pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Bureau of Air Quality

Technical Support Document
General Permit GP-5

January 31, 2013

Contents:

Abbreviations:

BAT	Best Available Technology
BHP	Brake Horsepower
CFR	Code of Federal Regulation
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DEG	Diethylene Glycol
GP	General permit
H_2S	Hydrogen Sulfide
HAP	Hazardous Air Pollutant
HCHO	Formaldehyde
MMBtu	Million British Thermal Units
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGL	Natural Gas Liquids
NMNEHC	Non Methane, Non Ethane Hydrocarbon
NO_X	Oxides of Nitrogen
NSCR	Non-Selective Catalytic Reduction
NSPS	New Source Performance Standards
PM	Particulate Matter
PPMV	Parts Per Million by Volume
REC	Reduced Emission Completion

SCR	Selective Catalytic Reduction
SI RICE	Spark Ignition Reciprocating Internal Combustion Engine
SO_X	Oxides of Sulfur
TEG	Triethylene Glycol
TPY	Tons Per Year
VOC	Volatile Organic Compound

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Executive Summary:

This technical support document was prepared by the Department of Environmental Protection (DEP or Department) of to include the background information of the sources and the associated air emissions, available controls and the rationale for the establishment of air permitting requirements sources covered by the General Permit for Natural Gas Compression and/or Processing Facilities, GP-5 which was released on February 2, 2013. These sources include stationary natural gas-fired spark ignition reciprocating internal combustion engines, natural gas-fired simple cycle turbines, centrifugal compressors, condensate tanks, glycol dehydrators, natural gas fractionation process units, storage vessels, pneumatic controllers, and sweetening units. The new GP-5 includes additional air emission sources located at natural gas compression and processing facilities and updates the Best Available Technology (BAT) requirements for the sources covered by the GP-5. In addition, U.S. EPA promulgated sector based New Source Performance Standards for the Oil and Gas Industry (40 CFR Part 60, Subpart OOOO) on August 16, 2012. Federal NSPS rules are incorporated in the Department's regulations by reference in 25 Pa. Code Chapter 122. Therefore, the revised GP-5 includes these requirements along with other Federal requirements.

Introduction:

Pursuant to Section 6.1 of the Air Pollution Control Act (APCA, 35 P.S Section 4006.1) and 25 Pa. Code §§127.514 and 127.611, the Department of Environmental Protection (PA DEP or Department) has issued General Plan Approvals and General Operating Permits (hereinafter referred to as **general permits** or **GP**) to specific categories of sources that are similar in design and operation, and can be adequately regulated with standardized specifications and conditions.

The Department first issued a General Permit for Natural Gas, Coal Bed Methane or Gob Gas Production or Recovery Facilities (BAQ-GPA/GP-5 or GP-5) on March 10, 1997, and revised it periodically. On July 27, 2006, PA DEP issued General Plan Approval and / or General Operating Permit for Natural Gas, Coal Bed Methane or Gob Gas Production or Recovery Facilities. This GP-5 applied to sources including internal combustion (compressor) engines with a rated capacity equal to or greater than 100 brake horsepower (bhp) and less than 1500 bhp, gas dehydration units, crude oil and brine storage tanks, vents and other equipment associated with this activity.

On March 26, 2011, the DEP published notice in the *Pennsylvania Bulletin* of minor amendments to GP-5 (41 Pa.B.1700). Along with certain minor amendments and clarifications, the revised GP-5 included conditions to limit the potential to emit of a source based on the specifications in the Application for Authorization to Use GP-5. The amended GP-5 allowed the applicant to propose lower emission limits based on the manufacturer's specifications and other operational limits. The amended GP-5 allowed the use of the cleaner burning and more efficient engines used throughout the industry. The amended GP-5 also clarified that the federal new source performance standards and national emission standards for hazardous air pollutants are applicable requirements, which are incorporated by reference in their entirety in the Pennsylvania Code.

The new GP-5 expands the applicability of the GP-5 to the sources located at natural gas compression and /or processing facilities with potential or actual emissions less than 100 tons/year (TPY) of criteria pollutants (NO_X, CO, SO_2, PM_{10}, and $PM_{2.5}$) less than 50 TPY of VOC, less than 10 TPY of any single hazardous air pollutant (HAP), less than 25 TPY of total HAPs, and less than 100,000 tons per year of greenhouse gases expressed as CO_2e. The NO_X and VOC emissions thresholds in Philadelphia, Bucks, Chester, Montgomery, and Delaware counties are 25 TPY.

Definitions:

Words and terms that are not otherwise defined in this General Permit have the meanings set forth in Section 3 of the APCA (35 P.S. § 4003) and Title 25, Article III including 25 Pa. Code § 121.1 (relating to definitions) unless the context indicates otherwise. The meanings set forth in applicable definitions codified in the Code of Federal Regulations including 40 CFR Part 60 Subparts Kb, KKK, LLL, JJJJ, KKKK, OOOO or 40 CFR Part 63 Subparts HH and ZZZZ also apply to this general permit.

Applicability / Scope:

GP-5 authorizes the construction, modification, and/or operation of source located at a natural gas compression and/or a gas processing facility. The applicability of this general permit may include any of the following:

Natural gas-fired spark ignition internal combustion engine.
Natural gas-fired simple cycle turbine.
Centrifugal compressor.
Glycol dehydration unit and associated equipment including Gas-Condensate-Glycol (“GCG”) separator (Flash tank separator).
Natural gas fractionation (such as De-propanizer, De-ethanizer, De-butanizer).
Storage vessel/tanks.
Equipment leaks.
Pneumatic controllers.
Sweetening units.

If any source located at the natural gas processing facility cannot be regulated under this general permit, a plan approval and/or an operating permit issued in accordance with 25 Pa. Code, Chapter 127, Subchapter B (relating to plan approval requirements) and/or Subchapter F (relating to operating permit requirements) will be required. Table 1 of Appendix A of this document gives a comparison of the applicability of the previous GP-5 and new GP-5.

Prohibited Use of GP-5:

GP-5 shall not be used for the construction, modification or operation of the any of the following air contamination source:

(a) A proposed source located at a Title V facility. Title V facility emission thresholds are as follows, calculated as a 12 month rolling sum:

- Nitrogen oxides (NOx) – 100 tons.
- Carbon monoxide (CO) – 100 tons.
- Sulfur oxides (SOx) – 100 tons.
- Particulate matter with an aerodynamic diameter less than 10 microns (PM10) – 100 tons.
- Particulate matter with an aerodynamic diameter less than 2.5 microns (PM2.5) – 100 tons.
- Volatile organic compounds (VOCs) – 50 tons.
- Any individual hazardous air pollutant (HAP) – 10 tons.
- Total hazardous air pollutants (HAPs) – 25 tons.
- Greenhouse gases, expressed as carbon dioxide equivalent (CO_2e) – 100,000 tons.

In Bucks, Chester, Delaware, Montgomery, or Philadelphia counties:

- Nitrogen oxides (NOx) – 25 tons.
- Volatile organic compounds (VOCs) – 25 tons.

(b) A proposed source that is subject to Title V permitting requirements specified in 25 Pa. Code Chapter 127, Subchapters F and G, prevention of significant deterioration and nonattainment new source review requirements specified in 25 Pa. Code Chapter 127, Subchapters D (relating to prevention of significant deterioration) or E (relating to new source review).

(c) Any engine or simple cycle turbine that is used as a “peak shaving engine generator” or source participating in an Emergency and Economic Load Response Program.

(d) Any engine or turbine that is used on a natural gas transmission line. Transmission line means a pipeline, other than a gathering line, that transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center.

Applicable Laws:

The facility owner or operator is obligated to comply with all applicable federal, state and local laws and regulations including, but not limited to: New Source Performance Standards codified at 40 CFR Part 60 (incorporated by reference in 25 Pa. Code § 122.3), National Emission Standards for Hazardous Air Pollutants codified at 40 CFR Part 63 (incorporated by reference in 25 Pa. Code § 127.35), 25 Pa. Code § 127.13(c)(1)(i) Particulate Matter, and 25 Pa Code § 123.21 Sulfur Compound Emissions. The applicable Federal regulations may include:

(a) **40 CFR Part 63, Subpart HH –** National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities. This subpart applies to the owners and operators of affected units located at natural gas production facilities that are major or area sources of HAPs, and that process, upgrade, or store natural gas prior to the point of custody transfer, or that process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user. The affected units are glycol dehydration units, storage vessels with the potential for flash emissions, and the group of ancillary equipment, and compressors intended to operate in volatile hazardous air pollutant service, which are located at natural gas processing plants.

(b) **40 CFR Part 60, Subpart JJJJ –** Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. This subpart establishes emission standards and compliance requirements for the control of emissions from stationary spark ignition (SI) internal combustion engines (ICE) that commenced construction, modification or reconstruction after June 12, 2006, where the SI ICE are manufactured on or after specified manufacture trigger dates. The manufacture trigger dates are based on the engine type, fuel used, and maximum engine horsepower.

(c) **40 CFR Part 60, Subpart Kb –** Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced After July 23, 1984. This rule applies to storage vessels with a capacity greater than or equal to 75 cubic meters (471 bbl).

(d) **40 CFR Part 60, Subpart KKK –** Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. This rule applies to compressors and other equipment at onshore natural gas processing facilities. As defined in this subpart, a natural gas processing plant is any processing site engaged in the extraction of natural gas liquids (NGLs) from field gas, fractionation of mixed NGLs to natural gas products, or both. NGLs are defined as the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

(e) **40 CFR Part 60, Subpart KKKK –** Standards of Performance for Stationary Combustion Turbines. This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

(f) **40 CFR Part 60, Subpart LLL –** Standards of Performance for Onshore Natural Gas Processing; SO_2 Emissions. This rule applies to sweetening units and sulfur recovery units at onshore natural gas processing facilities. As defined in this subpart, sweetening units are process devices that separate hydrogen sulfide (H_2S) and carbon dioxide (CO_2) from a sour natural gas stream. Sulfur recovery units are defined as process devices that recover sulfur from the acid gas (consisting of H_2S and CO_2) removed by a sweetening unit.

(g) **40 CFR Part 60, Subpart OOOO**– Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. This subpart establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities that commence construction, modification or reconstruction after August 23, 2011.

(h) **40 CFR Part 63, Subpart ZZZZ –** National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE). This rule establishes national emission limitations and operating limitations for HAPs emitted from stationary RICE. This rule applies to owners or operators of new and reconstructed stationary RICE of any horsepower rating which are located at a major or area source of HAP emissions. While all stationary RICE located at major or area sources are subject to the final rule (promulgated January 18, 2008, amending the final rule promulgated June 15, 2004), there are distinct requirements for regulated stationary RICE depending on their design, use, horsepower rating, fuel, and major or area HAP emission status.

General Methodology of determining Best Available Technology Limitations for GP-5:

New sources are required to control the emission of air pollutants to the maximum extent, consistent with the best available technology (BAT) as determined by the Department. BAT is defined in 25 Pa. Code §121.1 as equipment, devices, methods or techniques as determined by the Department which will prevent, reduce or control emissions of air contaminants to the maximum degree possible and which are available or may be made available. The applicable emission limits of Federal NSPS and NESHAPS will serve as a baseline for determining the BAT. The resources utilized in the determination of BAT include the data in the EPA's RACT/BACT/LAER Clearinghouse (RBLC), BAT included in the plan approvals which are determined on a case-by-case basis, general permits and other permits issued by other states, such as Ohio, West Virginia, and Colorado, for similar sources. For example, Ohio and West Virginia have finalized General Permits for Oil and Gas Industry. The Department also evaluated vendors' guaranteed emission limits and the available stack test data for the applicable sources. The emission limitations included in the GP-5 must be technically and economically achievable. In addition these emission limitations must be sustainable during the life of the unit.

Spark Ignition Internal Combustion Engines:

In the natural gas industry, spark ignition reciprocating internal combustion engines (SI-RICE) are used mainly as prime movers to drive compressors. There are different types of spark ignition reciprocating internal combustion engines used in the natural gas industry.

In an SI-RICE engine, a mixture of air and fuel is burned within the engine cylinder and the energy of expanding gases is converted into mechanical work at the engine crank shaft. The relative proportions of air and fuel in the combusted mixture is called the air-to-fuel (A/F) ratio. The A/F ratio is called "stoichiometric," if the mixture contains the minimum amount of air that supplies sufficient oxygen for complete combustion of the fuel with no oxygen or fuel left over after combustion.

Reciprocating engines are grouped into two general categories based on the combustion model used in their design: "rich-burn" and "lean-burn". The primary distinction between the two is the amount of excess air admitted prior to combustion. Rich-burn engines operate with a minimum amount of air required for combustion and lean-burn engines use 50% to 100% more air than is necessary for combustion.

Emissions from lean-burn and rich-burn engines:

The following are the main pollutants emitted from the exhaust, depending on the composition of the fuel used. Natural gas is the primary fuel used by the natural gas compression and/or processing industry. For engines, natural gas is the only fuel authorized by GP-5.

Oxides of nitrogen (NO_X):

Oxides of nitrogen (NO_X) are a family of compounds, including nitric oxide (NO) and nitrogen dioxide (NO_2). These compounds are produced from combustion with air which is 79% nitrogen. Nitric oxide (NO) and nitrogen dioxide (NO_2) are typically classified together as NO_X emissions. Nitric oxide is created from the oxidation of atmospheric nitrogen. Once in the atmosphere, NO reacts with diatomic oxygen to form NO_2, and further reacts to form ozone (O_3) and acid rain. NO_X production is heavily influenced by combustion temperature which, in turn, is affected by the amount of excess air present during combustion. There are three types of NO_X created during combustion: thermal, fuel, and prompt. Thermal NO_X is produced at very high temperatures by the reaction of atmospheric oxygen and nitrogen. Fuel NO_X results from oxidation of the nitrogen contained in the fuel. Prompt NO_X is formed from molecular nitrogen in the air combining with fuel in fuel-rich conditions. Typically the NO_X emissions are expressed as NO2.

Carbon Monoxide (CO):

Carbon monoxide (CO) is the result of incomplete combustion of carbon and oxygen when insufficient oxygen or poor mixing interferes with the mechanism to produce CO_2. CO formation is greatest when the fuel mixture is rich; however, CO also forms when a very fuel lean mixture cannot sustain complete combustion. Carbon monoxide emissions in gas engines are controlled primarily by the ratio of air to fuel.

Unburned hydrocarbons (NMNEHC):

Hydrocarbon emissions result from incomplete combustion of hydrocarbon fuels, which may vary according to the incoming composition of the fuel. The reactivity of particular hydrocarbon molecules varies considerably, some being nearly inert and some being very reactive in the production of photochemical smog. Methane is excluded from VOC regulations and measurements because it has a very low photochemical reactivity. NMNEHCs are all unburned fuel excluding methane and ethane. For the purpose of GP-5, emission limits for unburned hydrocarbons for SI-RICE and turbines excludes formaldehyde and are expressed as propane.

Formaldehyde:

HAPs account for a small percentage of all the combustion emissions. Although there may be a number of individual HAPs emitted, formaldehyde is the predominant component. In the combustor, partially burned methane results in the creation of formaldehyde.

Oxides of Sulfur (SO_X):

Sulfur will only be present in the exhaust of a gas engine when it is contained in the fuel. In most cases, natural gas contains only a trace amount of sulfur, if any. The Department has determined that for a typical natural gas fired engine, SO2 emission is 0.01 g/bhp-hr. Based on 0.01 g/bhp-hr, SO2 emission from 2370 bhp engine is less than 0.25 ton per year. Because the

SO2 emissions are of minor significance from natural gas-fired engines, the GP-5 does not include additional SO2 emission limitations or stack testing for engines.

