STAFF DETERMINATION FOR THE APPLICATION TO CONSTRUCT UNDER THE OHIO PREVENTION OF SIGNIFICANT DETERIORATION REGULATIONS FOR THE LIMA ENERGY LTD (INTEGRATED GASIFICATION COMBINED CYCLE FACILITY) - LIMA PLANT, PTI NO. 03-13445, FOR TWO COMBINED-CYCLE (580 MEGAWATTS) SYNTHETIC GAS AND NATURAL GAS FIRED GENERAL ELECTRIC 7FA TURBINES TO BE LOCATED IN LIMA, ALLEN, COUNTY, OHIO

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

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

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

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

For nonattainment areas, the requirements are:

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

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

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

For rural ozone nonattainment areas, the requirements are:

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

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

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

Site Description

The Lima Energy Ltd (L-E), a subsidiary of Global Energy, is proposing to build and operate two combined-cycle (580 megawatts) gas fired General Electric 7FA turbines burning synthetic gas (Syn Gas) and natural gas, two heat recovery steam generators (HRSG), a steam turbine, and a wet cooling tower. Total facility power generation will be approximately 580 MW gross including power generated in the steam turbine. This facility is to be located in Lima, Allen, County, Ohio.

This area is classified as attainment for all of the criteria pollutants, total suspended particulate matter, particulate matter less than 10 microns, sulfur dioxide, nitrogen oxides, carbon monoxide, volatile organic compounds (ozone) and lead.

New Source Review (NSR)/PSD Applicability

The Lima Energy Facility is classified as a "major" stationary source because the potential emissions exceed the 100 tons per year of one of the criteria pollutants (NO_x) and is also one of the 28 source categories because it will generate steam and therefore triggers the 100 tons per year threshold level in an attainment area and thus be classified as a major source under the federal Prevention of Significant Deterioration (PSD) program.

The new installation "Lima Energy Facility" is classified as a "major modification" of a stationary source because the potential emissions exceed the significant emission rate levels for particulate matter(PM)/particulate matter less than 10 microns (PM_{10}), ozone [as volatile organic compounds (VOCs)], sulfur dioxides (SO_2), and carbon monoxide (CO).

Emissions of sulfuric acid mist (H_2SO_4) associated with the Lima Energy Facility are below the PSD significant emissions level rates and therefore are not subject to PSD review.

Allen, County, Ohio where the proposed installation will be built is designated is an attainment area for all pollutants under the Clean Air Act Amendments of 1990. In this case, since the facility is classified as a "major" stationary source for PSD, and then any addition that would emit a regulated pollutant at a rate in excess of the significance levels would require the facility to perform a PSD analysis for those pollutants.

Table 1 shows the emissions from the proposed modification.

Table 1

Pollutant	Tons/Year	Significant Level
Nitrogen Oxides (NO_x)	1285.4	40
Sulfur Dioxide (SO_2)	338.2	40
Particulate Matter	166.7	25
Carbon Monoxide (CO)	680	100
Volatile Organic Compounds(VOC)	133.4	40
Lead	0.16	0.6
Mercury	0.02	0.1
Sulfuric Acid Mist (H_2SO_4)	4.6	7.0

Based upon the above information, PSD review is required for NO_x, SO_2, PM, VOCs and CO.

New Source Performance Standards (NSPS) Applicability

Each of the integrated gasification combined cycle syngas and natural gas fired combustion turbines/HRSG is subject to 40 CFR 60 Subpart GG, "Standards of Performance for Stationary Gas Turbines" and 40 CFR 60 Subpart Eb, "Standards of Performance for Large Municipal Waste Combustors for which Construction is Commenced After September 20, 1994".

The Stationary Gas Turbine NSPS applies to emissions for NO_x and SO_2. The emission standard for NO_x emissions applicable to the combustion turbine [from the equation in 40 CFR 60.332(a)(1)] is 0.0075 percent by volume (75 ppmv) at 15 percent oxygen on a dry basis. This standard is applicable to either fuel oil or natural gas combustion. The emission standard for SO_2 emissions applicable to the combustion turbine [from the equation in 40 CFR 60.333(b)] is 0.015 percent by volume (150 ppmv) at 15 percent oxygen on a dry basis. SO_2 emissions from combustion turbines are further limited by 40 CFR 60.333(b) which prohibits burning fuel that contains sulfur in excess of 0.8 percent by weight.

National Emission Standards for Hazardous Air Pollutants (NESHAP) Part 63, 112(g) and Ohio Administrative Code (OAC) rule 3745-31-28 Applicability

Currently there are no standards that have been promulgated for this project. If no standard has been promulgated, then the project is evaluated based upon the amount of Hazardous Air Pollutants emitted. If over the threshold levels, then a Maximum Achievable Control Technology (MACT) determination must be submitted for review.

The Lima Energy Facility will be accepting HAP emission restrictions to levels below 10 tons per year of any individual HAP and 25 tons per year of any combinations of HAPs to avoid submitting a MACT determination.

CONTROL TECHNOLOGY REVIEW

The new installation "Lima Energy Facility" is subject to PSD regulations which mandates a case-by-case Best Available Control Technology (BACT) analysis be performed for the following pollutant: NO_x, SO_2, PM, VOCs and CO. The application used a "top-down" approach to determine an appropriate level of control.

Site Description/Air Quality Designations

The new installation "Lima Energy Facility" has proposed to build and operate two integrated gasification combined cycle gas fired General Electric 7FA turbines burning syngas combined with natural gas, two heat recovery steam generators (HRSG), a steam turbine, and a wet cooling tower to be located in Lima, Allen County, Ohio. Under Section 107 of the Clean Air Act as of June 24, 1992, this area was classified as attainment for all of the criteria pollutants, i.e., total suspended particulates, sulfur dioxide, nitrogen oxides, carbon monoxide, lead, and volatile organic compounds (ozone).

Best Available Control Technology (BACT) Analysis

The permitting of this integrated gasification combined cycle gas turbine facility proposed by Lima Energy requires review under the Prevention of Significant Deterioration (PSD) regulations due to the significant emission rates of criteria pollutants (NO_x, CO, SO_2, PM_{10} and VOC). The 1977 Clean Air Act (CAA) established conditions for the approval of pre-construction permits under the PSD program. One of the requirements is that Best Available Control Technology (BACT) be installed for all pollutants regulated under the CAA which are emitted in significant amounts from new major sources or major modifications located in an attainment area.

BACT is defined in the PSD regulations as an emissions limitation based on the maximum degree of reduction for each pollutant subject to regulation which would be emitted from any proposed major stationary source or major modification which the Director, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable through application of production processes or available methods, systems, and techniques for control of such pollutants. Each BACT analysis is done on a case-by-case basis to determine the maximum achievable degree of reduction for each pollutant subject to PSD. The BACT evaluation considers the energy, environmental, economic, and other costs associated with each alternative technology, and the benefit of reduced emissions that the technology would bring.

Table 2 summarizes the BACT proposals for all emission units/pollutants in the project. The following sections describe and document the case-by-case BACT determination.

Table 2

BACT Summary

Emission Unit	Pollutant	BACT
Gas Turbines,	NO_x (syngas use)	Steam Injection to 15 ppm at 15% O_2
1765 MMBtu/hr Syngas Heat Input	NO_x (NG use)	Diluent Injection to 25 ppm at 15% O_2
	SO_2	Syngas cleanup to 40 ppm H_2S
	CO	Good Combustion Techniques and low VOC content of syngas fuel
	PM	Syngas Firing
	VOC	Good Combustion Techniques
Material Handling	PM	Enclosures
Flare	NO_x, SO_2, CO, PM, VOC	Good flare design
Cooling Tower	PM	High Efficiency Drift Eliminators
Wastewater Treatment	VOC	Good engineering design

BACT Determination Process

A "top-down" method was used to determine the best available control technology. In summary, the top-down process ranks all potentially available control technologies in descending order of control effectiveness. The most stringent or "top" alternative was evaluated first. That alternative was proposed as BACT unless the most stringent technology is not "achievable" in that case due to technical, energy, environmental, or economic considerations. If the most stringent technology was eliminated in this fashion, the next most stringent alternative was considered, and so on. Figure 1 lists the five steps in the process used and identifies some key items in each step. These elements are taken primarily from the EPA's *Draft New Source Review Workshop Manual* (October 1990).

Under no circumstances was a technology recommended that would not meet any New Source Performance Standards (NSPS) in 40 CFR Part 60. An NSPS defines the **minimum** level of control considered in the BACT analysis.

Figure 1 **Key Steps in a Top-Down BACT Analysis**

This clean coal technology can achieve very low emissions levels because of the nature its process. For example, NO_x emissions, even without Selective Catalytic Reduction (SCR), are lower than conventional coal-fired power plants with SCR. This is accomplished by gasifying the fuel in a low oxygen environment and creating a synthetic gas that can be efficiently cleaned before use in a gas turbine. NO_x is kept very low due to the ability to carefully control the gasification and combustion conditions and due to the overall thermal efficiency of the system. The conversion of the solid fuel to syngas also minimizes PM emissions and allows the removal of over 99% of the sulfur in the fuel before it is combusted in the gas turbine, minimizing the SO_2 emissions.

Examples of demonstrated control technologies permitted at conventional power plants were rigorously evaluated. However, Lima Energy's proposed Integrated Gasification Combined Cycle (IGCC) power station is not truly analogous to any conventional power plant. Its closest peers are three other operating IGCC in the United States. A few somewhat similar facilities are in the form of gasification cogen projects installed at refineries, such as a recent synthesis gas fired combined cycle project at a Star Enterprise facility in Delaware which was required to meet LAER. The proposed BACT control levels of approximately 15 ppm NO_x proposed by Lima Energy meet or exceed the levels achieved at these other IGCC facilities and the recent Star Enterprises LAER determination.

BACT for Oxides of Nitrogen (NO_x)

Gas Turbines

Nitrogen oxides (NO_x) are formed during the combustion of fuel in the turbine and are generally classified as either thermal NO_x or fuel-related NO_x. Thermal NO_x results when atmospheric nitrogen is oxidized at high temperatures to yield NO, NO_2 and other oxides of nitrogen. Fuel-related NO_x is formed from the chemically bound nitrogen in the fuel. For natural gas and syngas combustion, thermal NO_x formation is the dominant mechanism since there is little or no nitrogen bound in the fuel.

The rate of formation of thermal NO_x is a function of residence time and free oxygen, and is exponential with peak flame temperature. "Front-end NO_x" control techniques are aimed at controlling one or more of these variables. The most efficient front-end combustion controls for gas turbines include dry low NO_x combustors and diluent injection through the addition of water, steam, or nitrogen. "Add-on" controls attempt to chemically reduce the NO_x emissions after they are created through catalytic or non-catalytic techniques.

Step 1 - Identify All Control Technologies

In order to identify possible control technologies and emission rates, a review of EPA's RACT/BACT/LAER Clearinghouse and the California Air Resources Board databases was conducted. The results of these reviews provide a comprehensive list of NO_x control technologies that are used in industry today. Such a list is a good starting point for identifying available control technologies. (The complete survey results are in Appendix C of the permit application.)

It is also helpful to identify similar facilities in the area and state where the proposed facility will be located. In this way, we can identify acceptable emission standards in the region. Lima Energy has used this information to demonstrate that its NO_x emissions will not have a significant negative impact on ambient air quality.

The Lima Energy IGCC facility is unique because of the composition of the fuel that is fed to the turbines, synthesis gas. The nature of the syngas was described in Section 3.0 of the permit application, but a more detailed look at the gas makeup is helpful when reviewing capabilities of NO_x control technologies.

The following tables in the permit application summarize the information found:

- Table 6-2 Database Survey - Available NO_x Control Technologies;
- Table 6-3 Current NO_x emission levels at Region 5 facilities (existing and potential); and
- Table 6-4 Description of Lima Energy Fuel - Synthesis Gas

There are currently only three operating "clean coal" integrated gasification combined cycle facilities in the U.S. Although none of these facilities use the British Gas/Lurgi gasifier design, or use non-hazardous wastes as a component of their feed, they nevertheless are fairly comparable operations of the Lima Energy proposed project. These are Pinon Pine outside Reno, NV, Tampa Electric Polk Power Station in Lakeland, FL, and Wabash River in Terre Haute, IN. All are smaller than the proposed Lima Energy facility, and generally have higher permitted emission rates than those expected by L-E (See Table 6-5 of the permit application). The table illustrates NO_x control levels achieved in IGCC processes. To date, only steam injection has been proven as practicable NO_x emissions control. None of these IGCC processes employs SCR.

The Tampa Electric Polk Power Station was the first in the United States to use the advanced gasification combined cycle process in a full-size, commercial "grassroots" plant. The NO_x levels permitted for this facility are 25 ppmv @ 15% O_2. In size and operation, it is the most recent facility to be built that is similar to the plan for Lima Energy.

Another important comparison to note is a facility proposed in 1997 by Star Enterprise in Delaware, which was listed in the BACT/LAER database, and shown in Table 6-2 of the permit application. That facility will produce syngas through the gasification of petroleum coke in two Texaco gasifiers. This syngas will power two GE combustion turbines (90 MW each) which are designed for low sulfur diesel fuel as backup. The EPA database indicates that the lowest achievable emission rate (LAER) for this application was determined to be the use of nitrogen injection to control NO_x to 16 ppm at 15% O_2 and steam injection when firing low sulfur diesel fuel to control NO_x to 42 ppm at 15% O_2. We believe that this determination is the most recent comparable to the proposed Lima Energy project, and that similar control methods and emission limits are appropriate as BACT. This conclusion is discussed further in the remainder of this BACT analysis.

Based on the above described research and recommendations from OEPA, the following potential NO_x control technology options are evaluated in the BACT analysis:

- Dry-low NO_x;
- Moisturization and Diluent Injection ;
- Selective Catalytic Reduction (SCR); and
- $SCONO_x$™.

A description of each technology and its potential application to the syngas-fired turbines is included in the following section.

Step 2 - Eliminate Technically Infeasible Options

There are three important characteristics of syngas that must be considered in determining which control technologies are technically feasible for the IGCC system. First, the hydrogen content in syngas is significant (30%), whereas it is absent from natural gas. This creates significant differences in their combustion properties. Second, there is some sulfur in the syngas as a result of the high-sulfur coal raw material in the fuel briquettes. While most of the sulfur is removed by an acid gas cleanup process (as discussed in Section 6.3 of the permit

application), a small concentration of sulfur remains in the syngas. This impacts the feasibility of SCR and $SCONO_x$. Table 6-4 of the permit application displays the primary differences between the two fuels. The above referenced impacts are addressed in the following discussion. Lastly, other composition differences between syngas and natural gas, such as the presence of trace metals, cause additional feasibility and cost issues. For example, some of the trace metals expected to be present in the turbine exhaust are known catalyst poisons, which has caused vendors to be wary of providing a quotation for a SCR system and to refuse to provide a performance guarantee. These differences warrant the use of caution in judging feasibility or cost effectiveness.

Dry Low-NO_x Combustors

Dry-low NO_x combustors are not technically feasible for this application due to the potential for explosive mixtures (from the high hydrogen concentration in the syngas). A brief description of how the technology should work is given here.

Low NO_x combustors that operate without steam or water injection are referred to as dry low-NO_x combustors. The combustion chamber, or combustor, is the space inside the gas turbine where fuel and compressed air are burned. In conventional combustors, the fuel and air are injected into the combustor separately and mix in small, localized zones. The zones burn hot and produce significant amounts of NO_x. In contrast, dry low-NO_x combustors minimize combustion temperatures by providing a lean premixed air/fuel mixture, where air and fuel are mixed before entering the combustor. This minimizes fuel-rich pockets and allows the excess air to act as a heat sink. The lower temperatures reduce NO_x formation. However, because the mix is so lean, the flame must be stabilized with a pilot flame. Dry low-NO_x combustors in natural gas service can achieve emissions as low as 9 to 15 ppmvd NO_x (at 15 percent oxygen). Combustion modifications, such as low-NO_x burners reduce the concentration of NO_x emissions in the gas turbine flue gas by decreasing combustion temperature or decreasing the quantity of oxygen available for combustion.

As mentioned previously, dry-low NO_x combustors are not technically feasible for this application due to the potential for explosive mixtures in the combustion section. Figure 6-2 in the permit application is a formal statement from General Electric, the manufacturer of the turbines and dry-low NO_x systems, which details the incompatibility of syngas with this control equipment.

The turbine design will not accommodate installation of multiple burner types. Therefore, even though the turbines will fire natural gas as a start-up and backup fuel, dry-low NO_x burners cannot be installed in turbines that are designed to fire syngas.

Diluent Injection

The primary function of the addition of an inert diluent such as water and nitrogen into the syngas before use, and perhaps steam injection into the high temperature region of a combustor flame is to prevent NO_x formation by reducing the peak flame temperature. Higher combustion temperatures result in greater thermodynamic efficiency; however, higher temperatures also increase NO_x formation. Diluent addition during fuel gas conditioning reduces the heating value of syngas. Steam injection involves the injection of a controlled quantity of water or steam via a nozzle into the immediate vicinity of the combustion burner flame. NO_x emissions are reduced by cooling the combustion temperatures by either or both of these mechanisms. Water or steam injection can achieve emissions less than 15 ppmvd NO_x at 15 percent oxygen firing syngas fuel. Because of the higher heating value of natural gas fuel, diluent injection can only achieve emissions as low as 25 ppmvd NO_x at 15 percent oxygen. A secondary benefit of water/steam injection is increasing the density, and therefore the mass flow of the turbine exhaust and increase power output.

A negative attribute of water or steam injection is that the water or steam must be very pure before injection into the turbine. Any contaminants in the water or steam will cause a buildup of deposits on the turbine blades and other equipment. Deposits on the gas turbine blades reduce turbine efficiency, increase down time for

maintenance, and can lead to failure of the equipment in extreme circumstances.

Diluent and steam injection represents an inherently lower emitting process for syngas-fired turbines, and is a technically feasible control technology. Steam injection is the primary method that is proposed to reduce NO_x emissions for this Project.

Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) systems involve the post-combustion removal of NO_x from flue gas with a catalytic reactor. These systems selectively reduce NO_x by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. NO_x, ammonia, and oxygen react on the surface of the catalyst to form molecular nitrogen (N_2) and water. The primary chemical reactions are shown here.

$$4NO + 4NH_3 + O_2 = 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 = 3N_2 + 6H_2O$$

An SCR system is composed of an ammonia storage tank, an injection grid (system of nozzles that spray ammonia into the exhaust gas ductwork), a reactor which contains the catalyst and instrumentation, and electronic controls. An injection grid disperses NH_3 in the flue gas upstream of the catalyst, and NH_3 and NO_x are reduced to N_2 and water in the catalyst reactor. This control technique reduces both thermal NO_x and fuel NO_x in the exhaust streams.

In honeycomb-type catalysts, the size of the catalyst openings (i.e., pitch) is important. Smaller pitch equates to large surface area, and thus greater NO_x removal efficiency due to maximizing of the surface area on which the reactions take place. However, if the catalyst openings are too small, there is potential for clogging from contaminants. The residence time of the exhaust gases in the presence of the catalyst must be sufficient for the reactions to take place. The longer the exposure time of exhaust with the catalyst, the greater the resultant NO_x removal. Residence time is defined as the volume of the catalyst (e.g., ft^3) divided by the exhaust flow rate (ft^3/min). Additionally, certain potential compounds such as sulfur and several metals, if present in the exhaust gas stream, will "poison" the catalyst, reducing its performance and useful life.

The turbine exhaust gas must contain a minimum amount of oxygen and be within a particular temperature range in order for the selective catalytic reduction system to operate properly. The temperature range is dictated by the catalyst, which is typically made from noble metals, base metal oxides, or zeolite-based material. The typical temperature range for base-metal catalysts is 600 to 800°F. Keeping the exhaust gas temperature within this range is important. If it drops below 600°F, the reaction efficiency becomes too low and increased amounts of NO_x and ammonia will be released out the stack. If the reaction temperature gets too high, the catalyst may begin to decompose. For combined cycle units (such as this project), the ideal temperature window occurs within the heat recovery steam generator.

Selective catalytic reduction uses ammonia as a reducing agent in controlling NO_x emissions from gas turbines. The portion of the unreacted ammonia that passes through the catalyst and is emitted from the stack is called ammonia slip.

