 8.21 | 1.97 |
| $PM_{2.5}$ (Total) | 7.17 | 1.97 | 8.56 | 2.06 | 8.56 | 2.06 |

**GHG Pollutant Projected Actual Emission Rates (COG Combustion)**

| Pollutant | Boiler R-2 | | Boiler T-1 | | Boiler T-2 | |
|---|---|---|---|---|---|---|
| | Emission Factor | Emissions | Emission Factor | Emissions | Emission Factor | Emissions |
| | (lb/MMBtu)[2] | (ton/yr) | (lb/MMBtu)[2] | (ton/yr) | (lb/MMBtu)[2] | (ton/yr) |
| $CO_2$ | 103.29 | 14,191 | 103.29 | 12,407 | 103.29 | 12,407 |
| $CH_4$ | 1.1E-03 | 0.15 | 1.1E-03 | 0.13 | 1.1E-03 | 0.13 |
| $N_2O$ | 2.2E-04 | 0.03 | 2.2E-04 | 0.03 | 2.2E-04 | 0.03 |
| $CO_2e$[3] | | 14,204 | | 12,418 | | 12,418 |

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-21. Summary of Projected Actual Emissions from Existing Boilers**

**Criteria Pollutant Projected Actual Emission Rates (Natural Gas Combustion)**

| Pollutant | Boiler R-2 | | Boiler T-1 | | Boiler T-2 | |
|---|---|---|---|---|---|---|
| | Emission Factor (lb/MMcf)[4] | Emissions (ton/yr) | Emission Factor (lb/MMcf)[4] | Emissions (ton/yr) | Emission Factor (lb/MMcf)[4] | Emissions (ton/yr) |
| $NO_X$ | 280.00 | 0.00 | 280.00 | 13.95 | 280.00 | 13.95 |
| CO | 84.00 | 0.00 | 84.00 | 4.18 | 84.00 | 4.18 |
| VOC | 0.50 | 0.00 | 0.50 | 0.02 | 0.50 | 0.02 |
| $SO_2$ | 0.60 | 0.00 | 0.60 | 0.03 | 0.60 | 0.03 |
| Ammonia | 3.7 | 0.00 | 3.7 | 0.18 | 3.7 | 0.18 |
| Lead | 5.75E-04 | 0.00 | 5.75E-04 | 0.00 | 5.75E-04 | 0.00 |
| $PM_{Filt.}$ | 1.90 | 0.00 | 1.90 | 0.09 | 1.90 | 0.09 |
| $PM_{10}$ (Total) | 7.60 | 0.00 | 7.60 | 0.38 | 7.60 | 0.38 |
| $PM_{2.5}$ (Total) | 7.60 | 0.00 | 7.60 | 0.38 | 7.60 | 0.38 |

**GHG Pollutant Projected Actual Emission Rates (Natural Gas Combustion)**

| Pollutant | Boiler R-2 | | Boiler T-1 | | Boiler T-2 | |
|---|---|---|---|---|---|---|
| | Emission Factor (lb/MMBtu)[2] | Emissions (ton/yr) | Emission Factor (lb/MMBtu)[2] | Emissions (ton/yr) | Emission Factor (lb/MMBtu)[2] | Emissions (ton/yr) |
| $CO_2$ | 116.98 | 0 | 116.98 | 6,022 | 116.98 | 6,022 |
| $CH_4$ | 2.2E-03 | 0.00 | 2.2E-03 | 0.11 | 2.2E-03 | 1.1E-01 |
| $N_2O$ | 2.2E-04 | 0.00 | 2.2E-04 | 0.01 | 2.2E-04 | 1.1E-02 |
| $CO_2e$[3] | | 0 | | 6,028 | | 6,028 |

[1] Emission factors for $NO_x$, CO, VOC, $SO_2$, ammonia and PM species are based on statistical analysis of historical stack test data. Lead is based on AP-42 Section 12.2 (see air toxics calculations for more detail).

[2] GHG Emission factors from Tables C-1 and C-2, 40 CFR 98, Subpart C.

[3] GWP from Table A-1, 40 CFR 98, Subpart A.

Global Warming Potential (GWP) 25
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[4] Emission factors are based on AP-42 Section 1.4 except for ammonia which is from FIRE, Version 6.25.

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-22a. Cogen Project Air Toxics Emissions Summary - COG Operation**

| Hazardous Air Pollutant Type | *Project Future Potential Emissions* | | | | | | *Existing Potential* | Change in Air Toxics Potential to Emit (tpy) | ACHD De Minimis Thresholds (tpy) | Above De Minimis (tpy) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| | Emissions from Cogen Units (tpy) | Emissions from Package Boiler (tpy) | Emissions from Diesel Fire Pump (tpy) | Emissions from Storage Tanks (tpy) | Emissions from NG Heaters (tpy) | Total from the Project (tpy) | Sources to be Shutdown (tpy) | | | |
| HAP Metals | 2.4E-02 | 5.6E-04 | 0.00 | 0.00 | 1.5E-04 | 2.5E-02 | 9.4E-02 | -7.0E-02 | 1.00E-02 | No |
| Other Toxics | 63.7 | 1.0E-01 | 1.9E-04 | 3.9E-05 | 2.8E-02 | 63.8 | 111.8 | -48.0 | 0.25 | No |
| Mercury | 0.00 | 1.4E-05 | 0.00 | 0.00 | 3.8E-06 | 1.8E-05 | 2.4E-03 | -2.4E-03 | 1.00E-02 | No |
| POM | 3.6E-02 | 3.5E-05 | 5.0E-06 | 0.0E+00 | 9.3E-06 | 3.6E-02 | 3.0E-02 | 6.5E-03 | 1.00E-02 | No |
| Dioxin | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.00E-05 | No |
| Furans | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.00E-05 | No |
| PCBs | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.00E-02 | No |

1. No air toxics emissions are expected from roadway fugitives or material handling operations.

**Table C-22b. Cogen Project Air Toxics Emissions Summary - NG Operation**

| Hazardous Air Pollutant Type | *Project Future Potential Emissions* | | | | | | *Existing Potential* | Change in Air Toxics Potential to Emit (tpy) | ACHD De Minimis Thresholds (tpy) | Above De Minimis (tpy) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| | Emissions from Cogen Units (tpy) | Emissions from Package Boiler (tpy) | Emissions from Diesel Fire Pump (tpy) | Emissions from Storage Tanks (tpy) | Emissions from NG Heaters (tpy) | Total from the Project (tpy) | Sources to be Shutdown (tpy) | | | |
| HAP Metals | 6.1E-03 | 5.6E-04 | 0.00 | 0.00 | 1.5E-04 | 6.8E-03 | 9.4E-02 | -8.7E-02 | 1.00E-02 | No |
| Other Toxics | 46.3 | 1.0E-01 | 1.9E-04 | 3.9E-05 | 2.8E-02 | 46.5 | 111.8 | -65.4 | 0.25 | No |
| Mercury | 0.0E+00 | 1.4E-05 | 0.00 | 0.00 | 3.8E-06 | 1.8E-05 | 2.4E-03 | -2.4E-03 | 1.00E-02 | No |
| POM | 3.7E-02 | 3.5E-05 | 5.0E-06 | 0.0E+00 | 9.3E-06 | 3.7E-02 | 3.0E-02 | 6.8E-03 | 1.00E-02 | No |
| Dioxin | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.00E-05 | No |
| Furans | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.00E-05 | No |
| PCBs | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.00E-02 | No |

1. No air toxics emissions are expected from roadway fugitives or material handling operations.

**Table C-22c. Cogen Project Air Toxics Emissions Summary - Blended Operation**

| Hazardous Air Pollutant Type | *Project Future Potential Emissions* | | | | | | *Existing Potential* | Change in Air Toxics Potential to Emit (tpy) | ACHD De Minimis Thresholds (tpy) | Above De Minimis (tpy) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| | Emissions from Cogen Units (tpy) | Emissions from Package Boiler (tpy) | Emissions from Diesel Fire Pump (tpy) | Emissions from Storage Tanks (tpy) | Emissions from NG Heaters (tpy) | Total from the Project (tpy) | Sources to be Shutdown (tpy) | | | |
| HAP Metals | 1.8E-02 | 5.6E-04 | 0.00 | 0.00 | 1.5E-04 | 1.9E-02 | 9.4E-02 | -7.5E-02 | 1.00E-02 | No |
| Other Toxics | 59.94 | 1.0E-01 | 1.9E-04 | 3.9E-05 | 2.8E-02 | 60.1 | 111.8 | -51.8 | 0.25 | No |
| Mercury | 0.0E+00 | 1.4E-05 | 0.00 | 0.00 | 3.8E-06 | 1.8E-05 | 2.4E-03 | -2.4E-03 | 1.00E-02 | No |
| POM | 3.8E-02 | 3.5E-05 | 5.0E-06 | 0.0E+00 | 9.3E-06 | 3.8E-02 | 3.0E-02 | 7.9E-03 | 1.00E-02 | No |
| Dioxin | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.00E-05 | No |
| Furans | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.00E-05 | No |
| PCBs | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.00E-02 | No |

1. No air toxics emissions are expected from roadway fugitives or material handling operations.

Company Name: **U. S. Steel**
Facility Name: **Clairton**
Project Description: **Cogeneration Project**

Table C-23a. Summary of Future Air Toxics/HAP Emissions (Turbines + Duct Burners) for Coke Oven Gas Scenarios

| Pollutant | Emission Factor | Unit | Emission Factor Source | Air Toxic? (Category) | Equivalent Emission Factor (lb/MMscf) | Potential to Emit (Annual Average) (lb/hr) | Adjusted PTE for Cogen Design VOC Value (tpy) |
|---|---|---|---|---|---|---|---|
| Hydrogen Chloride | 5.24 | lb/MMScf | 2017 AEI Factor (Underfiring Testing Used as Surrogate for General Combustion) | Other Toxics | 5.244 | 17.9 | 19.1 |
| Benzene | 0.023 | lb/MMscf | 2017 AEI Factor for Boilers | Other Toxics | 0.023 | 0.1 | 0.3 |
| Chlorine | 0.07475 | lb/MMscf | 2017 AEI Factor (Underfiring Testing Used as Surrogate for General Combustion) | Other Toxics | 0.07475 | 0.3 | 1.1 |
| Carbon disulfide | 0.03795 | lb/MMscf | 2017 AEI Factor for Underfiring | Other Toxics | 0.03795 | 0.1 | 0.6 |
| Toluene | 0.00759 | lb/ton coal charged | AP-42, Table 12.2-16[1] | Other Toxics | 0.6325 | 0.5 | 2.3 |
| Phenol | 5.9E-06 | lb/ton coal charged | AP-42, Table 12.2-16[1] | Other Toxics | 4.9E-04 | 4.1E-04 | 1.7E-03 |
| Bis(2-ethylhexyl)phthalate | 7.8E-06 | lb/ton coal charged | AP-42, Table 12.2-16[1] | POM | 6.5E-04 | 5.4E-04 | 2.3E-03 |
| Indeno[1,2,3-cd]pyrene | 4.7E-08 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 3.9E-06 | 3.3E-06 | 1.4E-05 |
| Benzo[b]fluoranthene | 2.2E-07 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 1.9E-05 | 1.6E-05 | 6.6E-05 |
| Benzo[k]fluoranthene | 7.7E-08 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 6.4E-06 | 5.4E-06 | 2.3E-05 |
| Chrysene | 3.8E-07 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 3.1E-05 | 2.6E-05 | 1.1E-04 |
| Benzo[a]pyrene | 1.9E-05 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 1.6E-03 | 1.3E-03 | 5.6E-03 |
| Dibenz[a,h]anthracene | 3.4E-08 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 2.8E-06 | 2.4E-06 | 1.0E-05 |
| Benz[a]anthracene | 1.1E-07 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 8.9E-06 | 7.4E-06 | 3.2E-05 |
| Acetone | 0.068 | lb/ton coal charged | AP-42, Table 12.2-16[1] | Other Toxics | 5.65 | 4.7 | 20.1 |
| Lead and Lead Compounds | 5.1E-06 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 4.3E-04 | 1.5E-03 | 6.2E-03 |
| Manganese & Manganese Compounds | 2.9E-06 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 2.4E-04 | 8.3E-04 | 3.5E-03 |
| Nickel and Nickel Compounds | 2.2E-06 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 1.8E-04 | 6.1E-04 | 2.6E-03 |
| Arsenic, Inorganic | 3.8E-06 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 3.1E-04 | 1.1E-03 | 4.6E-03 |
| Barium | 5.4E-06 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 4.5E-04 | 1.5E-03 | 6.6E-03 |
| Beryllium and compounds | 4.5E-08 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 3.8E-06 | 1.3E-05 | 5.5E-05 |
| Cadmium | 2.3E-07 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 1.9E-05 | 6.5E-05 | 2.8E-04 |
| Chloromethane | 7.36E-03 | lb/ton coal charged | AP-42, Table 12.2-16[1] | Other Toxics | 0.61 | 5.1E-01 | 2.2 |
| Naphthalene | 9.5E-05 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 7.9E-03 | 6.6E-03 | 2.8E-02 |

1. Emission factors from AP-42 converted to lb/MMscf assuming 12,000 scf coke oven gas produced per ton of coal charged, per AP-42, Table 12.2-4, footnote f (05/08). Additional 15% added to all factors from AP-42.

| | |
|---|---|
| 12,000 | scf COG / ton coal charged |
| 1,000,000 | scf/MMscf |
| 1,711 | MMBtu/hr (max heat input case - all units) |
| 3.42 | MMscf/hr of COG consumed |
| 27.9 | VOC Emissions (See Criteria Emissions Calculations, tpy) |
| 7.8 | VOC Emission Factor - AP-42, Table 12.2-16 (lb/MMscf) |
| 75% | % Reduction - HCl from Control |

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-23b. Summary of Future Air Toxics/HAP Emissions (Duct Burners) for Natural Gas Scenarios (Using COG)**

| Pollutant | Emission Factor (lb/MMscf) | Emission Factor Source | Air Toxic? (Category) | Air Toxic? (Category) | Equivalent Emission Factor (lb/MMscf) | Potential to Emit (Annual Average) - (lb/hr) | Maximum Potential to Emit (tpy) |
|---|---|---|---|---|---|---|---|
| Hydrogen Chloride | 5.24 | lb/MMScf | 2017 AEI Factor (Underfiring Testing Used as Surrogate for General Combustion) | Other Toxics | 5.244 | 4.59 | 4.89 |
| Benzene | 0.023 | lb/MMscf | 2017 AEI Factor for Boilers | Other Toxics | 0.023 | 2.0E-02 | 8.6E-02 |
| Chlorine | 0.07475 | lb/MMscf | 2017 AEI Factor (Underfiring Testing Used as Surrogate for General Combustion) | Other Toxics | 0.07475 | 6.5E-02 | 2.8E-01 |
| Carbon disulfide | 0.03795 | lb/MMscf | 2017 AEI Factor for Underfiring | Other Toxics | 0.03795 | 3.3E-02 | 1.4E-01 |
| Toluene | 0.00759 | lb/ton coal charged | AP-42, Table 12.2-16[1] | Other Toxics | 0.6325 | 3.5E-01 | 1.5 |
| Phenol | 5.9E-06 | lb/ton coal charged | AP-42, Table 12.2-16[1] | Other Toxics | 4.9E-04 | 2.7E-04 | 1.2E-03 |
| Bis(2-ethylhexyl)phthalate | 7.8E-06 | lb/ton coal charged | AP-42, Table 12.2-16[1] | POM | 6.5E-04 | 3.6E-04 | 1.5E-03 |
| Indeno[1,2,3-cd]pyrene | 4.7E-08 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 3.9E-06 | 2.2E-06 | 9.3E-06 |
| Benzo[b]fluoranthene | 2.2E-07 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 1.9E-05 | 1.0E-05 | 4.4E-05 |
| Benzo[k]fluoranthene | 7.7E-08 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 6.4E-06 | 3.6E-06 | 1.5E-05 |
| Chrysene | 3.8E-07 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 3.1E-05 | 1.7E-05 | 7.4E-05 |
| Benzo[a]pyrene | 1.9E-05 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 1.6E-03 | 8.7E-04 | 3.7E-03 |
| Dibenz[a,h]anthracene | 3.4E-08 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 2.8E-06 | 1.6E-06 | 6.7E-06 |
| Benz[a]anthracene | 1.1E-07 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 8.9E-06 | 4.9E-06 | 2.1E-05 |
| Acetone | 0.068 | lb/ton coal charged | AP-42, Table 12.2-16[1] | Other Toxics | 5.65 | 3.1E+00 | 13.4 |
| Lead and Lead Compounds | 5.1E-06 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 4.3E-04 | 3.7E-04 | 1.6E-03 |
| Manganese & Manganese Compounds | 2.9E-06 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 2.4E-04 | 2.1E-04 | 9.0E-04 |
| Nickel and Nickel Compounds | 2.2E-06 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 1.8E-04 | 1.6E-04 | 6.7E-04 |
| Arsenic, Inorganic | 3.8E-06 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 3.1E-04 | 2.7E-04 | 1.2E-03 |
| Barium | 5.4E-06 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 4.5E-04 | 4.0E-04 | 1.7E-03 |
| Beryllium and compounds | 4.5E-08 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 3.8E-06 | 3.3E-06 | 1.4E-05 |
| Cadmium | 2.3E-07 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 1.9E-05 | 1.7E-05 | 7.1E-05 |
| Chloromethane | 7.36E-03 | lb/ton coal charged | AP-42, Table 12.2-16[1] | Other Toxics | 0.61 | 3.4E-01 | 1.5E+00 |
| Naphthalene | 9.5E-05 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 7.9E-03 | 4.4E-03 | 1.9E-02 |

1. Emission factors from AP-42 have an additional 15% added to them.

| | |
|---|---|
| 12,000 | scf COG / ton coal charged |
| 1,000,000 | scf/MMscf |
| 7.8 | VOC Emission Factor - AP-42, Table 12.2-16 (lb/MMscf) |
| 27.8 | VOC Emissions (See Criteria Emissions Calculations, tpy) |
| 67% | Approx. % of VOC from Duct Firing |
| 18.5 | Approx. VOC Emissions (tpy) from Duct Firing |
| 438 | MMBtu/hr from duct firing (max heat input case - all units) |
| 0.9 | MMscf/hr of COG consumed |
| 75% | % Reduction - HCl from Control |

**Table C-23c. Summary of Future Air Toxics/HAP Emissions (Turbines) for Natural Gas Scenarios**

| Pollutant | Emission Factor (lb/MMBtu) | Emission Factor Source | Air Toxic? (Category) | Potential to Emit (Annual Average) - (lb/hr) | Maximum Potential to Emit (tpy) |
|---|---|---|---|---|---|
| 1,3-Butadiene | 4.95E-07 | AP-42 Table 3.1-3, April 2000[1] | Other Toxics | 6.02E-04 | 2.6E-03 |
| Acetaldehyde | 4.60E-05 | AP-42 Table 3.1-3, April 2000[1] | Other Toxics | 5.60E-02 | 0.2 |
| Acrolein | 7.36E-06 | AP-42 Table 3.1-3, April 2000[1] | Other Toxics | 8.97E-03 | 3.8E-02 |
| Benzene | 1.38E-05 | AP-42 Table 3.1-3, April 2000[1] | Other Toxics | 1.68E-02 | 7.2E-02 |
| Ethylbenzene | 3.68E-05 | AP-42 Table 3.1-3, April 2000[1] | Other Toxics | 4.48E-02 | 1.9E-01 |
| Formaldehyde | 8.17E-04 | AP-42 Table 3.1-3, April 2000[1] | Other Toxics | 0.99 | 4.2 |
| Naphthalene | 8.97E-07 | AP-42 Table 3.1-3, April 2000[1] | POM | 1.09E-03 | 4.7E-03 |
| PAH | 1.52E-06 | AP-42 Table 3.1-3, April 2000[1] | POM | 1.85E-03 | 7.9E-03 |
| Propylene oxide | 3.34E-05 | AP-42 Table 3.1-3, April 2000[1] | Other Toxics | 4.06E-02 | 0.2 |
| Toluene | 1.50E-04 | AP-42 Table 3.1-3, April 2000[1] | Other Toxics | 1.82E-01 | 0.8 |
| Xylenes | 7.36E-05 | AP-42 Table 3.1-3, April 2000[1] | Other Toxics | 8.97E-02 | 0.4 |

1. Emission factors from AP-42 have an additional 15% added to them. POM factors reflect estimated, conservatively VOC control percentage of 40%.

| | |
|---|---|
| 1,218 | MMBtu/hr from gas turbines (max heat input case - all units) |
| 1.2 | MMscf/hr of NG consumed |

Company Name: U. S. Steel
Facility Name: Clairton
Project Description: Cogeneration Project

Table C-23d. Summary of Future Air Toxics/HAP Emissions for Blended Fuel Operation for Turbine

| Pollutant[1] | COG Emission Factor (lb/MMBtu) | NG Emission Factor[2] (lb/MMBtu) | Blended Fuel Emission Factor (lb/MMBtu) | Air Toxic? (Category) | Potential to Emit (Annual Average) - (lb/hr) | Adjusted PTE for Cogen Design VOC Value (tpy) |
|---|---|---|---|---|---|---|
| Hydrogen Chloride | 0.010 | 0 | 7.34E-03 | Other Toxics | 9.3 | 9.9 |
| Benzene | 4.60E-05 | 1.38E-05 | 3.63E-05 | Other Toxics | 4.60E-02 | 0.2 |
| Chlorine | 1.50E-04 | 0 | 1.05E-04 | Other Toxics | 0.1 | 0.6 |
| Carbon disulfide | 7.59E-05 | 0 | 5.31E-05 | Other Toxics | 0.1 | 0.3 |
| Toluene | 1.27E-03 | 1.50E-04 | 9.30E-04 | Other Toxics | 0.2 | 0.7 |
| Phenol | 9.79E-07 | 0 | 6.86E-07 | Other Toxics | 1.3E-04 | 5.3E-04 |
| Bis(2-ethylhexyl)phthalate | 1.30E-06 | 0 | 9.11E-07 | POM | 1.7E-04 | 7.1E-04 |
| Indeno[1,2,3-cd]pyrene | 7.88E-09 | 0 | 5.51E-09 | POM | 1.0E-06 | 4.3E-06 |
| Benzo[b]fluoranthene | 3.72E-08 | 0 | 2.60E-08 | POM | 4.7E-06 | 2.0E-05 |
| Benzo[k]fluoranthene | 1.28E-08 | 0 | 8.99E-09 | POM | 1.6E-06 | 7.0E-06 |
| Chrysene | 6.29E-08 | 0 | 4.40E-08 | POM | 8.0E-06 | 3.4E-05 |
| Benzo[a]pyrene | 3.12E-06 | 0 | 2.19E-06 | POM | 4.0E-04 | 1.7E-03 |
| Dibenz[a,h]anthracene | 5.67E-09 | 0 | 3.97E-09 | POM | 7.2E-07 | 3.1E-06 |
| Benz[a]anthracene | 1.78E-08 | 0 | 1.25E-08 | POM | 2.3E-06 | 9.7E-06 |
| Acetone | 1.13E-02 | 0 | 7.92E-03 | Other Toxics | 1.4 | 6.2 |
| Lead and Lead Compounds | 8.51E-07 | 0 | 5.96E-07 | HAP Metals | 7.5E-04 | 3.2E-03 |
| Manganese & Manganese Compounds | 4.83E-07 | 0 | 3.38E-07 | HAP Metals | 4.3E-04 | 1.8E-03 |
| Nickel and Nickel Compounds | 3.58E-07 | 0 | 2.51E-07 | HAP Metals | 3.2E-04 | 1.4E-03 |
| Arsenic, Inorganic | 6.27E-07 | 0 | 4.39E-07 | HAP Metals | 5.6E-04 | 2.4E-03 |
| Barium | 9.03E-07 | 0 | 6.32E-07 | HAP Metals | 8.0E-04 | 3.4E-03 |
| Beryllium and compounds | 7.55E-09 | 0 | 5.29E-09 | HAP Metals | 6.7E-06 | 2.8E-05 |
| Cadmium | 3.81E-08 | 0 | 2.67E-08 | HAP Metals | 3.4E-05 | 1.4E-04 |
| Chloromethane | 1.23E-03 | 0 | 8.59E-04 | Other Toxics | 0.2 | 0.7 |
| Naphthalene | 1.59E-05 | 8.97E-07 | 1.14E-05 | POM | 2.1E-03 | 8.9E-03 |
| Formaldehyde | 0 | 8.17E-04 | 2.45E-04 | Other Toxics | 0.3 | 1.3 |
| 1,3-Butadiene | 0 | 4.95E-07 | 1.48E-07 | Other Toxics | 1.9E-04 | 8.0E-04 |
| Acetaldehyde | 0 | 4.60E-05 | 1.38E-05 | Other Toxics | 1.7E-02 | 0.1 |
| Acrolein | 0 | 7.36E-06 | 2.21E-06 | Other Toxics | 2.8E-03 | 1.2E-02 |
| Ethylbenzene | 0 | 3.68E-05 | 1.10E-05 | Other Toxics | 1.4E-02 | 6.0E-02 |
| PAH | 0 | 1.52E-06 | 4.55E-07 | POM | 5.8E-04 | 2.5E-03 |
| Propylene oxide | 0 | 3.34E-05 | 1.00E-05 | Other Toxics | 1.3E-02 | 5.4E-02 |
| Xylenes | 0 | 7.36E-05 | 2.21E-05 | Other Toxics | 2.8E-02 | 0.1 |

1. Emission factors are from Tables 23a-d. Units converted using constants below.
2. Natural gas emission factors include both duct burners and turbine emission factors.

| | |
|---|---|
| 500 | COG Heat Content (Btu/scf) |
| 1,034 | NG Heat Content (Btu/scf) |
| 660 | Blended Fuel Heat Content (Btu/scf) |
| 70% | Percent COG in Blended Fuel (Turbine only) |
| 30% | Percent NG in Blended Fuel (Turbine only) |
| 1,699 | Max Heat Input for Blended Fuel Cases (MMBtu/hr) |
| 1266 | Tubine Max Heat Input for Blended Fuel Cases (MMBtu/hr) |

| | |
|---|---|
| 27.7 | VOC Emissions - Case 45 (tpy) |
| 67% | Approx. % of VOC from Duct Firing |
| 18.4 | Approx. VOC Emissions (tpy) from Duct Firing |
| 7.8 | VOC Emission Factor - AP-42, Table 12.2-16 (lb/MMscf) |
| 75% | % Reduction - HCl from Control |

Company Name: U. S. Steel
Facility Name: Clairton
Project Description: Cogeneration Project

Table C-23e. Summary of Future Air Toxics/HAP Emissions (Duct Burners) for Blend Scenarios (Using COG)

| Pollutant | Emission Factor (lb/MMscf) | Emission Factor Source | Air Toxic? (Category) | Air Toxic? (Category) | Equivalent Emission Factor (lb/MMscf) | Potential to Emit (Annual Average) - (lb/hr) | Maximum Potential to Emit (tpy) |
|---|---|---|---|---|---|---|---|
| Hydrogen Chloride | 5.24 | lb/MMScf | 2017 AEI Factor (Underfiring Testing Used as Surrogate for General Combustion) | Other Toxics | 5.244 | 4.5E+00 | 4.8E+00 |
| Benzene | 0.023 | lb/MMscf | 2017 AEI Factor for Boilers | Other Toxics | 0.023 | 2.0E-02 | 8.5E-02 |
| Chlorine | 0.07475 | lb/MMscf | 2017 AEI Factor (Underfiring Testing Used as Surrogate for General Combustion) | Other Toxics | 0.07475 | 6.5E-02 | 2.8E-01 |
| Carbon disulfide | 0.03795 | lb/MMscf | 2017 AEI Factor for Underfiring | Other Toxics | 0.03795 | 3.3E-02 | 1.4E-01 |
| Toluene | 0.00759 | lb/ton coal charged | AP-42, Table 12.2-16[1] | Other Toxics | 0.6325 | 3.5E-01 | 1.5 |
| Phenol | 5.9E-06 | lb/ton coal charged | AP-42, Table 12.2-16[1] | Other Toxics | 4.9E-04 | 2.7E-04 | 1.2E-03 |
| Bis(2-ethylhexyl)phthalate | 7.8E-06 | lb/ton coal charged | AP-42, Table 12.2-16[1] | POM | 6.5E-04 | 3.6E-04 | 1.5E-03 |
| Indeno[1,2,3-cd]pyrene | 4.7E-08 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 3.9E-06 | 2.2E-06 | 9.3E-06 |
| Benzo[b]fluoranthene | 2.2E-07 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 1.9E-05 | 1.0E-05 | 4.4E-05 |
| Benzo[k]fluoranthene | 7.7E-08 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 6.4E-06 | 3.5E-06 | 1.5E-05 |
| Chrysene | 3.8E-07 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 3.1E-05 | 1.7E-05 | 7.4E-05 |
| Benzo[a]pyrene | 1.9E-05 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 1.6E-03 | 8.6E-04 | 3.7E-03 |
| Dibenz[a,h]anthracene | 3.4E-08 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 2.8E-06 | 1.6E-06 | 6.7E-06 |
| Benz[a]anthracene | 1.1E-07 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 8.9E-06 | 4.9E-06 | 2.1E-05 |
| Acetone | 0.068 | lb/ton coal charged | AP-42, Table 12.2-16[1] | Other Toxics | 5.65 | 3.1E+00 | 13.3 |
| Lead and Lead Compounds | 5.1E-06 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 4.3E-04 | 3.7E-04 | 1.6E-03 |
| Manganese & Manganese Compounds | 2.9E-06 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 2.4E-04 | 2.1E-04 | 8.9E-04 |
| Nickel and Nickel Compounds | 2.2E-06 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 1.8E-04 | 1.6E-04 | 6.6E-04 |
| Arsenic, Inorganic | 3.8E-06 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 3.1E-04 | 2.7E-04 | 1.2E-03 |
| Barium | 5.4E-06 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 4.5E-04 | 3.9E-04 | 1.7E-03 |
| Beryllium and compounds | 4.5E-08 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 3.8E-06 | 3.3E-06 | 1.4E-05 |
| Cadmium | 2.3E-07 | lb/ton coal charged | AP-42, Table 12.2-15[1] | HAP Metals | 1.9E-05 | 1.7E-05 | 7.0E-05 |
| Chloromethane | 7.36E-03 | lb/ton coal charged | AP-42, Table 12.2-16[1] | Other Toxics | 0.61 | 3.4E-01 | 1.4E+00 |
| Naphthalene | 9.5E-05 | lb/ton coal charged | AP-42, Table 12.2-17[1] | POM | 7.9E-03 | 4.4E-03 | 1.9E-02 |

1. Emission factors from AP-42 have an additional 15% added to them.

| | |
|---|---|
| 12,000 | scf COG / ton coal charged |
| 1,000,000 | scf/MMscf |
| 7.8 | VOC Emission Factor - AP-42, Table 12.2-16 (lb/MMscf) |
| 27.7 | VOC Emissions (See Criteria Emissions Calculations, tpy) |
| 67% | Approx. % of VOC from Duct Firing |
| 18.4 | Approx. VOC Emissions (tpy) from Duct Firing |
| 433 | Duct Burners Max Heat Input for Blended Fuel Cases (MMBtu/hr) |
| 0.9 | MMscf/hr of COG consumed |
| 75% | % Reduction - HCl from Control |

**Company Name:** **U. S. Steel**
**Facility Name:** **Clairton**
**Project Description:** **Cogeneration Project**

**Table C-24. Summary of Existing Air Toxics Potential Emissions Summary - Clairton (tpy)**

| Classification | HAP Metals | Other Toxics | Mercury | POM | Dioxins | Furans | PCBs | Total |
|---|---|---|---|---|---|---|---|---|
| Boiler 1 (COG) | 1.1E-02 | 4.5E+01 | 0.0E+00 | 1.2E-02 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 4.5E+01 |
| Boiler 1 (NG) | 3.8E-02 | 1.9E+01 | 9.6E-04 | 2.4E-03 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 1.9E+01 |
| **Boiler 1 Max. Scenario (tpy)** | 3.8E-02 | 4.5E+01 | 9.6E-04 | 1.2E-02 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 4.5E+01 |
| Boiler 2 (COG) | 6.9E-03 | 2.8E+01 | 0.0E+00 | 7.6E-03 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 2.8E+01 |
| Boiler 2 (NG) | 2.4E-02 | 1.2E+01 | 6.1E-04 | 1.5E-03 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 1.2E+01 |
| **Boiler 2 Max. Scenario (tpy)** | 2.4E-02 | 2.8E+01 | 6.1E-04 | 7.6E-03 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 2.8E+01 |
| Boiler R-1 (COG) | 3.3E-03 | 1.3E+01 | 0.0E+00 | 3.6E-03 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 1.3E+01 |
| Boiler R-1 (NG) | 1.1E-02 | 5.7E+00 | 2.9E-04 | 7.1E-04 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 5.7E+00 |
| **Boiler R-1 Max. Scenario (tpy)** | 1.1E-02 | 1.3E+01 | 2.9E-04 | 3.6E-03 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 1.3E+01 |
| Boiler R-2 (COG) | 2.8E-03 | 1.2E+01 | 0.0E+00 | 3.1E-03 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 1.2E+01 |
| Boiler R-2 (NG) | 9.8E-03 | 4.9E+00 | 2.5E-04 | 6.2E-04 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 4.9E+00 |
| **Boiler R-2 Max. Scenario (tpy)** | 9.8E-03 | 1.2E+01 | 2.5E-04 | 3.1E-03 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 1.2E+01 |
| Boiler T-1 (COG) | 1.7E-03 | 6.9E+00 | 0.0E+00 | 1.8E-03 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 6.9E+00 |
| Boiler T-1 (NG) | 5.8E-03 | 2.9E+00 | 1.5E-04 | 3.6E-04 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 2.9E+00 |
| **Boiler T-1 Max. Scenario (tpy)** | 5.8E-03 | 6.9E+00 | 1.5E-04 | 1.8E-03 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 6.9E+00 |
| Boiler T-2 (COG) | 1.7E-03 | 6.9E+00 | 0.0E+00 | 1.8E-03 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 6.9E+00 |
| Boiler T-2 (NG) | 5.8E-03 | 2.9E+00 | 1.5E-04 | 3.6E-04 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 2.9E+00 |
| **Boiler T-2 Max. Scenario (tpy)** | 5.8E-03 | 6.9E+00 | 1.5E-04 | 1.8E-03 | 0.0E+00 | 0.0E+00 | 0.0E+00 | 6.9E+00 |
| **Total (tpy)** | **9.4E-02** | **1.1E+02** | **2.4E-03** | **3.0E-02** | **0.0E+00** | **0.0E+00** | **0.0E+00** | **1.1E+02** |

| | |
|---|---|
| **Company Name:** | U. S. Steel |
| **Facility Name:** | Clairton |
| **Project Description:** | Cogeneration Project |

**Table C-25. Reduced Potential to Emit Air Toxics - Clairton Boiler 1**

| | | |
|---|---|---|
| **Process Section:** | Boilers | |
| **Process Name:** | Boiler #1 | |
| **Emission Unit:** | **Boiler #1 - COG & Boiler #1 - NG** | |
| **Future Operation:** | 0 | hrs/yr |
| **Hours of Operation Reduction:** | 8,760 | hrs/yr |
| **Natural Gas Heat Content:** | 1,034 | Btu/scf |
| **COG Heat Content:** | 500 | Btu/scf |
| | | |
| **Required Heat Input:** | 760.00 | MMBtu/hr |
| **Maximum Fuel Usage:** | 6,657,600 | MMBtu/yr |
| | | |
| **Fuel Scenario:** | | |
| **Required Heat Input (COG):** | 760.00 | MMBtu/hr |
| **Required Heat Input (Natural Gas):** | 760.00 | MMBtu/hr |
| **Max. Fuel Usage (COG):** | 1.520 | MMscf/hr |
| **Max. Fuel Usage (Natural Gas):** | 0.735 | MMscf/hr |
| **Max. Fuel Usage (COG):** | 13,315 | MMscf/yr |
| **Max. Fuel Usage (Natural Gas):** | 6,441 | MMscf/yr |
| | | |
| **Fuel Type:** | COG and/or Natural Gas | |

**Reduced Potential Emissions from Boiler - Natural Gas**

| Pollutant | Potential Emissions (lb/hr) | Potential Emissions (tpy) | Emission Factor | Emission Factor Units | Emission Factor Source | Air Toxic? (Category) |
|---|---|---|---|---|---|---|
| Ammonia | 2.71 | 11.85 | 3.7 | lb/MMscf | FIRE, Version 6.25 | Other Toxics |
| Organics | | | | | | |
| 2-Methylnaphthalene | 2.03E-05 | 8.89E-05 | 2.76E-05 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| 3-Methylchloranthrene | 1.52E-06 | 6.67E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| 7,12-Dimethylbenz(a)anthracene | 1.35E-05 | 5.93E-05 | 1.84E-05 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Acenaphthene | 1.52E-06 | 6.67E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Acenaphthylene | 1.52E-06 | 6.67E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Anthracene | 2.03E-06 | 8.89E-06 | 2.76E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Benz(a)anthracene | 1.52E-06 | 6.67E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzene | 1.78E-03 | 7.78E-03 | 2.42E-03 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Benzo(a)pyrene | 1.01E-06 | 4.44E-06 | 1.38E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(b)fluoranthene | 1.52E-06 | 6.67E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(g,h,i)perylene | 1.01E-06 | 4.44E-06 | 1.38E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(k)fluoranthene | 1.52E-06 | 6.67E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Chrysene | 1.52E-06 | 6.67E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Dibenzo(a,h)anthracene | 1.01E-06 | 4.44E-06 | 1.38E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Dichlorobenzene | 1.01E-03 | 4.44E-03 | 1.38E-03 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Fluoranthene | 2.54E-06 | 1.11E-05 | 3.45E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Fluorene | 2.37E-06 | 1.04E-05 | 3.22E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Formaldehyde | 0.06 | 0.28 | 8.63E-02 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| n-Hexane | 1.52 | 6.67 | 2.07E+00 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Indeno(1,2,3-c,d)pyrene | 1.52E-06 | 6.67E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Naphthalene | 5.16E-04 | 2.26E-03 | 7.02E-04 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Phenanthrene | 1.44E-05 | 6.30E-05 | 1.96E-05 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Pyrene | 4.23E-06 | 1.85E-05 | 5.75E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Toluene | 2.88E-03 | 1.26E-02 | 3.91E-03 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Metal HAPs | | | | | | |
| Arsenic | 1.69E-04 | 7.41E-04 | 2.30E-04 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Beryllium | 1.01E-05 | 4.44E-05 | 1.38E-05 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Cadmium | 9.30E-04 | 4.07E-03 | 1.27E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Chromium | 1.18E-03 | 5.19E-03 | 1.61E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Cobalt | 7.10E-05 | 3.11E-04 | 9.66E-05 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Lead | 4.23E-04 | 1.85E-03 | 5.75E-04 | lb/MMscf | AP-42 Table 1.4-2, July 1998 | HAP Metals |
| Manganese | 3.21E-04 | 1.41E-03 | 4.37E-04 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Mercury | 2.20E-04 | 9.63E-04 | 2.99E-04 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | Mercury |
| Nickel | 1.78E-03 | 7.78E-03 | 2.42E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Selenium | 2.03E-05 | 8.89E-05 | 2.76E-05 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | N/A |
| Additional Air Toxics | | | | | | |
| Barium | 3.72E-03 | 1.63E-02 | 5.06E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |

Company Name: U. S. Steel
Facility Name: Clairton
Project Description: Cogeneration Project

Table C-25. Reduced Potential to Emit Air Toxics - Clairton Boiler 1

Reduced Potential Emissions from Boiler - COG

| Pollutant | Potential Emissions (lb/hr) | Potential Emissions (tpy) | Emission Factor | Emission Factor Units | Emission Factor Source | Air Toxic? (Category) |
|---|---|---|---|---|---|---|
| *Criteria Pollutants:* | | | | | | |
| Ammonia | 0.18 | 0.79 | 0.118 | lb/MMscf | 2017 AEI method (avg. from 200 stack test data from underfire) | Other Toxics |
| Organics | | | | | | |
| Hydrogen Chloride | 7.97 | 34.91 | 5.24 | lb/MMscf | 2017 AEI method (weighted avg. factor; from underfire stack testing) | Other Toxics |
| Benzene | 0.03 | 0.15 | 0.02 | lb/MMscf | 2017 AEI method (weighted avg. factor; from underfire stack testing) | Other Toxics |
| Chlorine | 0.11 | 0.50 | 0.07 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Carbon disulfide | 0.06 | 0.25 | 0.04 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Toluene | 0.96 | 0.74 | 0.63 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Phenol | 7.44E-04 | 5.75E-04 | 4.90E-04 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Bis(2-ethylhexyl)phthalate | 9.89E-04 | 7.63E-04 | 6.51E-04 | lb/MMscf | AP-42, Table 12.2-16[1] | POM |
| Indeno[1,2,3-cd]pyrene | 5.99E-06 | 4.62E-06 | 3.94E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benzo[b]fluoranthene | 2.83E-05 | 2.18E-05 | 1.86E-05 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benzo[k]fluoranthene | 9.76E-06 | 7.53E-06 | 6.42E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Chrysene | 4.78E-05 | 3.69E-05 | 3.14E-05 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benzo[a]pyrene | 2.37E-03 | 1.83E-03 | 1.56E-03 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Dibenz[a,h]anthracene | 4.31E-06 | 3.33E-06 | 2.84E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benz[a]anthracene | 1.35E-05 | 1.04E-05 | 8.89E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Acetone | 8.59 | 6.63 | 5.65 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Lead and Lead Compounds | 6.47E-04 | 2.83E-03 | 4.26E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Manganese & Manganese Compounds | 3.67E-04 | 1.61E-03 | 2.42E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Nickel and Nickel Compounds | 2.72E-04 | 1.19E-03 | 1.79E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Arsenic, Inorganic | 4.76E-04 | 2.09E-03 | 3.13E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Barium | 6.86E-04 | 3.01E-03 | 4.51E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Beryllium and compounds | 5.74E-06 | 2.51E-05 | 3.78E-06 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Cadmium | 2.90E-05 | 1.27E-04 | 1.91E-05 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Chloromethane | 0.93 | 0.72 | 0.61 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Naphthalene | 1.21E-02 | 9.32E-03 | 7.94E-03 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |

1. Emission factors from AP-42 converted to lb/MMscf assuming 12,000 scf coke oven gas produced per ton of coal charged, per AP-42, Table 12.2-4, footnote f (05/08). Additional 15% added to all factors from AP-42.

| | |
|---|---|
| 12,000 | scf COG / ton coal charged |
| 1,000,000 | scf/MMscf |
| 1.52 | MMscf/hr of COG consumed |
| 9.2 | VOC Emissions from COG - TV Review Memo Value (tpy) |
| 9.2 | VOC Potential Emissions Reduction (tpy) |
| 7.8 | VOC Emission Factor - AP-42, Table 12.2-16 (lb/MMscf) |

| | |
|---|---|
| Company Name: | U. S. Steel |
| Facility Name: | Clairton |
| Project Description: | Cogeneration Project |

Table C-26. Reduced Potential to Emit Air Toxics - Clairton Boiler 2

| | | |
|---|---|---|
| **Process Section:** | Boilers | |
| **Process Name:** | Boiler #2 | |
| **Emission Unit:** | **Boiler #2 - COG & Boiler #2 - NG** | |
| **Future Operation:** | 0 | hrs/yr |
| **Hours of Operation Reduction:** | 8,760 | hrs/yr |
| **Natural Gas Heat Content:** | 1,034 | Btu/scf |
| **COG Heat Content:** | 500 | Btu/scf |
| | | |
| **Required Heat Input:** | 481.00 | MMBtu/hr |
| **Maximum Fuel Usage:** | 4,213,560 | MMBtu/yr |
| | | |
| **Fuel Scenario:** | | |
| **Required Heat Input (COG):** | 481.00 | MMBtu/hr |
| **Required Heat Input (Natural Gas):** | 481.00 | MMBtu/hr |
| **Max. Fuel Usage (COG):** | 0.962 | MMscf/hr |
| **Max. Fuel Usage (Natural Gas):** | 0.465 | MMscf/hr |
| **Max. Fuel Usage (COG):** | 8,427 | MMscf/yr |
| **Max. Fuel Usage (Natural Gas):** | 4,077 | MMscf/yr |
| | | |
| **Fuel Type:** | COG and/or Natural Gas | |

Reduced Potential Emissions from Boiler - Natural Gas

| Pollutant | Potential Emissions (lb/hr) | Potential Emissions (tpy) | Emission Factor | Emission Factor Units | Emission Factor Source | Air Toxic? (Category) |
|---|---|---|---|---|---|---|
| Ammonia | 1.71 | 7.50 | 3.7 | lb/MMscf | FIRE, Version 6.25 | Other Toxics |
| Organics | | | | | | |
| 2-Methylnaphthalene | 1.28E-05 | 5.63E-05 | 2.76E-05 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| 3-Methylchloranthrene | 9.63E-07 | 4.22E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| 7,12-Dimethylbenz(a)anthracene | 8.56E-06 | 3.75E-05 | 1.84E-05 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Acenaphthene | 9.63E-07 | 4.22E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Acenaphthylene | 9.63E-07 | 4.22E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Anthracene | 1.28E-06 | 5.63E-06 | 2.76E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Benz(a)anthracene | 9.63E-07 | 4.22E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzene | 1.12E-03 | 4.92E-03 | 2.42E-03 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Benzo(a)pyrene | 6.42E-07 | 2.81E-06 | 1.38E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(b)fluoranthene | 9.63E-07 | 4.22E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(g,h,i)perylene | 6.42E-07 | 2.81E-06 | 1.38E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(k)fluoranthene | 9.63E-07 | 4.22E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Chrysene | 9.63E-07 | 4.22E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Dibenzo(a,h)anthracene | 6.42E-07 | 2.81E-06 | 1.38E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Dichlorobenzene | 6.42E-04 | 2.81E-03 | 1.38E-03 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Fluoranthene | 1.61E-06 | 7.03E-06 | 3.45E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Fluorene | 1.50E-06 | 6.56E-06 | 3.22E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Formaldehyde | 0.04 | 0.18 | 8.63E-02 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| n-Hexane | 0.96 | 4.22 | 2.07E+00 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Indeno(1,2,3-c,d)pyrene | 9.63E-07 | 4.22E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Naphthalene | 3.26E-04 | 1.43E-03 | 7.02E-04 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Phenanthrene | 9.10E-06 | 3.98E-05 | 1.96E-05 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Pyrene | 2.68E-06 | 1.17E-05 | 5.75E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Toluene | 1.82E-03 | 7.97E-03 | 3.91E-03 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Metal HAPs | | | | | | |
| Arsenic | 1.07E-04 | 4.69E-04 | 2.30E-04 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Beryllium | 6.42E-06 | 2.81E-05 | 1.38E-05 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Cadmium | 5.89E-04 | 2.58E-03 | 1.27E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Chromium | 7.49E-04 | 3.28E-03 | 1.61E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Cobalt | 4.50E-05 | 1.97E-04 | 9.66E-05 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Lead | 2.68E-04 | 1.17E-03 | 5.75E-04 | lb/MMscf | AP-42 Table 1.4-2, July 1998 | HAP Metals |
| Manganese | 2.03E-04 | 8.91E-04 | 4.37E-04 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Mercury | 1.39E-04 | 6.09E-04 | 2.99E-04 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | Mercury |
| Nickel | 1.12E-03 | 4.92E-03 | 2.42E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Selenium | 1.28E-05 | 5.63E-05 | 2.76E-05 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | N/A |
| Additional Air Toxics | | | | | | |
| Barium | 2.35E-03 | 1.03E-02 | 5.06E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |

Company Name: U. S. Steel
Facility Name: Clairton
Project Description: Cogeneration Project

Table C-26. Reduced Potential to Emit Air Toxics - Clairton Boiler 2

Reduced Potential Emissions from Boiler - COG

| Pollutant | Potential Emissions (lb/hr) | Potential Emissions (tpy) | Emission Factor | Emission Factor Units | Emission Factor Source | Air Toxic? (Category) |
|---|---|---|---|---|---|---|
| *Criteria Pollutants:* | | | | | | |
| Ammonia | 0.11 | 0.50 | 0.118 | lb/MMscf | 2017 AEI method (avg. from 200 stack test data from underfire) | Other Toxics |
| Organics | | | | | | |
| Hydrogen Chloride | 5.04 | 22.10 | 5.24 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Benzene | 0.02 | 0.10 | 0.02 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Chlorine | 0.07 | 0.31 | 0.07 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Carbon disulfide | 0.04 | 0.16 | 0.04 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Toluene | 0.61 | 0.47 | 0.63 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Phenol | 4.71E-04 | 3.63E-04 | 4.90E-04 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Bis(2-ethylhexyl)phthalate | 6.26E-04 | 4.83E-04 | 6.51E-04 | lb/MMscf | AP-42, Table 12.2-16[1] | POM |
| Indeno[1,2,3-cd]pyrene | 3.79E-06 | 2.92E-06 | 3.94E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benzo[b]fluoranthene | 1.79E-05 | 1.38E-05 | 1.86E-05 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benzo[k]fluoranthene | 6.18E-06 | 4.76E-06 | 6.42E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Chrysene | 3.02E-05 | 2.33E-05 | 3.14E-05 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benzo[a]pyrene | 1.50E-03 | 1.16E-03 | 1.56E-03 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Dibenz[a,h]anthracene | 2.73E-06 | 2.10E-06 | 2.84E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benz[a]anthracene | 8.56E-06 | 6.60E-06 | 8.89E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Acetone | 5.44 | 4.19 | 5.65 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Lead and Lead Compounds | 4.09E-04 | 1.79E-03 | 4.26E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Manganese & Manganese Compounds | 2.32E-04 | 1.02E-03 | 2.42E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Nickel and Nickel Compounds | 1.72E-04 | 7.55E-04 | 1.79E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Arsenic, Inorganic | 3.01E-04 | 1.32E-03 | 3.13E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Barium | 4.34E-04 | 1.90E-03 | 4.51E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Beryllium and compounds | 3.63E-06 | 1.59E-05 | 3.78E-06 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Cadmium | 1.83E-05 | 8.04E-05 | 1.91E-05 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Chloromethane | 0.59 | 0.45 | 0.61 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Naphthalene | 7.64E-03 | 5.89E-03 | 7.94E-03 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |

1. Emission factors from AP-42 converted to lb/MMscf assuming 12,000 scf coke oven gas produced per ton of coal charged, per AP-42, Table 12.2-4, footnote f (05/08). Additional 15% added to all factors from AP-42.

| | |
|---|---|
| 12,000 | scf COG / ton coal charged |
| 1,000,000 | scf/MMscf |
| 0.96 | MMscf/hr of COG consumed |
| 5.8 | VOC Emissions from COG - TV Review Memo Value (tpy) |
| 5.8 | VOC Potential Emissions Reduction (tpy) |
| 7.8 | VOC Emission Factor - AP-42, Table 12.2-16 (lb/MMscf) |

| | | |
|---|---|---|
| **Company Name:** | **U. S. Steel** | |
| **Facility Name:** | **Clairton** | |
| **Project Description:** | **Cogeneration Project** | |

**Table C-27. Reduced Potential to Emit Air Toxics - Clairton Boiler R-1**

| | | |
|---|---|---|
| **Process Section:** | Boilers | |
| **Process Name:** | Boiler R-1 | |
| **Emission Unit:** | **Boiler R-1 - COG & Boiler R-1 - NG** | |
| **Future Operation:** | 0 | hrs/yr |
| **Hours of Operation Reduction:** | 8,760 | hrs/yr |
| **Natural Gas Heat Content:** | 1,034 | Btu/scf |
| **COG Heat Content:** | 500 | Btu/scf |
| | | |
| **Required Heat Input:** | 229.00 | MMBtu/hr |
| **Maximum Fuel Usage:** | 2,006,040 | MMBtu/yr |
| | | |
| **Fuel Scenario:** | | |
| **Required Heat Input (COG):** | 229.00 | MMBtu/hr |
| **Required Heat Input (Natural Gas):** | 229.00 | MMBtu/hr |
| **Max. Fuel Usage (COG):** | 0.458 | MMscf/hr |
| **Max. Fuel Usage (Natural Gas):** | 0.222 | MMscf/hr |
| **Max. Fuel Usage (COG):** | 4,012 | MMscf/yr |
| **Max. Fuel Usage (Natural Gas):** | 1,941 | MMscf/yr |
| | | |
| **Fuel Type:** | COG and/or Natural Gas | |

**Reduced Potential Emissions from Boiler - Natural Gas**

| Pollutant | Potential Emissions (lb/hr) | Potential Emissions (tpy) | Emission Factor | Emission Factor Units | Emission Factor Source | Air Toxic? (Category) |
|---|---|---|---|---|---|---|
| Ammonia | 0.82 | 3.57 | 3.7 | lb/MMscf | FIRE, Version 6.25 | Other Toxics |
| Organics | | | | | | |
| 2-Methylnaphthalene | 6.11E-06 | 2.68E-05 | 2.76E-05 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| 3-Methylchloranthrene | 4.59E-07 | 2.01E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| 7,12-Dimethylbenz(a)anthracene | 4.08E-06 | 1.79E-05 | 1.84E-05 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Acenaphthene | 4.59E-07 | 2.01E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Acenaphthylene | 4.59E-07 | 2.01E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Anthracene | 6.11E-07 | 2.68E-06 | 2.76E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Benz(a)anthracene | 4.59E-07 | 2.01E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzene | 5.35E-04 | 2.34E-03 | 2.42E-03 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Benzo(a)pyrene | 3.06E-07 | 1.34E-06 | 1.38E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(b)fluoranthene | 4.59E-07 | 2.01E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(g,h,i)perylene | 3.06E-07 | 1.34E-06 | 1.38E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(k)fluoranthene | 4.59E-07 | 2.01E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Chrysene | 4.59E-07 | 2.01E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Dibenzo(a,h)anthracene | 3.06E-07 | 1.34E-06 | 1.38E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Dichlorobenzene | 3.06E-04 | 1.34E-03 | 1.38E-03 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Fluoranthene | 7.64E-07 | 3.35E-06 | 3.45E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Fluorene | 7.13E-07 | 3.12E-06 | 3.22E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Formaldehyde | 0.02 | 0.08 | 8.63E-02 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| n-Hexane | 0.46 | 2.01 | 2.07E+00 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Indeno(1,2,3-c,d)pyrene | 4.59E-07 | 2.01E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Naphthalene | 1.55E-04 | 6.81E-04 | 7.02E-04 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Phenanthrene | 4.33E-06 | 1.90E-05 | 1.96E-05 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Pyrene | 1.27E-06 | 5.58E-06 | 5.75E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Toluene | 8.66E-04 | 3.79E-03 | 3.91E-03 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Metal HAPs | | | | | | |
| Arsenic | 5.10E-05 | 2.23E-04 | 2.30E-04 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Beryllium | 3.06E-06 | 1.34E-05 | 1.38E-05 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Cadmium | 2.80E-04 | 1.23E-03 | 1.27E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Chromium | 3.57E-04 | 1.56E-03 | 1.61E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Cobalt | 2.14E-05 | 9.37E-05 | 9.66E-05 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Lead | 1.27E-04 | 5.58E-04 | 5.75E-04 | lb/MMscf | AP-42 Table 1.4-2, July 1998 | HAP Metals |
| Manganese | 9.68E-05 | 4.24E-04 | 4.37E-04 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Mercury | 6.62E-05 | 2.90E-04 | 2.99E-04 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | Mercury |
| Nickel | 5.35E-04 | 2.34E-03 | 2.42E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Selenium | 6.11E-06 | 2.68E-05 | 2.76E-05 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | N/A |
| Additional Air Toxics | | | | | | |
| Barium | 1.12E-03 | 4.91E-03 | 5.06E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |

| | |
|---|---|
| Company Name: | U. S. Steel |
| Facility Name: | Clairton |
| Project Description: | Cogeneration Project |

Table C-27. Reduced Potential to Emit Air Toxics - Clairton Boiler R-1

Reduced Potential Emissions from Boiler - COG

| Pollutant | Potential Emissions (lb/hr) | Potential Emissions (tpy) | Emission Factor | Emission Factor Units | Emission Factor Source | Air Toxic? (Category) |
|---|---|---|---|---|---|---|
| *Criteria Pollutants:* | | | | | | |
| Ammonia | 0.05 | 0.24 | 0.118 | lb/MMscf | 2017 AEI method (avg. from 200 stack test data from underfire) | Other Toxics |
| Organics | | | | | | |
| Hydrogen Chloride | 2.40 | 10.52 | 5.24 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Benzene | 0.01 | 0.05 | 0.02 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Chlorine | 0.03 | 0.15 | 0.07 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Carbon disulfide | 0.02 | 0.08 | 0.04 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Toluene | 0.29 | 0.22 | 0.63 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Phenol | 2.24E-04 | 1.73E-04 | 4.90E-04 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Bis(2-ethylhexyl)phthalate | 2.98E-04 | 2.30E-04 | 6.51E-04 | lb/MMscf | AP-42, Table 12.2-16[1] | POM |
| Indeno[1,2,3-cd]pyrene | 1.80E-06 | 1.39E-06 | 3.94E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benzo[b]fluoranthene | 8.51E-06 | 6.57E-06 | 1.86E-05 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benzo[k]fluoranthene | 2.94E-06 | 2.27E-06 | 6.42E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Chrysene | 1.44E-05 | 1.11E-05 | 3.14E-05 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benzo[a]pyrene | 7.15E-04 | 5.52E-04 | 1.56E-03 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Dibenz[a,h]anthracene | 1.30E-06 | 1.00E-06 | 2.84E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benz[a]anthracene | 4.07E-06 | 3.14E-06 | 8.89E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Acetone | 2.59 | 2.00 | 5.65 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Lead and Lead Compounds | 1.95E-04 | 8.54E-04 | 4.26E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Manganese & Manganese Compounds | 1.11E-04 | 4.84E-04 | 2.42E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Nickel and Nickel Compounds | 8.21E-05 | 3.59E-04 | 1.79E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Arsenic, Inorganic | 1.44E-04 | 6.29E-04 | 3.13E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Barium | 2.07E-04 | 9.05E-04 | 4.51E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Beryllium and compounds | 1.73E-06 | 7.57E-06 | 3.78E-06 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Cadmium | 8.73E-06 | 3.83E-05 | 1.91E-05 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Chloromethane | 0.28 | 0.22 | 0.61 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Naphthalene | 3.64E-03 | 2.81E-03 | 7.94E-03 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |

1. Emission factors from AP-42 converted to lb/MMscf assuming 12,000 scf coke oven gas produced per ton of coal charged, per AP-42, Table 12.2-4, footnote f (05/08). Additional 15% added to all factors from AP-42.

| | |
|---|---|
| 12,000 | scf COG / ton coal charged |
| 1,000,000 | scf/MMscf |
| 0.46 | MMscf/hr of COG consumed |
| 2.77 | VOC Emissions from COG - TV Review Memo Value (tpy) |
| 2.8 | VOC Potential Emissions Reduction (tpy) |
| 7.8 | VOC Emission Factor - AP-42, Table 12.2-16 (lb/MMscf) |

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-28. Reduced Potential to Emit Air Toxics - Clairton Boiler R-2**

| | | |
|---|---|---|
| **Process Section:** | Boilers | |
| **Process Name:** | Boiler R-2 | |
| **Emission Unit:** | **Boiler R-2 - COG & Boiler R-2 - NG** | |
| **Future Operation:** | 1,200 | hrs/yr |
| **Hours of Operation Reduction:** | 7,560 | hrs/yr |
| **Natural Gas Heat Content:** | 1,034 | Btu/scf |
| **COG Heat Content:** | 500 | Btu/scf |
| | | |
| **Required Heat Input:** | 229.00 | MMBtu/hr |
| **Maximum Fuel Usage:** | 1,731,240 | MMBtu/yr |
| | | |
| **Fuel Scenario:** | | |
| **Required Heat Input (COG):** | 229.00 | MMBtu/hr |
| **Required Heat Input (Natural Gas):** | 229.00 | MMBtu/hr |
| **Max. Fuel Usage (COG):** | 0.458 | MMscf/hr |
| **Max. Fuel Usage (Natural Gas):** | 0.222 | MMscf/hr |
| **Max. Fuel Usage (COG):** | 3,462 | MMscf/yr |
| **Max. Fuel Usage (Natural Gas):** | 1,675 | MMscf/yr |
| | | |
| **Fuel Type:** | COG and/or Natural Gas | |

**Reduced Potential Emissions from Boiler - Natural Gas**

| Pollutant | Potential Emissions (lb/hr) | Potential Emissions (tpy) | Emission Factor | Emission Factor Units | Emission Factor Source | Air Toxic? (Category) |
|---|---|---|---|---|---|---|
| Ammonia | 0.82 | 3.08 | 3.7 | lb/MMscf | FIRE, Version 6.25 | Other Toxics |
| Organics | | | | | | |
| 2-Methylnaphthalene | 6.11E-06 | 2.31E-05 | 2.76E-05 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| 3-Methylchloranthrene | 4.59E-07 | 1.73E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| 7,12-Dimethylbenz(a)anthracene | 4.08E-06 | 1.54E-05 | 1.84E-05 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Acenaphthene | 4.59E-07 | 1.73E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Acenaphthylene | 4.59E-07 | 1.73E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Anthracene | 6.11E-07 | 2.31E-06 | 2.76E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Benz(a)anthracene | 4.59E-07 | 1.73E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzene | 5.35E-04 | 2.02E-03 | 2.42E-03 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Benzo(a)pyrene | 3.06E-07 | 1.16E-06 | 1.38E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(b)fluoranthene | 4.59E-07 | 1.73E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(g,h,i)perylene | 3.06E-07 | 1.16E-06 | 1.38E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(k)fluoranthene | 4.59E-07 | 1.73E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Chrysene | 4.59E-07 | 1.73E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Dibenzo(a,h)anthracene | 3.06E-07 | 1.16E-06 | 1.38E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Dichlorobenzene | 3.06E-04 | 1.16E-03 | 1.38E-03 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Fluoranthene | 7.64E-07 | 2.89E-06 | 3.45E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Fluorene | 7.13E-07 | 2.70E-06 | 3.22E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Formaldehyde | 0.02 | 0.07 | 8.63E-02 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| n-Hexane | 0.46 | 1.73 | 2.07E+00 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Indeno(1,2,3-c,d)pyrene | 4.59E-07 | 1.73E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Naphthalene | 1.55E-04 | 5.87E-04 | 7.02E-04 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Phenanthrene | 4.33E-06 | 1.64E-05 | 1.96E-05 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Pyrene | 1.27E-06 | 4.82E-06 | 5.75E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Toluene | 8.66E-04 | 3.27E-03 | 3.91E-03 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Metal HAPs | | | | | | |
| Arsenic | 5.10E-05 | 1.93E-04 | 2.30E-04 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Beryllium | 3.06E-06 | 1.16E-05 | 1.38E-05 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Cadmium | 2.80E-04 | 1.06E-03 | 1.27E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Chromium | 3.57E-04 | 1.35E-03 | 1.61E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Cobalt | 2.14E-05 | 8.09E-05 | 9.66E-05 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Lead | 1.27E-04 | 4.82E-04 | 5.75E-04 | lb/MMscf | AP-42 Table 1.4-2, July 1998 | HAP Metals |
| Manganese | 9.68E-05 | 3.66E-04 | 4.37E-04 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Mercury | 6.62E-05 | 2.50E-04 | 2.99E-04 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | Mercury |
| Nickel | 5.35E-04 | 2.02E-03 | 2.42E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Selenium | 6.11E-06 | 2.31E-05 | 2.76E-05 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | N/A |
| Additional Air Toxics | | | | | | |
| Barium | 1.12E-03 | 4.24E-03 | 5.06E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-28. Reduced Potential to Emit Air Toxics - Clairton Boiler R-2**

**Reduced Potential Emissions from Boiler - COG**

| Pollutant | Potential Emissions (lb/hr) | Potential Emissions (tpy) | Emission Factor | Emission Factor Units | Emission Factor Source | Air Toxic? (Category) |
|---|---|---|---|---|---|---|
| *Criteria Pollutants:* | | | | | | |
| Ammonia | 0.05 | 0.21 | 0.118 | lb/MMscf | 2017 AEI method (avg. from 200 stack test data from underfire) | Other Toxics |
| Organics | | | | | | |
| Hydrogen Chloride | 2.40 | 9.08 | 5.24 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Benzene | 0.01 | 0.04 | 0.02 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Chlorine | 0.03 | 0.13 | 0.07 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Carbon disulfide | 0.02 | 0.07 | 0.04 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Toluene | 0.29 | 0.19 | 0.63 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Phenol | 2.24E-04 | 1.49E-04 | 4.90E-04 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Bis(2-ethylhexyl)phthalate | 2.98E-04 | 1.99E-04 | 6.51E-04 | lb/MMscf | AP-42, Table 12.2-16[1] | POM |
| Indeno[1,2,3-cd]pyrene | 1.80E-06 | 1.20E-06 | 3.94E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benzo[b]fluoranthene | 8.51E-06 | 5.67E-06 | 1.86E-05 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benzo[k]fluoranthene | 2.94E-06 | 1.96E-06 | 6.42E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Chrysene | 1.44E-05 | 9.59E-06 | 3.14E-05 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benzo[a]pyrene | 7.15E-04 | 4.77E-04 | 1.56E-03 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Dibenz[a,h]anthracene | 1.30E-06 | 8.66E-07 | 2.84E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benz[a]anthracene | 4.07E-06 | 2.71E-06 | 8.89E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Acetone | 2.59 | 1.73 | 5.65 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Lead and Lead Compounds | 1.95E-04 | 7.37E-04 | 4.26E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Manganese & Manganese Compounds | 1.11E-04 | 4.18E-04 | 2.42E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Nickel and Nickel Compounds | 8.21E-05 | 3.10E-04 | 1.79E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Arsenic, Inorganic | 1.44E-04 | 5.43E-04 | 3.13E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Barium | 2.07E-04 | 7.81E-04 | 4.51E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Beryllium and compounds | 1.73E-06 | 6.54E-06 | 3.78E-06 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Cadmium | 8.73E-06 | 3.30E-05 | 1.91E-05 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Chloromethane | 0.28 | 0.19 | 0.61 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Naphthalene | 3.64E-03 | 2.42E-03 | 7.94E-03 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |

1. Emission factors from AP-42 converted to lb/MMscf assuming 12,000 scf coke oven gas produced per ton of coal charged, per AP-42, Table 12.2-4, footnote f (05/08). Additional 15% added to all factors from AP-42.

| | |
|---|---|
| 12,000 | scf COG / ton coal charged |
| 1,000,000 | scf/MMscf |
| 0.46 | MMscf/hr of COG consumed |
| 2.77 | VOC Emissions from COG - TV Review Memo Value (tpy) |
| 2.4 | VOC Potential Emissions Reduction (tpy) |
| 7.8 | VOC Emission Factor - AP-42, Table 12.2-16 (lb/MMscf) |

| | | |
|---|---|---|
| **Company Name:** | U. S. Steel | |
| **Facility Name:** | Clairton | |
| **Project Description:** | Cogeneration Project | |

**Table C-29. Reduced Potential to Emit Air Toxics - Clairton Boiler T-1**

| | | |
|---|---|---|
| **Process Section:** | Boilers | |
| **Process Name:** | Boiler T-1 | |
| **Emission Unit:** | **Boiler T-1 - COG & Boiler T-1 - NG** | |
| **Future Operation:** | 2,200 | hrs/yr |
| **Hours of Operation Reduction:** | 6,560 | hrs/yr |
| **Natural Gas Heat Content:** | 1,034 | Btu/scf |
| **COG Heat Content:** | 500 | Btu/scf |
| | | |
| **Required Heat Input:** | 156.00 | MMBtu/hr |
| **Maximum Fuel Usage:** | 1,023,360 | MMBtu/yr |
| | | |
| **Fuel Scenario:** | | |
| **Required Heat Input (COG):** | 156.00 | MMBtu/hr |
| **Required Heat Input (Natural Gas):** | 156.00 | MMBtu/hr |
| **Max. Fuel Usage (COG):** | 0.312 | MMscf/hr |
| **Max. Fuel Usage (Natural Gas):** | 0.151 | MMscf/hr |
| **Max. Fuel Usage (COG):** | 2,047 | MMscf/yr |
| **Max. Fuel Usage (Natural Gas):** | 990 | MMscf/yr |
| | | |
| **Fuel Type:** | COG and/or Natural Gas | |

**Reduced Potential Emissions from Boiler - Natural Gas**

| Pollutant | Potential Emissions (lb/hr) | Potential Emissions (tpy) | Emission Factor | Emission Factor Units | Emission Factor Source | Air Toxic? (Category) |
|---|---|---|---|---|---|---|
| Ammonia | 0.56 | 1.82 | 3.7 | lb/MMscf | FIRE, Version 6.25 | Other Toxics |
| Organics | | | | | | |
| 2-Methylnaphthalene | 4.17E-06 | 1.37E-05 | 2.76E-05 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| 3-Methylchloranthrene | 3.12E-07 | 1.02E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| 7,12-Dimethylbenz(a)anthracene | 2.78E-06 | 9.11E-06 | 1.84E-05 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Acenaphthene | 3.12E-07 | 1.02E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Acenaphthylene | 3.12E-07 | 1.02E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Anthracene | 4.17E-07 | 1.37E-06 | 2.76E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Benz(a)anthracene | 3.12E-07 | 1.02E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzene | 3.64E-04 | 1.20E-03 | 2.42E-03 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Benzo(a)pyrene | 2.08E-07 | 6.83E-07 | 1.38E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(b)fluoranthene | 3.12E-07 | 1.02E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(g,h,i)perylene | 2.08E-07 | 6.83E-07 | 1.38E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(k)fluoranthene | 3.12E-07 | 1.02E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Chrysene | 3.12E-07 | 1.02E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Dibenzo(a,h)anthracene | 2.08E-07 | 6.83E-07 | 1.38E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Dichlorobenzene | 2.08E-04 | 6.83E-04 | 1.38E-03 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Fluoranthene | 5.21E-07 | 1.71E-06 | 3.45E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Fluorene | 4.86E-07 | 1.59E-06 | 3.22E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Formaldehyde | 0.01 | 0.04 | 8.63E-02 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| n-Hexane | 0.31 | 1.02 | 2.07E+00 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Indeno(1,2,3-c,d)pyrene | 3.12E-07 | 1.02E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Naphthalene | 1.06E-04 | 3.47E-04 | 7.02E-04 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Phenanthrene | 2.95E-06 | 9.68E-06 | 1.96E-05 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Pyrene | 8.68E-07 | 2.85E-06 | 5.75E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Toluene | 5.90E-04 | 1.94E-03 | 3.91E-03 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Metal HAPs | | | | | | |
| Arsenic | 3.47E-05 | 1.14E-04 | 2.30E-04 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Beryllium | 2.08E-06 | 6.83E-06 | 1.38E-05 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Cadmium | 1.91E-04 | 6.26E-04 | 1.27E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Chromium | 2.43E-04 | 7.97E-04 | 1.61E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Cobalt | 1.46E-05 | 4.78E-05 | 9.66E-05 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Lead | 8.68E-05 | 2.85E-04 | 5.75E-04 | lb/MMscf | AP-42 Table 1.4-2, July 1998 | HAP Metals |
| Manganese | 6.60E-05 | 2.16E-04 | 4.37E-04 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Mercury | 4.51E-05 | 1.48E-04 | 2.99E-04 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | Mercury |
| Nickel | 3.64E-04 | 1.20E-03 | 2.42E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Selenium | 4.17E-06 | 1.37E-05 | 2.76E-05 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | N/A |
| Additional Air Toxics | | | | | | |
| Barium | 7.64E-04 | 2.50E-03 | 5.06E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |

Company Name: U. S. Steel
Facility Name: Clairton
Project Description: Cogeneration Project

Table C-29. Reduced Potential to Emit Air Toxics - Clairton Boiler T-1

Reduced Potential Emissions from Boiler - COG

| Pollutant | Potential Emissions (lb/hr) | Potential Emissions (tpy) | Emission Factor | Emission Factor Units | Emission Factor Source | Air Toxic? (Category) |
|---|---|---|---|---|---|---|
| *Criteria Pollutants:* | | | | | | |
| Ammonia | 0.04 | 0.12 | 0.118 | lb/MMscf | 2017 AEI method (avg. from 200 stack test data from underfire) | Other Toxics |
| Organics | | | | | | |
| Hydrogen Chloride | 1.64 | 5.37 | 5.24 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Benzene | 0.01 | 0.02 | 0.02 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Chlorine | 0.02 | 0.08 | 0.07 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Carbon disulfide | 0.01 | 0.04 | 0.04 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Toluene | 0.20 | 0.11 | 0.63 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Phenol | 1.53E-04 | 8.85E-05 | 4.90E-04 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Bis(2-ethylhexyl)phthalate | 2.03E-04 | 1.18E-04 | 6.51E-04 | lb/MMscf | AP-42, Table 12.2-16[1] | POM |
| Indeno[1,2,3-cd]pyrene | 1.23E-06 | 7.12E-07 | 3.94E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benzo[b]fluoranthene | 5.80E-06 | 3.36E-06 | 1.86E-05 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benzo[k]fluoranthene | 2.00E-06 | 1.16E-06 | 6.42E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Chrysene | 9.81E-06 | 5.68E-06 | 3.14E-05 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benzo[a]pyrene | 4.87E-04 | 2.82E-04 | 1.56E-03 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Dibenz[a,h]anthracene | 8.85E-07 | 5.13E-07 | 2.84E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benz[a]anthracene | 2.77E-06 | 1.61E-06 | 8.89E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Acetone | 1.76 | 1.02 | 5.65 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Lead and Lead Compounds | 1.33E-04 | 4.35E-04 | 4.26E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Manganese & Manganese Compounds | 7.53E-05 | 2.47E-04 | 2.42E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Nickel and Nickel Compounds | 5.59E-05 | 1.83E-04 | 1.79E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Arsenic, Inorganic | 9.78E-05 | 3.21E-04 | 3.13E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Barium | 1.41E-04 | 4.62E-04 | 4.51E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Beryllium and compounds | 1.18E-06 | 3.86E-06 | 3.78E-06 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Cadmium | 5.95E-06 | 1.95E-05 | 1.91E-05 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Chloromethane | 0.19 | 0.11 | 0.61 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Naphthalene | 2.48E-03 | 1.44E-03 | 7.94E-03 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |

1. Emission factors from AP-42 converted to lb/MMscf assuming 12,000 scf coke oven gas produced per ton of coal charged, per AP-42, Table 12.2-4, footnote f (05/08). Additional 15% added to all factors from AP-42.

| | |
|---|---|
| 12,000 | scf COG / ton coal charged |
| 1,000,000 | scf/MMscf |
| 0.31 | MMscf/hr of COG consumed |
| 1.89 | VOC Emissions from COG - TV Review Memo Value (tpy) |
| 1.4 | VOC Potential Emissions Reduction (tpy) |
| 7.8 | VOC Emission Factor - AP-42, Table 12.2-16 (lb/MMscf) |

| | | |
|---|---|---|
| Company Name: | U. S. Steel | |
| Facility Name: | Clairton | |
| Project Description: | Cogeneration Project | |

Table C-30. Reduced Potential to Emit Air Toxics - Clairton Boiler T-2

| | | |
|---|---|---|
| Process Section: | Boilers | |
| Process Name: | Boiler T-2 | |
| Emission Unit: | Boiler T-2 - COG & Boiler T-2 - NG | |
| Future Operation: | 2,200 | hrs/yr |
| Hours of Operation Reduction: | 6,560 | hrs/yr |
| Natural Gas Heat Content: | 1,034 | Btu/scf |
| COG Heat Content: | 500 | Btu/scf |
| Required Heat Input: | 156.00 | MMBtu/hr |
| Maximum Fuel Usage: | 1,023,360 | MMBtu/yr |
| Fuel Scenario: | | |
| Required Heat Input (COG): | 156.00 | MMBtu/hr |
| Required Heat Input (Natural Gas): | 156.00 | MMBtu/hr |
| Max. Fuel Usage (COG): | 0.312 | MMscf/hr |
| Max. Fuel Usage (Natural Gas): | 0.151 | MMscf/hr |
| Max. Fuel Usage (COG): | 2,047 | MMscf/yr |
| Max. Fuel Usage (Natural Gas): | 990 | MMscf/yr |
| Fuel Type: | COG and/or Natural Gas | |