Particular Matter (PM):

The combustion of natural gas produces very low particulate matter emissions. The Department has determined that for a typical natural gas fired engine, PM emission is 0.03 g/bhp-hr. Based on 0.03 g/bhp-hr, PM emission from 2370 bhp engine is less than 0.8 ton per year. Because the PM emissions are of minor significance from natural gas-fired engines, the GP-5 does not include additional PM emission limitations or stack testing for engines. [(1)(2)]

Emission Control Technology:

Several technologies may be used to control emissions from engines. They primarily fall into two categories, combustion control and post combustion control.

Combustion Control:

Control of combustion temperature has been the principal focus of combustion process control in gas engines. Combustion control requires tradeoffs – higher temperatures favor complete consumption of the fuel and lower residual hydrocarbons and CO, but result in NO_X formation. Lean combustion dilutes the fuel mixture and reduces combustion temperatures and NO_X formation. This allows a higher compression ratio or peak firing pressures resulting in higher efficiency. However, if the mixture is too lean, misfiring (knocking) and incomplete combustion occur, increasing CO and VOC emissions. [(3)]

Because the NO_X produced by SI-RICE is primarily thermal NO_X, reducing the combustion temperature will result in less NO_X production. Thus, the main strategy for combustion control is to control the combustion temperature. This is most easily done by adding more air than what is required for complete combustion of the fuel. This raises the heat capacity of the gases in the cylinder so that for a given amount of energy released in the combustion reaction, the maximum temperature will be reduced. Any time excess air is introduced into the cylinder, the engine is said to be "lean." [(4)]

Combustion temperature can also be controlled to some extent in reciprocating engines by one or more of the following techniques:

- Delaying combustion by retarding ignition or fuel injection.

- Diluting the fuel-air mixture with exhaust gas recirculation (EGR), which replaces some of the air and contains water vapor that has a relatively high heat capacity and absorbs some of the heat of combustion.

- Modifying valve timing, compression ratio, turbocharging, and the combustion chamber configuration.

Post combustion emission reduction technology for rich-burn engines:

Three-Way Catalyst (for NO_X, CO and Hydrocarbon emissions):

In rich-burn engines, an after-treatment system such as a three-way catalyst, also known as non-selective catalytic reduction (NSCR), can be added to reduce NO_X emission levels. Three-way catalysts use oxygen to treat exhaust emissions. However, three-way catalysts do not use unburned combustion oxygen to reduce emissions. They make use of the oxygen within the constituent compounds. Oxygen from NO_X is used to oxidize the CO and HC. This converts the three pollutants into N_2, CO_2 and H_2O. Catalysts may be used in series to obtain lower emission levels. Typically, the reduction level for NO_X is > 95%, CO is >95%, and NMNEHC is >50%.

Post combustion emission reduction technology for lean-burn engines:

Oxidation Catalyst (for CO and Hydrocarbon reduction):

On lean-burn engines, oxidation catalysts using platinum and palladium are effective for lowering CO and NMHC levels in exhaust emissions. Methane is difficult to oxidize at exhaust temperatures provided by lean-burn engines; therefore, the control efficiency for methane can be very low. No air-fuel ratio control system is required with this type of catalyst and it can be applied to either rich-burn or lean-burn engines.

Selective Catalyst Reduction (for NO_X reduction):

Selective Catalytic Reduction (SCR) is an exhaust gas after-treatment that specifically targets the NO_X in engine exhaust and converts it to N_2 and H_2O. Unlike the three-way catalyst which uses oxygen from the exhaust stream to treat emissions, SCR injects a compound into the exhaust stream to start the reaction. The process begins when a small amount of urea is injected into the exhaust stream. After hydrolysis, the urea becomes ammonia and reacts with NO_X to break down into nitrogen and water. On closed-loop control systems SCR can reduce gas engine NO_X by 80%. [5][6][7]

Engine Size Grouping:

The Department chose the engine size groups using information on various engine makes and models available. Based on this information, the GP-5 groups the engines into the following categories: equal to or less than 100 bhp, greater than 100 bhp and equal to and less than 500 bhp, and greater than 500 bhp. The grouping is comparable to bhp categories in NSPS, 40 CFR Part 60, Subpart JJJJ.

Engine Emission Limits:

New sources are required to control the emission of air pollutants to the maximum extent, consistent with the best available technology (BAT) as determined by the Department. BAT is defined in 25 Pa. Code §121.1 as equipment, devices, methods or techniques as determined by the Department which will prevent, reduce or control emissions of air contaminants to the maximum degree possible and which are available or may be made available. The BAT in the final GP-5 is based on vendors' guaranteed emission standards, stack test data, available control technologies, and associated costs.

The Department evaluated uncontrolled emissions, control efficiency of various controls, and stack test results for SI ICE. Based on the evaluation, the Department has determined the emission limits in the GP-5 for rich-burn and lean-burn engines, as appropriate. Table 2 in Appendix A of this document gives a comparison summary of the emission limits for engines in the previous GP-5 and new GP-5. Appendix B contains the cost analysis of various emission control technologies.

Emission Limits for Existing Engines:

Any existing engine operating under GP-5 authorizations approved by the Department prior to the issuance of this General Permit shall continue to comply with the following emissions standards from the previously issued GP-5:

- NO_X, 2.0 g/bhp-hr
- CO, 2.0 g/bhp-hr
- NMHC excluding formaldehyde, 2.0 g/bhp-hr

In addition, the engines shall comply with all applicable requirements specified in 40 CFR Part 60, Subpart JJJJ (NSPS) and 40 CFR Part 63, Subpart ZZZZ (NESHAP).

Visible emissions shall not exceed either of the following limitations: equal to or greater than 10 percent for a period or periods aggregating more than three (3) minutes in any one hour or equal to or greater than 30 percent at any time.

Emission Limits for Lean and Rich burn Engines equal to or less than 100 BHP:

These engines are relatively small and are seldom employed in the field in the natural gas compression and or processing facilities. Under the previous plan approval exemption list, these engines were exempt from plan approval requirements. However, this exemption has been excluded from the revised plan approval exemption list in order to discourage installation of high emitting smaller (less than 100 bhp) engines. Therefore, the Department included emission limits for engines rated at equal to or less than 100 bhp in the final GP-5.

NO_X:

40 CFR Part 60, Subpart JJJJ, for engines rated equal to or less than 25 bhp, refers to 40 CFR part 1054 which has a NO_X + HC limit of 6 g/bhp-hr. For engines rated greater than 25 bhp and equal to or less than 100 bhp, 40 CFR, Part 60, Subpart JJJJ refers to 40 CFR 1048 101(c) for non-emergency engines which has a NO_X + HC limit of 2.83 g/bhp-hr, and Table 1 of 40 CFR Part 60, Subpart JJJJ for emergency engines which has a limit of NO_X + HC of 10 g/bhp-hr.

The Department analyzed vendors' data and found that predominantly engines rated less than 100 bhp are rich burn engines. However, the Department found a few lean burn engines that are rated near 100 bhp with NO_X emissions of approximately 2 g/bhp-hr. The Department evaluated cost effectiveness for SCR technology for these engines with uncontrolled NO_X emissions of 2 g/bhp-hr. Based on the evaluation the Department found that the cost effectiveness for SCR technology is greater than $48,000 per ton of NO_X removed, and therefore SCR is not considered as BAT.

The Department reviewed vendor's data for rich-burn engines rated less than 100 bhp which showed that the uncontrolled NOx emissions ranged from 11.41 to 21.08 g/bhp-hr. The Department evaluated cost effectiveness for three way catalyst technology for rich burn engines rated less than 100 bhp. Based on the cost analysis, the cost effectiveness for a 100 bhp engine is found to be less than $650 per ton of NO_X removed, and less than $1200 for a 50 bhp engine. Based on this information, 3-way catalyst is found to be technically and economically feasible option for rich burn engines. An NSCR three way catalyst has an emission reduction efficiency of at least 90% and will reduce these emissions to less than 2 g/bhp-hr. Based on the above, the Department has determined a NO_X emission limit of 2 g/bhp-hr as BAT for engines rated equal to or less than 100 bhp.

CO:

40 CFR Part 60, Subpart JJJJ, for engines rated equal to or less than 25 bhp, refers to 40 CFR part 1054 which has a CO limit of 455 g/bhp-hr. For engines rated greater than 25 bhp and equal to or less than 100 bhp, 40 CFR Part 60, Subpart JJJJ refers to 40 CFR 1048 101(c) for non-emergency engines which has a CO limit of 4.85 g/bhp-hr, and Table 1 of 40 CFR Part 60, Subpart JJJJ for emergency engines which has a limit of CO of 387 g/bhp-hr. The Department reviewed vendors' data for engines less than 100 bhp which showed that the uncontrolled CO emissions were as high as 17.58 g/b hp-hr. An NSCR three way catalyst has an emission reduction efficiency of at least 90% and will reduce these emissions to no greater than 2 g/bhp-hr. The Department evaluated cost effectiveness for three way catalyst technology for rich-burn engines rated less than 100 bhp. Based on the cost analysis, the cost effectiveness for a 100 bhp

engine is found to be less than $425 per ton of CO removed, and less than $900 per ton for a 50 bhp engine.

For lean-burn engines rated at 100 bhp and operating at 8,760 hours per year, CO emissions at an emission rate of 2.0 g/bhp-hr would be 1.92 tons per year, respectively. Therefore, no additional controls are warranted at these emission levels for lean-burn engines rated at equal to or less than 100 bhp.
Based on this information, the Department has determined CO emission limit of 2 g/bhp-hr as BAT for engines rated equal to or less than 100 bhp.

HC:

40 CFR Part 60, Subpart JJJJ, the Federal requirement for engines rated equal to or less than 25 bhp, refers to 40 CFR part 1054 which has a combined limit of 6 g/bhp-hr for HC and NO_X emissions. For engines rated greater than 25 bhp and equal to or less than 100 bhp, 40 CFR Part 60, Subpart JJJJ refers to 40 CFR 1048 101.c for non-emergency engines which has a NO_X + HC limit of 2.83 g/bhp-hr, and Table 1 of 40 CFR Part 60, Subpart JJJJ for emergency engines which has a limit of NO_X + HC of 10 g/bhp-hr. The Department reviewed vendors' data for engines less than 100 bhp which showed that the uncontrolled NMNEHC emissions ranged from 0.1 to 1 g/bhp-hr. Data from 2011 inventory also shows that NMNEHC emissions from engines rated less than 100 bhp range from 0.00027 to 1.2 TPY. Therefore the Department has excluded HC limit from GP-5 for engines rated equal to or less than 100 bhp. However, engines that are subject to 40 CFR Part 60, Subpart JJJJ must comply with applicable standards. Due to the very low emission level, the Department has not included an emission limitation for NMNEHC in the GP-5 for engines rated at equal to or less than 100 bhp. NSCR required to control NO_X and CO emissions from rich burn engines would also control NMNEHC emissions.

Formaldehyde (HCHO):

The previous GP-5 did not have an emissions limit for formaldehyde for engines rated equal to or less than 100 bhp. The Department evaluated uncontrolled emissions, control efficiency of various controls, and stack test results for engines. The federal regulations use CO emissions as a surrogate for formaldehyde emissions from lean-burn engines. Therefore no specific formaldehyde emission limit is established for engines rated equal to or less than 100 bhp in 40 CFR Part 63, Subpart ZZZZ, or 40 CFR Part 60, Subpart JJJJ. At a typical emission rate of 0.3 g/bhp-hr, a 500 bhp engine will emit no greater than 1.45 TPY. Due to the very low emission level, the department has not included an emission limitation for formaldehyde in the GP-5 for engines rated at equal to or less than 100 bhp. NSCR required to control NO_X and CO emissions from rich burn engines would also control formaldehyde emissions.

Visible Emissions:

Visible emissions shall not exceed either of the following limitations: equal to or greater than 10 percent for a period or periods aggregating more than three (3) minutes in any one hour or equal to or greater than 30 percent at any time.

Emission Limits for Lean burn engines greater than 100 BHP and equal to and less than 500 BHP:

The chart below shows a comparison of NO_X, CO, NMNEHC, and HCHO emission limits of the **previous GP-5** and the **new GP-5**. Table 2 in Appendix A of this document gives a comparison summary of the emission limits for engines in the previous GP-5 and new GP-5.

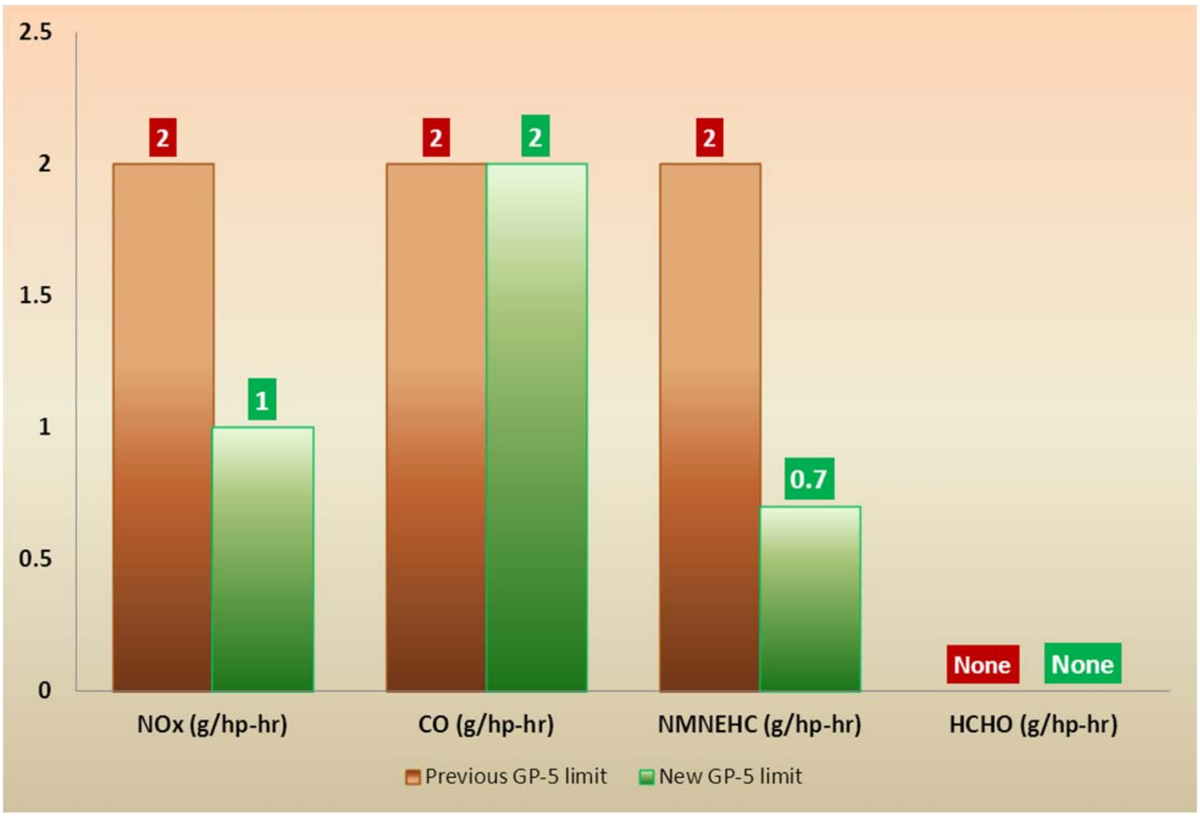

Chart 1: Previous and new GP-5 emission limits for lean burn engines > 100 and ≤ 500 bhp

NO_X:

The previous GP-5 had a NO_X emissions limit of 2 g/bhp-hr for engines rated greater than 100 bhp and equal to or less than 1500 bhp. As per 40 CFR Part 60, Subpart JJJJ, natural gas fired spark ignition non-emergency lean burn engines rated greater than 100 and equal to or less than 500 bhp are required to meet NO_X emission limit of 1 g/bhp-hr. A review of the emission limits contained in similar general permits from other states, such as Ohio, West Virginia, and Colorado, showed limits no more stringent than the federal requirement. The Department analyzed vendors' data for NO_X emissions for engines without add-on control rated at greater than 100 bhp and equal to or less than 500 bhp. While the NO_X emissions from these engines were as high as 16.4 g/bhp-hr, several engines achieved a NSPS NO_X emission rate of 1 g/bhp-hr.