SCR has never been employed at an IGCC facility. For all prior installations, it has not been considered technically feasible, because of the problems created by the unique composition of syngas. Most significant is the fact that the syngas contains sulfur, as well as several compounds that act as a catalyst poisons. Sulfur, even at relatively low levels, in the gas turbine exhaust would react with the ammonia added for the SCR and create ammonium bisulfate salts. These salts would cause serious plugging, loss of heat transfer and corrosion in the downstream portions of the heat recovery steam generator. Other composition differences between synthesis gas and other fuels where SCR has been applied could cause additional feasibility or cost concerns. Because of these issues and because of a lack of testing or research about SCR in a syngas application, most SCR catalyst vendors

are not interested in providing SCR for such an application. In fact, no vendors have been identified who would warrant SCR system performance if it were installed.

Regarding the ammonium bisulfate problems unique to SCR use on a combined cycle turbine with sulfur bearing fuels, the following provides further details of this issue. The oxidation of sulfur present in the synfuel during fuel combustion produces SO_2 and a small portion of SO_3. Additionally, the vanadium in the SCR catalyst will oxidize more of the SO_2 in the flue gas to SO_3. The ammonia present in the flue gas will react with the SO_3 to form ammonium sulfate and bisulfate salts. These salts can cause serious corrosion and plugging/fouling problems in a conventional HRSG. This is a serious concern, even at the relatively low levels of sulfur present in the syngas feed.

These ammonium salts would deposit onto heat transfer fins located inside the HRSG. As the flue gas passes over the heat transfer fins of the HRSG, ammonium sulfate and bisulfate condense from the gas and deposit directly onto the fins. The heat transfer efficiency of the fins gradually decreases as they become increasingly fouled with deposits. Power output from the turbine can also be significantly affected due to an increase in pressure drop within the HRSG resulting from the partial blockage of gas flow by these deposits. This pressure rise can also impact HRSG casing design requirements. In addition, ammonium bisulfate is highly corrosive and can corrode the heat transfer fins or tubes, impacting their design and reliability.

As deposits of ammonium salts increase, they would need to be cleaned from the surface of heat transfer fins in order to restore heat transfer efficiency and pressure within the HRSG. Adequate cleaning of the fins is not possible in a conventional designed HRSG because of the following:

- Access to interior tube banks in an HRSG is restricted;
- HRSG heat exchange elements are not designed for removal/replacement; and
- The catalyst in an HRSG is in close proximity to areas that would need water washing increasing the possibility of inadvertent wetting of the catalyst.

A second significant difference between synthesis gas and natural gas is the greater presence of metals in synthesis gas, which are known to deactivate the sensitive SCR catalyst. For example, SCR is impacted by compounds such as arsenic, even at very low levels (significantly below levels which might be health risk concerns). It is very hard to have confidence in any predicted system performance, control efficiency, or catalyst life for this unique application.

Some of these same deactivator compounds are present in the exhaust from distillate fuel fired gas turbines. While there are many gas turbines permitted with SCR and planned for use with distillate fuel as a backup fuel, there is very little actual operating experience using distillate fuel. Most units permitted with oil backup operate less than 500 hours per year on the backup fuel. Where distillate fuel has been used as a significant portion of the fuel, our investigation found that all such facilities were experiencing very significant problems such as plugging in the HRSG and catalyst deactivation. There is significant evidence to question whether SCR can reliably be used in such a service. Additionally, the industry experience with distillate fuel doesn't address any possible additional problems from synfuel's unique feedstocks.

There also is a growing experience base of SCR use in conventional coal combustion applications, which typically have many of these same exhaust gas characteristics, in many cases, at higher concentrations (See Table 3-5 of the permit application). However, key differences with a coal-fired system application include:

- SCR performance expectation in conventional coal service is significantly lower (i.e., higher outlet NO_x) than would be needed in this case. Coal SCR systems typically achieve 0.1-0.4 lb NO_x/MMBtu after SCR which is higher than the Lima Energy project proposes achieving (approximately 0.07 lb/MMBtu)

without any add-on controls;

- Ammonium bisulfate salts would form in the coal plant's air preheater, which is well-suited to handling precipitation/deposits/corrosion. An air preheater is easier to clean and replace components, and heat transfer is not inhibited by deposits. An air preheater is also not harmed as much by corrosion as the heat transfer fins in a HRSG; and

- Though likely not a large issue, the Lima Energy project's use of municipal waste or sludges as a component of the feedstock adds the potential of introducing additional compounds to the syngas not otherwise common in coal combustion exhaust.

The above issues raise serious questions of technical feasibility regarding attempting to apply SCR to this unique project. In evaluating this technology and the seriousness of these concerns, four SCR catalyst system providers were contacted. D.B. Riley declined to provide an estimate for our specific application. Hitachi failed to respond to repeated requests for a quotation over several months. Englehard provided a cost for a system designed for clean gas service, but would not quote on a coal-based synthesis gas application. Only Cormetech was willing to provide a quote for this project (attached). However, based on the above issues and the lack of any experience with this unique application, they are unwilling to guarantee the system's performance beyond initial startup.

The information presented here related to the feasibility of SCR to this application is summarized in the following statements:

- SCR has never been used in a synthetic gas application;

- No catalyst vendor is currently willing to warrant system performance;

- Most catalyst vendors are not even willing to propose participation in the project;

- Syngas exhaust contains sulfur, metals and possibly other compounds known to deactivate SCR catalyst or cause other problems;

- We are unaware of any research, testing, or design that has ever been done on SCR in a synthetic gas application;

- The above issues and unknowns raise significant questions about the expected performance and costs of SCR in this unique application;

- Previous BACT and LAER evaluations of synthesis gas-fired turbines have never required SCR; and

- The project proposed NO_x performance level is as low or lower than any truly similar application.

This information is analyzed below in relation to EPA's guidance (Draft NSR Workshop Manual) regarding determining technically availability and feasibility.

The fact that no vendor will guarantee the performance of SCR in this application is a strong indication of the lack of availability and the infeasibility of this technology for this application. EPA guidance suggests that such an indication can contribute to a determination of infeasibility, but that it alone is not sufficient justification. In addition to vendor feedback, a feasibility determination should also be based on physical, chemical, and

engineering principles.

In that regard, the earlier discussion outlined several chemical and design issues that significantly differentiate the potential use of SCR in this service verses other services where it has been successfully employed. These issues are pertinent to the successful operation of SCR and the reliable operation of the HRSG. Whether or not the problems outlined could be resolved, and if so, at what cost, is a difficult question to address. To truly resolve these feasibility issues, significant additional work would be required. Without additional testing and research specific to syngas, any cost estimate would have very little foundation and could vary significantly depending on the degree of aggressiveness or conservatism employed. On top of the already very high base costs for SCR, reasonable assumption attempting to address the above issues could double or triple the total costs, easily pushing them past the point of cost-effectiveness.

Additional testing and research on SCR in this service is necessary to gain confidence in estimating system performance in this service or assigning costs to the above issues. The need for such testing is illustrated by looking at the process commonly used for developing a new control technology. Such a process follows these steps (as outlined in EPA's Draft NSR Workshop Manual):

- Concept stage;
- Research and patenting;
- Bench scale or laboratory testing;
- Pilot scale testing;
- Licensing and commercial demonstration; and
- Commercial sales.

EPA does not consider a technology "available" until it has reached at least the last two above steps. While SCR is clearly an "available" technology and commercially demonstrated for many applications, within the above context, SCR is only at the "concept stage" for synthetic gas fired gas turbines. We are unaware of any research or testing (at any scale) that has been done on this unique application. Most vendors are not interested in selling SCR for this application because there are currently many unknowns and there are currently not enough applications of this type to justify the significant risks and necessary research. This project should not have to experience extended delays, significant costs, or extended trials to learn how to apply this expensive control technology on this new dissimilar source type.

Because of the lack of vendor confidence, the lack of experience with this source type, and because of the currently unresolvable technical difficulties, SCR is judged to be infeasible for this application. This finding is consistent with previous BACT and LAER determinations for synthetic gas fired gas turbines.

SCONO$_x$™

Another emerging catalytic reduction technology is SCONO$_x$™. SCONO$_x$™ is a catalytic oxidation and absorption system being developed by Goal Line Environmental Technologies. SCONO$_x$™ is a low-temperature back-end control system that operates effectively from 300 to 700°F. The NO_x is absorbed onto the catalytic surface using a potassium carbonate (K_2CO_3) absorber coating. The potassium carbonate coating reacts with the NO_2 to form potassium nitrites and nitrates that are deposited onto the catalyst system. The reactions are shown here.

$$NO + \frac{1}{2} O_2 = NO_2$$

$$2NO_2 + K_2CO_3 = CO_2 + KNO_2 + KNO_3$$

When all of the potassium carbonate absorber coating has been converted to nitrogen compounds, NO_x can no longer be absorbed and the catalyst must be regenerated. Regeneration is accomplished by passing a dilute hydrogen reducing gas across the surface of the catalyst in the absence of oxygen. Hydrogen in the gas reacts with the nitrites and nitrates to form water and molecular nitrogen. Carbon dioxide in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst.

$$KNO_2 + KNO_3 + 4H_2 + CO_2 = K_2CO_3 + 4H_2O_{(g)} + N_2$$

The regeneration gas is produced by reacting natural gas with oxygen from ambient air. A gas generator uses a two-stage process to produce hydrogen and carbon dioxide. In the first stage, natural gas and air are reacted across a partial oxidation catalyst to form carbon monoxide and hydrogen. Steam is added to the mixture and then passed across a low temperature shift catalyst, forming carbon dioxide and more hydrogen. The mixture is diluted to less than 4 percent hydrogen using steam.

To date, the only commercial installation of the $SCONO_x$™ process is on the Federal Plant in Los Angeles, California. This natural gas combustor is a small 25 MW facility. In evaluating technical feasibility to the large Lima Energy facility, the project has the following concerns:

- $SCONO_x$™ uses a series of dampers to regenerate the catalyst. The L-E facility is significantly larger than the Federal facility. This would require a redesign of the dampening system, which causes concern about adequate operation of the larger dampers.

- The catalyst is very susceptible to poisoning by sulfur. Because of the sulfur content of the syngas, a catalyst to absorb SO_2 would be required. Goal Line offers a SCOSOx catalyst; however, its operation is not proven and it would create an H_2S stream that must be treated.

- Goal Line is the proprietary provider of these catalysts, which has raised concerns regarding long-term catalyst availability and pricing.

- $SCONO_x$™ has been licensed to ABB Environmental Systems, Inc. for commercialization in the large turbine market; however, according to ABB, $SCONO_x$™ will not be made available for application to large combined cycle units for at least 12 months, and there are no current applications on large turbine units.

Therefore, $SCONO_x$™ is not considered technically available for this Project.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Control technologies for the technically feasible and available technologies are next ranked in order of effectiveness. Based on the analysis in Step 2, diluent injection is the only technically feasible control option for this project. The ranking is shown in Table 6-7 of the permit application.

In order to estimate the baseline NO_x emissions and potential reductions, assumptions were made about the amount of time that syngas and natural gas would be fired. The long-term average emissions case used in this BACT analysis assumes an average use of the backup natural gas fuel for 15.8 % of the time (15.27 x 10^6 MMBtu/yr). The long-term average annual natural gas usage was derived assuming use of the backup fuel at full-load for 12.5 % of the time (1.5 months/year) over the 15-year life of the add-on control, with the exception of the first two years. The gas turbines were assumed to operate 50% of the time on natural gas during the first year of operation and 25% the following year. The allowance for a higher percentage of backup fuel use during

the first two years covers potential startup problems or construction delays. The long-term average emissions rate (based on firing syngas 84.2% of the time at 15 ppmvd NO_x and firing natural gas 15.8% of the time at 25 ppmvd NO_x) using diluent injection as the base control method results in an average of 16.6 ppmvd NO_x at 15% oxygen.

Step 4 - Evaluate Most Effective Controls and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each feasible control technology. Based on the evaluation in Step 3 above, the only feasible NO_x control option for this Project is water/steam injection.

Step 5 - Select BACT for NO_x Control

The final step in the top-down BACT analysis process is to select BACT. For this unique application of a syngas-fired gas turbine facility, fuel moisturization and diluent injection is chosen as BACT. This technology will achieve an emission rate of 15 ppm NO_x at 15% O_2 for syngas firing and 25 ppm NO_x at 15% O_2 for natural gas firing. Based on a long-term average of no more than 15.8% natural gas firing, this corresponds to an average emission rate of 16.6 ppmvd NO_x.

The BACT selection of diluent injection to the NO_x levels described above is strongly supported by the evidence of both technical feasibility and cost-effectiveness. This selection is further justified by the designation of diluent injection as LAER for a similar syngas-fired combined cycle turbine project in Delaware, to 16 ppm NO_x at 15% oxygen for syngas firing and 42 ppm NO_x with diesel fuel firing (As listed in Table 6-2 from EPA's RBLIS database). A conversation with Ravi Rangan of the Delaware Department of Natural Resources and Environmental Control (5/5/00) confirmed that SCR was rejected as technologically infeasible for syngas-fired turbines based on relatively high amounts of sulfur in the fuel (compared to natural gas) that would form heat-stable salts and cause fouling in the system.

SCR and $SCONO_x$ have been determined to have significant problems regarding the technical feasibility of their application to syngas combustion turbines. Therefore, fuel moisturization / diluent injection is the next most stringent and technically feasible control technology, and is the best available option. We strongly believe this is a justifiable option for BACT, as is evidenced by the fact that the same control method was approved as LAER for a similar project in Delaware as described above.

Flare

Venting to the flare will only occur during emergency situations. The gasifier system can be shutdown rapidly through removal of oxygen and steam injection and solid fuel addition, which allows isolation of the reactor. This will avoid a flare or vent release of raw syngas; therefore, the potential emissions of NO_x are negligible. The maximum expected emissions of NO_x from the flare is 0.05 TPY. Good flare design is considered BACT for this level of emissions from the flare.

BACT for Sulfur Dioxide (SO_2)

Gas Turbines

The combustion of syngas in the gas turbines creates sulfur dioxide by the oxidation of the sulfur species in the fuel. Sulfur dioxide emissions from any combustion process are directly related to the sulfur content of the fuel being combusted. Emissions can be controlled either by limiting the sulfur content of the fuel or by scrubbing the SO_2 from the exhaust gas.

Step 1 - Identify All Control Technologies

The most common technologies used in the control of sulfur dioxide are amine-based gas cleanup operations and add-on control technologies such as flue gas desulfurization systems. Other alternatives to sweetening liquids with amines are caustic wash and molecular sieves. Amine-based gas cleanup is a step in the syngas production process that reduces sulfur content in the fuel for the turbines. Flue gas desulfurization (FGD) is a term that may refer to any chemical process used to remove SO_2 from combustion exhaust gases.

An FGD application usually operates by contacting the exhaust gas with an alkaline slurry or solution that absorbs and subsequently reacts with the acidic SO_2. FGD technologies may be wet, semi-dry, or dry based on the state of the reagent as it leaves the absorber vessel. Also, the reagent may be regenerable (where it is treated and reused) or nonregenerable (all waste streams are de-watered and discarded). Wet, calcium-based processes, which use lime (CaO) or limestone ($CaCO_3$) as the alkaline reagent, are the most common FGD processes in utility boiler applications. After the exhaust gas has been scrubbed, it is passed through a mist eliminator and exhausted to the atmosphere through a stack (EPRI, 1990).

Amine-based gas cleanup is a reduction type scrubbing process, commonly used for "gas sweetening" processes in refinery fuel gas or tail gas treatment settings where H_2S in the process gas may be treated before use as a fuel or release to the atmosphere. Fuel gas cleanup is not found in coal fired utility boiler applications because it is not technically feasible to clean up the fuel until after it has been combusted and the sulfur is in the form of sulfur dioxide.

Step 2 - Eliminate Technically Infeasible Options

Both amine-based gas cleanup and FGD as an add-on control would be feasible for use with Lima Energy's IGCC facility. The large volumes of syngas in this application make caustic wash and molecular sieves undesirable options due to prohibitive capital and operating costs, and disposal problems, as well as the fact that they do not provide any higher level of treatment than the other options. The two former options are the only ones to be considered in this analysis.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The applicant proposes that SO_2 emissions from the gas turbines will be minimized through treatment of the syngas with amine based gas scrubbing which will remove greater than 99% of H_2S in the syngas. The gas will be treated to achieve approximately 40 ppmv H_2S. This is as low or lower than the levels required and demonstrated at other similar sulfur removal applications. A comparison of different control methods and their effects on SO_2 emissions is shown in Table 6-8 of the permit application.

The syngas initially produced will contain as much as 0.5 % sulfur, primarily in the form of H_2S. After cooling, the syngas will be routed through a scrubbing tower where it will be contacted with a selective amine-type solvent which will absorb over 99 % of the sulfur, bringing the syngas sulfur content down to less than 40 ppm. Syngas at this reduced level of sulfur will result in combustion turbine SO_2 emissions of less than 0.04 lb/MMBtu.

Lima Energy's emission rate compares very favorably with SO_2 emissions BACT determinations for recent coal fired sources which average 0.25 lb/MMBtu and are no lower than 0.13 lb/MMBtu (See Table 6-9 of the permit application). This is one major environmental advantage to the coal gasification process. The proposed level of syngas treatment to 40 ppm maximum H_2S concentration represents the practical limitations of the technology and is, for perspective, significantly below the stringent NSPS Subpart J allowed concentration (160 ppm) for new petroleum refinery combustion devices. There are a few different amine based technologies (with slightly different amine/chemical solutions) however, all use the same basic principles and achieve comparable levels of sulfur removal.

Step 4 - Evaluate Most Effective Controls

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The top-down process requires that the evaluation begin with the most effective technology. The top technology is amine-based gas cleanup with the highest rate of emissions reduction. The energy and economic impacts of acid gas removal will be less than those involved with the installation of an add-on FGD system.

An additional control option considered is the possible combination of an FGD system for post-combustion SO_2 control following the pre-combustion gas treatment of the amine system. After amine-based treatment of the syngas to 40 ppm H_2S content, the approximate level of SO_2 in the combustion gases is 8 ppm. FGD systems are much less efficient at such low concentrations and high flow rates, because there is less tendency for mass transfer to occur. For comparison, FGD systems applied to coal-fired boilers are typically treating gas streams with a few percent of SO_2 in the exhaust, rather than the few parts per million levels present in this IGCC project.

If it were possible to get additional SO_2 removal by adding on FGD, recent data indicates that FGD system capital costs at a typical coal-fired power plant are approximately $100 per kW. (Ref: Maller, G. *Status of Flue Gas Desulfurization (FGD) Technology*, March 2000 at Seventh Annual APEC Technical Seminar.) Applying this rough cost basis to the proposed 197 MW gas turbines yields an estimated capital cost of $19.7 million per turbine. Even assuming a 95 % reduction of SO_2 for the FGD system (unlikely for this application), the annualized capital recovery cost is greater than $15,000/ton.

This high cost value does **not** include annual operating costs, and uses an unrealistically high value for tons of additional SO_2 reduced. The actual SO_2 reduction efficiency would clearly be much less than 95% for a system with very low concentrations of SO_2 in the uncontrolled exhaust gas. A smaller reduction in tons of SO_2 would increase the dollars per ton cost-effectiveness. Therefore, the addition of FGD following the amine treatment system is clearly not a cost-effective option for this application.

Step 5 - BACT for SO_2

The amine-based technology for syngas cleanup has the highest rate of emissions reduction. Technology options such as post-combustion sulfur treatment (FGD) on the exhaust gas from the gas turbines rather than pretreating the syngas would provide no greater benefit and are less practical because of the high volumes of exhaust gas and the low sulfur concentrations. A combination system with FGD as an add-on control following amine pre-treatment would clearly not be cost-effective due to the high cost of FGD systems and the relatively small amount of incremental sulfur reduction. For these reasons, the top technology, amine based gas cleanup is chosen as BACT for SO_2 emissions from the gas turbines.

Sulfur Plant

Sulfur still exists in the acid gas process stream from the syngas cleanup in the form of H_2S. At this point in the process, it is sent to a sulfur plant to recover the H_2S as elemental sulfur, which is sold as a by-product. The various ways to control this stream are discussed in this section.

Step 1 - Identify All Control Technologies

Sulfur recovery involves the conversion of H_2S to elemental sulfur, which is a sellable product. The most widely used conversion method for sulfur recovery is the Claus process (USEPA, 1996). A few other exotic processes are used in unique circumstances, but offer no higher level of control. After the acid gas cleanup, the scrubbed sulfur is steam stripped off the solvent and routed to a sulfur recovery plant, where it will be converted to elemental sulfur. This is accomplished in special reactors utilizing the Claus reaction ($2H_2S + SO_2 \rightarrow 3S + 2H_2O$). Approximately 95% of the sulfur is converted to elemental sulfur and removed. The exhaust or tail gas

from this process is typically then routed to a tail gas treatment process and then vented or incinerated.

