



PERMIT-TO-INSTALL APPLICATION
OHIO RIVER CLEAN FUELS FACILITY
VILLAGE OF WELLSVILLE, COLUMBIANA AND JEFFERSON COUNTIES, OHIO

SUBMITTED TO:

OHIO ENVIRONMENTAL PROTECTION AGENCY

SUBMITTED BY:

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MODULE 9

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1.0 PROCESS DESCRIPTION

The power block will be constructed in three phases. In the first phase, a 1,200-MMBtu/hr boiler (Phase 1 Boiler) will be constructed along with a steam turbine. In the second phase (about 18 months after startup), use of the Phase 1 Boiler will be discontinued when a nominal 230-MWe combustion turbine generator (CTG) and a separate steam turbine generator for power generation from gasification process generated steam will be brought on line. In the third phase (about 18 months after Phase 2) the second nominal 230-MWe combustion turbine generator (CTG) will be brought on line.

The completed combined cycle plant will consist of two CTGs, each exhausting to its own Heat Recovery Steam Generator (HRSG) and a process steam turbine generator (PTG) as illustrated in Figure 19 (see Attachment 9A). Figure 20 illustrates the components of the Phase 1 Boiler. Key components are discussed below.

1.1 Phase 1 Boiler

Prior to the construction of the first combustion turbine, a 1,200-MMBtu/hr natural gas/tailgas-fired boiler will be installed to provide steam. The steam will be used to produce electricity for initial plant operations using a steam turbine generator. Exhaust from the Phase 1 Boiler will be controlled by Selective Catalytic Reduction (SCR) to achieve NO_x emissions of 0.1 lb/MMBtu and catalytic oxidation to achieve CO emissions of 0.03 lb/MMBtu and VOC emissions of 0.011 lb/MMBtu. After installation of the combustion turbines, use of this boiler will be discontinued.

1.2 Combustion Turbine Generators

Two 230-MWe (nominal) CTGs will burn tailgas produced within the facility or natural gas. Tailgas streams combined to feed the CTGs include:

- syngas that has passed through Module 5 (Syngas Cleanup),
- tailgas generated within the Fischer-Tropsch trains, and
- tailgas generated within the Product Upgrade train.

The individual composition of these fuel streams are summarized below.

Table 1.2 Composition of Fuel Streams

Composition (mole%)	Syngas from PSA	Tailgas from F-T	Tailgas from Product Upgrade
H ₂ O	0.00	0.09	0.03
H ₂	15.96	33.27	51.35
CO	75.27	15.79	3.98

Composition (mole%)	Syngas from PSA	Tailgas from F-T	Tailgas from Product Upgrade
CO ₂	0.20	4.17	5.20
AR	0.26	0.10	0.04
N ₂	8.15	12.31	2.77
C1-C4	0.15	34.16	36.37
C5-C9	0.00	0.10	0.25
TOTALS	99.99	99.99	99.99
MW (lb/lb-mole)	23.9	17.21	15.14
Flow (MMscfd)	24.25	145.51	6.37
Flow (lb-mole/hr)	2,662	15,977	700

Due to the gas cleaning systems discussed in Module 5, these fuel streams are assumed to contain no sulfur species, metals, or other particulate contaminants.

The CTGs will be either General Electric (GE) 7FB or Siemens SGT6-5000F model turbines. Performance data for the Siemens model was utilized for this permit application. The two-on-one Combined Cycle will utilize the tailgas described above as the primary fuel with backup and startup operation on natural gas. The two CTGs will be equipped with a low-NO_x combustion systems resulting in reduced NO_x and CO emissions.

The exhaust from the CTGs will be controlled with Selective Catalytic Reduction (SCR) and Catalytic Oxidation. This control strategy will reduce NO_x, CO, and VOC emissions by approximately 80, 70, and 30 percent respectively.

1.3 Heat Recovery Steam Generator (HRSG)

The Combined Cycle uses one triple pressure, reheat cycle HRSG per CTG. The HRSG produces steam through heat exchange with the hot flue gas from the CTG.

1.4 Duct Burners

Supplemental firing (or duct firing) uses a burner in the sides of the duct upstream of the HRSG to raise the temperature of the exhaust gas which in turn increases the steam temperature and pressure allowing for more electrical generation from the STG. Duct firing allows for the management of load fluctuation (i.e., matching electrical output to demand).

The SCR and Catalytic Oxidation systems will also control emissions from the duct burners.

1.5 Steam Turbine Generator (STG)

The STG will consist of a single shaft, tandem compound, two-flow reheat turbine that will be directly connected to the electric generator. The generator output will be 36 MWe (nominal).

The turbine will consist of a single-flow high pressure section, a single-flow reheat intermediate pressure section, and a double-flow low pressure section with a downward exhaust. The turbine will operate at 3,600 rpm. The STG will not be a source of atmospheric emissions but it is included in this application due to its integral role in the combined cycle plant.

1.6 Process Steam Turbine Generator (PSTG)

A separate 484-MWe (nominal) Process Steam Turbine Generator will be provided in the power island to utilize the steam generated by the gasification process to produce additional electricity. The steam from the gasification process will be saturated requiring moisture separators between the PSTG pressure sections. The PSTG will have a water-cooled steam surface condenser to receive the exhaust steam from the low-pressure turbine sections. The PSTG will not be a source of atmospheric emissions and is not discussed further in this application.

2.0 AIR EMISSIONS INVENTORY

During the initial phase of plant operations, a large gas-fired boiler (Phase 1 Boiler) will be used to meet the plant's power and heat demands. After the first phase, use of the Phase 1 Boiler will be discontinued. Air emissions from the Phase 1 Boiler will result from the burning of tailgas or natural gas.

During the second and third phases, two gas-fired turbine generators (Combined Cycle Plant) will replace the Phase 1 Boiler. The emissions from the Combined Cycle Plant will vary depending on what fuel (tailgas or natural gas) is combusted. The emissions will also vary depending on tailgas temperature; in general, a decrease in tailgas temperature will result in an increase in emissions. For the emissions calculations, the worst-case scenario was used assuming only lower temperature tailgas will be combusted.

Emissions will also result from the use of duct burners associated with the HRSGs.

A basic description of the emission estimates follows; further details are provided in the accompanying Supporting Calculations (Attachment 9B). All exhaust emissions are calculated and expressed on a per generator basis unless stated otherwise.

2.1 Phase 1 Boiler

Air emissions from the 1,200-MMBtu/hr Phase 1 Boiler will result from combusting tailgas supplied by the Syngas Cleanup and/or Fischer-Tropsch processes. Because published emission factors are not available for boilers burning tailgas and because the composition of tailgas is expected to be similar to that of natural gas, emission estimates have been based on AP-42 Section 1.4 factors for Natural Gas Combustion adjusted for the expected heating value of the tailgas (487.5 Btu/scf) and an assumed 73% combustion efficiency for the boiler. Controlled emission estimates are based on the use of low-NO_x burners and selective catalytic reduction (SCR) for control of nitrogen oxides. Catalytic oxidation will be used to control carbon monoxide and volatile organic compound emissions. Good combustion practices and use of clean fuels will be used to reduce the formation of other pollutants. Detailed emission calculations are provided in Attachment 9B. Phase 1 Boiler emissions are based on 8,736 hours per year of normal operation and 24 hours of shutdown or startup operation during which exhaust gases are not controlled by SCR.

2.2 Gas-fired Turbine Generators

Emissions from the CTGs will also result from combusting tailgas supplied by the Syngas cleanup and Fischer-Tropsch processes or natural gas, as needed. The exhaust gas composition provided in the attached supporting calculations was obtained from estimated gas turbine performance data. Exhaust gas concentrations for NO_x, and CO were provided on a dry 15% O₂

basis; concentration adjustments to performance conditions were achieved utilizing the following equation.

$$\text{ppmv} = (\text{ppmvd @ 15\% O}_2) \times \frac{(20.95 - \%O_2)}{(20.95 - 15)} \times \frac{(100 - \%H_2O)}{100}$$

All exhaust constituent concentrations were provided as a volumetric basis except for particulate matter, which was provided in lb/hr. Exhaust emission rates, by mass, were obtained utilizing the conversion illustrated as follows.

$$\frac{\text{lb}}{\text{hr}} = \frac{\text{lb - mole}}{\text{hr}} \times \frac{\text{ppmv}}{10^6} \times \text{MW}$$

2.3 Duct Burners

The duct burners within the Combined Cycle plant are considered to be an emissions control technology. The duct burner emission rates provided in the attached supporting calculations were obtained from preliminary equipment performance estimates. Emissions estimates for burners were obtained utilizing the following equation.

$$\frac{\text{lb}}{\text{hr}} = \frac{\text{lb}}{\text{MMBTU}} \times \frac{\text{MMBTU}}{\text{hr}}$$

2.4 System Startup and Shutdown

2.4.1 Phase 1 Boiler

The Phase 1 Boiler will be the primary source of electrical power for the facility during the initial 18 months of operation. Start-up of the boiler will occur using natural gas or a combination of tailgas and natural gas. During startup, exhaust gases will not be of sufficient temperature (approximately 300° F) for SCR control. The duration and frequency of these events will be kept to the minimum possible. Startup and shutdown emissions have been based on one startup or shutdown lasting 24 hours annually.

2.4.2 Gas-Fired Turbine Generators

Typical 2-in-1 Combined Cycle operations account for an annual 7-day equipment inspection and 4 unscheduled 24-hour down periods. However, to be conservative, emissions were based on 100% operations (8,640 hours of normal operations and 120 hours of startup and shutdown). The startups and shutdowns were averaged into the total emission estimates, described further in the following section.

Startup emissions are provided for typical Combined Cycle data with a 50% margin added. Natural gas is expected to be the fuel used for startup operations. The different types of startup conditions are characterized as cold, warm, and hot. A cold start is the process of warming the gas turbine, HRSG, and steam turbine equipment following an extended outage (i.e., greater than 48 consecutive hours). This type of startup results in the highest emissions because of the amount of time required to slowly warm the hot gas path equipment. In addition, post-combustion control equipment, such as the SCR and oxidation catalysts, does not operate at peak efficiencies until some period of time into the startup procedure. A warm start is a startup following an outage period of greater than 8 hours but less than 48 hours. This type of startup is common following a weekend outage. Emissions and startup times are somewhat reduced because the hot gas path equipment still retains some heat. Finally, a hot start is a startup following an outage of less than 8 hours. This scenario results in the shortest startup times and the lowest emissions because of the significant amount of heat retained in the system.

The duration of startup phase and the emissions are provided in the attached supporting calculations worksheet. For calculation purposes, shutdown operations are assumed equivalent to startup in terms of duration and emission rates.

2.5 Overall Emissions

Emission estimates were segregated into two Phases. Phase 1 includes only the Phase 1 Boiler while Phase 2 includes the total emissions obtained by combining the two controlled CTGs and Duct Burners (for 8,640 hours of normal operation) with CTG startup and shutdown emission estimates.

The Combined Cycle Plant will utilize SCR and catalytic oxidation as control strategies for NO_x, CO, and VOCs. Permitted emission rates will be based on the CTGs hourly rate and a separate emission rate for startup and shutdowns (the aggregate of both CTGs). The total emission rates for both phases of the Power Block are presented below.

The total emissions for the initial phase of operations are those emissions resulting from operation of the gas-fired boiler only. Those emissions are provided below.

Table 2.5-A Summary of Phase 1 Boiler Actual Emissions

Operating Mode	Actual Criteria Emissions (tpy)									
	NO _x		CO		VOC		SO ₂		PM10	
	lb/hr	tpy	Lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Routine (8,736 hr/yr)	120	524.2	36	157.2	13.0	56.9	2.0	8.9	18.7	81.7
Startup/Shutdown (24 hr/yr)	473.8	5.7	36	0.4	13.0	0.2	2.0	0.0	18.7	0.2
Totals		530		157.6		57.1		8.9		81.9

The total emissions for the second phase of operations are those emissions resulting from operation of the turbines and duct burners. Those emissions are provided below.

Table 2.5-B Summary of CTG Actual Emissions

Unit/Mode	Actual Criteria Emissions (tpy)									
	NO _x		CO		VOC		SO ₂		PM10	
	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Turbine 1 w/Duct Burner (Routine)	57.1	246.5	23.1	99.8	26.62	115.0	21.1	91.0	18.2	78.7
Turbine 2 w/Duct Burner (Routine)	57.1	246.5	23.1	99.8	26.62	115.0	21.1	91.0	18.2	78.7
Startup	766.7	17.25	1,991.7	43.5	162.50	3.1	7.3	0.15	162.5	3.1
Phase 2 Total		510.26		243.1		233.1		182.1		160.5

3.0 SOURCE-SPECIFIC APPLICABLE REGULATIONS

This section presents information concerning applicable state and federal regulations as well as specific exemptions, as appropriate. State regulatory references are to the Ohio Administrative Code (OAC), unless otherwise noted. Source-specific regulations are discussed relative to each permit application module.

3.1 State Regulations

3.1.1 Control of Visible Particulate Emissions from Stationary Sources (3745-17-07)

The combined cycle plant includes stationary sources of particulate matter. Stationary sources are subject to Chapter 3745-17-07(A)(1)(a) which limits visible particulate emissions to less than 20% opacity as a six-minute average. Chapter 3745-17-07(A)(1)(b) further states that the 20% opacity limit may not be exceeded for more than six consecutive minutes in any sixty minutes and never shall the opacity exceed 60% as a 6-minute average.

3.1.2 Restrictions on Particulate Emissions from Fuel Burning Equipment (3745-17-10)

This rule applies to sources using fuel combustion to produce heat or power by indirect heat transfer. Transfer of heat through combustion of fuel in the gas turbines is an indirect form of heat transfer and therefore this rule is applicable.

The rule limits particulate emissions to 0.02 pounds per million Btu of actual heat input. The estimated high heating value heat input of each gas turbine is 2,134 MMBtu/hr at 49.8 °F. Based on this heat input, the allowable particulate emission rate from each gas turbine generator will be 42.7 lb/hr. Estimated emissions from each gas turbine are 16.1 lb/hr, so the turbines are expected to comply with this requirement.

The estimated high heating value heat input of each duct burner is 211 MMBtu/hr at 49.8 °F. Based on this heat input, the allowable particulate emission rate from each duct burner will be 4.2 lb/hr. Estimated emissions from each gas turbine are 2.1 lb/hr, so the duct burners are expected to comply with this requirement.

3.1.3 Restrictions on Particulate Emissions from Industrial Sources (3745-17-11)

Section B(4) of this regulation established emission limits for stationary gas turbines. Turbine exhaust particulate emissions are not permitted to exceed 0.040 pounds per million Btu of actual heat input. As indicated above, the ORCF gas turbines will achieve a particulate emission limit of less than 0.02 pounds per million Btu.

3.1.4 General Emission Limit Provisions (3745-18-06)

Section F establishes stationary gas turbine SO₂ emission rate of 0.5 lb/MMBtu actual heat input.

3.1.5 Permits to Install New Sources (3745-31)

The combined cycle plant will generate criteria pollutants from fuel combustion. These emission units are components of a major stationary source. Because the major stationary source is located within an attainment area for all criteria pollutants, according to 3745-31-12(A), each emissions unit is subject to an evaluation of best available control technology (BACT). The BACT analysis for these emission units is provided in Section 4.

3.1.6 Review of Major Stationary Sources of Hazardous Air Pollutants Requiring MACT Determinations (3745-31-28)

This state regulation prohibits the construction of a major MACT source without first applying for and obtaining a MACT determination from the director. Because the Phase 1 Boiler is expected to be a major source of the hazardous air pollutant, hexane, a MACT determination is required. However, because there is no current MACT standard applicable to the Phase 1 Boiler, a case-by-case determination has been proposed by ORCF. ORCF proposes to accept permit conditions consistent with the vacated Subpart DDDDD MACT standard for Industrial, Commercial, and Institutional Boilers and Process Heaters (40 CFR 63.7480). Specifically, the emission limit applicable to a large gaseous-fueled boiler is a carbon monoxide limit of 400 ppm by volume on a dry basis corrected to 3 percent oxygen on a 30-day rolling average. This limit is intended to demonstrate good combustion. Good combustion practice is recognized as BACT for control of volatile organic compounds from large gas-fired boilers.

3.1.7 Clean Air Mercury Rule (CAMR) (3745-108)

Ohio EPA has promulgated regulations under OAC 3745-108 to comply with the requirements of U.S. EPA's mercury model trading rule (Clean Air Mercury Rule (CAMR), 40 CFR Part 60, Subpart HHHH). While the federal CAMR is currently vacated, it is expected to be reinstated and applicable to ORCF. The rule will set limits on mercury emissions from coal-fired electric utilities with a capacity of greater than 25 MWe and cogeneration units that provide more than one-third of their electrical generating capacity for sale. Among other things, the rule will establish permitting and emissions reporting requirements for the affected emission units. When reinstated, ORCF will comply with applicable requirements of this rule.

3.1.8 Clean Air Interstate Rule (CAIR) (3745-109)

Ohio EPA has promulgated regulations under OAC 3745-109 to implement the Federal CAIR requirements. Among other things, the rule establishes permitting and emissions reporting requirements for the affected emission units. Emission budgets for the ORCF units will need to

be determined and included in the operating permits. CAIR has monitoring requirements similar to the Acid rain program.

Because ORCF intends to sell electricity from the CTGs, they will be considered electricity generating units (EGUs). As such, the emission units will be assigned annual NO_x allowances based on their initial operating history. The Phase 1 Boiler will not be an EGU and will therefore be subject to only an ozone season NO_x allowance.

3.1.9 Nitrogen Oxides – Reasonably Available Control Technology (3745-110)

This rule became effective on December 12, 2007. It establishes nitrogen oxide emission limitations for specific categories of stationary sources. The source group applicable to the proposed project is “very large boilers.” A very large boiler is an industrial boiler with a maximum heat input greater than 250 MMBtu/hr. The Phase 1 Boiler is therefore a very large boiler. The definition of a “stationary combustion turbine” includes any combustion turbine portion of a combined cycle steam/electric generating system.

3.2 Federal Regulations

3.2.1 NSPS Subpart Da – Stationary Generating Units (40 CFR 60.40a)

Subpart Da applies to each electric utility steam-generating unit that meets certain criteria. An electric utility steam-generating unit, as defined at 40 CFR 60.41Da, as:

any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 megawatts (MW) net-electrical output to any utility power distribution system for sale. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility.

For Subpart Da to be applicable, the unit must burn > 50% solid-derived fuel not meeting the definition of natural gas on a 12-month rolling average basis, and must commence operation after February 28, 2005. Phase 1 of the Power Block is expected to produce a nominal 200 MW of electricity, but it will not be produced for sale, therefore it will not be subject to Subpart Da.

The final Combined Cycle Plant is expected to produce 980 MW and export approximately 366 MWe gross power output for distribution to the electric power distribution system. The CTGs will therefore supply more than one-third (~37%) of their potential electric output capacity to the distribution system and therefore meet the definition of electric utility steam-generating units subject to Subpart Da.

The standard establishes emission limitations for SO₂ and NO_x and monitoring, record keeping, and reporting requirements.

3.2.2 NSPS Subpart Db – Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60.40b)

Subpart Db applies to each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)). This Subpart will apply to the Phase 1 Boiler.

The standard establishes emission limitations for SO₂, PM, and NO_x, and monitoring, record keeping, and reporting requirements.

3.2.3 Standards of Performance for Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (40 CFR 60 Subpart Ja)

The Phase 1 Boiler and CTGs described in this module are not affected facilities associated with the petroleum refining components of the facility. Subpart Ja is therefore not applicable to these emission units.

3.2.4 Acid Rain Program

The Acid Rain Program regulations are contained in 40 CFR Parts 72 through 78. The purpose of this part is to establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide (SO₂), nitrogen oxides (NO_x), and carbon dioxide (CO₂) emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program pursuant to Sections 412 and 821 of the CAA. This rule applies to utilities (anyone who sells power) that generate greater than 25 MW.

3.2.5 NSPS Subpart KKKK –Stationary Combustion Turbines (40 CFR 60.4300)

Subpart KKKK applies to CT/HRSG commencing operation after February 18, 2005 with a heat input \geq 10 MMBtu/hr based on the HHV of fuel. However, stationary CTs at IGCC electric utility steam generating units that are subject to NSPS Subpart Da are exempt from Subpart KKKK. Also, HRSGs and duct burners are not subject to KKKK.

3.2.6 MACT Applicability

The EPA has promulgated the final National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters (December 2006). The EPA has amended 40 CFR 63.7491(c) to exclude “an electric utility steam generating unit

(including a unit covered by 40 CFR part 60, Subpart Da) or a Mercury Budget unit covered by 40 CFR part 60, subpart HHHH.’’

On July 30, 2007, the Court of Appeals for the District of Columbia Circuit issued its mandate in NRDC v. EPA, vacating the Boilers Rule. See also discussion under Section 3.1.6, above.

3.2.7 Chemical Accident Prevention Provisions (40 CFR 68 Subpart G – Risk Management Plan)

The SCRs to be implemented for the CTGs will employ ammonia to control NO_x emissions. The quantity of ammonia stored for the SCR system is expected to exceed the storage threshold for applicability of this rule (10,000 pounds). Therefore, ORCF will provide a Risk Management Plan (RMP) that includes accidental release prevention and emergency response policies and programs, regulated substances handled, general accidental release prevention program, chemical-specific prevention steps, and measures to be implemented to ensure safety.