Reduced Potential Emissions from Boiler - Natural Gas

| Pollutant | Potential Emissions (lb/hr) | Potential Emissions (tpy) | Emission Factor | Emission Factor Units | Emission Factor Source | Air Toxic? (Category) |
|---|---|---|---|---|---|---|
| Ammonia | 0.56 | 1.82 | 3.7 | lb/MMscf | FIRE, Version 6.25 | Other Toxics |
| Organics | | | | | | |
| 2-Methylnaphthalene | 4.17E-06 | 1.37E-05 | 2.76E-05 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| 3-Methylchloranthrene | 3.12E-07 | 1.02E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| 7,12-Dimethylbenz(a)anthracene | 2.78E-06 | 9.11E-06 | 1.84E-05 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Acenaphthene | 3.12E-07 | 1.02E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Acenaphthylene | 3.12E-07 | 1.02E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Anthracene | 4.17E-07 | 1.37E-06 | 2.76E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Benz(a)anthracene | 3.12E-07 | 1.02E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzene | 3.64E-04 | 1.20E-03 | 2.42E-03 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Benzo(a)pyrene | 2.08E-07 | 6.83E-07 | 1.38E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(b)fluoranthene | 3.12E-07 | 1.02E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(g,h,i)perylene | 2.08E-07 | 6.83E-07 | 1.38E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Benzo(k)fluoranthene | 3.12E-07 | 1.02E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Chrysene | 3.12E-07 | 1.02E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Dibenzo(a,h)anthracene | 2.08E-07 | 6.83E-07 | 1.38E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Dichlorobenzene | 2.08E-04 | 6.83E-04 | 1.38E-03 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Fluoranthene | 5.21E-07 | 1.71E-06 | 3.45E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Fluorene | 4.86E-07 | 1.59E-06 | 3.22E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Formaldehyde | 0.01 | 0.04 | 8.63E-02 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| n-Hexane | 0.31 | 1.02 | 2.07E+00 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Indeno(1,2,3-c,d)pyrene | 3.12E-07 | 1.02E-06 | 2.07E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Naphthalene | 1.06E-04 | 3.47E-04 | 7.02E-04 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | POM |
| Phenanthrene | 2.95E-06 | 9.68E-06 | 1.96E-05 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Pyrene | 8.68E-07 | 2.85E-06 | 5.75E-06 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | N/A |
| Toluene | 5.90E-04 | 1.94E-03 | 3.91E-03 | lb/MMscf | AP-42 Table 1.4-3, July 1998 | Other Toxics |
| Metal HAPs | | | | | | |
| Arsenic | 3.47E-05 | 1.14E-04 | 2.30E-04 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Beryllium | 2.08E-06 | 6.83E-06 | 1.38E-05 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Cadmium | 1.91E-04 | 6.26E-04 | 1.27E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Chromium | 2.43E-04 | 7.97E-04 | 1.61E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Cobalt | 1.46E-05 | 4.78E-05 | 9.66E-05 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Lead | 8.68E-05 | 2.85E-04 | 5.75E-04 | lb/MMscf | AP-42 Table 1.4-2, July 1998 | HAP Metals |
| Manganese | 6.60E-05 | 2.16E-04 | 4.37E-04 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Mercury | 4.51E-05 | 1.48E-04 | 2.99E-04 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | Mercury |
| Nickel | 3.64E-04 | 1.20E-03 | 2.42E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |
| Selenium | 4.17E-06 | 1.37E-05 | 2.76E-05 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | N/A |
| Additional Air Toxics | | | | | | |
| Barium | 7.64E-04 | 2.50E-03 | 5.06E-03 | lb/MMscf | AP-42 Table 1.4-4, July 1998 | HAP Metals |

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration Project

**Table C-30. Reduced Potential to Emit Air Toxics - Clairton Boiler T-2**

**Reduced Potential Emissions from Boiler - COG**

| Pollutant | Potential Emissions (lb/hr) | Potential Emissions (tpy) | Emission Factor | Emission Factor Units | Emission Factor Source | Air Toxic? (Category) |
|---|---|---|---|---|---|---|
| *Criteria Pollutants:* | | | | | | |
| Ammonia | 0.04 | 0.12 | 0.118 | lb/MMscf | 2017 AEI method (avg. from 200 stack test data from underfire) | Other Toxics |
| Organics | | | | | | |
| Hydrogen Chloride | 1.64 | 5.37 | 5.24 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Benzene | 0.01 | 0.02 | 0.02 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Chlorine | 0.02 | 0.08 | 0.07 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Carbon disulfide | 0.01 | 0.04 | 0.04 | lb/MMscf | 2017 AEI method (weighted avg. factors from underfire stack testing) | Other Toxics |
| Toluene | 0.20 | 0.11 | 0.63 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Phenol | 1.53E-04 | 8.85E-05 | 4.90E-04 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Bis(2-ethylhexyl)phthalate | 2.03E-04 | 1.18E-04 | 6.51E-04 | lb/MMscf | AP-42, Table 12.2-16[1] | POM |
| Indeno[1,2,3-cd]pyrene | 1.23E-06 | 7.12E-07 | 3.94E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benzo[b]fluoranthene | 5.80E-06 | 3.36E-06 | 1.86E-05 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benzo[k]fluoranthene | 2.00E-06 | 1.16E-06 | 6.42E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Chrysene | 9.81E-06 | 5.68E-06 | 3.14E-05 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benzo[a]pyrene | 4.87E-04 | 2.82E-04 | 1.56E-03 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Dibenz[a,h]anthracene | 8.85E-07 | 5.13E-07 | 2.84E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Benz[a]anthracene | 2.77E-06 | 1.61E-06 | 8.89E-06 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |
| Acetone | 1.76 | 1.02 | 5.65 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Lead and Lead Compounds | 1.33E-04 | 4.35E-04 | 4.26E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Manganese & Manganese Compounds | 7.53E-05 | 2.47E-04 | 2.42E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Nickel and Nickel Compounds | 5.59E-05 | 1.83E-04 | 1.79E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Arsenic, Inorganic | 9.78E-05 | 3.21E-04 | 3.13E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Barium | 1.41E-04 | 4.62E-04 | 4.51E-04 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Beryllium and compounds | 1.18E-06 | 3.86E-06 | 3.78E-06 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Cadmium | 5.95E-06 | 1.95E-05 | 1.91E-05 | lb/MMscf | AP-42, Table 12.2-15[1] | HAP Metals |
| Chloromethane | 0.19 | 0.11 | 0.61 | lb/MMscf | AP-42, Table 12.2-16[1] | Other Toxics |
| Naphthalene | 2.48E-03 | 1.44E-03 | 7.94E-03 | lb/MMscf | AP-42, Table 12.2-17[1] | POM |

1. Emission factors from AP-42 converted to lb/MMscf assuming 12,000 scf coke oven gas produced per ton of coal charged, per AP-42, Table 12.2-4, footnote f (05/08). Additional 15% added to all factors from AP-42.

| | |
|---|---|
| 12,000 | scf COG / ton coal charged |
| 1,000,000 | scf/MMscf |
| 0.31 | MMscf/hr of COG consumed |
| 1.89 | VOC Emissions from COG - TV Review Memo Value (tpy) |
| 1.4 | VOC Potential Emissions Reduction (tpy) |
| 7.8 | VOC Emission Factor - AP-42, Table 12.2-16 (lb/MMscf) |

# APPENDIX D: BACT ANALYSIS

BURNS & McDONNELL

# Best Available Control Technology Analysis

United States Steel Corporation

## United States Steel Corporation

**Mon Valley Works - Clairton Cogeneration Project**
**Project No. 112420**

# Best Available Control Technology Analysis

prepared for

**United States Steel Corporation**
**Mon Valley Works - Clairton Cogeneration Project**
**Clairton, Pennsylvania**

**Project No. 112420**

**Revision 1**
**June 2019**

prepared by

**Burns & McDonnell Engineering Company, Inc.**
**Kansas City, Missouri**

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# LIST OF ABBREVIATIONS

| Abbreviation | Term/Phrase/Name |
|---|---|
| °F | degrees Fahrenheit |
| ACHD | Allegheny County Health Department |
| BACT | Best Available Control Technology |
| Burns & McDonnell | Burns & McDonnell Engineering Company, Inc. |
| $CaCO_3$ | Calcium carbonate (limestone) |
| CaO | Calcium oxide (lime) |
| CDS | Circulating Dry Scrubber |
| CEMS | Continuous Emissions Monitoring System |
| CFR | Code of Federal Regulations |
| $CH_4$ | Methane |
| CHP | Combined Heat and Power |
| CO | Carbon Monoxide |
| $CO_2$ | Carbon Dioxide |
| $CO_2e$ | Carbon Dioxide Equivalent (greenhouse gases) |
| COG | Coke Oven Gas |
| ESP | Electrostatic Precipitator |
| FGD | Flue Gas Desulfurization |
| GHG | Greenhouse Gas |
| GWP | Global Warming Potential |
| $H_2SO_4$ | Sulfuric Acid |
| HAP | hazardous air pollutant |

| **Abbreviation** | **Term/Phrase/Name** |
|---|---|
| HCl | hydrochloric acid |
| HF | hydrofluoric acid |
| HHV | higher heating value |
| HRSG | heat recovery steam generator |
| LAER | Lowest Achievable Emission Rate |
| Lb/lb-mol | pound per pound-mole |
| lb/MMBtu | pounds per million British thermal units |
| MMBtu/hr | million British thermal units per hour |
| MW | megawatt |
| $N_2O$ | nitrous oxide |
| $NO_2$ | nitrogen dioxide |
| NOx | nitrogen oxides |
| NSPS | New Source Performance Standard |
| NSR | New Source Review |
| $O_2$ | oxygen |
| PM | particulate matter |
| $PM_{2.5}$ | particulate matter less than 2.5 microns in diameter |
| $PM_{10}$ | particulate matter less than 10 microns in diameter |
| ppm | parts per million |
| PSD | Prevention of Significant Deterioration |
| RBLC | RACT/BACT/LAER clearinghouse |

| | |
|---|---|
| SCR | selective catalytic reduction |
| SDA | spray dryer absorption |
| SER | significant Emission Rate |
| SNCR | selective non-catalytic reduction |
| $SO_2$ | sulfur dioxide |
| $SO_3$ | sulfur trioxide |
| tpy | tons per year |
| U. S. Steel | United States Steel Corporation |
| VOC | volatile organic compounds |
| WESP | wet electrostatic precipitator |
| SDA | spray dryer absorption |
| SER | Significant Emission Rate |
| SNCR | selective non-catalytic reduction |

# 1.0 EXECUTIVE SUMMARY

United States Steel Corporation (U. S. Steel) operates the Mon Valley Works, an integrated coke and steel-making operation located in Allegheny County, Pennsylvania. The complex is comprised of three (3) main plants: the Irvin Plant, the Clairton Plant, and the Edgar Thomson Plant. The proposed project will involve the installation of new sources of air emissions at the Clairton Plant. The Clairton Plant is located in the City of Clairton, Pennsylvania and is currently authorized by Title V Operating Permit No. 0052.

The Clairton Plant is an existing major source of nitrogen oxides ($NO_x$), carbon monoxide (CO), sulfur dioxide ($SO_2$), particulate matter (PM), particulate matter less than 10 microns in diameter ($PM_{10}$), particulate matter less than 2.5 microns in diameter ($PM_{2.5}$), hazardous air pollutants (HAPs), and volatile organic compounds (VOCs), as defined in Allegheny County Health Department (ACHD) Air Pollution Regulations, §2101.20 of Article XXI. Portions of Allegheny County are currently designated as nonattainment for $SO_2$ and $PM_{2.5}$. The Clairton Plant is located in the portion of Allegheny County designated as nonattainment for $SO_2$ and $PM_{2.5}$. In addition, because the county is located within the Ozone Transport Region (OTR), the area is considered nonattainment for ozone precursor pollutants (NOx and VOC).

U. S. Steel is proposing to install a new cogeneration operation (Cogeneration Project) at the Clairton Plant. As part of this Project, three existing boilers at the Clairton Plant will be shut down. The Project will include the installation of state-of-the-art control technologies for multiple pollutants. As a result of the proposed project, there will be no net increase in emissions of $PM_{2.5}$ and $PM_{10}$, and a significant net decrease in emissions of $SO_2$, $NO_X$, and CO. The Project emissions increase will be below the Significant Emission Rate (SER) thresholds for triggering a major modification for all regulated New Source Review (NSR) pollutants.

The proposed Project involves the installation of a new cogeneration process at the Clairton Plant. The cogeneration process will be an energy-efficient, integrated combined heat and power process to generate electricity and steam to support the industrial processes of U. S. Steel's Mon Valley Works complex. The proposed cogeneration process will be configured with two (2) identical trains, each with a combustion turbine operated in combined cycle mode and a heat recovery steam generator (HRSG) with supplemental duct burning to provide additional heat in the HRSG. The units will be designed to be fired primarily with coke oven gas (COG), with the capability to fire natural gas or a COG/natural gas blend as an alternative (e.g., for startup, shutdown, and/or malfunction events).

The ACHD requires the application of Best Available Control Technology (BACT) for each regulated NSR pollutant regardless of Prevention of Significant Deterioration (PSD) program applicability. As such, a BACT analysis was prepared for $NO_x$, CO, $PM_{10}/PM_{2.5}$, VOC, $SO_2$, ammonia, and greenhouse gases (as carbon dioxide equivalents [$CO_2e$]) for the combined cycle (cogeneration) combustion turbines.

The BACT analysis was performed using the "top-down" approach. A summary of the BACT emission limits and the associated control technologies for the combined cycle combustion turbine are shown in Table 1-1.

**Table 1-1: Summary of BACT Results: Combined Cycle Combustion Turbines**

| Pollutant | Control | BACT Emission Limitation[a,b] | Compliance Method/ Averaging Period[c] |
|---|---|---|---|
| $NO_x$ | Selective catalytic reduction (SCR) and water injection | 7.5 ppm | 30-day rolling via CEMs |
| CO | Good combustion practices, oxidation catalyst | 3 ppm | 3-run stack test |
| $PM/PM_{10}/PM_{2.5}$[d] | Combustion controls, baghouse, and low ash fuels | 0.014 lb/MMBtu | 3-run stack test |
| VOC | Good combustion practices, oxidation catalyst | 5.1 ppm | 3-run stack test |
| $SO_2$ | Combustion controls, low sulfur fuels, circulating dry scrubber | 0.024 lb/MMBtu | 3-run stack test |
| Ammonia | Limiting ammonia input, use of ammonia instead of urea in SCR | 2 ppm | 3-run stack test |
| Greenhouse gases | Use of COG and natural gas as fuels, efficient turbine design | 864,096 tpy $CO_2e$[e] – both combustion turbines/duct burners combined | 12-month rolling based on CEMs |

(a) ppm = parts per million, dry volume basis; lb/MMBtu = pounds per million British thermal units; tpy = tons per year
(b) Concentration at 15% oxygen, dry volume basis, while operating at 70% load and greater under steady state conditions, unless otherwise noted.
(c) 3-run stack tests will be performed in accordance with ACHD-approved stack testing protocol.
(d) Filterable plus condensable particulate emissions.
(e) GHG BACT emission limitation includes combustion turbines/duct burners emissions combined from both turbine stacks. Includes carbon dioxide ($CO_2$), methane ($CH_4$) and nitrous oxide ($N_2O$) emissions multiplied by their global warming potentials and added to determine carbon dioxide equivalents ($CO_2e$).

In addition to the BACT analysis for the combustion turbines, a BACT analysis for the auxiliary emission sources was also conducted.

# 2.0 INTRODUCTION

United States Steel Corporation (U. S. Steel) operates the Mon Valley Works, an integrated coke and steel-making operation located in Allegheny County, Pennsylvania. The complex is comprised of three (3) main plants: the Irvin Plant, the Clairton Plant, and the Edgar Thomson Plant. The proposed project will involve the installation of new sources of air emissions at the Clairton Plant. The Clairton Plant is located in the City of Clairton, Pennsylvania and is currently authorized by Title V Operating Permit No. 0052.

The Clairton Plant is an existing major source of nitrogen oxides ($NO_x$), carbon monoxide (CO), sulfur dioxide ($SO_2$), particulate matter (PM), particulate matter less than 10 microns in diameter ($PM_{10}$), particulate matter less than 2.5 microns in diameter ($PM_{2.5}$), hazardous air pollutants (HAPs), and volatile organic compounds (VOCs), as defined in Allegheny County Health Department Air Pollution Regulations, §2101.20 of Article XXI. Allegheny County, or portions of it, is currently designated as nonattainment for $SO_2$ and $PM_{2.5}$.

U. S. Steel is proposing to install a new cogeneration operation (Cogeneration Project) at the Clairton Plant. As part of this project, existing boilers at the Clairton Plant will be shut down. The design of the project will include the installation of state-of-the-art control technologies for multiple pollutants. As a result of the proposed project, there will be no net increase in emissions of $PM_{2.5}$ and $PM_{10}$, and a significant net decrease in emissions of $SO_2$, $NO_X$, and CO.[1] The Project emissions increase will be below the Significant Emission Rate (SER) thresholds for triggering a major modification for all regulated New Source Review (NSR) pollutants.

The proposed Project involves the installation of a new combined heat and power process (Cogeneration Project) at the Clairton Plant. The Cogeneration Project will be an energy-efficient, integrated combined heat and power process to generate electricity as well as steam to support the industrial processes of U. S. Steel's Mon Valley Works complex. The proposed Cogeneration Project will be configured with two (2) identical trains, each with a General Electric 6B combustion turbine operated in combined cycle mode (hereinafter referred to as combustion turbine) and a heat recovery steam generator (HRSG) with duct

[1] Direct emissions of $CO_2e$ will increase as a result of the project. However, this is a combined heat and power process which will offset the electricity that is currently being purchased from the grid as well as producing steam in a more efficient manner, resulting in a net decrease overall of $CO_2e$ from current levels when considering both direct and indirect sources.

burning to provide additional heat in the HRSG. Each combustion turbine will have a maximum heat input rating of 637 million British thermal units per hour (MMBtu/hr) on a higher heating value (HHV) basis, and each HRSG will have a duct burner with a maximum heat input of 434 MMBtu/hr on an HHV basis, with a nominal output of 47 megawatts (MW)[2]. The units will be designed to be fired primarily with coke oven gas (COG), with the capability to fire natural gas or a COG/natural gas blend as an alternative (e.g., for startup, shutdown, and/or malfunction events). Following the installation of the new cogeneration units, existing boilers at the Clairton Plant will not be needed and will be shut down. In addition, the Clairton Plant is expected to be electrically independent, and/or may be a net exporter of electricity after completion of the Project, thereby significantly reducing the carbon footprint of the Mon Valley Works overall.

In addition to the two combined cycle combustion turbine trains, several other auxiliary emissions sources will also be added to the site as part of the Project. These auxiliary emission units include the following:

- Two 3.0-MMBtu/hr natural gas-fired dew point heaters
- One 75-horsepower (hp) emergency diesel fire pump with associated storage tank (200 gallons)
- One natural gas fired auxiliary package boiler (99 MMBtu/hr)
- Material handling emission sources (silos, truck unloading, and etc.)
- Paved haul roads

The Allegheny County Health Department (ACHD) requires the application of Best Available Control Technology (BACT) for each regulated NSR pollutant regardless of Prevention of Significant Deterioration (PSD) program applicability. As such, a BACT analysis was prepared for $NO_x$, CO, $PM_{10}/PM_{2.5}$, VOC, $SO_2$, ammonia, and greenhouse gases (as carbon dioxide equivalents [$CO_2e$]) for the combined cycle (cogeneration) combustion turbines. Additionally, a BACT analysis was performed for the auxiliary equipment/emission sources.

[2] Nominal output at 50 degrees Fahrenheit.

# 3.0 BACT ANALYSIS DISCUSSION

This section describes the process used for developing the BACT analysis for the combined cycle combustion turbines.

BACT is an emission limitation based on the maximum degree of reduction which the ACHD determines is achievable, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs.

The ACHD has directed by policy that BACT be determined using a "top-down" process. The "top-down" process was outlined in a December 1, 1987, memorandum from the EPA Assistant Administrator for Air and Radiation.

For purposes of this Installation Permit application, the U. S. Steel has prepared this BACT analysis consistent with EPA's top down approach, which consists of the following steps:

Step 1 – Identify all potential control technologies
Step 2 – Determine technical feasibility (of potential technologies)
Step 3 – Rank control technologies by control effectiveness
Step 4 – Evaluate most effective controls and document results
Step 5 – Select BACT

Each of these steps is discussed in further detail below.

Step 1 – Identify all potential control technologies. The first step in a "top-down" analysis is to identify, for all applicable emission units, all "available" control options. Available control options are defined as those air pollution control technologies or techniques that have a practical potential for application to the emissions unit and the regulated pollutant under evaluation and have been demonstrated in practice. Air pollution control technologies and techniques include the application of production processes or available methods, systems, and techniques, including innovative fuel combustion techniques and add-on controls.

Step 2 – Determine technical feasibility (of potential options). In the second step, the technical feasibility of the control options identified in Step 1 is evaluated with respect to source-specific factors. A demonstration of technical infeasibility should be documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

Step 3 – Rank control technologies by control effectiveness. All remaining control alternatives not eliminated in Step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis.

Step 4 – Evaluate most effective controls and document results. After the identification of available and technically feasible control technology options, the energy, environmental, and economic impacts are taken into account in this Step. For each control option, an objective evaluation of each impact is presented. Both beneficial and adverse impacts should be discussed and, where possible, quantified. If the permittee accepts the top alternative in the listing as BACT, the permittee proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis ends, and the results are proposed as BACT. If the top candidate is shown to be inappropriate due to energy, environmental, or economic impacts, the rationale for this finding is documented and the next level of control is analyzed.

Step 5 – Select BACT. The final BACT determination is presented in this Step.

The BACT analysis for the Project is also based on the following concepts:

- Emission limits are defined on a "case-by-case" analysis that considers site specific factors.
- Emission limits must be "achievable" on a long-term, day in and day out, basis.
- The technology must be available and feasible for a specific project.
- BACT does not redefine the facility as proposed (including fuels).

In establishing the emission limits, the BACT analysis must confirm that emission limits are achievable by the specific facility that is subject to the emission limits: (1) over the life of the facility; and (2) during all operating conditions, not just ideal conditions. The use of a safety factor or margin is well-established in the air permitting context to appropriately account for the uncertainty and operational variability that will occur over the life of a facility. This safety factor must be sufficient to allow permit holders to comply on a continuous basis. Emission limits should not be based on the lowest emissions rate or highest control efficiency ever documented by a similar facility for a short-term period. The emission limits must account for a full range of operating conditions and the inherent variability of complex fuel combustion and air pollution control systems.

To be considered in the permitting process, a control technology must be commercially available (i.e., it must be offered for sale on a commercial scale through commercial channels). Permittees are not required to explore research and development projects to determine whether a specific technology is suitable. In addition, to be considered feasible technology for purposes of inclusion in an analysis, a particular technology must have been previously demonstrated on a long-term basis and at commercial scale. In fact, even 2-3 years of operating history on a commercial scale has been determined to be insufficient to demonstrate that a particular technology is feasible.

The air permit and/or BACT analysis process cannot redefine the source. U. S. Steel has defined the "proposed facility" including the goals, objectives, purpose and basic design of the Project. Requiring alteration as to the type of power generating unit and/or range of fuels to be used would redefine the source.

Fuels can be an inherent part of a project design. In such cases, the air permitting process cannot be used to require a fuel other than the fuels proposed by U. S. Steel. As Congress explained, "the Administrator may consider the use of clean fuels to meet BACT requirements <u>if a permit applicant proposes</u> to meet such requirements by using clean fuel. <u>In no case is the Administrator compelled to require the mandatory use of clean fuels by a permit applicant</u>." (emphasis added). S. Rep. No. 101-228 at 338 (1989).

The first step in the "top-down" BACT process is the identification of potentially available control technologies. One of the ways to identify available control technologies is to review previous BACT determinations for similar sources. EPA's RACT/BACT/LAER Clearinghouse (RBLC) database was reviewed to identify recent BACT determinations for similar projects. This database is maintained on EPA's Technology Transfer Network website at www.epa.gov/ttn/catc. Advanced queries of the database were conducted to identify control technology determinations from January 2009 to March 2019 for sources similar to the proposed combined cycle combustion turbine. The results of the RBLC query can be found in Appendix A and Appendix B of this BACT analysis.

To identify previous control technology determinations for comparable sources, a query was run using the "standard search" in which the RBLC database was searched using the following parameters:

- Combustion turbines, Combined cycle >25 megawatts (MW), 15.250 – Other Gaseous Fuel & Gaseous Fuel Mixtures
- Combustion turbines, Combined cycle >25 MW, 15.210 – Natural Gas Combustion
- Draft Determinations and RBLC Permits issued during or after January 2000

After the queries were run, combustion turbines that were not similar (e.g., digester gas-fired, fuel oil-fired, boilers, larger than 200 MW, etc.) were eliminated from the search. Information on turbine emissions was sorted from the remaining combustion turbine listings. Very few entries for "other gaseous fuels and gaseous fuel mixtures" were found in the RBLC. A few refinery gas options were identified, but no specific combustion turbines combusting COG were identified. U. S. Steel is unaware of any other combustion turbines operating on COG. There are boilers that are operating on COG, however the boiler process and resulting emissions are significantly different than the combustion turbine process, therefore results of COG combustion in boilers is not considered to be comparable to this Project for the purposes of establishing BACT.

Appendix A contains the non-natural gas gaseous fuels RBLC results. Because the combustion turbines will also combust natural gas and/or a blend of natural gas with COG as backup to utilizing COG, the RBLC results from typical similar-sized frame combined cycle combustion turbines that combust natural gas only were also reviewed. Appendix B contains the similar-in-size RBLC results for combustion turbines utilizing natural gas for fuel.

A discussion of control options identified in the RBLC database is included in each subsection. COG is higher in sulfur than most natural gas found in the US and thus additional control was reviewed for $SO_2$ which is not typical for combined cycle combustion turbines which use traditional fuels such as natural gas. In addition, typical controls for natural gas combustion in combustion turbines do not include particulate matter ($PM_{10}/PM_{2.5}$) control, but for this project utilizing COG for fuel, additional PM control methods were reviewed.

It is important to keep in mind that this project is not subject to PSD, however emission rates presented are reflective of PSD BACT controls and emission limitations.

# 4.0 NOX BACT ANALYSIS – COMBUSTION TURBINES

The following sections outline the top-down steps for $NO_x$ emissions from the combustion turbines.

## 4.1 Step 1. Identify All Potential Control Strategies

$NO_x$ is primarily formed in combustion processes in two ways:

1. The combination of elemental nitrogen with oxygen in the combustion air within the high temperature environment of the combustor (thermal $NO_x$).
2. The oxidation of nitrogen contained in the fuel (fuel $NO_x$).

COG contains molecular nitrogen and ammonia. Therefore, the majority of the $NO_x$ emissions from the combustion turbines will originate as thermal $NO_x$. However, some $NO_x$ will be generated as the result of fuel-bound nitrogen oxidation. The rate of formation of thermal $NO_x$ is a function of residence time and free oxygen and is exponential with peak flame temperature. Natural gas contains negligible amounts of fuel-bound nitrogen, although some molecular nitrogen is present. Therefore, it is assumed that most $NO_x$ emissions from the combustion turbines will originate as thermal $NO_x$ when combusting either fuel or a blend of the two fuels.

The combustion turbines will be subject to the $NO_x$ emission limits set by the Standards of Performance for Stationary Combustion Turbines in Title 40 of the Code of Federal Regulations (CFR), Part 60, Subpart KKKK, and thus the BACT determination and resulting emission limits must be at least as stringent as this New Source Performance Standard (NSPS). During combined cycle operation, the duct burners in the HRSGs will also contribute to emissions exiting the stack. The NSPS limit for the combustion turbines and duct burners are:

- 25 ppm at 15% $O_2$ when combusting greater than 50% natural gas
- 74 ppm at 15% $O_2$ when combusting greater than 50% COG

Section 4.2 of the application narrative report identifies the applicable Subpart KKKK limits for the combustion turbines and duct burners.

Control of $NO_x$ emissions from combustion turbines is generally aimed at either the prevention of $NO_x$ formation or the capture and oxidation of post-combustion $NO_x$. Since the rate of formation of thermal $NO_x$ is a function of residence time and free oxygen, and is exponential with peak flame temperature, "front-end" control techniques are aimed at controlling one or more of these variables. These controls include the XONON™ system and low-$NO_x$ burners. The XONON system uses a catalyst to keep the system temperatures lower while low-$NO_x$ burners offer a staged combustion process, resulting in a lower peak flame temperature. Steam injection reduces the combustion temperature, thereby reducing the formation of $NO_x$.

Other control methods utilize add-on control equipment to remove $NO_x$ from the exhaust gas stream after its formation. The most common control techniques involve the injection of ammonia into the gas stream to reduce the $NO_x$ to molecular nitrogen and water. Ammonia can either be injected into the system without the use of a catalyst (selective non-catalytic reduction SNCR) or with the use of a catalyst (selective catalytic reduction, SCR). Finally, EMx™ (formerly $SCONO_x$™), a multi-pollutant control technology, relies upon a catalyst similar to the SCR process to reduce $NO_x$ emissions but does so without injecting ammonia into the exhaust gas stream.

The output from the RBLC search provided in Appendix A shows that a variety of emission limits and control technologies have been applied to combustion turbines for natural gas and other gaseous fuels combustion. The most stringent limits found during a review of EPA's database were for facilities located in ozone non-attainment areas. These facilities were required to meet such low emission limits since they were subject to Lowest Achievable Emission Rate (LAER) requirements.

Typical BACT determinations for combined cycle units that are located in attainment areas were in the 2 to 15 ppm range using low-$NO_x$ burners, water/steam injection, SCR, or a combination of these technologies. The lower emission rates listed utilize SCR.

## 4.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling $NO_x$ emissions are evaluated for technical feasibility in the following sections.

### 4.2.1 XONON™ System

The XONON™ system controls $NO_x$ emissions by preventing their formation. The key to the XONON™ system is the utilization of a chemical process versus a flame to combust fuel, thus limiting temperature and $NO_x$ formation. The XONON™ system is an integral part of the combustor. The fuel and air that are supplied to the combustor are thoroughly mixed before entering the catalyst. The catalyst is responsible for combusting the fuel to release its energy. Due to the low catalyst operating temperatures, the nitrogen molecules are not involved in the reaction chemistry; they pass through the catalyst unchanged, thereby eliminating $NO_x$ formation. The XONON™ system does have the same high outlet temperature, and some $NO_x$ is formed in the post-combustion process. However, use of the technology has limited $NO_x$ emissions to less than 2.5 ppm.

Currently, the XONON™ system has not had wide-scale application. It has been demonstrated on a 1.5-MW unit in California, with the unit operating in a base load capacity (24 hours a day, 7 days a week). Tests are underway to apply this technology to other types and sizes of turbines; however, testing data is currently unavailable. As this is a much larger combined cycle project, and the XONON™ system has yet to demonstrate applicability for such units, **the XONON™ system has been deemed technically infeasible for this Project.**

### 4.2.2 EMx™ System (formerly $SCONO_x$™)

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

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

The demonstrated application for $EM_x$™ is currently limited to combined cycle combustion turbines under approximately 50 MW in size. The $EM_x$™ system has not been demonstrated on any type of combustion source other than a combustion turbine. There are technical differences between the proposed combustion turbines versus those few sources where this technology has been demonstrated in practice. In addition, this is a combined cycle project that will utilize COG which has higher sulfur content than natural gas, and the EMx™ system has yet to demonstrate applicability for such units. Therefore, the EMx™ system has not been demonstrated to function efficiently on combined cycle combustion turbines utilizing COG and is not technically feasible. (Environmental Resource Management, 2014).

**Therefore, $EM_x^{TM}$ is technically infeasible for this Project.**

### 4.2.3 Selective Non-Catalytic Reduction

SNCR is a post-combustion $NO_x$ control technology in which a reagent (ammonia or urea) is injected into the exhaust gases to react chemically with $NO_x$, forming nitrogen and water. The success of this process in reducing $NO_x$ emissions is highly dependent on the ability to uniformly mix the reagent into the flue gas at a zone in the exhaust stream at which the flue gas temperature is within a narrow range, typically from 1,700°F to 2,000°F. To achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 seconds. The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range, the reagent will be converted to $NO_x$. Below the lower end of the temperature range, the reagent will not react with the $NO_x$ and the ammonia slip concentrations (ammonia discharge from the stack) will be very high. The flue gases from the HRSG have an exhaust temperature of approximately 350°F. Even strategically placing the ammonia injection further upstream would probably result only in peak temperatures of around 1,300°F. Such a low temperature would require that additional fuel be combusted at some point in order to raise the temperature to the levels where SNCR will operate effectively. Combustion of the additional fuel would not only increase the $NO_x$ emissions, but also all other criteria pollutants, especially CO. In addition, the added fuel used to raise the exhaust gas temperature will increase the annual operating costs for the facility.

SNCR has not been applied to any combustion turbines according to the RBLC database. Because of the comparatively low exhaust temperatures, fuel and energy requirements, environmental implications and economic considerations; **SNCR is considered to be technically infeasible for the combustion turbines and duct burners under consideration for this Project.**

### 4.2.4 Selective Catalytic Reduction

SCR is a post-combustion technology that employs ammonia in the presence of a catalyst to convert $NO_x$ to nitrogen and water. The function of the catalyst is to lower the activation energy of the $NO_x$ decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, de-activation due to aging, ammonia slip emissions, and the design of the ammonia injection system.

SCR represents state-of-the-art control for combined cycle, back-end gas turbine $NO_x$ removal. SCR technology is being permitted as LAER and BACT for combined cycle turbines at 2 to 9 ppm $NO_x$ for natural gas and refinery gas. Conventional SCR uses a metal honeycomb or "foil" catalyst support structure and requires the HRSG to reduce flue gas temperatures to less than 600°F.

The Project's turbines will operate with the exhaust gases reaching temperatures over 1,100°F prior to entering the HRSG. Duct burner firing and passage of the flue gasses through the HRSG will lower the temperature of the gas stream to approximately 350°F. By placing the catalyst bed at the correct strategic point within the HRSG, an SCR could effectively operate and reduce $NO_x$ emissions. A disadvantage of this system is that particles from the catalyst may become entrained in the exhaust stream and contribute to increased particulate matter emissions. In addition, ammonia slip reacts with the sulfur in the fuel creating ammonia bisulfates that become particulate matter. **SCR can be applied to the combined cycle turbines and duct burners and is considered technically feasible.**

### 4.2.5 Low-$NO_x$ Burners

Low NOx burners are currently available from most turbine manufacturers. This technology seeks to reduce combustion temperatures, thereby reducing $NO_x$ formation. In a conventional combustor, the air and fuel are introduced at an approximately stoichiometric ratio and air/fuel mixing occurs at the flame-front where diffusion of fuel and air reaches the combustible limit. A lean premixed combustor design premixes the fuel and air prior to combustion. Premixing results in a homogenous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher $NO_x$ emissions. A lean air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower combustion temperatures, which lowers $NO_x$ formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

The low NOx burners for this turbine cannot handle the COG fuel without significant mixing with natural gas. In order to handle the higher levels of hydrogen in the fuel, traditional diffusion combustors are required. **As such, low NOx burners are not considered technically feasible for the combined cycle combustion turbines.**

### 4.2.6 Water or Steam Injection

Steam and water injection work to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With steam 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 an efficiency penalty (typically 2 to 3%), but there is an increase in power output (typically 5 to 6%) due to the increased mass flow required to maintain turbine inlet temperature at manufacturer's specifications. Both CO and VOC emissions are increased by water injection depending on the amount of water that is injected. Water/steam injection is available for the combined cycle turbines and under consideration for this Project and is therefore considered technically feasible for the combined cycle combustion turbines.

### 4.2.7 Summary of the Technically Feasible Control Options

Technically feasible $NO_x$ control options for the combined cycle combustion turbines are summarized in Table 4-1. The expected performance has been determined considering the performance of existing systems, vendor guarantees, permitted emission limits, and the design requirements for the combustion turbines.

**Table 4-1: Summary of Technically Feasible $NO_x$ Control Technologies for Combined cycle Combustion Turbines**

| Control System | | Expected Performance (ppm @15% $O_2$) | Technical Feasibility | Comments |
|---|---|---|---|---|
| Combustion Controls | Low NOx burners | -- | Not feasible | Low NOx burners cannot handle COG without mixing with natural gas |
| | Water injection | 42 | Feasible | Standard on combustion turbine |
| Post combustion controls | XONON™ | N/A | Not feasible | Testing is still underway. Only used on one 1.5-MW unit not operating continuously. |
| | EMx™ | N/A | Not feasible | Not proven to work on COG. |
| | SNCR | N/A | Not feasible | Exhaust temperature is too low. |
| | SCR | < 9 | Feasible | 7.5 ppm is achievable with SCR on the COG |

## 4.3 Step 3. Rank the Technically Feasible Control Technologies

Add-on controls may be used for combustion turbines firing COG and natural gas. The combustion turbines under consideration come with steam injection as part of their standard packages; therefore, steam injection is assumed as the baseline for the proposed combustion turbines.

The technically feasible $NO_x$ control technologies for the combustion turbines are ranked by control effectiveness in Table 4-2.

**Table 4-2: Ranking of Technically Feasible $NO_x$ Control Technologies for Combined cycle Combustion Turbines**

| Control Technology | Reduction (%) | Controlled Emission Level (ppm)[a] |
|---|---|---|
| Selective catalytic reduction | ~80% | 7.5 ppm |
| Water injection | N/A (baseline) | 42 ppm |

(a) Emission rate for 70% to100% load, with and without duct firing for all fuels, at 15% $O_2$.