However, the proposed facility will recycle this tail gas stream back to the gas treatment process where the remaining sulfur is again absorbed by the selective amine solvent and the other exhaust becomes part of the syngas.

The proposed "total recycle" scheme will avoid a separate emissions point for the sulfur plant, and will reduce total emissions by maintaining total syngas sulfur content to the previously referenced levels, even with the addition of this stream. A more complete description of this sulfur removal and recovery process is included in Section 3.0 of this application.

Step 2 - Eliminate Technically Infeasible Options

Amine based absorption and Claus reaction based sulfur recovery technology are the gas cleaning techniques used in all recent sour gas treatment permit evaluations for the refining, gas, and power industries. Conventionally, however, this tail gas would be routed to an incinerator and vented out a tail gas stack. Both rerouting the Claus exhaust back to the gasifiers, and tail gas treatment/incineration are feasible options downstream of the Claus unit.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Table 6-10 of the permit application shows that the proposed sulfur recovery with tail gas recycle represents maximum control effectiveness. Elimination of the Claus tail gas emission point with tail gas recycle is superior to any alternative control technology for sulfur recovery.

Step 4 - Evaluate Most Effective Controls

The top technology of recycling the Claus plant waste stream represents the minimum impact as far as energy, environmental, and economic concerns versus incinerating the tail gas. The use of IGCC technology provides this unique opportunity.

Step 5 - BACT for SO_2

The applicant proposes the use of a syngas treatment process that will remove the sulfur from the syngas, convert it to elemental sulfur using a Claus process, and further reduce the SO_2 emissions by recycling the tail gas stream back to the gasifiers. These processes are proposed as BACT for sulfur recovery operations.

Flare

SO_2 emissions are minimized from the pilot flame by the use of clean natural gas as the pilot. Other venting to the flare will only occur during emergency situations. The gasifier system can be shutdown rapidly through removal of oxygen injection and solid fuel addition, which allows isolation of the reactor. This will avoid or minimize a flare or vent release of raw syngas; therefore, the emergency emissions of SO_2 are expected to be small. In emergency situations where possible, the syngas will be routed through the sulfur recovery process prior to venting at the flare, thus further reducing SO_2 emissions. Given minimal emissions, no control technologies are cost effective.

BACT for Carbon Monoxide (CO)

Gas Turbines

Carbon monoxide (CO) is formed as a result of incomplete combustion of a fuel. When a hydrocarbon fuel burns completely, the oxygen in the air combines with the hydrogen to form water and carbon dioxide (CO_2). If the combustion is incomplete then CO and VOC emissions are formed. Control of CO is accomplished by providing adequate fuel residence time and high combustion temperature in the combustion zone. As described earlier, low NO_x emissions are achieved through flame temperature control (by water or steam injection), which can result in higher levels of CO emissions.

The review of catalytic oxidation systems has been considered only after selection of appropriate NO_x controls. Utilizing syngas moisturization and steam injection to limit gas turbine exhaust gas to 16.6 ppmv NO_x at 15% oxygen (O_2) will achieve NO_x control.

The turbine design and combustion efficiency that will yield this concentration of NO_x is also expected to produce CO emissions at a reduced level of 16.6 ppmv. This is considered utilizing good combustion practices, and serves as the base case for comparison.

Step 1 - Identify All Control Technologies

Based on a review of the U.S. EPA's BACT/LAER Clearinghouse database and Radian's recent permitting experience, two CO control options were examined for the proposed combustion turbines: 1) catalytic oxidation; and 2) good combustion practices.

Catalytic Oxidation

In catalytic oxidation, turbine exhaust gas passes through a catalyst bed (typically platinum/rhodium) where oxidation of CO takes place. The catalyst has an operating temperature of 500°F - 1500°F and an optimum temperature range of 650°F - 1100°F. Hydrocarbons that are present in the exhaust gas are also oxidized to CO_2 and water vapor. As stated above, catalytic oxidation is capable of reducing CO levels by 90 percent; and for this application, the resulting gas turbine CO emission rate would be 1.66 ppmvd. Table 6-11 of the permit application outlines the energy and economic impacts of catalytic oxidation relating to CO control of 90%.

Another factor to consider is that CO catalysts are easily poisoned by metals, especially heavy metals and arsenic in the gas stream. The sulfur content of the gas stream also determines the operational life of the catalyst. Since the fuel to the gas turbine is syngas from coal/solid fuel gasification, it contains trace amounts of metals and sulfur in the flue gas. Additionally, variations in the concentrations of the contaminants can reduce catalyst life and significantly increase the cost of catalytic oxidation.

Combustion Controls

Good combustion practices in gas turbines involve combusting the fuel as efficiently as possible to reduce CO emissions. This requires proper air-to-fuel ratio and turbine design to achieve good mixing and turbulence, adequate temperature and residence time.

Step 2 - Eliminate Technically Infeasible Options

Both catalytic oxidation and combustion controls are technically feasible alternatives for CO control for this project. The combustion conditions that are favorable for NO_x control to 16.6 ppmvd are used as the base emissions level for this project.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

A review of the RBLC shows that the emission limits for CO and VOC from natural gas-fired turbines using a catalyst are both approximately in the 2 ppmvd range. Catalyst vendors quote a control efficiency of 80 to 90 percent for CO. There is no NSPS limit for CO emissions for gas turbines.

For the L-E facility, the turbine vendor has indicated that proper operation of the turbine will result in CO emissions of 15 ppmvd and VOC emission levels of 3.5 ppmvw while combusting the primary fuel, which is syngas. During natural gas firing, CO emissions are expected to be 25 ppmvd. A comparison of different control methods and their effects on CO emissions is shown in Table 6-11 of the permit application.

In order to estimate the baseline CO emissions and potential reductions, assumptions were made about the amount of time that syngas and natural gas would be fired. The long-term average emissions case used in this BACT analysis assumes an average use of the backup natural gas fuel for 15.8 % of the time (15.27 x 10^6 MMBtu/yr). The long-term average annual natural gas usage was derived assuming use of the backup fuel at full-load for 12.5 % of the time (1.5 months/year) over the 15-year life of the add-on control, with the exception of the first two years. The gas turbines were assumed to operate 50% of the time on natural gas during the first year of operation and 25% the following year. The allowance for a higher percentage of backup fuel use during the first two years covers potential startup problems or construction delays. The long-term average emissions rate (based on firing syngas 84.2% of the time at 15 ppmvd CO and firing natural gas 15.8% of the time at 25 ppmvd CO) using diluent injection as the base control method results in an average of 16.6 ppmvd CO.

Step 4 - Evaluate Most Effective Controls and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The top-down process requires that the evaluation begin with the most effective technology. The top technology is an oxidation catalyst. Combustion control is the control technique proposed for this project. Since the top alternative is not proposed for this project, the cost, environmental, and energy impacts must be examined.

Oxidation catalysts have associated environmental, energy, and cost impacts. The environmental impact associated with oxidation catalysts is the generation of acid gas emissions. In addition to oxidizing CO and VOC to CO_2 and water, the catalyst converts SO_2 to sulfuric acid mist. Use of a catalyst to control one pollutant could cause emissions of another pollutant, sulfuric acid mist.

Disposal of spent catalyst could also represent an environmental impact. The catalysts used must be replaced approximately every three to six years. The catalyst contains heavy metals that may cause the spent catalyst to be considered a hazardous waste. Catalyst vendors, however, typically accept return of spent catalysts for recovery and reuse of the catalyst's precious metals.

There are also energy impacts associated with CO catalysts. There is a power output penalty and a fuel penalty associated with use of a catalyst. The increased backpressure in the turbine that results from adding the catalyst increases the heat input required and reduces the power output.

The Combustion Turbine Work Group of the Industrial Combustion Coordinated Rulemaking (ICCR), prepared a document dated 4 September 1998 *Cost-Effectiveness of Oxidation Catalyst Control of Hazardous Air Pollutant (HAP) Emissions from Stationary Combustion Turbines.* The document evaluated oxidation catalysts for gas turbines and includes an estimate of the increased heat rate input required to compensate for the pressure drop associated with the catalyst. The Work Group used a heat rate increase of 0.105% per inch of pressure drop measured in inches of water. The document goes on to say that this is a low estimate and that most turbines would experience a higher increased heat rate requirement. For heavy-frame turbines, the document cites a "rule of thumb" estimate of 0.15% per inch of pressure drop. The analysis in the document assumed a pressure drop of 1 inch.

There are also significant cost impacts associated with oxidation catalysts. A cost estimate for oxidation catalyst installation and operation has been prepared for the L-E facility and is provided in Table 6-12 of the permit application. This estimate is based on information in the ICCR document discussed above and costing factors from EPA's OAQPS Control Cost Manual.

The cost associated with CO catalysts is $ 6,796 per ton of CO controlled. This is considered to be the incremental cost between the oxidation catalyst and combustion control. No costs are associated with the combustion control option because it is integral to the turbine design, and separating it for the purposes of assessing control costs is not possible.

Step 5 - BACT for CO

The final step in the top-down BACT analysis is to select BACT. Combustion control with an associated average CO emission rate of 16.6 ppmvd is chosen as BACT for this project. This technology will achieve an emission rate of 15 ppm CO at 15% O_2 for syngas firing and 25 ppm CO at 15% O_2 for natural gas firing. Based on a long-term average of 15.8% backup natural gas firing, this corresponds to an average emission rate of 16.6 ppmvd CO. Oxidation catalyst is not chosen as BACT due to strong negative economic impacts along with the associated environmental and energy impacts.

Flare

As a product of combustion, CO will be emitted from the flare. Good flare design and good combustion practices will limit these CO emissions. Given minimal emissions, no control technologies are cost effective.

BACT for Volatile Organic Compounds (VOC)

Gas Turbines

The gas turbines, though the syngas fuel is low in VOC components, have the potential to emit VOC as a product of incomplete combustion. As described in the above section for CO, the conditions that promote complete combustion, and therefore reduce VOC emissions also increase NO_x emissions. VOC emissions from syngas firing and steam injection to reduce NO_x to 15 ppm in the gas turbine results in expected emissions of 3.5 ppm.

Step 1 - Identify All Control Technologies

A search of the BACT/LAER database did not reveal any gas turbine installations with add-on controls; however, catalytic oxidation is a common control technology used to control VOC, as well as CO (See Section BACT for CO above).

Step 2 - Eliminate Technically Infeasible Options

The control techniques discussed above have both been used in practice, and are thought to be technically feasible for this process.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

A review of the RBLC shows that the emission limits for CO and VOC from natural gas-fired turbines using a catalyst are both approximately in the 2 ppmvd range. Catalyst vendors quote VOC control efficiencies in a range of 22-95 percent. The percentage removal used in this analysis is 80% -- it has been shown to be achievable in catalytic oxidation cost documentation (CTWG, 1998). There is no NSPS limit for VOC emissions

for gas turbines. A comparison of different control methods and their effects on VOC emissions is shown in Table 6-13 of the permit application.

Economic impacts must be considered in the evaluation of catalytic oxidation. A cost analysis was performed to determine the costs involved with catalytic oxidation as a control method for VOC emissions. This cost analysis uses a system cost as calculated in Table 6-11 of the permit application for CO removal (same annualized costs). The Purchased Equipment Cost remains the same in both analyses because it is based on the exhaust flow rate from the turbines. The calculations yield a cost effectiveness of over $55,000/ton VOC removed. The details of these calculations (in-depth capital cost description) are in Appendix D.

Step 4 - Evaluate Most Effective Controls and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The top-down process requires that the evaluation begin with the most effective technology. The top technology is an oxidation catalyst. Combustion control is the control technique proposed for this project. Since the top alternative is not proposed for this project, the cost, environmental, and energy impacts must be examined.

Oxidation catalysts have associated environmental energy, and cost impacts. These impacts were all discussed in Step 4 of the top-down analysis for CO. The cost impacts, however, are significantly greater in the case of VOC removal. As shown in Step 3, the catalytic oxidation cost effectiveness of over $55,000/ ton VOC removed far exceeds all practical expectations for a control method.

Step 5 - BACT for VOC

VOC will be controlled through the use of good combustion practices. This constitutes BACT for VOC from gas turbines. Additional controls would not be cost effective.

Flare

The combustion of natural gas in the emergency flare will have the potential to emit VOCs. These emissions will be minimized through good flare design and the use of good combustion practices. Given minimal emissions, no control technologies are cost effective.

Wastewater Treatment

Wastewater Treatment is a minor contributor to facility VOC emissions. The wastewater produced by the L-E facility will be treated prior to discharge. There are an estimated 1.9 TPY potential VOC emissions from the facility, based on the treatment of 10% of the total water intake at the facility, 50 ppm VOC in the wastewater, an EPA-documented percentage of uncontrolled emissions at petroleum processing facilities (50%), and a 50% control efficiency. BACT for these emissions will be enclosed piping and storage of any wastewater containing free-phase hydrocarbons to minimize evaporation of pollutants to the atmosphere.

BACT for Particulate Matter (PM)

Gas Turbines

Emissions of particulate matter (PM) and particulate matter less than 10 micrometers in diameter (PM_{10}) from the combustion turbine result from inert solids (ash) contained in the fuel, unburned fuel hydrocarbons which agglomerate to form particles, and mineral matter in the water injected into the turbine for NO_x control. All of the particulate matter emitted from the turbine is assumed to be less than 10 micrometers in diameter.

Syngas is a clean burning fuel. Such fuels are required for combustion turbines in order to prevent damage to the turbine blades and other high-precision turbine components. The installation of a particulate control device on a turbine firing clean fuels is considered to be impractical. Syngas contains essentially no inert solids (ash).

Neither electrostatic precipitators nor fabric filters are considered to be technically feasible options for combustion turbines because of the high exhaust flow rates low particulate loading associated with turbine exhaust. Additionally, the particle resistively associated with gas turbine exhaust is a problem for ESPs. ESPs remove particles by charging the particles and then collecting them on plates. ESP performance is greatly affected by the particles's ability to accept and maintain a charge. Because of the resistively of the exhaust particles from gas turbines, ESPs are not effective for control of turbine particulate matter control.

The only remaining control method is the use of clean burning syngas fuel; therefore, it is BACT for this project.

Fuel Briquette Handling

The briquettes are received by railcar, stored on a covered storage pile, moved by closed conveyors to a feed bunker hopper on top of the gasifier structure. During the transport, storage, and various handling activities, there is potential for the emission of particulate matter into the atmosphere. Wet suppression and partial enclosures are the two control techniques often used to reduce PM emissions from material handling activities. The rail car dump of briquettes is performed in an enclosed area. Emissions from conveyors are limited by the partial enclosure of the conveyor system. These techniques constitute BACT for material handling activities, and yield a control efficiency of 70%-90%. Wet suppression is not practical for this application because wetting the briquette would negatively impact their integrity; however, the fact that the briquettes are compressed manufactured fuel products directly reduces particulate emissions because they have very few low fines content.

Vitrified Frit Handling

Frit is generated in the gasification process. It is the solid slag product that contains the ash content of the solid feed to the gasfiers. It is approximately 1/4 in. or less mesh, and remains as large coarse particles, with negligible fines due to its nature and due to the water quenching that it receives immediately after emerging from the gasifiers. Particulate emissions will occur during transfer. Transfer to railcar by conveyor will occur on average 2 hrs/day.

The handling activities involved with the frit are very similar to those of the briquettes. The wet frit is discharged into a closed conveyor, which empties the product into a storage structure. The frit is stored in this structure before being transferred to railcars for delivery. The fact that the frit is wet initially and the large 1/4 in. or less mesh particle size make it relatively unsusceptible to creating dust or particle emissions. Expected emissions from frit handling activities are 0.20 TPY PM. The minimal emissions are reduced even further through utilizing a partially enclosed conveyor system and handling area; this is considered BACT.

Raw Materials Handling (Limestone, Petroleum Coke)

Transfer points in and out of the silos are controlled with the use of enclosed fixtures and transport routes (conveyors), much the same as the other material handling activities. Additionally, a baghouse is envisioned to control any PM from the storage in the silos. The control efficiency for these techniques is greater than 90%. These measures represent BACT for handling activities.

The limestone and pet coke on-site will be transferred to the silos directly from railcars. The emissions from these activities are accounted for as a series of transfer points. The sum of emissions from the limestone and pet coke handling activities is 0.162 TPY PM. The partial enclosure of the activities and the use of controls such as baghouses are considered BACT.

Cooling Towers

Dissolved particles are emitted from the cooling towers as the water evaporates during the evaporative cooling. These particulates often drop with the water droplets very close to the tower. The cooling towers for the L-E project will employ high efficiency mist eliminators that will minimize drift from the cooling towers. The design drift rate will be less than 0.005%. This technology represents BACT for cooling towers to minimize particulate emissions through minimizing drift rates.

Summary

All activities and processes at the Lima Energy facility that will emit criteria pollutants have been analyzed in detail to determine that BACT will be implemented for each. In this way, L-E will achieve superior environmental performance compared to other modern-day power plants. Table 6-9 of the permit application emphasizes that great strides can be made with syngas, by demonstrating that L-E's emissions of NO_x, SO_2, CO, and PM will all be significantly lower than contemporary coal-fired utilities. The incorporation of steam injection, good combustion practices, and a sulfur recovery process with a recovery rate of greater than 99% allow L-E to operate with BACT and demonstrate a "cleaner" way of producing power.

BACT Summary		
Emission Unit	**Pollutant**	**BACT**
Gas Turbines,	NO_x (syngas use)	Steam Injection to 15 ppm at 15% O_2
1765 MMBtu/hr Syngas Heat Input	NO_x (NG use)	Diluent Injection to 25 ppm at 15% O_2
	SO_2	Syngas cleanup to 40 ppm H_2S
	CO	Good Combustion Techniques and low VOC content of syngas fuel
	PM	Syngas Firing
	VOC	Good Combustion Techniques
Material Handling	PM	Enclosures
Flare	NO_x, SO_2, CO, PM, VOC	Good flare design
Cooling Tower	PM	High Efficiency Drift Eliminators
Wastewater Treatment	VOC	Good engineering design

<u>Ambient Air Quality Monitoring Requirements</u>

The Lima Energy facility installation is located in Lima County which is in Air Quality Control Region (AQCR) 177. The area is attainment or attainment/unclassifiable for particulate matter less than 10 microns (PM_{10}), sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), ozone (VOC/O_3) and lead.

The project will exceed the PSD significant emission rate for PM_{10}, SO_2, NO_2, VOC and CO. U.S. EPA regulations may require a year of ambient air quality data to be obtained as part of the PSD application. An applicant may conduct monitoring on-site, model to demonstrate a "de minimis" impact, or use existing air quality data to fulfill some of the requirements of a PSD ambient air quality analysis. If monitoring is required, U.S. EPA has set up specific conditions on the acceptability of existing air quality monitors to ensure the monitor is representative of air quality in this area.

In this instance, air quality modeling was submitted which indicated that project impacts would be well below PSD ambient monitoring thresholds. In addition, representative ambient ozone data are being collected in the region. Therefore, Lima Energy would not be required to conduct pre-application monitoring. Table 2, below summaries the predicted impact concentrations versus the De Minimus pre-application monitoring concentrations:

Table 2, predicted impact concentrations versus the De Minimus pre-application monitoring concentrations:

Monitoring Pollutant	Averaging Period	Predicted Impact Concentration	De Minimus Concentration
PM_{10}	24-hour	4.88 ug/m^3	10 ug/m^3
	Annual	0.62 ug/m^3	N/A
SO_2	24-hour	2.99 ug/m^3	13 ug/m^3
	Annual	0.06 ug/m^3	N/A
	3-hour	6.41 ug/m3	N/A
CO	1-hour	92.1 ug/m^3	N/A
	8-hour	54.9 ug/m^3	575 ug/m3
NO_2	Annual	0.32 ug/m3	14 ug/m3

Modeling

The proposed project would have PM_{10}, SO_2. CO and NO_2 emissions exceeding the PSD significant emission rates. This triggers the requirement for air quality modeling to assess the potential impact of the proposed project.

Modeling Results

The facility was evaluated using the ISCST3 model (version 00101). Dayton/Dayton (1987-1991, the most recent, available data on the Ohio EPA web page) meteorological data were used. Rural mode and regulatory default were assumed.

The maximum 24-hours and annual average PM_{10} concentrations due to the project were 4.88 ug/m3 and 0.62 ug/m3, respectively. These values are below the PSD PM_{10} significant impact increments. Therefore, no additional modeling to determine if the project will cause or contribute to violations of the NAAQS or PSD increments is necessary.

The maximum 3-hour, 24-hours and annual average SO_2 concentrations due to the project were 6.41 ug/m3, 2.99 ug/m3 and 0.06 ug/m3, respectively. These values are below the PSD SO_2 significant impact increments. Therefore, no additional modeling to determine if the project will cause or contribute to violations of the NAAQS or PSD increments is necessary.