4.0 BACT ANALYSIS

The Combined Cycle Plant consists of one 1,200-MMBtu/hr boiler (Phase 1 Boiler) and two combustion turbines generators (CTGs) with supplemental duct firing. A Best Available Control Technology (BACT) Analysis was conducted following EPA top-down methodology. The BACT significance thresholds were compared with facility emissions. Based on the analysis below, a summary of the selected BACT Technology and emission rates are shown in Table 4.1.

Table 4.1 - Summary of BACT Analysis

Source	Pollutant	Technology	Proposed BACT Limit (Normal Operation)	Proposed BACT Limit (Startup/Shutdown)
Each CTG (with duct firing)	NO _x	SCR	0.022 lb/MMBtu 57.06 lb/hr	370 lb/hr
	CO	Catalytic Oxidation/ Good combustion practices	0.008 lb/MMBtu 23.1 lb/hr	870 lb/hr
	VOC	Collateral control from Catalytic Oxidation/ Good combustion practices	0.012 lb/MMBtu 26.62 lb/hr	65 lb/hr
	SO ₂	Clean Fuel	0.0093 lb/MMBtu 21.06 lb/hr	2.5 lb/hr
	PM/PM10	Good combustion practices	0.008 lb/MMBtu 18.21 lb/hr	65 lb/hr
Phase 1 Boiler	NO _x	Low-NO _x Burners and SCR	0.1 lb/MMBtu 120 lb/hr	474 lb/hr
	CO	Catalytic Oxidation/ Good combustion practices	0.03 lb/MMBtu 36 lb/hr	Same
	VOC	Collateral control from Catalytic Oxidation/ Good combustion practices	0.011 lb/MMBtu 13.0 lb/hr	Same
	SO ₂	Low Sulfur Fuels	0.002 lb/MMBtu 2.0 lb/hr	Same
	PM/PM10	Clean Fuel/Good combustion practices	0.0156 lb/MMBtu 18.7 lb/hr	Same

Throughout this discussion, the terms “syngas” and “tailgas” may be used interchangeably. In general, syngas refers to the product of the gasification trains where coal is converted to carbon monoxide and hydrogen. This material is used as the feedstock to the F-T and Product Upgrade modules where liquid fuels are produced. “Tailgas” refers to syngas that is diverted to the power island from any downstream locations after the gas has gone through the cleaning system (Module 5). Tailgas is used in the facility for production of the electricity needed to power the facility with surplus electricity being sent to the grid. Tailgas characteristics were presented in Section 1.9 (Module 9- Combined Cycle Plant).

Also, duct burners combust fuel into the exhaust from the combustion turbines prior to the HRSG. The extra fuel consumes only oxygen present in the turbine exhaust with little or no addition of extra air. It is therefore impossible to control a duct burner using an add-on control device separate from the combustion turbine. The BACT analysis discussion for the duct burners is included in the combustion turbines.

4.1 CTG Nitrogen Oxide

NO_x is formed during combustion primarily by the by-products of the reaction of combustion air nitrogen and oxygen within the high temperature combustion zone (thermal NO_x), or by the oxidation of nitrogen in the fuel (fuel NO_x). Because the tailgas contains negligible amounts of fuel-bound nitrogen, essentially all combustion turbine NO_x emissions originate as thermal NO_x.

The rate of thermal NO_x formation in the combustion turbines is primarily a function of the fuel residence time, availability of oxygen, and peak flame temperature. Several NO_x control technologies are available to reduce the impacts of these variables during the combustion process and as post combustion controls. These are discussed in detail below.

4.1.1 Available Control Technologies – Nitrogen Oxide

A review of technical literature as well as the RBLC database for Process Type 15.200 – combined cycle and cogeneration units > 25 MW burning natural gas (15.210) and other gaseous fuels (15.250), located BACT determinations for nitrogen oxide (NO_x) in the following categories:

- Combustion Process Modifications
 - Diluent Injection (steam, water, nitrogen)
 - Dry low- NO_x (DLN) (Lean Pre-mix and Catalytic Combustion)
 - Flue Gas Recirculation

- Post-Combustion Exhaust Gas Treatment Systems
 - Selective non-catalytic reduction (SNCR)
 - Selective Catalytic reduction (SCR)

- EMx™ (formerly SCO NO_x™)

It is necessary to recognize the fundamental differences between natural gas-fired and syngas-fired combustion turbines when evaluating these techniques. Syngas has a much higher hydrogen content (about 30 to 40%) compared to natural gas (over 90% methane), and a much lower heating value (about 490 Btu/scf for syngas and 1,000 Btu/scf for natural gas). Also, the pre-treatment of the syngas includes a moisturization step which increases the content of water vapor in the gas. Together, these differences alter the combustion kinetics of the burner flame in a manner that prevents the use of lean-premix combustion techniques, which are the defining feature of effective Low-NO_x burner design. The pollution control strategy will focus on tailgas since it will be the primary fuel and natural gas will only be used during startup and fuel augmentation.

Combustion Process Modifications – Diluent Injection

Higher combustion temperatures may increase thermodynamic efficiency, but may also increase the formation of thermal NO_x. A diluent, such as steam, can be added to the tailgas to effectively lower the combustion temperature and formation of thermal NO_x.

Combustion Process Modifications – Dry Low-NO_x (DLN)

Dry Low- NO_x (DLN) burner technology has successfully been demonstrated to reduce thermal NO_x formation from combustion turbines utilizing natural gas. This technology utilizes a burner design that controls the stoichiometry and temperature of combustion by regulating the distribution and pre-mixing of fuel and air, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions.

Combustion Process Modifications – Flue Gas Recirculation

Flue gas recirculation significantly reduces NO_x emissions in industrial boilers by recirculating a portion of the boiler flue gas into the main combustion chamber. This process reduces the peak combustion temperature and lowers the percentage of oxygen in the combustion air/flue gas mixture; thus retarding the formation of NO_x caused by high flame temperatures (thermal NO_x).

Post-Combustion Exhaust Gas Treatment Systems – SNCR

SNCR is a post-combustion NO_x control technology in which a reagent (ammonia or urea) is injected in the exhaust gas to react with NO_x to form nitrogen and water without the use of a catalyst.

Post-Combustion Exhaust Gas Treatment Systems – EMx™

EMx™ (formerly known as SCO NO_x) is a control technology that utilizes a single catalyst to minimize CO, VOC, and NO_x emissions.

Post-Combustion Exhaust Gas Treatment Systems – SCR

The tailgas fired in the proposed combustion turbines is largely similar to the syngas-fired combustion turbines at permitted IGCC facilities in the United States. SCR technology has never been attempted on an IGCC plant using coal-derived syngas. BACT analyses for previously permitted IGCC plants have determined SCR is not technically feasible due to concerns regarding a back pressure energy penalty, catalyst performance, and potential operational impacts to downstream equipment from the sulfur content in the fuel. Several analyses noted the unavailability of meaningful performance guarantees from SCR suppliers. In other cases, the application of SCR to the IGCC process was not deemed cost effective due to increased operation and maintenance costs and the costs associated with reducing syngas sulfur to levels that are assumed to be adequate to minimize operational impacts.

Initial evaluation of the application of SCR to the ORCF project indicates that due to the extremely high sulfur removal necessary for the Fischer-Tropsch process, catalyst fouling and other operational concerns due to sulfur in the fuel would be alleviated. Under the proposed tailgas-firing scenario, SCR is believed to be technically feasible.

During most startup operations, the combustion turbines will be fired with tailgas. However, the initial startup and some cold startup scenarios, natural gas will be used to fire the combustion turbines. SCR is not technically feasible during the initial startup operations due to the low temperature where the SCR would be applied. As the operating temperature reaches the operational range of the SCR, the fuel would be changed to tailgas as soon as tailgas within specification was available and the SCR would be engaged. Also, when firing natural gas, the SCR will be utilized as soon as the exhaust temperature reaches the operational range of the SCR.

4.1.2 *Technically Infeasible Options – Nitrogen Oxide*

The following technologies were considered infeasible for this project.

Combustion Process Modifications – Diluent Injection

The tailgas combusted in the combustion turbines contains approximately 5% CO₂, which acts as a diluent. Therefore, additional dilution does not result in additional NO_x reduction. Therefore, diluent injection is not a technically feasible control technology for the proposed combustion turbines while firing tailgas. Diluent Injection would be technically feasible during natural gas firing.

Combustion Process Modifications – Dry Low-NO_x (DLN)

Available DLN burner technologies for combustion turbines are designed for natural gas (methane-based) fuels, but are not applicable to combustion turbines utilizing tailgas (hydrogen/CO-based), which has a different heating value, gas composition, and flammability characteristics. Research is ongoing to develop DLN technologies for tailgas and syngas-fueled combustion turbines, but no designs are currently available. Therefore, DLN burner technology is not technically feasible for tailgas and syngas-fueled combustion turbines due to potential explosion hazards in the combustion section associated with the high content of hydrogen in the fuel gas.

Combustion Process Modifications – Flue Gas Recirculation

Flue gas recirculation is being researched by combustion turbine manufactures, but is not currently an available control technology. While the technology may be a future option to reduce NO_x emissions, significant development work is required to complete maturation and integration of the concept into a power plant system, including validating all emissions characteristics and overall plant performance and operability. Additionally, current research efforts have focused on pre-mixed natural gas combustion, and results would need to be expanded to assess tailgas applications. Thus, flue gas recirculation is not technically feasible for the proposed combustion turbines.

Post-Combustion Exhaust Gas Treatment Systems – SNCR

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, which must occur in a very narrow high temperature range. 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, resulting in excess ammonia emissions. SNCR technology is occasionally used in conventional coal-fired heaters or boilers, but it has never been applied to natural gas combined cycle or syngas/tailgas units because no locations exist in the heat recovery steam generator with the optimal temperature and residence time that are necessary to accommodate the technology. Therefore, SNCR is not technically feasible.

Post-Combustion Exhaust Gas Treatment Systems – EMx™

All installations of the technology have been on small natural gas facilities. EMx™ has not been applied to large-scale tailgas/syngas combustion turbines, which creates concerns regarding the timing, feasibility of scaling up to a larger unit and use of different fuel, cost-effectiveness of necessary design improvements, and potential catalyst fouling. Therefore, EMx™ is not technically feasible.

4.1.3 Technology Ranking – Nitrogen Oxide

SCR is the only NO_x control technology determined to be technically feasible for the proposed combustion turbines during normal operations firing tailgas. SCR, combined with diluent injection, are the only NO_x control technologies determined to be technically feasible for the proposed CTL combustion turbines during natural gas firing.

4.1.4 Evaluate Most Effective Controls – Nitrogen Oxide

The use of SCR was identified as the only technically feasible NO_x control technology for the proposed combustion turbines during normal operations. A cost analysis was conducted to evaluate the economic impact at varying levels of control (70%, 80%, and 90%). The detailed analysis is included in Appendix A. It is important to note that this cost analysis was based on vendor information from their experience with natural gas fired turbines, since there is no data for turbines that fire syngas similar to this plant. Based on the cost analysis, and the fact that this technology while being proven in the natural gas fired turbine application has never been used for a syngas turbine, a control efficiency of 80% was selected as being both technically and economically feasible. This level of control was estimated as having an incremental cost of \$3,170 per ton removed. We believe that the actual incremental cost may be higher; however, given that this technology has not yet been applied there is no data to substantiate this.

The 90% control alternative, while potentially technically feasible, is more likely to represent a Lowest Achievable Emission Rate (LAER) and was rejected due to its higher incremental cost effectiveness. This is coupled with the lack of confidence in the ability of the system to meet 90% for syngas-fired turbines, since there is no operating data to confirm this performance level.

The use of SCR with 80% removal efficiency is expected to reduce NO_x emissions to 5 ppmvd (at 15% O₂) when firing syngas (tailgas). The nominal gross output for the 2 x 1 generator/HRSG/ steam turbine configuration is 980 MW. Therefore, the equivalent potential NO_x emission rate is approximately 0.1 lb/MWh, significantly lower than the applicable NSPS Subpart Da 1.0 lb/MWh.

The use of diluent injection combined with SCR was identified as the only technically feasible NO_x control technologies for the proposed combustion turbines during natural gas firing operations. The use of diluent injection combined with SCR will reduce NO_x emissions to 5 ppmvd (at 15% O₂).

4.1.5 Proposed BACT Limits and Control Options – Nitrogen Oxide

The use of SCR is proposed as BACT for the proposed combustion turbines with duct firing during normal operations to reduce NO_x emissions to 5 ppmvd (at 15% O₂) with a 10 ppmvd NH₃ slip [equivalent to 0.022 lb/MMBtu] when firing tailgas. Diluent injection using water or steam injection combined with SCR is proposed as BACT for the proposed combustion turbines

to reduce NO_x emissions to 5 ppmvd when firing natural gas. The proposed BACT NO_x limits are presented below for each combustion turbine.

The proposed NO_x BACT emission limit is equivalent to 5 ppmvd with a 10 ppmvd NH₃ slip (at 15% O₂). The nominal gross NO_x emission is 0.1 lb/MWh.

4.2 CTG Carbon Monoxide

CO emissions are a result of incomplete combustion. Providing adequate fuel residence time and higher temperatures in the combustion zone to ensure complete combustion can reduce CO emissions. However, these same control factors can increase NO_x emissions. Conversely, lower NO_x emission rates achieved through flame temperature control (by diluent injection) can increase CO emissions. The design strategy is to optimize the flame temperature to lower potential NO_x emissions, while minimizing the impact to potential CO emissions. Post-combustion control technologies have also been used to reduce CO emissions in some processes.

4.2.1 Available Control Technologies – Carbon Monoxide

Combustion Turbine Generators & Heat Recovery Steam Generators

A review of the RBLC database for Process Type 15.200 – combined cycle and cogeneration units > 25 MW burning natural gas (15.210) and other gaseous fuels (15.250), located BACT determinations for carbon monoxide (CO) in the following categories:

- Combustion Process Modifications
 - Good combustion practices
 - Catalytic combustion
- Post-Combustion Exhaust Gas Treatment Systems
 - EMx
 - Catalytic oxidation

Combustion Process Modifications – Good Combustion Practices

Good combustion practices include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure complete combustion. This technology has been determined to be BACT for CO emissions for combustion turbines, which use syngas/tailgas fired combustion turbines and therefore is considered technically feasible.

Combustion Process Modifications – Catalytic Combustion of Fuel (XONON)

The XONON™ system, developed by Catalytica and currently owned by Kawasaki, shows promise in future applications for simultaneously reducing NO_x, CO, and VOC emissions. The system will use a catalyst within the combustor. The air/fuel mixture will pass through the catalyst allowing fuel and air to react and achieve flameless combustion, thus preventing NO_x formation while achieving low CO and VOC emissions.

Post-Combustion Exhaust Gas Treatment Systems – EMx

EMx™ (formerly known as SCO NO_x) is a control technology that utilizes a single catalyst to minimize CO, VOC, and NO_x emissions.

Post-Combustion Exhaust Gas Treatment Systems – Catalytic Oxidation

Catalytic oxidation is a post-combustion control technology that utilizes a catalyst to oxidize CO into CO₂. Trace constituents in the combustion exhaust can create significant concerns regarding the fouling and subsequent reduced performance of the catalyst. Because of these concerns, the use of oxidation catalysts has been limited to processes combusting natural gas.

Initial evaluation of the application of catalytic oxidation to the ORCF project indicates that due to the extremely affective gas cleanup necessary for the Fischer-Tropsch process, catalyst poisoning and other operational concerns due to trace contaminants in the fuel would be alleviated. Under the proposed tailgas-firing scenario, catalytic oxidation is believed to be technically feasible.

4.2.2 Technically Infeasible Options – Carbon Monoxide

Combustion Process Modifications – Catalytic Combustion of Fuel (XONON)

The XONON™ system is currently being developed for gas turbines in the 1 to 15 MW size range only. This technology is not commercially available for the proposed gas turbines, and thus, is not technically feasible for the proposed facility.

Post-Combustion Exhaust Gas Treatment Systems – EMx

The EMx™ system was evaluated in the NO_x BACT analysis, and determined to not be technically feasible. It was determined not technically feasible because it has only been applied to small natural gas facilities.

4.2.3 Evaluate Most Effective Controls – Carbon Monoxide

The use of good combustion practice and catalytic oxidation are determined to be the most effective control alternative for carbon monoxide from the CTG/HRSGs. A cost analysis was conducted to evaluate the economic impact at varying levels of control (refer to Appendix A). This cost analysis was based on vendor information from their experience with natural gas fired turbines. Based on the cost analysis, a control efficiency of 70% was selected as being both technically and economically feasible.

The 80% control alternative, while potentially technically feasible, is more likely to represent a Lowest Achievable Emission Rate (LAER) and was rejected due to its excessive incremental cost effectiveness (approximately \$8,500 per ton).

The use of good combustion practice and catalytic oxidation with 70% removal efficiency will reduce CO emissions to 3 ppmvd (at 15% O₂), or 0.008 lb/MMBtu.

4.2.4 Proposed BACT Limits and Control Options – Carbon Monoxide

The use of good combustion practice and catalytic oxidation has been selected as BACT for potential CO emissions from the proposed CTG/HRSGs and integral duct burners. The BACT limit for CO emissions is proposed below.

Proposed CO BACT Limit: 0.008 lb/MMBtu (24-hour rolling average basis) and is equivalent to 3 ppmvd at 15% O₂.

4.3 CTG Volatile Organic Compounds

Volatile organic compounds (VOC) will be emitted as a by-product of incomplete combustion of tailgas or natural gas caused by insufficient residence time, inadequate air and fuel mixing, a lack of available oxygen, or low temperatures in the combustion zone.

4.3.1 Available Control Technologies – Volatile Organic Compounds

A review of technical literature as well as the RBLC database for Process Type 15.200 – combined cycle and cogeneration units > 25 MW burning natural gas (15.210) and other gaseous fuels (15.250), located BACT determinations for volatile organic compounds (VOC) in the following categories:

- Combustion Process Modifications
 - Good combustion practices
 - Catalytic combustion

- Post-Combustion Exhaust Gas Treatment Systems
 - EMx
 - Catalytic oxidation

Discussion concerning these technologies can be found in Section 4.2.1.

4.3.2 Technically Infeasible Options – Volatile Organic Compounds

Discussion concerning these technologies can be found in Section 4.2.2.

4.3.3 Technology Ranking – Volatile Organic Compounds

As with combustion turbine BACT for CO, good combustion practice and catalytic oxidation are the only technically feasible control technologies for VOC emissions from the IGCC CTG/HRSGs.

4.3.4 Evaluate Most Effective Controls – Volatile Organic Compounds

The use of good combustion practice and catalytic oxidation are determined to be the most effective control alternative for VOC from the CTG/HRSGs.

4.3.5 Proposed BACT Limits and Control Options – Volatile Organic Compounds

The use of good combustion process design and operating practices as well as incidental control using catalytic oxidation (30% reduction on VOCs) has been selected as BACT for potential VOC emissions from the proposed CTG/HRSGs and integral duct burners. The BACT limit for VOC emissions is proposed below. In the absence of an applicable NSPS, the proposed averaging period represents the averaging period associated with the ambient air quality standard for 26 lb/hr.

Proposed VOC BACT Limit: 0.012 lb/MMBtu (24-hour rolling average basis)

4.4 CTG Particulate Matter

Fuel quality and combustion efficiency are key drivers impacting the quantity and disposition of potential particulate emissions. In some processes, post-combustion control technologies can also be used to reduce particulates. Clean gaseous fuels such as syngas, will also be low in particulate emissions. Tailgas burned in the ORCF CTGs will have been cleaned of impurities in the syngas cleanup stages discussed in Section 2.1.5.

When the NSPS for Stationary Gas Turbines (40 CFR 60, Subpart GG) was promulgated in 1979, EPA acknowledged that, “Particulate emissions from stationary gas turbines are minimal.”

Similarly, the new NSPS for Stationary Combustion Turbines (40 CFR 60, Subpart KKKK) does not contain emission limits for PM or PM10. Performance standards for particulate matter control of stationary gas turbines have not been proposed or promulgated at the federal level.

4.4.1 Available Control Technologies – Particulate Matter

A review of the RBLC database for Process Type 15.200 – combined cycle and cogeneration units > 25 MW burning natural gas (15.210) and other gaseous fuels (15.250), located BACT determinations for particulate matter and PM10 in the following categories:

- Combustion Process Modifications
 - Good combustion practices
 - Catalytic combustion
- Post-Combustion Exhaust Gas Treatment Systems
 - Centrifugal collectors
 - Electrostatic precipitators
 - Wet Scrubbers
 - Fabric Filters or Baghouses

Combustion Process Modifications – Good Combustion Practices

Syngas and natural gas fall into the general category of clean, low-sulfur fuels. The use these fuels coupled with good combustion practices are technically feasible. Use of clean, low-sulfur fuel with good combustion is typically considered to be BACT for combustion turbines.

Post-Combustion Exhaust Gas Treatment Systems

Centrifugal collectors (cyclones) use inertial to removed particles from a gas stream. Electrostatic precipitators use electrical forces to remove particles from the gas stream. Wet scrubbers use physical absorption and fabric filters use a tightly woven fabric to trap the particles.

4.4.2 Technically Infeasible Options – Particulate Matter

Post-Combustion Exhaust Gas Treatment Systems

Post-combustion exhaust stack controls for PM/PM10 such as centrifugal collectors, electrostatic precipitators, wet scrubbers, and fabric Filters or baghouses are not appropriate for combined-cycle gas turbines. CTGs operate with a significant amount of excess air which generates high exhaust flow rates. Prior to being combusted, the particulate matter will have been removed from the tailgas through the High Pressure High Temperature filter and wet scrubber stages of Syngas

Cleanup. The minor PM/PM10 emissions coupled with a large volume of exhaust gas produces extremely low exhaust stream PM/PM10 concentrations and therefore post-combustion controls are not considered technically feasible for the proposed combustion turbines.