## 4.4 Step 4. Evaluate the Most Effective Controls

Recent BACT determinations have indicated $NO_x$ emission limits of 2 to 15 ppm for combined cycle units that are fired with natural gas (Appendix A). The combustion turbines under consideration are able to achieve < 9 ppm on a long-term basis with SCR while combusting either COG, natural gas or a blend of the two fuels.

The Project's combined cycle units will have an SCR system located in the HRSG, along with water injection which is standard on the combustion turbines. The SCR vendors have indicated that $NO_x$ emission rates below 9 ppm are achievable with or without the duct burners for natural gas combustion. The SCR system will therefore be able to meet 7.5 ppm for all loads down to 70% load, including when duct firing while combusting COG, natural gas or a COG-natural gas blend. Because SCR represents the most effective control and has been selected as BACT, an economic feasibility determination is not required, per 40 CFR 52.21. The energy and environmental considerations for the selected BACT are discussed below for informational purposes.

**SCR is selected as BACT for control of $NO_x$ emissions from the proposed combined cycle combustion turbines, along with water injection.**

### 4.4.1 Selective Catalytic Reduction

#### 4.4.1.1 Energy Impacts

An SCR system results in a loss of energy due to the pressure drop across the SCR catalyst. To compensate for the energy loss in the SCR system, additional fuel combustion is required to maintain the net energy output, which also results in additional air pollutant emissions.

#### 4.4.1.2 Environmental Impacts

SCR systems consist of an ammonia injection system and a catalytic reactor. Unreacted ammonia may escape through to the exhaust gas. This is commonly called "ammonia slip." Because ammonia is a $PM_{2.5}$ precursor and the Project is located in a nonattainment area, the Project is being designed to have no greater than 2 ppm ammonia slip. The ammonia that is released may also react with other pollutants in the exhaust stream to create fine particulates in the form of ammonium salts. The storing of the ammonia on-site is also an environmental and safety concern. SCR catalysts must be replaced on a routine basis, and in some cases, these catalysts may be classified as a hazardous waste. This typically requires either returning the material to the manufacturer for recycling and reuse or disposal in designated landfills.

### 4.4.2 Water Injection

#### 4.4.2.1 Energy Impacts

Water injection is usually accompanied by an efficiency penalty (typically 2 to 3%) and an increase in power output (typically 5 to 6%). No significant energy impacts are associated with water injection.

#### 4.4.2.2 Environmental Impacts

Water injection uses water, a natural resource, to control $NO_x$ emissions.

## 4.5 Step 5. Proposed $NO_x$ BACT Determination

The BACT recommended for control of $NO_x$ emissions from the combined cycle combustion turbines is water injection with SCR. These controls will meet a $NO_x$ emission limit of 7.5 ppm at 15% oxygen ($O_2$) for all loads down to 70%, with and without duct firing, for COG and natural gas combustion, including blends. Compliance will be determined with a $NO_x$ Continuous Emissions Monitoring System (CEMS) on a 30-day rolling average, excluding start-up and shutdown.

# 5.0 CO BACT ANALYSIS – COMBUSTION TURBINES

The following sections outline the top-down BACT analysis for CO emissions from the Project combustion turbines.

## 5.1 Step 1. Identify Potential Control Strategies

CO is a byproduct resulting from incomplete fuel combustion. Control of CO is typically accomplished by providing adequate fuel residence time and a high temperature in the combustion zone to complete combustion. These control factors, however, also tend to result in increased emissions of $NO_x$. Conversely, a lower $NO_x$ emission rate achieved through flame temperature control (by steam injection or dry lean pre-mix) can result in higher levels of CO emissions. A compromise is usually established where the flame temperature reduction is set to achieve a low $NO_x$ emission rate while keeping CO emissions to an acceptable level.

CO emissions from combustion turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Post-combustion CO control involves the use of catalytic oxidation; front-end CO control involves controlling the combustion process to suppress CO formation.

The technologies identified for reducing CO emissions from the Project's combustion turbines are the EMx™ system, an oxidation catalyst, and combustion controls. The standard technology for reducing CO emissions is to maintain "good combustion" through proper control and monitoring of the combustion process.

A survey of the RBLC database (Appendix A) indicated that most new combined cycle turbines in attainment areas have been required to install add-on controls to control CO emissions from combined cycle turbines combusting natural gas. CO emissions from natural gas-fired combined cycle turbines in the RBLC ranged from 0.9 to 25 ppm.

## 5.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling CO emissions are evaluated for technical feasibility in the following sections.

### 5.2.1 EMx™ System

The EMx™ system was described in the BACT analysis for $NO_x$. The $EM_x$™ system simultaneously oxidizes CO to $CO_2$, NO to $NO_2$, and then absorbs $NO_2$ onto the surface of a catalyst using a potassium carbonate absorber coating. VOCs are also removed by the catalyst system. The system does not use ammonia and operates most effectively at temperatures ranging from 300°F to 700°F. Operation of $EM_x$™ requires natural gas, water, steam, electricity, and ambient air. Steam and reformed natural gas are used periodically to regenerate the catalyst bed and are an integral part of the process. Because $EM_x$™ does not use ammonia there are no ammonia emissions from this technology.

Regeneration of the catalyst is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of oxygen. Hydrogen in the gas reacts with the nitrites and nitrates to form water and nitrogen. $CO_2$ in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst. The regeneration gas is produced by reacting natural gas with a carrier gas (such as steam) over a steam-reforming catalyst.

The demonstrated application for $EM_x$™ is currently limited to combined cycle combustion turbines under approximately 50 MW in size. The $EM_x$™ system has not been demonstrated on any type of fuel other than natural gas on a small combustion turbine.

**Therefore, the $EM_x$™ system is not considered a technically feasible method of controlling CO emissions from the proposed combined cycle combustion turbines and duct burners.**

### 5.2.2 Oxidation Catalyst

Oxidation catalysts are a post-combustion technology which does not rely on the introduction of additional chemicals, such as ammonia, for a reaction to occur. The oxidation of CO to $CO_2$ utilizes excess air present in the turbine exhaust. The activation energy required for this reaction to occur is lowered in the presence of a catalyst. Products of combustion are introduced into a catalyst bed, with the optimum temperature range for these systems being between 700°F and 1,100°F. The addition of a catalyst bed onto the turbine exhaust will create a pressure drop, resulting in back pressure to the turbine. This has the effect of reducing the efficiency of the turbine and its power generating capabilities. It is expected that the catalyst will be placed in the HRSG where the temperature will be optimal for the catalytic reaction.

**The use of an oxidation catalyst is considered to be a technically feasible method of controlling CO emissions from the proposed combined cycle combustion turbines and duct burners.**

### 5.2.3 Combustion Control

"Good combustion practices" include operational and combustion design elements to control the amount and distribution of excess air in the flue gas to ensure there is enough oxygen present for complete combustion. Such control practices applied to the proposed turbines can achieve CO emission levels of 4 ppm at 100% load.

**Good combustion practices are considered to be a technically feasible method of controlling CO emissions from the proposed combined cycle combustion turbines and duct burners.**

### 5.2.4 Summary of the Technically Feasible Control Options

The technically feasible CO control options for the proposed combined cycle combustion turbines are summarized in Table 5-1. The expected performance has been determined considering the performance of existing systems, vendor guarantees, permitted emission limits, and the design requirements for the turbines.

**Table 5-1: Summary of Technically Feasible CO Control Technologies for Combined cycle Combustion Turbines**

| Control System | | Expected Performance (ppm)[a] | Technical Feasibility | Comments |
|---|---|---|---|---|
| Combustion controls | | 42[b] | Feasible | Standard on turbines. Not an add-on control |
| Post combustion controls | Oxidation catalyst | 3 | Feasible | Produces $CO_2$ emissions |
| | EMx™ | N/A | Not feasible | Not demonstrated on COG. |

(a) Limits valid for 100% load with duct firing down to 70% load.
(b) Average ppm at 100% load with no duct firing on 70°F day.

## 5.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible CO control technologies for the combustion turbines are ranked by control effectiveness in Table 5-2.

**Table 5-2: Ranking of Technically Feasible CO Control Technologies for Combined cycle Combustion Turbines**

| Control Technology | Reduction (%) | Controlled Emission Level (ppm)[a] |
|---|---|---|
| Oxidation catalyst | 90% | 3 |
| Combustion control | Not applicable (baseline) | 42[b] |

(a) Limits valid for 100% load with duct firing down to 70% load.
(b) Average ppm at 100% load with no duct firing on a 70°F day.

## 5.4 Step 4. Evaluate the Most Effective Control Technologies

Operating the proposed combined cycle combustion turbines with good combustion practices will achieve approximately 42 ppm at 15 % $O_2$ on a long-term basis for 100% load without duct firing. With an oxidation catalyst, the emission will be reduced to 3 ppm at 15% $O_2$ for all fuels, with and without duct burning. The next step is to review each of the technically feasible control options for environmental, energy, and economic impacts.

### 5.4.1 Oxidation Catalyst

#### 5.4.1.1 Energy Impacts

The addition of an oxidation catalyst bed into the turbine exhaust will create additional pressure drop, resulting in back pressure to the turbine. This has the effect of reducing the efficiency of the turbine and its power-generating capabilities.

#### 5.4.1.2 Environmental Impacts

The oxidation catalyst oxidizes CO to $CO_2$, which would be released to the atmosphere. $CO_2$ is a greenhouse gas and a regulated pollutant. However, the oxidation catalyst will also reduce the amount of methane ($CH_4$, also a greenhouse gas). Considering the global warming potential of both greenhouse gases, the net effect is an overall decrease in greenhouse gas emissions on a $CO_{2e}$ basis.

As with many controls that utilize catalysts for removal of pollutants, the catalyst must be disposed of after it is spent. The catalyst may be considered hazardous waste and require special treatment or disposal. Even if it is not hazardous, it adds to the existing landfills.

#### 5.4.1.3 Economic Impacts

U. S. Steel has selected the highest control available for CO emissions; therefore, no economic analysis is necessary.

The energy and environmental impacts listed above do not outweigh the benefits of controlling CO emissions with the use of an oxidation catalyst.

**An oxidation catalyst along with good combustion practices was selected as BACT for control of CO emissions from the combined cycle combustion turbines.**

## 5.5 Step 5. Proposed CO BACT Determination

The BACT recommended for control of CO emissions from the proposed combustion turbines is good combustion practices and the use of an oxidation catalyst. These controls will meet a CO emission limit of 3 ppm at 15% $O_2$ during steady-state conditions for all loads down to 70% with and without duct firing for all fuels. Compliance with the proposed limit is based on a 3-run stack test average as conducted in accordance with the approved stack testing protocol.

# 6.0 VOC BACT ANALYSIS - COMBUSTION TURBINES

The following sections outline the top-down BACT process for VOC emissions from combustion turbines and duct burners.

## 6.1 Step 1. Identify Potential Control Strategies

Like CO, VOC is a product resulting from incomplete combustion. VOC emissions occur when a portion of the fuel remains unburned or is only partially burned during the combustion process. With COG and natural gas, some organics are unreacted trace constituents of the gas, while others may be products of the heavier hydrocarbon constituents. Partially-burned hydrocarbons result from poor air-to-fuel mixing prior to, or during, combustion or incorrect air-to-fuel ratios in the combustion turbine.

The technologies identified for reducing VOC emissions from combined cycle combustion turbines are the same as identified for CO control: the EMx™ system, an oxidation catalyst (also referred to as a CO catalyst), and combustion controls. The standard technology for reducing VOC emissions is to maintain "good combustion" through proper control and monitoring of the combustion process through the air-to-fuel ratio. In addition, since most of the BACT determinations for CO for combined cycle combustion turbines also include an oxidation catalyst, determinations for VOC emissions often include an oxidation catalyst along with good combustion practices. A survey of the RBLC database (see results in Appendix A) indicates that combustion controls is the most prevalent BACT control for VOC emissions from combustion turbines. Oxidation catalysts are also listed as LAER and BACT for VOC emissions from the combustion of natural gas and other gaseous fuels. VOC emissions from the permitted facilities ranged from 1 ppm to 4 ppm for natural gas-fired combustion turbines and 1 ppm to 4 ppm for other gaseous fuels combustion.

## 6.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling VOC emissions are evaluated for technical feasibility in the following sections.

### 6.2.1 EMx™ System

The EMx™ system was described in the BACT analysis for $NO_x$ (Section 4.2.2). It can also be evaluated for controlling VOC emissions by up to 20%. The EMx™ system does not use ammonia and operates most effectively at temperatures ranging from 300°F to 700°F. Operation of $EM_x$™ requires natural gas, water, steam, electricity, and ambient air. Steam and reformed natural gas are used periodically to regenerate the catalyst bed and are an integral part of the process. Because $EM_x$™ does not use ammonia as a reagent, there are no ammonia emissions from this technology.

Regeneration of the catalyst is accomplished by passing a dilute hydrogen reducing gas across the surface of the catalyst in the absence of oxygen. Hydrogen in the gas reacts with the nitrites and nitrates to form water and nitrogen. $CO_2$ in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst. The regeneration gas is produced by reacting natural gas with a carrier gas (such as steam) over a steam-reforming catalyst.

The demonstrated application for $EM_x$™ is currently limited to combined cycle combustion turbines under approximately 50 (MW) in size, combusting natural gas only. The $EM_x$™ system has not been demonstrated on any type of fuel other than natural gas.

**Therefore, the $EM_x$™ system is not considered a technically feasible method of controlling VOC emissions from the proposed combined cycle combustion turbines and duct burners.**

### 6.2.2 Oxidation Catalyst

As discussed in Section 5.2.2, oxidation catalysts are a post-combustion technology that do not rely on the introduction of additional chemicals, such as ammonia or urea, for a reaction to occur. The catalyst beds that reduce CO also promote the oxidation of VOC, thereby reducing VOC emissions. Such systems typically achieve a maximum of 35 to 40% removal of VOC, as opposed to the much higher efficiencies achieved for CO reduction.

**The use of an oxidation catalyst for VOC control is considered to be technically feasible for the combined cycle combustion turbines.**

### 6.2.3 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to ensure there is enough oxygen present for complete combustion (i.e. controlling the air-to-fuel ratio). Such control practices applied to the proposed combustion turbines can achieve VOC emission levels of approximately 12 ppm when combusting natural gas or COG without an oxidation catalyst for all loads down to 70% without duct firing.

**Good combustion practices are a technically feasible method of controlling VOC emissions from the proposed combustion turbines.**

### 6.2.4 Summary of the Technically Feasible Control Options

The technical feasibility of the VOC control options for the proposed combustion turbines is summarized in Table 6-1. The expected performance has been determined considering the performance of existing systems, vendor guarantees, permitted emission limits, and the design requirements for the turbines.

**Table 6-1: Summary of Technically Feasible VOC Control Technologies for Combined cycle Combustion Turbines**

<table>
<tr><th colspan="2">Control System</th><th>Expected Performance (ppm)</th><th>Technical Feasibility</th><th>Comments</th></tr>
<tr><td colspan="2">Combustion controls</td><td>12<br>(with duct firing)</td><td>Feasible</td><td>Standard on the proposed combustion turbine. Not an add-on control</td></tr>
<tr><td rowspan="2">Post combustion controls</td><td>Oxidation catalyst</td><td>5.1</td><td>Feasible</td><td>Produces $CO_2$ emissions.</td></tr>
<tr><td>EMx™</td><td>N/A</td><td>Not feasible</td><td>Not demonstrated on COG fuel</td></tr>
</table>

## 6.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible VOC control technologies for the proposed combined cycle combustion turbines are ranked by control effectiveness in Table 6-2.

**Table 6-2: Ranking of Technically Feasible VOC Control Technologies for Combined cycle Combustion Turbines**

| Control Technology | Reduction (%) | Controlled Emission Level (ppm)[a] |
|---|---|---|
| Oxidation catalyst | 40% | 5.1 |
| Combustion control | Not applicable (baseline) | 12 |

(a) Emission rate for 100% load to 70% load, with and without duct firing.

## 6.4 Step 4. Evaluate the Most Effective Control Technologies

The next step is to review each of the technically feasible control options for environmental, energy, and economic impacts.

## 6.4.1 Oxidation Catalyst

### 6.4.1.1 Energy Impacts

The addition of a catalyst bed onto the turbine exhaust for the oxidation catalyst will create additional pressure drop, resulting in increased back pressure to the turbines. This has the effect of reducing the efficiency of the turbines and their power-generating capabilities.

### 6.4.1.2 Environmental Impacts

The oxidation catalyst oxidizes CO and VOC to $CO_2$ which is released to the atmosphere. $CO_2$ is a greenhouse gas and a regulated pollutant.

As with many controls that utilize catalysts for pollutant removal, the catalyst must be disposed of after it is spent. The catalyst may be considered hazardous waste and require special treatment or disposal. Even if it is not hazardous, it adds to the existing landfills.

### 6.4.1.3 Economic Impacts

U. S. Steel has selected the highest control available for VOC emissions; therefore, no economic analysis is necessary.

## 6.4.2 Combustion Control

No energy, environmental, or economic impacts are associated with combustion controls.

## 6.5 Step 5. Proposed VOC BACT Determination

The BACT recommended for control of VOC emissions from the proposed combustion turbine is the use of good combustion practices with the added control of an oxidation catalyst. These controls will meet a VOC emission limit of 5.1 ppm at 15% $O_2$ with and without duct firing, for all steady state loads down to 70% for COG and natural gas combustion. This emission rate represents the lowest emission rate achievable for VOC emissions with an oxidation catalyst for these turbines combusting primarily COG. Compliance with the proposed limit is based on a 3-run stack test average as conducted in accordance with the approved stack testing protocol.

# 7.0 $SO_2$ BACT ANALYSIS – COMBUSTION TURBINES

The following sections outline the top-down BACT analysis for $SO_2$ emissions from combustion turbines. Typical natural gas combustion in combustion turbines results in very low $SO_2$ emissions and as such, $SO_2$ is typically much lower than other uncontrolled criteria pollutants. However, to further reduce $SO_2$ emissions, U. S. Steel has reviewed post-combustion techniques that may be applicable to the combustion turbines and duct burners.

The combustion turbines will be subject to the $SO_2$ emission limits set by the Standards of Performance for Stationary Combustion Turbines in Title 40 of the Code of Federal Regulations (CFR), Part 60, Subpart KKKK, and thus the BACT determination and resulting emission limits must be at least as stringent as this New Source Performance Standard (NSPS). During combined cycle operation, the duct burners in the HRSGs will also contribute to emissions exiting the stack. The NSPS $SO_2$ limit for the combustion turbines and duct burners is 0.06 lb/MMBtu heat input or 0.90 lb/MW-hr (gross) heat output and thus the BACT limit needs to be at least as stringent as the NSPS limit. Part 4.2 in the application narrative identifies the applicable Subpart KKKK limits for the combustion turbines and duct burners.

## 7.1 Step 1. Identify Potential Control Strategies

The majority of the fuel sulfur combusted in the combustion turbine leaves the turbine as $SO_2$ or is converted to other forms of sulfur such as sulfuric acid ($H_2SO_4$) mist or as ammonium sulfate. The RBLC does not list any add-on controls for $SO_2$ emissions from combustion turbines. However, due to the combustion of COG, RBLC entries for $SO_2$ controls typical of a coal-fired boiler were evaluated for these turbines.

### 7.1.1 Pre-Combustion Control of $SO_2$

U. S. Steel already pre-treats the COG prior to combustion at Clairton with a vacuum carbonate scrubber followed by a two stage Claus process and Shell Claus Off-gas Treatment (SCOT) to remove nearly all of the hydrogen sulfide contained in the fuel. This process is not capable of removing the remaining organic sulfur compounds present in low concentrations in the coke oven gas. A review of available technologies did not identify a single stage process capable of removing the multiple compounds to further reduce the sulfur in the gas prior to combustion.

### 7.1.2 Post-Combustion Control of $SO_2$

As stated previously, $SO_2$ emission control on simple-cycle and combined cycle combustion turbines has traditionally not been required. Due to the expected sulfur content of the COG, U. S. Steel has reviewed post-combustion techniques that may be applicable to the combustion turbines and duct burners. The $SO_2$ controls typically applied to coal-fired power plants are robust systems that have been proven in practice to control $SO_2$ emissions from the combustion of coal. Common technologies used for $SO_2$ emission control at coal-fired power plants, generally referred to as flue gas desulfurization (FGD), include the following:

- Wet FGD
- Semi-dry FGD
    - Circulating dry scrubber (CDS)
    - Spray dryer absorber
- Dry FGD
    - ReACT
    - Dry sorbent injection

## 7.2 Step 2. Identify Technically Feasible Control Technologies

Each of the potential $SO_2$ emission control technologies, and their technical feasibility, are discussed in this section.

### 7.2.1 Pre-combustion $SO_2$ Control

The pre-combustion sulfur removal that U. S. Steel performs on the COG is state of the art and among the highest level of treatment performed in the United States. Additional pre-combustion sulfur removal options were reviewed but were dismissed as technically infeasible for several reasons, but most importantly is that no other facilities are using these systems for additional sulfur controls. These processes for further sulfur removal are associated with excessive costs, ground-space requirements (especially considering this is an existing facility), corrosion problems, potential reagent fouling due to other constituents in the COG, and other process issues. As such control of $SO_2$ will be limited to review of post-combustion controls. **The pretreatment of the COG that U. S. Steel is performing currently is considered the baseline for this BACT discussion and further removal via pre-treatment processes is not considered feasible for the combustion turbines and duct burners.**

### 7.2.2 Post-combustion $SO_2$ Control

#### 7.2.2.1 Wet FGD

Wet FGD processes are similar to dry FGD technology, except the sorbent is injected into the flue in an aqueous slurry instead of a dry powder. $SO_2$ in the flue gas dissolves into the alkaline slurry to form an aqueous solution of neutralized sulfate salts, which are then dewatered and disposed of or marketed as a by-product. Wet FGD systems have $SO_2$ removal efficiencies of 90 to 95% depending on the sorbent used. While wet FGD is widely used on coal-fired power plants to achieve high levels of $SO_2$ control, this technology cannot achieve $H_2SO_4$ mist or particulate emission reductions as high as those seen with a dry FGD process. **Wet FGD is considered technically feasible for use on the combustion turbines.**

### 7.2.2.2 Semi-Dry FGD

Two types of semi-dry FGD processes are available with different operating characteristics. Each type is discussed below.

#### 7.2.2.2.1 Spray Dryer Absorber

Semi-dry FGD, also called spray dryer absorption (SDA) is very similar to dry FGD, except the alkaline sorbent is injected into the flue gas as a highly-concentrated alkaline slurry. The water in the alkaline slurry typically evaporates, leaving the alkaline sorbent to react with the gas-phase sulfur compounds to form sulfate salts. Fabric filters and electrostatic preceptors (ESPs) are suitable means of particulate control following FGD reactors. Particulate matter controls are discussed further in Section 8.0. Semi-dry FGD systems have achieved $SO_2$ removal efficiencies between 80 and 90% at coal-fired power plants. **The use of SDA paired with particulate matter control is a technically feasibly control option for the combustion turbines although it has not been placed on combustion turbines.**

#### 7.2.2.2.2 Circulating Dry Scrubber

Circulating dry FGD, or CDS, is a semi-dry FGD technology that recirculates the alkaline sorbent in the system after it has reacted with $SO_2$ in the flue gas to form sulfate salts. Hydrated lime is injected into the system along with a separate nozzle for water injection. Sulfate salts are formed and then are removed from the flue gas by the downstream, particulate control technology. The salts are then recirculated into the flue gas for enhanced $SO_2$ removal and improved sorbent usage. CDS systems have achieved $SO_2$ removal efficiencies of greater than 95% at coal-fired power plants. **CDS paired with particulate matter control is technically feasible for this project although it has not been placed on combustion turbines.**

### 7.2.2.3 Dry FGD

Dry FGD processes can vary, but the basic control process involves injecting a dry alkaline sorbent, such as lime or limestone, directly into the furnace (for a coal-fired steam generator), an FGD reactor, or downstream ductwork. The alkaline sorbent reacts with the gas-phase sulfur compounds to form sulfate salts, which are then removed using downstream particulate control technologies. Fabric filters and electrostatic preceptors (ESPs) are suitable means of particulate control following dry FGD reactors. Two types of dry FGD are discussed below.

#### 7.2.2.3.1 ReACT™

The ReACT™ system for $SO_2$ control is a regenerative dry FGD system with a three-stage process. Ammonia is injected into flue gas and the gas passes through a slowly-moving bed of activated coke (an adsorber). The activated coke adsorbs $SO_2$, and clean gas is vented to the exhaust stack. The activated coke is then conveyed to a regenerator, which thermally desorbs sulfur compounds from the coke to create a sulfur-rich gas. The regenerated activated coke is returned to the adsorber, and the sulfur-rich gas is vented to a sulfuric acid recovery unit which extracts sulfur compounds from the regenerator gas. The first U.S. commercial installation of this technology was implemented at a 321-MW coal-fired power plant and controls $SO_2$ emissions by more than 90%. With very little operating data, even on coal-fired power plants, **the use of the ReACT™ system for $SO_2$ control is not considered technically feasible for reduction of $SO_2$ emissions from combustion turbines utilizing COG.**

#### 7.2.2.3.2 Dry Sorbent Injection

Sorbent injection technologies employed to control $SO_2$ emissions consist of injecting a dry, powdered sorbent or reactant upstream of a particulate control device. The most common injection chemicals for $SO_2$ removal include sodium carbonate ($Na_2CO_3$), sodium bicarbonate ($NaHCO_3$) and hydrated lime ($Ca(OH)_2$). Trona (sodium sesquicarbonate dihydrate, $Na_2CO_3 \bullet NaHCO_3 \bullet 2H_2O$) has also been used. The sorbents react with $SO_2$ to produce a solid byproduct that can be collected in the particulate control system. Adequate mixing of the sorbent in the flue gas and sufficient residence time for reaction are needed to achieve $SO_2$ removal.

Sorbent injection has been used at coal-fired power plants to control $H_2SO_4$ emissions. These applications have also achieved $SO_2$ emission reductions, but at a lower control efficiency. The sorbents used in the sorbent injection process will react preferentially with sulfur trioxide ($SO_3$), $H_2SO_4$ and hydrochloric acid (HCl) in the flue gas before reacting with the $SO_2$. Therefore, large quantities of sorbent are needed to achieve moderate levels of $SO_2$ removal (40% to 60% control). Adding large quantities of sorbent increases the loading on the downstream particulate control device, which impacts its performance. Additional loading leads to higher pressure drop across the particulate control device, requiring more fan power to operate. **Sorbent injection is considered technically feasible for use on the combustion turbines.**

### 7.2.3 Summary of the Technically Feasible Control Options

The technical feasibility of the $SO_2$ control options evaluated for the proposed combustion turbines is summarized in Table 7-1. The expected performance of these technologies has been determined considering the performance of existing systems, vendor guarantees, permitted emission limits, and the design requirements for the turbines.

**Table 7-1: Summary of Technically Feasible $SO_2$ Control Technologies for Combined cycle Combustion Turbines**

| Control System | | Expected Reduction [a,b] | Technical Feasibility | Comments |
|---|---|---|---|---|
| Pre-combustion controls | | N/A (baseline) | Feasible | Further pre-combustion controls beyond baseline have many identified issues: space required, corrosion and fouling |
| Post combustion controls | Wet FGD | 70% - 95% | Feasible | Increases or does not control PM |
| | Semi-dry FGD – Circulating dry scrubber | 70-95% | Feasible | Not demonstrated on combustion turbines, requires downstream PM control device |
| | Semi-dry FGD – Spray dry absorber | 70% - 90% | Feasible | Not demonstrated on combustion turbines, requires downstream PM control device |
| | Dry FGD – ReACT | 90% | Not feasible | Not demonstrated on combustion turbines, very little experience on coal-fired power plants |
| | Dry FGD - Dry sorbent injection | 40-60% | Feasible | Not demonstrated on combustion turbines, requires downstream PM control device |

(a) Based on U.S. EPA Air Pollution Control Technology Fact Sheet for Flue Gas Desulfurization (FGD) – Wet, Spray-dry and Dry Scrubbers (EPA-452/F-03-034).

(b) **Note most performance data is based on coal-fired boiler applications.** The sulfur content of the COG, natural gas and COG-natural gas blend will be lower. The $SO_2$ removal efficiency will therefore be lower than that seen with a coal-fired boiler application. The lower end of ranges shown is more reflective of a lower-sulfur gaseous fuel.

## 7.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible $SO_2$ control technologies for the combustion turbines are ranked by control effectiveness in Table 7-2.

**Table 7-2. Ranking of Technically Feasible $SO_2$ Control Technologies for Combined cycle Combustion Turbines**

| Combustion Turbine Option | Reduction (%) |
|---|---|
| Circulating Dry Scrubber (CDS) | 70 - 95% |
| Wet FGD | 70 – 95% |
| Spray Dryer Absorber (SDA) | 70 – 90% |
| Dry sorbent injection | 40 – 60% |

## 7.4 Step 4. Evaluate the Most Effective Control Technologies

Step 4 evaluates the energy, environmental and economic impacts from the add-on $SO_2$ control technologies for $SO_2$ emissions from the combustion turbines.

### 7.4.1 Wet FGD

#### 7.4.1.1 Energy Impacts

The pumping of sorbent slurry is the most energy intensive component in the operation of an FGD system. As such, wet and semi-dry FGD systems have higher overall energy demands than dry FGD systems. Wet and semi-dry FGD systems do not require as fine of a sorbent powder as dry FGD systems. This results in a smaller energy requirement for sorbent pulverization.

#### 7.4.1.2 Environmental Impacts

Most wet FGD systems use calcium or sodium-based sorbents. A wet FGD system typically uses limestone for the reaction and produces gypsum as a by-product. The limestone and gypsum material handling will increase $PM/PM_{10}/PM_{2.5}$ emissions from the Project. Since Allegheny County is nonattainment for $PM_{2.5}$, this could be a significant issue. Wet FGD systems also create additional emissions of $CO_2$, a regulated greenhouse gas. Further, a wet FGD system will not control $H_2SO_4$ emissions as well as semi-dry and dry FGD technologies.

#### 7.4.1.3 Economic Impacts

Wet FGD systems have higher capital and annual operating costs than dry and semi-dry FGD systems. As wet FGD systems saturate the flue gas, the absorber tower and inlet and outlet ductwork must be constructed of high-grade alloy materials. Wet FGD systems use large pumps to circulate the alkaline slurry, which increases the power consumption of the system. However, wet FGD systems require less expensive reagents (limestone, $CaCO_3$) than dry or semi-dry FGD systems.

Because wet scrubbing may increase emissions of PM/$PM_{10}$/$PM_{2.5}$ from the Project in a $PM_{2.5}$ nonattainment area and because wet scrubbing is much more expensive than dry FGD and semi-dry FGD systems, **wet FGD has been removed from consideration for $SO_2$ control from the combustion turbines.**

### 7.4.2 Semi-Dry FGD – Spray Dryer Absorber

#### 7.4.2.1 Energy Impacts

The pumping of sorbent slurry is considered to be the most energy intensive component in the operation of an FGD system. As such, semi-dry FGD systems have higher overall energy demands than dry FGD systems. Semi-dry FGD systems do not require as fine of a sorbent powder as dry FGD systems. This results in a smaller energy requirement for sorbent pulverization. Semi-dry FGD systems require the use of a downstream particulate control device. These devices contribute additional pressure drop to the system, which requires additional fan power.

#### 7.4.2.2 Environmental Impacts

Most semi-dry FGD systems use calcium-based sorbents. The reaction of these alkaline reagents with gas-phase sulfur compounds results in the formation of sulfur salts, which must be disposed of. Semi-dry FGD systems absorb HCl, HF and mercury from flue gas in addition to $SO_2$, which is considered to be an environmentally-beneficial impact of operating a semi-dry FGD system.

#### 7.4.2.3 Economic Impacts

SDA systems will have higher annual costs than CDS systems due to the higher amount of sorbent that is required and not "circulated" back into the system. As the flue gas is not saturated, it is less corrosive and lower-cost materials of construction can be used. However, semi-dry FGD systems require more expensive reagents (lime, CaO) than wet FGD systems.

### 7.4.3 Semi-Dry FGD – Circulating Dry Scrubber

#### 7.4.3.1 Energy Impacts

Dry and semi-dry systems benefit from not requiring the pumping of a sorbent slurry. The pumping of a sorbent slurry is the most energy intensive component in the operation of an FGD system. As such, dry FGD systems have lower overall energy demands than wet and semi-dry FGD systems. Semi-dry FGD systems do not require the finer sorbent that dry FGD systems require. This results in less energy requirements for sorbent pulverization for the semi-dry systems. Dry and semi-dry FGD systems also require the use of a downstream particulate control device. These devices contribute additional pressure drop to the system, which requires additional fan power.

#### 7.4.3.2 Environmental Impacts

Semi-dry FGD systems use calcium-based sorbents, and the reaction of these alkaline reagents with gas-phase sulfur compounds results in the formation of sulfur salts, which must be disposed of. These systems FGD systems absorb HCl, hydrofluoric acid (HF), and other acid gases from flue gas in addition to $SO_2$, which is considered to be an environmentally-beneficial impact of operating a dry FGD system.

#### 7.4.3.3 Economic Impacts

CDS systems have lower annual operating costs than dry FGD and spray dryer absorber because the design require less water and power. As the flue gas is dry, it is less corrosive and lower-cost materials of construction can be used. However, CDS FGD systems require more expensive reagents (lime, CaO) than wet FGD systems.

### 7.4.4 Dry FGD - Dry Sorbent Injection

#### 7.4.4.1 Energy Impacts

Dry sorbent injection is not an energy-intensive technology. Blowers are used to inject the dry sorbent into the flue gas, so large pumps are not required as in a wet FGD system. However, dry sorbent injection does require the use of a downstream particulate control device. These devices contribute additional pressure drop to the system, which requires additional fan power.

#### 7.4.4.2 Environmental Impacts

Dry sorbent injection will also absorb acid gases, such as HCl and HF from flue gas in addition to $SO_2$, which is considered to be an environmentally-beneficial impact of operating a dry sorbent injection system.

#### 7.4.4.3 Economic Impacts

Dry sorbent injection systems have lower capital costs than dry, semi-dry and wet FGD systems because the designs require no water and less power. This technology does not require a large reactor. However, dry sorbent injection requires large amounts of expensive reagents to achieve moderate levels of $SO_2$ removal.

## 7.5 Step 5. Proposed $SO_2$ BACT Determination

The use of a circulating dry scrubber and a fabric filter represents BACT for $SO_2$ control in the proposed combined cycle combustion turbines. These operational controls will limit $SO_2$ emissions, including duct burner emissions, to 0.024 lb/MMBtu. Compliance with the proposed limit is based on a 3-run stack test average as conducted in accordance with the approved stack testing protocol.

# 8.0 PM BACT ANALYSIS – COMBUSTION TURBINES

The following sections outline the top-down steps for particulate matter ($PM/PM_{10}/PM_{2.5}$) emissions from the combustion turbines.

## 8.1 Step 1. Identify Potential Control Strategies

Particulate ($PM/PM_{10}/PM_{2.5}$) emissions from gaseous fuels in combustion sources consist of inert contaminants in gas, sulfates from fuel sulfur or mercaptans used as odorants, dust drawn in from the ambient air, and particles of carbon and hydrocarbons resulting from incomplete combustion. Therefore, units firing fuels with low ash content, low sulfur content and high combustion efficiency exhibit correspondingly low particulate emissions. COG is proposed as the primary fuel for the combustion turbines with natural gas and blends of the two fuels as back-up. The COG has a higher sulfur content than natural gas, therefore, as discussed in the $SO_2$ BACT, additional sulfur control is proposed.

A contributor to $PM/PM_{10}/PM_{2.5}$ emissions in combined cycle turbines with SCR for $NO_x$ control is the ammonium sulfates that are produced when $NO_x$ and ammonia react with sulfur in the fuel. Sulfur is present in all proposed fuels for this Project. Because of the sulfur, ammonium sulfates can form, as illustrated by the following equations:

$$2NH_3 + SO_3 + H_2O \rightarrow (NH_4)_2\ HSO_4$$

$$NH_3 + SO_3 + H_2O \rightarrow NH_4\ HSO_4$$

Ammonium sulfates are also formed when the ammonia content of the flue gas exceeds that of $SO_3$. The amount of ammonium bisulfate can then increase as the ammonia slip increases. Other variables include velocity and temperature profiles, oxygen levels, water content, cycling, presence of an oxidation catalyst or duct burner and ammonia-to-$SO_3$ ratios. Therefore, it is expected that combustion turbines with SCR will have higher particulate emissions than those without SCR.

Post-combustion controls, such as ESPs or baghouses, have never been applied to commercial gas-fired combustion turbines. However, the project anticipates the use of dry flue gas desulfurization (FGD) to control $SO_2$ emissions while combusting COG. This method of $SO_2$ control consists of injecting alkaline reagents into the flue gas. The reagent absorbs and reacts with $SO_2$ in the flue gas to form salt particles that must be removed from the gas stream. Because the selected method of $SO_2$ control will require the control of particulate matter emissions, control technologies that have never been implemented on commercial combustion turbines (fabric filters, dry ESPs and wet ESPs) are being considered for this project.

A survey of the RBLC database (Appendix A and Appendix B) shows no add-on PM/$PM_{10}$/$PM_{2.5}$ control technologies for combined cycle combustion turbine units. Proper combustion control and the firing of fuels with negligible or zero ash content (such as natural gas) is the predominant control method listed.

## 8.2 Step 2. Identify Technically Feasible Control Technologies

Particulate control devices are not typically installed on gas turbines. Post-combustion controls, such as ESPs or baghouses, have never been applied to commercial gas-fired turbines. However, due to the expected particulate loading (including the PM due to the circulating dry scrubber), review of the options for post-combustion control of PM emissions was performed.

### 8.2.1 Dry Electrostatic Precipitator (ESP)

A dry ESP is a PM control technology that utilizes electrical charges to attract particulate matter present in the gas stream. An ESP consists of negatively charged discharge electrodes and positively charged collection plates. The negatively charged electrodes create a corona of electrical charges transmitting a negative charge to the particulate matter in the gas stream. The negatively charged particulate matter is then attracted to the ESP's positively charged collection plate. Particulate matter accumulates on the collection plate until the plate is mechanically "rapped" causing the PM to fall into hoppers. The PM that collects in the hoppers is then removed by the waste handling system. An ESP consists of a series of the electrical fields described above in order to capture any PM that may be re-entrained in the flue gas stream during rapping. Some emissions during rapping of the last field are unavoidable.