The Department evaluated cost effectiveness for SCR technology for lean burn engines rated at 500 bhp with uncontrolled NO_X emission of 1 g/bhp-hr. Based on the evaluation the Department found that the cost effectiveness for SCR technology is greater than $42,000 per ton of NO_X removed, and therefore SCR is not considered as BAT for engines rated between 100 bhp and 500 bhp.

Based on the above information, the Department has determined a NO_X emission limit of 1 g/bhp-hr as BAT for engines rated greater than 100 bhp and equal to or less than 500 bhp. **This translates to a 50% reduction in emissions from the previous GP-5 limit.**

CO:

The previous GP-5 had a CO emissions limit of 2 g/bhp-hr for engines rated greater than 100 bhp and equal to or less than 1500 bhp. As per 40 CFR Part 60, Subpart JJJJ, natural gas fired spark ignition non-emergency lean burn engines rated greater than 100 and equal to or less than 500 bhp are required to meet CO emission limit of 2 g/bhp-hr. A review of the emission limits contained in similar general permits from other states, such as Ohio, West Virginia, and Colorado, showed limits no more stringent than the federal requirement. The Department analyzed vendors' data for CO emissions for engines without add-on control rated at greater than 100 bhp and equal to or less than 500 bhp. While the CO emissions from these engines were as high as 4 g/bhp-hr, several engines achieved a NSPS CO emission rate of 2 g/bhp-hr. For lean-burn engines rated at 100 and 500 bhp and operating at 8,760 hours per year, CO emissions at an emission rate of 2.0 g/bhp-hr would range from 1.92 to 9.65 tons per year, respectively. Therefore, no additional controls are warranted at these emission levels. Based on the above, the Department has determined a CO limit of 2.0 g/bhp-hr as BAT for engines rated greater than 100 bhp and equal to or less than 500 bhp. **This emission limit is the same as the previous GP-5 limit.**

NMNEHC:

The previous GP-5 had a VOC emissions limit of 2 g/bhp-hr for engines rated greater than 100 bhp and equal to or less than 1500 bhp. As per 40 CFR Part 60, Subpart JJJJ, natural gas fired spark ignition non-emergency lean burn engines rated greater than 100 bhp and equal to or less than 500 bhp are required to meet VOC emission limit of 0.7 g/bhp-hr not including formaldehyde. A review of the emission limits contained in similar general permits from other states, such as Ohio, West Virginia, and Colorado, showed limits no more stringent than the federal requirement. The Department analyzed vendors' data for NMNEHC emissions for engines without add-on control rated at greater than 100 bhp and equal to or less than 500 bhp.

While the NMNEHC emissions from these engines were as high as 1 g/bhp-hr, several engines achieved a NSPS NMNEHC emission rate of 0.7 g/bhp-hr. For engines rated greater than 100 and equal to or less than 500 bhp operating 8760 hours per year, NMNEHC emissions at an emission rate of 0.7 g/bhp-hr would range from 0.68 to 3.38 TPY, respectively. In addition, the Department's cost analysis show that the cost effectiveness of an oxidation catalyst is greater than $13,000 per ton of NMNEHC removed for an engine rated at 500 bhp with a pre-control NMNEHC emission rate of 0.7 g/bhp-hr. Therefore, an oxidation catalyst is considered as cost prohibitive for engines rated at equal to or less than 500 BHP. Based on the above, the Department determined NMNEHC emission limits for lean-burn engines rated greater than 100 bhp and equal to or less than 500 bhp as 0.70 g/bhp-hr. This limit translates to approximately 65% reduction in emissions from the previous GP-5 limit.

Formaldehyde (HCHO):

The previous GP-5 did not have an emissions limit for formaldehyde for engines rated greater than 100 bhp and equal to or less than 1500 bhp. The Department evaluated uncontrolled emissions, control efficiency of various controls, and stack test results for engines. The federal regulations use CO emissions as a surrogate for formaldehyde emissions from lean-burn engines. Therefore no specific formaldehyde emission limit is established for engines rated greater than 100 and equal to or less than 500 bhp in 40 CFR Part 63, Subpart ZZZZ, or 40 CFR Part 60, Subpart JJJJ. At a typical emission rate of 0.3 g/bhp-hr, a 500 bhp engine will emit no greater than 1.45 TPY. In addition, the Department's cost analysis show that the cost effectiveness of an oxidation catalyst is greater than $32,000 per ton of formaldehyde removed for an engine rated at 500 bhp with a pre-control NMNEHC emission rate of 0.3 g/bhp-hr. Therefore, an oxidation catalyst is considered as cost prohibitive for engines rated at equal to or less than 500 BHP. Due to the very low emission level, the Department has not included an emission limitation for formaldehyde in the GP-5 for engines rated at greater than 100 bhp and equal to or less than 500 bhp.

Visible Emissions:

Visible emissions shall not exceed either of the following limitations: equal to or greater than 10 percent for a period or periods aggregating more than three (3) minutes in any one hour or equal to or greater than 30 percent at any time.

Emission Limits for Lean burn engines greater than 500 BHP:

The chart below shows a comparison of NOX, CO, NMNEHC, and HCHO emission limits of the **previous GP-5** and the **new GP-5**. Table 2 in Appendix A of this document gives a comparison summary of the emission limits for engines in the previous GP-5 and new GP-5, and Table 3 shows stack test results for various engines.

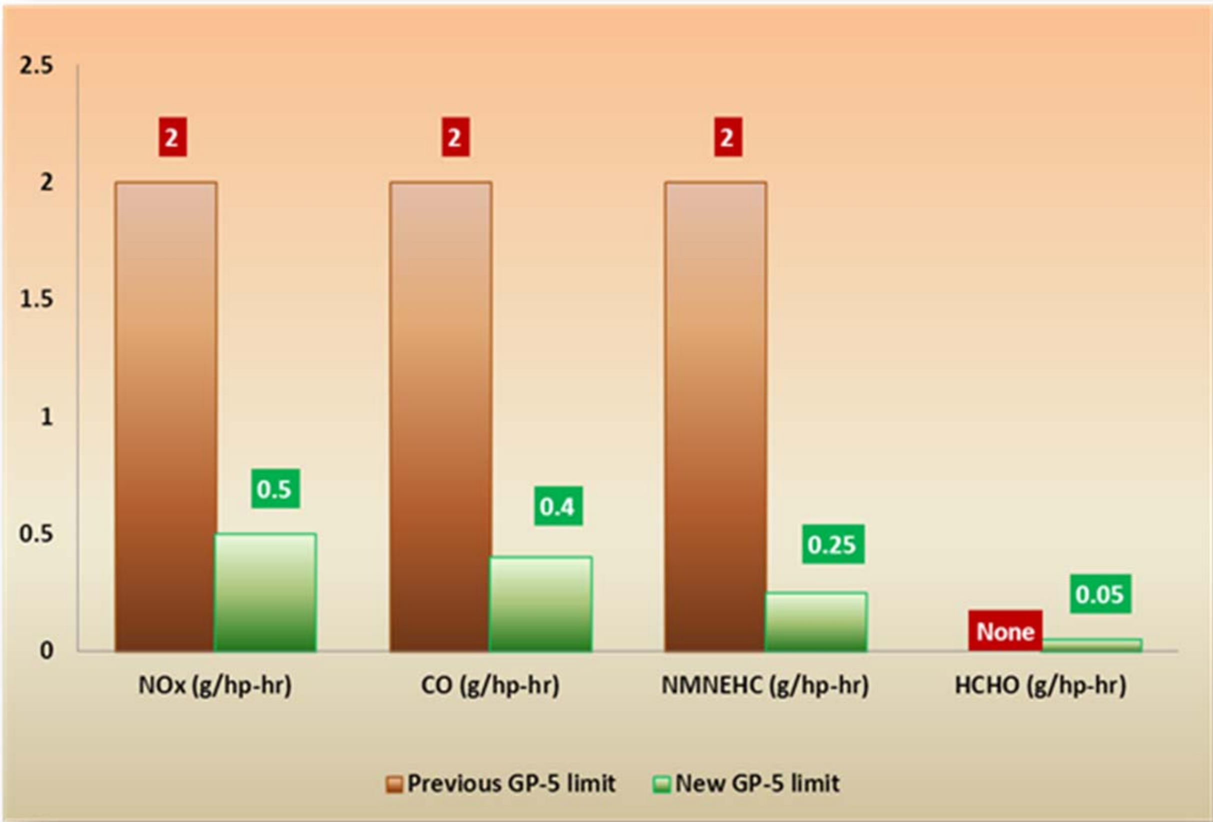

Chart 2: Previous and new GP-5 emission limits for lean burn engines > 500 bhp

NO_X:

The previous GP-5 had a NO_X emissions limit of 2 g/bhp-hr for engines rated greater than 500 bhp. As per 40 CFR Part 60, Subpart JJJJ, natural gas fired spark ignition non-emergency lean burn engines rated greater than 500 bhp are required to meet NOx emission limit of 1 g/bhp-hr. A review of the emission limits contained in similar general permits from other states, such as Ohio, West Virginia, and Colorado, showed limits no more stringent than the federal requirement. The Department has reviewed vendors' guarantees (not-to-exceed limits) and emissions of NO_X for lean-burn engines rated at greater than 500 bhp from different engine manufacturers. Vendor guarantee data showed a NO_X limit of 0.5 g/bhp-hr. Stack test results show NO_X emissions from these engines ranged from 0.22 to 0.50 g/bhp-hr. Due to limited available test data, the Department determined that a NO_X emission limit of 0.5 g/bhp-hr is appropriate for engines rated greater than 500 bhp in order to accommodate variability. The

Department's cost analysis show that cost effectiveness for SCR for engines rated between 500 bhp and 4000 bhp range from $71,000 to $60,000 per ton of NOx removed. Therefore, the SCR is considered as cost prohibitive for engines rated at greater than 500 BHP. Based on the above information, the Department has determined a NO_X emission limit of 0.5 g/bhp-hr as BAT for engines rated greater than 500 bhp. **This translates to 75% reduction in emissions from the previous GP-5 limit and a 50% reduction in emissions from the NSPS.**

CO:

The previous GP-5 had a CO emissions limit of 2 g/bhp-hr for engines rated greater than 500 bhp. As per 40 CFR Part 60, Subpart JJJJ, natural gas fired spark ignition non-emergency lean burn engines rated greater than 500 bhp are required to meet CO emission limit of 2 g/bhp-hr. As per 40 CFR Part 63, Subpart ZZZZ, existing natural gas fired spark ignition non-emergency lean burn engines rated greater than 500 bhp, located at an area source of HAPs, are required to meet CO emission limit of 93% CO reduction or 47 ppmvd @ 15% O_2 (approximately 0.4 g/bhp-hr). The Department believes that new sources can also meet this requirement by installing a CO catalyst. A review of the emission limits contained in similar general permits from other states, such as Ohio, West Virginia, and Colorado, showed limits no more stringent than the federal requirement except Colorado which has a limit of 1.5 g/bhp-hr in some cases. The Department has reviewed vendors' guarantees (not-to-exceed limits) and emissions of CO for lean-burn engines rated at greater than 500 bhp from different engine manufacturers. Vendor guarantee data showed a CO limit ranged from 1.2 g/bhp-hr to 2.8 g/bhp-hr. Using a CO catalyst with 90% control will reduce the emissions to 0.12 g/bhp-hr to 0.28 g/bhp-hr. Due to limited available test data, the Department determined that a CO emission limit of 47 ppmvd @ 15% O_2 or 93% reduction is appropriate for engines rated greater than 500 bhp in order to accommodate variability. The Department's cost analysis shows that cost effectiveness for oxidation catalyst technology for engines greater than 500 bhp with uncontrolled CO emission rate of 2 g/bhp-hr is less than $2700 per ton of CO removed. Therefore, the CO catalyst is considered as cost effective for engines rated greater than 500 BHP. Based on the above information, the Department has determined a CO emission limit of 93% CO reduction or 47 ppmvd @ 15% O_2 as BAT for engines rated greater than 500 bhp which is consistent with the federal requirements found in 40 CFR Part 63, Subpart ZZZZ. **This translates to approximately 80% reduction in emissions from the previous GP-5 limit.**

NMNEHC:

The previous GP-5 had a VOC emissions limit of 2 g/bhp-hr for engines rated greater than 500 bhp. As per 40 CFR Part 60, Subpart JJJJ, natural gas fired spark ignition non-emergency lean burn engines rated greater than 500 bhp are required to meet VOC emission limit of 0.7 g/bhp-hr. A review of the emission limits contained in similar general permits from other states, such as Ohio, West Virginia, and Colorado, showed limits no more stringent than the federal requirement. Department has reviewed vendors' guarantees (not-to-exceed limits) and emissions of NMNEHC for lean-burn engines rated at greater than 500 bhp from different engine manufacturers. For engines greater than 500 bhp, pre-controlled NMNEHC emissions range from 0.48 g/bhp-hr to 1.0 g/bhp-hr. The oxidation catalyst required to control CO emissions would also control NMNEHC emissions from these engines. Using 1.0 g/bhp-hr as uncontrolled emission rate and employing oxidation catalyst control technology that reduces NMNEHC emission by 75%, controlled emission is 0.25 g/bhp-hr. The Department also reviewed stack test results from engines greater than 500 bhp and found that the engines are able to achieve NMNEHC emission rate of 0.25 g/bhp-hr or less. Based on the above, the Department determined 0.25 g/bhp-hr as BAT for NMNEHC emissions. **This translates to approximately 87.5% reduction in emissions from the previous GP-5 limit.**

Formaldehyde (HCHO):

The previous GP-5 did not have an emissions limit for formaldehyde for engines rated greater than 500 bhp. The federal regulations use CO emissions as a surrogate for formaldehyde emissions from lean-burn engines. Therefore no specific formaldehyde emission limit is established for lean-burn engines rated greater than 500 bhp located at non-major facilities in 40 CFR Part 63, Subpart ZZZZ, or 40 CFR Part 60, Subpart JJJJ. For engines greater than 500 bhp, the Department reviewed vendors' guarantees (not-to-exceed limits) and pre-controlled emissions from engines from different engine manufacturers. The uncontrolled emissions ranged from 0.1 g/bhp-hr to 0.36 g/bhp-hr. An engine with uncontrolled formaldehyde emission rate of 0.36 g/bhp-hr and a HCHO reduction efficiency of 85%, can achieve a controlled emissions rate of 0.05 g/bhp-hr. The stack test data (see Appendix A, Table 5) confirms that a formaldehyde emission level of 0.05 g/bhp-hr is technically achievable. The oxidation catalyst required to control CO emissions would also control formaldehyde emissions from these engines. Based on the above, the Department has determined 0.05 g/bhp-hr as the BAT limit.

Visible Emissions:

Visible emissions shall not exceed either of the following limitations: equal to or greater than 10 percent for a period or periods aggregating more than three (3) minutes in any one hour or equal to or greater than 30 percent at any time.

Emission Limits for Rich Burn Engines equal to or greater than 100 BHP and equal to and less than 500 BHP:

The chart below shows a comparison of NOX, CO, NMNEHC, and HCHO emission limits of the previous GP-5 and the new GP-5.   Table 2 in Appendix A of this document gives a comparison summary of the emission limits for engines in the previous GP-5 and new GP-5.