The maximum 1-hour and 8-hour average CO concentrations due to the project were 92.1 ug/m3 and 54.9 ug/m3, respectively. These values are below the PSD CO significant impact increments. Therefore, no additional modeling to determine if the project will cause or contribute to violations of the NAAQS or PSD increments is necessary.

The maximum annual average NO_2 concentration due to the project was 0.32 ug/m3. This value is below the PSD NO_2 significant impact increment. Therefore, no additional modeling to determine if the project will cause or contribute to violations of the NAAQS or PSD increments is necessary.

PSD Increment Analysis

No significant impact was predicted. Therefore no PSD analyses were required.

NAAQS Analysis

No significant impact was predicted. Therefore no NAAQS analyses were required.

Secondary Impact Analysis

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

Conclusions

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

State of Ohio Environmental Protection Agency

RE: DRAFT PERMIT TO INSTALL **CERTIFIED MAIL**
ALLEN COUNTY

Street Address: Mailing Address: Lazarus Gov. Center

Lazarus Gov. Center **TELE:** (614) 644-3020 **FAX:** (614) 644-2329

Application No: 03-13445

DATE: 11/14/2001

Lima Energy Company
Dwight Lockwood
312 Walnut Street, Suite 2000
Cincinnati, OH 45202

You are hereby notified that the Ohio Environmental Protection Agency has made a draft action recommending that the Director issue a Permit to Install for the air contaminant source(s) [emissions unit(s)] shown on the enclosed draft permit. This draft action is not an authorization to begin construction or modification of your emissions unit(s). The purpose of this draft is to solicit public comments on the proposed installation. A public notice concerning the draft permit will appear in the Ohio EPA Weekly Review and the newspaper in the county where the facility will be located. Public comments will be accepted by the field office within 30 days of the date of publication in the newspaper. Any comments you have on the draft permit should be directed to the appropriate field office within the comment period. A copy of your comments should also be mailed to Robert Hodanbosi, Division of Air Pollution Control, Ohio EPA, P.O. Box 1049, Columbus, OH, 43266-0149.

A Permit to Install may be issued in proposed of final form based on the draft action, any written public comments received within 30 days of the public notice, or record of a public meeting if one is held. You will be notified in writing of a scheduled public meeting. Upon issuance of a final Permit to Install a fee of **$1400** will be due. Please do not submit any payment now.

The Ohio EPA is urging companies to investigate pollution prevention and energy conservation. Not only will this reduce pollution and energy consumption, but it can also save you money. If you would like to learn ways you can save money while protecting the environment, please contact our Office of Pollution Prevention at (614) 644-3469. If you have any questions about this draft permit, please contact the field office where you submitted your application, or Mike Ahern, Field Operations & Permit Section at (614) 644-3631.

Very truly yours,

Thomas G. Rigo
Field Operations and Permit Section
Division of Air Pollution Control

CC: USEPA **NWDO** **Lima-Allen Reg Plan Com** **IN**

DRAFT PERMIT TO INSTALL 03-13445

Application Number:	03-13445
APS Premise Number:	0302020336
Permit Fee:	**To be entered upon final issuance**
Name of Facility:	Lima Energy Company
Person to Contact:	Dwight Lockwood
Address:	312 Walnut Street, Suite 2000 Cincinnati, OH 45202

Location of proposed air contaminant source(s) [emissions unit(s)]:
1046 South Main Street
Lima, Ohio

Description of proposed emissions unit(s):
290 MW Synthetic gas/natural gas fired turbines(2).

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

This permit is granted subject to the conditions attached hereto.

Ohio Environmental Protection Agency

Director

A. State and Federally Enforceable Permit To Install General Terms and Conditions

1. Monitoring and Related Recordkeeping and Reporting Requirements

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

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

ii. The date(s) analyses were performed.

iii. The company or entity that performed the analyses.

iv. The analytical techniques or methods used.

v. The results of such analyses.

vi. The operating conditions existing at the time of sampling or measurement.

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

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

i. Reports of any required monitoring and/or recordkeeping of federally enforceable information shall be submitted to the appropriate Ohio EPA District Office or local air agency.

ii. Quarterly written reports of (i) any deviations from federally enforceable <u>emission limitations</u>, <u>operational restrictions</u>, <u>and control device operating parameter limitations</u>, excluding deviations resulting from malfunctions reported in accordance with OAC rule 3745-15-06, that have been detected by the testing, monitoring and recordkeeping requirements specified in this permit, (ii) the probable cause of such deviations, and (iii) any corrective actions or preventive measures taken, shall be made to the appropriate Ohio EPA District Office or local air agency. The written reports shall be submitted quarterly, i.e., by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters. See B.10 below if no deviations occurred during the quarter.

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

iv. Each written report shall be signed by a responsible official certifying that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.

2. Scheduled Maintenance/Malfunction Reporting

Any scheduled maintenance of air pollution control equipment shall be performed in accordance with paragraph (A) of OAC rule 3745-15-06. The malfunction, i.e., upset, of any emissions units or any associated air pollution control system(s) shall be reported to the appropriate Ohio EPA District Office or local air agency in accordance with paragraph (B) of OAC rule 3745-15-06. (The definition of an upset condition shall be the same as that used in OAC rule 3745-15-06(B)(1) for a malfunction.) The verbal and written reports shall be submitted pursuant to OAC rule 3745-15-06.
Except as provided in that rule, any scheduled maintenance or malfunction necessitating the shutdown or bypassing of any air pollution control system(s) shall be accompanied by the shutdown of the emission unit(s) that is (are) served by such control system(s).

3. Risk Management Plans

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

4. Title IV Provisions

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

5. Severability Clause

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

6. General Requirements

a. The permittee must comply with all terms and conditions of this permit. Any noncompliance with the federally enforceable terms and conditions of this permit constitutes a violation of the Act, and is grounds for enforcement action or for permit revocation, revocation and reissuance, or modification, or for denial of a permit renewal application.

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

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

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

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

7. Fees

The permittee shall pay fees to the Director of the Ohio EPA in accordance with ORC section 3745.11 and OAC Chapter 3745-78. The permittee shall pay all applicable Permit To Install fees within 30 days after the issuance of this Permit To Install.

8. Federal and State Enforceability

Only those terms and conditions designated in this permit as federally enforceable, that are required under the Act, or any of its applicable requirements, including relevant provisions designed to limit the potential to emit of a source, are enforceable by the Administrator of the U.S. EPA, the State, and citizens under the Act. All other terms and conditions of this permit

shall not be federally enforceable and shall be enforceable under State law only.

9. Compliance Requirements

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

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

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

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

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

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

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

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

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

10. Permit To Operate Application

a. If the permittee is required to apply for a Title V permit pursuant to OAC Chapter 3745-77, the permittee shall submit a complete Title V permit application or a complete

Title V permit modification application within twelve (12) months after commencing operation of the emissions units covered by this permit. However, if the proposed new or modified source(s) would be prohibited by the terms and conditions of an existing Title V permit, a Title V permit modification must be obtained before the operation of such new or modified source(s) pursuant to OAC rule 3745-77-04(D) and OAC rule 3745-77-08(C)(3)(d).

b. If the permittee is required to apply for permit(s) pursuant to OAC Chapter 3745-35 , the source(s) identified in this Permit To Install is (are) permitted to operate for a period of up to one year from the date the source(s) commenced operation. Permission to operate is granted only if the facility complies with all requirements contained in this permit and all applicable air pollution laws, regulations, and policies. Pursuant to OAC Chapter 3745-35, the permittee shall submit a complete operating permit application within thirty (30) days after commencing operation of the source(s) covered by this permit.

11. Best Available Technology

As specified in OAC Rule 3745-31-05, all new sources must employ Best Available Technology (BAT). Compliance with the terms and conditions of this permit will fulfill this requirement.

B. State Only Enforceable Permit To Install General Terms and Conditions

1. Compliance Requirements

The emissions unit(s) identified in this Permit to Install shall remain in full compliance with all applicable State laws and regulations and the terms and conditions of this permit.

2. Reporting Requirements Related to Monitoring and Recordkeeping Requirements

The permittee shall submit required reports in the following manner:

a. Reports of any required monitoring and/or recordkeeping of state-only enforceable information shall be submitted to the appropriate Ohio EPA District Office or local air agency.

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

3. Permit Transfers

Any transferee of this permit shall assume the responsibilities of the prior permit holder. The appropriate Ohio EPA District Office or local air agency must be notified in writing of any transfer of this permit.

4. Air Pollution Nuisance

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

5. Termination of Permit To Install

This permit to install shall terminate within eighteen months of the effective date of the permit to install if the owner or operator has not undertaken a continuing program of installation or modification or has not entered into a binding contractual obligation to undertake and complete within a reasonable time a continuing program of installation or modification. This deadline may

be extended by up to 12 months if application is made to the Director within a reasonable time before the termination date and the party shows good cause for any such extension.

6. Construction of New Sources(s)

The proposed emissions unit(s) shall be constructed in strict accordance with the plans and application submitted for this permit to the Director of the Ohio Environmental Protection Agency. There may be no deviation from the approved plans without the express, written approval of the Agency. Any deviations from the approved plans or the above conditions may lead to such sanctions and penalties as provided under Ohio law. Approval of these plans does not constitute an assurance that the proposed facilities will operate in compliance with all Ohio laws and regulations. Additional facilities shall be installed upon orders of the Ohio Environmental Protection Agency if the proposed sources cannot meet the requirements of this permit or cannot meet applicable standards.

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

7. Public Disclosure

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

8. Applicability

This Permit to Install is applicable only to the emissions unit(s) identified in the Permit To Install. Separate application must be made to the Director for the installation or modification of any other emissions unit(s).

9. Construction Compliance Certification

The applicant shall provide Ohio EPA with a written certification (see enclosed form) that the facility has been constructed in accordance with the Permit To Install application and the terms and conditions of the Permit to Install. The certification shall be provided to Ohio EPA upon completion of construction but prior to startup of the source.

10. Additional Reporting Requirements When There Are No Deviations of Federally Enforceable Emission Limitations, Operational Restrictions, or Control Device Operating Parameter Limitations (See Section A of This Permit)

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

C. Permit To Install Summary of Allowable Emissions

The following information summarizes the total allowable emissions, by pollutant, based on the individual allowable emissions of each air contaminant source identified in this permit.

SUMMARY (for informational purposes only)
TOTAL PERMIT TO INSTALL ALLOWABLE EMISSIONS

Pollutant	Tons Per Year
NOx	1285.4
VOC	133.4
CO	680.0
SO2	338.2
PM	166.7
Formaldehyde	6.6
HCL	9.6
Sulfuric Acid	4.6
Lead	0.16
Mercury	0.02
Cadmium	0.08
Dioxin/Furan	0.000508 pounds/yr

A. State and Federally Enforceable Permit To Install Facility Specific Terms and Conditions

None

B. State Only Enforceable Permit To Install Facility Specific Terms and Conditions

1. The permit to install for these emissions units (P001 and P002) was evaluated based on the actual materials and the design parameters of the emissions units' exhaust system, as specified by the permittee in the permit to install application. The Ohio EPA's "Review of New Sources of Air Toxic Emissions" policy ("Air Toxic Policy") was applied for each pollutant emitted by these emissions units using data from the permit to install application and the SCREEN 3.0 model. The predicted 1-hour maximum ground-level concentration from the use of the SCREEN 3.0 model was compared to the MAGLC. The following summarizes the results of the modeling for the "worst case" pollutants:

   Pollutant: Formaldehyde*
   TLV (ug/m3): 272.69
   Maximum Hourly Emission Rate (lbs/hr): 2.5
   Predicted 1-Hour Maximum Ground-Level Concentration (ug/m3):0.57
   MAGLC (ug/m3): 6.49

   Pollutant: Sulfuric Acid *
   TLV (ug/m3): 1000
   Maximum Hourly Emission Rate (lbs/hr):1.06
   Predicted 1-Hour Maximum Ground-Level Concentration (ug/m3): 0.40
   MAGLC (ug/m3): 23.8

   Pollutant: Hydrogen Chloride*
   TLV (ug/m3): 5497
   Maximum Hourly Emission Rate (lbs/hr): 2.2
   Predicted 1-Hour Maximum Ground-Level Concentration (ug/m3):0.82
   MAGLC (ug/m3):130.9

   Pollutant: Nickle*
   TLV (ug/m3): 100
   Maximum Hourly Emission Rate (lbs/hr):1.09
   Predicted 1-Hour Maximum Ground-Level Concentration (ug/m3):0.41
   MAGLC (ug/m3):2.38

* This was modeled for emissions units P001 & P002 combined.

Physical changes to or changes in the method of operation of the emissions units after their installation or modification could affect the parameters used to determine whether or not the "Air Toxic Policy" is satisfied. Consequently, prior to making a change that could impact such parameters, the permittee shall conduct an evaluation to determine that the "Air Toxic Policy" will still be still satisfied. If, upon evaluation, the permittee determines that the "Air Toxic Policy" will not be satisfied, the permittee will not make the change. Changes that can affect the parameters used in applying the "Air Toxic Policy" include the following:

a. changes in the composition of the materials used, or the use of new materials, that would result in the emission of a compound with a lower Threshold Limit Value (TLV), as indicated in the most recent version of the handbook entitled "American Conference of Governmental Industrial Hygienists (ACGIH)," than the lowest TLV value previously modeled;

b. changes in the composition of the materials, or use of new materials, that would result in an increase in emissions of any pollutant with a listed TLV that was proposed in the application and modeled; and

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

If the permittee determines that the "Air Toxic Policy" will be satisfied for the above changes, the Ohio EPA will not consider the change(s) to be a "modification" under OAC rule 3745-31-01(VV)(1)(a)(ii), and a modification of the existing permit to install will not be required. If the change(s) is (are) defined as a modification under other provisions of the modification definition (other than (VV)(1)(a)(ii)), then the permittee shall obtain a final permit to install prior to the change.

The permittee shall collect, record, and retain the following information when it conducts evaluations to determine that the changed emissions unit will still satisfy the "Air Toxic Policy:"

a. a description of the parameters changed (e.g.,composition of materials, new pollutants emitted, change in stack/exhaust parameters, etc.);

b. documentation of its evaluation and determination that the changed emissions unit still satisfies the "Air Toxic Policy"; and

c. where computer modeling is performed, a copy of the resulting computer model runs that show the results of the application of the "Air Toxic Policy" for the change.

Part III - SPECIAL TERMS AND CONDITIONS FOR SPECIFIC EMISSIONS UNIT(S)

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

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

Operations, Property, and/or Equipment	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
F001 - Material Handling and Storage [refuse derived fuel (RDF) and coal]	OAC rule 3745-31-05 (A)(3)	0.5 ton particulate emissions (PE)/yr No visible emissions except for a period of time not to exceed 1-minute during any 60-minute observation period. Best available control measures that are sufficient to minimize or eliminate visible emissions of fugitive dust (See A.I.2.c. - A.I.2.d.)
	OAC rule 3745-31-10 through 3745-31-20	See A.I.2.b.
	OAC rule 3745-17-08 (B)(6)	See A.I.2.e.
	OAC rule 3745-17-07 (B)(6)	See A.I.2.e.

2. Additional Terms and Conditions

2.a The material handling operations and storage areas that are covered under this permit are all those associated with the RDF and coal handling and storage.

2.b The permittee shall employ Best Available Control Technology (BACT) for controlling PE/PM_{10} on this emissions unit. BACT has been determined to be the use of best available control measures (see A.I.2.c.).

2.c The permittee shall employ best available control measures on this emissions unit for the purpose of ensuring compliance with all applicable requirements. In accordance with the permittee's permit application, the permittee shall employ the following control methods:

i. full enclosure of all conveyors; and

ii. partial enclosure of the storage areas and transfer points.

Nothing in this paragraph shall prohibit the permittee from employing additional control measures to ensure compliance. Any implementation of additional the control measures shall continue on any such operation until further observation confirms that use of the measures are unnecessary.

2.d Implementation of the above-mentioned control measures in accordance with the terms and conditions of this permit is appropriate and sufficient to satisfy the requirements of OAC rule 3745-31-05 (A)(3).

2.e The emission limitation specified by this rule is less rule is less stringent than the emission limitation established pursuant to OAC rule 3745-31-05(A)(3).

II. Operational Restrictions

None

III. Monitoring and/or Record Keeping Requirements

1. Except as otherwise provided in this section, the permittee shall perform an inspection on this emissions unit on a daily basis. The inspection shall include checks for any visible fugitive emissions from this emissions unit. The presence or absence of any visible fugitive emissions shall be noted in an operations log. If visible fugitive emissions are observed, the permittee shall also note the following in the operations log:

a. the color of the emissions;

b. whether the emissions are representative of normal operations;

c. if the emissions are not representative of normal operations, the cause of the abnormal emissions;

d. the total duration of any visible emission incident; and

e. any corrective actions taken to eliminate the visible emissions.

2. The above-mentioned inspections shall be performed during representative, normal, operating conditions of this emissions unit and when the weather conditions allow.

3. The permittee may, upon receipt of written approval from the appropriate Ohio EPA District Office or local air agency, modify the above-mentioned inspection frequencies if operating experience indicates that less frequent inspections would be sufficient to ensure compliance with the above-mentioned applicable requirements.

4. The permittee shall maintain records of the date and reason any required inspection was not performed.

IV. Reporting Requirements

1. The permittee shall submit annual written reports which (a) identify all days during which any visible fugitive emissions were observed which are not representative of normal operations and (b) describe any corrective actions taken to eliminate the visible fugitive emissions. These reports shall be submitted to the Director (the appropriate Ohio EPA District Office or local air agency) by January 31 and July 31 of each year and shall cover the previous 6-month period.

V. Testing Requirements

1. Compliance with the allowable emission limitations of this permit shall be determined in accordance with the following methods:

   a. Emission Limitation:
   0.5 ton PE/yr

   Applicable Compliance Method:
   Emission limitations were developed by applying a 80% control efficiency for best available control measures to the maximum potential uncontrolled emission rate of 2.7 tons PE/yr. The maximum potential uncontrolled emission rate was calculated using AP-42 emission factors (Section 13.2, dated 1/95) with a throughput of 5600 tons/day. Ongoing compliance shall be demonstrated through the monitoring and record keeping requirements in section A.III.

   b. Emission Limitation:
   No visible emissions except for a period of time not to exceed 1-minute during any 60-minute observation period.

   Applicable Compliance Method:

Emissions Unit ID: F001

If required, compliance with the visible emission limitation specified above shall be determined in accordance with Test Method 22 as set forth in "Appendix on Test Methods" in 40 CFR, Part 60 ("Standards of Performance for New Stationary Sources"), as such Appendix existed on July 1, 1996, and the modifications listed in paragraphs (B)(4)(a) through (B)(4)(c) of OAC rule 3745-17-03.

VI. Miscellaneous Requirements

None

B. State Only Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

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

Operations, Property, and/or Equipment	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
F001 - Material Handling and Storage (RDF and coal)		none

2. Additional Terms and Conditions

2.a None

II. Operational Restrictions

None

III. Monitoring and/or Recordkeeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

Part III - SPECIAL TERMS AND CONDITIONS FOR SPECIFIC EMISSIONS UNIT(S)

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

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

Operations, Property, and/or Equipment	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
F002 - Material Handling and Storage (Vitrified Frit)	OAC rule 3745-31-05 (A)(3)	0.2 ton particulate emissions (PE)/yr No visible emissions except for a period of time not to exceed 1-minute during any 60-minute observation period. Best available control measures that are sufficient to minimize or eliminate visible emissions of fugitive dust (See A.I.2.c. - A.I.2.d.)
	OAC rule 3745-31-10 through 3745-31-20	See A.I.2.b.
	OAC rule 3745-17-08 (B)(6)	See A.I.2.e.
	OAC rule 3745-17-07 (B)(6)	See A.I.2.e.

2. Additional Terms and Conditions

2.a The material handling operations and storage areas that are covered under this permit are al those associated with the vitrified frit handling and storage.

2.b The permittee shall employ Best Available Control Technology (BACT) for controlling PE/PM_{10} on this emissions unit. BACT has been determined to be the use of best available control measures (see A.I.2.c.).

2.c The permittee shall employ best available control measures on this emissions unit for the purpose of ensuring compliance with all applicable requirements. In accordance with the permittee's permit application, the permittee shall employ the following control methods:

i. full enclosure of all conveyors; and

ii. partial enclosure of the storage areas and transfer points.

Nothing in this paragraph shall prohibit the permittee from employing additional control measures to ensure compliance. Any implementation of additional the control measures shall continue on any such operation until further observation confirms that use of the measures are unnecessary.