Dry ESPs are intentionally operated at high temperatures to prevent corrosion problems that can result from condensable acid gases. Dry ESPs are technically feasible, demonstrated, and an accepted control technology for reducing PM emissions. **Dry ESPs will be retained for further BACT analysis as a feasible control technology for filterable PM emissions.**

### 8.2.2 Wet Electrostatic Precipitator (WESP)

A wet ESP (WESP) operates in saturated flue gas conditions where the flue gas is below the dew point of many acid gases and other condensable particulate materials. The collector plates of a WESP are washed with water instead of by "rapping" as in a dry ESP. The typical location of a WESP is downstream of a wet FGD system used for $SO_2$ control. WESP systems have limited demonstrated performance on coal-fired applications. In the few applications that have included a WESP system, the unit fired high-sulfur bituminous coal, and the WESP system was primarily installed for $H_2SO_4$ control.

This Project proposes the use of dry FGD technology for $SO_2$ control, which will reduce $H_2SO_4$ upstream of the particulate fabric filter. The dry FGD system will require a baghouse as the downstream particulate control device as an integral part of the system. The particulate loading from the dry FDG system is too high for a dry ESP or WESP. The fabric filter is also needed to provide to residence time required to complete the reaction between the reagent (lime) and the $SO_2$ in the flue gas.

**A WESP is not considered technically feasible for this project because WESPs operate in saturated conditions typical of those following wet FGD, and wet FGD has been eliminated as a technically feasible control option.**

### 8.2.3 Fabric Filter Baghouse

A fabric filter baghouse is a particulate collection device that utilizes fabric filters or "bags" to collect particulate matter. The design for a fabric filter baghouse is fairly simple. The flue gas enters an enclosure that contains compartmentalized groups of bags, then is directed through the bags. As the flue gas enters the fabric filter enclosure, particulate matter accumulates on the bags and a "filter cake" is formed on the outside of the bags. The filter cake is a significant part of the filtering media in a fabric filter. The filtered flue gas then exits the baghouse.

When the pressure drop across the baghouse reaches a set level due to filter cake buildup, ambient air is pulsed into the inside of bags to knock the filter cake off the bag and into hoppers below. The particulate matter is then handled by a pneumatic ash handling system and sent to disposal. The bags are operated in a manner to allow for cleaning, maintenance, and repair of one compartment (or group of bags) at a time.

Fabric filter baghouses are highly efficient, technically feasible, demonstrated, and an accepted control technology for reducing filterable PM emissions. **Fabric filter baghouses are considered a technically feasible control technology for PM emissions from the combustion turbines.**

## 8.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible $PM/PM_{10}/PM_{2.5}$ control technologies for the combustion turbines are ranked by control effectiveness in Table 8-1.

**Table 8-1: Ranking of Technically Feasible $PM/PM_{10}/PM_{2.5}$ Control Technologies for Combined cycle Combustion Turbine**

| Control Technology | Control Efficiency (Range, %) |
|---|---|
| Fabric Filter (Baghouse) | 99 - 99.9[a] |
| Dry ESP | 96.0 - 99.2[b] |

(a) Based on U.S. EPA Air Pollution Control Technology Fact Sheet for Fabric Filter - Pulse-Jet Cleaned Type (EPA-452/F-03-025) and Fabric Filter - Reverse-Air/Jet Cleaned Type (EPA-452/F-03-026).

(b) Based on U.S. EPA Air Pollution Control Technology Fact Sheet for Dry ESP - Wire-Pipe Type (EPA-452/F-03-027) and Dry ESP - Wire-Plate Type (EPA-452/F-03-028). Note this is based on coal-fired boiler applications with likely much higher particulate loading. There is no direct information on how a dry ESP will perform on a high-sulfur gaseous fuel.

## 8.4 Step 4. Evaluate the Most Effective Control Technologies

A baghouse was identified as the control technology with the greatest control efficiency. Because a baghouse is the highest ranked technology, further energy, environmental, and economic analyses are not warranted.

## 8.5 Step 5. Proposed $PM/PM_{10}/PM_{2.5}$ BACT Determination

The use of a baghouse represents BACT for $PM/PM_{10}/PM_{2.5}$ control in the proposed combined cycle combustion turbines. These controls will limit $PM/PM_{10}/PM_{2.5}$ emissions, including duct burner emissions, to 0.014 lb/MMBtu for COG and natural gas combustion. This emission rate includes front and back half $PM/PM_{10}/PM_{2.5}$ emissions, takes into account emissions from the ammonium sulfate produced from sulfur and ammonia slip that could be emitted as $PM/PM_{10}/PM_{2.5}$, and includes the duct burner emissions that will be emitted out of the turbine stack. Compliance with this limit is based on 3-run stack tests based on an approved stack testing protocol.

# 9.0 AMMONIA BACT ANALYSIS – COMBUSTION TURBINES

Because Allegheny County is nonattainment for $PM_{2.5}$, the ACHD has determined that ammonia emissions are also a criteria pollutant that should be subject to BACT requirements. The following sections outline the top-down BACT analysis for ammonia emissions from the Project combustion turbines.

## 9.1 Step 1. Identify Potential Control Strategies

### 9.1.1 Limiting Ammonia Input

Limiting the amount of ammonia injected upstream of an SCR system is the primary method to prevent ammonia slip. The proposed $NO_x$ BACT emissions limitation takes into account the need to also limit ammonia slip. As the $NO_x$ limit decreases, more ammonia is needed and ammonia slip emissions increase. For this analysis, maintaining a proper stoichiometric ratio to limit ammonia slip is considered a technically feasible, efficient, and demonstrated control strategy for controlling ammonia emissions.

### 9.1.2 Using Ammonia Instead of Urea in the SCR

The SCR can use various forms of ammonia for the reagent. Anhydrous ammonia, aqueous ammonia and urea are the most common forms of ammonia used in SCR systems. Because U. S. Steel already has support facilities and tanks of anhydrous ammonia on-site, they will continue to use the existing ammonia storage and handling systems for the new SCR system for the combustion turbines. The use of anhydrous ammonia as a reagent results in lower levels of ammonia slip than urea. The use of ammonia as a reagent is considered a technically feasible control technology.

## 9.2 Step 2. Identify Technically Feasible Control Technologies

There are no add-on controls available for ammonia emissions from combustion turbines. The two methods of reducing ammonia emissions, using ammonia as the reagent and limiting ammonia input, are both technically feasible options for reducing ammonia emissions from the combustion turbines and duct burners.

## 9.3 Step 3. Rank the Technically Feasible Control Technologies

Because using ammonia as the reagent and limiting ammonia input are both inherent to the ammonia use in the SCR, there is nothing to rank. Both options for ammonia reduction will be employed for the combustion turbines.

## 9.4 Step 4. Evaluate the Most Effective Control Technologies

Reducing the amount of ammonia input can potentially increase the emissions of $NO_x$, however with state-of-the-art methods to monitor the operation of the SCR and ammonia injection, the risk of not meeting the $NO_x$ limit is very low, even with reduced over-injection of ammonia. Thus, there are no energy or economic considerations for either utilizing ammonia as the reagent or limiting the ammonia injection rate.

## 9.5 Step 5. Proposed Ammonia BACT Determination

The use of ammonia as the reagent in the SCR and limiting the ammonia injection rate is considered BACT for the proposed combined cycle combustion turbines with duct burners. These operational controls will limit ammonia emissions to 2 ppm at 15% $O_2$ for COG and natural gas combustion. Compliance with this limit is based the average of 3-run stack tests conducted in accordance with the approve stack testing protocol.

# 10.0 GHG BACT ANALYSIS – COMBUSTION TURBINES

For the proposed combined cycle combustion turbines, the $CO_2e$ emissions are due to $CO_2$, $CH_4$ and nitrous oxide ($N_2O$) emissions. The global warming potential (GWP) of $CH_4$ and $N_2O$ emissions are normalized to the warming potential of carbon dioxide (as $CO_2e$) by multiplying the $CH_4$ emissions by 25 and the $N_2O$ emissions by 298. Despite the higher warming potentials of $CH_4$ and $N_2O$ compared to $CO_2$, it is expected that $CO_2$ emissions will still account for over 99 percent of the GWP for the combustion turbines, based on published emission factors.

There are two broad strategies for reducing $CO_2$ emissions from stationary combustion processes such as combustion turbines. The first is to minimize the production of $CO_2$ through the use of low-carbon fuels and through aggressive energy-efficient design. The use of gaseous fuels, such as natural gas and COG, reduces the production of $CO_2$ during the combustion process relative to burning solid fuels (e.g., coal or coke) and liquid fuels (e.g., distillate or residual oils). Additionally, a highly-efficient operation requires less fuel for process heat, which directly impacts the amount of $CO_2$ produced. Establishing an aggressive basis for energy recovery and facility efficiency will reduce $CO_2$ production.

Energy efficiency reduces $CO_2$ emissions by optimizing the operation of the combustion turbine, thereby reducing the amount of fuel burned per megawatt-hour produced. Energy efficiency reduces $CO_2$ emissions by shifting fuel consumption from the existing boilers to the new cogeneration unit, thereby reducing the amount of fuel burned per steam produced. Additionally, the cogeneration unit produces power reducing U. S. Steel's net import of power, further reducing the total $CO_2$ emissions.

Combustion control optimization and energy efficient equipment is a main control strategy for emissions of greenhouse gases. Potential options that may increase efficiency include the following:

- Reduced overall fuel input to produce the same amount of steam
- Electricity generation to offset imported power to the site
- Use of waste heat from power generation to produce process steam
- Fuel gas heating via gas compression to improve turbine efficiency
- Inlet air filtration system utilizing high efficiency media filters to remove combustion air contaminants
- Steam injected combustors for improved performance, enhanced operability, and lower emissions.

The second strategy for $CO_2$ emission reduction is carbon capture and sequestration. The inherent design of the combustion turbines produces a dilute $CO_2$ stream for potential capture. No commercially-available, post-combustion $CO_2$ capture systems are known to have been installed on combined cycle combustion turbines. The systems that do exist are only demonstration projects on coal-fired power plants. Therefore, post-combustion capture is technically infeasible for the control of $CO_2$ emissions from the proposed combined cycle combustion turbines. Further, $CO_2$ sequestration requires the $CO_2$ to be captured, and capture methods are not considered technically feasible for this project.

BACT for greenhouse gas emissions from the combustion turbines is determined to be the use of COG and natural gas (backup) as fuels and efficient turbine design. These design options will allow the combustion turbines to not exceed a total of 864,096 tpy $CO_2e$ for both combustion turbines/duct burners combined of greenhouse gases as $CO_2e$.

# 11.0 BACT ANALYSIS FOR AUXILIARY EQUIPMENT

The following sections outline a review of BACT for the auxiliary equipment and emission sources proposed for the Project.

## 11.1 Emergency Diesel Fire Pump

One 74-hp emergency diesel fire pump will be constructed as part of the Project. The fire pump will operate for up to 100 hours per year or less for testing, maintenance, and other non-emergency operations. BACT for the fire pump must be at least as stringent as required in the NSPS for Compression Ignition RICE (40 CFR Part 60, Subpart IIII). Because of the limited hours of operation, post-combustion controls are not economically feasible. However, pre-combustion controls such as burning ULSD fuel can be utilized to reduce $SO_2$ and $PM/PM_{10}/PM_{2.5}$ emissions. Additionally, good combustion practices inherent to the design and proper operation of the generators will be used.

The use of ULSD fuel, good combustion practices, and compliance with the NSPS emissions standards (Tier 3 for the fire pump) have been selected as BACT for the emergency diesel fire pump. These emission standards are shown in Table 11-1 below.

**Table 11-1: Tier 3 Emission Standards for Emergency Diesel Fire Pumps 37 ≤ kW ≤ 75**

| Pollutant | Emission Factor g/kW-hr (g/hp-hr) |
|---|---|
| $NMHC + NO_x$ | 4.7 (3.5) |
| CO | 5.0 (3.7) |
| PM | 0.40 (0.30) |

(a) $NMHC + NO_x$ = nonmethane hydrocarbons plus nitrogen oxides, CO = carbon monoxide, PM = particulate matter, g/kW-hr = grams per kilowatt hour, g/hp-hr = grams per horsepower hour.

## 11.2 Dew Point Heaters

Two 3-MMBtu/hr dew point heaters will be constructed as part of the Project. The dew point heaters will combust natural gas and will be utilized to heat the natural gas (back up fuel) as needed prior to combustion in the combustion turbines. Although permitted for full-time operation, in actuality the dew point heaters are only expected to operate up to one hour per day when the combustion turbines are operating on natural gas (which is a back-up fuel and should be very intermittent). Dew point heaters are not typically designed for post-combustion add-on controls and control on such small units are not typical nor economically feasible. As such, controls typical include pre-combustion controls such as limiting the ash content of fuel to reduce $PM/PM_{10}/PM_{2.5}$ emissions and limiting the sulfur content of the fuel to reduce $SO_2$ emissions. The dew point heaters will be equipped with low NOx burners to control emissions of NOx. Combustion controls such as good combustion practices will be used to control $NO_x$, CO and VOC emissions.

The use of low-ash, low-sulfur fuels (natural gas), low $NO_x$ burners and good combustion practices have been selected as BACT for the small dew point heaters.

## 11.3 Material Handling - Silos

Material handling systems for hydrated lime as well as baghouse waste will have the potential to release $PM/PM_{10}/PM_{2.5}$ filterable emissions. The hydrated lime will be delivered to the site via haul trucks which will pneumatically unload the hydrated lime into the hydrated lime storage silo. The hydrated lime storage silo will have a bin vent filter on the silo to control emissions of $PM/PM_{10}/PM_{2.5}$. From there, the hydrated lime will be pneumatically conveyed to one of two lime day bins (one for each cogeneration unit). Each of the day bins will be vented into its corresponding cogeneration unit so therefore there will be no emissions from the day bins. Waste from the baghouse will be removed to a waste storage silo via pneumatic conveying. The waste storage silo will also be controlled via a bin vent filter.

Bin vent filters collect PM emissions in the same manner as a fabric filter baghouse; i.e., the vent filter separates PM from an exhaust stream by filtering the stream. The filter is located atop a silo and the collected material is discharged directly back into the silo. Bin vent filters are a technically feasible control technology for collecting $PM/PM_{10}/PM_{2.5}$ filterable emissions from an enclosed point source. Bin vent filters are the most common and one of the most efficient control technologies from material handling point sources, such as silos.

Bin vent filter grain loading guarantees vary from 0.2 gr/dscf down to as low as 0.001 gr/dscf for select vendors for limited applications. Based on a review of material handling sources at similar facilities, grain loading BACT rates are typically seen at 0.02 gr/dscf to 0.005 gr/dscf.

Bin vent filters with grain loading of 0.002 gr/dscf for the hydrated lime and waste silos is considered BACT for the material handling emission sources for the control of $PM/PM_{10}/PM_{2.5}$ emissions.

## 11.4 Haul Roads

The Project, specifically the air pollution controls, will require the hauling of material on- and off-site. This includes delivery of hydrated lime and anhydrous ammonia for the reduction of $SO_2$ in the circulating dry scrubber and reduction of $NO_x$ in the selective catalytic reduction system, respectively. In addition, particulate waste that is collected in the baghouse will be hauled off-site for disposal from the waste silo. $PM/PM_{10}/PM_{2.5}$ emissions will be released during the hauling of these materials on the roads as silt on the roads becomes resuspended into the atmosphere within the U. S. Steel – Clairton Plant.

Several methods of control of the emissions from the haul roads is currently in-use at the facility. These controls will also be used to control emissions from the existing and new haul routes proposed for this Project. All haul roads will be paved; this includes the new roadways that may be built to accommodate the Project. In addition to the paving of the haul roads, U. S. Steel proposes to use best management practices which consist of watering, vacuum sweeping, maintenance, and dust suppression. The use of paved haul roads as well as best management practices has been selected as BACT for the paved roads.

# 12.0 BACT FOR AUXILIARY BOILER

The auxiliary boiler is rated at 99.0 MMBtu/hr and is proposed to operate only up to 1,000 hours per year. The RBLC has limited information on BACT conclusions for natural gas-fired auxiliary boilers that are similar in size to the proposed boiler (50 to 150 MMBtu/hr.) (See Appendix C.) The RBLC tables also show high variability for emission rates for each pollutant.

## 12.1 BACT for Nitrogen Oxides - Auxiliary Boiler

The following sections outline the top-down steps for $NO_x$ emissions from the auxiliary boiler.

### 12.1.1 Step 1. Identify Potential Control Strategies

SCR, low-$NO_x$ burners, combustion controls, and FGR are listed as BACT in the RBLC for auxiliary boilers. $NO_x$ emissions listed in the RBLC range from 0.01 to 0.36 lb/MMBtu for similar-sized auxiliary boilers utilizing low-$NO_x$ burners, ultra-low NOx burners, flue gas recirculation (FGR) and combustion controls. Only one similar-sized boiler has SCR listed and it is located in Alaska.

### 12.1.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling $NO_x$ emissions are evaluated for technical feasibility in the following sections.

#### 12.1.2.1 SCR

The RBLC listed one unit with SCR as BACT for a similarly sized auxiliary boiler (approximately 50 MMBtu/hr). An SCR can likely reduce emissions further, however the cost to add SCR to remove less than a ton of NOx emissions will not be economically feasible on this small unit, therefore, SCR is not considered further.

**As a result, an SCR system will not be reviewed further for the auxiliary boiler.**

#### 12.1.2.2 Low-$NO_x$ Burners

Low-$NO_x$ burners are currently available from most auxiliary boiler manufacturers. This technology seeks to reduce combustion temperatures, thereby reducing $NO_x$. In a conventional combustor, the air and fuel are introduced at an approximately stoichiometric ratio, and air/fuel mixing occurs at the flame front where diffusion of fuel and air reaches the combustible limit. A lean premixed combustor design premixes the fuel and air prior to combustion. Premixing results in a homogenous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher $NO_x$ emissions. A lean air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower combustion temperatures, which lowers $NO_x$ formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment. Various emission rates are given by vendors for low-NOx burners.

**Low-$NO_x$ burners are available on auxiliary boilers and are considered both baseline and technically feasible for the auxiliary boiler.**

#### 12.1.2.3 Flue Gas Recirculation (Ultra-low NOx Burners)

In most cases, ultra-low NOx burners are low-NOx burners with the addition of flue gas recirculation (FGR). FGR provides additional control of $NO_x$ emissions through the burning process.

**Flue gas recirculation is available on auxiliary boiler and is considered both baseline and technically feasible for the auxiliary boiler.**

#### 12.1.2.4 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to confirm that there is enough oxygen present for complete combustion.

**As a result, combustion control is considered baseline for the auxiliary boiler and is technically feasible.**

### 12.1.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible $NO_x$ control technologies for the 99 MMBtu/hr auxiliary boiler are ranked by control effectiveness in Table 12-1.

**Table 12-1. Ranking of $NO_x$ Control Technologies for the Auxiliary Boiler**

| Control Technology | Reduction (%) | Controlled Emission Level (lb/MMBtu) |
|---|---|---|
| FGR and low-NOx burners | 50 | 0.02 |
| Low-$NO_x$ burners, and combustion control | Not applicable (baseline) | 0.04 |

Source: Based on vendor data

### 12.1.4 Step 4. Evaluate the Most Effective Control Technologies

Each technically feasible control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

### 12.1.5 Low-$NO_x$ Burners, FGR and Combustion Control

Because the low-$NO_x$ burners come standard on most auxiliary boilers and combustion control is accomplished through operation of the auxiliary boiler, there are no incremental energy, environmental, or economic impacts associated with these controls. Further, there is an additional cost associated with FGR (to achieve ultra-low NOx emissions), but this cost is considered insignificant.

### 12.1.6 Steps 5. Proposed BACT for $NO_x$

Since low-$NO_x$ burners. FGR, and combustion control are considered economically feasible, low-$NO_x$ burners and FGR was selected as BACT for $NO_x$ from the auxiliary boiler at an emission rate of 0.02 lb/MMBtu.

## 12.2 BACT for Carbon Monoxide - Auxiliary Boiler

The following sections outline the top-down steps for CO emissions from the auxiliary boiler.

### 12.2.1 Step 1. Identify Potential Control Strategies

The RBLC cites good combustion practices for BACT control for all but one entry, which also includes an oxidation catalyst. As with the turbine, good combustion control will help control emissions of CO from the auxiliary boiler. An oxidation catalyst system may be available to control CO emissions from the auxiliary boiler, along with good combustion practices. Emission limits range from 0.0075 lb/MMBtu to 0.0842 lb/MMBtu. It is important to note that NOx and CO are inversely related in boiler emissions. Therefore, if a unit has very low NOx emissions, the CO emissions may be higher.

### 12.2.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling CO emissions are evaluated for technical feasibility in the following sections.

#### 12.2.2.1 Oxidation Catalyst System

The oxidation catalyst system is an add-on control that converts CO and VOC to $CO_2$ by use of a catalyst, Section 5.2.2 describes the oxidation catalyst system for gas-fired units. While an oxidation catalyst is a potential control for the auxiliary boiler, with such few permitted hours of operation (up to 1,000 hours), an oxidation catalyst would not be considered economically feasible and would only remove up to 1.5 tons of CO and VOC combined.

**An oxidation catalyst system is not considered feasible for this small auxiliary boiler with limited hours of operation.**

#### 12.2.2.2 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to confirm that there is enough oxygen present for complete combustion.

**Good combustion practices are a technically feasible method of controlling CO emissions from the auxiliary boiler.**

### 12.2.3 Step 3. Rank the Technically Feasible Control Technologies

The feasible CO control technologies for the 99 MMBtu/hr auxiliary boiler are ranked by control effectiveness in Table 12-2.

**Table 12-2: Ranking of CO Control Technologies for the Auxiliary Boiler**

| Control Technology | Reduction (%) | Controlled Emission Level (lb/MMBtu) |
|---|---|---|
| Combustion control | Not applicable (baseline) | 0.055 |

Source: Based on AP-42

### 12.2.4 Step 4. Evaluate the Most Effective Control Technologies

Combustion control does not have any economic, environmental or energy impacts.

### 12.2.5 Step 5. Proposed BACT for CO

Since add-on controls are not economically feasible for CO, combustion control was selected as BACT for CO from the auxiliary boiler at an emission rate of 0.055 lb/MMBtu.

**BACT for CO emissions from the auxiliary boiler is good combustion practices.**

## 12.3 BACT for Volatile Organic Compounds - Auxiliary Boiler

The following sections outline the top-down steps for VOC emissions from the auxiliary boiler.

### 12.3.1 Step 1. Identify Potential Control Strategies

The RBLC lists good combustion practices for VOC BACT for all entries except for two facilities. It is likely that these two facilities have add-on controls due to high hours of operation and/or because it was determined to be BACT for CO emissions. As with the turbine, good combustion control will help control emissions of VOC from the auxiliary boiler. Emission rates vary from the various sized auxiliary boilers, ranging from 0.0026 lb/MMBtu to 0.0164 lb/MMBtu.

### 12.3.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling VOC emissions are evaluated for technical feasibility in the following sections.

#### 12.3.2.1 Oxidation Catalyst System

An oxidation catalyst system may be used on an auxiliary boiler this size. The oxidation catalyst system is an add-on control that converts CO and VOC to $CO_2$ by use of a catalyst. Section 6.2.2 describes the oxidation catalyst system for gas-fired units. However, as described in Section 12.2.2.1 for CO emissions, an oxidation catalyst would not be economically feasible on this limited-use (up to 1,000 hours per year) auxiliary boiler. Further, an oxidation catalyst can only remove between 30 and 50% of VOC emissions. Only up to 1.5 tons of all pollutants would be removed by such a system and thus the oxidation catalyst is not considered feasible for the auxiliary boiler.

**An oxidation catalyst system is not considered feasible for the auxiliary boiler with limited hours of operation.**

#### 12.3.2.2 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to confirm that there is enough oxygen present for complete combustion.

**Good combustion practices are a technically feasible method of controlling VOC emissions from the proposed auxiliary boiler.**

### 12.3.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible VOC control technologies for the 100 MMBtu/hr auxiliary boiler are ranked by control effectiveness in Table 12-3.

**Table 12-3: Ranking of VOC Control Technologies for the Auxiliary Boiler**

| Control Technology | Reduction (%) | Controlled Emission Level (lb/MMBtu) |
|---|---|---|
| Combustion control | Not applicable (baseline) | 0.0055 |

Source: Based on AP-42

### 12.3.4 Step 4. Evaluate the Most Effective Control Technologies

Technically feasible control technology was evaluated for energy, environmental, and economic impacts.

### 12.3.5 Step 5. Proposed BACT for VOC

Since add-on controls are not economically feasible for VOC, combustion control was selected as BACT for VOC from the auxiliary boiler at an emission rate of 0.0055 lb/MMBtu.

**BACT for VOC emissions from the auxiliary boiler is good combustion practices.**

## 12.4 BACT for Particulate Matter - Auxiliary Boiler

The following sections outline the top-down steps for PM/$PM_{10}$/$PM_{2.5}$ emissions from the auxiliary boiler.

### 12.4.1 Steps 1-5. Identify, Rank, and Select BACT

The RBLC does not list any control strategies other than good combustion practices and low ash fuel (natural gas). No add-on controls were identified for significant removal of these pollutants from the auxiliary boiler exhaust. The only technically feasible option for control of PM is good combustion practices. The RBLC lists emission rates of 0.0005 lb/MMBtu for similar sized auxiliary boilers (approximately 100 MMBtu/hr) up to 0.0164 lb/MMBtu for both $PM_{10}$ and $PM_{2.5}$.

Since add-on controls are not feasible for PM emissions for such a small gas-fired unit, combustion control was selected as BACT for PM/$PM_{10}$/$PM_{2.5}$ from the auxiliary boiler at an emission rate of 0.0075 lb/MMBtu.

## 12.5 BACT for Sulfur Dioxide – Auxiliary Boiler

The following sections outline the top-down steps for $SO_2$ emissions from the auxiliary boiler.

### 12.5.1 Step 1-5 Identify, Rank and Select BACT

There are no add-on control technologies for controlling $SO_2$ emissions from an auxiliary boiler. As with the combustion turbine, using low sulfur fuel and controlling combustion is the only technologically feasible control option.

BACT is use of lower sulfur fuel and good combustion practices. This will achieve an emission rate of 0.03 tons per year of $SO_2$ from the auxiliary boiler.

## 12.6 BACT for Greenhouse Gases - Auxiliary Boiler (Steps 1-5)

The auxiliary boiler will be fired exclusively on natural gas, is rated at 99 MMBtu/hr, and will be permitted to be fired a total of 1,000 hours per year. GHG emissions from this unit are estimated to be on the order of 5,796 tons $CO_2e$ per year. The basic GHG BACT reasoning presented for the turbine essentially applies to this boiler as well. GHG BACT for this boiler will be the following:

- Use of clean fuels (exclusive use of natural gas)
- Maintain the unit according to the manufacturer's specifications, and
- Record the annual hours of operation and annual fuel use and report the GHG emissions annually.

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# APPENDIX A - COMBUSTON TURBINE NON-NATURAL GAS FUELS AND BLENDS RBLC RESULTS

**Table A-1: RBLC Results for Combustion Turbines**
**Other Gaseous Fuels and Natural Gas Fuel Blends**
**Nitrogen Oxide Emissions**

| RBLC ID | Permit Date | Facility name | Company Name | State | Throughput | Throughput Units | Control Device | Emission Limit | Units | Primary Fuel |
|---|---|---|---|---|---|---|---|---|---|---|
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | | 0 | | Natural Gas Ethane Blend |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | | 0 | | Natural Gas Ethane Blend |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 3338 | MMBtu/hr | Dry Low NOx combustion technology, SCR at all steady state operating loads, good combustion and operating practices | 2 | PPMDV @ 15% O2 | Natural Gas |
| TX-0702 | 8/8/2014 | UTILITIES TURBINES | FORMOSA PLASTICS CORPORATION | TX | 35000 | LB/H | Dry lo-NOx burners with SCR and good engineering/combustion practices will be used to control NOx emissions from turbines will achieve maximum 2ppmvd at 15% oxygen. | 2 | PPMVD | natural gas, hydrogen, tail gas |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | Water/steam injection, SCR, good combustion practices | 6 | PPMDV @ 15% O2 | Ultra low sulfur diesel |
| LA-0288 | 5/23/2014 | LAKE CHARLES CHEMICAL COMPLEX | SASOL CHEMICALS (USA) LLC | LA | 1791 | MM BTU/HR | Low NOx combustors (gas turbines), low NOx burners (duct burners), and selective catalytic reduction (SCR) | 146.12 | LB/HR | Process Gas |

**Table A-2: RBLC Results for Combustion Turbines**
**Other Gaseous Fuels and Natural Gas Fuel Blends**
**Carbon Monoxide Emissions**

| RBLC ID | Permit Date | Facility name | Company Name | State | Throughput | Throughput Units | Control Device | Emission Limit | Units | Primary Fuel |
|---|---|---|---|---|---|---|---|---|---|---|
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | | 0 | | Natural Gas Ethane Blend |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | | 0 | | Natural Gas Ethane Blend |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 3338 | MMBtu/hr | Oxidation catalyst operated at all steady state operating loads and good combustion practices | 2 | PPMDV @ 15% O2 | Natural Gas |
| TX-0702 | 8/8/2014 | UTILITIES TURBINES | FORMOSA PLASTICS CORPORATION | TX | 35000 | LB/H | CO emissions will be minimized by good | 25 | PPMVD | natural gas, hydrogen, tail |
| LA-0288 | 5/23/2014 | LAKE CHARLES CHEMICAL COMPLEX | SASOL CHEMICALS (USA) LLC | LA | 1791 | MM BTU/HR | Good combustion practices | 81.46 | LB/HR | Process Gas |
| IN-0287 | 7/10/2018 | DUKE ENERGY INDIANA, LLC - EDWARDSPORT GENERATING STATION | DUKE ENERGY INDIANA, LLC - EDWARDSPORT GENERATING | IN | 2129 | MMBtu/hr | good combustion practices | 250.8 | TONS/YR | natural gas and syn gas |

**Table A-3: RBLC Results for Combustion Turbines**
**Other Gaseous Fuels and Natural Gas Fuel Blends**
**Volatile Organic Compound Emissions**

| RBLC ID | Permit Date | Facility name | Company Name | State | Throughput | Throughput Units | Control Device | Emission Limit | Units | Primary Fuel |
|---|---|---|---|---|---|---|---|---|---|---|
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | | 0 | | Natural Gas Ethane Blend |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | | 0 | | Natural Gas Ethane Blend |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | | 1 | PPMDV @ 15% O2 | Natural gas |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 3338 | MMBtu/hr | Oxidation catalyst and good combustion practices | 1.5 | PPMDV @ 15% O2 | Natural Gas |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | Oxidation catalyst, water/steam injection, good combustion practices | 2 | PPMDV @ 15% O2 | Ultra low sulfur diesel |
| LA-0288 | 5/23/2014 | LAKE CHARLES CHEMICAL COMPLEX | SASOL CHEMICALS (USA) LLC | LA | 1791 | MM BTU/HR | Good combustion practices | 2.72 | LB/HR | Process Gas |
| TX-0702 | 8/8/2014 | UTILITIES TURBINES | FORMOSA PLASTICS CORPORATION | TX | 35000 | LB/H | Good combustion practices to limit VOC emissions to 4 | 4 | PPMVD | natural gas, hydrogen, tail gas |
| IN-0287 | 7/10/2018 | DUKE ENERGY INDIANA, LLC - EDWARDSPORT GENERATING STATION | DUKE ENERGY INDIANA, LLC - EDWARDSPORT GENERATING | IN | 2129 | MMBtu/hr | good combustion practices | 48.5 | TONS/YEAR | natural gas and syn gas |

Table A-4: RBLC Results for Combustion Turbines
Other Gaseous Fuels and Natural Gas Fuel Blends
Sulfur Dioxide Emissions

| RBLC ID | Permit Date | Facility name | Company Name | State | Throughput | Throughput Units | Control Device | Emission Limit | Units | Primary Fuel |
|---|---|---|---|---|---|---|---|---|---|---|
| TX-0702 | 8/8/2014 | UTILITIES TURBINES | FORMOSA PLASTICS CORPORATION | TX | 35000 | LB/H | So2 emissions are controlled by limiting fuel sulfur content to less than 0.1 grains/dscf. | 0.0005 | LB/MMBTU | natural gas, hydrogen, tail gas |
| LA-0288 | 5/23/2014 | LAKE CHARLES CHEMICAL COMPLEX | SASOL CHEMICALS (USA) LLC | LA | 1791 | MM BTU/HR | Use of gaseous fuels with a sulfur content no more than 0.005 gr/scf | 2.83 | LB/HR | Process Gas |

Table A-5: RBLC Results for Combustion Turbines
Other Gaseous Fuels and Natural Gas Fuel Blends
Particulate Matter Emissions

| RBLC ID | Permit Date | Facility name | Company Name | State | Throughput | Throughput Units | Control Device | Emission Limit | Units | Primary Fuel |
|---|---|---|---|---|---|---|---|---|---|---|
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | | 0 | | Natural Gas Ethane Blend |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | | 0 | | Natural Gas Ethane Blend |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | | 0 | | Natural Gas Ethane Blend |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | | 0 | | Natural Gas Ethane Blend |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | | 0 | | Natural Gas Ethane Blend |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | | 0 | | Natural Gas Ethane Blend |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 3338 | MMBtu/hr | Low sulfur fuel, good combustion practicies | 0.005 | LB/MMBTU | Natural Gas |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 3338 | MMBtu/hr | Low sulfur fuel, good combustion practices | 0.005 | LB/MMBTU | Natural Gas |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 3338 | MMBtu/hr | Low sulfur fuel, good combustion practices | 0.005 | LB/MMBTU | Natural Gas |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | Low sulfur fuels and good combustion practices | 0.0068 | LB/MMBTU | Natural gas |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | Low sulfur fuels and good combustion practices | 0.0068 | LB/MMBTU | Natural gas |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | Low sulfur fuels and good combustion practices | 0.0068 | LB/MMBTU | Natural gas |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | Water/steam injection, ULSD fuel (CCCT only - duct burner is not fired with ULSD), good combustion practices | 0.0415 | LB/MMBTU | Ultra low sulfur diesel |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | Water/steam injection, ULSD fuel (CCCT only - duct | 0.0415 | LB/MMBTU | Ultra low sulfur diesel |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 0 | | Water/steam injection, ULSD fuel (CCCT only - duct | 0.0415 | LB/MMBTU | Ultra low sulfur diesel |
| TX-0588 | 8/4/2010 | PORT ARTHUR REFINERY | MOTIVA ENTERPRISES LLC | TX | 0 | | No add-on control was required for PM control | 2.07 | T/YR | Natural Gas and refinery |
| LA-0288 | 5/23/2014 | LAKE CHARLES CHEMICAL COMPLEX | SASOL CHEMICALS (USA) LLC | LA | 1791 | MM BTU/HR | Use of gaseous fuels and good combustion practices | 6.72 | LB/HR | Process Gas |
| LA-0288 | 5/23/2014 | LAKE CHARLES CHEMICAL COMPLEX | SASOL CHEMICALS (USA) LLC | LA | 1791 | MM BTU/HR | Use of gaseous fuels and good combustion practices | 6.72 | LB/HR | Process Gas |
| IN-0287 | 7/10/2018 | DUKE ENERGY INDIANA, LLC - EDWARDSPORT GENERATING STATION | DUKE ENERGY INDIANA, LLC - EDWARDSPORT GENERATING | IN | 2129 | MMBtu/hr | good combustion practices | 14.3 | TONS/YEAR | natural gas and syn gas |
| IN-0287 | 7/10/2018 | DUKE ENERGY INDIANA, LLC - EDWARDSPORT GENERATING STATION | DUKE ENERGY INDIANA, LLC - EDWARDSPORT GENERATING | IN | 2129 | MMBtu/hr | good combustion practices | 14.3 | TONS/YEAR | natural gas and syn gas |
| IN-0287 | 7/10/2018 | DUKE ENERGY INDIANA, LLC - EDWARDSPORT GENERATING STATION | DUKE ENERGY INDIANA, LLC - EDWARDSPORT GENERATING | IN | 2129 | MMBtu/hr | good combustion practices | 14.3 | TONS/YEAR | natural gas and syn gas |

**Table A-6: RBLC Results for Combustion Turbines**
**Other Gaseous Fuels and Natural Gas Fuel Blends**
**Ammonia Emissions**

| RBLC ID | Permit Date | Facility name | Company Name | State | Throughput | Throughput Units | Control Device | Emission Limit | Units | Primary Fuel |
|---|---|---|---|---|---|---|---|---|---|---|
| TX-0702 | 8/8/2014 | UTILITIES TURBINES | FORMOSA PLASTICS CORPORATION | TX | 35000 | LB/H | Ammonia emissions are minimized with good management practices of the SCR so that ammonia slip to maximum 10 ppmvd at 15% oxygen | 10 | PPMVD | natural gas, hydrogen, tail gas |

**Table A-7: RBLC Results for Combustion Turbines**
**Other Gaseous Fuels and Natural Gas Fuel Blends**
**Greenhouse Gas Emissions**

| RBLC ID | Permit Date | Facility name | Company Name | State | Throughput | Throughput Units | Control Device | Emission Limit | Units | Primary Fuel |
|---|---|---|---|---|---|---|---|---|---|---|
| LA-0288 | 5/23/2014 | LAKE CHARLES CHEMICAL COMPLEX | SASOL CHEMICALS (USA) LLC | LA | 1791 | MM BTU/HR | Use of natural gas as feedstock and good combustion practices | 958992 | TPY | Process Gas |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 3338 | MMBtu/hr | Low sulfur fuel, good combustion practices | 0.005 | LB/MMBTU | Natural Gas |
| PA-0310 | 9/2/2016 | CPV FAIRVIEW ENERGY CENTER | CPV FAIRVIEW, LLC | PA | 3338 | MMBtu/hr | low sulfur fuel and good combustion practices | 3352086 | TONS | Natural Gas |