4.4.3 Technology Ranking – Particulate Matter

The use of clean syngas fuel or natural gas and good combustion practices is considered to be BACT for PM/PM10 control for the proposed ORCF combustion turbines. These operational controls will limit filterable plus condensable PM/PM10 emissions to 18.21 lb/hr based on 0.008 lb/MMBtu input to the gasifier when operating on syngas.

4.4.4 Evaluate Most Effective Controls – Particulate Matter

A cost-effectiveness evaluation is not needed for this BACT assessment because only one technology (use of clean fuels and good combustion practices) exists and it has been selected as BACT.

4.4.5 Proposed BACT Limits and Control Options – Particulate Matter

The use of clean syngas fuel or natural gas and good combustion practices is considered to be BACT for PM/PM10 control for the proposed combustion turbines. These operational controls will limit filterable plus condensable PM/PM10 emissions to 18.21 lb/hr based on 0.008 lb/MMBtu input.

4.5 CTG Sulfur Dioxide

The combustion turbines oxidize sulfur compounds in fuel primarily into sulfur dioxide (SO₂). Emissions can be controlled or limited by using a low sulfur fuel (i.e., natural gas), removing the sulfur from the fuel, or by removing SO₂ from the exhaust gas.

The following SO₂ control technologies were evaluated for the proposed combustion turbines:

4.5.1 Available Control Technologies – Sulfur Dioxide

A review of the RBLC database, vendor data, and available literature identified the following SO₂ control technologies to be evaluated for the proposed combustion turbines:

- Pre-Combustion Fuel Gas Treatment Systems
 - Chemical Absorption Acid Gas Removal
 - Physical Absorption Acid Gas Removal

- Post-Combustion Exhaust Gas Treatment Systems
 - Flue Gas Desulfurization

Pre-Combustion Fuel Gas Treatment - Chemical & Physical Acid Gas Removal Systems

During the gasification process, sulfur in the feedstock converts primarily into H₂S, and will also convert into minor quantities of other sulfur species, such as COS. Commercially available Acid Gas Removal (AGR) systems are capable of removing greater than 99% of the sulfur compounds from syngas/tailgas. AGR systems are commonly used for gas sweetening processes of refinery fuel gas or tailgas treatment systems, and are typically coupled with processes that produce useful sulfur byproducts.

AGR systems can employ either chemical or physical absorption methods. Chemical absorption methods are amine-based systems that utilize solvents, such as methyldiethanolamine (MDEA), to bond with the H₂S in the tailgas. A stripper column is then used to regenerate the solvent and produce an acid gas stream containing H₂S that can be processed into useful sulfur by-products. An MDEA AGR system has been determined as BACT for all operating and permitted IGCC facilities. The two operating IGCC facilities in the United States (Polk Power Station and Wabash River) both use amine (MDEA) systems to reduce the tailgas total sulfur concentration to 100 to 400 ppm. The CTL process involves taking the gas out of the AGR removal process through the Fischer-Tropsch (FT) Synthesis process, and the gas coming out of the FT process (tailgas) is used as fuel in the combustion turbines. In order for the FT process to function properly the sulfur content in the gas must be less than 1.0 ppm sulfur. Therefore, chemical absorption methods are not technically feasible for this process.

Other types of AGR systems utilize physical absorption methods that employ a physical solvent to remove sulfur from gas streams, such as mixtures of dimethyl ethers of polyethylene glycol (SELEXOL[®]) or methanol (Rectisol[®]). These systems operate by absorbing H₂S under pressure into the solvent. Dissolved acid gases are removed resulting in a regenerated solvent for reuse and the production of an acid gas stream containing H₂S that can be processed into useful sulfur by-products. Physical absorption methods have historically been used to purify gas streams in the chemical processing and natural gas industries, and can achieve sulfur removal to the level required by FT process of less than 1.0 ppm sulfur. Physical acid gas removal systems are a technically feasible control technology.

Post-Combustion Exhaust Gas Treatment - Flue Gas Desulfurization

Flue gas desulfurization (FGD) is a post-combustion SO₂ control technology that causes a reaction between an alkaline compound and SO₂ in the exhaust gas. FGD systems are most commonly used by conventional pulverized coal units and can typically achieve greater than 95% removal efficiency on new facilities. The FGD process results in a solid by-product that requires the installation of a significant number of ancillary support systems to accommodate

treatment, handling, and disposal. FGD is more readily applied to high SO₂ concentration gas streams, such as those present with direct combustion coal units.

4.5.2 Technically Infeasible Options – Sulfur Dioxide

Post-Combustion Exhaust Gas Treatment - Flue Gas Desulfurization

No examples were identified where an FGD system has been applied to a tailgas/syngas fired combustion turbine facility or similar process, such as a natural gas fired unit. Therefore, FGD is not technically feasible for the proposed combustion turbines. Even if feasible to the tailgas fired processes, FGD could not achieve the high removal efficiencies associated with AGR systems and would not provide appreciable SO₂ removal.

4.5.3 Technology Ranking – Sulfur Dioxide

The use of physical acid gas removal was identified as the only technically feasible SO₂ and acid gas emissions control technology applicable to the proposed combustion turbines.

4.5.4 Evaluate Most Effective Controls – Sulfur Dioxide

The AGR design reduces tailgas sulfur concentrations by greater than 99%, and produces a secondary gas stream that can be processed into potentially useful sulfur byproducts. The solvent used by the AGR system will be regenerated and reused. Overall, no collateral environmental issues have been identified that would preclude the AGR design option from consideration as BACT for the proposed project.

4.5.5 Proposed BACT Limits and Control Options – Sulfur Dioxide

The proposed BACT limits associated with a tailgas sulfur content of 1.0 ppmvd (expressed as H₂S) are presented below for each combustion turbine. This sulfur content is approximately equivalent to 0.006 grains of sulfur per 100 dry standard cubic feet (dscf) of gas. This sulfur concentration is equivalent to an emission rate of 21.06 lb SO₂/hr or 0.0093 lb/MMBtu.

4.6 Phase 1 Boiler Nitrogen Oxide

A 1,200-MMBtu/hr Phase 1 Boiler will be installed to provide steam for the steam turbine during Phase 1 of the project. The Boiler will operate for the first 18 months for primary plant power generation, however, once the CTGs come on line the operations of the Phase 1 Boiler will be discontinued. This is a significant factor in the BACT analysis.

Like the CTGs, NO_x is formed during combustion primarily by the reaction of combustion air nitrogen and oxygen in the high temperature combustion zone (thermal NO_x), or by the oxidation of nitrogen in the fuel (fuel NO_x.) The rate of NO_x formation is a function of fuel residence time,

oxygen availability, and temperature in the combustion zone. Primary fired Boiler NO_x control technologies focus on combustion process controls.

4.6.1 Available Control Technologies – Nitrogen Oxide

A review of the RBLC database, vendor data, and available literature identified the following NO_x control technologies to be evaluated for the proposed Phase 1 Boiler:

- Pre-Combustion Fuel Gas Treatment Systems
 - Low-NO_x Burners
 - Low-NO_x Burners with Flue Gas Recirculation

- Post-Combustion Exhaust Gas Treatment Systems
 - Selective Catalytic Reduction (SCR)
 - Selective Non-Catalytic Reduction (SNCR)
 - Non-Selective Catalytic Reduction (NSCR)
 - EMx™

There were no facilities identified that fired syngas or tailgas.

Combustion Process Modifications – Low-NO_x Burners

Low-NO_x burners reduce the formation of thermal NO_x by incorporating a burner design that controls the stoichiometry and temperature of combustion by regulating the distribution and mixing of fuel and air. As a result, fuel-rich pockets in the combustion zone that produce elevated temperatures and higher potential NO_x emissions are minimized. Historically, low-NO_x burners have been selected as BACT for syngas/tailgas-fired heaters and boilers. Therefore, low-NO_x burner technology is technically feasible for the proposed tailgas fired boiler.

Combustion Process Modifications – Low-NO_x Burners with Flue Gas Recirculation

Flue gas recirculation (FGR) is used to reduce NO_x emissions in some processes by recirculating a portion of the flue gas into the main combustion chamber. This process reduces the peak combustion temperature and oxygen in the combustion air/flue gas mixture, which reduces the formation of thermal NO_x. FGR has the potential to reduce combustion efficiency resulting in greater carbon monoxide emissions.

Post-Combustion Exhaust Gas Treatment Systems – SCR

SCR is a post-combustion technology that reduces NO_x emissions by reacting NO_x with ammonia in the presence of a catalyst. SCR technology has been most commonly applied to pulverized coal generating units and to natural gas fired combustions turbines.

Post-Combustion Exhaust Gas Treatment Systems – SNCR

SNCR is a post-combustion NO_x control technology where ammonia or urea is injected into the exhaust to react with NO_x to form nitrogen and water without the use of a catalyst.

Post-Combustion Exhaust Gas Treatment Systems – NSCR

NSCR is a post-combustion control technology that utilizes a catalyst to reduce NO_x emissions under fuel-rich conditions. The technology has been utilized in the automobile industry and for reciprocating engines.

Post-Combustion Exhaust Gas Treatment Systems – EMx

EMxTM is a post-combustion control technology that utilizes a single catalyst to minimize CO, VOC, and NO_x emissions.

SCR and the use of low-NO_x burner technology were the only technically feasible control options identified for reducing NO_x emissions. The only applications of SCR identified by the RBLC search were located in an area where the SIP influenced the NO_x reductions which were more stringent than BACT. Only two facilities were identified as being similar to the 1,200-MMBtu/hr Phase 1 Boiler (i.e., VA 0255 and LA-0140). These facilities used Low-NO_x burners and good combustion practices as BACT for NO_x. There were no facilities identified that fired syngas or tailgas.

4.6.2 Technically Infeasible Options – Nitrogen Oxide

Combustion Process Modifications – Low-NO_x Burners with Flue Gas Recirculation

Application of FGR was not identified for boilers similar to the 1,200-MMBtu/hr Phase 1 Boiler. There were several boilers and heaters that identified FGR as Lowest Achievable Emission Rate (LAER) and some that were significantly smaller (i.e., WA-0301 363 MMBtu/hr Boiler). Therefore, FGR has not been previously demonstrated for the intended operation of the Phase 1 Boiler.

Post-Combustion Exhaust Gas Treatment Systems – SNCR

Use of this technology requires uniform mixing of the reagent and exhaust gas within a narrow high temperature range (1,600°F - 1,900°F). Operations outside of this temperature range will significantly reduce removal efficiencies and may result in ammonia emissions or increased NO_x emissions. The Phase 1 Boiler's exhaust temperatures range from approximately 700°F and 900°F. Thus, SNCR is not technically feasible for the proposed Phase 1 Boiler.

Post-Combustion Exhaust Gas Treatment Systems – NSCR

A RBLC search was performed over the previous 10-year period for other gaseous fuels and gaseous fuel mixtures in boilers and process heaters similar to the 1,200 MMBtu/hr Phase 1 Boiler. No similar application was identified. NSCR technology requires a fuel-rich environment for NO_x reduction, which will not be available in the proposed Phase 1 Boiler. Therefore, NSCR is not a technically feasible for the proposed fired Phase 1 Boiler.

Post-Combustion Exhaust Gas Treatment Systems – EMx

Recent analyses by state agencies have determined that the technology is currently not feasible for syngas/tailgas fired process heater and boiler applications. For example, the Oregon Department of Environmental Quality (ODEQ) concurred that EMxTM was not technically feasible for a proposed 140 MMBtu/hr auxiliary boiler project. ODEQ also noted that a small boiler (4.2 MMBtu/hr) project in California installed an EMxTM system, but the South Coast Air Quality Management District determined application of the technology could not demonstrate the necessary emission reductions. Based on these determinations and the limited scope of commercial installations, EMxTM is not technically feasible for the proposed fired heaters.

4.6.3 Technology Ranking – Nitrogen Oxide

SCR and the use of low-NO_x burner technology were the only technically feasible control options identified for reducing NO_x emissions from gaseous fuel boilers. SCR has the potential to provide the highest level of emission reduction.

4.6.4 Evaluate Most Effective Controls – Nitrogen Oxide

A RBLC search was performed for units that burn other gaseous fuels and gaseous fuel mixtures in boilers similar to the 1,200-MMBtu/hr Phase 1 Boiler. The only application of SCR identified by the RBLC search was located in an area where the SIP influenced the NO_x reductions which were more stringent than BACT. There were no applications of SCR similar to the Phase 1 Boiler, and the closest application (VA 0255) used Low-NO_x Content Fuel and Low-NO_x Burners to demonstrate BACT emission rate of 0.61 lb/MMBtu compared to our proposed 0.1 lb/MMBtu. Low-NO_x burner technology has historically been selected as BACT for gaseous fueled fired boilers.

It should also be recognized that the Phase I Boiler is only intended to be operated as the primary power unit for the first 18 months of plant operation. After that time, its use will be discontinued. An analysis of the cost-effectiveness considering 18 months of operations versus the capital cost of the SCR system would ultimately demonstrate that it is not cost-effective to purchase and install an SCR system for this planned operational scenario. However, ORCF acknowledges the increased NO_x emission reduction effectiveness of incorporating an SCR system in addition to the historically accepted Low-NO_x burner technology.

4.6.5 Proposed BACT Limits and Control Options – Nitrogen Oxide

The use of low-NO_x burner technology and SCR is proposed as BACT for NO_x emissions from the proposed Phase 1 Boiler. In order to incorporate SCR control for the Phase 1 Boiler, ORCF proposes an alternative configuration whereby the SCR system required for one of the CTGs will be designed to also control the exhaust from the Phase 1 Boiler. When the CTG comes on line, the SCR will be capable of controlling the CTG exhaust instead of the Phase 1 Boiler. This arrangement, utilizing low-NO_x burner technology and SCR, will achieve the specified level of 0.1 lb/MMBtu (120 lb/hr) during operation of the Phase 1 Boiler.

4.7 Phase 1 Boiler Carbon Monoxide and Volatile Organic Compounds

Potential CO and VOC emissions are due to incomplete combustion that is typically a result of inadequate air and fuel mixing, a lack of available oxygen, or low temperatures in the combustion zone. Fuel quality and good combustion practices can limit CO and VOC emissions. Good combustion practice has commonly been determined as BACT for syngas/tailgas fired heaters and boilers. Post-combustion control technologies using catalytic oxidation have also been used in some processes to reduce CO and VOC emissions.

4.7.1 Available Control Technologies – Carbon Monoxide and Volatile Organic Compounds

A review of the RBLC database, vendor data, and available literature identified the following CO and VOC control technologies to be evaluated for the proposed Phase 1 Boiler:

- Combustion Process Modifications
 - Good combustion practices
- Post-Combustion Exhaust Gas Treatment Systems
 - Catalytic oxidation
 - EMx

There were no facilities identified that fired syngas or tailgas.

Combustion Process Modifications – Good Combustion Practices

Good combustion practices include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure complete combustion. Good combustion practice has historically been determined as BACT for CO and VOC emissions from syngas/tailgas-fired boilers and is a technically feasible control strategy for the proposed Phase 1 Boiler.

Post-Combustion Exhaust Gas Treatment Systems – Catalytic Oxidation

Catalytic oxidation is a post-combustion control technology that utilizes a catalyst to oxidize CO and VOC into CO₂ or H₂O. The technology has most commonly been applied to natural gas fired combustion turbines.

Post-Combustion Exhaust Gas Treatment Systems – EMx

EMx™ is a post-combustion control technology that utilizes a single catalyst to minimize CO, VOC, and NO_x emissions.

*4.7.2 Technically Infeasible Options – Carbon Monoxide and Volatile Organic*Post-Combustion Exhaust Gas Treatment Systems – Catalytic Oxidation

There were no applications of catalytic oxidation similar to the Phase 1 Boiler. The closest application (VA 0255) used good combustion practices to demonstrate BACT for CO and VOC.

Post-Combustion Exhaust Gas Treatment Systems – EMx

EMx™ technology is discussed in the NO_x BACT analysis and determined to not be technically feasible.

4.7.3 Technology Ranking – Carbon Monoxide and Volatile Organic Compounds

Good combustion practice is the only demonstrated control strategy that historically been selected as BACT for CO and VOC emissions for similar applications to the Phase 1 Boiler. However, because a catalytic oxidation system will be developed for control of CO and VOC from the Combined Cycle Plant, ORCF has elected to install that system for use during Phase 1 of the project.

4.7.4 Evaluate Most Effective Controls – Carbon Monoxide and Volatile Organic Compounds

Good combustion practice is the only feasible control strategy identified, and has historically been selected as BACT for CO and VOC emissions from syngas/tailgas fired Phase 1 Boiler. However, ORCF has elected to include catalytic oxidation as a control device for CO and VOC during Phase 1 of the project.

4.7.5 Proposed BACT Limits and Control Options – Carbon Monoxide and Volatile Organic Compounds

The use of good combustion practices and catalytic oxidation is proposed as BACT for potential CO and VOC emissions from the proposed Phase 1 Boiler. The BACT limits for CO and VOC emissions are proposed below.

- Proposed CO BACT Limit: 36 lb/hr (0.03 lb/MMBtu)
- Proposed VOC BACT Limit: 13.0 lb/hr (0.011 lb/MMBtu)

4.8 Phase 1 Boiler Particulate Matter

Fuel quality and combustion efficiency are key drivers affecting the quantity and disposition of potential particulate emissions. In some processes, post-combustion control technologies can also be used to reduce particulates.

4.8.1 Available Control Technologies – Particulate Matter

The following particulate emissions control technologies were evaluated for the proposed Phase 1 Boiler.

- Pre-Combustion Control
 - Clean Fuels
 - Good Combustion Practices
- Post-Combustion Control
 - Electrostatic Precipitation
 - Baghouse

There were no facilities identified that fired syngas or tailgas.

Clean Fuels

Fuels containing ash have the potential to produce particulate matter emissions. Additionally, fuels containing sulfur have the potential to produce sulfur compounds that may form condensable particulate matter emissions. Tailgas consumed by the proposed Phase 1 Boiler will contain negligible amounts of particulate matter and is considered a low-sulfur-fuel. Therefore, the use of clean fuels is a technically feasible control technology for the boiler.

Good Combustion Practice

The use of good combustion practice is a technically feasible technology that can minimize the potential particulate emissions associated with incomplete combustion.

Electrostatic Precipitation

ESP is a post-combustion particulate emissions control most readily applied to large volume gas streams containing high particulate concentrations. No examples have been found where an ESP has been applied to a syngas/tailgas fired process heater or boiler due to the reduced volume and minimal particulate concentration of the associated exhaust gas stream.

Baghouse

A baghouse is a post-combustion control technology that utilizes a fine mesh filter to remove particulate emissions primarily from large volume gas streams containing high particulate concentrations. No examples have been found where a baghouse has been applied to a syngas/tailgas fired process heater or boiler due to the reduced volume and minimal particulate concentration of the associated exhaust gas stream.

*4.8.2 Technically Infeasible Options – Particulate Matter*Electrostatic Precipitation

No examples have been found where an ESP has been applied to a syngas/tailgas fired process heater or boiler due to the reduced volume and minimal particulate concentration of the associated exhaust gas stream. Therefore, ESP is not technically feasible for the proposed Phase 1 Boiler.

Baghouse

No examples have been found where a baghouse has been applied to a syngas/tailgas fired process heater or boiler due to the reduced volume and minimal particulate concentration of the associated exhaust gas stream. Therefore, baghouse technology is not technically feasible for the proposed Phase 1 Boiler.

4.8.3 Technology Ranking – Particulate Matter

The use of clean fuels and good combustion practices are the only technically feasible control technologies identified.

4.8.4 Evaluate Most Effective Controls – Particulate Matter

The use of clean fuels and good combustion practices are the only technically feasible control technologies identified. Both of these technologies can be utilized in this process.

4.8.5 Proposed BACT Limits and Control Options – Particulate Matter

The use of clean fuels and good combustion practices has been proposed as BACT. The proposed BACT limit is presented below.

Proposed Particulate Emissions (PM10 – filterable) BACT Limit: 18.7 lb/hr (0.0156 lb/MMBtu).

The total proposed annual particulate emission from the Phase 1 Boiler, based on this scenario, is 82 tpy. Therefore, the use of clean fuels and good combustion practices is proposed as BACT for particulate emissions from the proposed Phase 1 Boiler. Alternatively, natural gas may be used as a back up fuel which will not increase the particulate emissions over using syngas/tailgas firing.

4.9 Phase 1 Boiler Sulfur Dioxide

4.9.1 Available Control Technologies – Sulfur Dioxide

The following SO₂ control technologies were evaluated for the Phase I Boiler.

- Pre-Combustion Control
 - Lower Sulfur Fuels
- Post-Combustion Control
 - Flue Gas Desulfurization

Low-Sulfur-Fuels

Potential SO₂ emissions are directly related to the sulfur content of fuels. The gas fed to the FT Synthesis Unit requires less than 1 ppmvd, and therefore the Rectisol[®] process in the AGR unit will be used to reach less than 1 ppm of sulfur in the tailgas. All fuel gas used throughout the plant is first desulfurized in the AGR unit, and therefore contains less than 1 ppm sulfur (expressed as H₂S). The concentration in the exhaust of each fired heater will be less than 1 ppmvd. Minimizing fuel sulfur content through the use of natural gas (startup only) or low sulfur tailgas has been determined to be BACT for many combustion processes, including fired process heaters. Therefore, using low-sulfur-fuel is a technically feasible control technology.