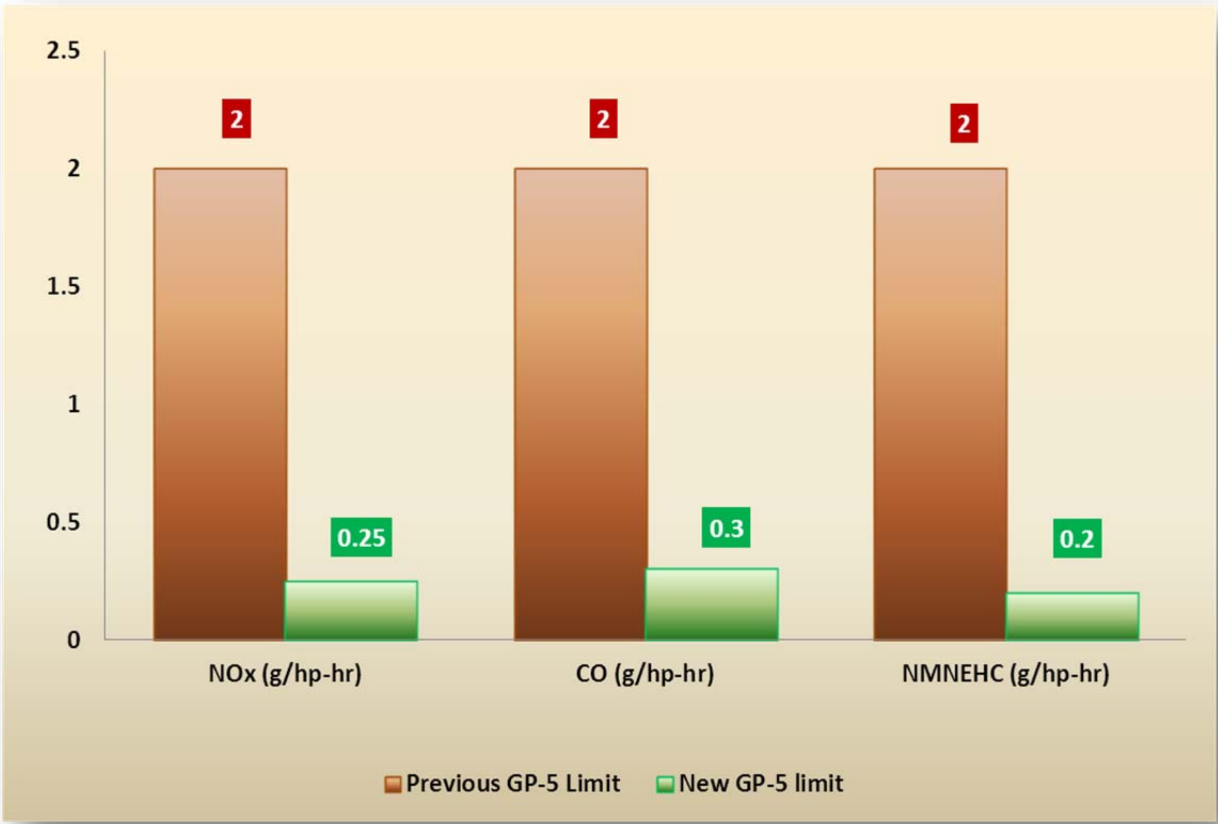

Chart 3: Previous and new GP-5 emission limits for rich burn engines ≥ 100 and ≤ 500 bhp

NO_X:

The previous GP-5 had a NO_X emissions limit of 2 g/bhp-hr for engines rated greater than 100 bhp and equal to or less than 1500 bhp. As per 40 CFR Part 60, Subpart JJJJ, natural gas fired spark ignition non-emergency rich burn engines rated greater than 100 and equal to or less than 500 bhp are required to meet NO_X emission limit of 1 g/bhp-hr. A review of the emission limits contained in similar general permits from other states, such as Ohio, West Virginia, and Colorado, showed limits no more stringent than the federal requirement. The evaluation of uncontrolled emission data from these rich-burn engines indicates emissions of NO_X ranging from 13 to 16.4 g/bhp-hr. Cost analysis from both EPA and the Department show that NSCR (non-selective catalytic reduction) is cost effective for rich burn engines rated at greater than 100 bhp at a cost of less than $177 per ton removed. The Department reviewed vendors' guarantees (not-to-exceed limits) and uncontrolled emissions of NO_X for rich-burn engines rated at greater than 100 bhp from different engine manufacturers. The vendor data indicates that 98.8% NO_X reduction can be achieved by the NSCR system. An engine with uncontrolled NO_X emission rate of 16.4 g/bhp-hr and a catalyst NO_X reduction efficiency of 98.8%, can achieve a controlled emissions rate of 0.25 g/bhp-hr with a sufficient margin. Based on the above, the Department has determined 0.25 g/bhp-hr as the BAT limit. **This translates to an 87.5% reduction in emissions from the previous GP-5 limit.**

CO:

The previous GP-5 had a CO emissions limit of 2 g/bhp-hr for engines rated greater than 100 bhp and equal to or less than 1500 bhp. As per 40 CFR Part 60, Subpart JJJJ, natural gas fired spark ignition non-emergency rich burn engines rated greater than 100 and equal to or less than 500 bhp are required to meet CO emission limit of 2 g/bhp-hr. A review of the emission limits contained in similar general permits from other states, such as Ohio, West Virginia, and Colorado, showed limits no more stringent than the federal requirement. The Department reviewed vendors' guarantees (not-to-exceed limits) of uncontrolled emissions of CO for rich burn engines rated at greater than 100 bhp from different engine manufacturers. Uncontrolled emissions of CO range from 1.7 g/bhp-hr to 14.8 g/bhp-hr. The vendor data indicates that with a pre-controlled CO emission rate of 9 g/bhp-hr, NSCR can achieve an emission rate 0.15 to 0.25 g/bhp-hr. Cost analysis from both EPA and the Department show that NSCR (non-selective catalytic reduction) is cost effective for rich burn engines rated at greater than 100 bhp at a cost of less than $177 per ton removed. An engine with uncontrolled CO emission rate as high as 14.8 g/bhp-hr and a catalyst CO reduction efficiency of 98%, can achieve a controlled emissions rate of 0.30 g/bhp-hr. Based on the above, the Department has determined 0.30 g/bhp-hr as the **BAT limit. This translates to an 85% reduction in emissions from the previous GP-5 limit.**

NMNEHC:

The previous GP-5 had a VOC emissions limit of 2 g/bhp-hr for engines rated greater than 100 bhp and equal to or less than 500 bhp. As per 40 CFR Part 60, Subpart JJJJ, natural gas fired spark ignition non-emergency rich burn engines rated greater than 100 and equal to or less than 500 bhp are required to meet NMNEHC emission limit of 0.7 g/bhp-hr. A review of the emission limits contained in similar general permits from other states, such as Ohio, West Virginia, and Colorado, showed limits no more stringent than the federal requirement. The Department reviewed vendors' guarantees (not-to-exceed limits) of uncontrolled NMNEHC emissions for rich burn engines rated at greater than 100 bhp from different engine manufacturers. Uncontrolled emissions of NMNEHC ranged from 0.07 g/bhp-hr to 0.44 g/bhp-hr. Cost analysis from both EPA and the Department show that NSCR (non-selective catalytic reduction) is cost effective for rich burn engines rated at greater than 100 bhp at a cost of less than $177 per ton removed. The vendor data indicates that 60% NMNEHC reduction can be achieved by the NSCR system with a pre-controlled emission rate of 0.4 g/bhp-hr. An engine with uncontrolled NMNEHC emission rate of 0.44 g/bhp-hr and a catalyst NMNEHC reduction efficiency of 60%, can achieve a controlled emissions rate of 0.20 g/bhp-hr. Based on the above, the Department has determined 0.20 g/bhp-hr as the BAT limit. **This translates to a 90% reduction in emissions from the previous GP-5 limit.**

Formaldehyde (HCHO):

The previous GP-5 did not have a formaldehyde emissions limit for engines rated greater than 100 bhp and equal to or less than 500 bhp. There is no specific formaldehyde emission limit established for rich-burn engines rated greater 100 bhp, and equal to or less than 500 bhp located at non-major facilities in 40 CFR, Part 63, Subpart ZZZZ, or 40 CFR Part 60, Subpart JJJJ. The required NSCR also controls formaldehyde emissions from rich-burn engines. At a typical post-control emission rate of 0.3 g/bhp-hr, a 500 bhp engine will emit no greater than 1.45 TPY. Due to the very low emission level, the Department did not establish an emission limit for formaldehyde in the GP-5. NSCR required to control NOX and CO emissions from rich burn engines would also control formaldehyde emissions.

Visible Emissions:

Visible emissions shall not exceed either of the following limitations: equal to or greater than 10 percent for a period or periods aggregating more than three (3) minutes in any one hour or equal to or greater than 30 percent at any time.

Rich Burn engines greater than 500 BHP:

The chart below shows a comparison of NOX, CO, NMNEHC, and HCHO emission limits of the previous GP-5 and the new GP-5. Table 2 in Appendix A of this document gives a comparison summary of the emission limits for engines in the previous GP-5 and new GP-5.

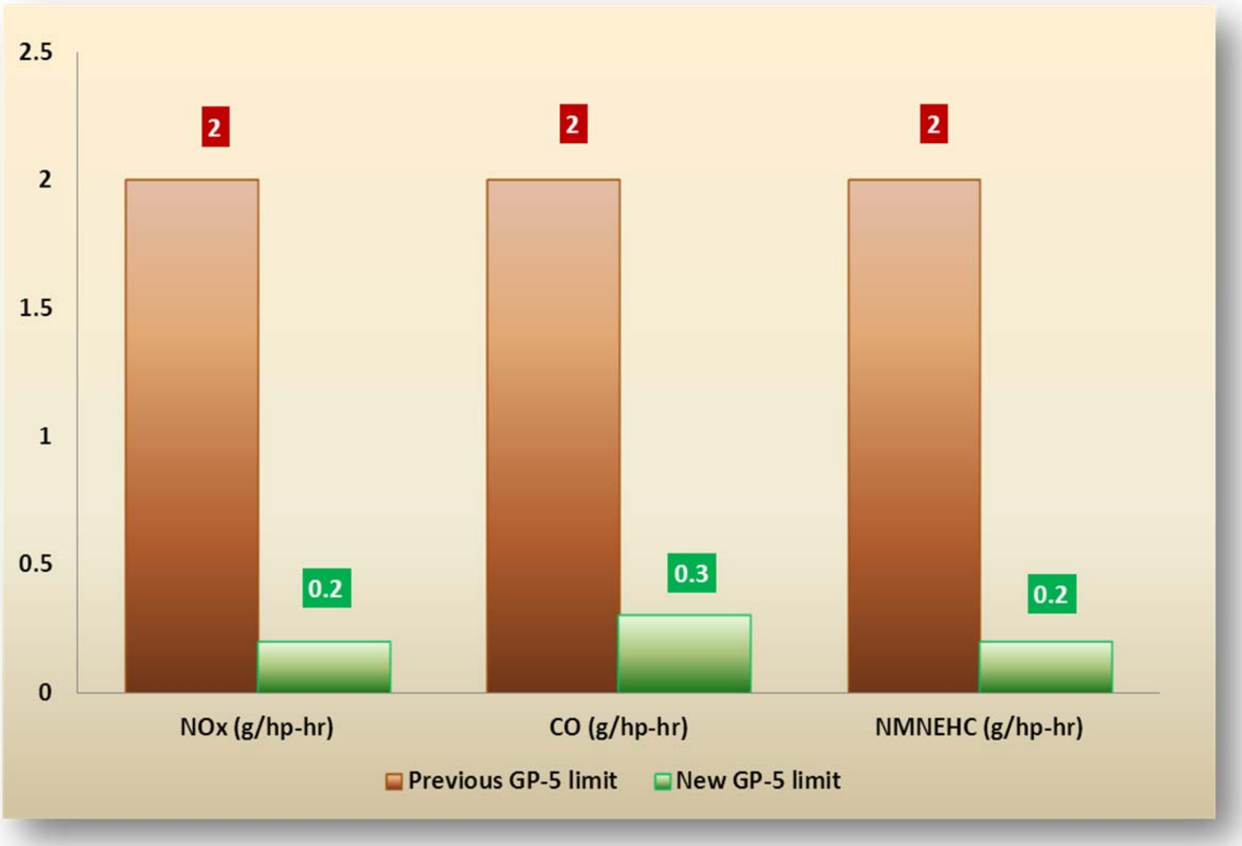

Chart 4: Previous and new GP-5 emission limits for rich burn engines > 500 bhp

NO_X:

The previous GP-5 had a NO_X emissions limit of 2 g/bhp-hr for engines rated greater than 500 bhp. As per 40 CFR Part 60, Subpart JJJJ, natural gas fired spark ignition non-emergency rich burn engines rated greater than 500 bhp are required to meet NOx emission limit of 1 g/bhp-hr. A review of the emission limits contained in similar general permits from other states, such as Ohio, West Virginia, and Colorado, showed limits no more stringent than the federal requirement. The Department reviewed vendors' guarantees (not-to-exceed limits) and uncontrolled emissions of NO_X for rich-burn engines rated at greater than 500 bhp from different engine manufacturers. Uncontrolled emissions of NO_X range from 13 to 16 g/bhp-hr. Cost analysis from both EPA and the Department show that NSCR (non-selective catalytic reduction) is cost effective for rich burn engines rated at greater than 100 bhp at a cost of less than $177 per ton removed. The vendor data indicates that 98.8% NO_X reduction can be achieved by the

NSCR system with a pre-controlled NO_X emission rate of 13 g/bhp-hr. This translates to a post-control NO_X emission rate of 0.15 g/bhp-hr. An engine with uncontrolled NO_X emission rate of 16 g/bhp-hr and a catalyst NO_X reduction efficiency of 98.8%, can achieve a controlled emissions rate of approximately 0.20 g/bhp-hr. The stack test results from a 1980 bhp engine indicate that actual NO_X emissions range from 0.02 to 0.14 g/bhp-hr. Based on the above, the Department has determined 0.20 g/bhp-hr as the BAT limit. **This translates to a 90% reduction in emissions from the previous GP-5 limit.**

CO:

The previous GP-5 had a CO emissions limit of 2 g/bhp-hr for engines rated greater than 500 bhp. As per 40 CFR Part 60, Subpart JJJJ, natural gas fired spark ignition non-emergency rich burn engines rated greater than 500 bhp are required to meet CO emission limit of 2 g/bhp-hr. A review of the emission limits contained in similar general permits from other states, such as Ohio, West Virginia, and Colorado, showed limits no more stringent than the federal requirement except Colorado has a limit of 1.5 g/bhp-hr in some cases. The Department reviewed vendors' guarantees (not-to-exceed limits) of uncontrolled emissions of CO for rich burn engines rated at greater than 500 bhp from different engine manufacturers. Uncontrolled emissions of CO range from 2.28 g/bhp-hr to 14.8 g/bhp-hr. The vendor data indicates that with a pre-controlled CO emission rate of 9 g/bhp-hr, NSCR can achieve an emission rate 0.15 to 0.25 g/bhp-hr. Cost analysis from both EPA and the Department show that NSCR (non-selective catalytic reduction) is cost effective for rich burn engines rated at greater than 100 bhp at a cost of less than $177 per ton removed. An engine with uncontrolled CO emission rate of 14.8 g/bhp-hr and NSCR with CO reduction efficiency of 98%, can achieve a controlled emissions rate of approximately 0.30 g/bhp-hr. The stack test results also confirm that CO emissions from rich burn engines installed with NSCR can achieve CO emission rate of less than 0.30 g/bhp-hr. The stack test results from a 1980 bhp engine indicate that actual CO emissions range from 0.07 to 0.22 g/bhp-hr. Based on the above, the Department has determined 0.30 g/bhp-hr as the BAT limit. **This translates to an 85% reduction in emissions from the previous GP-5 limit.**

NMNEHC:

The previous GP-5 had a VOC emissions limit of 2 g/bhp-hr for engines rated greater than 500 bhp. As per 40 CFR Part 60, Subpart JJJJ, natural gas fired spark ignition non-emergency rich burn engines rated greater than 500 bhp are required to meet NMNEHC emission limit of 0.7 g/bhp-hr. A review of the emission limits contained in similar general permits from other states, such as Ohio, West Virginia, and Colorado, showed limits no more stringent than the federal requirement. The Department reviewed vendors' guarantees (not-to-exceed limits) of uncontrolled NMNEHC emissions for rich burn engines rated at greater than 100 bhp from different engine manufacturers. Uncontrolled emissions of NMNEHC ranged from 0.15 g/bhp-hr to 0.3 g/bhp-hr. The vendor data indicates that 60% NMNEHC reduction can be achieved by the NSCR system with a pre-controlled emission rate of 0.4 g/bhp-hr. Cost analysis from both EPA and the Department show that NSCR (non-selective catalytic reduction) is cost effective for rich burn engines rated at greater than 100 bhp at a cost of less than $177 per ton removed. An engine with uncontrolled NMNEHC emission rate of 0.3 g/bhp-hr and NSCR with NMNEHC reduction efficiency of 60%, can achieve a controlled emissions rate of 0.20 g/bhp-hr. The stack test results from a 1980 bhp engine indicate that actual NMNEHC emissions range from 0.01 to 0.03 g/bhp-hr, which confirm that NMNEHC emissions of 0.20 g/bhp-hr is achievable. Based on the above, the Department has determined 0.20 g/bhp-hr as the BAT limit. This translates to a **90% reduction in emissions from the previous GP-5 limit**.