2.d Implementation of the above-mentioned control measures in accordance with the terms and conditions of this permit is appropriate and sufficient to satisfy the requirements of OAC rule 3745-31-05 (A)(3).

2.e The emission limitation specified by this rule is less rule is less stringent than the emission limitation established pursuant to OAC rule 3745-31-05(A)(3).

II. Operational Restrictions

None

III. Monitoring and/or Record Keeping Requirements

1. Except as otherwise provided in this section, the permittee shall perform an inspection on this emissions unit on a daily basis. The inspection shall include checks for any visible fugitive emissions from this emissions unit. The presence or absence of any visible fugitive emissions shall be noted in an operations log. If visible fugitive emissions are observed, the permittee shall also note the following in the operations log:

a. the color of the emissions;

b. whether the emissions are representative of normal operations;

c. if the emissions are not representative of normal operations, the cause of the abnormal emissions;

d. the total duration of any visible emission incident; and

e. any corrective actions taken to eliminate the visible emissions.

2. The above-mentioned inspections shall be performed during representative, normal, operating conditions of this emissions unit and when the weather conditions allow.

3. The permittee may, upon receipt of written approval from the appropriate Ohio EPA District Office or local air agency, modify the above-mentioned inspection frequencies if operating experience indicates that less frequent inspections would be sufficient to ensure compliance with the above-mentioned applicable requirements.

4. The permittee shall maintain records of the date and reason any required inspection was not performed.

IV. Reporting Requirements

1. The permittee shall submit annual written reports which (a) identify all days during which any visible fugitive emissions were observed which are not representative of normal operations and (b) describe any corrective actions taken to eliminate the visible fugitive emissions. These reports shall be submitted to the Director (the appropriate Ohio EPA District Office or local air agency) by January 31 and July 31 of each year and shall cover the previous 6-month period.

V. Testing Requirements

1. Compliance with the allowable emission limitations of this permit shall be determined in accordance with the following methods:

a. Emission Limitation:
0.2 ton PE/yr

Applicable Compliance Method:
Emission limitations were developed by applying a 70% control efficiency for best available control measures to the maximum potential uncontrolled emission rate of 0.7 tons PE/yr. The maximum potential uncontrolled emission rate was calculated using AP-42 emission factors (Section 13.2.4, dated 1/95) with a throughput of 500 tons/day. Ongoing compliance shall be demonstrated through the monitoring and record keeping requirements in section A.III.

b. Emission Limitation:
No visible emissions except for a period of time not to exceed 1-minute during any 60-minute observation period.

Applicable Compliance Method:
If required, compliance with the visible emission limitation specified above shall be

determined in accordance with Test Method 22 as set forth in "Appendix on Test Methods" in 40 CFR, Part 60 ("Standards of Performance for New Stationary Sources"), as such Appendix existed on July 1, 1996, and the modifications listed in paragraphs (B)(4)(a) through (B)(4)(c) of OAC rule 3745-17-03.

VI. Miscellaneous Requirements

None

B. State Only Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

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

Operations, Property, and/or Equipment	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
F002 - Material Handling and Storage (Vitrified Frit)		none

2. Additional Terms and Conditions

2.a None

II. Operational Restrictions

None

III. Monitoring and/or Recordkeeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

Part III - SPECIAL TERMS AND CONDITIONS FOR SPECIFIC EMISSIONS UNIT(S)

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

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

Operations, Property, and/or Equipment	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
F003 - Material Handling and Storage (Limestone and Pet Coke)	OAC rule 3745-31-05 (A)(3)	0.2 ton particulate emissions (PE)/yr No visible emissions except for a period of time not to exceed 1-minute during any 60-minute observation period. Best available control measures that are sufficient to minimize or eliminate visible emissions of fugitive dust (See A.I.2.c. - A.I.2.d.)
	OAC rule 3745-31-10 through 3745-31-20	See A.I.2.b.
	OAC rule 3745-17-08 (B)(6)	See A.I.2.e.
	OAC rule 3745-17-07 (B)(6)	See A.I.2.e.

2. Additional Terms and Conditions

2.a The material handling and storage areas that are covered under this permit are all those associated with limestone and pet coke handling and storage.

2.b The permittee shall employ Best Available Control Technology (BACT) for controlling PE/PM_{10} on this emissions unit. BACT has been determined to be the use of best available control measures (see A.I.2.c.).

2.c The permittee shall employ best available control measures on this emissions unit for the purpose of ensuring compliance with all applicable requirements. In accordance with the permittee's permit application, the permittee employ the following control methods:

i. full enclosure of all conveyors; and

ii. partial enclosure of the storage areas and transfer points.

Nothing in this paragraph shall prohibit the permittee from employing additional control measures to ensure compliance. Any implementation of additional the control measures shall continue on any such operation until further observation confirms that use of the measures are unnecessary.

2.d Implementation of the above-mentioned control measures in accordance with the terms and conditions of this permit is appropriate and sufficient to satisfy the requirements of OAC rule 3745-31-05 (A)(3).

2.e The emission limitation specified by this rule is less rule is less stringent than the emission limitation established pursuant to OAC rule 3745-31-05(A)(3).

II. Operational Restrictions

None

III. Monitoring and/or Record Keeping Requirements

1. Except as otherwise provided in this section, the permittee shall perform an inspection on this emissions unit on a daily basis. The inspection shall include checks for any visible fugitive emissions from this emissions unit. The presence or absence of any visible fugitive emissions shall be noted in an operations log. If visible fugitive emissions are observed, the permittee shall also note the following in the operations log:

   a. the color of the emissions;

   b. whether the emissions are representative of normal operations;

   c. if the emissions are not representative of normal operations, the cause of the abnormal emissions;

   d. the total duration of any visible emission incident; and

   e. any corrective actions taken to eliminate the visible emissions.

2. The above-mentioned inspections shall be performed during representative, normal, operating

conditions of this emissions unit and when the weather conditions allow.

3. The permittee may, upon receipt of written approval from the appropriate Ohio EPA District Office or local air agency, modify the above-mentioned inspection frequencies if operating experience indicates that less frequent inspections would be sufficient to ensure compliance with the above-mentioned applicable requirements.

4. The permittee shall maintain records of the date and reason any required inspection was not performed.

IV. Reporting Requirements

1. The permittee shall submit annual written reports which (a) identify all days during which any visible fugitive emissions were observed which are not representative of normal operations and (b) describe any corrective actions taken to eliminate the visible fugitive emissions. These reports shall be submitted to the Director (the appropriate Ohio EPA District Office or local air agency) by January 31 and July 31 of each year and shall cover the previous 6-month period.

V. Testing Requirements

1. Compliance with the allowable emission limitations of this permit shall be determined in accordance with the following methods:

   a. Emission Limitation:
   0.2 ton PE/yr

   Applicable Compliance Method:
   Emission limitations were developed by applying a 70% control efficiency for best available control measures to the maximum potential uncontrolled emission rate of 0.5 tons PE/yr. The maximum potential uncontrolled emission rate was calculated using AP-42 emission factors (Section 13.2, dated 1/95) with a throughput of 135 tons/day. Ongoing compliance shall be demonstrated through the monitoring and record keeping requirements in section A.III.

   b. Emission Limitation:
   No visible emissions except for a period of time not to exceed 1-minute during any 60-minute observation period.

   Applicable Compliance Method:
   If required, compliance with the visible emission limitation specified above shall be determined in accordance with Test Method 22 as set forth in "Appendix on Test

Methods" in 40 CFR, Part 60 ("Standards of Performance for New Stationary Sources"), as such Appendix existed on July 1, 1996, and the modifications listed in paragraphs (B)(4)(a) through (B)(4)(c) of OAC rule 3745-17-03.

VI. Miscellaneous Requirements

None

B. State Only Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

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

Operations, Property, and/or Equipment	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
F003 - Material Handling and Storage (Limestone and Pet Coke)		none

2. Additional Terms and Conditions

2.a None

II. Operational Restrictions

None

III. Monitoring and/or Recordkeeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

Part III - SPECIAL TERMS AND CONDITIONS FOR SPECIFIC EMISSIONS UNIT(S)

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

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

Operations, Property, and/or Equipment	Applicable Rules/Requirements	
P001 - Syngas/Natural Gas Turbine, Unit #1 of a Combined Cycle System and Gasification Plant	OAC Rule 3745-31-05 (A)(3)	
		OAC Rule 3745-31-05 (D)
		OAC rule 3745-31-10 through 3745-31-20

	Applicable Emissions Limitations/Control Measures	
		20.0 tons NOx/yr 50.0 tons CO/yr 2.5 tons VOC/yr
	See A.I.2.b.	
		3.3 tons formaldehyde per rolling 12-month period, See A.II.1.
40 CFR Part 60, Subpart Eb	visible particulate emissions shall not exceed 10 percent opacity as a six-minute average	See A.I.2.a.
	178.0 lbs NO_x/hr & 642.7 tons NO_x/yr	25 ppmvd nitrogen oxides (NO_x) at 15% Oxygen and 25 ppmvd carbon monoxide (CO)at 15% Oxygen when firing natural gas or blended fuel
	251.0 lbs CO/hr & 340.0 tons CO/yr	
	38.6 lbs Sulfur Dioxide (SO_2)/hr & 169.1 tons SO_2/yr	15 ppmvd NO_x at 15% Oxygen and 15 ppmvd CO at 15% Oxygen when firing syngas
	18.0 lbs Particulate Emissions (PE)/hr & 78.8 tons PE/yr, See A.I.2.f.	642.7 tons NO_x ,340.0 tons CO, 169.1 tons SO_2, 78.8 tons PE, and 66.7 tons VOC per rolling 12-month period
	15.0 lbs Volatile Organic Compounds (VOC)/hr & 66.7 tons VOC/yr,	when firing syngas, emissions shall not exceed:
OAC Rule 3745-17-07(A)	1.25 lbs formaldehyde/hr	
		0.020 mg cadmium/dscm at 7% Oxygen
40 CFR Part 60, Subpart GG	0.53 lb sulfuric acid/hr & 2.3 tons sulfuric acid/yr	0.20 mg lead/dscm at 7% Oxygen
OAC rule 3745-18-06(F)		
	0.009 lb cadmium/hr & 0.04 ton cadmium/yr	0.080 mg mercury/dscm at 7% Oxygen
OAC Rule 3745-17-11(B)(4)		13 ng dioxin/furan per dscm at 7% Oxygen
	0.018 lb lead/hr & 0.08 ton lead/yr	
OAC Rule 3745-103		
	0.0013 lb mercury/hr & 0.01 ton mercury/yr	25 ppmvd HCL at 7% Oxygen, or 5 percent of the potential HCL emissions (95 percent reduction by weight or volume), whichever is less stringent
40 CFR Part 75		
	0.000000029 lb dioxin/furan per hr & 0.000254 lb dioxin/furan per yr	
		See A.I.2.c.
	1.1 lb hydrogen chloride (HCL)/hr & 4.8 tons HCL/yr	See A.I.2.d.
	Start-up and shut-down emissions	See A.I.2.c.

See A.I.2.c.

See A.I.2.e.

See A.I.2.e.

2. Additional Terms and Conditions

2.a. The permittee shall employ Best Available Control Technology (BACT) for controlling NO_x, SO_2, CO, PE/PM_{10}, and VOC on this emissions unit. BACT has been determined to be the following determinations have been made for each pollutant:

PE - Use of only clean burning fuels (natural gas and syngas), in an efficient combustion turbine.

NO_x - Use of dilution injection into the combustion zone at the emission concentrations established above.

CO - Use of efficient combustion technology at the emission concentrations established above.

VOC - Use of efficient combustion technology.

SO_2 - Use of a solvent-based absorption technology prior to combustion.

2.b The requirements of this rule also include compliance with the requirements of OAC rule 3745-31-10 through 20, and 40 CFR Part 60, Subpart GG and Eb.

2.c The emission limitation specified by this rule is less rule is less stringent than the emission limitation established pursuant to OAC rule 3745-31-05(A)(3).

2.d The emission limitations specified by this rule is less rule are less stringent than the emission limitations established pursuant to OAC rule 3745-31-05(A)(3). Except as provided for in the terms and conditions in this permit, the permittee is not exempt from meeting any additional requirements of 40 CFR Part 60, Subpart GG. and 40 CFR Part 60, Subpart Eb.

2.e If the permittee is subject to the requirements of 40 CFR Part 75 concerning acid rain, the permittee shall ensure that any affected emissions unit complies with those requirements. Emissions exceeding any allowances that are lawfully held under Title IV of the Act, or

any regulations adopted thereunder, are prohibited.

2.f It is assumed that all PE emissions are PM_{10}.

2.g The annual emission limits above include 200 hours of start-up and shut-down emissions. It has been determined that there are additional NOx, CO, and VOC emissions associated with start-up and shut-down periods. These estimated worst case emissions rates are described in condition A.III.1.

II. Operational Restrictions

1. The permittee has requested a transitional period to allow for additional natural gas usage during the initial 24 months this emissions unit is in operation. During this initial 24 month period following startup*, the maximum allowable natural gas usage for this emissions unit shall not exceed the amounts specified in the following table:

months	allowable NG usage (mmcf)
1-12	8,190
13-24	4,095

After the initial 24 month transition period, the maximum annual fuel usage for this emissions unit shall not exceed 2050 mmcf of natural gas per rolling 12-month period.

To ensure enforceability during the first 12 calendar months following the transition period, the permittee shall not exceed the fuel usage restrictions specified in the following table:

months	Cumulative Summation of allowable fuel usage (mmcf)
25	400
25-26	800
25-27	1200
25-28	1600
25-29	2000
25-36	2050

After the first 36 calendar months of operation, compliance with the annual usage restrictions shall be based on a rolling, 12-month summation.

*Startup for the facility shall be defined as the date when emissions units P001 is set in operation for any purpose. Start-up for the daily operation of the turbine is described in condition A.II.2.

2. This emissions unit shall have a maximum allowable fuel flow of 1.81 million scf/hr when firing natural gas, and a maximum allowable fuel flow of 6.95 million scf/hr when firing syngas. The permittee shall operate this emissions unit within the parameters specified above, except for start-up and shut-down. Start-up shall be defined as the time necessary to bring the unit to it's minimum operating temperature (as recommended by the vendor), but under no circumstances shall it exceed 60 minutes in duration. Shut-down periods shall not exceed 60 minutes in duration.

3. With the exception of start-up and shut-down periods, emissions unit P001 shall be operated at minimum of 50% load. The permittee may petition the Ohio EPA, Northwest District Office (NWDO) to operate at a greater load range if it can demonstrate to the agency's satisfaction that the emissions unit will comply with all applicable emission limits in this permit, and modeling requirements pursuant to Engineering Guide no. 69.

4. The permittee shall burn only natural gas and syngas in this emissions unit. For the purposes of this permit, syngas shall be defined as the gasification of any of the following products: coal, pet coke, and refuse derived fuel (RDF). The permittee may request the gasification of additional products in as described in condition A.VI.2.

5. The permittee shall be limited to 200 hours of operation per year for start-ups and shut-downs.

III. Monitoring and/or Record Keeping Requirements

1. The permittee shall maintain monthly records of the following for emissions unit P001:

   a. number and duration of each start-up;

   b. number and duration of each shut-down;

   c. the start-up and shut-down emissions* for NOx, CO, and VOC in tons per month;

   In addition to the above information, the permittee shall maintain monthly records of the following information for emissions unit P001:

   d. during the first 36 calendar months of operation following startup, the quantity of natural gas fired and the quantity of syngas fired, in million cubic feet;

   e. beginning the first month after the first 36 months of operation following startup, the rolling, 12- month summation of the quantity of natural gas fired and the quantity of syngas fired, in million cubic feet;

f. the monthly emission* rate for PE, NOx, SO2, CO, VOC, and formaldehyde (including start-up and shut-down emissions), in tons;

g. during the first 36 calendar months of operation following startup, the annual emissions of PE, NOx, SO2, CO, VOC, and formaldehyde, (including start-up and shut-down emissions) in tons; and

h. beginning the first month after the first 36 months of operation following startup, the rolling, 12- month summation of the emission rates for PE, NOx, SO2, CO, VOC, and formaldehyde (including start-up and shut-down emissions), in tons. .

*The permittee shall use continuous emissions monitoring (CEM) data to determine emissions for those pollutants where a CEM is installed. During the periods where a CEM is not operational or for pollutants where a CEM is not installed, the permittee shall use the most recent testing data/emission factors available for each respective pollutant, in conjunction with the quantity of fuel fired, as recorded above, to determine monthly emissions. Where CEMs data is not available for start-up and shutdown periods, the emission factors/rates the be used are as follows: 200 lbs NOx/hr, 500 lbs CO/hr, and 25 lbs VOC/hr.

2. For each day during which the permittee burns a fuel other than natural gas or syngas, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

3. The information management system for this emissions unit shall be capable of monitoring and recording the fuel flow in million cu ft, and hours of operation .

4. Except for periods described in 40 CFR part 60.13, the permittee shall install, operate, and maintain equipment to continuously monitor* and record SO_2, NO_x, CO, and opacity of the particulate emissions from this emissions unit, in the units specified in the terms and conditions of this permit. The averaging time for the continuous monitoring and recording equipment shall be 6 minutes (block) for the opacity monitor and 3 hours (block) for all other monitors. The span value of the SO_2, NO_x, and CO continuous emission monitoring systems shall be 125 percent of the maximum estimated hourly potential emissions of the emissions unit. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.13 or as approved by the Ohio EPA.

The permittee shall maintain records of all data obtained by the continuous SO_2, NO_x, CO, and opacity monitoring systems including, but not limited to, parts per million SO_2, NO_x, CO, and opacity on an instantaneous (one-minute) basis, emissions of SO_2, NO_x, CO, and opacity in the units

specified in the terms and conditions of this permit, results of daily zero/span calibration checks, and magnitude of manual calibration adjustments.

5. The permittee shall operate and maintain equipment to continuously monitor and record the O_2 from this emissions unit in percent O_2. The span value of the continuous emission monitoring system shall be 25 percent O_2. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.13 or as approved by the Ohio EPA, Central Office. The permittee may install a CO_2 monitor in lieu of an O_2 monitor with prior approval from the Ohio EPA, Central Office.

   The permittee shall maintain records of all data obtained by the continuous O_2 monitoring system including, but not limited to percent O_2 on an instantaneous (one-minute) basis, results of daily zero/span calibration checks, and magnitude of manual calibration adjustments.

   * The installation and operation of systems to continuously monitor and record emissions of SO_2 and NO_x may be performed in lieu of continuously monitoring the fuel consumption, water ratio, and nitrogen & sulfur contents of the fuel being fired in the turbine, as required by 40 CFR 60.334. When SO_2, NO_x, or CO emissions are not obtained due to continuous emission monitoring system breakdowns, repairs, calibration checks, or other event, emissions data shall be obtained using Method 19 of 40 CFR Part 60, Appendix A or other method as approved by the Ohio EPA, Central Office.

IV. Reporting Requirements

1. The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than natural gas or syngas was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

2. The permittee shall submit deviation (excursion) reports which identify all exceedances of the rolling, 12-month fuel usage limitations and, for the first 36 calendar months of operation, all exceedances of the maximum allowable natural gas usage.

3. The permittee shall submit quarterly reports which identify each period during which an exemption for ice-fog provided in 40 CFR 60.332(f) is in effect. The report shall include the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time when the air pollution control system was reactivated.

4. Pursuant to OAC rules 3745-15-04, 3745-35-02, and ORC sections 3704.03(I) and 3704.031 and 40 CFR Parts 60.7 and 60.13(h), the permittee shall submit reports within 30 days following the end of each calendar quarter to the Ohio EPA NWDO documenting the date, commencement and completion times, duration, magnitude, reason (i.e., startup and shutdown periods as defined in Condition A.II.2., malfunctions, etc.), and corrective actions taken (if any), of all instances of SO_2,

NO_x, CO, and opacity values in excess of the limits specified in the terms and conditions of this permit. These reports shall also contain the total SO_2, NO_x, and CO emissions for the calendar quarter (in tons).

The permittee shall submit reports within 30 days following the end of each calendar quarter to the Ohio EPA, NWDO documenting any continuous SO_2, NO_x, CO, O_2, and opacity monitoring system downtime while the emissions unit was on line (date, time, duration and reason) along with any corrective action(s) taken. The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason and corrective action(s) taken for each time period of emissions unit and control equipment malfunctions. The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line shall also be included in the quarterly report.

If there are no excess emissions during the calendar quarter, the permittee shall submit a statement to that effect along with the emissions unit operating time during the reporting period and the date, time, reason, and corrective action(s) taken for each time period of emissions unit, control equipment, and/or monitoring system malfunctions. The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line also shall be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during the previous calendar quarter.