Flue Gas Desulfurization

FGD is a post-combustion SO₂ control technology that reacts an alkaline solution with SO₂ in the exhaust gas. FGD systems are more readily applied to high SO₂ concentrations gas streams, such as with a pulverized coal unit

*4.9.2 Technically Infeasible Options – Sulfur Dioxide*Flue Gas Desulfurization

FGD systems are more readily applied to high SO₂ concentrations gas streams, such as with a pulverized coal unit. FGD has not historically been used to control SO₂ emissions from the combustion of natural gas or other low-sulfur fuels. Therefore, FGD technology is not technically feasible for the proposed fired heaters.

4.9.3 Technology Ranking – Sulfur Dioxide

Low-sulfur fuels is the only technically feasible SO₂ control technology identified and therefore is ranks as number one for the proposed Phase I Boiler.

4.9.4 Evaluate Most Effective Controls – Sulfur Dioxide

The use of low-sulfur fuels is the only technically feasible SO₂ control technology identified for the proposed Phase I Boiler.

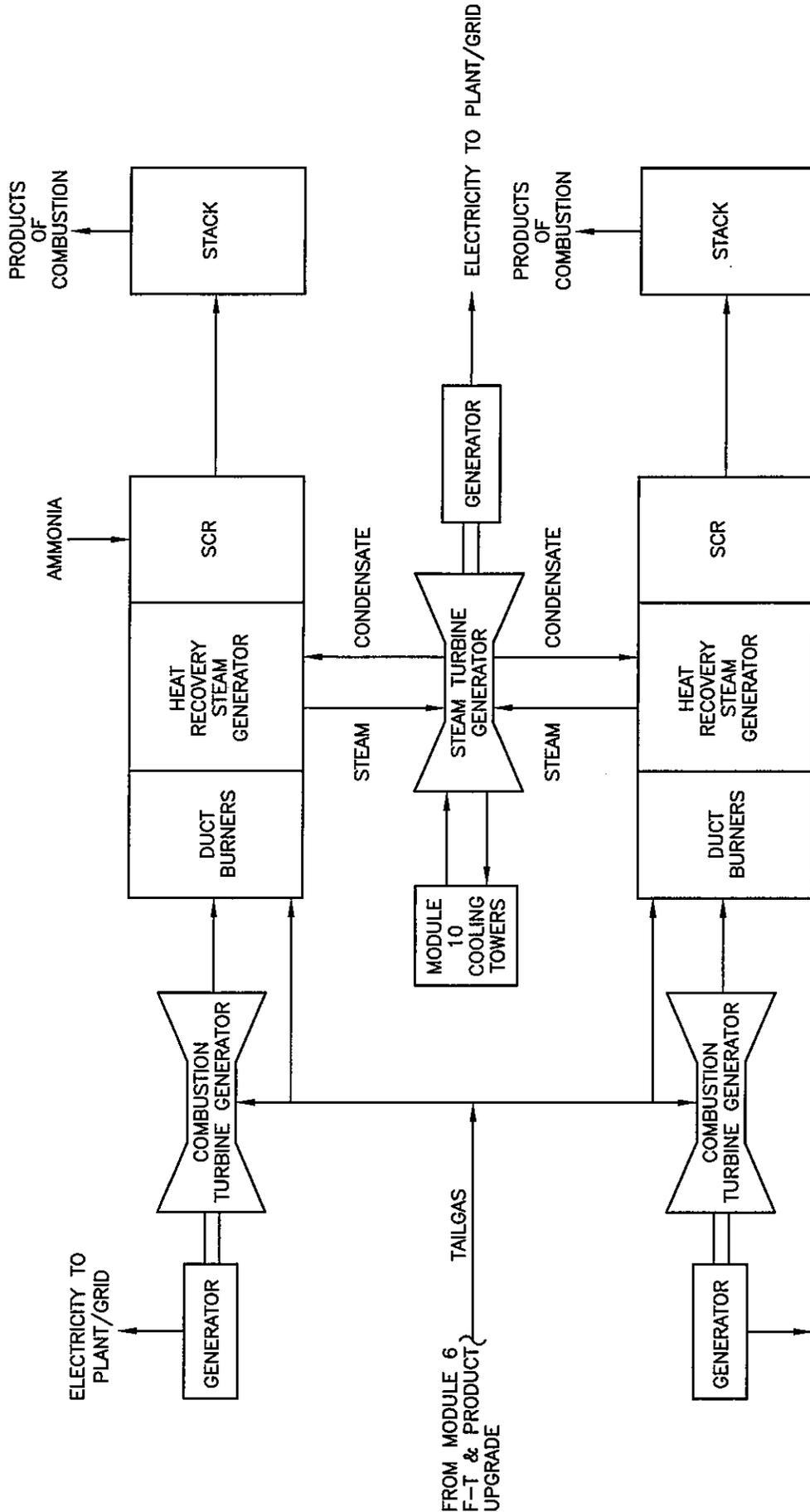
4.9.5 Proposed BACT Limits and Control Options – Sulfur Dioxide

The use of low sulfur fuels (tailgas) is proposed as BACT for SO₂ emissions from the proposed Phase 1 Boiler.

Proposed SO₂ BACT Limit: 2.0 lb/hr (0.002 lb/MMBtu)

The total proposed annual SO₂ emissions from the Phase 1 Boiler based on this scenario is 8.9 tpy. Therefore, the use of low sulfur fuels is proposed as BACT for SO₂ emissions from the proposed Phase 1 Boiler.

**ATTACHMENT 9A
MODULE 9
FIGURES**



FROM MODULE 6
F-T & PRODUCT
UPGRADE

SUBMITTAL & REVISION RECORD		
NO	DATE	DESCRIPTION
A	08/22/07	DRAFT SUBMISSION, AS: 061-933-MODULE-9-COMBINED-CYCLE-PLANT.dwg
B	12/17/07	AIR PERMIT APPLICATION

C&E

Civil & Environmental Consultants, Inc.
 333 Baldwin Road - Pittsburgh, PA 15205-9072
 412-429-2324 • 800-365-2324
 www.cecinc.com

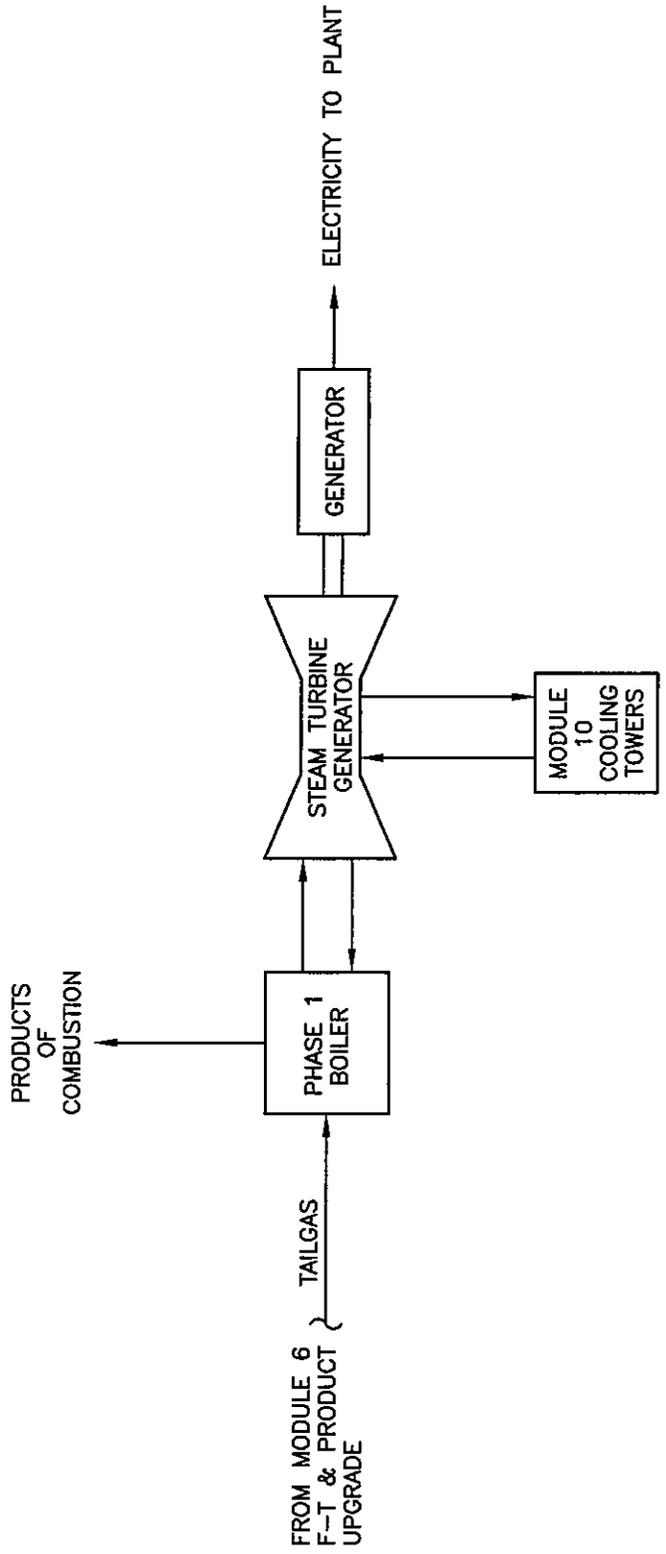
APPROVED: *[Signature]*
 DRAWN BY: JRWILKC CHKD BY: DJL DWG SCALE: N.T.S.

PROJECT NO: 061-933.0002
 LAST EDIT DATE: 11/26/07

OHIO RIVER CLEAN FUELS, LLC
 PROPOSED COAL TO LIQUID FUEL PLANT
 COLUMBIANA AND JEFFERSON COUNTY
 WELLSVILLE, OHIO

MODULE 9
 COMBINED CYCLE PLANT

FIGURE NO: 19



SUBMITTAL & REVISION RECORD		
NO	DATE	DESCRIPTION
A	12/17/07	AIR PERMIT APPLICATION
OHIO RIVER CLEAN FUELS, LLC PROPOSED COAL TO LIQUID FUEL PLANT COLUMBIANA AND JEFFERSON COUNTY WELLSVILLE, OHIO		
MODULE 9 PHASE 1 BOILER		
PROJECT NO:	061-933.0002	FIGURE NO:
DRAWN BY:	LKC	CHKD BY:
APPROVED:	<i>Kuma</i>	
DWG SCALE:	DJL	N.T.S.
LAST EDIT DATE:	11/26/07	FIGURE NO:
		20



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 www.cecinc.com

**ATTACHMENT 9B
MODULE 9
SUPPORTING CALCULATIONS**

Combined Power Block Criteria Pollutant Emissions Resulting from Normal Operations and Startup/Shutdown

Source	Mode	Notes	NO _x		CO		VOC		PM ₁₀		SO ₂	
			lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Phase 1 Boiler	Routine	Controlled	120.0	524.2	36.0	157.2	13.0	56.9	18.7	81.8	2.0	8.9
Startup Emission	SU/SD	SCR off line	473.8	5.7	36.0	0.4	13.0	0.2	18.7	0.2	2.0	0.0
Phase 1 Totals				529.8		157.7		57.1		82.0		8.9
Turbine w/Duct Burner	Routine	Controlled	57.1	246.5	23.1	99.8	26.6	115.0	18.2	78.7	21.1	91.0
Turbine w/Duct Burner	Routine	Controlled	57.1	246.5	23.1	99.8	26.6	115.0	18.2	78.7	21.1	91.0
Startup Emission	SU/SD	SCR off line	370.0	17.3	870.0	43.5	65.0	3.1	65.0	3.1	2.5	0.1
CTG Total				510.3		243.1		233.1		160.5		182.1

Emissions in this table are a summary from the detailed calculations in tables: Phase I Boiler Detailed Calculation, Combustion Turbine Detailed Calculation, and the Combustion Turbine Start-up Emissions Detailed Calculation.

Combined Power Block Hazardous Air Pollutant Emissions

Hazardous Air Pollutant	CAS Number	Phase 1 Boiler		2 CTGs	
		lb/hr	tpy	lb/hr	tpy
Total POM	NA	0.000	0.001	0	0
1,3-Butadiene	106-99-0	0	0	0.001	0.006
Acetaldehyde	75-07-0	0	0	0.123	0.538
Acrolein	107-02-8	0	0	0.020	0.086
Benzene	71-43-2	0.007	0.031	0.037	0.161
dichlorobenzene	95-50-1	0.004	0.018	0	0
Ethylbenzene	100-41-4	0	0	0.098	0.430
Formaldehyde	50-00-0	0.253	1.109	2.180	9.548
hexane	110-54-3	6.076	26.611	0	0
Naphthalene	91-20-3	0.002	0.009	0.004	0.017
PAH	7784-49-2	0	0	0.007	0.030
Propylene Oxide	75-56-9	0	0	0.089	0.390
toluene	108-88-3	0.011	0.050	0.399	1.748
Xylenes	1330-20-7	0	0	0.196	0.861
arsenic	7440-38-2	0.001	0.003	0	0
beryllium	7440-41-7	0.000	0.000	0	0
cadmium	7440-43-9	0.004	0.016	0	0
chromium	7440-47-3	0.005	0.021	0	0
cobalt	7440-48-4	0.000	0.001	0	0
manganese	7439-96-5	0.001	0.006	0	0
mercury	7439-97-6	0.001	0.004	0.003	0.014
nickel	7440-02-0	0.007	0.031	0	0
selenium	74482-49-2	0.000	0.000	0	0
Total HAPs		6.373	27.912	3.157	13.829

Power Block Other Emissions

Ammonia emissions (assume 10 ppmvd SCR NH3 slip) =	51.11 lb/hr (2 CTGs) 224 tpy (total)
--	---

Phase I Boiler Detailed Calculation Sheet

BACT Limits for Phase 1 Boiler Criteria Pollutants

NO _x ¹	0.10	lb/MMBtu
CO ²	0.03	lb/MMBtu
VOC ³	3.9	lb/MMSCF
PE/PM10 ³	0.0156	lb/MMBtu
SO _x ³	0.6	lb/MMSCF

Emission Factors provided by AP-42 1.4-1 & 1.4-2 (7/1998)

Heater Efficiency ⁴ =	0.7273	%
Operating days =	365	Days
Annual Operating hours =	8736	Hours (plus 24 hrs startup/shutdown)
Fuel Heating Value	487.5	MMBTU/MMSCF
Annual Fuel use =	29,568.00	MMSCF

Phase 1 Boiler Uncontrolled Routine Operating Emission Limits											
Unit Type	Fuel Rate	NO _x		CO		VOC		PE/PM10		SO _x	
		MMBTU/hr	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr
Phase 1 Boiler	1,200	473.8	2069.8	120.0	524.2	18.6	81.3	18.7	81.8	2.0	8.9

Phase 1 Boiler BACT (Controlled) Routine Operating Emission Limits											
Unit Type	Fuel Rate	NO _x		CO		VOC		PE/PM10		SO _x	
		MMBTU/hr	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr
Phase 1 Boiler	1,200	120.0	524.2	36.0	157.2	13.0	56.9	18.7	81.8	2.0	8.9

Proposed BACT Limit - Phase 1 Boiler (Startup/Shutdown with SCR offline, CatOx operating)											
Unit Type	Fuel Rate	NO _x		CO		VOC		PE/PM10		SO _x	
		MMBTU/hr	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr
Phase 1 Boiler	1,200	473.8	5.7	36.0	0.4	13.0	0.2	18.7	0.2	2.0	0.0
Total Routine + Startup/Shutdown Controlled Annual Emissions			529.8		157.7		57.1		82.0		8.9

Hazardous Air Pollutant Emissions					
Pollutant	Emission Factor ⁵ (lb/MMSCF)	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (tpy)	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Total POM	8.80E-05	0.00	0.0	0.00	0.0
benzene	2.10E-03	0.01	0.0	0.00	0.0
dichlorobenzene	1.20E-03	0.00	0.0	0.00	0.0
formaldehyde	7.50E-02	0.25	1.1	0.18	0.8
hexane	1.80E+00	6.08	26.6	4.25	18.6
naphthalene	6.10E-04	0.00	0.0	0.00	0.0
toluene	3.40E-03	0.01	0.1	0.01	0.0
arsenic	2.00E-04	0.00	0.0	0.00	0.0
beryllium	1.20E-05	0.00	0.0	0.00	0.0
cadmium	1.10E-03	0.00	0.0	0.00	0.0
chromium	1.40E-03	0.00	0.0	0.00	0.0
cobalt	8.40E-05	0.00	0.0	0.00	0.0
manganese	3.80E-04	0.00	0.0	0.00	0.0
mercury	2.60E-04	0.00	0.0	0.00	0.0
nickel	2.10E-03	0.01	0.0	0.01	0.0
selenium	2.40E-05	0.00	0.0	0.00	0.0
Total		6.37	27.9	4.47	19.6
Largest Single HAP		6.08	26.6	4.25	18.6

Emission Factors provided by AP-42 Tables 1.4-3 & 1.4-4 (7/1998)

Notes:

- Per agreement with Ohio EPA, ORFC has accepted a 0.1 lb/MMBtu emissions limit for NO_x via installation of SCR. Uncontrolled emission estimates are based on the AP-42 Section 1.4 factor for low-NO_x burners (140 lb/MMscf).
- ORFC agrees to accept the 0.1 lb/MMBtu CO limit per Ohio EPA request, and will perform further feasibility analysis during the FEED study. An additional estimated 70% control will be achieved through use of the catalytic oxidation system that will also be used for the CTGs starting in Phase 2 of the Power Block development. Uncontrolled emission estimates are based on the 0.1 lb/MMBtu assumed good combustion practice CO emission rate.
- Factors from AP-42, Table 1.4-2, (PE/PM10 factor converted from 7.6 lb/MMscf based on fuel characteristics). 30% control efficiency is assumed for use of catalytic oxidation.
- Fired Heater Efficiency includes 10% Excess Fired Heater Duty
- Controlled organic HAP emission rates assume 30% control via use of catalytic oxidation.

Combustion Turbine Detailed Calculation Sheet

Turbines 1 and 2 have identical emissions. These tables present information for only 1 turbine.

CTG Exhaust Data

CTG Exhaust Composition:		
O ₂	11.09	%mole
H ₂ O	7.77	%mole
CO	10.0	ppmvd @15%O ₂
CO	15.3	ppmv
SO ₂	2.16	ppmv
NO _x	25.0	ppmvd @15%O ₂
NO _x	38.2	ppmv
VOC	10.0	ppmvd @15%O ₂
VOC	15.3	ppmv

Mole Flow Rate
150,318 lb-mole/hr

CTG Exhaust Emission Rates									
NO _x (as NO ₂)		CO		VOC		SO ₂		PM	
lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
264.20	1141.37	64.33	277.90	36.76	158.80	20.80	89.85	16.10	69.55

Duct Burners Emissions Data

Burner gas HHV Rate
211 MMBTU/hr

Duct Burner Emission Rates		
CO	0.06	lb/MMBTU/hr
NO _x	0.10	lb/MMBTU/hr
VOC	0.006	lb/MMBTU/hr
PM	0.01	lb/MMBTU/hr
SO ₂	0.60	lb/MMSCF

Duct Burner Emission Rates									
NO _x (as NO ₂)		CO		VOC		SO ₂		PM	
lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
21.10	91.15	12.66	54.69	1.27	5.47	0.26	1.14	2.11	9.12

Note: 487.5 btu/scf is the heat content of the tail gas.
8640 hours of Normal Operation. This does not include startup or shutdowns.

Total (CTG + Duct Burner) Potential Emissions

Total Uncontrolled Emissions									
NO _x (as NO ₂)		CO		VOC		SO ₂		PM	
lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
285.30	1249.64	76.99	337.21	38.02	166.55	21.06	90.97	18.21	78.67

Total Controlled Emissions									
NO _x (as NO ₂) ¹		CO ²		VOC ³		SO ₂		PM	
lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
57.06	246.50	23.10	99.78	26.62	114.99	21.06	90.97	18.21	78.67

Note: ¹ NO_x control efficiency is 80%
² CO control efficiency is 70%
³ VOC control efficiency is 30%

Supporting Calculations

Combustion Turbine Start-up Detailed Calculation Sheet

These tables contain potential emissions for both Turbine 1 and 2 start-up emissions.