HCHO:

The previous GP-5 did not have a formaldehyde emissions limit for engines rated greater than 500 bhp. 40 CFR Part 63, Subpart ZZZZ requires a formaldehyde limit of 2.7 ppmvd @ 15% O2 or 76% reduction for existing rich-burn engines rated at greater than 500 bhp and located at an area source of HAPs. The Department believes that new engines can also meet this requirement by using an NSCR (non-selective catalytic reduction) system that is able to achieve formaldehyde emission reduction of at least 76% for rich-burn engines rated at greater than 500 bhp. The vendor data confirms that a formaldehyde limit of 2.7 ppmvd @ 15% O2 or 76% reduction is achievable with a pre-controlled emission rate of 0.05 g/bhp-hr. Therefore, the Department has determined a formaldehyde emission limitation of 2.7 ppmvd at 15% oxygen or 76% reduction for rich-burn engines rated at greater than 500 bhp as BAT in the GP-5. NSCR required to control NO_X, CO, and NMNEHC emissions from rich burn engines would also control formaldehyde emissions.

Visible Emissions:

Visible emissions shall not exceed either of the following limitations: equal to or greater than 10 percent for a period or periods aggregating more than three (3) minutes in any one hour or equal to or greater than 30 percent at any time.

Simple Cycle Turbines:

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Gas turbines are essentially composed of three major components: compressor, combustor, and power turbine. In the compressor section, ambient air is drawn in and compressed up to 30 times ambient pressure and directed to the combustor section where fuel is introduced, ignited, and burned. Hot gases from the combustion section are diluted with additional air from the compressor section and directed to the power turbine section. Energy from the hot exhaust gases, which expand in the power turbine section, is recovered in the form of shaft horsepower. The shaft horsepower used needed to drive the internal compressor and external load.

The primary pollutants from gas turbine engines are nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), particulate matter (PM), and hazardous air pollutants (HAPs). Nitrogen oxide formation is strongly dependent on the high temperatures developed in the combustor. Carbon monoxide, VOC, HAP, and PM are primarily the result of incomplete combustion. Emissions of sulfur compounds, mainly sulfur dioxide (SO_2), are directly related to the sulfur content of the fuel. Trace to low amounts of HAP and SO_2 are emitted from gas turbines.

While GP-5 allows the use of natural gas-fired simple cycle turbines rated at equal to or greater than 15,000 bhp, the total greenhouse gas emissions (expressed as CO_2e) from the facility may limit the use of gas turbines significantly greater than 15,000 bhp. For example, a gas turbine rated at 16,000 bhp would emit 63,875 tons of CO_2e per year of the 100,000 tons per year Title V facility emission threshold.

Emissions from Turbines:

Oxides of nitrogen (NO_X):

See discussion under SI-RICE for more details on NO_X production in the combustion chamber.

Carbon Monoxide (CO):

CO and VOC emissions both result from incomplete combustion. CO results when there is insufficient residence time at high temperature or incomplete mixing to complete the final step in fuel carbon oxidation. The oxidation of CO to CO_2 at gas turbine temperatures is a slow reaction compared to most hydrocarbon oxidation reactions. In gas turbines, failure to achieve CO burnout may result from quenching by dilution air. With liquid fuels, this can be aggravated by carryover of larger droplets from the atomizer at the fuel injector. Carbon monoxide emissions are also dependent on the loading of the gas turbine. For example, a gas turbine operating under a full load will experience greater fuel efficiencies which will reduce the formation of carbon monoxide. The opposite is also true, a gas turbine operating under a light to medium load will experience reduced fuel efficiencies (incomplete combustion) which will increase the formation of carbon monoxide.

Unburned hydrocarbons (NMNEHC):

The pollutants commonly classified as VOC can encompass a wide spectrum of volatile organic compounds some of which are hazardous air pollutants. These compounds are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. With natural gas, some organics are carried over as unreacted, trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents. With liquid fuels, large droplet carryover to the quench zone accounts for much of the unreacted and partially pyrolized volatile organic emissions. Similar to CO emissions, VOC emissions are affected by the gas turbine operating load conditions. Volatile organic compounds emissions are higher for gas turbines operating at low loads as compared to similar gas turbines operating at higher loads.

After the GP-5 was proposed for comment, the Department obtained additional information and received further information from commentators regarding CO and NMHC emissions from simple cycle turbines. The VOC emissions from simple cycle turbines have been identified in the final GP-5 as non-methane non-ethane hydrocarbons (NMNEHC) as opposed to the NMHC identified in the proposed GP-5 as NMNEHC is better representative of VOC emissions. The Department evaluated uncontrolled emissions, control efficiency of various controls, and stack test results for simple cycle turbines. For the purpose of GP-5, emission limits for unburned hydrocarbons for SI-RICE and turbines excludes formaldehyde and are expressed as propane.

Formaldehyde:

Available data indicate that emission levels of HAP are lower for gas turbines than for other combustion sources. This is due to the high combustion temperatures reached during normal operation. Formaldehyde is the predominant HAP emission from natural gas-fired simple cycle turbines. Since the formaldehyde emissions are very low for turbines, the GP-5 does not include emission limitations for formaldehyde from turbines. The Department calculated that for a 5,000 horsepower turbine, formaldehyde emissions are less than 0.063 ton per year (based on 0.0003 lb/MMBtu). For a 30,000 horsepower turbine, formaldehyde emissions are less than 0.08 ton per year (based on 0.0001 lb/MMBtu).

Oxides of Sulfur (SO_{X}):

Sulfur will only be present in the exhaust of gas turbines when it is contained in the fuel. In most cases, natural gas contains only a trace amount of sulfur, if any. Since the SO_2 emissions are of minor significance from natural gas-fired turbines, the GP-5 does not include additional SO_2 emission limitations or stack testing for turbines. Turbines must comply with all applicable requirements of 40 CFR Part 60, Subpart KKKK.

Particular Matter (PM):

PM emissions from turbines primarily result from carryover of noncombustible trace constituents in the fuel. Even though the filterable portion of the total particulate matter from natural gas-fired turbines is low, the condensable portion of the total particulate matter is considerably higher than the filterable particulate matter. For the purposes of GP-5, the particulate matter emission limitations include filterable and condensable particulate matter emissions.

Turbine emission reduction technologies:

There are three generic types of emission controls in use for gas turbines, wet controls using steam or water injection to reduce combustion temperatures for NO_X control, dry controls using advanced combustor design to suppress NO_X formation and/or promote CO burnout, and post-combustion catalytic control to selectively reduce NO_X and/or oxidize CO emission from the turbine.

Oxidation Catalyst:

Carbon monoxide oxidation catalysts are typically used on turbines to achieve control of CO emissions, especially turbines that use steam injection, which can increase the concentrations of CO and unburned hydrocarbons in the exhaust. CO catalysts are also being used to reduce VOC and organic HAPs emissions. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium.

Other formulations, such as metal oxides for emission streams containing chlorinated compounds, are also used. The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to carbon dioxide (CO_2) and water (H_2O) as the emission stream passes through the catalyst bed. The oxidation process takes place spontaneously, without the requirement for introducing reactants.

Water Injection:

Water or steam injection is a technology that has been demonstrated to effectively suppress NOx emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one. Depending on the initial NO_X levels, such rates of injection may reduce NO_X by 60 percent or higher. Both CO and VOC emissions are increased by water injection, and the level of CO and VOC increases will depend on the amount of water injection.

Dry Controls:

Since thermal NO_X is a function of both temperature (exponentially) and time (linearly), the basis of dry controls are to either lower the combustor temperature using lean mixtures of air and/or fuel staging, or decrease the residence time of the combustor. A combination of methods may be used to reduce NO_X emissions such as lean combustion and staged combustion (two stage lean/lean combustion or two stage rich/lean combustion).

Lean combustion involves increasing the air-to-fuel ratio of the mixture so that the peak and average temperatures within the combustor will be less than that of the stoichiometric mixture, thus suppressing thermal NO_X formation. Introducing excess air not only creates a leaner mixture but it also can reduce residence time at peak temperatures.

Two-stage lean/lean combustors are essentially fuel-staged, premixed combustors in which each stage burns lean. The two-stage lean/lean combustor allows the turbine to operate with an extremely lean mixture while ensuring a stable flame. A small stoichiometric pilot flame ignites the premixed gas and provides flame stability. The NO_X emissions associated with the high temperature pilot flame are insignificant. Low NO_X emission levels are achieved by this combustor design through cooler flame temperatures associated with lean combustion and avoidance of localized "hot spots" by premixing the fuel and air.

Two stage rich/lean combustors are essentially air-staged, premixed combustors in which the primary zone is operated fuel rich and the secondary zone is operated fuel lean. The rich mixture produces lower temperatures (compared to stoichiometric) and higher concentrations of CO, because of incomplete combustion. The rich mixture also decreases the amount of oxygen available for NO_X generation. Before entering the secondary zone, the exhaust of the primary zone is quenched (to extinguish the flame) by large amounts of air and a lean mixture is created. The lean mixture is pre-ignited and the combustion completed in the secondary zone. NO_X formation in the second stage is minimized through combustion in a fuel lean, lower temperature environment. Staged combustion is identified through a variety of names, including Dry-Low NOX (DLN), Dry-Low Emissions (DLE), or SoLoNOX.

Catalytic Reduction Systems:

Selective catalytic reduction (SCR) systems selectively reduce NO_X emissions by injecting ammonium (NH3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH3, and O2 react on the surface of the catalyst to form N_2 and H_2O. The exhaust gas must contain a minimum amount of O2 and be within a particular temperature range (typically 450oF to 850oF) in order for the SCR system to operate properly.

The temperature range is dictated by the catalyst material which is typically made from noble metals, including base metal oxides such as vanadium and titanium, or zeolite-based material. The removal efficiency of an SCR system in good working order is typically from 65 to 90 percent. Exhaust gas temperatures greater than the upper limit (850^{o}F) cause NO_X and NH3 to pass through the catalyst unreacted. Ammonia emissions, called NH3 slip, may be a consideration when specifying an SCR system.

Ammonia, either in the form of liquid anhydrous ammonia, or aqueous ammonia hydroxide is stored on site or injected into the exhaust stream upstream of the catalyst. Although an SCR system can operate alone, it is typically used in conjunction with water-steam injection systems or lean-premix system to reduce NO_X emissions to their lowest levels (less than 10 ppm at 15 percent oxygen for SCR and wet injection systems).

The catalyst and catalyst housing used in SCR systems tend to be very large and dense (in terms of surface area to volume ratio) because of the high exhaust flow rates and long residence times required for NO_X, O2, and NH3, to react on the catalyst. Most catalysts are configured in a parallel-plate, "honeycomb" design to maximize the surface area-to-volume ratio of the catalyst.

Some SCR installations incorporate CO oxidation catalyst modules along with the NO_X reduction catalyst for simultaneous CO/ NO_X control.

New catalytic reduction technologies have been developed and are currently being commercially demonstrated for gas turbines. Such technologies include, but are not limited to, the SCONOX and the XONON systems, both of which are designed to reduce NO_X and CO emissions. The SCONOX system is applicable to natural gas fired gas turbines. It is based on a unique integration of catalytic oxidation and absorption technology. CO and NO are catalytically oxidized to CO_2 and NO_2. The NO_2 molecules are subsequently absorbed on the treated surface of the SCONOX catalyst. The system manufacturer guarantees CO emissions of 1 ppm and NO_X emissions of 2 ppm. The SCONOX system does not require the use of ammonia, eliminating the potential of ammonia slip conditions evident in existing SCR systems.

The XONON system utilizes a flameless combustion system where fuel and air reacts on a catalyst surface, preventing the formation of NO_X while achieving low CO and unburned hydrocarbon emission levels. The overall combustion process consists of the partial combustion of the fuel in the catalyst module followed by completion of the combustion downstream of the catalyst. The partial combustion within the catalyst produces no NO_X, and the combustion downstream of the catalyst occurs in a flameless homogeneous reaction that produces almost no NO_X. The system is totally contained within the combustor of the gas turbine and is not a process for clean-up of the turbine exhaust. Note that this technology has not been fully demonstrated as of the drafting of this section. The catalyst manufacturer claims that gas turbines equipped with the XONON Catalyst emit NO_X levels below 3 ppm and CO and unburned hydrocarbons levels below 10 ppm.[8]

Turbine Emission Limits:

Appendix B of this document contains the cost analysis of various emission control technologies.

Emission Limits for Simple Cycle Turbines rated less than 1000 BHP:

The Department has excluded turbines rated less than 1000 bhp from GP-5 since, in accordance with the exemption list (Technical Guidance Document #275-2101-003), these turbines are exempted from permitting requirements.

Emission Limits for Simple Cycle Turbines rated equal to or greater than 1000 BHP and less than 5000 BHP:

NOx:

The previous GP-5 was not applicable to turbines. As per 40 CFR Part 60, Subpart KKKK, NO_X emission standard for natural gas fired mechanical drive turbines rated equal to or less than 50

MMBtu per hr of heat input (approximately 7000 bhp) is 100 ppmvd @ 15% oxygen. Vendors' guaranteed data show that natural gas fired turbine with dry low NO_X combustor, and rated at less than 5000 bhp can achieve equal to or less than 25 ppm of NO_X emissions @ 15% oxygen. The Department evaluated cost effectiveness for SCR technology for these turbines with uncontrolled NO_X emissions of 25 ppmvd @ 15% oxygen. Based on the evaluation the Department found that the cost effectiveness for SCR technology range from $45,000 to $62,000 per ton of NO_X removed for turbines rated equal to or greater than 1000 bhp and less than 5000 bhp. Therefore, SCR technology is considered as a cost prohibitive option for NO_X control. A review of the stack test results indicates that NO_X emissions of 25 ppmvd @ 15% oxygen is achievable for turbines rated at equal to or greater than 1000 bhp and less than 5000 bhp. Based on the above the Department has determined 25 ppmvd @ 15% O_2 as BAT for NO_X for turbines rated equal to or greater than 1000 bhp and less than 5000 bhp.