5. Pursuant to OAC rules 3745-15-04, 3745-35-02, and ORC sections 3704.03(I) and 3704.031, the permittee shall submit a summary of the excess emission report pursuant to 40 CFR Part 60.7. The summary shall be submitted to the Ohio EPA, NWDO within 30 days following the end of each calendar quarter in a manner prescribed by the Director.

6. The permittee shall submit deviation (excursion) reports that identify each time when this emissions unit was not in compliance with the requirements of condition A.II.2., A.II.3., and A.II.5. above.

7. In lieu of the excess emissions reports required under 40 CFR Part 60.334, the permittee shall submit excess and emissions reports for emissions unit P001 in accordance with this permit.

8. The permittee shall submit semiannual reports as required by 40 CFR Part 60.59b(h).

9. Except as specified in condition A.IV.1, all deviation reports shall be submitted in accordance with the General Terms and Conditions of this permit.

10. This emissions unit is subject to the applicable provisions of Subpart GG and Eb of the New Source Performance Standards (NSPS) as promulgated by the United States Environmental

Protection Agency, 40 CFR Part 60.

The application and enforcement of these standards are delegated to the Ohio EPA. The requirements of 40 CFR Part 60 are also federally enforceable.

Pursuant to 40 CFR Part 60.7 and 60.59b, the permittee is hereby advised of the requirement to report the following at the appropriate times:

a. construction date - intent to construct (no later than 30 days after such date);
b. anticipated start-up date (not more than 60 days or less than 30 days prior to such date);
c. actual start-up date (within 15 days after such date);
d. the types of fuels that are planning on being combusted;
e. the combustion units maximum capacity;
f. any documents associated with the siting requirements as specified in 40 CFR Part 60.59b(b)(5); and
g. date of performance testing, at least 45 days prior to testing.

Reports are to be sent to:

Ohio Environmental Protection Agency
DAPC - Permit Management Unit
Lazarus Government Center
P.O.1049
Columbus, Ohio 43216-1049

and

Ohio Environmental Protection Agency
Northwest District Office
Division of Air Pollution Control
347 North Dunbridge Road
Bowling Green, Ohio 43402

V. Testing Requirements/Compliance Methods Determinations

1. The permittee shall conduct, or have conducted, emission testing for this emissions unit in accordance with the following requirements:

   a. The emissions testing shall be conducted while firing both natural gas and syngas individually. The emission testing while firing natural gas shall be conducted within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of this emissions unit. The emissions testing while firing syngas shall be conducted within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after the initial use of syngas in this emissions unit.

   b. The emissions testing shall be conducted to demonstrate compliance with the NO_x and CO outlet concentrations, and the mass emissions limitations for NO_x, CO, VOC, SO_2, PE, and Formaldehyde. Emission testing shall also be conducted to demonstrate compliance with the outlet concentrations and mass emissions limitations for cadmium, lead, mercury, HCL, and dioxin/furans when firing syngas.

   c. The following test method(s) shall be employed to demonstrate compliance with the above emissions limitations: for NO_x, Method 20 of 40 CFR Part 60, Appendix A; for PE, Method 5 of 40 CFR Part 60, Appendix A; for formaldehyde, SW-846 Method 0011 or CARB Method 316; for VOC, Method 25 of 40 CFR Part 60, Appendix A; SO_2 Method 6 of 40 CFR Part 60, Appendix A; for CO Method 10 of 40 CFR Part 60, Appendix A, for

cadmium, Method 29 of 40 CFR Part 60, Appendix A; for lead, Method 29 of 40 CFR Part 60, Appendix A; for mercury, Method 29 of 40 CFR Part 60, Appendix A; for HCL, Method 26 of 40 CFR Part 60, Appendix A; for dioxin/furan, Method 23 of 40 CFR Part 60, Appendix A; and for air flow and moisture content determinations, Methods 1-4 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA, NWDO.

d. In addition to the above pollutants, emissions testing shall also be performed for the following pollutants while firing syngas: Total Chromium, Vanadium, Zinc, Cobalt, Arsenic, Antimony, Manganese, Beryllium, Benzene, Selenium, Carbon Disulfide, and Carbonyl Sulfide. The permittee shall propose the testing methodology for these pollutants consistent with US EPA test methods.

e. The permittee shall develop site specific emission factors for all pollutants tested. These emission factors shall be in units of lbs of emissions per volume of fuel consumed.

f. The following testing requirements are pursuant to 40 CFR Part 60, Part 60.58b:

   i. when testing for dioxin/furan emissions, the minimum sampling time shall be 4 hours per test run;

   ii. when testing for mercury and PE, the minimum sample volume shall be 1.7 cubic meters;

   iii. when testing PE, the probe and filter holder heating in the sample train shall be set to provide a gas temperature of no greater than 160 +/- 14 degrees Celcius; and,

   iv. the minimum frequency of testing shall be such that it complies with the requirements of 40 CFR Part 60, Part 60.58b.

g. The testing shall be performed at peak load (as defined by 40 CFR Part 60, Subpart GG), unless otherwise specified or approved by the Ohio EPA, NWDO.

h. Not later than 45 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the Ohio EPA, NWDO. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the tests, and the person(s) who will be conducting the tests. Failure to submit such notification for review and approval prior to the tests may result in the Ohio EPA, NWDO refusal to accept the results of the emission tests.

i. Personnel from the Ohio EPA, NWDO shall be permitted to witness the tests, examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the

emissions from the emissions unit and/or the performance of the control equipment.

j. A comprehensive written report on the results of the emissions tests shall be signed by the person or persons responsible for the tests and submitted to the Ohio EPA, NWDO within 30 days following completion of the tests. The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Ohio EPA, NWDO.

k. As part of the stack test report, the permittee shall include test results that are in the units of measurement established in this permit as well as in the units of measurement established in 40 CFR Part 60, Subpart Eb.

l. In lieu of the test methods and procedures required under 40 CFR Part 60.335, the permittee shall follow the testing requirements in accordance with this permit.

2. Within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of such emissions unit, the permittee shall conduct certification tests of the continuous NO_x and CO monitoring systems pursuant to ORC section 3704.03(I) and 40 CFR Part 60, Appendix B, Performance Specification 6*. Personnel from the Ohio EPA, Northwest District Office shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. In accordance with OAC rule 3745-15-04, copies of all the test results shall be submitted within 30 days after the test is completed. Copies of the test results shall be sent to the Ohio EPA, Northwest District Office and the Ohio EPA, Central Office. Certification of the continuous NO_x and CO monitoring systems shall be granted upon determination by the Ohio EPA, Central Office that the system meets all requirements of ORC section 3704.03(I) and 40 CFR Part 60, Appendix B, Performance Specification 6*.

3. Within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of such emissions unit, the permittee shall conduct certification tests of the continuous O_2 monitoring systems pursuant to ORC section 3704.03(I) and 40 CFR Part 60, Appendix B, Performance Specification 3. Personnel from the Ohio EPA, Northwest District Office shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. In accordance with OAC rule 3745-15-04, all copies of the test results shall be submitted within 30 days after the test is completed. Copies of the test results shall be sent to the Ohio EPA, Northwest District Office and the Ohio EPA, Central Office. Certification of the continuous O_2 monitoring system shall be granted upon determination by the Ohio EPA, Central Office that the system meets all requirements of ORC section 3704.03(I) and 40 CFR Part 60, Appendix B, Performance Specification 3.

* The permittee may use 40 CFR Part 60, Appendix B, Performance Specification 2 and Performance Specification 4 in conjunction with a fuel flow monitor as described in 40 CFR Part 75 to meet these requirements if approved by the Ohio EPA, Central Office.

4. Within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of such emissions unit, the permittee shall conduct certification tests on the continuous opacity monitoring system equipment pursuant to ORC section 3704.03(I) and 40 CFR Part 60, Appendix B, Performance Specification 1. Personnel from the Ohio EPA, Northwest District Office shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. In accordance with OAC rule 3745-15-04, all copies of the test results shall be submitted within 30 days after the test is completed. Copies of the test results shall be sent to the Ohio EPA, Northwest District Office and the Ohio EPA, Central Office. Certification of the continuous opacity monitoring system shall be granted upon determination by the Ohio EPA, Central Office that the system meets all requirements of ORC section 3704.03(I), and 40 CFR Part 60, Appendix B, Performance Specification 1 including section 5.1.9 (mandatory).

5. Compliance with the allowable emission limitations in this permit shall be determined according to the following methods:

   a. <u>Emission Limitation</u>
   25 ppmvd NO_x at 15% Oxygen when firing natural gas or blended fuel
   15 ppmvd NO_x at 15% Oxygen when firing syngas
   178.0 lbs NO_x/hr & 642.7 tons NO_x per rolling 12-month period

   <u>Applicable Compliance Method</u>
   Compliance with the allowable outlet concentrations and the lbs/hr emission limitation shall be demonstrated by the performance testing as described in condition A.V.1 and continuous emissions monitoring requirement as described in conditions A.III.4. and A.V.2. Compliance with the annual emission limitations shall be determined by the record keeping required in condition A.III.1.

   b. <u>Emission Limitation</u>
   18.0 lbs PE/hr & 78.8 tons PE per rolling 12-month period

   <u>Applicable Compliance Method</u>
   Compliance with the allowable outlet concentrations & the lbs/hr emission limitations shall be demonstrated by the performance testing as described in condition A.V.1. Compliance with the annual emission limitations shall be determined by the record keeping required in condition A.III.1.

c. Emission Limitation
38.6 lbs SO_2/hr & 169.1 tons SO_2 per rolling 12-month period

Applicable Compliance Method
Compliance with the allowable outlet concentrations and the lbs/hr emission limitation shall be demonstrated by the performance testing as described in condition A.V.1 and continuous emissions monitoring requirement as described in conditions A.III.4. and A.V.2. Compliance with the annual emission limitations shall be determined by the record keeping required in condition A.III.1.

d. Emission Limitation
15.0 lbs VOC/hr & 66.7 tons VOC per rolling 12-month period

Applicable Compliance Method
Compliance with the lbs/hr emission limitations shall be demonstrated by the performance testing as described in condition A.V.1. Compliance with the annual emission limitations shall be determined by the record keeping required in condition A.III..1.

e. Emission Limitation
25 ppmvd CO at 15% Oxygen when firing natural gas
15 ppmvd CO at 15% Oxygen when firing syngas
251.0 lbs CO/hr & 340.0 tons CO per rolling 12-month period

Applicable Compliance Method
Compliance with the allowable outlet concentrations and the lbs/hr emission limitation shall be demonstrated by the performance testing as described in condition A.V.1 and continuous emissions monitoring requirement as described in conditions A.III.4. and A.V.2. Compliance with the annual emission limitations shall be determined by the record keeping required in condition A.III.1.

f. Emission Limitation
1.25 lbs formaldehyde/hr & 3.3 tons formaldehyde per rolling 12-month period

Applicable Compliance Method
Compliance with the lbs/hr emission limitations shall be demonstrated by the performance testing as described in condition A.V.1. Compliance with the annual emission limitations shall be determined by the record keeping required in condition A.III.1.

g. Emission Limitation
0.020 mg cadmium/dscm at 7% Oxygen
0.009 lb cadmium/hr & 0.04 ton cadmium/yr

0.20 mg lead/dscm at 7% Oxygen
0.018 lb lead/hr & 0.08 ton lead/yr

0.080 mg mercury/dscm at 7% Oxygen
0.0013 lb mercury/hr & 0.01 ton mercury/yr

13 ng dioxin/furan per dscm at 7% Oxygen
0.000000029 lb dioxin/furan per hr & 0.000254 lb dioxin/furan per yr

25 ppmvd HCL at 7% Oxygen, or 5 percent of the potential HCL emissions
(95 percent reduction by weight or volume), whichever is less stringent
1.1 lb HCL/hr & 4.8 tons HCL/yr

Applicable Compliance Method
Compliance with the allowable outlet concentrations and the lbs/hr emission limitations shall be demonstrated by the performance testing as described in condition A.V.1. Compliance with the annual emission limitations shall be determined multiplying the hourly emission limit by 8760 hrs/yr and dividing by 2000 lbs/ton.

h. Emission Limitation
0.53 lb sulfuric acid/hr & 2.3 tons sulfuric acid/yr

Applicable Compliance Method
The allowable lbs/hr emission limitation the represents the potential to emit based on engineering calculations while firing syngas. If required, compliance with the allowable lbs/hr emission limitation shall be determined by approved U.S. EPA test methods. Compliance with the annual emission limitations shall be determined multiplying the hourly emission limit by 8760 hrs/yr and dividing by 2000 lbs/ton.

i. Emission Limitation
Start-up and shut-down emissions
20.0 tons NOx/yr
50.0 tons CO/yr
2.5 tons VOC/yr

Applicable Compliance Method
Compliance with the annual emission limitations shall be demonstrated by the record keeping required in condition A.III.1.

j. Emission Limitation
Visible particulate emissions shall not exceed 10 percent opacity as a six-minute average.

Applicable Compliance Method
If required, compliance with the visible emissions limitations established by this permit shall be determined by Method 9, 40 CFR Part 60 Appendix A.

VI. Miscellaneous Requirements

1. The permittee may petition the Ohio EPA, Northwest District Office (NWDO) to operate at a greater load range if it can demonstrate to the agency's satisfaction that the emissions unit will comply with all applicable emission limits in this permit, and modeling requirements pursuant to Engineering Guide no. 69.

2. The permittee may also petition the Ohio EPA, NWDO to use additional materials for the production of syngas if it can demonstrate to the agency's satisfaction that the emissions unit will comply with Ohio EPA's "Air Toxics Policy" and all applicable emission limits in this permit.

3. Prior to the installation of the continuous NO_x ,CO, SO_2, and opacity monitoring systems, the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specification 6 (or as described in condition A.V.1.) for approval by the Ohio EPA, Central Office.

   Prior to the installation of the continuous O_2 monitoring system, the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specification 3 for approval by the Ohio EPA, Central Office.

   Prior to the installation of the continuous opacity monitoring system, the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specification 1 for approval by the Ohio EPA, Central Office.

4. Within 30 days of the start-up of this emissions unit, the permittee shall develop a written quality assurance/quality control plan for the continuous NO_x ,CO, SO_2, O_2, and opacity monitoring systems designed to ensure continuous valid and representative readings of NO_x ,CO, SO_2,O_2, and opacity emissions. The plan shall follow the requirements of 40 CFR Part 60, Appendix F, except as otherwise specified in 40 CFR Part 60, Subpart Eb, or as approved by the Ohio EPA, Central office. The quality assurance/quality control plan and a logbook dedicated to the continuous NO_x, CO, SO_2, O_2, and opacity monitoring systems must be kept on site and available for inspection during regular office hours.

5. Per the requirements of condition A.V.1.d., the permittee is required to perform emissions testing for numerous HAPs, for which emissions limitations are not established in this permit. This emissions data is to be used when calculating HAPs potential to emit. In addition, Ohio EPA will review this emissions data to determine if the permit adequately addresses all pollutants of concern. The Ohio EPA reserves the right to modify this permit for the purpose of establishing additional emission limits or performance standards for any of these pollutants. Any newly established limits or standards would be consistent with Best Available Technology requirements and all other applicable rules and regulations.

6. The permittee shall provide training and certification for all operators and supervisors as described in 40 CFR Part 60, Subpart 60.54b. The permittee shall maintain records on showing the names of all operators and supervisors who, have received certification and training as described in 40 CFR Part 60, Subpart 60.59b.

7. The permittee shall develop a site specific operating manual, provide training on the operating

manual, and maintain records showing the names of all persons who have been provided the training, as described in 40 CFR Part 60, Subpart 60.54b and 60.59b respectively.

8. A siting analysis shall be conducted in accordance with 40 CFR Part 60.57.

9. The permittee is exempt from the requirement in 40 CFR Part 60, Subpart Eb which pertain to the development of a materials separation plan, as this facility does not accept municipal solid waste.

10. The permittee is exempt from the requirements of 40 CFR Part 60, Subpart Eb which pertain to the monitoring, record keeping, and reporting on the operation of a post combustion particulate control device, as there is no such device on this emissions unit.

11. The permittee is exempt from the requirements of 40 CFR Part 60, Subpart Eb. which pertain to the monitoring, record keeping, and reporting on the generation of fugitive ash, as this facility does not generate fugitive ash as this operation is described in 40 CFR Part 60, Subpart Eb.

12. Within 90 days of the of the start-up of this emissions unit, the permittee shall develop a preventative maintenance and malfunction abatement plan/system for the gasification operations at this facility. The plan should clearly document how the permittee maintains the system(s) in good working order, i.e. the type of inspections done on the equipment as well as the frequency. The quality assurance/quality control plan and logbooks/records dedicated to the system must be kept on site and available for inspection during regular office hours. This plan should also specify the responsible person(s) for notifying this office in the event of an equipment malfunction that results in emissions to the atmosphere.

B. State Only Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

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

Operations, Property, and/or Equipment	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
P001 - Syngas/Natural Gas Turbine, Unit #1 of a Combined Cycle System and Gasification Plant	OAC rule 3745-31-05(A)(3)	None

2. Additional Terms and Conditions

2.a None

II. Operational Restrictions

None

III. Monitoring and/or Recordkeeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

Part III - SPECIAL TERMS AND CONDITIONS FOR SPECIFIC EMISSIONS UNIT(S)

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

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

Operations, Property, and/or Equipment	Applicable Rules/Requirements	
P002 - Syngas/Natural Gas Turbine, Unit #2 of a Combined Cycle System and Gasification Plant	OAC Rule 3745-31-05 (A)(3)	
		OAC Rule 3745-31-05 (D)
		OAC rule 3745-31-10 through 3745-31-20

	Applicable Emissions Limitations/Control Measures	
	See A.I.2.b.	4.8 tons HCL/yr,
40 CFR Part 60, Subpart Eb	visible particulate emissions shall not exceed 10 percent opacity as a six-minute average	Start-up and shut-down emissions 20.0 tons NOx/yr 50.0 tons CO/yr 2.5 tons VOC/yr
OAC Rule 3745-17-07(A)	178.0 lbs NO_x/hr & 642.7 tons NO_x/yr	3.3 tons formaldehyde per rolling 12-month period, See A.II.1.
40 CFR Part 60, Subpart GG	251.0 lbs CO/hr & 340.0 tons CO/yr	See A.I.2.a.
OAC rule 3745-18-06(F)	38.6 lbs Sulfur Dioxide (SO_2)/hr & 169.1 tons SO_2/yr	25 ppmvd nitrogen oxides (NO_x) at 15% Oxygen and 25 ppmvd carbon monoxide (CO)at 15% Oxygen when firing natural gas or blended fuel
OAC Rule 3745-17-11(B)(4)	18.0 lbs Particulate Emissions (PE)/hr & 78.8 tons PE/yr, See A.I.2.f.	15 ppmvd NO_x at 15% Oxygen and 15 ppmvd CO at 15% Oxygen when firing syngas
OAC Rule 3745-103	15.0 lbs Volatile Organic Compounds (VOC)/hr & 66.7 tons VOC/yr,	642.7 tons NO_x ,340.0 tons CO, 169.1 tons SO_2, 78.8 tons PE, and 66.7 tons VOC per rolling 12-month period
40 CFR Part 75	1.25 lbs formaldehyde/hr	when firing syngas, emissions shall not exceed:
	0.53 lb sulfuric acid/hr & 2.3 tons sulfuric acid/yr	0.020 mg cadmium/dscm at 7% Oxygen
	0.009 lb cadmium/hr & 0.04 ton cadmium/yr	0.20 mg lead/dscm at 7% Oxygen
	0.018 lb lead/hr & 0.08 ton lead/yr	0.080 mg mercury/dscm at 7% Oxygen
	0.0013 lb mercury/hr & 0.01 ton mercury/yr	13 ng dioxin/furan per dscm at 7% Oxygen
	0.000000029 lb dioxin/furan per hr & 0.000254 lb dioxin/furan per yr	25 ppmvd HCL at 7% Oxygen, or 5 percent of the potential HCL emissions (95 percent reduction by weight or volume), whichever is less stringent
	1.1 lb hydrogen chloride (HCL)/hr &	

See A.I.2.c.

See A.I.2.d.

See A.I.2.c.

See A.I.2.c.

See A.I.2.e.

See A.I.2.e.

2. Additional Terms and Conditions

2.a. The permittee shall employ Best Available Control Technology (BACT) for controlling NO_x, SO_2, CO, PE/PM_{10}, and VOC on this emissions unit. BACT has been determined to be the following determinations have been made for each pollutant:

PE - Use of only clean burning fuels (natural gas and syngas), in an efficient combustion turbine.

NO_x - Use of dilution injection into the combustion zone at the emission concentrations established above.