System Startup Emissions Data (lb/start)

Start Type	Duration (hr)	Startup Emissions									
		NOx		CO		VOC		SO ₂		PM	
		lb/start	avg lb/hr	lb/start	avg lb/hr	lb/start	avg lb/hr	lb/start	avg lb/hr	lb/start	avg lb/hr
Cold	6	2200	367	5200	867	300	50	14.68	2.45	300	50
Warm	4	900	225	2500	625	200	50	9.79	2.45	200	50
Hot	2	350	175	1000	500	125	63	4.89	2.45	125	63

CTG Exhaust Emissions Calculations (for both turbines in lb/hr and ton/yr)

Start Type	Duration (hr)	Emissions (based on 5 startups and 5 shutdowns per year)									
		NOx		CO		VOC		SO ₂		PM	
		avg lb/hr	ton/yr	avg lb/hr	ton/yr	avg lb/hr	ton/yr	avg lb/hr	ton/yr	avg lb/hr	ton/yr
Cold	6	367	11.00	867	26.00	50	1.50	2.45	0.07	50	1.50
Warm	4	225	4.50	625	12.50	50	1.00	2.45	0.05	50	1.00
Hot	2	175	1.75	500	5.00	63	0.63	2.45	0.02	63	0.63
Total	12		17.25		43.50		3.13		0.15		3.13

Supporting Calculations

Combustion Turbine Hazardous Air Pollutant Emission Estimates

Emissions are shown for one CTG with maximum heat input rating of MMBtu/hr

CAS #	Compound	Emission Factors (lb/MMBtu) ¹	Uncontrolled		Efficiency (%) ²	Controlled	
			(lb/hr)	(ton/yr)		(lb/hr)	(ton/yr)
106-99-0	1,3-Butadiene	4.30E-07	9.43E-04	4.13E-03	30%	6.60E-04	2.89E-03
75-07-0	Acetaldehyde	4.00E-05	8.77E-02	3.84E-01	30%	6.14E-02	2.69E-01
107-02-8	Acrolein	6.40E-06	1.40E-02	6.15E-02	30%	9.82E-03	4.30E-02
71-43-2	Benzene	1.20E-05	2.63E-02	1.15E-01	30%	1.84E-02	8.07E-02
100-41-4	Ethylbenzene	3.20E-05	7.02E-02	3.07E-01	30%	4.91E-02	2.15E-01
50-00	Formaldehyde	7.10E-04	1.56E+00	6.82E+00	30%	1.09E+00	4.77E+00
7439-97-6	Mercury	52 pptv in exhaust ³	1.57E-03	6.87E-03	0% ⁴	1.57E-03	6.87E-03
91-20-3	Naphthalene	1.30E-06	2.85E-03	1.25E-02	30%	2.00E-03	8.74E-03
7784-49-2	PAH	2.20E-06	4.82E-03	2.11E-02	30%	3.38E-03	1.48E-02
75-56-9	Propylene Oxide	2.90E-05	6.36E-02	2.79E-01	30%	4.45E-02	1.95E-01
108-88-3	Toluene	1.30E-04	2.85E-01	1.25E+00	30%	2.00E-01	8.74E-01
1330-20-7	Xylenes	6.40E-05	1.40E-01	6.15E-01	30%	9.82E-02	4.30E-01
Total			2.3	9.9		1.6	6.9
Largest Single HAP (formaldehyde)						1.1	4.8

¹ AP-42 Table 3.1-3 factors for natural gas-fired stationary gas turbines. CTG Heat input will range from 1,728 MMBtu/hr to 2,193 MMBtu/hr. HHV used for all calculations. Annual emissions assume 8,760 hr/yr operation.

² VOCs will be controlled by the catalytic oxidizer (30% controlled assumed).

³ Estimated Hg concentration in exhaust based on review of Hg partitioning at other similar facilities. Calculation is based on 150,318 lb-mole/hr exhaust flow rate for one CTG (as shown on Page 9B-3).

⁴ Hg removal efficiency shown here indicates that additional post-combustion control is not employed. Mercury control will have been achieved prior to combustion through syngas cleaning steps occurring in Module 5 (carbon beds). The overall mercury removal efficiency relative to mercury present in feedstock is expected to approach 99.4%.

**ATTACHMENT 9C
MODULE 9
DOCUMENTATION**

LIST OF REFERENCES

- Tampa Electric Polk Power Station IGCC Project – *Final Technical Report*, August 2002.
- U.S. EPA, RACT/BACT/LAER Clearinghouse (RBLC);
website: <http://cfpub.epa.gov/RBLC>
- Wabash River Coal Gasification Repowering Project – *Final Technical Report*, August 2000.

RBLC Matching Facilities for Search Criteria:
 Permit Date Between 12/07/2000 And 12/07/2007
 And Process Type: "11.310" Utility- and Large Industrial-Size Boilers/Furnaces (>250 million BTU/H): Natural Gas (includes propane and liquefied petroleum gas)
 Pollutant: Nitrogen Oxides (NO_x)

RBLCID	FACILITY NAME	PROCESS NAME	THRUPUT UNIT	THRUPUT UNIT	PROCESS NOTES	CTRLDESC	EMIS LIMIT1	EMIS LIMIT1 UNIT
VA-0255	VA POWER - POSSUM POINT GRAYS FERRY COGEN	BOILER, TANGENTIALLY-FIRED, UNIT 3	1150	MMBTU/H	Tangentially-fired boiler (unit 3) converted from coal to natural gas only.	Low NOx content fuel and low NOx burners	0.61	LB/MMBTU
PA-0187	PARTNERSHIP	AUXILIARY BOILER, NATURAL GAS	1119	MMBTU/H	Auxiliary boiler used to produce steam for steam generator.	Low NOx Burners	0.1	LB/MMBTU
SC-0091	COLUMBIA ENERGY CENTER	BOILER, NATURAL GAS	550	MMBTU/H	Not Available	Low NOx burners and flue gas recirculation	0.04	LB/MMBTU
LA-0174	PORT HUDSON OPERATIONS	POWER BOILER NO. 5	987	MMBTU/H	Emission point No. 27.	Low NOx Burners	0.1	LB/MMBTU
LA-0140	GAYLORD CONTAINER CORPORATION	BOILER NO. 10C	797.6	MMBTU/H	Not Available	Staged combustion, good equipment design, proper combustion techniques	0.329	LB/MMBTU
IA-0067	MIDAMERICAN ENERGY COMPANY	AUXILIARY BOILER	429.4	MMBTU/H	The unit is limited to 876 hrs/yr.	Low NOx Burners	0.14	LB/MMBTU

RBLC Matching Facilities for Search Criteria:
 Permit Date Between: 12/07/2000 And 12/07/2007
 And Process Type "1.310" Utility- and Large Industrial-Size Boilers/Furnaces (>250 million BTU/H): Natural Gas (includes propane and liquefied petroleum gas)
 Pollutant: Sulfur Dioxide (SO₂)

RBLCID	FACILITY NAME	PROCESS NAME	THRUPUT UNIT	THRUPUT	PROCESS NOTES	CTRLDESC	EMIS LIMIT 1	EMIS LIMIT 1 UNIT
VA-0255	VA POWER - FOSSUM POINT	BOILER, TANGENTIALLY-FIRED, UNIT 3	1150	MMBTU/H	Tangentially-fired boiler (unit 3) converted from coal to natural gas only.	Low sulfur fuel	0.0028	LB/MMBTU
PA-0187	GRAYS FERRY COGEN PARTNERSHIP	AUXILIARY BOILER, NATURAL GAS	1119	MMBTU/H	Auxiliary boiler used to produce steam for steam generator.	Good combustion practice and low sulfur fuel	0.0009	LB/MMBTU
SC-0091	COLUMBIA ENERGY CENTER	BOILER, NATURAL GAS	550	MMBTU/H	Not Available	Low sulfur fuel	0.0018	LB/MMBTU
LA-0174	PORT HUDSON OPERATIONS	POWER BOILER NO. 5	987	MMBTU/H	Emission point No. 27.	Fueled by natural gas	5.19	LB/MMBTU
LA-0140	GAYLORD CONTAINER CORPORATION	BOILER NO. 10C	797.8	MMBTU/H	Not Available	Not Available	Not Available	LB/MMBTU
IA-0067	MIDAMERICAN ENERGY COMPANY	AUXILIARY BOILER	429.4	MMBTU/H	The unit is limited to 676 hrs/yr.	Good combustion practices	0.0006	LB/MMBTU

RBLC Matching Facilities for Search Criteria:
 Permit Date Between: 12/07/2000 And 12/07/2007
 And Process Type "11.310" Utility- and Large Industrial-Size Boilers/Furnaces (>250 million BTU/Hr): Natural Gas (includes propane and liquefied petroleum gas)
 Pollutant: Particulate Matter (PM)

RBLCID	FACILITY NAME	PROCESS NAME	THRUPUT UNIT	PROCESS NOTES	CTRLDESC	EMIS LIMIT1 UNIT	EMIS LIMIT1 UNIT
VA-0255	VA POWER - POSSUM POINT	BOILER, TANGENTIALLY-FIRED, UNIT 3	1150 MMBTU/H	Tangentially-fired boiler (unit 3) converted from coal to natural gas only.	Clean fuel and good combustion practices	0.023	LB/MMBTU
PA-0187	GRAYS FERRY COGEN PARTNERSHIP	AUXILIARY BOILER, NATURAL GAS	1119 MMBTU/H	Auxiliary boiler used to produce steam for steam generator.	Good combustion	0.005	LB/MMBTU
SC-0091	COLUMBIA ENERGY CENTER	BOILER, NATURAL GAS	550 MMBTU/H	Not Available	Good combustion	0.009	LB/MMBTU
LA-0174	FORT HUDSON OPERATIONS	POWER BOILER NO. 5	987 MMBTU/H	Emission point No. 27.	Fueled by natural gas	0.007	LB/MMBTU
LA-0140	GAYLORD CONTAINER CORPORATION	BOILER NO. 10C	797.6 MMBTU/H	Not Available	Wet scrubber	0.0717	LB/MMBTU
IA-0067	MIDAMERICAN ENERGY COMPANY	AUXILIARY BOILER	429.4 MMBTU/H	The unit is limited to 876 hrs/yr.	Good combustion	0.0076	LB/MMBTU

RBLC Matching Facilities for Search Criteria:
 Permit Date Between: 12/07/2000 And 12/07/2007
 And Process Type "1.310" Utility- and Large Industrial-Size Boilers/Furnaces (>250 million BTU/H): Natural Gas (Includes propane and liquefied petroleum gas)
 Pollutant: Carbon Monoxide

RBLCID	FACILITY NAME	PROCESS NAME	THRUPUT UNIT	THRUPUT UNIT	PROCESS NOTES	CTRLDESC	EMIS LIMIT UNIT	EMIS LIMIT UNIT
VA-0255	IVA POWER - POSSUM POINT	BOILER, TANGENTIALLY-FIRED, UNIT 3	1150	MMBTU/H	Tangentially-fired boiler (unit 3) converted from coal to natural gas only.	Good combustion practices	0.024	LB/MMBTU
PA-0187	GRAYS FERRY COGEN PARTNERSHIP	AUXILIARY BOILER, NATURAL GAS	1119	MMBTU/H	Auxiliary boiler used to produce steam for steam generator.	Good combustion practices	0.04	LB/MMBTU
SC-0091	COLUMBIA ENERGY CENTER	BOILER, NATURAL GAS	550	MMBTU/H	Not Available	Good combustion practices and clean fuel	0.06	LB/MMBTU
LA-0174	PORT HUDSON OPERATIONS	POWER BOILER NO. 5	987	MMBTU/H	Emission point No. 27.	Good equipment designs and proper combustion	0.07	LB/MMBTU
LA-0140	GAYLORD CONTAINER CORPORATION	BOILER NO. 10C	797.6	MMBTU/H	Not Available	Good equipment designs and proper combustion	1.13	LB/MMBTU
IA-0067	MIDAMERICAN ENERGY COMPANY	AUXILIARY BOILER	429.4	MMBTU/H	The unit is limited to 876 hrs/yr.	Good combustion practices	0.094	LB/MMBTU

RBLC Matching Facilities for Search Criteria:
 Permit Date Between: 12/07/2000 And 12/07/2007
 And Process Type "11,310" Utility- and Large Industrial-Size Boilers/Furnaces (>250 million BTU/H): Natural Gas (includes propane and liquefied petroleum gas)
 Pollutant: Volatile Organic Compounds (VOC)

RBLCID	FACILITY NAME	PROCESS NAME	THRUPUT UNIT	THRUPUT UNIT	PROCESS NOTES	CTRLDESC	EMIS LIMIT1	EMIS LIMIT1 UNIT
VA-0255	VA POWER - POSSUM POINT	BOILER, TANGENTIALLY-FIRED, UNIT 3	1150	MMBTU/H	Tangentially-fired boiler (unit 3) converted from coal to natural gas only.	Good combustion practices	0.0054	LB/MMBTU
PA-0187	GRAYS FERRY COGEN PARTNERSHIP	AUXILIARY BOILER, NATURAL GAS	1119	MMBTU/H	Auxiliary boiler used to produce steam for steam generator.	Good combustion practices	0.0054	LB/MMBTU
SC-0091	COLUMBIA ENERGY CENTER	BOILER, NATURAL GAS	550	MMBTU/H	Not Available	Good combustion practices	0.004	LB/MMBTU
LA-0174	PORT HUDSON OPERATIONS	POWER BOILER NO. 5	987	MMBTU/H	Emission point No. 27.	Not Available	Not Available	LB/MMBTU
LA-0140	GAYLORD CONTAINER CORPORATION	BOILER NO. 10C	797.6	MMBTU/H	Not Available	Good equipment design, proper combustion techniques	14.24	LB/HR
IA-0067	MIDAMERICAN ENERGY COMPANY	AUXILIARY BOILER	429.4	MMBTU/H	The unit is limited to 876 hrs/yr.	Good combustion practices	0.0055	LB/MMBTU

CTG Summary

**Combined Cycle Syngas Turbine
BACT Cost Summary**

PARAMETER	UNITS	SCR-1 SCR @ 7.5 ppm NOx	SCR-2 SCR @ 5ppm NOx	SCR-3 SCR @ 2.5 ppm NOx	CatOx-1 CatOx @ 3ppm CO	CatOx-2 CatOx @ 2 ppm CO
Gross Unit Output	MW	232.00	232.00	232.00	232.00	232.00
Gross Unit Heat Rate, HHV	Btu/kw-Hr	9,451	9,451	9,451	9,451	9,451
Annual Operating Hours at 100% Load	Hours	8,760	8,760	8,760	8,760	8,760
Unit Capacity Factor	%	100.0%	100.0%	100.0%	100.0%	100.0%
Max. Hourly Heat Input, HHV	MMBtu/Hr	2,192.6	2,192.6	2,192.6	2,192.6	2,192.6
Annual Heat Input, HHV	MMBtu/Yr	19,207,456	19,207,456	19,207,456	19,207,456	19,207,456
NOx Reduction						
Design Removal Efficiency	%	70.0%	80.0%	90.0%		
Current Emission Rate	Lb/MMBtu	0.111	0.111	0.111		
Controlled Emission Rate	Lb/MMBtu	0.033	0.022	0.011		
Annual Tons Removed	tons/year	745.9	852.5	959.1		
Total Capital Investment (TCI)	\$	\$ 3,043,126	\$ 3,399,853	\$ 4,015,545		
Total Annual Costs	\$/Year	\$ 2,819,492	\$ 3,157,475	\$ 3,629,571		
Control Cost	\$/Ton NOx	\$ 3,780	\$ 3,704	\$ 3,784		
Incremental Control Cost	\$/Ton NOx	N/A	\$ 3,170	\$ 4,430		
CO Reduction						
Design Removal Efficiency	%				80.0%	80.0%
Current Emission Rate	Lb/MMBtu				0.0270	0.0270
Controlled Emission Rate	Lb/MMBtu				0.0081	0.0054
Annual Tons Removed	tons/year				18.8	207.8
Total Capital Investment (TCI)	\$				\$ 2,023,751	\$ 2,393,926
Total Annual Costs	\$/Year				\$ 1,993,875	\$ 2,212,866
Control Cost	\$/Ton CO				\$ 10,964	\$ 10,650
Incremental Control Cost	\$/Ton CO				N/A	\$ 8,456

Emission Calcs

Baard Energy LLC
Ohio River Clean Fuels Project
Combined Cycle Syngas Turbine
Emission Calculations

PARAMETER	UNITS	SCR-1 SCR @ 7.5 ppm NOx	SCR-2 SCR @ 5 ppm NOx	SCR-3 SCR @ 2.5 ppm NOx	CatOx-1 CatOx @ 3 ppm CO	CatOx-2 CatOx @ 2 ppm CO	Siemens Performance Data
Gross Unit Output	MW	232.0	232.0	232.0	232.0	232.0	
Gross Unit Heat Rate, HHV	Btu/kW-Hr	9,451	9,451	9,451	9,451	9,451	
Annual Operating Hours at 100% Load	Hours	8,760	8,760	8,760	8,760	8,760	
Unit Capacity Factor =	%	100.0%	100.0%	100.0%	100.0%	100.0%	
Max. Hourly Heat Input, HHV	MMBtu/Hr	2,192.6	2,192.6	2,192.6	2,192.6	2,192.6	
Annual Heat Input, HHV	MMBtu/Yr	19,207,456	19,207,456	19,207,456	19,207,456	19,207,456	
NOx Reduction							
Design Removal Efficiency	%	70.0%	80.0%	90.0%	70.0%	80.0%	
Aqueous Ammonia Usage	Cpm	1.04	1.19	1.34	0.000	0.000	
Current Emission Rate	Lb/Hr	243.3	243.3	243.3	243.3	243.3	
Controlled Emission Rate	Lb/MMBtu	0.111	0.111	0.111	0.111	0.111	
Current Annual Tons Emitted	Lb/Hr	73.0	73.0	73.0	73.0	73.0	
Controlled Annual Tons Emitted	Lb/MMBtu	0.033	0.022	0.011	0.111	0.111	
Annual Tons Removed	tons/year	1,065.7	1,065.7	1,065.7	1,065.7	1,065.7	
CO Reduction	tons/year	319.7	213.1	106.6	1,065.7	1,065.7	
Design Removal Efficiency	%	0.0%	0.0%	0.0%	0.0%	80.0%	
Current Emission Rate	Lb/Hr	59.3	59.3	59.3	59.3	59.3	
Controlled Emission Rate	Lb/MMBtu	0.027	0.027	0.027	0.027	0.027	
Current Annual Tons Emitted	Lb/Hr	59.3	59.3	59.3	59.3	59.3	
Controlled Annual Tons Emitted	Lb/MMBtu	0.027	0.027	0.027	0.008	0.005	
Annual Tons Removed	tons/year	259.7	259.7	259.7	259.7	259.7	
	tons/year	0.0	0.0	0.0	78.0	51.9	
	tons/year				181.8	207.8	

SCR-1

BACT Cost Calculation

SCR-1 SCR @ 7.5 ppm NOx

Cost Item	Cost Factor	Reference	Cost (\$2007)
Direct Costs (DC)			
Purchased Equipment Costs (PEC)			
SCR System & Auxiliary Equipment	As estimated, A	Vendor Quote	\$ 1,500,000
Instrumentation	0.1 x A	(EPA, 1995a)	\$ 150,000
State Sales Taxes	7.7500% x A	NV State Sales Tax	\$ 116,250
Freight	0.05 x A	(EPA, 1995a)	\$ 75,000
PEC Total (B)			\$ 1,841,250
Direct Installation Costs (DIC)			
Foundation and Supports	0.08 x B	(Ulrich, 1984)	\$ 147,300
Labor	0.14 x B	(EPA, 1990a)	\$ 257,775
Electrical	0.04 x B	(EPA, 1990a)	\$ 73,650
Additional Duct Work	\$6,533 /#/sf of duct	Peters & Timmerhaus	
Piping	0.02 x B	(EPA, 1995a)	\$ 36,825
Insulation	0.01 x B	(EPA, 1995a)	\$ 18,413
Painting	0.01 x B	(EPA, 1990a)	\$ 18,413
DIC Total			\$ 552,375
Total DC = PEC + DIC			\$ 2,393,625
Indirect Costs (IC)			
Engineering	0.1 x B	(EPA, 1990a)	\$ 184,125
Construction Overhead	0.05 x B	(EPA, 1990a)	\$ 92,063
Contractor Fees	0.1 x B	(EPA, 1990a)	\$ 184,125
Start-up	0.02 x B	(EPA, 1990a)	\$ 36,825
Performance Testing	0.01 x B	(EPA, 1990a)	\$ 18,413
Contingencies	0.03 x B	(EPA, 1990a)	\$ 55,238
Simple Interest During Construction	8.55% x B x 0.5 years	Estimate	\$ 78,713
Total IDC			\$ 649,501
Total Capital Investment (TCI) = DC + IC			\$ 3,043,126

SCR-1

Annual Costs

Operating Cost Factors for the SCR System

Cost Data			
Interest Rate	7.00%		Capital Recovery Factor (CRF)
Catalyst Life	3		0.381
Equipment Life	20		0.094

Direct Annual Costs, \$/YR

Power Loss due to Pressure Drop across Catalyst			
Operating Labor			
Supervisory Labor			
Maintenance Labor and Materials			
Steam and Natural Gas			
Aqueous Ammonia			
Catalyst Cleaning			
Revenue Loss during Cat Replacement (a)			
Catalyst Replacement Labor (b)			
Catalyst Replacement (CR) (c)			
Sales Tax (d)			
Capital Recovery			
Total Direct Annual Costs, \$/YEAR			

	FACTOR	REFERENCE	Costs, \$/YEAR
	0.14% per inch @ 2 inch wg of pressure drop, \$0.035/Kwh	Vendor	\$ 199,167
	10% of Operating Labor	Industry Average/Estimate (EPA, 1993a)	\$ 40,150
	Materials = 50% of maintenance labor	Vendor	\$ 4,015
		Vendor	
		Vendor Quote	\$ 273,619
		Estimate	\$ 4,400
		Estimate	\$ 584,640
		Estimate	\$ 11,200
		Estimate	\$ 750,000
		Sales Tax	\$ 58,125
		(EPA, 1995a)	\$ 534,983
			\$ 2,460,299

Indirect Annual Costs, \$/YEAR

Overhead			
Insurance and Administration			
Capital Recovery			
Property Tax			
Total Indirect Annual Costs, \$/YEAR			