CO:

As per 40 CFR Part 60, Subpart KKKK, natural gas fired turbines rated equal to or greater than 1000 and less than 5000 bhp do not have an emission limitation for CO. Vendors' guaranteed data show that natural gas fired turbine with dry low NOX combustor, and rated at less than 5000 bhp can achieve equal to or less than 25 ppm of CO emissions @ 15% oxygen. The Department evaluated cost effectiveness for oxidation catalyst technology for these turbines with uncontrolled CO emissions of 25 ppmvd @ 15% oxygen. Based on the evaluation, the Department found that the cost effectiveness for oxidation catalyst technology ranges from $10,000 to $52,000 per ton of CO and HC removed for turbines rated equal to or greater than 1000 bhp and less than 5000 bhp. Therefore, oxidation catalyst technology is considered as a cost prohibitive option for CO control. A review of the stack test results indicates that CO emissions of 25 ppmvd @ 15% oxygen is achievable for turbines rated at equal to or greater than 1000 bhp and less than 5000 bhp. Based on the above, the Department has determined 25 ppmvd @ 15% O2 as BAT for CO for turbines rated equal to or greater than 1000 bhp and less than 5000 bhp.

NMNEHC:

As per 40 CFR Part 60, Subpart KKKK, natural gas fired turbines rated equal to or greater than 1000 and less than 5000 bhp do not have an emission limitation for NMNEHC. Vendors' guaranteed data show that natural gas fired turbine with dry low NO_X combustor, and rated at less than 5000 bhp can achieve equal to or less than 25 ppm of HC emissions @ 15% oxygen (as methane). The Department evaluated cost effectiveness for oxidation catalyst technology for these turbines with uncontrolled HC emissions of 25 ppmvd @ 15% oxygen (as methane). Based on the evaluation, the Department found that the cost effectiveness for oxidation catalyst technology ranges from $10,000 to $52,000 per ton of CO and HC removed for turbines rated equal to or greater than 1000 bhp and less than 5000 bhp. Therefore oxidation catalyst technology is considered as a cost prohibitive option for HC control. Based on the above, the Department would have determined 25 ppmvd @ 15% O2 (as methane) as BAT for NMNEHC for turbines rated equal to or greater than 1000 bhp and less than 5000 bhp. In order to accurately quantify hydrocarbons from the exhaust of these turbines, the limit has been converted into NMNEHC, reported as propane. The Department has determined 9 ppmvd @ 15% O2 (as propane) as BAT for NMNEHC for turbines rated equal to or greater than 1000 bhp and less than 5000 bhp.

HCHO:

Since 40 CFR Part 63, Subpart YYYY applies to stationary combustion turbines located at a major source of HAP emissions only, natural gas fired turbines located at a non-major facility are not covered by 40 CFR Part 63, Subpart YYYY. GP-5 is applicable only to natural gas-fired turbines located at non-major facilities. HCHO emissions from natural gas fired turbines are significantly lower than HCHO emissions from natural gas-fired reciprocating internal combustion engines. Vendors' data show that HCHO emissions from natural gas-fired simple cycle turbines ranging in size from 4,700 to 30,000 bhp are 0.6 to 2.6 tons per year. Due to the very low emission level, the Department has not included an emission limitation for formaldehyde in the GP-5 for simple cycle turbines rated equal to or greater than 1000 bhp and less than 5000 bhp.

Particulate Matter (PM):

As per 40 CFR Part 60, Subpart KKKK, natural gas fired turbines rated equal to or greater than 1000 and less than 5000 bhp do not have an emission limitation for PM. Even though the filterable portion of the total particulate matter from natural gas-fired turbines is low, the condensable portion of the total particulate matter is considerably higher than the filterable particulate matter. The emissions of total PM, especially condensable PM, should be limited and monitored in turbines rated at 1,000 horsepower or more. The Department has recently issued a plan approval for a natural gas-fired simple cycle turbine with a total PM emission limitation of 0.03 lb/MMBtu. Based on the above, the Department has determined 0.03 lb/MMBtu as BAT for total particulate matter for turbines rated equal to or greater than 1000 bhp and less than 5000 bhp.

Emission Limits for Simple Cycle Turbines equal to or greater than 5000 BHP and less than 15000 BHP:

NOx:

As per 40 CFR Part 60, Subpart KKKK, NOx emission standard for natural gas fired mechanical drive turbines rated equal to or less than 50 MMBtu per hr of heat input (approximately 7000 bhp) is 100 ppmvd @ 15% Oxygen and the NO_X emission standard for natural gas fired mechanical drive turbines rated greater than 50 MMBtu per hr of heat input (approximately 7000 bhp) and less than or equal to 850 MMBtu per hr of heat input (approximately 115,000 bhp) is 25 ppmvd @ 15% oxygen. Vendors' guaranteed data show that natural gas fired turbine with dry low NO_X combustor, and rated at equal to or greater than 5000 bhp and less than 15,000 bhp could achieve equal to or less than 15 ppm of NO_X emissions @ 15% oxygen. The Department evaluated cost effectiveness for SCR technology for these turbines with uncontrolled NO_X emissions of 15 ppmvd @ 15% oxygen. Based on the evaluation the Department found that the cost effectiveness for SCR technology range from $71,000 to $76,000 per ton of NO_X removed for turbines rated equal to or greater than 5000 bhp and less than to 15,000 bhp. Therefore SCR technology is considered as a cost prohibitive option for NO_X control. A review of the stack test results show that a NO_X emission level of 15 ppmvd @ 15% oxygen is achievable for turbines rated at equal to or greater than 5000 bhp and less than 15,000 bhp. Based on the above the Department has determined 15 ppmvd @ 15% O2 as BAT for NO_X for turbines rated equal to or greater than 5000 bhp and less than 15,000 bhp.

CO:

As per 40 CFR Part 60, Subpart KKKK, natural gas fired turbines rated equal to or greater than 5000 bhp and less than 15,000 bhp do not have an emission limitation for CO. Vendors' guaranteed data show that natural gas fired turbine with dry low NO_X combustor, and rated at equal to or greater than 5000 bhp and less than 15,000 bhp can achieve equal to or less than 25 ppm of CO emissions @ 15% oxygen. The Department evaluated cost effectiveness for oxidation catalyst technology for these turbines with uncontrolled CO emissions of 25 ppmvd @ 15% oxygen. Based on the evaluation, the Department found that the cost effectiveness for oxidation catalyst technology is as high as $10,000 per ton of CO and HC removed for turbines rated equal to or greater than 5000 bhp and less than 15,000 bhp. Therefore oxidation catalyst technology is considered as a cost prohibitive option for CO control. A review of the stack test results indicates that CO emissions of 25 ppmvd @ 15% oxygen is achievable for turbines rated at equal to or greater than 5000 bhp and less than 15,000 bhp. Based on the above, the Department has determined 25 ppmvd @ 15% O2 as BAT for CO for turbines rated equal to or greater than 5000 bhp and less than 15,000 bhp.

NMNEHC:

As per 40 CFR Part 60, Subpart KKKK, natural gas fired turbines rated equal to or greater than 5000 bhp and less than 15,000 bhp do not have an emission limitation for NMNEHC. Vendors' guaranteed data show that natural gas fired turbine with dry low NO_X combustor, and rated at equal to or greater than 5000 bhp and less than 15,000 bhp can achieve equal to or less than 25 ppm of HC emissions @ 15% oxygen (as methane). The Department evaluated cost effectiveness for oxidation catalyst technology for these turbines with uncontrolled HC emissions of 25 ppmvd @ 15% oxygen (as methane). Based on the evaluation, the Department found that the cost effectiveness for oxidation catalyst technology is as high as $10,000 per ton of CO and HC removed for turbines rated equal to or greater than 5000 bhp and less than 15,000 bhp. Therefore oxidation catalyst technology is considered as a cost prohibitive option for HC control. Based on the above, the Department would have determined 25 ppmvd @ 15% O2 (as methane) as BAT for NMNEHC for turbines rated equal to or greater than 5000 bhp and less than 15,000 bhp. In order to accurately quantify hydrocarbons from the exhaust of these turbines, the limit has been converted into NMNEHC, reported as propane. The Department has determined 9 ppmvd @ 15% O2 (as propane) as BAT for NMNEHC for turbines rated equal to or greater than 5000 bhp and less than 15,000 bhp.

HCHO:

Since 40 CFR Part 63, Subpart YYYY applies to stationary combustion turbines installed at a major source of HAP emissions only, natural gas fired turbines installed at a non-major facility are not covered by 40 CFR Part 63, Subpart YYYY. HCHO emissions from natural gas fired turbines are significantly lower than HCHO emissions from natural gas-fired reciprocating internal combustion engines. Vendors' data show that HCHO emissions from natural gas-fired simple cycle turbines ranging in size from 4,700 to 30,000 bhp are 0.6 to 2.6 tons per year. Due to the very low emission level, the Department has not included an emission limitation for formaldehyde in the GP-5 for simple cycle turbines rated equal to or greater than 5000 bhp and less than 15,000 bhp.

Particulate Matter (PM):

As per 40 CFR Part 60, Subpart KKKK, natural gas fired turbines rated equal to or greater than 5000 bhp and less than 15,000 bhp do not have an emission limitation for PM. Even though the filterable portion of the total particulate matter from natural gas-fired turbines is low, the condensable portion of the total particulate matter is considerably higher than the filterable particulate matter. The emissions of total PM, especially condensable PM, should be limited and monitored in turbines rated at 1,000 horsepower or more. The Department has recently issued a plan approval for a natural gas-fired simple cycle turbine with a total PM emission limitation of 0.03 lb/MMBtu. The Department has determined 0.03 lb/MMBtu as BAT for PM for turbines rated equal to or greater than 5000 bhp and less than 15,000 bhp.

Emission Limits for Simple Cycle Turbines rated equal to or greater than 15,000 BHP:

NOx:

As per 40 CFR Part 60, Subpart KKKK, NOx emission standard for natural gas fired mechanical drive turbines rated greater than 50 MMBtu per hr of heat input (approximately 7000 bhp) and less than or equal to 850 MMBtu per hr of heat input (approximately 115,000 bhp) is 25 ppmvd @ 15% Oxygen and the NO_X emission standard for natural gas fired mechanical drive turbines rated greater than 850 MMBtu per hr of heat input (approximately 115,000 bhp) is 15 ppmvd @ 15% Oxygen. Vendors' guaranteed data show that natural gas fired turbine with dry low NO_X combustor, and rated at equal to or greater than 15,000 bhp could achieve equal to or less than 15 ppm of NO_X emissions @ 15% oxygen. The Department evaluated cost effectiveness for SCR technology for these turbines with uncontrolled NO_X emissions of 15 ppmvd @ 15% oxygen.

Based on the evaluation the Department found that the cost effectiveness for SCR technology range from $69,000 to $71,000 per ton of NO_X removed for turbines rated equal to or greater than 15,000 bhp. Therefore SCR technology is considered as a cost prohibitive option for NO_X control. A review of the stack test results indicates that NO_X emissions of 15 ppmvd @ 15% oxygen is achievable for turbines rated at equal to or greater than 15,000 bhp. Based on the above the Department has determined 15 ppmvd @ 15% O2 as BAT for NO_X for turbines rated equal to or greater than 15,000 bhp.

CO:

As per 40 CFR Part 60, Subpart KKKK, natural gas fired turbines rated at equal to or greater than 15000 bhp do not have an emission limitation for CO. Vendors' guaranteed data show that natural gas fired turbine with dry low NOx combustor, and rated at equal to or greater than 15,000 bhp can achieve equal to or less than 25 ppm of CO emissions @ 15% oxygen. The Department evaluated cost effectiveness for oxidation catalyst technology for these turbines with uncontrolled CO emissions of 25 ppmvd @ 15% oxygen and a CO control efficiency of 80%. However, catalyst systems are able to achieve CO reduction as high as 99% at higher capital cost. Based on the evaluation, the Department found that the cost effectiveness for oxidation catalyst technology ranges from $4,000 to $6,500 per ton of CO, VOCs, and formaldehyde removed for turbines rated equal to or greater than 15,000 bhp.

For a natural gas-fired turbine, the Department determined that an oxidation catalyst is economically feasible for the control of CO emissions at $5,071 per ton CO removed. The Department determined that the use of oxidation catalyst is considered as BAT for the control of CO emissions from gas turbines. The Department has determined that the use of an oxidation catalyst to control emissions of CO, VOCs, and formaldehyde has been determined to be BAT for Solar Mars 100-15002S III turbines rated at 13,300 bhp and 15,000 bhp constructed at the Texas Eastern, Holbrook compressor station in Green County, Solar Mars turbine rated at 16,000 bhp constructed at the Dominion Finnefrock compressor station in Clinton County, Solar Mars turbine rated at 15,000 bhp constructed at the Tennessee Gas Pipeline, 315 station in Tioga County, and a Solar Mars turbine rated at 15,000 bhp constructed at Penn State University in Centre County. Therefore, oxidation catalyst technology is considered as a cost effective option for CO control at an uncontrolled baseline CO emission level of 25 ppm @ 15% O2.

However, actual emission data from new turbines rated equal to or greater than 15,000 bhp indicates that 10 ppm of CO at 15% O2 has been achieved. The Department evaluated cost effectiveness for oxidation catalyst technology for these turbines with uncontrolled CO emissions of 10 ppmvd @ 15% oxygen. Based on the evaluation, the Department found that the cost effectiveness for oxidation catalyst technology is greater than $15,000 per ton of CO and HC removed for turbines rated equal to or greater than 15,000 bhp. Therefore oxidation catalyst technology is considered as a cost prohibitive option for CO control at an uncontrolled baseline CO emission level of 10 ppm @ 15% O2. Therefore, the Department has determined an emission limit of 10 ppmvd @ 15% O2 or a CO reduction efficiency requirement of 93% as BAT for CO for simple cycle turbines rated at equal to or greater than 15,000 BHP.

NMNEHC:

As per 40 CFR Part 60, Subpart KKKK, natural gas fired turbines rated at equal to or greater than 15,000 bhp do not have an emission limitation for NMNEHC. Vendors' guaranteed data show that natural gas fired turbine with dry low NO_X combustor, and rated at equal to or greater than 15,000 bhp can achieve equal to or less than 25 ppm of HC emissions @ 15% oxygen (as methane), which is equivalent to 9 ppm of HC emissions @ 15% oxygen (as propane). However, actual emission data from new turbines rated equal to or greater than 15,000 bhp indicates that 5 ppm of NMNEHC at 15% O2 (as propane) has been achieved. The required oxidation catalyst for the control of CO emissions can also typically reduce NMNEHC emissions from turbines by 50%. Therefore the Department has determined an NMNEHC emission limit of 5 ppmvd @ 15% O2 (as propane) or a NMNEHC reduction efficiency requirement of 50% as BAT for simple cycle turbines rated at equal to or greater than 15,000 BHP.

HCHO:

Since 40 CFR Part 63, Subpart YYYY applies to stationary combustion turbines installed at a major source of HAP emissions only, natural gas fired turbines installed at a non-major facility are not covered by 40 CFR Part 63, Subpart YYYY. HCHO emissions from natural gas fired turbines are significantly lower than HCHO emissions from natural gas-fired reciprocating internal combustion engines. Vendors' data show that HCHO emissions from natural gas-fired simple cycle turbines ranging in size from 4,700 to 30,000 bhp are 0.6 to 2.6 tons per year. Due to the very low emission level, the Department has not included an emission limitation for formaldehyde in the GP-5 for simple cycle turbines rated equal to or greater than 15,000 bhp. The required oxidation catalyst for the control of CO emissions would also reduce formaldehyde emissions from turbines.

Particulate Matter (PM):

As per 40 CFR Part 60, Subpart KKKK, natural gas fired turbines rated equal to or greater than 15,000 bhp do not have an emission limitation for PM. Even though the filterable portion of the total particulate matter from natural gas-fired turbines is low, the condensable portion of the total particulate matter is considerably higher than the filterable particulate matter. The emissions of total PM, especially condensable PM, should be limited and monitored in turbines rated at 1,000 horsepower or more. The Department has recently issued plan approvals for natural gas-fired simple cycle turbines with a total PM emission limitation of 0.03 lb/MMBtu. Based on the above, the Department has determined 0.03 lb/MMBtu as BAT for PM for turbines rated equal to or greater than 15,000 bhp.