# APPENDIX B - COMBUSTION TURBINE NATURAL GAS RBLC RESULTS

**Table B-1: RBLC Results for Combustion Turbines**
**Natural Gas Combustion**
**Nitrogen Oxide Emissions**

| RBLC ID | Permit Date | Facility name | Company Name | State | Throughput | Throughput Units | Control Device | Emission Limit | Units | Primary Fuel |
|---|---|---|---|---|---|---|---|---|---|---|
| MI-0410 | 7/25/2013 | THETFORD GENERATING STATION | CONSUMERS ENERGY COMPANY | MI | 171 | MMBTU/H | Dry low-NOx combustors | 0.09 | LB/MMBTU | natural gas |
| CA-1177 | 7/22/2009 | OTAY MESA ENERGY CENTER LLC | OTAY MESA ENERGY CENTER LLC | CA | 171.7 | MW | SCR | 2 | PPMVD@15 % OXYGEN | Natural gas |
| CA-1178 | 3/20/2009 | APPLIED ENERGY LLC | APPLIED ENERGY LLC | CA | 0 | | SCR | 2 | PPM | Natural gas |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | SCR | 2 | PPMVD | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | SCR | 2 | PPMVD | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | SCR | 2 | PPMVD | Natural Gas |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | SCR | 2 | PPMVD | NATURAL GAS |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | SCR, DRY LOW NOX COMBUSTORS | 2 | PPMVD | NATURAL GAS |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | SCR, DRY LOW NOX COMBUSTORS | 2 | PPMVD | NATURAL GAS |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | SCR, DRY LOW NOX COMBUSTORS | 2 | PPMVD | NATURAL GAS |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | SCR, DRY LOW NOX COMBUSTORS | 2 | PPMVD | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | DRY LOW NOX BURNERS (LNB), SELECTIVE CATALYTIC REDUCTION (SCR) | 2 | PPMVD | NATURAL GAS |
| CA-1212 | 10/18/2011 | PALMDALE HYBRID POWER PROJECT | CITY OF PALMDALE | CA | 154 | MW | DRY LOW NOX (DLN) COMBUSTORS, SELECTIVE CATALYTIC REDUCTION (SCR) | 2 | PPMVD | NATURAL GAS |
| TX-0618 | 10/15/2012 | CHANNEL ENERGY CENTER LLC | CHANNEL ENERGY CENTER LLC | TX | 180 | MW | Selective catalytic reduction | 2 | PPMVD | natural gas |
| TX-0619 | 9/26/2012 | DEER PARK ENERGY CENTER | DEER PARK ENERGY CENTER LLC | TX | 180 | MW | Selective Catalytic Reduction | 2 | PPMVD | natural gas |
| TX-0620 | 9/12/2012 | ES JOSLIN POWER PLANT | CALHOUN PORT AUTHORITY | TX | 195 | MW | Selective catalytic reduction | 2 | PPMVD | natural gas |
| TX-0678 | 7/16/2014 | FREEPORT LNG PRETREATMENT FACILITY | FREEPORT LNG DEVELOPMENT LP | TX | 87 | MW | Selective Catalytic Reduction | 2 | PPMVD | natural gas |
| TX-0709 | 9/13/2013 | SAND HILL ENERGY CENTER | CITY OF AUSTIN | TX | 173.9 | MW | SCR | 2 | PPM | Natural Gas |
| TX-0710 | 12/1/2014 | VICTORIA POWER STATION | VICTORIA WLE L.P. | TX | 197 | MW | Selective Catalytic Reduction | 2 | PPMVD | natural gas |
| TX-0767 | 10/2/2015 | LON C. HILL POWER STATION | LON C. HILL, L.P. | TX | 195 | MW | Selective Catalytic Reduction | 2 | PPM | natural gas |
| CA-1209 | 3/11/2010 | HIGH DESERT POWER PROJECT | HIGH DESERT POWER PROJECT LLC | CA | 190 | MW | DRY LOW NOX BURNERS (LNB), SELECTIVE CATALYTIC REDUCTION (SCR) | 2.5 | PPMVD | NATURAL GAS |
| *LA-0331 | 9/21/2018 | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 921 | MM BTU/h | Low NOx Burners, SCR, and Good Combustion Practices | 2.5 | PPMV | Natural Gas |

**Table B-1: RBLC Results for Combustion Turbines**
**Natural Gas Combustion**
**Nitrogen Oxide Emissions**

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| CO-0073 | 7/22/2010 | PUEBLO AIRPORT GENERATING STATION | BLACK HILLS ELECTRIC GENERATION, LLC | CO | 373 | MMBTU/H | Dry Low NOx (DLN) Combustor and Selective Catalytic Reduction (SCR) | 3 | PPMVD AT 15% O2 | natural gas |
| MI-0412 | 12/4/2013 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | HOLLAND BOARD OF PUBLIC WORKS | MI | 647 | MMBTU/H for each CTGHRSG | SCR with DLNB (selective catalytic reduction with dry low NOx burners). | 3 | PPM | natural gas |
| MI-0424 | 12/5/2016 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | HOLLAND BOARD OF PUBLIC WORKS | MI | 554 | MMBTU/H, each | Selective catalytic reduction with dry low NOx burners (SCR with DLNB). | 3 | PPM AT 15% O2 | Natural gas |
| WY-0070 | 8/28/2012 | CHEYENNE PRAIRIE GENERATING STATION | BLACK HILLS POWER, INC. | WY | 40 | MW | SCR | 3 | PPMV AT 15% O2 | Natural Gas |
| WY-0070 | 8/28/2012 | CHEYENNE PRAIRIE GENERATING STATION | BLACK HILLS POWER, INC. | WY | 40 | MW | SCR | 3 | PPMV AT 15% O2 | Natural Gas |
| AK-0071 | 12/20/2010 | INTERNATIONAL STATION POWER PLANT | CHUGACH ELECTRIC ASSOCIATION, INC. | AK | 59900 | hp ISO | Selective Catalytic Reduction and Dry Low NOx Combustion | 5 | PPMDV | Natural Gas |
| TX-0698 | 9/5/2013 | BAYPORT COMPLEX | AIR LIQUIDE LARGE INDUSTRIES U.S., L.P. | TX | 90 | MW | DLN and Closed Loop Emissions Controls (CLEC) | 5 | PPMVD | natural gas |
| CO-0076 | 12/11/2014 | PUEBLO AIRPORT GENERATING STATION | BLACK HILLS ELECTRIC GENERATION, LLC | CO | 373 | MMBTU/H each | SCR and dry low NOx burners | 8 | LB/H | natural gas |
| MI-0402 | 11/17/2011 | SUMPTER POWER PLANT | WOLVERINE POWER SUPPLY COOPERATIVE INC. | MI | 130 | MW electrical output | Low NOx burners | 9 | PPM | Natural gas |
| CO-0073 | 07/22/2010 | PUEBLO AIRPORT GENERATING | BLACK HILLS ELECTRIC | CO | 373 | MMBTU/H | good combustion control and catalytic | 4 | PPMVD AT | natural gas |
| OH-0356 | 12/18/2012 | DUKE ENERGY HANGING ROCK ENERGY | DUKE ENERGY HANGING ROCK, LLC | OH | 172 | MW | Dry Low NOx burners and Selective Catalytic Reduction | 21.1 | LB/H | NATURAL GAS |
| LA-0257 | 12/6/2011 | SABINE PASS LNG TERMINAL | SABINE PASS LNG, LP & SABINE PASS | LA | 286 | MMBTU/H | water injection | 22.94 | LB/H | natural gas |
| *LA-0331 | 9/21/2018 | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 263 | MM BTU/h | Selective Catalytic Reduction (SCR), exclusive combustion of fuel gas, and good | 25 | PPMV | Natural Gas |
| *LA-0331 | 09/21/2018  ACT | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 921 | MM BTU/h | Catalytic Oxidation, Proper Equipment Design and Good Combustion Practices. | 1.1 | PPMV | Natural Gas |
| *LA-0331 | 09/21/2018  ACT | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 263 | MM BTU/h | Proper Equipment Design, Proper Operation, and Good Combustion Practices. | 1.5 | PPMV | Natural Gas |
| OH-0356 | 12/18/2012 | DUKE ENERGY HANGING ROCK ENERGY | DUKE ENERGY HANGING ROCK, LLC | OH | 172 | MW | Dry Low NOx burners and Selective Catalytic Reduction | 27.6 | LB/H | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | SCR | 30 | LB/H | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | SCR | 30 | LB/H | NATURAL GAS |
| MI-0412 | 12/4/2013 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | HOLLAND BOARD OF PUBLIC WORKS | MI | 647 | MMBTU/H for each CTGHRSG | SCR with DLNB (selective catalytic reduction with dry low NOx burners). | 43.7 | LB/H | natural gas |
| MI-0424 | 12/5/2016 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | HOLLAND BOARD OF PUBLIC WORKS | MI | 554 | MMBTU/H; EACH | Selective catalytic reduction with dry low NOx burners (SCR with DLNB). | 43.7 | LB/H | Natural gas |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | SCR | 52.4 | LB/H | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | SCR | 52.4 | LB/H | NATURAL GAS |

**Table B-1: RBLC Results for Combustion Turbines**
**Natural Gas Combustion**
**Nitrogen Oxide Emissions**

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| CA-1212 | 10/18/2011 | PALMDALE HYBRID POWER PROJECT | CITY OF PALMDALE | CA | 110 | MMBTU/H | DRY LOW NOX (DLN) COMBUSTORS, SELECTIVE CATALYTIC REDUCTION (SCR) | 57 | LB/EVENT | NATURAL GAS |
| CA-1212 | 10/18/2011 | PALMDALE HYBRID POWER PROJECT | CITY OF PALMDALE | CA | 154 | MW | DRY LOW NOX (DLN) COMBUSTORS, SELECTIVE CATALYTIC REDUCTION (SCR) | 96 | LB/EVENT | NATURAL GAS |
| CA-1209 | 3/11/2010 | HIGH DESERT POWER PROJECT | HIGH DESERT POWER PROJECT LLC | CA | 190 | MW | DRY LOW NOX BURNERS (LNB), SELECTIVE CATALYTIC REDUCTION (SCR) | 97 | LB/SHUTDOWN | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | SCR | 114 | LB/H | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | SCR | 114 | LB/H | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | DRY LOW NOX BURNERS (LNB), SELECTIVE CATALYTIC REDUCTION (SCR) | 115 | LB/H | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | DRY LOW NOX BURNERS (LNB), SELECTIVE CATALYTIC REDUCTION (SCR) | 152 | LB/H | NATURAL GAS |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | SCR, DRY LOW NOX COMBUSTORS | 160 | LB/H | NATURAL GAS |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | SCR, DRY LOW NOX COMBUSTORS | 160 | LB/H | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | DRY LOW NOX BURNERS (LNB), SELECTIVE CATALYTIC REDUCTION (SCR) | 249.9 | LB/H | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | DRY LOW NOX BURNERS (LNB), SELECTIVE CATALYTIC REDUCTION (SCR) | 333.3 | LB/H | NATURAL GAS |
| CA-1209 | 3/11/2010 | HIGH DESERT POWER PROJECT | HIGH DESERT POWER PROJECT LLC | CA | 190 | MW | DRY LOW NOX BURNERS (LNB), SELECTIVE CATALYTIC REDUCTION (SCR) | 3541 | LB/COLD STARTUP | NATURAL GAS |

**Table B-2: RBLC Results for Combustion Turbines**
**Natural Gas Combustion**
**Carbon Monoxide Emissions**

| RBLC ID | Permit Date | Facility name | Company Name | State | Throughput | Throughput Units | Control Device | Emission Limit | Units | Primary Fuel |
|---|---|---|---|---|---|---|---|---|---|---|
| MI-0402 | 11/17/2011 | SUMPTER POWER PLANT | WOLVERINE POWER SUPPLY COOPERATIVE INC. | MI | 130 | MW electrical output | | 0.048 | LB/MMBTU | Natural gas |
| MI-0410 | 7/25/2013 | THETFORD GENERATING STATION | CONSUMERS ENERGY COMPANY | MI | 171 | MMBTU/H | Efficient combustion | 0.11 | LB/MMBTU | natural gas |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | OXIDATION CATALYST SYSTEM | 1.5 | PPMVD | NATURAL GAS |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | OXIDATION CATALYST SYSTEM | 1.5 | PPMVD | NATURAL GAS |
| CA-1212 | 10/18/2011 | PALMDALE HYBRID POWER PROJECT | CITY OF PALMDALE | CA | 154 | MW | OXIDATION CATALYST SYSTEM | 1.5 | PPMVD | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | OXIDATION CATALYST SYSTEM | 2 | PPMVD | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | OXIDATION CATALYST SYSTEM | 2 | PPMVD | Natural Gas |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | OXIDATION CATALYST SYSTEM | 2 | PPMVD | NATURAL GAS |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | OXIDATION CATALYST SYSTEM | 2 | PPMVD | NATURAL GAS |
| TX-0709 | 9/13/2013 | SAND HILL ENERGY CENTER | CITY OF AUSTIN | TX | 173.9 | MW | OC | 2 | PPM | Natural Gas |
| TX-0767 | 10/2/2015 | LON C. HILL POWER STATION | LON C. HILL, L.P. | TX | 195 | MW | Oxidation Catalyst | 2 | PPM | natural gas |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | OXIDATION CATALYST SYSTEM | 3 | PPMVD | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | OXIDATION CATALYST SYSTEM | 3 | PPMVD | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | CATALYTIC OXIDATION SYSTEM | 3 | PPMVD | NATURAL GAS |
| CA-1209 | 3/11/2010 | HIGH DESERT POWER PROJECT | HIGH DESERT POWER PROJECT LLC | CA | 190 | MW | OXIDATION CATALYST SYSTEM | 4 | PPMVD | NATURAL GAS |
| CO-0073 | 7/22/2010 | PUEBLO AIRPORT GENERATING STATION | BLACK HILLS ELECTRIC GENERATION, LLC | CO | 373 | MMBTU/H | Good combustion control and catalytic oxidation | 4 | PPMVD AT 15% O2 | natural gas |
| MI-0412 | 12/4/2013 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | HOLLAND BOARD OF PUBLIC WORKS | MI | 647 | MMBTU/H for each CTGHRSG | Oxidation catalyst technology and good combustion practices. | 4 | PPM | natural gas |
| MI-0424 | 12/5/2016 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | HOLLAND BOARD OF PUBLIC WORKS | MI | 554 | MMBTU/H, each | Oxidation catalyst technology and good combustion practices. | 4 | PPM | Natural gas |
| TX-0618 | 10/15/2012 | CHANNEL ENERGY CENTER LLC | CHANNEL ENERGY CENTER LLC | TX | 180 | MW | Good combustion | 4 | PPMVD | natural gas |
| TX-0619 | 9/26/2012 | DEER PARK ENERGY CENTER | DEER PARK ENERGY CENTER LLC | TX | 180 | MW | good combustion | 4 | PPMVD | natural gas |
| TX-0620 | 9/12/2012 | ES JOSLIN POWER PLANT | CALHOUN PORT AUTHORITY | TX | 195 | MW | good combustion | 4 | PPMVD | natural gas |
| TX-0678 | 7/16/2014 | FREEPORT LNG PRETREATMENT FACILITY | FREEPORT LNG DEVELOPMENT LP | TX | 87 | MW | oxidation catalyst | 4 | PPMVD | natural gas |
| TX-0710 | 12/1/2014 | VICTORIA POWER STATION | VICTORIA WLE L.P. | TX | 197 | MW | oxidation catalyst | 4 | PPMVD | natural gas |
| WY-0070 | 8/28/2012 | CHEYENNE PRAIRIE GENERATING STATION | BLACK HILLS POWER, INC. | WY | 40 | MW | Oxidation Catalyst | 4 | PPMV AT 15% O2 | Natural Gas |

**Table B-2: RBLC Results for Combustion Turbines**
**Natural Gas Combustion**
**Carbon Monoxide Emissions**

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| WY-0070 | 8/28/2012 | CHEYENNE PRAIRIE GENERATING STATION | BLACK HILLS POWER, INC. | WY | 40 | MW | Oxidation Catalyst | 4 | PPMV AT 15% O2 | Natural Gas |
| *LA-0331 | 9/21/2018 | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 921 | MM BTU/h | Oxidation Catalyst, Proper Design, Good Combustion Practices. | 5 | PPMV | Natural Gas |
| TX-0698 | 9/5/2013 | BAYPORT COMPLEX | AIR LIQUIDE LARGE INDUSTRIES U.S., L.P. | TX | 90 | MW | DLN and Closed Loop Emissions Controls (CLEC) | 15 | PPMVD | natural gas |
| TX-0727 | 3/31/2015 | CEDAR BAYOU ELECTRIC GENERATING STATION | NRG TEXAS POWER LLC | TX | 187 | MW/turbine | Oxidation catalysts | 15 | PPMVD | Natural Gas |
| CO-0073 | 07/22/2010  ACT | PUEBLO AIRPORT GENERATING STATION | BLACK HILLS ELECTRIC GENERATION, LLC | CO | 373 | MMBTU/H | good combustion control and catalytic oxidation | 4 | PPMVD AT 15% O2 | natural gas |
| OH-0356 | 12/18/2012 | DUKE ENERGY HANGING ROCK ENERGY | DUKE ENERGY HANGING ROCK, LLC | OH | 172 | MW | Good combustion practices burning natural gas | 25.7 | LB/H | NATURAL GAS |
| *LA-0331 | 9/21/2018 | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 263 | MM BTU/h | Proper Equipment Design, Proper Operation, and Good Combustion Practices. | 36 | PPMV | Natural Gas |
| CO-0076 | 12/11/2014 | PUEBLO AIRPORT GENERATING STATION | BLACK HILLS ELECTRIC GENERATION, LLC | CO | 373 | MMBTU/H each | Catalytic Oxidation. | 38 | LB/H | natural gas |
| *LA-0331 | 09/21/2018  ACT | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 921 | MM BTU/h | Catalytic Oxidation, Proper Equipment Design and Good Combustion Practices. | 1.1 | PPMV | Natural Gas |
| *LA-0331 | 09/21/2018  ACT | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 263 | MM BTU/h | Proper Equipment Design, Proper Operation, and Good Combustion Practices. | 1.5 | PPMV | Natural Gas |
| LA-0257 | 12/6/2011 | SABINE PASS LNG TERMINAL | SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL | LA | 286 | MMBTU/H | Good combustion practices and fueled by natural gas | 43.6 | LB/H | natural gas |
| OH-0356 | 12/18/2012 | DUKE ENERGY HANGING ROCK ENERGY | DUKE ENERGY HANGING ROCK, LLC | OH | 172 | MW | Good combustion practices burning natural gas | 45.9 | LB/H | NATURAL GAS |
| CA-1209 | 3/11/2010 | HIGH DESERT POWER PROJECT | HIGH DESERT POWER PROJECT LLC | CA | 190 | MW | OXIDATION CATALYST SYSTEM | 183 | LB/COLD STARTUP | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | OXIDATION CATALYST SYSTEM | 224 | LB/H | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | OXIDATION CATALYST SYSTEM | 224 | LB/H | NATURAL GAS |
| CA-1209 | 3/11/2010 | HIGH DESERT POWER PROJECT | HIGH DESERT POWER PROJECT LLC | CA | 190 | MW | OXIDATION CATALYST SYSTEM | 239 | LB/SHUTDOWN | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | OXIDATION CATALYST SYSTEM | 247 | LB/H | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | OXIDATION CATALYST SYSTEM | 247 | LB/H | NATURAL GAS |
| MI-0412 | 12/4/2013 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | HOLLAND BOARD OF PUBLIC WORKS | MI | 647 | MMBTU/H for each CTGHRSG | Oxidation catalyst technology and good combustion practices. | 247.3 | LB/H | natural gas |
| MI-0424 | 12/5/2016 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | HOLLAND BOARD OF PUBLIC WORKS | MI | 554 | MMBTU/H; EACH | Oxidation catalyst technology and good combustion practices. | 247.3 | LB/H | Natural gas |
| CA-1212 | 10/18/2011 | PALMDALE HYBRID POWER PROJECT | CITY OF PALMDALE | CA | 110 | MMBTU/H | OXIDATION CATALYST SYSTEM | 337 | LB/EVENT | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | CATALYTIC OXIDATION SYSTEM | 370.3 | LB/H | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | CATALYTIC OXIDATION SYSTEM | 373.6 | LB/H | NATURAL GAS |
| CA-1212 | 10/18/2011 | PALMDALE HYBRID POWER PROJECT | CITY OF PALMDALE | CA | 154 | MW | CATALYST OXIDATION SYSTEM | 410 | LB/EVENT | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | CATALYTIC OXIDATION SYSTEM | 429.6 | LB/H | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | CATALYTIC OXIDATION SYSTEM | 483.5 | LB/H | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | OXIDATION CATALYST SYSTEM | 674 | LB/H | NATURAL GAS |

**Table B-2: RBLC Results for Combustion Turbines**
**Natural Gas Combustion**
**Carbon Monoxide Emissions**

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | OXIDATION CATALYST SYSTEM | 674 | LB/H | NATURAL GAS |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | OXIDATION CATALYST SYSTEM | 1000 | LB/H | NATURAL GAS |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | OXIDATION CATALYST SYSTEM | 1000 | LB/H | NATURAL GAS |

**Table B-3: RBLC Results for Combustion Turbines**
**Natural Gas Combustion**
**Volatile Organic Compound Emissions**

| RBLC ID | Permit Date | Facility name | Company Name | State | Throughput | Throughput Units | Control Device | Emission Limit | Units | Primary Fuel |
|---|---|---|---|---|---|---|---|---|---|---|
| MI-0410 | 7/25/2013 | THETFORD GENERATING STATION | CONSUMERS ENERGY COMPANY | MI | 171 | MMBTU/H | Efficient combustion; natural gas fuel. | 0.017 | LB/MMBTU | natural gas |
| LA-0257 | 12/6/2011 | SABINE PASS LNG TERMINAL | SABINE PASS LNG, LP & SABINE PASS | LA | 286 | MMBTU/H | Good combustion practices and fueled by natural gas | 0.66 | LB/H | natural gas |
| FL-0364 | 3/21/2018 | SEMINOLE GENERATING STATION | SEMINOLE ELECTRIC COOPERATIVE, INC. | FL | 3514 | MMBtu/hr | Oxidation catalyst | 1 | PPMVD@15 % O2 | Natural gas |
| TX-0817 | 2/17/2017 | CHOCOLATE BAYOU STEAM GENERATING (CBSG) STATION | INEOS USALLC | TX | 50 | MW | OXIDATION CATALYST | 1 | PPMDV | NATURAL GAS |
| *LA-0331 | 9/21/2018 | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 921 | MM BTU/h | Catalytic Oxidation, Proper Equipment Design and Good Combustion Practices. | 1.1 | PPMV | Natural Gas |
| *LA-0331 | 9/21/2018 | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 263 | MM BTU/h | Proper Equipment Design, Proper Operation, and Good Combustion Practices. | 1.5 | PPMV | Natural Gas |
| CA-1177 | 7/22/2009 | OTAY MESA ENERGY CENTER LLC | OTAY MESA ENERGY CENTER LLC | CA | 171.7 | MW | | 2 | PPMVD@15 % OXYGEN | Natural gas |
| CA-1178 | 3/20/2009 | APPLIED ENERGY LLC | APPLIED ENERGY LLC | CA | 0 | | Oxidation catalyst | 2 | PPM | Natural gas |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | | 2 | PPMVD | NATURAL GAS |
| TX-0618 | 10/15/2012 | CHANNEL ENERGY CENTER LLC | CHANNEL ENERGY CENTER LLC | TX | 180 | MW | Good combustion | 2 | PPMVD | natural gas |
| TX-0619 | 9/26/2012 | DEER PARK ENERGY CENTER | DEER PARK ENERGY CENTER LLC | TX | 180 | MW | good combustion, use of natural gas | 2 | PPMVD | natural gas |
| TX-0620 | 9/12/2012 | ES JOSLIN POWER PLANT | CALHOUN PORT AUTHORITY | TX | 195 | MW | good combustion and natural gas as fuel | 2 | PPMVD | natural gas |
| TX-0678 | 7/16/2014 | FREEPORT LNG PRETREATMENT FACILITY | FREEPORT LNG DEVELOPMENT LP | TX | 87 | MW | oxidation catalyst | 2 | PPMVD | natural gas |
| TX-0709 | 9/13/2013 | SAND HILL ENERGY CENTER | CITY OF AUSTIN | TX | 173.9 | MW | | 2 | PPM | Natural Gas |
| TX-0767 | 10/2/2015 | LON C. HILL POWER STATION | LON C. HILL, L.P. | TX | 195 | MW | oxidation catalyst | 2 | PPM | natural gas |
| WY-0070 | 8/28/2012 | CHEYENNE PRAIRIE GENERATING STATION | BLACK HILLS POWER, INC. | WY | 40 | MW | Oxidation Catalyst | 3 | PPMV AT 15% O2 | Natural Gas |
| WY-0070 | 8/28/2012 | CHEYENNE PRAIRIE GENERATING STATION | BLACK HILLS POWER, INC. | WY | 40 | MW | Oxidation Catalyst | 3 | PPMV AT 15% O2 | Natural Gas |
| OH-0356 | 12/18/2012 | DUKE ENERGY HANGING ROCK ENERGY | DUKE ENERGY HANGING ROCK, LLC | OH | 172 | MW | Using efficient combustion technology | 3.2 | LB/H | NATURAL GAS |
| CO-0073 | 7/22/2010 | PUEBLO AIRPORT GENERATING STATION | BLACK HILLS ELECTRIC GENERATION, LLC | CO | 373 | MMBTU/H | good combustion control and catalytic oxidation | 4 | PPMVD AT 15% O2 | natural gas |
| MI-0412 | 12/4/2013 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | HOLLAND BOARD OF PUBLIC WORKS | MI | 647 | MMBTU/H for each CTGHRSG | Oxidation catalyst technology and good combustion practices. | 4 | PPM | natural gas |
| MI-0424 | 12/5/2016 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | HOLLAND BOARD OF PUBLIC WORKS | MI | 554 | MMBTU/H, each | Oxidation catalyst technology and good combustion practices. | 4 | PPM AT 15% O2 | Natural gas |
| TX-0710 | 12/1/2014 | VICTORIA POWER STATION | VICTORIA WLE L.P. | TX | 197 | MW | oxidation catalyst | 4 | PPMVD | natural gas |
| OH-0356 | 12/18/2012 | DUKE ENERGY HANGING ROCK ENERGY | DUKE ENERGY HANGING ROCK, LLC | OH | 172 | MW | Using efficient combustion technology | 7.3 | LB/H | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | | 23.9 | LB/H | NATURAL GAS |

**Table B-3: RBLC Results for Combustion Turbines**
**Natural Gas Combustion**
**Volatile Organic Compound Emissions**

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | | 27.7 | LB/H | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | | 27.7 | LB/H | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | | 27.7 | LB/H | NATURAL GAS |
| MI-0412 | 12/4/2013 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | HOLLAND BOARD OF PUBLIC WORKS | MI | 647 | MMBTU/H for each CTGHRSG | Oxidation catalyst technology and good combustion practices. | 198.9 | LB/H | natural gas |

Table B-4: RBLC Results for Combustion Turbines
Natural Gas Combustion
Sulfur Dioxide Emissions

| RBLC ID | Permit Date | Facility name | Company Name | State | Throughput | Throughput Units | Control Device | Emission Limit | Units | Primary Fuel |
|---|---|---|---|---|---|---|---|---|---|---|
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | | 0.2 | LB/H | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | | 0.4 | LB/H | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | | 0.4 | LB/H | NATURAL GAS |
| CO-0073 | 07/22/2010 | PUEBLO AIRPORT GENERATING | BLACK HILLS ELECTRIC | CO | 373 | MMBTU/H | good combustion control and catalytic | 4 | PPMVD AT | natural gas |
| OH-0356 | 12/18/2012 | DUKE ENERGY HANGING ROCK ENERGY | DUKE ENERGY HANGING ROCK, LLC | OH | 172 | MW | Burning natural gas in an efficient combustion turbine burning low sulfur fuel | 1.2 | LB/H | NATURAL GAS |
| *LA-0331 | 09/21/2018  ACT | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 921 | MM BTU/h | Catalytic Oxidation, Proper Equipment Design and Good Combustion Practices. | 1.1 | PPMV | Natural Gas |
| OH-0356 | 12/18/2012 | DUKE ENERGY HANGING ROCK ENERGY | DUKE ENERGY HANGING ROCK, LLC | OH | 172 | MW | Burning natural gas in an efficient combustion turbine burning low sulfur fuel | 1.52 | LB/H | NATURAL GAS |
| *LA-0331 | 09/21/2018  ACT | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 263 | MM BTU/h | Proper Equipment Design, Proper Operation, and Good Combustion Practices. | 1.5 | PPMV | Natural Gas |
| TX-0678 | 7/16/2014 | FREEPORT LNG PRETREATMENT FACILITY | FREEPORT LNG DEVELOPMENT LP | TX | 87 | MW | | 3.68 | LB/H | natural gas |
| *LA-0331 | 9/21/2018 | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 921 | MM BTU/h | Exclusive Combustion of Low Sulfur Fuel and Proper Engineering Practices | 4 | PPMV | Natural Gas |
| *LA-0331 | 9/21/2018 | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 263 | MM BTU/h | Exclusive Combustion of Low Sulfur Fuel | 4 | PPMV | Natural Gas |

Table B-5: RBLC Results for Combustion Turbines
Natural Gas Combustion
Particulate Matter Emissions

| RBLC ID | Permit Date | Facility name | Company Name | State | Throughput | Throughput Units | Control Device | Emission Limit | Units | Primary Fuel |
|---|---|---|---|---|---|---|---|---|---|---|
| TX-0698 | 9/5/2013 | BAYPORT COMPLEX | AIR LIQUIDE LARGE INDUSTRIES U.S., L.P. | TX | 90 | MW | | 0 | | natural gas |
| TX-0709 | 9/13/2013 | SAND HILL ENERGY CENTER | CITY OF AUSTIN | TX | 173.9 | MW | | 0 | | Natural Gas |
| TX-0710 | 12/1/2014 | VICTORIA POWER STATION | VICTORIA WLE L.P. | TX | 197 | MW | | 0 | | natural gas |
| CA-1212 | 10/18/2011 | PALMDALE HYBRID POWER PROJECT | CITY OF PALMDALE | CA | 154 | MW | USE PUC QUALITY NATURAL GAS | 0.0048 | LB/MMBTU | NATURAL GAS |
| CA-1212 | 10/18/2011 | PALMDALE HYBRID POWER PROJECT | CITY OF PALMDALE | CA | 154 | MW | USE PUC QUALITY NATURAL GAS | 0.0048 | LB/MMBTU | NATURAL GAS |
| CA-1212 | 10/18/2011 | PALMDALE HYBRID POWER PROJECT | CITY OF PALMDALE | CA | 154 | MW | USE PUC QUALITY NATURAL GAS | 0.0048 | LB/MMBTU | NATURAL GAS |
| AK-0071 | 12/20/2010 | INTERNATIONAL STATION POWER PLANT | CHUGACH ELECTRIC ASSOCIATION, INC. | AK | 59900 | hp ISO | Good Combustion Practices | 0.0066 | LB/MMBTU | Natural Gas |
| AK-0071 | 12/20/2010 | INTERNATIONAL STATION POWER PLANT | CHUGACH ELECTRIC ASSOCIATION, INC. | AK | 59900 | hp ISO | Good Combustion Practices | 0.0066 | LB/MMBTU | Natural Gas |
| AK-0071 | 12/20/2010 | INTERNATIONAL STATION POWER PLANT | CHUGACH ELECTRIC ASSOCIATION, INC. | AK | 59900 | hp ISO | Good Combustion Practices | 0.0066 | LB/MMBTU | Natural Gas |
| MI-0402 | 11/17/2011 | SUMPTER POWER PLANT | WOLVERINE POWER SUPPLY COOPERATIVE INC. | MI | 130 | MW electrical output | | 0.0066 | LB/MMBTU | Natural gas |
| MI-0402 | 11/17/2011 | SUMPTER POWER PLANT | WOLVERINE POWER SUPPLY COOPERATIVE INC. | MI | 130 | MW electrical output | | 0.0066 | LB/MMBTU | Natural gas |
| MI-0412 | 12/4/2013 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | HOLLAND BOARD OF PUBLIC WORKS | MI | 647 | MMBTU/H for each CTGHRSG | Good combustion practices and the use of pipeline quality natural gas. | 0.007 | LB/MMBTU | natural gas |
| MI-0424 | 12/5/2016 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | HOLLAND BOARD OF PUBLIC WORKS | MI | 554 | MMBTU/H, each | Good combustion practices and the use of pipeline quality natural gas. | 0.007 | LB/MMBTU | Natural gas |
| MI-0410 | 7/25/2013 | THETFORD GENERATING STATION | CONSUMERS ENERGY COMPANY | MI | 171 | MMBTU/H | Efficient combustion; natural gas fuel. | 0.01 | LB/MMBTU | natural gas |
| MI-0412 | 12/4/2013 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | HOLLAND BOARD OF PUBLIC WORKS | MI | 647 | MMBTU/H for each CTGHRSG | Good combustion practices and the use of pipeline quality natural gas. | 0.014 | LB/MMBTU | natural gas |
| MI-0412 | 12/4/2013 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | HOLLAND BOARD OF PUBLIC WORKS | MI | 647 | MMBTU/H for each CTGHRSG | Good combustion practices and the use of pipeline quality natural gas. | 0.014 | LB/MMBTU | natural gas |
| MI-0424 | 12/5/2016 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | HOLLAND BOARD OF PUBLIC WORKS | MI | 554 | MMBTU/H, each | Good combustion practices and the use of pipeline quality natural gas. | 0.014 | LB/MMBTU | Natural gas |
| MI-0424 | 12/5/2016 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | HOLLAND BOARD OF PUBLIC WORKS | MI | 554 | MMBTU/H, each | Good combustion practices and the use of pipeline quality natural gas. | 0.014 | LB/MMBTU | Natural gas |
| MI-0410 | 7/25/2013 | THETFORD GENERATING STATION | CONSUMERS ENERGY COMPANY | MI | 171 | MMBTU/H | Efficient combustion; natural gas fuel. | 0.02 | LB/MMBTU | natural gas |
| MI-0410 | 7/25/2013 | THETFORD GENERATING STATION | CONSUMERS ENERGY COMPANY | MI | 171 | MMBTU/H | Efficient combustion; natural gas fuel. | 0.02 | LB/MMBTU | natural gas |
| LA-0257 | 12/6/2011 | SABINE PASS LNG TERMINAL | SABINE PASS LNG, LP & SABINE PASS | LA | 286 | MMBTU/H | Good combustion practices and fueled by natural gas | 2.08 | LB/H | natural gas |
| LA-0256 | 12/6/2011 | COGENERATION PLANT | WESTLAKE VINYLS COMPANY LP | LA | 475 | MMBTU/H | USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES | 3.72 | LB/H | NATURAL GAS |
| LA-0256 | 12/6/2011 | COGENERATION PLANT | WESTLAKE VINYLS COMPANY LP | LA | 475 | MMBTU/H | USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES | 3.72 | LB/H | NATURAL GAS |
| LA-0256 | 12/6/2011 | COGENERATION PLANT | WESTLAKE VINYLS COMPANY LP | LA | 475 | MMBTU/H | USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES | 3.72 | LB/H | NATURAL GAS |
| WY-0070 | 8/28/2012 | CHEYENNE PRAIRIE GENERATING STATION | BLACK HILLS POWER, INC. | WY | 40 | MW | good combustion practices | 4 | LB/H | Natural Gas |

**Table B-5: RBLC Results for Combustion Turbines**
**Natural Gas Combustion**
**Particulate Matter Emissions**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| WY-0070 | 8/28/2012 | CHEYENNE PRAIRIE GENERATING STATION | BLACK HILLS POWER, INC. | WY | 40 | MW | good combustion practices | 4 | LB/H | Natural Gas |
| CO-0073 | 7/22/2010 | PUEBLO AIRPORT GENERATING STATION | BLACK HILLS ELECTRIC GENERATION, LLC | CO | 373 | MMBTU/H | Use of pipeline quality natural gas and good combustor design | 4.3 | LB/H | natural gas |
| CO-0073 | 7/22/2010 | PUEBLO AIRPORT GENERATING STATION | BLACK HILLS ELECTRIC GENERATION, LLC | CO | 373 | MMBTU/H | Use of pipeline quality natural gas and good combustor design | 4.3 | LB/H | natural gas |
| *LA-0331 | 9/21/2018 | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 263 | MM BTU/h | Exclusive Combustion of Fuel Gas, Good Combustion Practices Including Proper | 4.5 | LB/H | Natural Gas |
| *LA-0331 | 9/21/2018 | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 263 | MM BTU/h | Exclusive Combustion of Fuel Gas, Good Combustion Practices Including Proper | 4.5 | LB/H | Natural Gas |
| VA-0319 | 8/27/2012 | GATEWAY COGENERATION 1, LLC - SMART WATER PROJECT | GATEWAY GREEN ENERGY | VA | 593 | MMBTU/H | Clean burning fuels and good combustion practices. | 5 | LB/H | Natural Gas |
| VA-0319 | 8/27/2012 | GATEWAY COGENERATION 1, LLC - SMART WATER PROJECT | GATEWAY GREEN ENERGY | VA | 593 | MMBTU/H | Clean-burning fuels and good combustion practices. | 5 | LB/H | Natural Gas |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | USE NATURAL GAS | 6 | LB/H | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | USE NATURAL GAS | 6 | LB/H | NATURAL GAS |
| CO-0073 | 07/22/2010 | PUEBLO AIRPORT GENERATING | BLACK HILLS ELECTRIC | CO | 373 | MMBTU/H | good combustion control and catalytic | 4 | PPMVD AT 15% | natural gas |
| TX-0817 | 2/17/2017 | CHOCOLATE BAYOU STEAM GENERATING (CBSG) STATION | INEOS USALLC | TX | 50 | MW | | 6.98 | LB/H | NATURAL GAS |
| TX-0817 | 2/17/2017 | CHOCOLATE BAYOU STEAM GENERATING (CBSG) STATION | INEOS USALLC | TX | 50 | MW | | 6.98 | LB/H | NATURAL GAS |
| TX-0817 | 2/17/2017 | CHOCOLATE BAYOU STEAM GENERATING (CBSG) STATION | INEOS USALLC | TX | 50 | MW | | 6.98 | LB/H | NATURAL GAS |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | USE PUC QUALITY NATURAL GAS | 8.91 | LB/H | NATURAL GAS |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | USE PUC QUALITY NATURAL GAS | 8.91 | LB/H | NATURAL GAS |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | USE PUC QUALITY NATURAL GAS | 8.91 | LB/H | NATURAL GAS |
| *LA-0331 | 09/21/2018  ACT | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 921 | MM BTU/h | Catalytic Oxidation, Proper Equipment Design and Good Combustion Practices. | 1.1 | PPMV | Natural Gas |
| *LA-0331 | 09/21/2018  ACT | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 263 | MM BTU/h | Proper Equipment Design, Proper Operation, and Good Combustion Practices. | 1.5 | PPMV | Natural Gas |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | USE PUC QUALITY NATURAL GAS | 8.91 | LB/H | NATURAL GAS |
| *LA-0331 | 9/21/2018 | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 921 | MM BTU/h | Exclusive Combustion of Fuel Gas and Good Combustion Practices. | 9.53 | LB/H | Natural Gas |
| *LA-0331 | 9/21/2018 | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 921 | MM BTU/h | Exclusive Combustion of Fuel Gas and Good Combustion Practices. | 9.53 | LB/H | Natural Gas |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | USE PUC QUALITY NATURAL GAS | 11.78 | LB/H | NATURAL GAS |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | USE PUC QUALITY NATURAL GAS | 11.78 | LB/H | NATURAL GAS |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | USE PUC QUALITY NATURAL GAS | 11.78 | LB/H | NATURAL GAS |
| CA-1192 | 6/21/2011 | AVENAL ENERGY PROJECT | AVENAL POWER CENTER LLC | CA | 180 | MW | USE PUC QUALITY NATURAL GAS | 11.78 | LB/H | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | PUC QUALITY NATURAL GAS | 12 | LB/H | NATURAL GAS |