	FACTOR	REFERENCE	Costs, \$/YEAR
	60% of sum of all labor costs + maintenance materials	(EPA, 1990a)	\$ 26,499
	3% of TCI	(EPA, 1990a)	\$ 91,294
	CRF X (TCI - initial catalyst charge)	N/A	\$ 210,968
	1% of TCI	Estimate	\$ 30,431
			\$ 359,192

Total Annual Costs, \$/YEAR

\$ 2,819,492

Total Net NOx Reductions (TPY)

Input from Emissions Calculations sheet

745.9

Cost Effectiveness, \$/TON NOx

\$ 3,780

Total Net CO Reductions (TPY)

Input from Emissions Calculations sheet

-

Cost Effectiveness, \$/TON CO

N/A

SCR-2

BACT Cost Calculation

SCR-2 SCR @ 5 ppm NOx

Cost Item	Cost Factor	Reference	Cost (\$2007)
Direct Costs (DC)			
Purchased Equipment Costs (PEC)			
SCR System & Auxiliary Equipment	As estimated, A	Vendor Quote	\$ 1,730,000
Instrumentation	0.1 x A	(EPA, 1995a)	\$ 173,000
State Sales Taxes	7.7500% x A	NV State Sales Tax	\$ 134,075
Freight	0.05 x A	(EPA, 1995a)	\$ 86,500
PEC Total (B)			\$ 2,123,575
Direct Installation Costs (DIC)			
Foundation and Supports	0 x B	(Ulrich, 1984)	\$ -
Labor	0.14 x B	(EPA, 1990a)	\$ 297,301
Electrical	0.04 x B	(EPA, 1990a)	\$ 84,943
Additional Duct Work	\$6,533 /l/sf/sf of duct	Peters & Timmerhaus	
Piping	0.02 x B	(EPA, 1995a)	\$ 42,472
Insulation	0.01 x B	(EPA, 1995a)	\$ 21,236
Painting	0.01 x B	(EPA, 1990a)	\$ 21,236
DIC Total			\$ 467,187
Total DC = PEC + DIC			\$ 2,590,762
Indirect Costs (IC)			
Engineering	0.1 x B	(EPA, 1990a)	\$ 212,358
Construction Overhead	0.05 x B	(EPA, 1990a)	\$ 106,179
Contractor Fees	0.1 x B	(EPA, 1990a)	\$ 212,358
Start-up	0.02 x B	(EPA, 1990a)	\$ 42,472
Performance Testing	0.01 x B	(EPA, 1990a)	\$ 21,236
Contingencies	0.03 x B	(EPA, 1990a)	\$ 63,707
Simple Interest During Construction	8.55% x B x 0.5 years	Estimate	\$ 90,783
Total IDC			\$ 749,091
Total Capital Investment (TCI) = DC + IC			\$ 3,339,853

SCR-2

Annual Costs

Operating Cost Factors for the SCR System

Cost Data

Interest Rate	7.00%	Capital Recovery Factor (CRF)	
Catalyst Life	3		0.381
Equipment Life	20		0.094

Direct Annual Costs, \$/YR

	FACTOR	REFERENCE	Costs, \$/YEAR
Power Loss due to Pressure Drop across Catalyst	0.14% per inch @ 3 inch wg of pressure drop,		
Operating Labor	\$0.035/Kwh	Vendor	\$ 298,751
Supervisory Labor		Industry Average/Estimate	\$ 40,150
Maintenance Labor and Materials	10% of Operating Labor	(EPA, 1993a)	\$ 4,015
Steam and Natural Gas	Materials = 50% of maintenance labor	Vendor	
Aqueous Ammonia		Vendor	
Catalyst Cleaning		Vendor Quote	\$ 312,707
Revenue Loss during Cat Replacement (a)		Estimate	\$ 4,400
		Estimate	\$ 584,640
Catalyst Replacement Labor (b)		Estimate	\$ 11,200
Catalyst Replacement (CR) (c)		Estimate	\$ 865,000
Sales Tax (d)		Sales Tax	\$ 67,038
Capital Recovery	7.75%	(EPA, 1995a)	\$ 582,200
Total Direct Annual Costs, \$/YEAR	(a + b + c + d) * CRF		\$ 2,770,101

Indirect Annual Costs, \$/YEAR

Overhead	60% of sum of all labor costs + maintenance materials	(EPA, 1990a)	\$ 26,499
Insurance and Administration		(EPA, 1990a)	\$ 100,196
Capital Recovery	3% of TCI	N/A	\$ 227,281
Property Tax	CRF X (TCI - initial catalyst charge)	Estimate	\$ 93,399
Total Indirect Annual Costs, \$/YEAR	1% of TCI		\$ 387,374

Total Annual Costs, \$/YEAR

\$ 3,157,475

Total Net NOx Reductions (TPY)

Input from Emissions Calculations sheet

852.5

Cost Effectiveness, \$/TON NOx

\$ 3,704

Total Net CO Reductions (TPY)

Input from Emissions Calculations sheet

-

Cost Effectiveness, \$/TON CO

N/A

SCR-3

BACT Cost Calculation

SCR-3 SCR @ 2.5 ppm NOx

Cost Item	Cost Factor	Reference	Cost (\$2007)
Direct Costs (DC)			
Purchased Equipment Costs (PEC)			
SCR System & Auxiliary Equipment	As estimated, A	Vendor Quote	\$ 2,080,000
Instrumentation	0.1 x A	(EPA, 1995a)	\$ 208,000
State Sales Taxes	7.7500% x A	NV State Sales Tax	\$ 161,200
Freight	0.05 x A	(EPA, 1995a)	\$ 104,000
PEC Total (B)			\$ 2,553,200
Direct Installation Costs (DIC)			
Foundation and Supports	0 x B	(Ulrich, 1984)	\$ -
Labor	0.14 x B	(EPA, 1990a)	\$ 357,448
Electrical	0.04 x B	(EPA, 1990a)	\$ 102,128
Additional Duct Work	\$6,533 /lft/sf of duct	Peters & Timmerhaus	
Piping	0.02 x B	(EPA, 1995a)	\$ 51,064
Insulation	0.01 x B	(EPA, 1995a)	\$ 25,532
Painting	0.01 x B	(EPA, 1990a)	\$ 25,532
DIC Total			\$ 561,704
Total DC = PEC + DIC			\$ 3,114,904
Indirect Costs (IC)			
Engineering	0.1 x B	(EPA, 1990a)	\$ 255,320
Construction Overhead	0.05 x B	(EPA, 1990a)	\$ 127,660
Contractor Fees	0.1 x B	(EPA, 1990a)	\$ 255,320
Start-up	0.02 x B	(EPA, 1990a)	\$ 51,064
Performance Testing	0.01 x B	(EPA, 1990a)	\$ 25,532
Contingencies	0.03 x B	(EPA, 1990a)	\$ 76,596
Simple Interest During Construction	8.55% x B x 0.5 years	Estimate	\$ 109,149
Total IDC			\$ 900,641
Total Capital Investment (TCI) = DC + IC			\$ 4,015,545

SCR-3

Annual Costs

Operating Cost Factors for the SCR System

Cost Data		
Interest Rate	7.00%	Capital Recovery Factor (CRF)
Catalyst Life	3	0.381
Equipment Life	20	0.094

Direct Annual Costs, \$/YR

	FACTOR	REFERENCE	Costs, \$/YEAR
Power Loss due to Pressure Drop across Catalyst	0.14% per inch @ 4 inch w/g of pressure drop,		
Operating Labor	\$0.035/Kwh	Vendor	\$ 398,335
Supervisory Labor		Industry Average/Estimate	\$ 40,150
Maintenance Labor and Materials	10% of Operating Labor	(EPA, 1993a)	\$ 4,015
Steam and Natural Gas	Materials = 50% of maintenance labor	Vendor	
Aqueous Ammonia		Vendor Quote	\$ 351,795
Catalyst Cleaning		Estimate	\$ 4,400
Revenue Loss during Cat Replacement (a)		Estimate	\$ 584,640
Catalyst Replacement Labor (b)		Estimate	\$ 11,200
Catalyst Replacement (CR) (c)		Estimate	\$ 1,040,000
Sales Tax (d)		Sales Tax	\$ 80,600
Capital Recovery	7.75%	(EPA, 1995a)	\$ 654,052
Total Direct Annual Costs, \$/YEAR	(a + b + c + d) * CRF		\$ 3,169,188

Indirect Annual Costs, \$/YEAR

Overhead	60% of sum of all labor costs + maintenance materials	(EPA, 1990a)	\$ 26,499
Insurance and Administration		(EPA, 1990a)	\$ 120,466
Capital Recovery	3% of TCI	N/A	\$ 273,262
Property Tax	CRF X (TCI - initial catalyst charge)	Estimate	\$ 40,155
Total Indirect Annual Costs, \$/YEAR	1% of TCI		\$ 460,383

Total Annual Costs, \$/YEAR

\$ 3,629,571

Total Net NOx Reductions (TPY)

959.1

Cost Effectiveness, \$/TON NOx

\$ 3,784

Total Net CO Reductions (TPY)

-

Cost Effectiveness, \$/TON CO

N/A

CatOx-1

BACT Cost Calculation

CatOx-1 CatOx @ 3 ppm CO

Cost Item	Cost Factor	Reference	Cost (\$2007)
Direct Costs (DC)			
Purchased Equipment Costs (PEC)			
Oxidation Catalyst & Auxiliary Equipment	As estimated, A	Vendor Quote	\$ 1,000,000
Instrumentation	0.1 x A	(EPA, 1995a)	\$ 100,000
State Sales Taxes	7.7500% x A	NV State Sales Tax	\$ 77,500
Freight	0.05 x A	(EPA, 1995a)	\$ 50,000
PEC Total (B)			\$ 1,227,500
Direct Installation Costs (DIC)			
Foundation and Supports	0.08 x B	(Ulrich, 1984)	\$ 98,200
Labor	0.14 x B	(EPA, 1990a)	\$ 171,850
Electrical	0.04 x B	(EPA, 1990a)	\$ 49,100
Additional Duct Work	\$6,533 //l/s/ft of duct	Peters & Timmerhaus	
Piping	0.02 x B	(EPA, 1995a)	\$ 24,550
Insulation	0.01 x B	(EPA, 1995a)	\$ 12,275
Painting	0.01 x B	(EPA, 1990a)	\$ 12,275
DIC Total			\$ 368,250
Total DC = PEC + DIC			\$ 1,595,750
Indirect Costs (IC)			
Engineering	0.1 x B	(EPA, 1990a)	\$ 122,750
Construction Overhead	0.05 x B	(EPA, 1990a)	\$ 61,375
Contractor Fees	0.1 x B	(EPA, 1990a)	\$ 122,750
Start-up	0.02 x B	(EPA, 1990a)	\$ 24,550
Performance Testing	0.01 x B	(EPA, 1990a)	\$ 12,275
Contingencies	0.03 x B	(EPA, 1990a)	\$ 36,825
Simple Interest During Construction	8.55% x B x 0.5 years	Estimate	\$ 52,476
Total IDC			\$ 433,001
Total Capital Investment (TCI) = DC + IC			\$ 2,028,751

CatOx-1

Annual Costs

Operating Cost Factors for the CatOx System

Cost Data

Interest Rate
Catalyst Life
Equipment Life

7.00%
3
20

Capital Recovery Factor (CRF)
0.381
0.094

Direct Annual Costs, \$/YR

	FACTOR	REFERENCE	Costs, \$/YEAR
Power Loss due to Pressure Drop across Catalyst	0.14% per inch @ 1.5 inch wg of pressure drop, \$0.035/Kwh		
Operating Labor	\$55/hr @ 1 hr/12 hr shift, 2 shifts per day	Vendor	\$ 149,376
Supervisory Labor	10% of Operating Labor	Industry Average/Estimate (EPA, 1993a)	\$ 40,150
Maintenance Labor and Materials	Materials = 50% of maintenance labor	Vendor	\$ 4,015
Steam and Natural Gas		Vendor	
Catalyst Cleaning	80 man-hours per year @ \$55/hr	Estimate	\$ 4,400
Revenue Loss during Cat Replacement (a)	72 hours @ \$0.035 Kw	Estimate	\$ 584,640
Catalyst Replacement Labor (b)	8 workers for 40 hours @ \$35/hr every 10 years	Estimate	\$ 11,200
Catalyst Replacement (CR) (c)		Estimate	\$ 500,000
Sales Tax (d)		Sales Tax	\$ 38,750
Capital Recovery	(a + b + c + d) * CRF	(EPA, 1995a)	\$ 432,337
Total Direct Annual Costs, \$/YEAR			\$ 1,764,868

Indirect Annual Costs, \$/YEAR

Overhead	60% of sum of all labor costs + maintenance materials	(EPA, 1990a)	\$ 26,499
Insurance and Administration	3% of TCI	(EPA, 1990a)	\$ 60,863
Capital Recovery	CRF X (TCI - initial catalyst charge)	N/A	\$ 140,646
Property Tax	0% of TCI	Estimate	\$ -
Total Indirect Annual Costs, \$/YEAR			\$ 228,007

Total Annual Costs, \$/YEAR

\$ 1,992,875

Total Net NOx Reductions (TPY)

-

Cost Effectiveness, \$/TON NOx

N/A

Total Net CO Reductions (TPY)

181.8

Cost Effectiveness, \$/TON CO

\$ 10,964

CatOx-2

BACT Cost Calculation

CatOx-2 CatOx @ 2 ppm CO

Cost Item	Cost Factor	Reference	Cost (\$2007)
Direct Costs (DC)			
Purchased Equipment Costs (PEC)			
SCR Catalyst & Auxiliary Equipment	As estimated, A	Vendor Quote	\$ 1,180,000
Instrumentation	0.1 x A	(EPA, 1995a)	\$ 118,000
State Sales Taxes	7.7500% x A	NV State Sales Tax	\$ 91,450
Freight	0.05 x A	(EPA, 1995a)	\$ 59,000
PEC Total (B)			\$ 1,448,450
Direct Installation Costs (DIC)			
Foundation and Supports	0.08 x B	(Ulrich, 1984)	\$ 115,876
Labor	0.14 x B	(EPA, 1990a)	\$ 202,783
Electrical	0.04 x B	(EPA, 1990a)	\$ 57,938
Additional Duct Work	\$6,533 /lf/sf of duct	Peters & Timmerhaus	
Piping	0.02 x B	(EPA, 1995a)	\$ 28,969
Insulation	0.01 x B	(EPA, 1995a)	\$ 14,485
Painting	0.01 x B	(EPA, 1990a)	\$ 14,485
DIC Total			\$ 434,535
Total DC = PEC + DIC			\$ 1,882,985
Indirect Costs (IC)			
Engineering	0.1 x B	(EPA, 1990a)	\$ 144,845
Construction Overhead	0.05 x B	(EPA, 1990a)	\$ 72,423
Contractor Fees	0.1 x B	(EPA, 1990a)	\$ 144,845
Start-up	0.02 x B	(EPA, 1990a)	\$ 28,969
Performance Testing	0.01 x B	(EPA, 1990a)	\$ 14,485
Contingencies	0.03 x B	(EPA, 1990a)	\$ 43,454
Simple Interest During Construction	8.55% x B x 0.5 years	Estimate	\$ 61,921
Total IDC			\$ 510,941
Total Capital Investment (TCI) = DC + IC			\$ 2,393,926

CatOx-2

Annual Costs

Operating Cost Factors for the SCR System

Cost Data

Interest Rate	7.00%	Capital Recovery Factor (CRF)	0.381
Catalyst Life	3		0.094
Equipment Life	20		

Direct Annual Costs, \$/YR

	FACTOR	REFERENCE	Costs, \$/YEAR
Power Loss due to Pressure Drop across Catalyst	0.14% per inch @ 2 inch wg of pressure drop,		
Operating Labor	\$0.035/Kwh	Vendor	\$ 199,167
Supervisory Labor	\$55/hr @ 1 hr/12 hr shift, 2 shifts per day	Industry Average/Estimate	\$ 40,150
Maintenance Labor and Materials	10% of Operating Labor	(EPA, 1993a)	\$ 4,015
Steam and Natural Gas	Materials = 50% of maintenance labor	Vendor	
Catalyst Cleaning	Vendor	Vendor	
Revenue Loss during Cat Replacement (a)	80 man-hours per year @ \$55/hr	Estimate	\$ 4,400
	72 hours @ \$0.035 Kw	Estimate	\$ 584,640
	8 workers for 40 hours @ \$35/hr every 10 years	Estimate	
Catalyst Replacement Labor (b)		Estimate	\$ 11,200
Catalyst Replacement (CR) (c)		Estimate	\$ 590,000
Sales Tax (d)		Sales Tax	\$ 45,725
Capital Recovery		(EPA, 1995a)	\$ 469,290
Total Direct Annual Costs, \$/YEAR			\$ 1,948,587

Indirect Annual Costs, \$/YEAR

Overhead	60% of sum of all labor costs + maintenance materials	(EPA, 1990a)	\$ 26,499
Insurance and Administration	3% of TCI	(EPA, 1990a)	\$ 71,818
Capital Recovery	CRF X (TCI - initial catalyst charge)	N/A	\$ 165,962
Property Tax	0% of TCI	Estimate	\$ -
Total Indirect Annual Costs, \$/YEAR			\$ 264,278

Total Annual Costs, \$/YEAR

\$ 2,212,866

Total Net NOx Reductions (TPY)

-

Cost Effectiveness, \$/TON NOx

N/A

Total Net CO Reductions (TPY)

207.8

Cost Effectiveness, \$/TON CO

\$ 10,650

**ATTACHMENT 9D
MODULE 9
OEPA APPLICATION FORMS**

Section II - Specific Air Contaminant Source Information

NOTE: One copy of this section should be filled out for each air contaminant source covered by this PTI application. See the line by line PTI instructions for additional information.

1. Company identification (name for air contaminant source for which you are applying): Combined Cycle Plant
2. List all equipment that are part of this air contaminant source: 1 Gas Turbine Generator, 1 Heat Recovery Steam Generator and 1 Steam Turbine Generator. The Steam Turbine Generator is shared with the second, identical Gas Turbine Generator.
3. Air Contaminant Source Installation or Modification Schedule (must be completed regardless of date of installation or modification):

When did/will you begin to install or modify the air contaminant source? (month/year) SECOND QUARTER 2008

When did/will you begin to operate the air contaminant source? (month/year) THIRD QUARTER 2011 OR after issuance of PTI

4. Emissions Information: The following table requests information needed to determine the applicable requirements and the compliance status of this air contaminant source with those requirements. Suggestions for how to estimate emissions may be found in the instructions to the Emissions Activity Category (EAC) forms required with this application. If you need further assistance, contact your Ohio EPA permit representative.

- If total potential emissions of HAPs or any Air Toxic is greater than 1 ton/yr, fill in the table for that (those) pollutant(s). For all other pollutants, if "Emissions before controls (max), lb/hr" multiplied by 24 hours/day is greater than 10 lb/day, fill in the table for that pollutant.
- If you have no add-on control equipment, "Emissions before controls" will be the same as "Actual emissions"
- Annual emissions should be based on operating 8760 hr/yr unless you are requesting operating restrictions to limit emissions in line # 8 or have described inherent limitations below.
- If you use units other than lb/hr or ton/yr, specify the units used (e.g., gr/dscf, lb/ton charged, lb/MMBtu, ton/12-months).
- Requested Allowable (ton/yr) is often equivalent to Potential to Emit (PTE) as defined in OAC rule 3745-31-01 and OAC rule 3745-77-01.

Pollutant	Emissions before controls (max) (lb/hr)	Actual emissions (lb/hr)	Actual emissions (ton/year)	Requested Allowable (lb/hr)	Requested Allowable (ton/year)
Particulate emissions (PE) (formerly particulate matter, PM)	18.21	18.21	78.67	18.21	78.67
PM ₁₀ (PM < 10 microns in diameter)	18.21	18.21	78.67	18.21	78.67
Sulfur dioxide (SO ₂)	21.06	21.06	90.97	21.06	90.97
Nitrogen oxides (NO _x)	285.30	57.06	246.50	57.06	246.50
Carbon monoxide (CO)	76.99	23.10	99.78	23.10	99.78
Organic compounds (OC)	38.02	26.62	114.99	26.62	114.99
Volatile organic compounds (VOC)	38.02	26.62	114.99	26.62	114.99
Total HAPs	2.3	1.6	6.9	1.6	6.9
Highest single HAP: (Formaldehyde)	1.56	1.1	4.8	1.1	4.8
Air Toxics (Ammonia):	25.6	25.6	112	25.6	112

Section II - Specific Air Contaminant Source Information

Provide your calculations as an attachment and explain how all process variables and emission factors were selected. Note the emissions factor(s) employed and document the origin. Example: AP-42, Table 4.4-3 (8/97); stack test, Method 5, 4/96; mass balance based on MSDS; etc.

5. Does this air contaminant source employ emissions control equipment?

Yes - fill out the applicable information below.

No - proceed to item # 6.