Centrifugal Compressors:

Compression is necessary to move natural gas along a pipeline. Two types of compressors are used at gathering and boosting stations: centrifugal compressors and reciprocating compressors. Centrifugal compressors are equipped with either wet seal or dry seal systems. 40 CFR Part 60, Subpart OOOO requires a 95 percent reduction in VOC emissions from compressors with wet seal systems. This can be accomplished through flaring or by routing captured gas back to a compressor suction or fuel system.

The owner or operator shall comply with the applicable requirements specified in 40 CFR Part 60, Subpart OOOO.

Reciprocating Compressors:

40 CFR Part 60, Subpart OOOO requires the replacement of rod packing systems in reciprocating compressors. Over time, these packing systems can wear, leaking gas and VOCs. 40 CFR Part 60, Subpart OOOO provides two options for replacing rod packing: every 26,000 hours of operation (operating hours must be monitored and documented) or every 36 months (monitoring and documentation of operating hours not required).

The owner or operator shall comply with the applicable requirements specified in 40 CFR Part 60, Subpart OOOO.

Glycol Dehydrators:

All natural gas well streams contain water vapor as they leave the reservoir. In many instances, free water is produced along with the natural gas. Natural gas cools as it travels up the well bore to the surface as a result of pressure reduction and conduction of heat through the pipe to cooler formations. Therefore, since the ability of gas to hold water vapor decreases as the gas temperature decreases, natural gas is nearly always saturated with water vapor when it reaches surface equipment. Additional cooling of the saturated gas will cause the formation of free water. The process for removal of water vapor from natural gas is known as dehydration.

Dehydrators are designed to remove water from the natural gas vapor stream, thereby reducing corrosion and preventing the formation of hydrates, which are solid compounds that can cause flow restrictions and plugging in valves and even pipelines. The dry liquid glycol usually flows downward in an absorption tower, counter-current to the natural gas. The glycol absorbs most of the water from the natural gas, but it also absorbs other materials present in the gas stream. The dried natural gas exits the top of the tower. The water-rich glycol leaves the bottom of the tower and flows to the regenerator. The regenerator heats the glycol to drive off water vapor, and the water vapor is usually vented directly to the atmosphere through the regenerator vent stack. While water has a boiling point of 212 degrees Fahrenheit, glycol does not boil until 400 degrees Fahrenheit. This difference in the boiling points allow for the easy removal of water from the glycol. The dry glycol is then returned to the absorber. Glycol has a high affinity for water and a relatively low affinity for non-aromatic hydrocarbons, which makes it a very good absorbent fluid for drying natural gas. However, the glycol does absorb small amounts of methane and other hydrocarbons from the natural gas. The hydrocarbons are released to the atmosphere, along with the water vapor from the regenerator vent.

Some glycol dehydrators have additional equipment. Two common additions are flash tanks and regenerator vent emissions control equipment. The flash tank is placed in the rich glycol loop between the absorber and the regenerator. The glycol line pressure is dropped in the flash tank, causing most of the light hydrocarbons to flash into the vapor phase. The flash gas is usually routed to the regenerator burner as fuel. The methane emissions from the regenerator vent can be significantly reduced by using a flash tank. Regenerator vent control devices on units reduce emissions of benzene, toluene, ethylbenzene, and xylenes (BTEX) and volatile organic compounds (VOC) to the atmosphere. These compounds are absorbed from the gas stream and driven off with the water in the regenerator vent. Control devices usually condense the water and hydrocarbon (containing BTEX and heavier VOC), then decant the hydrocarbon for sale and the water for disposal.

Emissions from glycol dehydration units are often controlled by using a condenser on the regenerator still vent and then venting to atmosphere or to the regenerator reboiler firebox, other heaters, or a flare. Emissions from rich glycol flash tank vents are often controlled by combustion or by recycling back to low-pressure inlet gas streams. According to the Department of Energy's Office of Fossil Energy, these systems have been shown to recover 90 to 99 percent of methane that would otherwise be flared into the atmosphere. [9]

Emission Limits for Glycol Dehydrators:

Table 6 in Appendix A of this document gives a comparison summary of the requirements for glycol dehydrators in the previous GP-5 and the new GP-5.

Existing Glycol Dehydrators:

The owner or operator of any existing glycol dehydrator authorized to operate under a GP-5 previously issued shall continue to comply with the emission standards and other requirements established in the previously issued GP-5 under which the subject source is authorized to operate, as well as any applicable requirements established in 40 CFR Part 60, Subpart HH. The final GP-5 contains a condition for existing glycol dehydrators authorized to operate under a GP-5 issued previously on March 10, 1997 or March 23, 2011 to continue to comply with the same emissions standards and other requirements.

New Glycol Dehydrators:

The owner or operator of each glycol dehydrator located at natural gas compression and/or processing facility shall comply with the applicable requirements established in 40 CFR Part 63, Subpart HH. The owner or operator of each glycol dehydrator located at natural gas compression and/or processing facility shall also comply with the visible emissions and malodor requirements to satisfy BAT requirements.

The owner or operator of a new glycol dehydrator, which is not subject to the requirements included in 40 CFR Part 63, Subpart HH and has a total uncontrolled potential emission rate of VOC in excess of five (5) tons per year shall be controlled either by at least 95% with a condenser, a flare or other air cleaning device, or any alternative methods as approved by the Department. This control efficiency requirement must be demonstrated to the satisfaction of the Department. The owner or operator of a new glycol dehydrator shall also comply with the work practice, testing, visible emissions, malodor, and recordkeeping requirements. Additionally, during the development of 40 CFR Part 60, Subpart OOOO and 40 CFR Part 63, Subpart HH, EPA reviewed source test data and determined that a destruction efficiency of 95% is appropriate for continuous compliance of the glycol dehydrator.

The owner or operator of a new glycol dehydrator, which is not subject to the requirements included in 40 CFR Part 63, Subpart HH and has a total uncontrolled potential emission rate of VOC equal to or less than five (5) tons per year shall comply with the visible emissions, malodor, and recordkeeping requirements. This requirement is consistent with the requirement contained in the oil and gas general permit from Ohio EPA.

Storage Vessels/Storage Tanks:

GP-5 incorporates all applicable federal NSPS Subparts K, Kb, OOOO and NESHAP Subpart HH regulations by reference. In addition, GP-5 incorporates 25 Pa. Code §§ 129.56 and 129.57 by reference. 40 CFR Part 60, Subpart OOOO includes inspection and monitoring requirements for storage vessels. The requirements include that the owner or operator must conduct the no detectable emissions test procedure in accordance with Method 21 at 40 CFR Part 60, Appendix A-7.

Equipment Leaks:

Equipment leaks are typically low-level, unintentional losses of process gas from the sealed surfaces of above-ground process equipment. Equipment components that tend to leak include valves, flanges and other connectors, pump seals, compressor seals, pressure relief valves, open-ended lines, and sampling connections. These components represent mechanical joints, seals, and rotating surfaces, which in time tend to wear and develop leaks. The following requirements have been included to minimize and/or eliminate the equipment leaks.

Limiting emissions resulting from equipment leaks:

In addition to the applicable equipment leak provisions in 40 CFR Part 60, Subparts KKK and OOOO and 40 CFR Part 63, Subpart HH, the owner or operator of the natural gas compression and/or processing facility shall, at a minimum on a monthly basis, perform a leak detection and repair program which includes audible, visual, and olfactory ("AVO") inspections.

Within 180 days after the initial startup of a source, the owner or operator of the facility shall, at a minimum on a quarterly basis, use forward looking infrared ("FLIR") cameras or other leak detection monitoring devices approved by the Department for the detection of fugitive leaks. The Department may grant an extension for use of FLIR camera upon receipt of a written request from the owner or operator of the facility documenting the justification for the requested extension.

If any leak is detected, the owner or operator of the facility shall repair the leak as expeditiously as practicable, but no later than fifteen (15) days after the leak is detected, except as provided in 40 CFR § 60.482-9. The owner or operator shall record each leak detected and the associated repair activity. These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

Pneumatic Controllers:

Pneumatic controllers are automated instruments used for maintaining liquid levels, pressure, and temperature at wells and gas processing plants, among other locations in the oil and gas industry. These controllers often are powered by high-pressure natural gas and may release gas (including VOCs and methane) with every valve movement, or continuously in many cases as part of their normal operations.

40 CFR Part 60, Subpart OOOO affects high-bleed, gas driven controllers (with a gas bleed rate greater than 6 scfh) that are located between the wellhead and the point where gas enters the transmission pipeline. The rule sets limits for controllers based on location. For controllers used at gathering and boosting stations, the gas bleed limit is 6 scfh at an individual controller. The rule phases in this requirement over one year, to give manufacturers of pneumatic controllers time to test and document that the gas bleed rate of their pneumatic controllers is below 6 scfh.

Pneumatic controllers shall comply with all applicable requirements specified in 40 CFR Part 60, Subpart OOOO (NSPS).

Natural Gas Processing:

The natural gas used by consumers is composed almost entirely of methane. The field gas from the wells in some cases may contain natural gas liquids. For example, while the gas extracted in the southwest region of PA may contain more natural gas liquids (wet gas), the gases extracted from the wells in northeast and northcentral regions of PA tend to contain very low or no liquids (dry gas). The producer of wet gas may remove the liquids before sending the gas to interstate pipelines. The dry gas may not need additional processing.

Natural gas liquids (NGLs) can be very valuable by-products of natural gas processing. NGLs include ethane, propane, butane, iso-butane, and natural gasoline.

Emissions from Natural Gas Processing Operations:

In accordance with 25 Pa. Code §§ 127.11 and 127.12(a)(5), the owner or operator of a fractionation unit located at an onshore natural gas processing plant shall comply with 40 CFR Part 60, Subpart KKK – Standards of Performance for Equipment Leaks of VOCs from Onshore Natural Gas Processing Plants.

Sweetening Units:

In addition to water, oil, and NGL removal, one of the most important parts of gas processing involves the removal of sulfur and carbon dioxide. Natural gas from some wells contains significant amounts of sulfur and carbon dioxide. This natural gas, because of the rotten smell provided by its sulfur content, is commonly called 'sour gas'. Sour gas is undesirable because the sulfur compounds it contains can be extremely harmful, even lethal, to breathe. Sour gas can also be extremely corrosive. In addition, the sulfur that exists in the natural gas stream can be extracted and marketed on its own. In fact, according to the USGS, U.S. sulfur production from gas processing plants accounts for about 15 percent of the total U.S. production of sulfur.

Sulfur exists in natural gas as hydrogen sulfide (H_2S), and the gas is usually considered sour if the hydrogen sulfide content exceeds 5.7 milligrams of H_2S per cubic meter of natural gas. The process for removing hydrogen sulfide from sour gas is commonly referred to as 'sweetening' the gas.

The primary process for sweetening sour natural gas is quite similar to the processes of glycol dehydration and NGL absorption. In this case, however, amine solutions are used to remove the hydrogen sulfide. The sour gas is run through a tower, which contains the amine solution. This solution has an affinity for sulfur, and absorbs it much like glycol absorbing water. There are two principle amine solutions used, monoethanolamine (MEA) and diethanolamine (DEA). Either of these compounds, in liquid form, will absorb sulfur compounds from natural gas as it passes through. The effluent gas is virtually free of sulfur compounds, and thus loses its sour gas status. Like the process for NGL extraction and glycol dehydration, the amine solution used can be regenerated (that is, the absorbed sulfur is removed), allowing it to be reused to treat more sour gas.

Although most sour gas sweetening involves the amine absorption process, it is also possible to use solid desiccants like iron sponges to remove the sulfide and carbon dioxide.

Sulfur can be sold and used if reduced to its elemental form. Elemental sulfur is a bright yellow powder like material, and can often be seen in large piles near gas treatment plants, as is shown. In order to recover elemental sulfur from the gas processing plant, the sulfur containing discharge from a gas sweetening process must be further treated. The process used to recover sulfur is known as the Claus process, and involves using thermal and catalytic reactions to extract the elemental sulfur from the hydrogen sulfide solution. [10]

Emissions from Sweetening Units:

In accordance with 25 Pa. Code §§ 127.11 and 127.12(a)(5), the owner or operator of a sweetening unit shall also comply with the applicable requirements of 40 CFR Part 60, Subpart KKK and Subpart OOOO.

Testing and Monitoring Requirements:

The Department has included performance testing, monitoring, recordkeeping, and reporting requirements for the owner or operator to demonstrate compliance with the emission limitations for the affected sources. The owner or operator shall comply with all applicable NSPS and NESHAP testing and monitoring requirements.

Record Keeping Requirements:

The owner or operator of the facility is required to maintain records that clearly demonstrate to the Department that the facility is not a Title V facility. In addition, the owner or operator of the facility must keep records to demonstrate compliance with the facility-wide emission limitations. These records shall be maintained at a minimum on a monthly basis and the emissions shall be calculated on a 12-month rolling sum basis.

These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request. The Department reserves the right to request additional information necessary to determine compliance with this General Permit.

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Appendix A:

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Table 1: Previous GP-5 Vs. New GP-5 Applicability

Previous GP-5	New GP-5
NG-fired engines ≥100 HP to < 1500 HP	All size NG-fired engines located at a non-major facility
Glycol Dehydrator	Glycol Dehydrator and associated equipment (excluding re-boiler)
	- Natural gas-fired simple cycle turbines. - Centrifugal compressors. - Natural gas fractionation process units (such as De-propanizer, De-ethanizer, De-butanizer). - Storage vessels/tanks. - Pneumatic controllers. - Sweetening Units. - Equipment leaks.