**Table B-5: RBLC Results for Combustion Turbines**
**Natural Gas Combustion**
**Particulate Matter Emissions**

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | PUC QUALITY NATURAL GAS | 12 | LB/H | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | PUC QUALITY NATURAL GAS | 12 | LB/H | Natural Gas |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | PUC QUALITY NATURAL GAS | 12 | LB/H | Natural Gas |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | USE NATURAL GAS | 12 | LB/H | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | USE NATURAL GAS | 12 | LB/H | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | USE NATURAL GAS | 12 | LB/H | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | USE NATURAL GAS | 12 | LB/H | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | USE NATURAL GAS | 12 | LB/H | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | USE NATURAL GAS | 12 | LB/H | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | USE NATURAL GAS | 13.5 | LB/H | NATURAL GAS |
| CA-1211 | 3/11/2011 | COLUSA GENERATING STATION | PACIFIC GAS & ELECTRIC COMPANY | CA | 172 | MW | USE NATURAL GAS | 13.5 | LB/H | NATURAL GAS |
| OH-0356 | 12/18/2012 | DUKE ENERGY HANGING ROCK ENERGY | DUKE ENERGY HANGING ROCK, LLC | OH | 172 | MW | Burning natural gas in an efficient combustion turbine | 15 | LB/H | NATURAL GAS |
| TX-0678 | 7/16/2014 | FREEPORT LNG PRETREATMENT FACILITY | FREEPORT LNG DEVELOPMENT LP | TX | 87 | MW | | 15.22 | LB/H | natural gas |
| TX-0767 | 10/2/2015 | LON C. HILL POWER STATION | LON C. HILL, L.P. | TX | 195 | MW | Good combustion practices and use of pipeline quality natural gas | 16 | LB/HR | natural gas |
| TX-0767 | 10/2/2015 | LON C. HILL POWER STATION | LON C. HILL, L.P. | TX | 195 | MW | Good combustion practices and use of pipeline quality natural gas | 16 | LB/HR | natural gas |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | PUC QUALITY NATURAL GAS | 18 | LB/H | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | PUC QUALITY NATURAL GAS | 18 | LB/H | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | USE PUC QUALITY NATURAL GAS | 18 | LB/H | NATURAL GAS |
| CA-1191 | 3/11/2010 | VICTORVILLE 2 HYBRID POWER PROJECT | CITY OF VICTORVILLE | CA | 154 | MW | PUC QUALITY NATURAL GAS | 18 | LB/H | NATURAL GAS |
| TX-0620 | 9/12/2012 | ES JOSLIN POWER PLANT | CALHOUN PORT AUTHORITY | TX | 195 | MW | | 18 | LB/H | natural gas |
| TX-0620 | 9/12/2012 | ES JOSLIN POWER PLANT | CALHOUN PORT AUTHORITY | TX | 195 | MW | good combustion and natural gas as fuel | 18 | LB/H | natural gas |
| TX-0620 | 9/12/2012 | ES JOSLIN POWER PLANT | CALHOUN PORT AUTHORITY | TX | 195 | MW | good combustion and natural gas as fuel | 18 | LB/H | natural gas |
| OH-0356 | 12/18/2012 | DUKE ENERGY HANGING ROCK ENERGY | DUKE ENERGY HANGING ROCK, LLC | OH | 172 | MW | Burning natural gas in an efficient combustion turbine | 19.9 | LB/H | NATURAL GAS |
| TX-0618 | 10/15/2012 | CHANNEL ENERGY CENTER LLC | CHANNEL ENERGY CENTER LLC | TX | 180 | MW | Good combustion and the use of gaseous fuel | 27 | LB/H | natural gas |
| TX-0618 | 10/15/2012 | CHANNEL ENERGY CENTER LLC | CHANNEL ENERGY CENTER LLC | TX | 180 | MW | good combustion and the use of gaseous fuel | 27 | LB/H | natural gas |
| TX-0618 | 10/15/2012 | CHANNEL ENERGY CENTER LLC | CHANNEL ENERGY CENTER LLC | TX | 180 | MW | good combustion and the use of gaseous fuel | 27 | LB/H | natural gas |
| TX-0619 | 9/26/2012 | DEER PARK ENERGY CENTER | DEER PARK ENERGY CENTER LLC | TX | 180 | MW | good combustion and use of natural gas | 27 | LB/H | natural gas |
| TX-0619 | 9/26/2012 | DEER PARK ENERGY CENTER | DEER PARK ENERGY CENTER LLC | TX | 180 | MW | good combustion and the use of natural gas | 27 | LB/H | natural gas |

**Table B-5: RBLC Results for Combustion Turbines**
**Natural Gas Combustion**
**Particulate Matter Emissions**

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| TX-0619 | 9/26/2012 | DEER PARK ENERGY CENTER | DEER PARK ENERGY CENTER LLC | TX | 180 | MW | | 27 | LB/H | natural gas |

**Table B-6: RBLC Results for Combustion Turbines**
**Natural Gas Combustion**
**Ammonia Emissions**

| RBLC ID | Permit Date | Facility name | Company Name | State | Throughput | Throughput Units | Control Device | Emission Limit | Units | Primary Fuel |
|---|---|---|---|---|---|---|---|---|---|---|
| CO-0073 | 07/22/2010 | PUEBLO AIRPORT GENERATING | BLACK HILLS ELECTRIC | CO | 373 | MMBTU/H | good combustion control and catalytic | 4 | PPMVD AT 15% | natural gas |
| *LA-0331 | 09/21/2018  ACT | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 921 | MM BTU/h | Catalytic Oxidation, Proper Equipment Design and Good Combustion Practices. | 1.1 | PPMV | Natural Gas |
| *LA-0331 | 09/21/2018  ACT | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 263 | MM BTU/h | Proper Equipment Design, Proper Operation, and Good Combustion Practices. | 1.5 | PPMV | Natural Gas |
| WY-0070 | 8/28/2012 | CHEYENNE PRAIRIE GENERATING STATION | BLACK HILLS POWER, INC. | WY | 40 | MW | | 10 | PPM AT 15% O2 | Natural Gas |
| WY-0070 | 8/28/2012 | CHEYENNE PRAIRIE GENERATING STATION | BLACK HILLS POWER, INC. | WY | 40 | MW | | 10 | PPMV AT 15% O2 | Natural Gas |
| OH-0356 | 12/18/2012 | DUKE ENERGY HANGING ROCK ENERGY | DUKE ENERGY HANGING ROCK, LLC | OH | 172 | MW | | 28 | LB/H | NATURAL GAS |
| OH-0356 | 12/18/2012 | DUKE ENERGY HANGING ROCK ENERGY | DUKE ENERGY HANGING ROCK, LLC | OH | 172 | MW | | 31.7 | LB/H | NATURAL GAS |

**Table B-1: RBLC Results for Combustion Turbines**
**Natural Gas Combustion**
**Greenhouse Gas Emissions**

| RBLC ID | Permit Date | Facility name | Company Name | State | Throughput | Throughput Units | Control Device | Emission Limit | Units | Primary Fuel |
|---|---|---|---|---|---|---|---|---|---|---|
| TX-0633 | 11/29/2012 | CHANNEL ENERGY ENERGY CENTER, LLC | CALPINE CORPORATION-CHANNEL ENERGY CENTER, | TX | 0 | | | 1.82 | T/YR | Natural Gas |
| CO-0073 | 07/22/2010 | PUEBLO AIRPORT GENERATING | BLACK HILLS ELECTRIC | CO | 373 | MMBTU/H | good combustion control and catalytic | 4 | PPMVD AT | natural gas |
| TX-0633 | 11/29/2012 | CHANNEL ENERGY ENERGY CENTER, LLC | CALPINE CORPORATION-CHANNEL ENERGY CENTER, LLC | TX | 0 | | | 1.86 | T/YR | Natural Gas |
| TX-0633 | 11/29/2012 | CHANNEL ENERGY ENERGY CENTER, LLC | CALPINE CORPORATION-CHANNEL ENERGY CENTER, LLC | TX | 0 | | | 18.22 | T/YR | Natural Gas |
| *LA-0331 | 09/21/2018  ACT | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 921 | MM BTU/h | Catalytic Oxidation, Proper Equipment Design and Good Combustion Practices. | 1.1 | PPMV | Natural Gas |
| TX-0633 | 11/29/2012 | CHANNEL ENERGY ENERGY CENTER, LLC | CALPINE CORPORATION-CHANNEL ENERGY CENTER, LLC | TX | 0 | | | 18.55 | T/YR | Natural Gas |
| *LA-0331 | 09/21/2018  ACT | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 263 | MM BTU/h | Proper Equipment Design, Proper Operation, and Good Combustion Practices. | 1.5 | PPMV | Natural Gas |
| CA-1212 | 10/18/2011 | PALMDALE HYBRID POWER PROJECT | CITY OF PALMDALE | CA | 154 | MW | | 774 | LB/MW-H | NATURAL GAS |
| TX-0761 | 9/15/2015 | SR BERTRON ELECTRIC GENERATING STATION | NRG TEXAS POWER | TX | 301 | MMBTU/H | | 825 | LB /MW H | natural gas |
| TX-0762 | 9/15/2015 | CEDAR BAYOU ELECTRIC GENERATING STATION | NRG TEXAS POWER | TX | 301 | MMBTU/H | | 825 | LB CO2/MWH | natural gas |
| MI-0402 | 11/17/2011 | SUMPTER POWER PLANT | WOLVERINE POWER SUPPLY COOPERATIVE INC. | MI | 130 | MW electrical output | | 954 | LB/MW-H | Natural gas |
| TX-0817 | 2/17/2017 | CHOCOLATE BAYOU STEAM GENERATING (CBSG) STATION | INEOS USALLC | TX | 50 | MW | | 1000 | LB/MW H | NATURAL GAS |
| MI-0410 | 7/25/2013 | THETFORD GENERATING STATION | CONSUMERS ENERGY COMPANY | MI | 171 | MMBTU/H | Efficient combustion; energy efficiency | 20141 | T/YR | natural gas |
| LA-0256 | 12/6/2011 | COGENERATION PLANT | WESTLAKE VINYLS COMPANY LP | LA | 475 | MMBTU/H | USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES | 55576.77 | LB/H | NATURAL GAS |
| *LA-0331 | 9/21/2018 | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 263 | MM BTU/h | Combust low carbon fuel gas, good combustion practices, good operation and | 134907 | T/YR | Natural Gas |
| VA-0319 | 8/27/2012 | GATEWAY COGENERATION 1, LLC - SMART WATER PROJECT | GATEWAY GREEN ENERGY | VA | 593 | MMBTU/H | Controlled by the use of low carbon fuels and high efficiency design. The heat rate | 295961 | T/YR | Natural Gas |
| MI-0424 | 12/5/2016 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | HOLLAND BOARD OF PUBLIC WORKS | MI | 554 | MMBTU/H, each | Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural | 312321 | T/YR | Natural gas |
| MI-0412 | 12/4/2013 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | HOLLAND BOARD OF PUBLIC WORKS | MI | 647 | MMBTU/H for each CTGHRSG | Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural | 339125 | T/YR | natural gas |
| TX-0633 | 11/29/2012 | CHANNEL ENERGY ENERGY CENTER, LLC | CALPINE CORPORATION-CHANNEL ENERGY CENTER, | TX | 0 | | | 984393 | T/YR | Natural Gas |
| *LA-0331 | 9/21/2018 | CALCASIEU PASS LNG PROJECT | VENTURE GLOBAL CALCASIEU PASS, LLC | LA | 921 | MM BTU/h | Combust low carbon fuel gas and good combustion practices | 2602275 | T/YR | Natural Gas |
| LA-0257 | 12/6/2011 | SABINE PASS LNG TERMINAL | SABINE PASS LNG, LP & SABINE PASS | LA | 286 | MMBTU/H | Good combustion/operating practices and fueled by natural gas - use GE LM2500+G4 | 4872107 | TONS/YEAR | natural gas |

**Table B-1: RBLC Results for Combustion Turbines**
**Natural Gas Combustion**
**Greenhouse Gas Emissions**

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| TX-0633 | 11/29/2012 | CHANNEL ENERGY ENERGY CENTER, LLC | CALPINE CORPORATION-CHANNEL ENERGY CENTER, | TX | 0 | | | 10020391 | T/YR | Natural Gas |

# APPENDIX C – AUXILIARY BOILER RBLC RESULTS

**Appendix C - RBLC Results for Auxiliary Boiler**

| RBLC ID | Facility Name | Permit Date | Throughput | Units | Controls | Emission Limit | Units | Type |
|---|---|---|---|---|---|---|---|---|
| Nitrogen Dioxide | | | | | | | | |
| MD-0046 | Keys Energy Center | 10/31/2014 | 93 | MMBtu/hr | Ultra LNB, GCP, Clean fuels | 0.0100 | lb/MMBtu | BACT-PSD |
| MD-0040 | CPV St Charles | 11/12/2008 | 93 | MMBtu/hr | LNB, FGR | 0.0110 | lb/MMBtu | BACT-PSD |
| TX-0772 | Port of Beaumont Petroleum Transload Terminal (PBPTT) | 11/6/2015 | 95.7 | MMBtu/hr | LNB, FGR | 0.0110 | lb/MMBtu | BACT-PSD |
| IA-0107 | Marshalltown Generating Station | 4/14/2014 | 60.1 | MMBtu/hr | None | 0.0130 | lb/MMBtu | BACT-PSD |
| TX-0708 | La Paloma Energy Center | 2/7/2013 | 150 | MMBtu/hr | LNB | 0.0200 | lb/MMBtu | BACT-PSD |
| WV-0025 | Moundsville Combined Cycle Power Plant | 11/21/2014 | 100 | MMBtu/hr | Ultra LNB, FGR, GCP | 0.0200 | lb/MMBtu | BACT-PSD |
| OH-0352 | Oregon Clean Energy Center | 6/18/2013 | 99 | MMBtu/hr | LNB, FGR | 0.0200 | lb/MMBtu | BACT-PSD |
| IN-0158 | St. Joseph Energy Center, LLC | 12/3/2012 | 80 | MMBtu/hr | LNB, FGR | 0.0320 | lb/MMBtu | BACT-PSD |
| AR-0140 | Big River Steel LLC | 9/18/2013 | 67 | MMBtu/hr | LNB, Clean Fuels, GCP | 0.0350 | lb/MMBtu | BACT-PSD |
| AR-0140 | Big River Steel LLC | 9/18/2013 | 51.2 | MMBtu/hr | LNB, GCP, Clean fuels | 0.0350 | lb/MMBtu | BACT-PSD |
| AL-0286 | Mount Vernon Mill | 3/25/2010 | 70 | MMBtu/hr | LNB, FGR | 0.0350 | lb/MMBtu | BACT-PSD |
| SC-0112 | Nucor Steel - Berkeley | 5/5/2008 | 50.21 | MMBtu/hr | Ultra LNB | 0.0350 | lb/MMBtu | BACT-PSD |
| SC-0116 | Cytec Carbon Fibers, LLC | 4/30/2008 | 50 | MMBtu/hr | None | 0.0360 | lb/MMBtu | BACT-PSD |
| OK-0137 | Ponca City Refinery | 2/9/2009 | 95 | MMBtu/hr | Ultra LNB | 0.0360 | lb/MMBtu | BACT-PSD |
| TX-0714 | S R Bertron Electric Generating Station | 12/19/2014 | 80 | MMBtu/hr | LNB | 0.0360 | lb/MMBtu | BACT-PSD |
| LA-0295 | Westlake Facility | 7/12/2016 | 63 | MMBtu/hr | GCP, FGR | 0.0437 | lb/MMBtu | BACT-PSD |
| OH-0323 | Titan Tire Corporation of Bryan | 6/5/2008 | 50.4 | MMBtu/hr | None | 0.0476 | lb/MMBtu | BACT-PSD |
| OR-0048 | Carty Plant | 12/29/2010 | 91 | MMBtu/hr | LNB | 0.0495 | lb/MMBtu | BACT-PSD |
| MI-0412 | Holland Board of Public Works - East 5th Street | 12/4/2013 | 95 | MMBtu/hr | LNB, FGR, GCP | 0.0500 | lb/MMBtu | BACT-PSD |
| MI-0424 | Holland Board of Public Works - East 5th Street | 12/5/2016 | 83.5 | MMBtu/hr | LNB, FGR, GCP | 0.0500 | lb/MMBtu | BACT-PSD |
| MI-0412 | Holland Board of Public Works - East 5th Street | 12/4/2013 | 55 | MMBtu/hr | LNB, GCP | 0.0500 | lb/MMBtu | BACT-PSD |
| OH-0315 | New Steel International, Inc., Haverhill | 5/6/2008 | 50.4 | MMBtu/hr | LNB | 0.0500 | lb/MMBtu | BACT-PSD |
| FL-0356 | Okeechobee Clean Energy Center | 3/9/2016 | 99.8 | MMBtu/hr | LNB | 0.0500 | lb/MMBtu | BACT-PSD |
| MI-0410 | Thetford Generating Station | 7/25/2013 | 100 | MMBtu/hr | LNB, FGR | 0.0500 | lb/MMBtu | BACT-PSD |
| TX-0732 | Waste Heat Boiler No. 36 | 6/5/2015 | 100 | MMBtu/hr | GCP | 0.1100 | lb/MMBtu | BACT-PSD |
| OH-0310 | American Municipal Power Generating Station | 10/8/2009 | 150 | MMBtu/hr | None | 0.1333 | lb/MMBtu | BACT-PSD |
| OK-0135 | Pryor Plant Chemical | 2/23/2009 | 80 | MMBtu/hr | LNB, GCP | 0.2000 | lb/MMBtu | BACT-PSD |
| SC-0122 | Cytec Carbon Fibers, LLC | 4/30/2008 | 50 | MMBtu/hr | None | 0.3600 | lb/MMBtu | BACT-PSD |
| AK-0083 | Kenai Nitrogen Operations | 1/6/2015 | 50 | MMBtu/hr | SCR | 7.0000 | ppm | BACT-PSD |
| CA-1212 | Palmdale Hybrid Power Project | 10/18/2011 | 110 | MMBtu/hr | None | 9.0000 | ppm | BACT-PSD |
| TX-0713 | Tenaska Brownsville Generating Station | 4/29/2014 | 90 | MMBtu/hr | Ultra LNB | 9.0000 | ppm | BACT-PSD |
| TX-0712 | Trinidad Generating Facility | 11/20/2014 | 110 | MMBtu/hr | Ultra LNB | 9.0000 | ppm | BACT-PSD |

## Appendix C - RBLC Results for Auxiliary Boiler

| RBLC ID | Facility Name | Permit Date | Throughput | Units | Controls | Emission Limit | Units | Type |
|---|---|---|---|---|---|---|---|---|
| | | | | Carbon Monoxide | | | | |
| IA-0107 | Marshalltown Generating Station | 4/14/2014 | 60.1 | MMBtu/hr | Ox Cat | 0.0164 | lb/MMBtu | BACT-PSD |
| MD-0040 | CPV St Charles | 11/12/2008 | 93 | MMBtu/hr | None | 0.0200 | lb/MMBtu | BACT-PSD |
| MD-0041 | CPV St. Charles | 4/23/2014 | 93 | MMBtu/hr | GCP | 0.0200 | lb/MMBtu | BACT-PSD |
| NJ-0080 | Hess Newark Energy Center | 11/1/2012 | 100 | MMBtu/hr | Clean Fuels | 0.0245 | lb/MMBtu | BACT-PSD |
| NJ-0084 | PSEG Fossil LLC Sewaren Generating Station | 3/10/2016 | 80 | MMBtu/hr | GCP, Clean fuels | 0.0360 | lb/MMBtu | BACT-PSD |
| TX-0714 | S R Bertron Electric Generating Station | 12/19/2014 | 80 | MMBtu/hr | LNB | 0.0370 | lb/MMBtu | BACT-PSD |
| NJ-0085 | Middlesex Energy Center, LLC | 7/19/2016 | 97.5 | MMBtu/hr | GCP, Clean fuels | 0.0370 | lb/MMBtu | BACT-PSD |
| NY-0103 | Cricket Valley Energy Center | 2/3/2016 | 60 | MMBtu/hr | GCP | 0.0375 | lb/MMBtu | BACT-PSD |
| NJ-0079 | Woodbridge Energy Center | 7/25/2012 | 91.6 | MMBtu/hr | GCP, Clean fuels | 0.0376 | lb/MMBtu | BACT-PSD |
| WV-0025 | Moundsville Combined Cycle Power Plant | 11/21/2014 | 100 | MMBtu/hr | GCP | 0.0400 | lb/MMBtu | BACT-PSD |
| AL-0286 | Mount Vernon Mill | 3/25/2010 | 70 | MMBtu/hr | None | 0.0400 | lb/MMBtu | BACT-PSD |
| OK-0137 | Ponca City Refinery | 2/9/2009 | 95 | MMBtu/hr | Ultra LNB, GCP | 0.0400 | lb/MMBtu | BACT-PSD |
| OH-0350 | Republic Steel | 7/18/2012 | 65 | MMBtu/hr | GCP | 0.0400 | lb/MMBtu | BACT-PSD |
| OH-0352 | Oregon Clean Energy Center | 6/18/2013 | 99 | MMBtu/hr | GCP | 0.0550 | lb/MMBtu | BACT-PSD |
| AR-0138 | Nucor Corporation - Nucor Steel, Arkansas | 2/17/2012 | 50.4 | MMBtu/hr | GCP | 0.0610 | lb/MMBtu | BACT-PSD |
| SC-0112 | Nucor Steel - Berkeley | 5/5/2008 | 50.21 | MMBtu/hr | GCP, Clean fuels | 0.0610 | lb/MMBtu | BACT-PSD |
| NY-0104 | CPV Valley Energy Center | 8/1/2013 | 73.5 | MMBtu/hr | GCP | 0.0721 | lb/MMBtu | BACT-PSD |
| OH-0336 | Campbell Soup Company | 12/14/2010 | | | None | 0.0750 | lb/MMBtu | BACT-PSD |
| MI-0410 | Thetford Generating Station | 7/25/2013 | 100 | MMBtu/hr | GCP | 0.0750 | lb/MMBtu | BACT-PSD |
| MI-0412 | Holland Board of Public Works - East 5th Street | 12/4/2013 | 55 | MMBtu/hr | GCP | 0.0770 | lb/MMBtu | BACT-PSD |
| MI-0424 | Holland Board of Public Works - East 5th Street | 12/5/2016 | 83.5 | MMBtu/hr | GCP | 0.0770 | lb/MMBtu | BACT-PSD |
| MI-0412 | Holland Board of Public Works - East 5th Street | 12/4/2013 | 95 | MMBtu/hr | GCP | 0.0770 | lb/MMBtu | BACT-PSD |
| MD-0046 | Keys Energy Center | 10/31/2014 | 93 | MMBtu/hr | GCP | 0.0800 | lb/MMBtu | BACT-PSD |
| FL-0356 | Okeechobee Clean Energy Center | 3/9/2016 | 99.8 | MMBtu/hr | GCP | 0.0800 | lb/MMBtu | BACT-PSD |
| OH-0323 | Titan Tire Corporation of Bryan | 6/5/2008 | 50.4 | MMBtu/hr | None | 0.0800 | lb/MMBtu | BACT-PSD |
| AR-0140 | Big River Steel LLC | 9/18/2013 | 51.2 | MMBtu/hr | GCP, Clean fuels | 0.0824 | lb/MMBtu | BACT-PSD |
| AR-0140 | Big River Steel LLC | 9/18/2013 | 67 | MMBtu/hr | GCP, Clean fuels | 0.0824 | lb/MMBtu | BACT-PSD |
| OK-0135 | Pryor Plant Chemical | 2/23/2009 | 80 | MMBtu/hr | GCP | 0.0825 | lb/MMBtu | BACT-PSD |
| IN-0158 | St. Joseph Energy Center, LLC | 12/3/2012 | 80 | MMBtu/hr | GCP | 0.0830 | lb/MMBtu | BACT-PSD |
| OH-0315 | New Steel International, Inc., Haverhill | 5/6/2008 | 50.4 | MMBtu/hr | None | 0.0839 | lb/MMBtu | BACT-PSD |
| OH-0310 | American Municipal Power Generating Station | 10/8/2009 | 150 | MMBtu/hr | None | 0.0840 | lb/MMBtu | BACT-PSD |
| TX-0731 | Corpus Christi Terminal Condensate Splitter | 4/10/2015 | 129 | MMBtu/hr | GCP | 50.0000 | ppm | BACT-PSD |
| TX-0751 | Eagle Mountain Steam Electric Station | 6/18/2015 | 73.3 | MMBtu/hr | None | 50.0000 | ppm | BACT-PSD |
| AK-0083 | Kenai Nitrogen Operations | 1/6/2015 | 50 | MMBtu/hr | None | 50.0000 | ppm | BACT-PSD |
| CA-1212 | Palmdale Hybrid Power Project | 10/18/2011 | 110 | MMBtu/hr | None | 50.0000 | ppm | BACT-PSD |
| TX-0772 | Port of Beaumont Petroleum Transload Terminal (PBPTT) | 11/6/2015 | 95.7 | MMBtu/hr | GCP | 50.0000 | ppm | BACT-PSD |
| TX-0708 | La Paloma Energy Center | 2/7/2013 | 150 | MMBtu/hr | GCP | 75.0000 | ppm | BACT-PSD |

Appendix C - RBLC Results for Auxiliary Boiler

| RBLC ID | Facility Name | Permit Date | Throughput | Units | Controls | Emission Limit | Units | Type |
|---|---|---|---|---|---|---|---|---|
| Volatile Organic Compounds | | | | | | | | |
| SC-0112 | Nucor Steel - Berkeley | 5/5/2008 | 50.21 | MMBtu/hr | GCP, Clean fuels | 0.0026 | lb/MMBtu | BACT-PSD |
| LA-0295 | Westlake Facility | 7/12/2016 | 63 | MMBtu/hr | Ox Cat, GCP | 0.0033 | lb/MMBtu | BACT-PSD |
| IA-0107 | Marshalltown Generating Station | 4/14/2014 | 60.1 | MMBtu/hr | Ox Cat | 0.0050 | lb/MMBtu | BACT-PSD |
| IN-0158 | St. Joseph Energy Center, LLC | 12/3/2012 | 80 | MMBtu/hr | GCP | 0.0050 | lb/MMBtu | BACT-PSD |
| OH-0310 | American Municipal Power Generating Station | 10/8/2009 | 150 | MMBtu/hr | None | 0.0052 | lb/MMBtu | BACT-PSD |
| OH-0323 | Titan Tire Corporation of Bryan | 6/5/2008 | 50.4 | MMBtu/hr | None | 0.0054 | lb/MMBtu | BACT-PSD |
| OH-0350 | Republic Steel | 7/18/2012 | 65 | MMBtu/hr | GCP | 0.0054 | lb/MMBtu | BACT-PSD |
| AL-0312 | Belk Chip-N-Saw Facility | 5/26/2016 | 60 | MMBtu/hr | GCP | 0.0054 | lb/MMBtu | BACT-PSD |
| AR-0140 | Big River Steel LLC | 9/18/2013 | 51.2 | MMBtu/hr | GCP, Clean fuels | 0.0054 | lb/MMBtu | BACT-PSD |
| AK-0083 | Kenai Nitrogen Operations | 1/6/2015 | 50 | MMBtu/hr | None | 0.0054 | lb/MMBtu | BACT-PSD |
| AL-0282 | Lenzing Fibers, Inc. | 1/22/2014 | 100 | MMBtu/hr | GCP | 0.0054 | lb/MMBtu | BACT-PSD |
| IA-0096 | Verasun Charles City, LLC | 11/18/2008 | 50 | MMBtu/hr | None | 0.0054 | lb/MMBtu | BACT-PSD |
| MO-0082 | Archer Daniels Midland-Mexico | 10/5/2010 | 85.6 | MMBtu/hr | GCP | 0.0055 | lb/MMBtu | BACT-PSD |
| AL-0286 | Mount Vernon Mill | 3/25/2010 | 70 | MMBtu/hr | None | 0.0055 | lb/MMBtu | BACT-PSD |
| OH-0315 | New Steel International, Inc., Haverhill | 5/6/2008 | 50.4 | MMBtu/hr | None | 0.0056 | lb/MMBtu | BACT-PSD |
| WV-0025 | Moundsville Combined Cycle Power Plant | 11/21/2014 | 100 | MMBtu/hr | GCP, Clean fuels | 0.0060 | lb/MMBtu | BACT-PSD |
| OK-0156 | Northstar Agri Ind Enid | 7/31/2013 | 95 | MMBtu/hr | GCP | 0.0060 | lb/MMBtu | BACT-PSD |
| OH-0352 | Oregon Clean Energy Center | 6/18/2013 | 99 | MMBtu/hr | GCP | 0.0060 | lb/MMBtu | BACT-PSD |
| OK-0135 | Pryor Plant Chemical | 2/23/2009 | 80 | MMBtu/hr | None | 0.0063 | lb/MMBtu | BACT-PSD |
| MI-0412 | Holland Board of Public Works - East 5th Street | 12/4/2013 | 55 | MMBtu/hr | GCP | 0.0080 | lb/MMBtu | BACT-PSD |
| MI-0412 | Holland Board of Public Works - East 5th Street | 12/4/2013 | 95 | MMBtu/hr | GCP | 0.0080 | lb/MMBtu | BACT-PSD |
| MI-0424 | Holland Board of Public Works - East 5th Street | 12/5/2016 | 83.5 | MMBtu/hr | GCP | 0.0080 | lb/MMBtu | BACT-PSD |
| MI-0410 | Thetford Generating Station | 7/25/2013 | 100 | MMBtu/hr | GCP, Clean fuels | 0.0080 | lb/MMBtu | BACT-PSD |
| MO-0081 | American Energy Producers, Inc. | 1/22/2009 | 95 | MMBtu/hr | None | 0.0164 | lb/MMBtu | BACT-PSD |

**Appendix C - RBLC Results for Auxiliary Boiler**

| RBLC ID | Facility Name | Permit Date | Throughput | Units | Controls | Emission Limit | Units | Type |
|---|---|---|---|---|---|---|---|---|
| | | | | Sulfur Dioxide | | | | |
| AR-0140 | BIG RIVER STEEL LLC | 9/18/2013 | 51.2 | MMBtu/hr | COMBUSTION OF NATURAL GAS AND GCP | 5.88 | X10^-4 LB/M | BACT-PSD |
| AR-0140 | BIG RIVER STEEL LLC | 9/18/2013 | 67 | MMBtu/hr | COMBUSTION OF NATURAL GAS AND GCP | 5.88 | X10^-4 LB/M | BACT-PSD |
| SC-0112 | NUCOR STEEL - BERKELEY | 5/5/2008 | 50.21 | MMBtu/hr | NATURAL GAS COMBUSTION WITH GCP | 0.0006 | LB/MMBTU | BACT-PSD |
| AL-0286 | MOUNT VERNON MILL | 3/25/2010 | 70 | MMBtu/hr | | 0.0006 | LB/MMBTU | BACT-PSD |
| IN-0158 | ST. JOSEPH ENEGRY CENTER, LLC | 12/3/2012 | 80 | MMBtu/hr | FUEL SPECIFICATIONS | 0.0022 | LB/MMBTU | BACT-PSD |
| *VA-0321 | BRUNSWICK COUNTY POWER STATION | 3/12/2013 | 66.7 | MMBtu/hr | Low sulfur fuel. | 0.0011 | LB/MMBTU | BACT-PSD |
| | | | | | | | | |
| OK-0135 | PRYOR PLANT CHEMICAL | 2/23/2009 | 80 | MMBtu/hr | | 0.2 | LB/H | BACT-PSD |
| TX-0772 | PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL ( | 11/6/2015 | 95.7 | MMBtu/hr | Fuel total sulfur content will be less than or equal to 5 grains/100 dscf. | 5 | GR/100 SCF | BACT-PSD |
| *MI-0433 | MEC NORTH, LLC AND MEC SOUTH LLC | 6/29/2018 | 61.5 | MMBtu/hr | GCP and the use of pipeline quality natural gas. | 1.8 | LB/MMSCF | BACT-PSD |
| *MI-0433 | MEC NORTH, LLC AND MEC SOUTH LLC | 6/29/2018 | 61.5 | MMBtu/hr | GCP and the use of pipeline quality natural gas. | 1.8 | LB/MMSCF | BACT-PSD |
| OH-0310 | AMERICAN MUNICIPAL POWER GENERATING STATION | 10/8/2009 | 150 | MMBtu/hr | | 0.09 | LB/H | BACT-PSD |
| | | | | | | | | |
| AR-0138 | NUCOR CORPORATION - NUCOR STEEL, ARKANSAS | 2/17/2012 | 50.4 | MMBtu/hr | NATURAL GAS COMBUSTION | 0.1 | LB/H | BACT-PSD |
| | | | | | | | | |
| OH-0315 | NEW STEEL INTERNATIONAL, INC., HAVERHILL | 5/6/2008 | 50.4 | MMBtu/hr | | 0.03 | LB/H | BACT-PSD |
| *FL-0363 | DANIA BEACH ENERGY CENTER | 12/4/2017 | 99.8 | MMBtu/hr | Clean fuels | 0 | | BACT-PSD |
| FL-0356 | OKEECHOBEE CLEAN ENERGY CENTER | 3/9/2016 | 99.8 | MMBtu/hr | Use of low-sulfur gas | 2 | GR. S/100 SC | BACT-PSD |