CO - Use of efficient combustion technology at the emission concentrations established above.

VOC - Use of efficient combustion technology.

SO_2 - Use of a solvent-based absorption technology prior to combustion.

2.b. The requirements of this rule also include compliance with the requirements of OAC rule 3745-31-10 through 20, 40 CFR Part 52.21, and 40 CFR Part 60, Subpart GG and Eb.

2.c. The emission limitation specified by this rule is less rule is less stringent than the emission limitation established pursuant to OAC rule 3745-31-05(A)(3).

2.d. The emission limitations specified by this rule are less rule is less stringent than the emission limitations established pursuant to OAC rule 3745-31-05(A)(3). Except as provided for in the terms and conditions in this permit, the permittee is not exempt from meeting any additional requirements of 40 CFR Part 60, Subpart GG. and 40 CFR Part 60, Subpart Eb.

2.e. If the permittee is subject to the requirements of 40 CFR Part 75 concerning acid rain, the permittee shall ensure that any affected emissions unit complies with those requirements. Emissions exceeding any allowances that are lawfully held under Title IV of the Act, or any regulations adopted thereunder, are prohibited.

2.f. It is assumed that all PE emissions are PM_{10}.

2.g. The annual emission limits above include 200 hours of start-up and shut-down emissions. It has been determined that there are additional NOx, CO, and VOC emissions associated with start-up and shut-down periods. These estimated worst case emissions rates are described in condition A.III.1.

II. Operational Restrictions

1. The permittee has requested a transitional period to allow for additional natural gas usage during the initial 24 months this emissions unit is in operation. During this initial 24 month period following startup*, the maximum allowable natural gas usage for this emissions unit shall not exceed the amounts specified in the following table:

months	allowable NG usage (mmcf)
1-12	8,190
13-24	4,095

After the initial 24 month transition period, the maximum annual fuel usage for this emissions unit shall not exceed 2050 mmcf of natural gas per rolling 12-month period.

To ensure enforceability during the first 12 calendar months following the transition period, the permittee shall not exceed the fuel usage restrictions specified in the following table:

months	Cumulative Summation of allowable fuel usage (mmcf)
25	400
25-26	800
25-27	1200
25-28	1600
25-29	2000
25-36	2050

After the first 36 calendar months of operation, compliance with the annual usage restrictions shall be based on a rolling, 12-month summation.

*Startup for the facility shall be defined as the date when emissions units P002 is set in operation for any purpose. Start-up for the daily operation of the turbine is described in condition A.II.2.

2. This emissions unit shall have a maximum allowable fuel flow of 1.81 million scf/hr when firing natural gas, and a maximum allowable fuel flow of 6.95 million scf/hr when firing syngas. The permittee shall operate this emissions unit within the parameters specified above, except for start-up and shut-down. Start-up shall be defined as the time necessary to bring the unit to it's minimum operating temperature (as recommended by the vendor), but under no circumstances shall it exceed 60 minutes in duration. Shut-down periods shall not exceed 60 minutes in duration.

3. With the exception of start-up and shut-down periods, emissions unit P002 shall be operated at minimum of 50% load. The permittee may petition the Ohio EPA, Northwest District Office (NWDO) to operate at a greater load range if it can demonstrate to the agency's satisfaction that the emissions unit will comply with all applicable emission limits in this permit, and modeling requirements pursuant to Engineering Guide no. 69.

4. The permittee shall burn only natural gas and syngas in this emissions unit. For the purposes of this permit, syngas shall be defined as the gasification of any of the following products: coal, pet coke, and refuse derived fuel (RDF). The permittee may request the gasification of additional products in as described in condition A.VI.2.

5. The permittee shall be limited to 200 hours of operation per year for start-ups and shut-downs.

III. Monitoring and/or Record Keeping Requirements

1. The permittee shall maintain monthly records of the following for emissions unit P002:

   a. number and duration of each start-up;

   b. number and duration of each shut-down;

   c. the start-up and shut-down emissions* for NOx, CO, and VOC in tons per month;

   In addition to the above information, the permittee shall maintain monthly records of the following information for emissions unit P002:

   d. during the first 36 calendar months of operation following startup, the quantity of natural

gas fired and the quantity of syngas fired, in million cubic feet;

e. beginning the first month after the first 36 months of operation following startup, the rolling, 12- month summation of the quantity of natural gas fired and the quantity of syngas fired, in million cubic feet;

f. the monthly emission* rate for PE, NOx, SO2, CO, VOC, and formaldehyde (including start-up and shut-down emissions), in tons;

g. during the first 36 calendar months of operation following startup, the annual emissions of PE, NOx, SO2, CO, VOC, and formaldehyde, (including start-up and shut-down emissions) in tons; and

h. beginning the first month after the first 36 months of operation following startup, the rolling, 12- month summation of the emission rates for PE, NOx, SO2, CO, VOC, and formaldehyde (including start-up and shut-down emissions), in tons. .

*The permittee shall use continuous emissions monitoring (CEM) data to determine emissions for those pollutants where a CEM is installed. During the periods where a CEM is not operational or for pollutants where a CEM is not installed, the permittee shall use the most recent testing data/emission factors available for each respective pollutant, in conjunction with the quantity of fuel fired, as recorded above, to determine monthly emissions. Where CEMs data is not available for start-up and shutdown periods, the emission factors/rates the be used are as follows: 200 lbs NOx/hr, 500 lbs CO/hr, and 25 lbs VOC/hr.

2. For each day during which the permittee burns a fuel other than natural gas or syngas, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

3. The information management system for this emissions unit shall be capable of monitoring and recording the fuel flow in million cu ft, and hours of operation .

4. Except for periods described in 40 CFR part 60.13, the permittee shall install, operate, and maintain equipment to continuously monitor* and record SO_2, NO_x, CO, and opacity of the particulate emissions from this emissions unit, in the units specified in the terms and conditions of this permit. The averaging time for the continuous monitoring and recording equipment shall be 6 minutes (block) for the opacity monitor and 3 hours (block) for all other monitors. The span value of the SO_2, NO_x, and CO continuous emission monitoring systems shall be 125 percent of the maximum estimated hourly potential emissions of the emissions unit. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.13 or as approved by the Ohio EPA.

The permittee shall maintain records of all data obtained by the continuous SO_2, NO_x, CO, and opacity monitoring systems including, but not limited to,

parts per million SO_2, NO_x, CO, and opacity on an instantaneous (one-minute) basis, emissions of SO_2, NO_x, CO, and opacity in the units specified in the terms and conditions of this permit, results of daily zero/span calibration checks, and magnitude of manual calibration adjustments.

5. The permittee shall operate and maintain equipment to continuously monitor and record the O_2 from this emissions unit in percent O_2. The span value of the continuous emission monitoring system shall be 25 percent O_2. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.13 or as approved by the Ohio EPA, Central Office. The permittee may install a CO_2 monitor in lieu of an O_2 monitor with prior approval from the Ohio EPA, Central Office.

   The permittee shall maintain records of all data obtained by the continuous O_2 monitoring system including, but not limited to percent O_2 on an instantaneous (one-minute) basis, results of daily zero/span calibration checks, and magnitude of manual calibration adjustments.

   * The installation and operation of systems to continuously monitor and record emissions of SO_2 and NO_x may be performed in lieu of continuously monitoring the fuel consumption, water ratio, and nitrogen & sulfur contents of the fuel being fired in the turbine, as required by 40 CFR 60.334. When SO_2, NO_x, or CO emissions are not obtained due to continuous emission monitoring system breakdowns, repairs, calibration checks, or other event, emissions data shall be obtained using Method 19 of 40 CFR Part 60, Appendix A or other method as approved by the Ohio EPA, Central Office.

IV. Reporting Requirements

1. The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than natural gas or syngas was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

2. The permittee shall submit deviation (excursion) reports which identify all exceedances of the rolling, 12-month fuel usage limitations and, for the first 36 calendar months of operation, all exceedances of the maximum allowable natural gas usage.

3. The permittee shall submit quarterly reports which identify each period during which an exemption for ice-fog provided in 40 CFR 60.332(f) is in effect. The report shall include the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time when the air pollution control system was reactivated.

4. Pursuant to OAC rules 3745-15-04, 3745-35-02, and ORC sections 3704.03(I) and 3704.031 and 40 CFR Parts 60.7 and 60.13(h), the permittee shall submit reports within 30 days following the end of each calendar quarter to the Ohio EPA NWDO documenting the date, commencement and completion times, duration, magnitude, reason (i.e., startup and shutdown periods as defined in Condition A.II.2., malfunctions, etc.), and corrective actions taken (if any), of all instances of SO_2, NO_x, CO, and opacity values in excess of the limits specified in the terms and conditions of this permit. These reports shall also contain the total SO_2, NO_x, and CO emissions for the calendar quarter (in tons).

   The permittee shall submit reports within 30 days following the end of each calendar quarter to the Ohio EPA, NWDO documenting any continuous SO_2, NO_x, CO, O_2, and opacity monitoring system downtime while the emissions unit was on line (date, time, duration and reason) along with any corrective action(s) taken. The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason and corrective action(s) taken for each time period of emissions unit and control equipment malfunctions. The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line shall also be included in the quarterly report.

   If there are no excess emissions during the calendar quarter, the permittee shall submit a statement to that effect along with the emissions unit operating time during the reporting period and the date, time, reason, and corrective action(s) taken for each time period of emissions unit, control equipment, and/or monitoring system malfunctions. The total operating time of the emissions unit and the total operating time of the analyzer while the emissions unit was on line also shall be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during the previous calendar quarter.

5. Pursuant to OAC rules 3745-15-04, 3745-35-02, and ORC sections 3704.03(I) and 3704.031, the permittee shall submit a summary of the excess emission report pursuant to 40 CFR Part 60.7. The summary shall be submitted to the Ohio EPA, NWDO within 30 days following the end of each calendar quarter in a manner prescribed by the Director.

6. The permittee shall submit deviation (excursion) reports that identify each time when this emissions unit was not in compliance with the requirements of condition A.II.2., A.II.3., and A.II.5. above.

7. In lieu of the excess emissions reports required under 40 CFR Part 60.334, the permittee shall submit excess and emissions reports for emissions unit P002 in accordance with this permit.

8. The permittee shall submit semiannual reports as required by 40 CFR Part 60.59b(h).

9. Except as specified in condition A.IV.1, all deviation reports shall be submitted in accordance with the General Terms and Conditions of this permit.

10. This emissions unit is subject to the applicable provisions of Subpart GG and Eb of the New Source Performance Standards (NSPS) as promulgated by the United States Environmental Protection Agency, 40 CFR Part 60.

    The application and enforcement of these standards are delegated to the Ohio EPA. The requirements of 40 CFR Part 60 are also federally enforceable.

    Pursuant to 40 CFR Part 60.7 and 60.59b, the permittee is hereby advised of the requirement to report the following at the appropriate times:

    a. construction date - intent to construct (no later than 30 days after such date);
    b. anticipated start-up date (not more than 60 days or less than 30 days prior to such date);
    c. actual start-up date (within 15 days after such date);
    d. the types of fuels that are planning on being combusted;
    e. the combustion units maximum capacity;
    f. any documents associated with the siting requirements as specified in 40 CFR Part 60.59b(b)(5); and
    g. date of performance testing, at least 45 days prior to testing.

    Reports are to be sent to:

    Ohio Environmental Protection Agency
    DAPC - Permit Management Unit
    Lazarus Government Center
    P.O.1049
    Columbus, Ohio 43216-1049

    and

    Ohio Environmental Protection Agency
    Northwest District Office
    Division of Air Pollution Control
    347 North Dunbridge Road
    Bowling Green, Ohio 43402

V. Testing Requirements/Compliance Methods Determinations

1. The permittee shall conduct, or have conducted, emission testing for this emissions unit in accordance with the following requirements:

    a. The emissions testing shall be conducted while firing both natural gas and syngas individually. The emission testing while firing natural gas shall be conducted within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of this emissions unit. The

emissions testing while firing syngas shall be conducted within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after the initial use of syngas in this emissions unit.

b. The emissions testing shall be conducted to demonstrate compliance with the NO_x and CO outlet concentrations, and the mass emissions limitations for NO_x, CO, VOC, SO_2, PE, and Formaldehyde. Emission testing shall also be conducted to demonstrate compliance with the outlet concentrations and mass emissions limitations for cadmium, lead, mercury, HCL, and dioxin/furans when firing syngas.

c. The following test method(s) shall be employed to demonstrate compliance with the above emissions limitations: for NO_x, Method 20 of 40 CFR Part 60, Appendix A; for PE, Method 5 of 40 CFR Part 60, Appendix A; for formaldehyde, SW-846 Method 0011 or CARB Method 316; for VOC, Method 25 of 40 CFR Part 60, Appendix A; SO_2 Method 6 of 40 CFR Part 60, Appendix A; for CO Method 10 of 40 CFR Part 60, Appendix A, for cadmium, Method 29 of 40 CFR Part 60, Appendix A; for lead, Method 29 of 40 CFR Part 60, Appendix A; for mercury, Method 29 of 40 CFR Part 60, Appendix A; for HCL, Method 26 of 40 CFR Part 60, Appendix A; for dioxin/furan, Method 23 of 40 CFR Part 60, Appendix A; and for air flow and moisture content determinations, Methods 1-4 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA, NWDO.

d. In addition to the above pollutants, emissions testing shall also be performed for the following pollutants while firing syngas: Total Chromium, Vanadium, Zinc, Cobalt, Arsenic, Antimony, Manganese, Beryllium, Benzene, Selenium, Carbon Disulfide, and Carbonyl Sulfide. The permittee shall propose the testing methodology for these pollutants consistent with US EPA test methods.

e. The permittee shall develop site specific emission factors for all pollutants tested. These emission factors shall be in units of lbs of emissions per volume of fuel consumed.

f. The following testing requirements are pursuant to 40 CFR Part 60, Part 60.58b:

i. when testing for dioxin/furan emissions, the minimum sampling time shall be 4 hours per test run;

ii. when testing for mercury and PE, the minimum sample volume shall be 1.7 cubic meters;

iii. when testing PE, the probe and filter holder heating in the sample train shall be set to provide a gas temperature of no greater than 160 +/- 14 degrees Celcius; and,

iv. the minimum frequency of testing shall be such that it complies with the requirements of 40 CFR Part 60, Part 60.58b.

g. The testing shall be performed at peak load (as defined by 40 CFR Part 60, Subpart GG), unless otherwise specified or approved by the Ohio EPA, NWDO.

h. Not later than 45 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the Ohio EPA, NWDO. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the tests, and the person(s) who will be conducting the tests. Failure to submit such notification for review and approval prior to the tests may result in the Ohio EPA, NWDO refusal to accept the results of the emission tests.

i. Personnel from the Ohio EPA, NWDO shall be permitted to witness the tests, examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

j. A comprehensive written report on the results of the emissions tests shall be signed by the person or persons responsible for the tests and submitted to the Ohio EPA, NWDO within 30 days following completion of the tests. The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Ohio EPA, NWDO.

k. As part of the stack test report, the permittee shall include test results that are in the units of measurement established in this permit as well as in the units of measurement established in 40 CFR Part 60, Subpart Eb.

l. In lieu of the test methods and procedures required under 40 CFR Part 60.335, the permittee shall follow the testing requirements in accordance with this permit.

2. Within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of such emissions unit, the permittee shall conduct certification tests of the continuous NO_x and CO monitoring systems pursuant to ORC section 3704.03(I) and 40 CFR Part 60, Appendix B, Performance Specification 6*. Personnel from the Ohio EPA, Northwest District Office shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. In accordance with OAC rule 3745-15-04, copies of all the test results shall be submitted within 30 days after the test is completed. Copies of the test results shall be sent to the Ohio EPA, Northwest District Office and the Ohio EPA, Central Office. Certification of the continuous NO_x and CO monitoring systems shall be granted upon determination by the Ohio EPA, Central Office that the system meets all requirements of ORC section 3704.03(I) and 40 CFR Part 60, Appendix

B, Performance Specification 6*.

3. Within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of such emissions unit, the permittee shall conduct certification tests of the continuous O_2 monitoring systems pursuant to ORC section 3704.03(I) and 40 CFR Part 60, Appendix B, Performance Specification 3. Personnel from the Ohio EPA, Northwest District Office shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. In accordance with OAC rule 3745-15-04, all copies of the test results shall be submitted within 30 days after the test is completed. Copies of the test results shall be sent to the Ohio EPA, Northwest District Office and the Ohio EPA, Central Office. Certification of the continuous O_2 monitoring system shall be granted upon determination by the Ohio EPA, Central Office that the system meets all requirements of ORC section 3704.03(I) and 40 CFR Part 60, Appendix B, Performance Specification 3.

   * The permittee may use 40 CFR Part 60, Appendix B, Performance Specification 2 and Performance Specification 4 in conjunction with a fuel flow monitor as described in 40 CFR Part 75 to meet these requirements if approved by the Ohio EPA, Central Office.

4. Within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of such emissions unit, the permittee shall conduct certification tests on the continuous opacity monitoring system equipment pursuant to ORC section 3704.03(I) and 40 CFR Part 60, Appendix B, Performance Specification 1. Personnel from the Ohio EPA, Northwest District Office shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. In accordance with OAC rule 3745-15-04, all copies of the test results shall be submitted within 30 days after the test is completed. Copies of the test results shall be sent to the Ohio EPA, Northwest District Office and the Ohio EPA, Central Office. Certification of the continuous opacity monitoring system shall be granted upon determination by the Ohio EPA, Central Office that the system meets all requirements of ORC section 3704.03(I), and 40 CFR Part 60, Appendix B, Performance Specification 1 including section 5.1.9 (mandatory).

5. Compliance with the allowable emission limitations in this permit shall be determined according to the following methods:

   a. <u>Emission Limitation</u>
      25 ppmvd NO_x at 15% Oxygen when firing natural gas or blended fuel
      15 ppmvd NO_x at 15% Oxygen when firing syngas
      178.0 lbs NO_x/hr & 642.7 tons NO_x per rolling 12-month period

      <u>Applicable Compliance Method</u>

Compliance with the allowable outlet concentrations and the lbs/hr emission limitation shall be demonstrated by the performance testing as described in condition A.V.1 and continuous emissions monitoring requirement as described in conditions A.III.4. and A.V.2. Compliance with the annual emission limitations shall be determined by the record keeping required in condition A.III.1.

b. Emission Limitation
18.0 lbs PE/hr & 78.8 tons PE per rolling 12-month period

Applicable Compliance Method
Compliance with the allowable outlet concentrations & the lbs/hr emission limitations shall be demonstrated by the performance testing as described in condition A.V.1. Compliance with the annual emission limitations shall be determined by the record keeping required in condition A.III.1.

c. Emission Limitation
36.6 lbs SO_2/hr & 169.1 tons SO_2 per rolling 12-month period

Applicable Compliance Method
Compliance with the allowable outlet concentrations and the lbs/hr emission limitation shall be demonstrated by the performance testing as described in condition A.V.1 and continuous emissions monitoring requirement as described in conditions A.III.4. and A.V.2. Compliance with the annual emission limitations shall be determined by the record keeping required in condition A.III.1.

d. Emission Limitation
15.0 lbs VOC/hr & 66.7 tons VOC per rolling 12-month period

Applicable Compliance Method
Compliance with the lbs/hr emission limitations shall be demonstrated by the performance testing as described in condition A.V.1. Compliance with the annual emission limitations shall be determined by the record keeping required in condition A.III..1.

e. Emission Limitation
25 ppmvd CO at 15% Oxygen when firing natural gas
15 ppmvd CO at 15% Oxygen when firing syngas
251.0 lbs CO/hr & 340.0 tons CO per rolling 12-month period

Applicable Compliance Method
Compliance with the allowable outlet concentrations and the lbs/hr emission limitation shall be demonstrated by the performance testing as described in condition A.V.1 and continuous emissions monitoring requirement as described in conditions A.III.4. and A.V.2. Compliance with the annual emission limitations shall be determined by the record keeping required in condition A.III.1.

f. Emission Limitation
1.25 lbs formaldehyde/hr & 3.3 tons formaldehyde per rolling 12-month period

Applicable Compliance Method
Compliance with the lbs/hr emission limitations shall be demonstrated by the performance testing as described in condition A.V.1. Compliance with the annual emission limitations shall be determined by the record keeping required in condition A.III.1.

g. Emission Limitation
0.020 mg cadmium/dscm at 7% Oxygen
0.009 lb cadmium/hr & 0.04 ton cadmium/yr

0.20 mg lead/dscm at 7% Oxygen
0.018 lb lead/hr & 0.08 ton lead/yr

0.080 mg mercury/dscm at 7% Oxygen
0.0013 lb mercury/hr & 0.01 ton mercury/yr

13 ng dioxin/furan per dscm at 7% Oxygen
0.000000029 lb dioxin/furan per hr & 0.000254 lb dioxin/furan per yr

25 ppmvd HCL at 7% Oxygen, or 5 percent of the potential HCL emissions (95 percent reduction by weight or volume), whichever is less stringent
1.1 lb HCL/hr & 4.8 tons HCL/yr

Applicable Compliance Method
Compliance with the allowable outlet concentrations and the lbs/hr emission limitations shall be demonstrated by the performance testing as described in condition A.V.1. Compliance with the annual emission limitations shall be determined multiplying the hourly emission limit by 8760 hrs/yr and dividing by 2000 lbs/ton.

h. Emission Limitation
0.53 lb sulfuric acid/hr & 2.3 tons sulfuric acid/yr

Applicable Compliance Method
The allowable lbs/hr emission limitation the represents the potential to emit based on engineering calculations while firing syngas. If required, compliance with the allowable lbs/hr emission limitation shall be determined by approved U.S. EPA test methods. Compliance with the annual emission limitations shall be determined multiplying the hourly emission limit by 8760 hrs/yr and dividing by 2000 lbs/ton.

i. Emission Limitation
Start-up and shut-down emissions
20.0 tons NOx/yr
50.0 tons CO/yr
2.5 tons VOC/yr

Applicable Compliance Method
Compliance with the annual emission limitations shall be demonstrated by the record keeping required in condition A.III.1.

j. Emission Limitation
Visible particulate emissions shall not exceed 10 percent opacity as a six-minute average.