Note: Pollutant abbreviations used below: Particulates = PE; Organic compounds = OC; Sulfur dioxide = SO₂; Nitrogen oxides = NO_x; Carbon monoxide = CO

Cyclone/Multiclone

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: Cyclone Multiclone Rotoclone Other _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Fabric Filter/Baghouse

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Operating pressure drop range (inches of water): Minimum: _____ Maximum: _____
Pressure type: Negative pressure Positive pressure
Fabric cleaning mechanism: Reverse air Pulse jet Shaker Other _____
 Lime injection or fabric coating agent used: Type: _____ Feed rate: _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Wet Scrubber

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: Spray chamber Packed bed Impingement Venturi Other _____
Operating pressure drop range (inches of water): Minimum: _____ Maximum: _____
pH range for scrubbing liquid: Minimum: _____ Maximum: _____
Scrubbing liquid flow rate (gal/min): _____
Is scrubber liquid recirculated? Yes No
Water supply pressure (psig): _____ NOTE: This item for spray chambers only.
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Electrostatic Precipitator

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____

Section II - Specific Air Contaminant Source Information

Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: Plate-wire Flat-plate Tubular Wet Other _____
Number of operating fields: _____

This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Concentrator

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design regeneration cycle time (minutes): _____
Minimum desorption air stream temperature (°F): _____
Rotational rate (revolutions/hour): _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Catalytic Incinerator

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Minimum inlet gas temperature (°F): _____
Combustion chamber residence time (seconds): _____
Minimum temperature difference (°F) across catalyst during air contaminant source operation: _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Thermal Incinerator/Thermal Oxidizer

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Minimum operating temperature (°F) and location: _____ (See line by line instructions.)
Combustion chamber residence time (seconds): _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Flare

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: Enclosed Elevated (open)
Ignition device: Electric arc Pilot flame
Flame presence sensor: Yes No
 This is the only control equipment on this air contaminant source

Section II - Specific Air Contaminant Source Information

If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Condenser

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: Indirect contact Direct contact
Maximum exhaust gas temperature (°F) during air contaminant source operation: _____
Coolant type: _____
Design coolant temperature (°F): Minimum _____ Maximum _____
Design coolant flow rate (gpm): _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Carbon Absorber

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: On-site regenerative Disposable
Maximum design outlet organic concentration (ppmv): _____
Carbon replacement frequency or regeneration cycle time (specify units): _____
Maximum temperature of the carbon bed, after regeneration (including any cooling cycle): _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Dry Scrubber

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Reagent(s) used: Type: _____ Injection rate(s): _____
Operating pressure drop range (inches of water): Minimum: _____ Maximum: _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Paint booth filter

Type: Paper Fiberglass Water curtain Other _____
Design control efficiency (%): _____ Basis for efficiency: _____

Other, describe Catalytic Oxidation and SCR

Manufacturer: TBD Year installed: 2008
What do you call this control equipment: Combined Cycle Plant
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): Varies Basis for efficiency: See BACT Analysis

Section II - Specific Air Contaminant Source Information

This is the only control equipment on this air contaminant source

If no, this control equipment is: Primary Secondary Parallel

List any other air contaminant sources that are also vented to this control equipment:

Syngas that has passed through the Rectisol component of Module 5 (Syngas Cleanup) with further processing through the Linde PSA; Tailgas generated within the Fischer-Tropsch trains; and Tailgas generated within the Product Upgrade train.

6. Attach a Process or Activity Flow Diagram to this application for each air contaminant source included in the application. The diagram should indicate their relationships to one another. See the line by line PTI instructions for additional information.
7. Emissions egress point(s) information: PTIs which allow total emissions in excess of the thresholds listed below will be subject to an air quality modeling analysis. This analysis is to assure that the impact from the requested project will not exceed Ohio's Acceptable Incremental Impacts for criteria pollutants and/or Maximum Allowable Ground Level Concentrations (MAGLC) for air toxics. Permit requests that would have unacceptable impacts can not be approved as proposed. See the line by line PTI instructions for additional information.

Complete the tables below if the requested allowable annual emission rate for this PTI exceeds any of the following:

- Particulate Matter (PM10): 10 tons per year
- Sulfur Dioxide (SO2): 25 tons per year
- Nitrogen Oxides (NOx): 25 tons per year
- Carbon Monoxide (CO): 100 tons per year
- Air Toxic: 1 ton per year. An air toxic is any air pollutant for which the American Council of Governmental Industrial Hygienists (ACGIH) has established a Threshold Limit Value (TLV).

Complete Table 7-A below for each stack emissions egress point. An egress point is a point at which emissions from an air contaminant source are released into the ambient (outside) air. List each individual egress point on a separate line.

Table 7-A, Stack Egress Point Information						
Company Name or ID for the Egress Point (examples: Stack A; Boiler Stack; etc.)	Type Code*	Stack Egress Point Shape and Dimensions (in)(examples: round 10 inch ID; rectangular 14 X 16 inches; etc.)	Stack Egress Point Height from the Ground (ft)	Stack Temp. at Max. Capacity (F)	Stack Flow Rate at Max. Capacity (ACFM)	Minimum Distance to the Property Line (ft)
Combustion Turbine Generator (CTG) Stack 1	A	20 ft round diameter	160	192	600,000	500

*Type codes for stack egress points:

- A. vertical stack (unobstructed): There are no obstructions to upward flow in or on the stack such as a rain cap.
- B. vertical stack (obstructed): There are obstructions to the upward flow, such as a rain cap, which prevents or inhibits the air flow in a vertical direction.
- C. non-vertical stack: The stack directs the air flow in a direction which is not directly upward.

Section II - Specific Air Contaminant Source Information

Complete Table 7-B below for each fugitive emissions egress point. List each individual egress point on a separate line. Refer to the description of the fugitive egress point type codes below the table for use in completing the type code column of the table. For air contaminant sources like roadways and storage piles, only the first 5 columns need to be completed. For an air contaminant source with multiple fugitive emissions egress points, include only the primary egress points.

Table 7-B, Fugitive Egress Point Information					
Company ID for the Egress Point (examples; Garage Door B, Building C; Roof Monitor; etc.)	Type Code*	Egress Point Description (examples; garage door, 12 X 30 feet, west wall; outside gravel storage piles; etc.)	Fugitive Egress Point Height from the Ground (ft)	Minimum Distance to the Property Line (ft)	Exit Gas Temp. (F)

*Type codes for fugitive egress point:

- D. door or window
- E. other opening in the building without a duct
- F. no stack and no building enclosing the air contaminant source (e.g., roadways)

Complete Table 7-C below for each Stack Egress Point identified in Table 7-A above. In each case, use the dimensions of the largest nearby building, building segment or structure. List each individual egress point on a separate line. Use the same Company Name or ID for the Egress Point in Table 7-C that was used in Table 7-A. See the line by line PTI instructions for additional information.

Table 7-C, Egress Point Additional Information (Add rows as necessary)			
Company ID or Name for the Egress Point	Building Height (ft)	Building Width (ft)	Building Length (ft)
CTG 1 Stack	15	100	80

8. Request for Federally Enforceable Limits

As part of this permit application, do you wish to propose voluntary restrictions to limit emissions in order to avoid specific requirements listed below, (i.e., are you requesting federally enforceable limits to obtain synthetic minor status)?

- yes
- no
- not sure - please contact me if this affects me

If yes, why are you requesting federally enforceable limits? Check all that apply.

- a. to avoid being a major source (see OAC rule 3745-77-01)
- b. to avoid being a major MACT source (see OAC rule 3745-31-01)
- c. to avoid being a major modification (see OAC rule 3745-31-01)
- d. to avoid being a major stationary source (see OAC rule 3745-31-01)
- e. to avoid an air dispersion modeling requirement (see Engineering Guide # 69)
- f. to avoid another requirement. Describe: _____

If you checked a., b. or d., please attach a facility-wide potential to emit (PTE) analysis (for each pollutant) and synthetic minor strategy to this application. (See line by line instructions for definition of PTE.) If you checked c., please attach a net emission change analysis to this application.

Section II - Specific Air Contaminant Source Information

9. If this air contaminant source utilizes any continuous emissions monitoring equipment for indicating or demonstrating compliance, complete the following table. This does not include continuous parametric monitoring systems.

Company ID for Egress Point	Type of Monitor	Applicable performance specification (40 CFR 60, Appendix B)	Pollutant(s) Monitored
CTG Stack 1	TBD	NSPS, Subpart Da	NOx, SO2, CO or O2

10. Do you wish to permit this air contaminant source as a portable source, allowing relocation within the state in accordance with OAC rule 3745-31-03 or OAC rule 3745-31-05?

- yes - Note: notification requirements in rules cited above must be followed.
- no

11. The appropriate Emissions Activity Category (EAC) form(s) must be completed and attached for each air contaminant source. At least one complete EAC form must be submitted for each air contaminant source for the application to be considered complete. Refer to the list attached to the PTI instructions.

EMISSIONS ACTIVITY CATEGORY FORM STATIONARY INTERNAL COMBUSTION ENGINE

This form is to be completed for each stationary reciprocating or gas turbine engine. State/Federal regulations which may apply to stationary internal combustion engines are listed in the instructions. Note that there may be other regulations which apply to this emissions unit which are not included in this list.

1. Reason this form is being submitted (Check one)
 - New Permit Renewal or Modification of Air Permit Number (e.g. P001)_P002_____

2. Maximum Operating Schedule: 24 hours per day; 365 days per year
 If the schedule is less than 24 hours/day or 365 days/year, what limits the schedule to less than maximum? See instructions for examples. _____

3. Engine type: Gas turbine Reciprocating

4. Purpose of engine: Driving pump or compressor Driving electrical generator

5. Normal use of engine: Emergency only Non-emergency

6. Engine Manufacturer:
7. Siemens Model No: SGT-6 - 5000F or equivalent

8. Engine exhaust configuration:
 - simple cycle *(no heat recovery)*
 - regenerative cycle *(heat recovery to preheat combustion air)*
 - cogeneration cycle *(heat recovered to produce steam)*
 - combined cycle *(heat recovered to produce steam which drives generator)*
 (for turbines only)

9. Input capacities (million BTU/hr): Rated 1,988 (LHV) Maximum 2,193 (HHV) Normal _____
 Supplemental burner (duct burner) input capacity, if equipped (million BTU/hr):
 Rated: _____ Maximum 211 (HHV) Normal _____

10. Output capacities (Horsepower): Rated: _____ Maximum _____ Normal _____
 (Kilowatts): Rated: _____ Maximum 232,000 Normal _____
 (lbs steam/hr)*: Rated: _____ Maximum _____ Normal _____
 *required for cogeneration or combined cycle units only

11. Type of ignition: non-spark (diesel) spark

12. Type of fuel fired (check all that apply):

- single fuel No. 2 oil, low-sulfur natural gas landfill gas
 dual fuel No. 2 oil, high-sulfur diesel digester gas
 gasoline
 other, explain System Tail Gas propane

12. Complete the following table for all fuels identified in question 11 that are used for the engine and any supplemental (duct) burners, if equipped:

Fuel	Heat Content (BTU/unit)	wt. %	wt. %	Fuel Usage		
		Ash	Sulfur	Estimated Maximum Per Year	Normal Per Hour	Max. Per Hour
Nat. gas	BTU/cu ft		gr/scf	cu ft	cu ft	cu ft
No. 2 oil	BTU/gal			gal	gal	gal
Gasoline	BTU/gal			gal	gal	gal
Diesel	BTU/gal			gal	gal	gal
Landfill/digester gas	BTU/cf		ppm	cu ft	cu ft	cu ft
Other (show units)	487.5 BTU/cf			39,399.34 lbm/yr	2192.6 lbm/hr	2192.6 lbm/hr
<i>List supplemental (duct) burner fuel and information below (show units):</i>						

13. Type of combustion cycle (check all that apply):

- 2-stroke 4-stroke
 rich-burn lean-burn
 carbureted fuel injected
 other, explain Not applicable

14. Emissions control techniques (check all that apply):

- prestratified charge nonselective catalytic reduction (NSCR)
 catalytic oxidation (CO) selective catalytic reduction (SCR)
 air/fuel ratio injection timing retard (ITR)
 2-stage rich/lean combustion 2-stage lean/lean combustion
 water/steam injection preignition chamber combustion (PCC)
 other, explain Diluent injection (Only when using natural gas); Low sulfur fuel; Low mercury fuel

For each emissions control technique checked above, explain what pollutants are controlled by each technique: SCR controls NOx; Catalytic Oxidation controls CO, VOCs and formaldehyde; Diluent injection controls NOx only when being fired by natural gas; Low sulfur fuel controls SO2; Low mercury fuel controls mercury

Section II - Specific Air Contaminant Source Information

NOTE: One copy of this section should be filled out for each air contaminant source covered by this PTI application. See the line by line PTI instructions for additional information.

1. Company identification (name for air contaminant source for which you are applying): Combined Cycle Plant
2. List all equipment that are part of this air contaminant source: 1 Gas Turbine Generator, 1 Heat Recovery Steam Generator and 1 Steam Turbine Generator. The Steam Turbine Generator is shared with the second, identical Gas Turbine Generator.
3. Air Contaminant Source Installation or Modification Schedule (must be completed regardless of date of installation or modification):

When did/will you begin to install or modify the air contaminant source? (month/year) SECOND QUARTER 2008

When did/will you begin to operate the air contaminant source? (month/year) THIRD QUARTER 2011 OR after issuance of PTI

4. Emissions Information: The following table requests information needed to determine the applicable requirements and the compliance status of this air contaminant source with those requirements. Suggestions for how to estimate emissions may be found in the instructions to the Emissions Activity Category (EAC) forms required with this application. If you need further assistance, contact your Ohio EPA permit representative.

- If total potential emissions of HAPs or any Air Toxic is greater than 1 ton/yr, fill in the table for that (those) pollutant(s). For all other pollutants, if "Emissions before controls (max), lb/hr" multiplied by 24 hours/day is greater than 10 lb/day, fill in the table for that pollutant.
- If you have no add-on control equipment, "Emissions before controls" will be the same as "Actual emissions"
- Annual emissions should be based on operating 8760 hr/yr unless you are requesting operating restrictions to limit emissions in line # 8 or have described inherent limitations below.
- If you use units other than lb/hr or ton/yr, specify the units used (e.g., gr/dscf, lb/ton charged, lb/MMBtu, ton/12-months).
- Requested Allowable (ton/yr) is often equivalent to Potential to Emit (PTE) as defined in OAC rule 3745-31-01 and OAC rule 3745-77-01.

Pollutant	Emissions before controls (max) (lb/hr)	Actual emissions (lb/hr)	Actual emissions (ton/year)	Requested Allowable (lb/hr)	Requested Allowable (ton/year)
Particulate emissions (PE) (formerly particulate matter, PM)	18.21	18.21	78.67	18.21	78.67
PM ₁₀ (PM < 10 microns in diameter)	18.21	18.21	78.67	18.21	78.67
Sulfur dioxide (SO ₂)	21.06	21.06	90.97	21.06	90.97
Nitrogen oxides (NO _x)	285.30	57.06	246.50	57.06	246.50
Carbon monoxide (CO)	76.99	23.10	99.78	23.10	99.78
Organic compounds (OC)	38.02	26.62	114.99	26.62	114.99
Volatile organic compounds (VOC)	38.02	26.62	114.99	26.62	114.99
Total HAPs	2.3	1.6	6.9	1.6	6.9
Highest single HAP: (Formaldehyde)	1.56	1.1	4.8	1.1	4.8
Air Toxics: (Ammonia)	25.6	25.6	112	25.6	112

Section II - Specific Air Contaminant Source Information

Provide your calculations as an attachment and explain how all process variables and emission factors were selected. Note the emissions factor(s) employed and document the origin. Example: AP-42, Table 4.4-3 (8/97); stack test, Method 5, 4/96; mass balance based on MSDS; etc.

5. **Does this air contaminant source employ emissions control equipment?**

Yes - fill out the applicable information below.

No - proceed to item # 6.

Note: Pollutant abbreviations used below: Particulates = PE; Organic compounds = OC; Sulfur dioxide = SO₂; Nitrogen oxides = NO_x; Carbon monoxide = CO

Cyclone/Multiclone

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: Cyclone Multiclone Rotoclone Other _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Fabric Filter/Baghouse

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Operating pressure drop range (inches of water): Minimum: _____ Maximum: _____
Pressure type: Negative pressure Positive pressure
Fabric cleaning mechanism: Reverse air Pulse jet Shaker Other _____
 Lime injection or fabric coating agent used: Type: _____ Feed rate: _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Wet Scrubber

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: Spray chamber Packed bed Impingement Venturi Other _____
Operating pressure drop range (inches of water): Minimum: _____ Maximum: _____
pH range for scrubbing liquid: Minimum: _____ Maximum: _____
Scrubbing liquid flow rate (gal/min): _____
Is scrubber liquid recirculated? Yes No
Water supply pressure (psig): _____ NOTE: This item for spray chambers only.
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Electrostatic Precipitator

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____

Section II - Specific Air Contaminant Source Information

Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: Plate-wire Flat-plate Tubular Wet Other _____
Number of operating fields: _____

This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Concentrator

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NOx CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design regeneration cycle time (minutes): _____
Minimum desorption air stream temperature (°F): _____
Rotational rate (revolutions/hour): _____

This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Catalytic Incinerator

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NOx CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Minimum inlet gas temperature (°F): _____
Combustion chamber residence time (seconds): _____
Minimum temperature difference (°F) across catalyst during air contaminant source operation: _____

This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Thermal Incinerator/Thermal Oxidizer

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NOx CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Minimum operating temperature (°F) and location: _____ (See line by line instructions.)
Combustion chamber residence time (seconds): _____

This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Flare

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NOx CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____

Type: Enclosed Elevated (open)
Ignition device: Electric arc Pilot flame
Flame presence sensor: Yes No
 This is the only control equipment on this air contaminant source

Section II - Specific Air Contaminant Source Information

If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Condenser

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____

Type: Indirect contact Direct contact
Maximum exhaust gas temperature (°F) during air contaminant source operation: _____
Coolant type: _____
Design coolant temperature (°F): Minimum _____ Maximum _____
Design coolant flow rate (gpm): _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Carbon Absorber

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: On-site regenerative Disposable
Maximum design outlet organic compound concentration (ppmv): _____
Carbon replacement frequency or regeneration cycle time (specify units): _____
Maximum temperature of the carbon bed, after regeneration (including any cooling cycle): _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Dry Scrubber

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Reagent(s) used: Type: _____ Injection rate(s): _____
Operating pressure drop range (inches of water): Minimum: _____ Maximum: _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Paint booth filter

Type: Paper Fiberglass Water curtain Other _____
Design control efficiency (%): _____ Basis for efficiency: _____

Other, describe Catalytic Oxidation and SCR

Manufacturer: TBD Year installed: 2008
What do you call this control equipment: Combined Cycle Plant
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____

Design control efficiency (%): Varies Basis for efficiency: See BACT Analysis

Section II - Specific Air Contaminant Source Information

This is the only control equipment on this air contaminant source

If no, this control equipment is: Primary Secondary Parallel

List any other air contaminant sources that are also vented to this control equipment:

Syngas that has passed through the Rectisol component of Module 5 (Syngas Cleanup) with further processing through the Linde PSA; Tailgas generated within the Fischer-Tropsch trains; and Tailgas generated within the Product Upgrade train.

6. Attach a Process or Activity Flow Diagram to this application for each air contaminant source included in the application. The diagram should indicate their relationships to one another. See the line by line PTI instructions for additional information.
7. Emissions egress point(s) information: PTIs which allow total emissions in excess of the thresholds listed below will be subject to an air quality modeling analysis. This analysis is to assure that the impact from the requested project will not exceed Ohio's Acceptable Incremental Impacts for criteria pollutants and/or Maximum Allowable Ground Level Concentrations (MAGLC) for air toxics. Permit requests that would have unacceptable impacts can not be approved as proposed. See the line by line PTI instructions for additional information.

Complete the tables below if the requested allowable annual emission rate for this PTI exceeds any of the following:

- Particulate Matter (PM10): 10 tons per year
- Sulfur Dioxide (SO2): 25 tons per year
- Nitrogen Oxides (NOx): 25 tons per year
- Carbon Monoxide (CO): 100 tons per year
- Air Toxic: 1 ton per year. An air toxic is any air pollutant for which the American Council of Governmental Industrial Hygienists (ACGIH) has established a Threshold Limit Value (TLV).

Complete Table 7-A below for each stack emissions egress point. An egress point is a point at which emissions from an air contaminant source are released into the ambient (outside) air. List each individual egress point on a separate line.

Table 7-A, Stack Egress Point Information						
Company Name or ID for the Egress Point (examples: Stack A; Boiler Stack; etc.)	Type Code*	Stack Egress Point Shape and Dimensions (in)(examples: round 10 inch ID; rectangular 14 X 16 inches; etc.)	Stack Egress Point Height from the Ground (ft)	Stack Temp. at Max. Capacity (F)	Stack Flow Rate at Max. Capacity (ACFM)	Minimum Distance to the Property Line (ft)
Combustion Turbine Generator (CTG) Stack 2	A	20 ft round diameter	160	192	600,000	500

*Type codes for stack egress points:

- A. vertical stack (unobstructed): There are no obstructions to upward flow in or on the stack such as a rain cap.
- B. vertical stack (obstructed): There are obstructions to the upward flow, such as a rain cap, which prevents or inhibits the air flow in a vertical direction.
- C. non-vertical stack: The stack directs the air flow in a direction which is not directly upward.

Section II - Specific Air Contaminant Source Information

Complete Table 7-B below for each fugitive emissions egress point. List each individual egress point on a separate line. Refer to the description of the fugitive egress point type codes below the table for use in completing the type code column of the table. For air contaminant sources like roadways and storage piles, only the first 5 columns need to be completed. For an air contaminant source with multiple fugitive emissions egress points, include only the primary egress points.