## Appendix C - RBLC Results for Auxiliary Boiler

| RBLC ID | Facility Name | Permit Date | Throughput | Units | Controls | Emission Limit | Units | Type |
|---|---|---|---|---|---|---|---|---|
| PM10- Total | | | | | | | | |
| AR-0140 | Big River Steel LLC | 9/18/2013 | 51.2 | MMBtu/hr | GCP, Clean fuels | 0.0005 | lb/MMBtu | BACT-PSD |
| AR-0140 | Big River Steel LLC | 9/18/2013 | 67 | MMBtu/hr | GCP, Clean fuels | 0.0005 | lb/MMBtu | BACT-PSD |
| MD-0041 | CPV St. Charles | 4/23/2014 | 93 | MMBtu/hr | GCP, Clean fuels | 0.0050 | lb/MMBtu | BACT-PSD |
| NJ-0084 | PSEG Fossil LLC Sewaren Generating Station | 3/10/2016 | 80 | MMBtu/hr | Clean Fuels | 0.0050 | lb/MMBtu | BACT-PSD |
| MA-0039 | Salem Harbor Station Redevelopment | 1/30/2014 | 80 | MMBtu/hr | None | 0.0050 | lb/MMBtu | BACT-PSD |
| NJ-0085 | Middlesex Energy Center, LLC | 7/19/2016 | 97.5 | MMBtu/hr | Clean Fuels | 0.0050 | lb/MMBtu | BACT-PSD |
| OK-0135 | Pryor Plant Chemical | 2/23/2009 | 80 | MMBtu/hr | None | 0.0063 | lb/MMBtu | BACT-PSD |
| MI-0412 | Holland Board of Public Works - East 5th Street | 12/4/2013 | 55 | MMBtu/hr | GCP | 0.0070 | lb/MMBtu | BACT-PSD |
| MI-0412 | Holland Board of Public Works - East 5th Street | 12/4/2013 | 95 | MMBtu/hr | GCP | 0.0070 | lb/MMBtu | BACT-PSD |
| MI-0424 | Holland Board of Public Works - East 5th Street | 12/5/2016 | 83.5 | MMBtu/hr | GCP | 0.0070 | lb/MMBtu | BACT-PSD |
| MI-0410 | Thetford Generating Station | 7/25/2013 | 100 | MMBtu/hr | GCP, Clean fuels | 0.0070 | lb/MMBtu | BACT-PSD |
| CA-1212 | Palmdale Hybrid Power Project | 10/18/2011 | 110 | MMBtu/hr | Clean Fuels | 0.0073 | lb/MMBtu | BACT-PSD |
| AK-0083 | Kenai Nitrogen Operations | 1/6/2015 | 50 | MMBtu/hr | None | 0.0074 | lb/MMBtu | BACT-PSD |
| MD-0046 | Keys Energy Center | 10/31/2014 | 93 | MMBtu/hr | GCP, Clean fuels | 0.0075 | lb/MMBtu | BACT-PSD |
| OH-0352 | Oregon Clean Energy Center | 6/18/2013 | 99 | MMBtu/hr | Clean Fuels | 0.0080 | lb/MMBtu | BACT-PSD |
| OK-0156 | Northstar Agri Ind Enid | 7/31/2013 | 95 | MMBtu/hr | GCP | 0.0130 | lb/MMBtu | BACT-PSD |
| MO-0081 | American Energy Producers, Inc. | 1/22/2009 | 95 | MMBtu/hr | None | 0.0164 | lb/MMBtu | BACT-PSD |
| PM2.5- Total | | | | | | | | |
| AR-0140 | Big River Steel LLC | 9/18/2013 | 51.2 | MMBtu/hr | GCP, Clean fuels | 0.0005 | lb/MMBtu | BACT-PSD |
| AR-0140 | Big River Steel LLC | 9/18/2013 | 67 | MMBtu/hr | GCP, Clean fuels | 0.0005 | lb/MMBtu | BACT-PSD |
| WV-0025 | Moundsville Combined Cycle Power Plant | 11/21/2014 | 100 | MMBtu/hr | GCP, Clean fuels | 0.0050 | lb/MMBtu | BACT-PSD |
| NJ-0084 | PSEG Fossil LLC Sewaren Generating Station | 3/10/2016 | 80 | MMBtu/hr | Clean Fuels | 0.0050 | lb/MMBtu | BACT-PSD |
| MA-0039 | Salem Harbor Station Redevelopment | 1/30/2014 | 80 | MMBtu/hr | None | 0.0050 | lb/MMBtu | BACT-PSD |
| NJ-0085 | Middlesex Energy Center, LLC | 7/19/2016 | 97.5 | MMBtu/hr | Clean Fuels | 0.0050 | lb/MMBtu | BACT-PSD |
| MI-0412 | Holland Board of Public Works - East 5th Street | 12/4/2013 | 55 | MMBtu/hr | GCP | 0.0070 | lb/MMBtu | BACT-PSD |
| MI-0412 | Holland Board of Public Works - East 5th Street | 12/4/2013 | 95 | MMBtu/hr | GCP | 0.0070 | lb/MMBtu | BACT-PSD |
| MI-0424 | Holland Board of Public Works - East 5th Street | 12/5/2016 | 83.5 | MMBtu/hr | GCP | 0.0070 | lb/MMBtu | BACT-PSD |
| MI-0410 | Thetford Generating Station | 7/25/2013 | 100 | MMBtu/hr | GCP, Clean fuels | 0.0070 | lb/MMBtu | BACT-PSD |
| CA-1212 | Palmdale Hybrid Power Project | 10/18/2011 | 110 | MMBtu/hr | Clean Fuels | 0.0073 | lb/MMBtu | BACT-PSD |
| AK-0083 | Kenai Nitrogen Operations | 1/6/2015 | 50 | MMBtu/hr | None | 0.0074 | lb/MMBtu | BACT-PSD |
| OK-0156 | Northstar Agri Ind Enid | 7/31/2013 | 95 | MMBtu/hr | GCP | 0.0126 | lb/MMBtu | BACT-PSD |
| IN-0158 | St. Joseph Energy Center, LLC | 12/3/2012 | 80 | MMBtu/hr | GCP, Clean fuels | 0.0075 | lb/MMBtu | BACT-PSD |

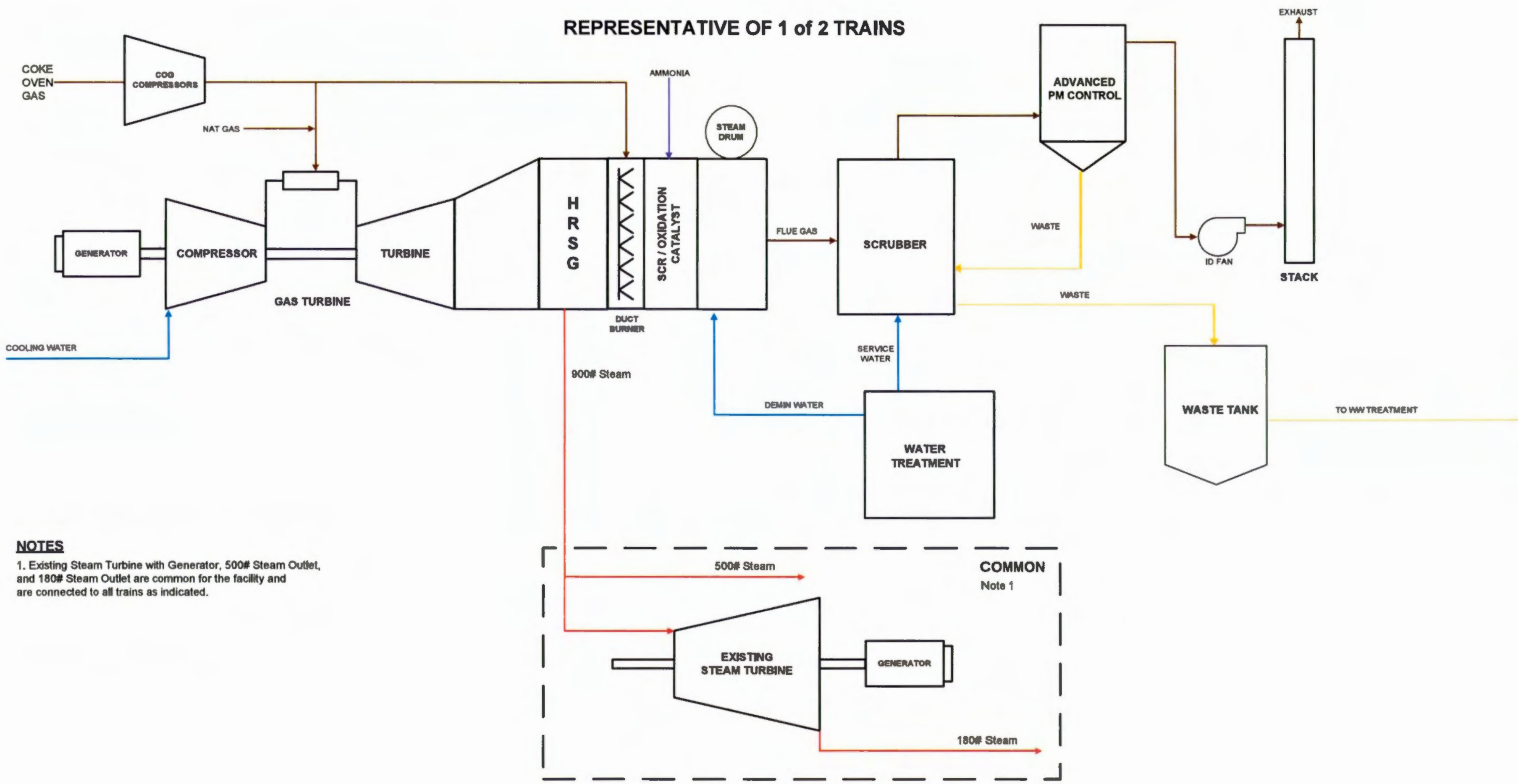
## Appendix C - RBLC Results for Auxiliary Boiler

| RBLC ID | Facility Name | Permit Date | Throughput | Units | Controls | Emission Limit | Units | Type |
|---|---|---|---|---|---|---|---|---|
| **Greenhouse Gases - Carbon Dioxide** | | | | | | | | |
| AR-0140 | Big River Steel LLC | 9/18/2013 | 51.2 | MMBtu/hr | GCP | 117.0000 | lb/MMBtu | BACT-PSD |
| NY-0116 | Fab 8, Luther Forest Technology Campus | 3/29/2013 | | | GCP, Clean fuels | 118.0000 | lb/MMBtu | BACT-PSD |
| NY-0116 | Fab 8, Luther Forest Technology Campus | 3/29/2013 | | | GCP, Clean fuels | 160.0000 | lb/MMBtu | BACT-PSD |
| **Greenhouse Gases - Carbon Dioxide Equivalents** | | | | | | | | |
| AR-0140 | Big River Steel LLC | 9/18/2013 | 67 | MMBtu/hr | GCP | 117.0000 | lb/MMBtu | BACT-PSD |
| MI-0424 | Holland Board of Public Works - East 5th Street | 12/5/2016 | 83.5 | MMBtu/hr | GCP | 118.3469 | lb/MMBtu | BACT-PSD |
| MI-0412 | Holland Board of Public Works - East 5th Street | 12/4/2013 | 95 | MMBtu/hr | GCP | 118.3634 | lb/MMBtu | BACT-PSD |
| MI-0412 | Holland Board of Public Works - East 5th Street | 12/4/2013 | 55 | MMBtu/hr | GCP | 118.3645 | lb/MMBtu | BACT-PSD |
| NY-0103 | Cricket Valley Energy Center | 2/3/2016 | 60 | MMBtu/hr | GCP, Clean fuels | 119.0000 | lb/MMBtu | BACT-PSD |
| MA-0039 | Salem Harbor Station Redevelopment | 1/30/2014 | 80 | MMBtu/hr | None | 119.0000 | lb/MMBtu | BACT-PSD |
| TX-0812 | Crude Oil Processing Facility | 10/31/2016 | 104 | MMBtu/hr | GCP | 120.3021 | lb/MMBtu | BACT-PSD |
| WV-0025 | Moundsville Combined Cycle Power Plant | 11/21/2014 | 100 | MMBtu/hr | Clean Fuels | 120.8100 | lb/MMBtu | BACT-PSD |
| AK-0083 | Kenai Nitrogen Operations | 1/6/2015 | 50 | MMBtu/hr | None | 2,384.4000 | lb/MMBtu | BACT-PSD |

# APPENDIX E: PROCESS FLOW DIAGRAM

## SIMPLIFIED PFD FOR ICON COGEN

Diagram is for graphical representation purposes only. Actual equipment arrangement may vary. Not to be used for construction.

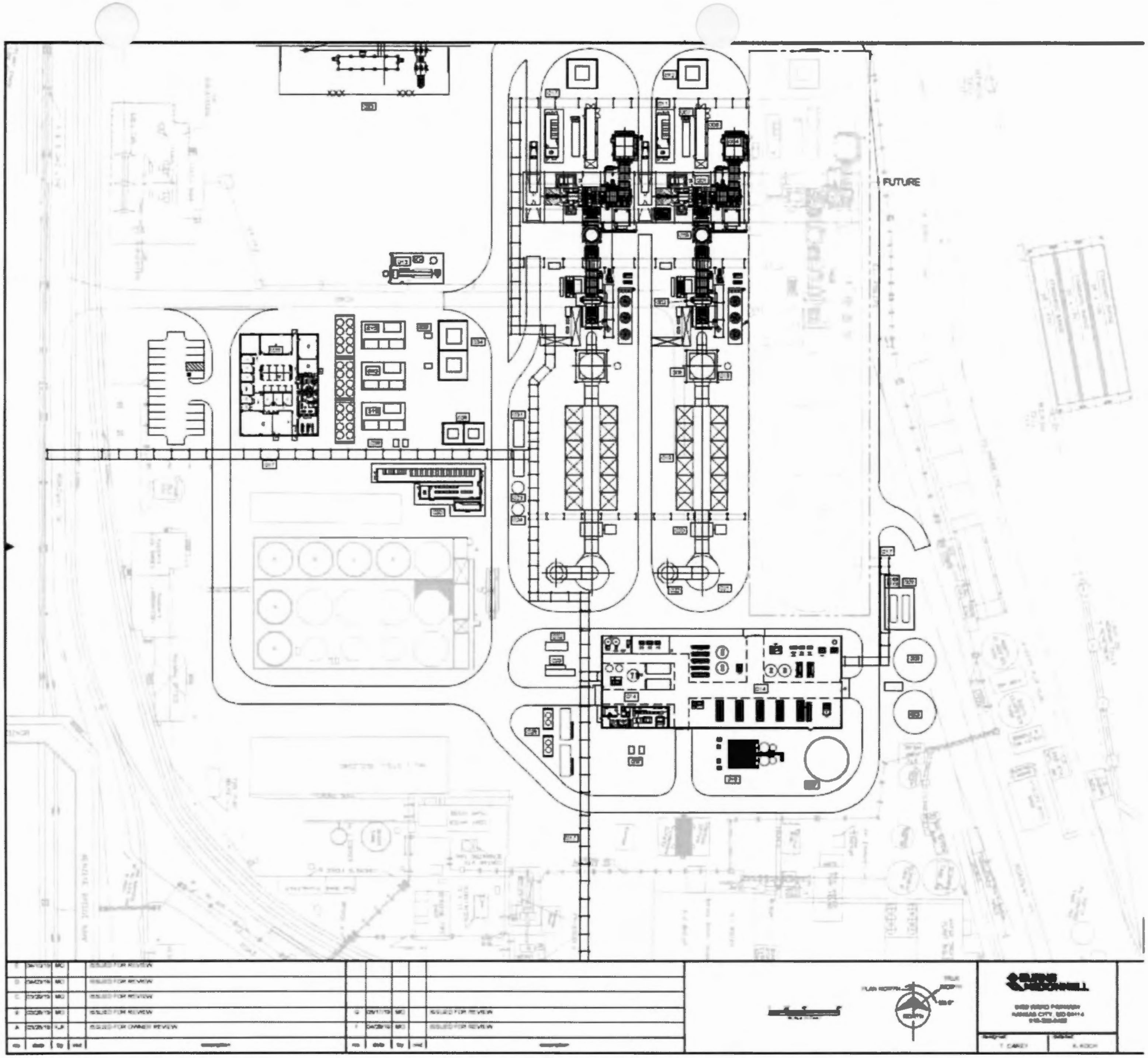



**NOTES**

1. Existing Steam Turbine with Generator, 500# Steam Outlet, and 180# Steam Outlet are common for the facility and are connected to all trains as indicated.

# APPENDIX F: SITE MAP


(General Project Location Indicated by Shaded Polygon)




(Preliminary Arrangement)

# APPENDIX G: PRELIMINARY EMISSIONS SPECIFICATIONS

Company Name: **U. S. Steel**
Facility Name: **Clairton**
Project Description: **Cogeneration Project**

| | | Performance Data Used in Development of Annual Average Emission Rates | | | |
|---|---|---|---|---|---|
| **Case #** | | 3 | 4 | 5 | 8 |
| **Case Description** | | 100% GTG Load, Normal Duct Firing | 100% GTG Load, Full Duct Firing | 100% GTG Load, No Duct Firing | 70% GTG Load, No Duct Firing |
| Ambient Temperature | | 50 F | 50 F | 50 F | 50 F |
| Gas Turbine Load | | 100% | 100% | 100% | 70% |
| No. of Gas Turbines | | 2 | 1 | 2 | 2 |
| Gas Turbine Fuel | | COG | COG | COG | COG |
| Duct Burner Fuel | | COG | COG | COG | COG |
| **Gas Turbine Generator Performance** | | | | | |
| Electrical Output | *kW* | 47,040 | 47,040 | 47,040 | 32,928 |
| GTG Heat Input- HHV (per GTG) | *MMBtu/hr* | 613 | 613 | 613 | 461 |
| **Duct Burner Fuel Consumption** | | | | | |
| Heat Input - HHV (per HRSG) | *MMBtu/hr* | 146.3 | 368.5 | 0.0 | 0.0 |
| **Stack Emissions at Exit** | | | | | |
| **NOx Emissions** | | | | | |
| NOx,@15% O2 Out of SCR | *ppmvd* | 9.0 | 9.0 | 9.0 | 9.0 |
| NOx, as NO2 Out of SCR | *lb/hr* | 19.0 | 24.6 | 15.3 | 11.6 |
| **NH3 Emissions** | | | | | |
| NH3 slip @ 15% O2 | *ppmvd* | 2 | 2 | 2 | 2 |
| NH3 slip | *lb/hr* | 1.9 | 2.4 | 1.5 | 1.1 |
| **CO Emissions** | | | | | |
| CO out of catalyst, @ 15% O2 | *ppmvd* | 2.01 | 2.56 | 1.43 | 0.92 |
| CO out of catalyst | *lb/hr* | 3.1 | 5.1 | 1.8 | 0.9 |
| **SO2 Emissions** | | | | | |
| SO2 in Exhaust Gas (Post Control) | *lb/hr* | 18.1 | 23.5 | 14.6 | 11.0 |
| SO2 in Exhaust Gas (Post Control) | *lb/MMBtu* | 0.0239 | 0.0239 | 0.0239 | 0.0239 |
| **Volatile Organic Compounds** | | | | | |
| VOC @ 15% O2 | *ppmvd* | 2.7 | 4.4 | 0.9 | 0.8 |
| VOC as CH4 | *lb/hr* | 2.4 | 5.0 | 0.6 | 0.5 |
| **Particulates (See Note 1)** | | | | | |
| PM10, front half (Post Control) | *lb/hr* | 1.05 | 1.07 | 1.04 | 0.75 |
| PM10, front & back half (Post Control) | *lb/hr* | 4.11 | 4.09 | 4.12 | 2.99 |
| PM10, front & back half (Post Control) | *lb/MMBtu* | 0.0054 | 0.0042 | 0.0067 | 0.0065 |
| **GHG Emissions** | | | | | |
| CO2 in Exhaust Gas | *lb/hr* | 81,261 | 105,054 | 65,600 | 49,375 |
| CH4 in Exhaust Gas (CO2e) | *lb/hr* | 46.0 | 59.5 | 37.2 | 28.0 |
| N2O in Exhaust Gas (CO2e) | *lb/hr* | 54.9 | 70.9 | 44.3 | 33.3 |
| GHG (CO2e) in Exhaust Gas | *lb/hr* | 81,362 | 105,184 | 65,682 | 49,437 |

**Notes:**
1. All particulate matter is assumed to be PM2.5.
2. Emissions reported on the basis of lb/hr are for one combustion turbine and one HRSG.

Company Name: **U. S. Steel**
Facility Name: **Clairton**
Project Description: **Cogeneration P**

| | | Performance Data Used Exclusively for Short-Term Emission Rates | | | |
|---|---|---|---|---|---|
| **Case #** | | **10** | **11** | **12** | **15** |
| **Case Description** | | 100% GTG Load, Normal Duct Firing | 100% GTG Load, Full Duct Firing | 100% GTG Load, No Duct Firing | 70% GTG Load, No Duct Firing |
| Ambient Temperature | | 0 F | 0 F | 0 F | 0 F |
| Gas Turbine Load | | 100% | 100% | 100% | 70% |
| No. of Gas Turbines | | 2 | 1 | 2 | 2 |
| Gas Turbine Fuel | | COG | COG | COG | COG |
| Duct Burner Fuel | | COG | COG | COG | COG |
| **Gas Turbine Generator Performance** | | | | | |
| Electrical Output | *kW* | 46,647 | 46,647 | 46,647 | 32,653 |
| GTG Heat Input- HHV (per GTG) | *MMBtu/hr* | 600 | 600 | 600 | 451 |
| **Duct Burner Fuel Consumption** | | | | | |
| Heat Input - HHV (per HRSG) | *MMBtu/hr* | 242.7 | 433.6 | 0.0 | 0.0 |
| **Stack Emissions at Exit** | | | | | |
| **NOx Emissions** | | | | | |
| NOx,@15% O2 Out of SCR | *ppmvd* | 9.0 | 9.0 | 9.0 | 9.0 |
| NOx, as NO2 Out of SCR | *lb/hr* | 21.1 | 25.9 | 15.0 | 11.3 |
| **NH3 Emissions** | | | | | |
| NH3 slip @ 15% O2 | *ppmvd* | 2 | 2 | 2 | 2 |
| NH3 slip | *lb/hr* | 2.1 | 2.6 | 1.5 | 1.1 |
| **CO Emissions** | | | | | |
| CO out of catalyst, @ 15% O2 | *ppmvd* | 2.21 | 2.62 | 1.31 | 1.01 |
| CO out of catalyst | *lb/hr* | 3.8 | 5.5 | 1.6 | 0.9 |
| **SO2 Emissions** | | | | | |
| SO2 in Exhaust Gas (Post Control) | *lb/hr* | 20.1 | 24.7 | 14.3 | 10.8 |
| SO2 in Exhaust Gas (Post Control) | *lb/MMBtu* | 0.0239 | 0.0239 | 0.0239 | 0.0239 |
| **Volatile Organic Compounds** | | | | | |
| VOC @ 15% O2 | *ppmvd* | 3.7 | 4.9 | 1.0 | 0.9 |
| VOC as CH4 | *lb/hr* | 3.6 | 5.9 | 0.7 | 0.5 |
| **Particulates (See Note 1)** | | | | | |
| PM10, front half (Post Control) | *lb/hr* | 1.73 | 1.76 | 1.71 | 1.23 |
| PM10, front & back half (Post Control) | *lb/hr* | 7.86 | 7.83 | 7.90 | 5.71 |
| PM10, front & back half (Post Control) | *lb/MMBtu* | 0.0093 | 0.0076 | 0.0132 | 0.0127 |
| **GHG Emissions** | | | | | |
| CO2 in Exhaust Gas | *lb/hr* | 90,246 | 110,680 | 64,264 | 48,312 |
| CH4 in Exhaust Gas (CO2e) | *lb/hr* | 51.1 | 62.7 | 36.4 | 27.4 |
| N2O in Exhaust Gas (CO2e) | *lb/hr* | 60.9 | 74.7 | 43.4 | 32.6 |
| GHG (CO2e) in Exhaust Gas | *lb/hr* | 90,358 | 110,817 | 64,344 | 48,372 |

**Notes:**
1. All particulate matter is assumed to be PM2.5.
2. Emissions reported on the basis of lb/hr are for one combı

**Company Name:** U. S. Steel
**Facility Name:** Clairton
**Project Description:** Cogeneration P

**Performance Data Used in Development of Annual Average Emission Rates**

| Case # | | 17 | 18 | 19 | 22 | 24 | 25 | 26 | 29 | 31 | 32 | 33 | 36 | 41 | 42 | 43 | 45 | 46 | 47 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Case Description** | | 100% GTG Load, Normal Duct Firing | 100% GTG Load, Full Duct Firing | 100% GTG Load, No Duct Firing | 70% GTG Load, No Duct Firing | 100% GTG Load, Normal Duct Firing | 100% GTG Load, Full Duct Firing | 100% GTG Load, No Duct Firing | 70% GTG Load, No Duct Firing | 100% GTG Load, Normal Duct Firing | 100% GTG Load, Full Duct Firing | 100% GTG Load, No Duct Firing | 70% GTG Load, No Duct Firing | 100% GTG Load, Normal Duct Firing | 100% GTG Load, Full Duct Firing | 100% GTG Load, No Duct Firing | 100% GTG Load, Normal Duct Firing | 100% GTG Load, Full Duct Firing | 100% GTG Load, No Duct Firing |
| Ambient Temperature | | 30 F | 30 F | 30 F | 30 F | 70 F | 70 F | 70 F | 70 F | 85 F | 85 F | 85 F | 85 F | 30 F | 30 F | 30 F | 30 F | 30 F | 30 F |
| Gas Turbine Load | | 100% | 100% | 100% | 70% | 100% | 100% | 100% | 70% | 100% | 100% | 100% | 70% | 100% | 100% | 100% | 100% | 100% | 100% |
| No. of Gas Turbines | | 2 | 1 | 2 | 2 | 2 | 1 | 2 | 2 | 2 | 1 | 2 | 2 | 2 | 1 | 2 | 2 | 1 | 2 |
| Gas Turbine Fuel | | COG | COG | COG | COG | COG | COG | COG | COG | COG | COG | COG | COG | Natural Gas | Natural Gas | Natural Gas | Blend | Blend | Blend |
| Duct Burner Fuel | | COG | COG | COG | COG | COG | COG | COG | COG | COG | COG | COG | COG | COG | COG | COG | COG | COG | COG |
| **Gas Turbine Generator Performance** | | | | | | | | | | | | | | | | | | | |
| Electrical Output | kW | 49,315 | 49,315 | 49,315 | 34,521 | 44,786 | 44,786 | 44,786 | 30,695 | 42,429 | 42,429 | 42,429 | 28,885 | 47,772 | 47,772 | 47,772 | 49,207 | 49,207 | 49,207 |
| GTG Heat Input- HHV (per GTG) | MMBtu/hr | 637 | 637 | 637 | 476 | 587 | 587 | 587 | 439 | 561 | 561 | 561 | 422 | 609 | 609 | 609 | 633 | 633 | 633 |
| **Duct Burner Fuel Consumption** | | | | | | | | | | | | | | | | | | | |
| Heat Input - HHV (per HRSG) | MMBtu/hr | 218.6 | 389.4 | 0.0 | 0.0 | 70.9 | 355.1 | 0.0 | 0.0 | 72.4 | 341.6 | 0.0 | 0.0 | 218.9 | 375.8 | 0.0 | 216.7 | 383.9 | 0.0 |
| **Stack Emissions at Exit** | | | | | | | | | | | | | | | | | | | |
| **NOx Emissions** | | | | | | | | | | | | | | | | | | | |
| NOx,@15% O2 Out of SCR | ppmvd | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 |
| NOx, as NO2 Out of SCR | lb/hr | 21.4 | 25.7 | 16.0 | 11.9 | 16.5 | 23.6 | 14.7 | 11.0 | 15.9 | 22.6 | 14.1 | 10.6 | 22.0 | 25.9 | 16.5 | 21.7 | 25.9 | 16.2 |
| **NH3 Emissions** | | | | | | | | | | | | | | | | | | | |
| NH3 slip @ 15% O2 | ppmvd | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| NH3 slip | lb/hr | 2.1 | 2.5 | 1.6 | 1.2 | 1.6 | 2.3 | 1.5 | 1.1 | 1.6 | 2.2 | 1.4 | 1.0 | 2.2 | 2.6 | 1.6 | 2.1 | 2.6 | 1.6 |
| **CO Emissions** | | | | | | | | | | | | | | | | | | | |
| CO out of catalyst, @ 15% O2 | ppmvd | 2.23 | 2.60 | 1.48 | 0.95 | 1.53 | 2.40 | 1.18 | 0.89 | 1.38 | 2.29 | 0.98 | 0.90 | 1.77 | 2.17 | 0.89 | 2.01 | 2.40 | 1.21 |
| CO out of catalyst | lb/hr | 3.9 | 5.4 | 1.9 | 0.9 | 2.0 | 4.6 | 1.4 | 0.8 | 1.8 | 4.2 | 1.1 | 0.8 | 3.2 | 4.6 | 1.2 | 3.5 | 5.0 | 1.6 |
| **SO2 Emissions** | | | | | | | | | | | | | | | | | | | |
| SO2 in Exhaust Gas (Post Control) | lb/hr | 20.4 | 24.5 | 15.2 | 11.4 | 15.7 | 22.5 | 14.0 | 10.5 | 15.1 | 21.6 | 13.4 | 10.1 | 4.4 | 7.1 | 0.5 | 14.2 | 18.0 | 9.4 |
| SO2 in Exhaust Gas (Post Control) | lb/MMBtu | 0.0239 | 0.0239 | 0.0239 | 0.0239 | 0.0239 | 0.0239 | 0.0239 | 0.0239 | 0.0239 | 0.0239 | 0.0239 | 0.0239 | 0.005 | 0.007 | 0.001 | 0.0168 | 0.0177 | 0.0148 |
| **Volatile Organic Compounds** | | | | | | | | | | | | | | | | | | | |
| VOC @ 15% O2 | ppmvd | 3.3 | 4.5 | 0.9 | 0.8 | 1.9 | 4.4 | 0.9 | 0.8 | 2.0 | 4.5 | 0.9 | 0.9 | 3.2 | 4.3 | 0.8 | 3.2 | 4.4 | 0.9 |
| VOC as CH4 | lb/hr | 3.3 | 5.3 | 0.7 | 0.5 | 1.5 | 4.9 | 0.6 | 0.4 | 1.5 | 4.7 | 0.6 | 0.4 | 3.3 | 5.1 | 0.6 | 3.2 | 5.3 | 0.6 |
| **Particulates (See Note 1)** | | | | | | | | | | | | | | | | | | | |
| PM10, front half (Post Control) | lb/hr | 1.10 | 1.11 | 1.08 | 0.78 | 1.01 | 1.03 | 1.01 | 0.72 | 0.98 | 1.00 | 0.97 | 0.70 | 1.07 | 1.09 | 1.06 | 1.09 | 1.11 | 1.08 |
| PM10, front & back half (Post Control) | lb/hr | 4.30 | 4.29 | 4.32 | 3.11 | 3.97 | 3.95 | 3.97 | 2.87 | 3.82 | 3.80 | 3.82 | 2.78 | 4.26 | 4.24 | 4.27 | 4.29 | 4.27 | 4.30 |
| PM10, front & back half (Post Control) | lb/MMBtu | 0.0050 | 0.0042 | 0.0068 | 0.0065 | 0.0060 | 0.0042 | 0.0068 | 0.0065 | 0.0060 | 0.0042 | 0.0068 | 0.0066 | 0.0051 | 0.0043 | 0.0070 | 0.0050 | 0.0042 | 0.0068 |
| **GHG Emissions** | | | | | | | | | | | | | | | | | | | |
| CO2 in Exhaust Gas | lb/hr | 91,598 | 109,884 | 68,194 | 50,917 | 70,435 | 100,858 | 62,841 | 47,040 | 67,813 | 96,633 | 60,060 | 45,162 | 101,282 | 118,077 | 77,846 | 94,840 | 112,732 | 71,640 |
| CH4 in Exhaust Gas (CO2e) | lb/hr | 51.9 | 62.2 | 38.6 | 28.8 | 39.9 | 57.1 | 35.6 | 26.6 | 38.4 | 54.7 | 34.0 | 25.6 | 50.2 | 59.7 | 36.9 | 51.5 | 61.6 | 38.4 |
| N2O in Exhaust Gas (CO2e) | lb/hr | 61.8 | 74.2 | 46.0 | 34.4 | 47.5 | 68.1 | 42.4 | 31.8 | 45.8 | 65.2 | 40.5 | 30.5 | 59.8 | 71.2 | 44.0 | 61.4 | 73.5 | 45.7 |
| GHG (CO2e) in Exhaust Gas | lb/hr | 91,711 | 110,020 | 68,278 | 50,980 | 70,522 | 100,983 | 62,919 | 47,098 | 67,897 | 96,753 | 60,135 | 45,218 | 101,392 | 118,208 | 77,927 | 94,953 | 112,867 | 71,724 |

**Notes:**
1. All particulate matter is assumed to be PM2.5.
2. Emissions reported on the basis of lb/hr are for one combu

# APPENDIX H: AIR TOXICS POLICY REVIEW

# APPENDIX H - AIR TOXICS POLICY REVIEW

ACHD has county-specific guidelines for addressing toxic air contaminants. U. S. Steel completed an analysis of potential air toxics to be emitted from the proposed sources in the Installation Permit in accordance with ACHD's "Policy for Air Toxics Review of Installation Permit Applications", hereafter referred to as the "Policy". As shown in the following section, the project does not trigger the Air Toxics Program as there is a net decrease in air toxics as a result of the Project.

The Policy was adopted on November 7, 2012 by the Allegheny County Board of Health and amended on January 9, 2013.[1] The Policy provides a definitive method of evaluating the potential impact of air emissions of toxic contaminants from projects that require the submittal of an Installation Permit application within Allegheny County. The Policy applies for an Installation Permit that are expected increase the net potential air toxics emissions from the facility into the ambient air and do not belong to any one of the following categories:

- Projects resulting in an emissions increase less than the *de minimis* levels;
- Projects that are solely for the installation or in-kind replacement of pollution control device;
- Exempt activities such as those in Article XXI 2102.04.a.5; or
- Projects that include equipment where EPA has published risk assessment guidance (e.g., Municipal Waste Combustors).

ACHD's 10-step Guide to the Policy for Air Toxics Review of Installation Permit Applications was followed to ensure fulfillment of all requirements outlined in the Policy. The step-wise procedure followed by U. S. Steel according to the guidance document is outlined below.

## 1.1. AIR TOXICS ANALYSIS PROCEDURE

### 1.1.1. Step 1 - Determination of Air Toxic Pollutants to be Emitted

Each emission source from the proposed Installation Permit was evaluated for the potential to emit air toxics. Pollutants were designated as an air toxic based on toxicity information found in EPA's Integrated Risk Information System (IRIS), EPA's Provisional Peer Reviewed Toxicity Values (PPRTVs), California EPA's Toxicity Criteria Database, the Agency for Toxic Substances and Disease Registry (ATSDR), and Health Effects Assessment Summary Table (HEAST), per the guidance set forth in the Policy. Under the Policy, air toxics does not include any criteria pollutant or carbon dioxide.

A detailed account of the air toxics pollutants with the potential to be emitted by each source affected by the proposed project (i.e., the new cogeneration units, package boiler, emergency fire pump, diesel storage tank, and dewpoint heaters, as well as three existing boilers to be shutdown is given in the accompanying Installation Permit application package. Contemporaneously with this project, U. S. Steel is requesting enforceable restrictions on the operation of the three (3) remaining boilers in order to reduce the facility's potential emissions of air toxics. See the detailed emissions calculations included as Appendix C for a comprehensive list of the air toxics..

[1] https://alleghenycounty.us/uploadedFiles/Allegheny_Home/Health_Department/Programs/Air_Quality/ATG_final_2013-01-09_boh.pdf

### 1.1.2. Step 2 - Determination of Annual Potential Emissions

Potential annual emissions of air toxics were calculated for all point-sources associated with the Project. Emission rates were generally calculated using published emission factors and assuming maximum proposed operating schedules for each source. This procedure was done for new emissions sources as well as the existing emission sources being shutdown as a result of this project. Additionally, the change in potential emissions of air toxics from three boilers that will remain with limited operation has been included in the accounting. Details regarding the calculations can be found in the Installation Permit application (see Appendix C). The future potential air toxics emissions are detailed in the following tables:

- Cogeneration Unit - Tables C-23a through C-23e (depicts emissions from both units combined);
- Diesel Emergency Fire Pump – Table C-5;
- Diesel Storage Tank – Table C-9;
- Package Boiler – Table C-6a; and
- Dewpoint Heaters – Table C-6b (shows emissions per heater of which there are two).

The existing potential to emit air toxics from the equipment being shutdown as part of this project (i.e., Clairton Boilers 1, 2, and R-1) or operationally restricted contemporaneously with this project (i.e., Clairton Boilers R-2, T-1, and T-2) are found in Tables C-25 through C-30 and are summarized in Table C-24.

### 1.1.3. Step 3 - Comparison of Net Potential Air Toxics Emissions to De Minimis Levels

The air toxic pollutants identified in Step 1 were classified as either Polychlorobiphenols (PCB), Polycyclic Organic Matter (POM), Mercury, Dioxins, Furans, Hazardous Air Pollutant Metals (MHAP), or All Other air toxics (Other). The sum of the potential annual emissions for each project source (new equipment and equipment to be shutdown) and future restricted operation of existing boilers was calculated for each air toxics category. These emissions increase (net potential air toxics emissions) totals were then compared to the de minimis thresholds provided in ACHD's Air Toxic Guidelines Implementation Document. The de minimis levels are as follows:

- Polychlorobiphenols (PCBs) – 20 pounds per year (lb/yr)[1E-2 tpy];
- Polycyclic Organic Matter (POM) – 20 lb/yr [1E-2 tpy];
- Mercury – 20 lb/yr [1E-2 tpy];
- Dioxins – 0.02 lb/yr [1E-5 tpy];
- Furans – 0.02 lb/yr [1E-5 tpy];
- Hazardous Air Pollutant Metals (MHAP) – 20 lb/yr [1E-2 tpy]; and
- All Other Air Toxics – 500 lb/yr [0.25 tpy].

Based on the comparison of the change in annual potential emissions to ACHD's de minimis thresholds for each Air Toxic category, it was determined that proposed project did not exceed de minimis levels as summarized in Table H-1 and Tables C-22a, C-22b and C-22c of Appendix C. Since the project does not result in a change in the potential to emit air toxics in excess of de minimis levels, no further analysis is required under the Policy.

**Table H-1. Air Toxics Emissions Summary for Sources in Proposed Installation Permit**

| Classification | Air Toxic Potential Emissions from New Equipment – Coke Oven Gas Scenario (tpy) | Air Toxic Potential Emissions from New Equipment – Natural Gas Scenario (tpy) | Air Toxic Potential Emissions from New Equipment – Fuel Blend Scenario (tpy) | Air Toxic Potential Emissions from New Equipment – Worst-Case Scenario (tpy) | Reduced Air Toxic Potential Emissions from Equipment to be Shutdown/ Restricted (tpy) | Net Potential Air Toxics Emissions Increase (tpy) | *De Minimis* Threshold (tpy) | Above De Minimis? |
|---|---|---|---|---|---|---|---|---|
| Polychlorobiphenols (PCBs) | 0 | 0 | 0 | 0 | 0 | 0 | 1.0E-2 | No |
| Polycyclic Organic Matter (POM) | 3.6E-2 | 3.7E-2 | 3.8E-2 | 3.8E-2 | 3.0E-2 | 7.9E-3 | 1.0E-2 | No |
| Mercury | 1.8E-5 | 1.8E-5 | 1.8E-5 | 1.8E-5 | 2.4E-3 | -2.4E-3 | 1.0E-2 | No |
| Dioxins | 0 | 0 | 0 | 0 | 0 | 0 | 1.0E-5 | No |
| Furans | 0 | 0 | 0 | 0 | 0 | 0 | 1.0E-5 | No |
| Hazardous Air Pollutant Metals (MHAP) | 2.5E-2 | 6.8E-3 | 1.9E-2 | 2.5E-2 | 9.4E-2 | -7.0E-2 | 1.0E-2 | No |
| All Other Air Toxics | 63.8 | 46.5 | 60.1 | 63.8 | 111.8 | -48.0 | 0.25 | No |

## 1.2. AIR TOXICS ANALYSIS CONCLUSIONS

As shown in Table H-1 above and Tables C-22a, C-22b and C-22c of Appendix C, the emissions increase associated with the project is less than the de minimis levels. Since the project does not result in a change in the potential to emit air toxics in excess of de minimis levels, no further analysis under the Policy is required as the project is not predicted, per ACHD policy, to significantly affect public health.