Applicable Compliance Method
If required, compliance with the visible emissions limitations established by this permit

shall be determined by Method 9, 40 CFR Part 60 Appendix A.

VI. Miscellaneous Requirements

1. The permittee may petition the Ohio EPA, Northwest District Office (NWDO) to operate at a greater load range if it can demonstrate to the agency's satisfaction that the emissions unit will comply with all applicable emission limits in this permit, and modeling requirements pursuant to Engineering Guide no. 69.

2. The permittee may also petition the Ohio EPA, NWDO to use additional materials for the production of syngas if it can demonstrate to the agency's satisfaction that the emissions unit will comply with Ohio EPA's "Air Toxics Policy" and all applicable emission limits in this permit.

3. Prior to the installation of the continuous NO_x ,CO, SO_2, and opacity monitoring systems, the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specification 6 (or as described in condition A.V.1.) for approval by the Ohio EPA, Central Office.

   Prior to the installation of the continuous O_2 monitoring system, the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specification 3 for approval by the Ohio EPA, Central Office.

   Prior to the installation of the continuous opacity monitoring system, the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specification 1 for approval by the Ohio EPA, Central Office.

4. Within 30 days of the start-up of this emissions unit, the permittee shall develop a written quality assurance/quality control plan for the continuous NO_x ,CO, SO_2, O_2, and opacity monitoring systems designed to ensure continuous valid and representative readings of NO_x ,CO, SO_2,O_2, and opacity emissions. The plan shall follow the requirements of 40 CFR Part 60, Appendix F, except as otherwise specified in 40 CFR Part 60, Subpart Eb, or as approved by the Ohio EPA, Central office. The quality assurance/quality control plan and a logbook dedicated to the continuous NO_x, CO, SO_2, O_2, and opacity monitoring systems must be kept on site and available for inspection during regular office hours.

5. Per the requirements of condition A.V.1.d., the permittee is required to perform emissions testing for numerous HAPs, for which emissions limitations are not established in this permit. This emissions data is to be used when calculating HAPs potential to emit. In addition, Ohio EPA will review this emissions data to determine if the permit adequately addresses all pollutants of

concern. The Ohio EPA reserves the right to modify this permit for the purpose of establishing additional emission limits or performance standards for any of these pollutants. Any newly established limits or standards would be consistent with Best Available Technology requirements and all other applicable rules and regulations.

6. The permittee shall provide training and certification for all operators and supervisors as described in 40 CFR Part 60, Subpart 60.54b. The permittee shall maintain records on showing the names of all operators and supervisors who, have received certification and training as described in 40 CFR Part 60, Subpart 60.59b.

7. The permittee shall develop a site specific operating manual, provide training on the operating manual, and maintain records showing the names of all persons who have been provided the training, as described in 40 CFR Part 60, Subpart 60.54b and 60.59b respectively.

8. A siting analysis shall be conducted in accordance with 40 CFR Part 60.57.

9. The permittee is exempt from the requirement in 40 CFR Part 60, Subpart Eb which pertain to the development of a materials separation plan, as this facility does not accept municipal solid waste.

10. The permittee is exempt from the requirements of 40 CFR Part 60, Subpart Eb which pertain to the monitoring, record keeping, and reporting on the operation of a post combustion particulate control device, as there is no such device on this emissions unit.

11. The permittee is exempt from the requirements of 40 CFR Part 60, Subpart Eb. which pertain to the monitoring, record keeping, and reporting on the generation of fugitive ash, as this facility does not generate fugitive ash as this operation is described in 40 CFR Part 60, Subpart Eb.

12. Within 90 days of the of the start-up of this emissions unit, the permittee shall develop a preventative maintenance and malfunction abatement plan/system for the gasification operations at this facility. The plan should clearly document how the permittee maintains the system(s) in good working order, i.e. the type of inspections done on the equipment as well as the frequency. The quality assurance/quality control plan and logbooks/records dedicated to the system must be kept on site and available for inspection during regular office hours. This plan should also specify the responsible person(s) for notifying this office in the event of an equipment malfunction that results in emissions to the atmosphere.

B. State Only Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

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

Operations, Property, and/or Equipment	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
P002 - Syngas/Natural Gas Turbine, Unit #1 of a Combined Cycle System and Gasification Plant	OAC rule 3745-31-05(A)(3)	none

2. Additional Terms and Conditions

2.a None

II. Operational Restrictions

None

III. Monitoring and/or Recordkeeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

Part III - SPECIAL TERMS AND CONDITIONS FOR SPECIFIC EMISSIONS UNIT(S)

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

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

Operations, Property, and/or Equipment	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
P003 - Cooling Tower	OAC rule 3745-31-10 through 3745-31-20	See A.I.2.a.
	OAC rule 3745-31-05 (A)(3)	See A.I.2.b. 1.88 lbs PE/hr & 8.2 tons PE/yr
	OAC rule 3745-17-11 (B)	See A.I.2.c.
	OAC rule 3745-17-07 (A)	visible particulate emissions shall not exceed 20 percent opacity as a six-minute average, except as provided by rule

2. Additional Terms and Conditions

2.a Per the requirements of OAC rule 3745-31-10 through 3745-31-20, the permittee is required to perform a Best Available Control Technology (BACT) review for PE/PM_{10}. The implementation of high efficiency drift eliminators and operating under the terms and conditions of this permit constitute BACT for this emissions unit.

2.b The requirements of this rule also include compliance with the requirements of OAC rule 3745-31-10 through 20, and OAC rule 3745-17-07 (A).

2.c The emission limitation specified by this rule is less rule is less stringent than the emission limitation established pursuant to OAC rule 3745-31-05(A)(3).

II. Operational Restrictions

1. The permittee shall maintain an average total dissolved solids content of 3,000 ppm or less in this emissions unit.

III. Monitoring and/or Recordkeeping Requirements

1. The permittee shall perform the following monitoring requirements for emissions unit P003 on a monthly basis:

   a. test and record the total dissolved solids content;

   b. determine the average dissolved solids content based on a rolling 12 month average.

IV. Reporting Requirements

1. The permittee shall submit deviation reports in accordance with the general terms and conditions of this permit that identify any exceedances of the average total dissolved solids content.

V. Testing Requirements

1. Compliance with the allowable emission limitations in this permit shall be determined according to the following methods:

   a. <u>Emission Limitation</u>
   1.88 lbs PE/hr & 8.2 tons PE/yr

   <u>Applicable Compliance Method</u>
   Compliance with the lbs/hr emission limitation shall be demonstrated by applying the maximum drift loss factor 0.0005 percent to the maximum average total dissolved solids content of 3,000 ppm for the cooling water. If required, the permittee shall submit a testing proposal which will demonstrate that the maximum drift loss does not exceed 0.0005 percent. Compliance with the annual emission limitation shall be demonstrated by the multiplying the hourly emission rate by 8760 hours and dividing by 2000 lbs/ton.

VI. Miscellaneous Requirements

None

B. State Only Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

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

Operations, Property, and/or Equipment	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
P003 - Cooling Tower	OAC rule 3745-31-05(A)(3)	none

2. Additional Terms and Conditions

2.a None

II. Operational Restrictions

None

III. Monitoring and/or Recordkeeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

NEW SOURCE REVIEW FORM B

PTI Number: 03-13445 Facility ID: 0302020336

FACILITY NAME Lima Energy Company

FACILITY DESCRIPTION Combined Cycle power plant CITY/TWP Lima

SIC CODE 4911 SCC CODE EMISSIONS UNIT ID F001

EMISSIONS UNIT DESCRIPTION Fuel Briquette Material Handling & Storage

DATE INSTALLED 8/01

EMISSIONS: (Click on bubble help for Air Quality Descriptions)

Pollutants	Air Quality Description	Actual Emissions Rate		PTI Allowable	
		Short Term Rate	Tons Per Year	Short Term Rate	Tons Per Year
Particulate Matter	in attainment for all		0.5		0.5
PM_{10}					
Sulfur Dioxide					
Organic Compounds					
Nitrogen Oxides					
Carbon Monoxide					
Lead					
Other: Air Toxics					

APPLICABLE FEDERAL RULES:

NSPS? NESHAP? PSD? Y OFFSET POLICY?

WHAT IS THE BAT DETERMINATION, AND WHAT IS THE BASIS FOR THE DETERMINATION?
Enter Determination

IS THIS SOURCE SUBJECT TO THE AIR TOXICS POLICY? y

OPTIONAL: WHAT IS THE CAPITAL COST OF CONTROL EQUIPMENT? $n/a

TOXIC AIR CONTAMINANTS

Ohio EPA's air toxics policy applies to contaiminants for which the American Conference of Governmental Industrial Hygienists (ACGIH) has a listed threshold limit value.

AIR TOXICS MODELING PERFORMED*? YES n NO

IDENTIFY THE AIR CONTAMINANTS:

NEW SOURCE REVIEW FORM B

PTI Number: 03-13445 Facility ID: 0302020336

FACILITY NAME Lima Energy Company

FACILITY DESCRIPTION Combined Cycle power plant CITY/TWP Lima

Emissions Unit ID: P003

SIC CODE 4911 SCC CODE EMISSIONS UNIT ID F002

EMISSIONS UNIT DESCRIPTION Vitrified Frit Handling & Storage

DATE INSTALLED 8/01

EMISSIONS: (Click on bubble help for Air Quality Descriptions)

Pollutants	Air Quality Description	Actual Emissions Rate		PTI Allowable	
		Short Term Rate	Tons Per Year	Short Term Rate	Tons Per Year
Particulate Matter	in attainment for all		0.2		0.2
PM_{10}					
Sulfur Dioxide					
Organic Compounds					
Nitrogen Oxides					
Carbon Monoxide					
Lead					
Other: Air Toxics					

APPLICABLE FEDERAL RULES:

NSPS? NESHAP? PSD? Y OFFSET POLICY?

WHAT IS THE BAT DETERMINATION, AND WHAT IS THE BASIS FOR THE DETERMINATION?
Enter Determination

IS THIS SOURCE SUBJECT TO THE AIR TOXICS POLICY? y

OPTIONAL: WHAT IS THE CAPITAL COST OF CONTROL EQUIPMENT? $n/a

TOXIC AIR CONTAMINANTS

Ohio EPA's air toxics policy applies to contaiminants for which the American Conference of Governmental Industrial Hygienists (ACGIH) has a listed threshold limit value.

AIR TOXICS MODELING PERFORMED*? YES x NO

IDENTIFY THE AIR CONTAMINANTS:

NEW SOURCE REVIEW FORM B

PTI Number: 03-13445 Facility ID: 0302020336

FACILITY NAME Lima Energy Company

FACILITY DESCRIPTION Combined Cycle power plant CITY/TWP Lima

Emissions Unit ID: P003

SIC CODE 4911 SCC CODE EMISSIONS UNIT ID F003

EMISSIONS UNIT DESCRIPTION Raw Material Handling & Storage (Limestone and Pet Coke)

DATE INSTALLED 8/01

EMISSIONS: (Click on bubble help for Air Quality Descriptions)

Pollutants	Air Quality Description	Actual Emissions Rate		PTI Allowable	
		Short Term Rate	Tons Per Year	Short Term Rate	Tons Per Year
Particulate Matter	in attainment for all		0.2		0.2
PM_{10}					
Sulfur Dioxide					
Organic Compounds					
Nitrogen Oxides					
Carbon Monoxide					
Lead					
Other: Air Toxics					

APPLICABLE FEDERAL RULES:

NSPS? NESHAP? PSD? Y OFFSET POLICY?

WHAT IS THE BAT DETERMINATION, AND WHAT IS THE BASIS FOR THE DETERMINATION?
Enter Determination

IS THIS SOURCE SUBJECT TO THE AIR TOXICS POLICY? y

OPTIONAL: WHAT IS THE CAPITAL COST OF CONTROL EQUIPMENT? $n/a

TOXIC AIR CONTAMINANTS

Ohio EPA's air toxics policy applies to contaiminants for which the American Conference of Governmental Industrial Hygienists (ACGIH) has a listed threshold limit value.

AIR TOXICS MODELING PERFORMED*? YES x NO

IDENTIFY THE AIR CONTAMINANTS:

NEW SOURCE REVIEW FORM B

PTI Number: 03-13445 Facility ID: 0302020336

FACILITY NAME Lima Energy Company

FACILITY DESCRIPTION Combined Cycle power plant CITY/TWP Lima

Emissions Unit ID: P003

SIC CODE 4911 SCC CODE 2-03-002-02 EMISSIONS UNIT ID P001

EMISSIONS UNIT DESCRIPTION NG/Syngas Turbine, Turbine #1 in a Combined Cycle System

DATE INSTALLED 8/01

EMISSIONS: (Click on bubble help for Air Quality Descriptions)

Pollutants	Air Quality Description	Actual Emissions Rate		PTI Allowable	
		Short Term Rate	Tons Per Year	Short Term Rate	Tons Per Year
Particulate Matter	in attainment for all	18.0	78.8	18.0	78.8
PM_{10}		same as PM			
Sulfur Dioxide		38.6	169.1	38.6	169.1
Organic Compounds		15.0	66.7	15.0	66.7
Nitrogen Oxides		168	642.7	178	642.7
Carbon Monoxide		78	340	251	340
Lead		0.018	0.08	0.018	0.08
Other: Air Toxics	Eb metal limits	please see permit			

APPLICABLE FEDERAL RULES:

NSPS? NESHAP? GG & Eb PSD? Y OFFSET POLICY?

WHAT IS THE BAT DETERMINATION, AND WHAT IS THE BASIS FOR THE DETERMINATION?
Enter Determination

IS THIS SOURCE SUBJECT TO THE AIR TOXICS POLICY? y

OPTIONAL: WHAT IS THE CAPITAL COST OF CONTROL EQUIPMENT? $ unkn

TOXIC AIR CONTAMINANTS

Ohio EPA's air toxics policy applies to contaiminants for which the American Conference of Governmental Industrial Hygienists (ACGIH) has a listed threshold limit value.

AIR TOXICS MODELING PERFORMED*? x YES ____ NO

IDENTIFY THE AIR CONTAMINANTS: Formaldehyde, Sulfuric Acid, HCL, & Nickle

NEW SC
PTI Num
FACILIT

Emissions Unit ID: P003

FACILITY DESCRIPTION Combined Cycle power plant CITY/TWP Lima

SIC CODE 4911 SCC CODE 2-03-002-02 EMISSIONS UNIT ID P002

EMISSIONS UNIT DESCRIPTION NG/Syngas Turbine, Turbine #2 in a Combined Cycle System

DATE INSTALLED 8/01

EMISSIONS: (Click on bubble help for Air Quality Descriptions)

Pollutants	Air Quality Description	Actual Emissions Rate		PTI Allowable	
		Short Term Rate	Tons Per Year	Short Term Rate	Tons Per Year
Particulate Matter	in attainment for all	18	78.8	18	78.8
PM_{10}		Same as PM			
Sulfur Dioxide		38.6	169.1	38.6	169.1
Organic Compounds		15	66.7	15	66.7
Nitrogen Oxides		168	642.7	178	642.7
Carbon Monoxide		78	340	251	340
Lead		0.018	0.8	0.018	0.08
Other: Air Toxics	Eb metal limits	please see permit			

APPLICABLE FEDERAL RULES:

NSPS? NESHAP? GG & Eb PSD? Y OFFSET POLICY?

WHAT IS THE BAT DETERMINATION, AND WHAT IS THE BASIS FOR THE DETERMINATION?
Enter Determination

IS THIS SOURCE SUBJECT TO THE AIR TOXICS POLICY? y

OPTIONAL: WHAT IS THE CAPITAL COST OF CONTROL EQUIPMENT? $unkn

TOXIC AIR CONTAMINANTS

Ohio EPA's air toxics policy applies to contaiminants for which the American Conference of Governmental Industrial Hygienists (ACGIH) has a listed threshold limit value.

AIR TOXICS MODELING PERFORMED*? x YES ____ NO

IDENTIFY THE AIR CONTAMINANTS: Formaldehyde, Sulfuric Acid, HCL, & Nickle

NEW SOURCE REVIEW FORM B

PTI Number: 03-13445 Facility ID: 0302020336

FACILITY NAME Lima Energy Company

FACILITY DESCRIPTION Combined Cycle power plant CITY/TWP Lima

Emissions Unit ID: P003

SIC CODE 4911 SCC CODE 2-88-888-01 EMISSIONS UNIT ID P003

EMISSIONS UNIT DESCRIPTION Cooling Tower

DATE INSTALLED 8/01

EMISSIONS: (Click on bubble help for Air Quality Descriptions)

Pollutants	Air Quality Description	Actual Emissions Rate		PTI Allowable	
		Short Term Rate	Tons Per Year	Short Term Rate	Tons Per Year
Particulate Matter				1.88	8.2
PM_{10}					
Sulfur Dioxide					
Organic Compounds					
Nitrogen Oxides					
Carbon Monoxide					
Lead					
Other: Air Toxics					

APPLICABLE FEDERAL RULES:

NSPS? NESHAP? PSD? Y OFFSET POLICY?

WHAT IS THE BAT DETERMINATION, AND WHAT IS THE BASIS FOR THE DETERMINATION?
Enter Determination

IS THIS SOURCE SUBJECT TO THE AIR TOXICS POLICY? y

OPTIONAL: WHAT IS THE CAPITAL COST OF CONTROL EQUIPMENT? $unkn

TOXIC AIR CONTAMINANTS

Ohio EPA's air toxics policy applies to contaiminants for which the American Conference of Governmental Industrial Hygienists (ACGIH) has a listed threshold limit value.

AIR TOXICS MODELING PERFORMED*? _____ YES x NO

IDENTIFY THE AIR CONTAMINANTS: _____

Ohio EPA Permit to Install Information Form Please describe below any documentation which is being submitted with this recommendation (must be sent the same day). Electronic items should be submitted with the e-mail transmitting the PTI terms, and in software that CO can utilize. If mailing any hard copy, this section must be printed as a cover page. All items must be clearly labeled indicating the PTI name and number. Submit hard copy items to **Pam McGraner**, AQM&P, DAPC, Central Office, and electronic files to **airpti@epa.state.oh.us**

Please fill out the following. If the checkbox does not work, replace it with an 'X'	Electronic	**Additional information** File Name Convention (your PTI # plus this letter)	Hard Copy	None
Calculations (required)	☒	0313445**c**.wpd	☐	
Modeling form/results	☐	0000000**s**.wpd	☒	☐
PTI Application (complete or partial)*	☐	0000000**a**.wpd	☒	☐
BAT Study	☐	0000000**b**.wpd	☒	☐
Other/misc.	☐	0000000**t**.wpd	☐	☐

* Mandatory for netting, PSD, nonattainment NSR, 112(g), 21-07(G)(9)(g) and 21-09(U)(2)(f) - 2 complete copies.

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NEW SOURCE REVIEW FORM B

PTI Number: 03-13445 Facility ID: 0302020336

FACILITY NAME Lima Energy Company

FACILITY DESCRIPTION Combined Cycle power plant CITY/TWP Lima

Emissions Unit ID: P003

Please complete (see comment bubble to the left for additional instructions):

NSR Discussion