Table 7-B, Fugitive Egress Point Information					
Company ID for the Egress Point (examples; Garage Door B, Building C; Roof Monitor; etc.)	Type Code*	Egress Point Description (examples: garage door, 12 X 30 feet, west wall; outside gravel storage piles; etc.)	Fugitive Egress Point Height from the Ground (ft)	Minimum Distance to the Property Line (ft)	Exit Gas Temp. (F)

*Type codes for fugitive egress point:

- D. door or window
- E. other opening in the building without a duct
- F. no stack and no building enclosing the air contaminant source (e.g., roadways)

Complete Table 7-C below for each Stack Egress Point identified in Table 7-A above. In each case, use the dimensions of the largest nearby building, building segment or structure. List each individual egress point on a separate line. Use the same Company Name or ID for the Egress Point in Table 7-C that was used in Table 7-A. See the line by line PTI instructions for additional information.

Table 7-C, Egress Point Additional Information (Add rows as necessary)			
Company ID or Name for the Egress Point	Building Height (ft)	Building Width (ft)	Building Length (ft)
CTG 2 Stack	15	100	80

8. Request for Federally Enforceable Limits

As part of this permit application, do you wish to propose voluntary restrictions to limit emissions in order to avoid specific requirements listed below, (i.e., are you requesting federally enforceable limits to obtain synthetic minor status)?

- yes
- no
- not sure - please contact me if this affects me

If yes, why are you requesting federally enforceable limits? Check all that apply.

- a. to avoid being a major source (see OAC rule 3745-77-01)
- b. to avoid being a major MACT source (see OAC rule 3745-31-01)
- c. to avoid being a major modification (see OAC rule 3745-31-01)
- d. to avoid being a major stationary source (see OAC rule 3745-31-01)
- e. to avoid an air dispersion modeling requirement (see Engineering Guide # 69)
- f. to avoid another requirement. Describe: _____

If you checked a., b. or d., please attach a facility-wide potential to emit (PTE) analysis (for each pollutant) and synthetic minor strategy to this application. (See line by line instructions for definition of PTE.) If you checked c., please attach a net emission change analysis to this application.

Section II - Specific Air Contaminant Source Information

9. If this air contaminant source utilizes any continuous emissions monitoring equipment for indicating or demonstrating compliance, complete the following table. This does not include continuous parametric monitoring systems.

Company ID for Egress Point	Type of Monitor	Applicable performance specification (40 CFR 60, Appendix B)	Pollutant(s) Monitored
CTG Stack 2	TBD	NSPS, Subpart Da	NO _x , SO ₂ , CO or O ₂

10. Do you wish to permit this air contaminant source as a portable source, allowing relocation within the state in accordance with OAC rule 3745-31-03 or OAC rule 3745-31-05?

- yes - Note: notification requirements in rules cited above must be followed.
- no

11. The appropriate Emissions Activity Category (EAC) form(s) must be completed and attached for each air contaminant source. At least one complete EAC form must be submitted for each air contaminant source for the application to be considered complete. Refer to the list attached to the PTI instructions.

EMISSIONS ACTIVITY CATEGORY FORM STATIONARY INTERNAL COMBUSTION ENGINE

This form is to be completed for each stationary reciprocating or gas turbine engine. State/Federal regulations which may apply to stationary internal combustion engines are listed in the instructions. Note that there may be other regulations which apply to this emissions unit which are not included in this list.

1. Reason this form is being submitted (Check one)

New Permit Renewal or Modification of Air Permit Number (e.g. P001)_P002_____

2. Maximum Operating Schedule: 24 hours per day; 365 days per year

If the schedule is less than 24 hours/day or 365 days/year, what limits the schedule to less than maximum? See instructions for examples. _____

3. Engine type: Gas turbine Reciprocating

4. Purpose of engine: Driving pump or compressor Driving electrical generator

5. Normal use of engine: Emergency only Non-emergency

6. Engine Manufacturer:

7. Siemens Model No: SGT-6 - 5000F or equivalent

8. Engine exhaust

configuration:

(for turbines only)

- simple cycle *(no heat recovery)*
 regenerative cycle *(heat recovery to preheat combustion air)*
 cogeneration cycle *(heat recovered to produce steam)*
 combined cycle *(heat recovered to produce steam which drives generator)*

9. Input capacities (million BTU/hr): Rated 1,988 (LHV) Maximum 2,193 (HHV) Normal _____

Supplemental burner (duct burner) input capacity, if equipped (million BTU/hr):

Rated: _____ Maximum 211 (HHV) Normal _____

10. Output capacities (Horsepower): Rated: _____ Maximum _____ Normal _____

(Kilowatts): Rated: _____ Maximum 232,000 Normal _____

(lbs steam/hr)*: Rated: _____ Maximum _____ Normal _____

**required for cogeneration or combined cycle units only*

11. Type of ignition: non-spark (diesel) spark

12. Type of fuel fired (check all that apply):

- single fuel No. 2 oil, low-sulfur natural gas landfill gas
 dual fuel No. 2 oil, high-sulfur diesel digester gas
 gasoline propane
 other, explain System Tail Gas

12. Complete the following table for all fuels identified in question 11 that are used for the engine and any supplemental (duct) burners, if equipped:

Fuel	Heat Content (BTU/unit)	wt. %	wt. %	Fuel Usage		
		Ash	Sulfur	Estimated Maximum Per Year	Normal Per Hour	Max. Per Hour
Nat. gas	BTU/cu ft		gr/scf	cu ft	cu ft	cu ft
No. 2 oil	BTU/gal			gal	gal	gal
Gasoline	BTU/gal			gal	gal	gal
Diesel	BTU/gal			gal	gal	gal
Landfill/digester gas	BTU/cf		ppm	cu ft	cu ft	cu ft
Other (show units)	487.5 BTU/cf			39,399.34 lbm/yr	2192.6 lbm/hr	2192.6 lbm/hr
<i>List supplemental (duct) burner fuel and information below (show units):</i>						

13. Type of combustion cycle (check all that apply):

- 2-stroke 4-stroke
 rich-burn lean-burn
 carbureted fuel injected
 other, explain Not applicable

14. Emissions control techniques (check all that apply):

- prestratified charge nonselective catalytic reduction (NSCR)
 catalytic oxidation (CO) selective catalytic reduction (SCR)
 air/fuel ratio injection timing retard (ITR)
 2-stage rich/lean combustion 2-stage lean/lean combustion
 water/steam injection preignition chamber combustion (PCC)
 other, explain Diluent injection (Only when using natural gas); Low sulfur fuel; Low mercury fuel

For each emissions control technique checked above, explain what pollutants are controlled by each technique: SCR controls NO_x; Catalytic Oxidation controls CO, VOCs and formaldehyde; Diluent injection controls NO_x only when being fired by natural gas; Low sulfur fuel controls SO₂; Low mercury fuel controls mercury

NOTE: One copy of this section should be filled out for each air contaminant source covered by this PTI application. See the line by line PTI instructions for additional information.

1. Company identification (name for air contaminant source for which you are applying): Combined Cycle Plant
2. List all equipment that are part of this air contaminant source: Phase I Boiler
3. Air Contaminant Source Installation or Modification Schedule (must be completed regardless of date of installation or modification):

When did/will you begin to install or modify the air contaminant source? (month/year) SECOND QUARTER 2008

When did/will you begin to operate the air contaminant source? (month/year) THIRD QUARTER 2011 OR after issuance of PTI

4. Emissions Information: The following table requests information needed to determine the applicable requirements and the compliance status of this air contaminant source with those requirements. Suggestions for how to estimate emissions may be found in the instructions to the Emissions Activity Category (EAC) forms required with this application. If you need further assistance, contact your Ohio EPA permit representative.

- If total potential emissions of HAPs or any Air Toxic is greater than 1 ton/yr, fill in the table for that (those) pollutant(s). For all other pollutants, if "Emissions before controls (max), lb/hr" multiplied by 24 hours/day is greater than 10 lb/day, fill in the table for that pollutant.
- If you have no add-on control equipment, "Emissions before controls" will be the same as "Actual emissions"
- Annual emissions should be based on operating 8760 hr/yr unless you are requesting operating restrictions to limit emissions in line # 8 or have described inherent limitations below.
- If you use units other than lb/hr or ton/yr, specify the units used (e.g., gr/dscf, lb/ton charged, lb/MMBtu, ton/12-months).
- Requested Allowable (ton/yr) is often equivalent to Potential to Emit (PTE) as defined in OAC rule 3745-31-01 and OAC rule 3745-77-01.

Pollutant	Emissions before controls (max) (lb/hr)	Actual emissions (lb/hr)	Actual emissions (ton/year)	Requested Allowable (lb/hr)	Requested Allowable (ton/year)
Particulate emissions (PE) (formerly particulate matter, PM)	18.7	18.7	82.0	18.7	82.0
PM ₁₀ (PM < 10 microns in diameter)	18.7	18.7	82.0	18.7	82.0
Sulfur dioxide (SO ₂)	2.0	2.0	8.9	2.0	8.9
Nitrogen oxides (NO _x)	473.8	120.0	529.8	120.0	529.8
Carbon monoxide (CO)	120.0	36.0	157.7	36.0	157.7
Organic compounds (OC)	18.6	13.0	57.1	13.0	57.1
Volatile organic compounds (VOC)	18.6	13.0	57.1	13.0	57.1
Total HAPs	6.4	4.5	19.6	4.5	19.6
Highest single HAP: (HEXANE)	6.1	4.3	18.6	4.3	18.6
Air Toxics (see instructions):	6.4	4.5	19.6	4.5	19.6

Provide your calculations as an attachment and explain how all process variables and emission factors were selected. Note the emissions factor(s) employed and document the origin. Example: AP-42, Table 4.4-3 (8/97); stack test, Method 5, 4/96; mass balance based on MSDS; etc.

Section II - Specific Air Contaminant Source Information

5. Does this air contaminant source employ emissions control equipment?

Yes - fill out the applicable information below.

No - proceed to item # 6.

Note: Pollutant abbreviations used below: Particulates = PE; Organic compounds = OC; Sulfur dioxide = SO₂; Nitrogen oxides = NO_x; Carbon monoxide = CO

Cyclone/Multiclone

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: Cyclone Multiclone Rotoclone Other _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Fabric Filter/Baghouse

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Operating pressure drop range (inches of water): Minimum: _____ Maximum: _____
Pressure type: Negative pressure Positive pressure
Fabric cleaning mechanism: Reverse air Pulse jet Shaker Other _____
 Lime injection or fabric coating agent used: Type: _____ Feed rate: _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Wet Scrubber

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: Spray chamber Packed bed Impingement Venturi Other _____
Operating pressure drop range (inches of water): Minimum: _____ Maximum: _____
pH range for scrubbing liquid: Minimum: _____ Maximum: _____
Scrubbing liquid flow rate (gal/min): _____
Is scrubber liquid recirculated? Yes No
Water supply pressure (psig): _____ NOTE: This item for spray chambers only.
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Electrostatic Precipitator

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____

Section II - Specific Air Contaminant Source Information

Type: Plate-wire Flat-plate Tubular Wet Other _____
Number of operating fields: _____

This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Concentrator

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NOx CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design regeneration cycle time (minutes): _____
Minimum desorption air stream temperature (°F): _____
Rotational rate (revolutions/hour): _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Catalytic Incinerator

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NOx CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Minimum inlet gas temperature (°F): _____
Combustion chamber residence time (seconds): _____
Minimum temperature difference (°F) across catalyst during air contaminant source operation: _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Thermal Incinerator/Thermal Oxidizer

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NOx CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Minimum operating temperature (°F) and location: _____ (See line by line instructions.)
Combustion chamber residence time (seconds): _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Flare

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NOx CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: Enclosed Elevated (open)
Ignition device: Electric arc Pilot flame
Flame presence sensor: Yes No
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Section II - Specific Air Contaminant Source Information

Condenser

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____

Type: Indirect contact Direct contact
Maximum exhaust gas temperature (°F) during air contaminant source operation: _____
Coolant type: _____
Design coolant temperature (°F): Minimum _____ Maximum _____
Design coolant flow rate (gpm): _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment: _____

Carbon Absorber

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: On-site regenerative Disposable
Maximum design outlet organic compound concentration (ppmv): _____
Carbon replacement frequency or regeneration cycle time (specify units): _____
Maximum temperature of the carbon bed, after regeneration (including any cooling cycle): _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment: _____

Dry Scrubber

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Reagent(s) used: Type: _____ Injection rate(s): _____
Operating pressure drop range (inches of water): Minimum: _____ Maximum: _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment: _____

Paint booth filter

Type: Paper Fiberglass Water curtain Other _____
Design control efficiency (%): _____ Basis for efficiency: _____

Other, describe Low NO_x Burner, Catalytic oxidation, and SCR

Manufacturer: TBD Year installed: 2008
What do you call this control equipment: Combined Cycle Plant
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____

Design control efficiency (%): Varies Basis for efficiency: _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel

Section II - Specific Air Contaminant Source Information

List any other air contaminant sources that are also vented to this control equipment:
 Syngas that has passed through the Rectisol component of Module 5 (Syngas Cleanup) with further processing through the Linde PSA; Tailgas generated within the Fischer-Tropsch trains; and Tailgas generated within the Product Upgrade train.

6. Attach a Process or Activity Flow Diagram to this application for each air contaminant source included in the application. The diagram should indicate their relationships to one another. See the line by line PTI instructions for additional information.
7. Emissions egress point(s) information: PTIs which allow total emissions in excess of the thresholds listed below will be subject to an air quality modeling analysis. This analysis is to assure that the impact from the requested project will not exceed Ohio's Acceptable Incremental Impacts for criteria pollutants and/or Maximum Allowable Ground Level Concentrations (MAGLC) for air toxics. Permit requests that would have unacceptable impacts can not be approved as proposed. See the line by line PTI instructions for additional information.

Complete the tables below if the requested allowable annual emission rate for this PTI exceeds any of the following:

- Particulate Matter (PM10): 10 tons per year
- Sulfur Dioxide (SO2): 25 tons per year
- Nitrogen Oxides (NOx): 25 tons per year
- Carbon Monoxide (CO): 100 tons per year
- Air Toxic: 1 ton per year. An air toxic is any air pollutant for which the American Council of Governmental Industrial Hygienists (ACGIH) has established a Threshold Limit Value (TLV).

Complete Table 7-A below for each stack emissions egress point. An egress point is a point at which emissions from an air contaminant source are released into the ambient (outside) air. List each individual egress point on a separate line.

Table 7-A, Stack Egress Point Information						
Company Name or ID for the Egress Point (examples: Stack A; Boiler Stack; etc.)	Type Code*	Stack Egress Point Shape and Dimensions (in)(examples: round 10 inch ID; rectangular 14 X 16 inches; etc.)	Stack Egress Point Height from the Ground (ft)	Stack Temp. at Max. Capacity (F)	Stack Flow Rate at Max. Capacity (ACFM)	Minimum Distance to the Property Line (ft)
Phase I Boiler Stack	A	Round 16" ID	45	325	300,000	600

*Type codes for stack egress points:

- A. vertical stack (unobstructed): There are no obstructions to upward flow in or on the stack such as a rain cap.
- B. vertical stack (obstructed): There are obstructions to the upward flow, such as a rain cap, which prevents or inhibits the air flow in a vertical direction.
- C. non-vertical stack: The stack directs the air flow in a direction which is not directly upward.

Complete Table 7-B below for each fugitive emissions egress point. List each individual egress point on a separate line. Refer to the description of the fugitive egress point type codes below the table for use in completing the type code column of the table. For air contaminant sources like roadways and storage piles, only the first 5 columns need to be completed. For an air contaminant source with multiple fugitive emissions egress points, include only the primary egress points.

Table 7-B, Fugitive Egress Point Information					
Company ID for the Egress Point (examples; Garage Door B, Building C; Roof Monitor; etc.)	Type Code*	Egress Point Description (examples: garage door, 12 X 30 feet, west wall; outside gravel storage piles; etc.)	Fugitive Egress Point Height from the Ground (ft)	Minimum Distance to the Property Line (ft)	Exit Gas Temp. (F)

Section II - Specific Air Contaminant Source Information

*Type codes for fugitive egress point:

- D. door or window
- E. other opening in the building without a duct
- F. no stack and no building enclosing the air contaminant source (e.g., roadways)

Complete Table 7-C below for each Stack Egress Point identified in Table 7-A above. In each case, use the dimensions of the largest nearby building, building segment or structure. List each individual egress point on a separate line. Use the same Company Name or ID for the Egress Point in Table 7-C that was used in Table 7-A. See the line by line PTI instructions for additional information.

Table 7-C, Egress Point Additional Information (Add rows as necessary)			
Company ID or Name for the Egress Point	Building Height (ft)	Building Width (ft)	Building Length (ft)
Phase I Boiler Stack	15	100	80

8. Request for Federally Enforceable Limits

As part of this permit application, do you wish to propose voluntary restrictions to limit emissions in order to avoid specific requirements listed below, (i.e., are you requesting federally enforceable limits to obtain synthetic minor status)?

- yes
- no
- not sure - please contact me if this affects me

If yes, why are you requesting federally enforceable limits? Check all that apply.

- a. to avoid being a major source (see OAC rule 3745-77-01)
- b. to avoid being a major MACT source (see OAC rule 3745-31-01)
- c. to avoid being a major modification (see OAC rule 3745-31-01)
- d. to avoid being a major stationary source (see OAC rule 3745-31-01)
- e. to avoid an air dispersion modeling requirement (see Engineering Guide # 69)
- f. to avoid another requirement. Describe: _____

If you checked a., b. or d., please attach a facility-wide potential to emit (PTE) analysis (for each pollutant) and synthetic minor strategy to this application. (See line by line instructions for definition of PTE.) If you checked c., please attach a net emission change analysis to this application.

9. If this air contaminant source utilizes any continuous emissions monitoring equipment for indicating or demonstrating compliance, complete the following table. This does not include continuous parametric monitoring systems.

Company ID for Egress Point	Type of Monitor	Applicable performance specification (40 CFR 60, Appendix B)	Pollutant(s) Monitored
Phase I Boiler Stack	TBD	NSPS, Subpart Db	NOx

10. Do you wish to permit this air contaminant source as a portable source, allowing relocation within the state in accordance with OAC rule 3745-31-03 or OAC rule 3745-31-05?

- yes - Note: notification requirements in rules cited above must be followed.
- no

11. The appropriate Emissions Activity Category (EAC) form(s) must be completed and attached for each air contaminant source. At least one complete EAC form must be submitted for each air contaminant source for the application to be considered complete. Refer to the list attached to the PTI instructions.

EMISSIONS ACTIVITY CATEGORY FORM FUEL BURNING OPERATION

This form is to be completed for each fuel burning operation. State/Federal regulations which may apply to fuel burning operations are listed in the instructions. Note that there may be other regulations which apply to this emissions unit which are not included in this list

1. Reason this form is being submitted (check one)

New Permit Renewal or Modification of Air Permit Number(s) (e.g. B001) B001_____

2. Maximum Operating Schedule: 24 hours per day; 365 days per year

If the schedule is less than 24 hours/day or 365 days/year, what limits the schedule to less than maximum? See instructions for examples.

3. Input Capacity (million Btu/hr):

Rated <i>(Indicate units if other than mmBtu/hr)</i>	Maximum <i>(Indicate units if other than mmBtu/hr)</i>	Normal <i>(Indicate units if other than mmBtu/hr)</i>
1200	1200	1000

4. Output Capacity:

Rated <i>(lb steam/hr)</i>	Maximum <i>(lb steam/hr)</i>	Normal <i>(lb steam/hr)</i>
		990,000 lb/hr at 700 psig

Not applicable - operation does not produce steam.

5. Percent of Operating Time Used for:

Process: 100 %

Space Heat: _____%

6. Type of Draft (check one):

Natural Induced Forced

7. Type of combustion monitoring (check one):

Fuel/Air Ratio Oxygen None

Other (describe) _____

8. Type of Fuel Fired (complete all that apply):

Fuel*	Fired as...	Min. Heat Content (Btu/unit)	Max. % Ash	Max. % Sulfur	Max. Annual Fuel Use	Average Hourly Fuel Use	Maximum Hourly Fuel Use
Coal	<input type="checkbox"/> Primary <input type="checkbox"/> Backup				tons	lbs	lbs
No. 2 Fuel Oil	<input type="checkbox"/> Primary <input type="checkbox"/> Backup				gal	gal	gal
No. 6 Fuel Oil	<input type="checkbox"/> Primary <input type="checkbox"/> Backup				gal	gal	gal
Other** Oil	<input type="checkbox"/> Primary <input type="checkbox"/> Backup				gal	gal	gal
Natural Gas	<input type="checkbox"/> Primary <input checked="" type="checkbox"/> Backup				MMSCF ft ³	SCF ft ³	SCF ft ³
Wood	<input type="checkbox"/> Primary <input type="checkbox"/> Backup				tons	lbs	lbs
LPG	<input type="checkbox"/> Primary <input type="checkbox"/> Backup				gal	gal	gal
Other**	<input checked="" type="checkbox"/> Primary <input type="checkbox"/> Backup	487.5/cf	NIL	0.001	29,649.23 MMSCF	2,820,513 SCF	3,384,615.30 SCF
Other**	<input type="checkbox"/> Primary <input type="checkbox"/> Backup						

* Please identify all combinations of fuels that are co-fired: _____

** Identify other fuel(s): ___Process Tail gas_____

Coal-Fired Units

9. Type of Coal Firing (check one):

- Pulverized-Wet Bottom Hand-Fired Chain Grate Traveling Grate
 Pulverized-Dry Bottom Cyclones Spreader Stoker Fluidized Bed
 Underfeed Stoker Other (describe) _____

10. Flyash Reinjection:

- Yes No

11. Overfire Air:

- Yes No

Oil-Fired Units

12. Oil Preheater:

- Yes - Indicate Temperature _____ deg. F
 No