Table 2: Previous GP-5 Vs. New GP-5 Engines

	Previous GP-5	New GP-5							
Pollutant	Lean-Burn or Rich-Burn Engines ≥100 HP to <1500 HP	Lean-Burn			Percent Reduction from previous GP-5	Rich-Burn			Percent Reduction from previous GP-5
		≤100 HP	>100 HP to ≤500 HP	>500 HP		≤100 HP	>100 HP to ≤500 HP	>500 HP	
NO_X	2.0	2.0	1.0	0.50	75%	2.0	0.25	0.20	90%
CO	2.0	2.0	2.0	47 ppmvd or 93% control	80%	2.0	0.30	0.30	85%
VOC	2.0	-	0.70*	0.25*	87.5%	-	0.20*	0.20*	90%
HCHO	None	-	-	0.05		-	-	2.7 ppmvd or 76% control	

Allowable Emissions Limits for engines in g/bhp-hr or ppmvd corrected to 15% O_2

*NMNEHC (as propane excluding HCHO)

Percent reduction for engines > 500 HP

Table 3: Stack Test Results (Engines > 500 BHP)

REGION	COUNTY	BHP	Type/Make	Oxidation Catalyst	VOC Reported As:	Stack Testing NO_X (g/bhp-hr)	Stack Testing VOC (g/bhp-hr)	Stack Testing CO (g/bhp-hr)	Avg. BHP
Northwest	Warren	600	Ajax DPC-600LE	No	Not Reported	0.128		1.425	449
Northwest	McKean	840	Waukesha F3524GSI	Yes	Propane	0.06	0.0004	0.03	672
Southwest	Fayette	1340	Caterpillar G3516LE	Yes	Not Classified	0.22	0.41	1.42	572
Northcentral	Tioga	1340	Caterpillar G3516TALE	No	Propane	0.37	0.24	0.86	1340
Southwest	Washington	1340	Caterpillar G3516B	Yes	Propane	0.38	0.05	0.08	1233
Northcentral	Potter	1340	Caterpillar G3516LE	No	Propane	0.38	0.3	0.13	1340
Northwest	McKean	1340	Caterpillar G3516LE	No	Propane	0.39	0.09	1.14	268
Southwest	Washington	1340	Caterpillar G3516B	Yes	Propane	0.41	0.1	0.07	1300
Southwest	Washington	1340	Caterpillar G3516LE	Yes	Propane	0.44	0.11	0.04	1340
Northcentral	Lycoming	1340	Caterpillar G3516LE	No	Propane	0.45	0.12	0.01	1286
Northcentral	Lycoming	1340	Caterpillar G3516LE	No	Propane	0.46	0.7	0.01	1275
Southwest	Washington	1340	Caterpillar G3516LE	Yes	Propane	0.46	0.1	0.02	1340
Southwest	Washington	1340	Caterpillar G3516LE	No	Propane	0.47	0.08	0.04	1340
Southwest	Washington	1380	Caterpillar G3516B	Yes	Propane	0.27	0.07	0.01	1340
Southwest	Greene	1380	Caterpillar G3516B	Yes	Propane	0.34	0.03	0.03	1274
Southwest	Fayette	1380	Caterpillar G3516B	Yes	Propane	0.36	0.04	0.03	1390
Southwest	Fayette	1380	Caterpillar G3516B	Yes	Propane	0.37	0.04	0.08	1384
Southwest	Greene	1380	Caterpillar G3516B	Yes	Propane	0.38	0.04	0.03	1254

Southwest	Fayette	1380	Caterpillar G3516B	Yes	Propane	0.4	0.04	0.02	1381
Southwest	Washington	1480	Waukesha L7042GSI	No	Not Reported	0.08		2.34	497
Northwest	Elk	1775	Caterpillar G3606	Yes	Propane	0.27	0.09	0.03	1654
Southwest	Westmoreland	1775	Caterpillar G3606	Yes	Propane	0.29	0.1	0.08	1798
Northwest	Elk	1775	Caterpillar G3606	Yes	Propane	0.34	0.14	0.03	1619
Southwest	Greene	2370	Caterpillar G3608LE	Yes	Propane	0.24	0.189	0.01	2488.5
Southwest	Greene	2370	Caterpillar G3608LE	Yes	Propane	0.29	0.02	0.02	2289.4
Southwest	Westmoreland	2370	Caterpillar G3608	Yes	Propane	0.34	0.06	0.01	2284
Southwest	Westmoreland	2370	Caterpillar G3608	Yes	Propane	0.35	0.04	0.02	2308
Northcentral	Lycoming	2370	Caterpillar G3608		Propane	0.43	0.05	0.02	2139
Northcentral	Lycoming	2370	Caterpillar G3608		Propane	0.46	0.04	0.01	2122
Northeast	Susquehanna	2370	Caterpillar G3608LE	Yes	Methane	0.491	0.207	0.087	2180
Northcentral	Lycoming	2370	Caterpillar G3608		Propane	0.5	0.11	0.01	2081
Southwest	Westmoreland	3550	Caterpillar G3612	Yes	Propane	0.31	0.06	0.05	3350

Table 4: Rich-Burn Engine Information (Vendors' Guarantees)

Make	Model	HP	NO_X	CO	VOC	HCHO
Cummins	GTA8.3	118	13.00	8.60	0.07	- -
Cummins	G8.3	190	16.40	1.70	0.07	- -
Cummins	G8.3	175	14.50	2.40	0.08	- -
Cat	3412SITA	593	17.00	2.28	0.15	- -
Cat		1050	13.44	13.10	0.19	0.27
Waukesha	L3524GSI	840	15.00	13.00	0.20	- -
Waukesha	L5794GSI	1380	15.00	13.00	0.20	- -
Waukesha	L7044GSI	1680	15.00	13.00	0.20	- -
Cat		365	13.35	13.35	0.24	- -
Waukesha	F18GSI/GSID	400	16.00	8.00	0.25	- -
Waukesha	H24GSI/GSID	530	16.00	8.00	0.25	- -
Waukesha	L36GSI/GSID	800	16.00	8.00	0.25	- -
Waukesha	P48GSI/GSID	1065	16.00	8.00	0.25	- -
Cat		500	14.22	14.20	0.26	0.18
Cat	G3406TA	276	14.85	14.80	0.28	- -
Waukesha	L7042GSI	1480	13.00	9.00	0.30	- -
Waukesha	P9390GSI	1960	13.00	9.00	0.30	- -
Waukesha	P9390GSI	1320 - 1980	13.00	9.00	0.30	- -
Cat	3408SITA	460	16.24	0.90	0.44	- -
Average			14.79	8.91	0.23	0.23
Median			15.00	9.00	0.25	0.23

Table 5: Formaldehyde Test Results

Summatiwn of Formaldehyde Tests Results (EPA Method 323) and Statistics w... CO Results from Concurrent Testing

			Mfg. HCOH Emission*	Formaldehyde Results			CO Results			
Engine Type	Engine HP	Catalyst?	Estimate (g/bhp-hr)	g/bhp-hr	lb/hr	tpy	g/bhp-hr	lb/hr	tpy	Comments
CAT 3516LE	1340	N	0.22-0.28	0.11	0.33	1.45	1.45	4.27	18.70	Average of 5 runs
CAT 3516LE	1340	N	0.26	0.12	0.26	1.12				No CO Results
CAT 3516LE	1340	N	0.26	0.06	0.13	0.57				No CO Results
CAT 3516LE	1340	Y	0.22-0.28	0.03	0.08	0.36	0.05	0.15	0.66	
CAT 3516LE	1340	Y	0.22-0.28	0.02	0.06	0.27	0.05	0.15	0.66	These four engines were all at
CAT 3516LE	1340	N	0.22-0.28	0.20	0.60	2.63	1.70	5.02	22.00	the same site, using same gas,
CAT 3516LE	1340	N	0.22-0.28	0.17	0.49	2.15	1.56	4.60	20.10	and tested the same week.
CAT 3516LE	1340	Y	0.28	0.02	0.06	0.26	0.09	0.27	1.16	
CAT 3516LE	1340	Y	0.28	0.05	0.15	0.65	0.15	0.44	1.94	These four engines were all at
CAT 3516LE	1340	Y	0.28	0.04	0.12	0.52	0.11	0.32	1.42	the same site, using same gas,
CAT 3516LE	1340	Y	0.28	0.05	0.15	0.65	0.13	0.38	1.68	and tested the same week.
CAT 3516LE	1340	Y	0.28	0.02	0.06	0.26	0.11	0.32	1.42	
CAT 3516LE	1340	Y	0.28	0.01	0.03	0.13	0.03	0.09	0.39	
CAT 3516LE	1340	Y	0.28	0.01	0.03	0.13	0.02	0.06	0.26	
CAT 3516LE	1340	Y	0.28	0.01	0.03	0.13	0.07	0.21	0.91	
CAT 3516LE	1340	Y	0.28	0.03	0.09	0.39	0.16	0.47	2.07	
CAT 3516LE	1340	Y	0.28	0.00	0.00	0.00	0.01	0.03	0.13	
CAT 3516LE	1340	Y	0.28	0.00	0.00	0.00	0.02	0.06	0.26	
CAT 3516LE	1340	Y	0.28	0.02	0.06	0.26	0.18	0.53	2.33	These three tested the same
CAT 3516LE	1340	Y	0.28	0.03	0.09	0.39	0.22	0.65	2.85	week at the same site with same
CAT 3516LE	1340	Y	0.28	0.00	0.00	0.00	0.02	0.06	0.26	gas.
CAT 3516LE	1340	Y	0.28	0.02	0.06	0.26	0.10	0.30	1.30	These three tested the same
CAT 3516LE	1340	Y	0.28	0.02	0.06	0.26	0.10	0.30	1.30	week at the same site with same
CAT 3516LE	1340	Y	0.28	0.02	0.06	0.26	0.12	0.35	1.55	gas.
CAT 3606LE	1985	N	0.40	0.09	0.36	1.56	1.67	6.23	27.30	

* The emission estimate is given as a range because the emission estimate varies with when the engine was manufactured and what emissions setting it was ordered with. The spec sheets for these engines was not available to the compiler of this data.

Note that all engines are below the lowest manufacturers emission estimate.

Averages/Statistics	Average	Standard Deviation	TPY Average
HCOH G3516LE w/catalyst	0.02 g/hp-hr	0.19	0.27
HCOH G3516LE w/o catalyst	0.13 g/hp-hr	0.73	1.58
CO G3516LE w/catalyst	0.09 g/hp-hr	0.78	
CO G3516LE w/o catalyst	1.60 g/hp-hr	3.77	

Table 6: Previous GP-5 Vs. Revised GP-5 Glycol Dehydrators

Previous GP-5	New GP-5
Glycol Dehydrator	Glycol Dehydrators and associated equipment including Gas-Condensate-Glycol (GCG) separators (Flash Tanks)
VOC > 10 tons per year are required to control 85% of VOC emissions.	New large glycol dehydrators are required to comply with the applicable 40 CFR Part 63, Subpart HH, and visible emissions and malodors requirements.
	New small glycol dehydrators which has a total uncontrolled PTE VOC emission rate in excess of 5 tons per year are required to control 95% of VOC emissions, work practice, testing, visible emissions, and malodors requirements.
	New small glycol dehydrators which has a total uncontrolled PTE VOC emission rate equal to or less than 5 tons per year are required to comply with visible emissions, and malodors requirements.

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Appendix B

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SCR Cost Analysis for 100 BHP Natural Gas-Fired Lean-Burn Engine

		Miratech
HP	**100**	**250**
Hrs	**8760**	**8760**
Capital Cost:		
SCR Catalyst Housing	$18,958.40	$47,396.00
Control System	$5,120.00	$12,800.00
Reductant Storage & Delivery	$1,000.00	$2,500.00
Insulation	$780.00	$1,950.00
Equipement Cost (EC)	**$25,858.40**	
Freight (6% of EC)	$1,551.50	
Total Equipment Cost (TEC)	**$27,409.90**	
Installation Cost	$101,561.00	$101,561.00
Total Capital Cost (TCC)	**$128,970.90**	
Annual Operating Cost:		
Catalyst replacement	$1,066.40	$2,666.00
Urea Cost	$12,381.60	$30,954.00
Parts Cost	$1,070.00	$2,675.00
On-Site Testing	$5,000.00	$5,000.00
Labor - $30/hr, 30 min/shift and supervisor - 15% of Labor)	$18,888.75	
Maintenance (5% of TCC - Most Vendors)	$6,448.55	
Overhead (60% of Maintenance - OAQPS)	$3,869.13	
PropertyTax+Ins.+Admn. (4% of TCC - OAQPS)	$5,158.84	
Capital Recovery (10 yrs @ 10%)	$20,893.29	
Total Annual Operating Cost (TAOC)	**$74,776.54**	
Uncontrolled NOx TPY (Calculated TPY is based on 2.0 g/hp-hr)	1.93	
NOx removed TPY (80% Eff.)	1.54	
Cost-Effectiveness ($/Ton NOx removed)	**$48,442.57**	

Cost Basis:
Quote from Miratech from 1/13/1999
Scaled to 2010 via CPI adjustment of 1.36
Includes costs for catalyst housing, control system, reductant storage and delivery, installation, catalyst replacement, urea, and parts

SCR Cost Analysis for 500 BHP Natural Gas-Fired Lean-Burn Engine

		Miratech
HP	**500**	**250**
Hrs	**8760**	**8760**
Capital Cost:		
SCR Catalyst Housing	$94,792.00	$47,396.00
Control System	$25,600.00	$12,800.00
Reductant Storage & Delivery	$5,000.00	$2,500.00
Insulation	$3,900.00	$1,950.00
Equipement Cost (EC)	**$129,292.00**	
Freight (6% of EC)	$7,757.52	
Total Equipment Cost (TEC)	**$137,049.52**	
Installation Cost	$101,561.00	$101,561.00
Total Capital Cost (TCC)	**$238,610.52**	
Annual Operating Cost:		
Catalyst replacement	$5,332.00	$2,666.00
Urea Cost	$61,908.00	$30,954.00
Parts Cost	$5,350.00	$2,675.00
On-Site Testing	$5,000.00	$5,000.00
Labor - $30/hr, 30 min/shift and supervisor - 15% of Labor)	$18,888.75	
Maintenance (5% of TCC - Most Vendors)	$11,930.53	
Overhead (60% of Maintenance - OAQPS)	$7,158.32	
PropertyTax+Ins.+Admn. (4% of TCC - OAQPS)	$9,544.42	
Capital Recovery (10 yrs @ 10%)	$38,654.90	
Total Annual Operating Cost (TAOC)	**$163,766.92**	
Uncontrolled NOx TPY (Calculated TPY is based on 1.0 g/hp-hr)	4.82	
NOx removed TPY (80% Eff.)	3.86	
Cost-Effectiveness ($/Ton NOx removed)	**$42,437.32**	

Cost Basis:
Quote from Miratech from 1/13/1999
Scaled to 2010 via CPI adjustment of 1.36
Includes costs for catalyst housing, control system, reductant storage and delivery, installation, catalyst replacement, urea, and parts

SCR Cost Analysis for 1000 BHP Natural Gas-Fired Lean-Burn Engine

		Miratech
HP	**1000**	**250**
Hrs	**8760**	**8760**
Capital Cost:		
SCR Catalyst Housing	$189,584.00	$47,396.00
Control System	$51,200.00	$12,800.00
Reductant Storage & Delivery	$10,000.00	$2,500.00
Insulation	$7,800.00	$1,950.00
Equipement Cost (EC)	$258,584.00	
Freight (6% of EC)	$15,515.04	
Total Equipment Cost (TEC)	**$274,099.04**	
Installation Cost	$101,561.00	$101,561.00
Total Capital Cost (TCC)	**$375,660.04**	
Annual Operating Cost:		
Catalyst replacement	$10,664.00	$2,666.00
Urea Cost	$123,816.00	$30,954.00
Parts Cost	$10,700.00	$2,675.00
On-Site Testing	$5,000.00	$5,000.00
Labor - $30/hr, 30 min/shift and supervisor - 15% of Labor)	$18,888.75	
Maintenance (5% of TCC - Most Vendors)	$18,783.00	
Overhead (60% of Maintenance - OAQPS)	$11,269.80	
PropertyTax+Ins.+Admn. (4% of TCC - OAQPS)	$15,026.40	
Capital Recovery (10 yrs @ 10%)	$60,856.93	
Total Annual Operating Cost (TAOC)	**$275,004.88**	
Uncontrolled NOx TPY (Calculated TPY is based on 0.5 g/hp-hr)	4.82	
NOx removed TPY (80% Eff.)	3.86	
Cost-Effectiveness ($/Ton NOx removed)	**$71,262.68**	
Cost Basis:		
Quote from Miratech from 1/13/1999		
Scaled to 2010 via CPI adjustment of 1.36		
Includes costs for catalyst housing, control system, reductant storage and delivery, installation, catalyst replacement, urea, and parts		

SCR Cost Analysis for 2000 BHP Natural Gas-Fired Lean-Burn Engine

		Miratech
HP	2000	250
Hrs	8760	8760
Capital Cost:		
SCR Catalyst Housing	$379,168.00	$47,396.00
Control System	$102,400.00	$12,800.00
Reductant Storage & Delivery	$20,000.00	$2,500.00
Insulation	$15,600.00	$1,950.00
Equipement Cost (EC)	$517,168.00	
Freight (6% of EC)	$31,030.08	
Total Equipment Cost (TEC)	**$548,198.08**	
Installation Cost	$101,561.00	$101,561.00
Total Capital Cost (TCC)	**$649,759.08**	
Annual Operating Cost:		
Catalyst replacement	$21,328.00	$2,666.00
Urea Cost	$247,632.00	$30,954.00
Parts Cost	$21,400.00	$2,675.00
On-Site Testing	$5,000.00	$5,000.00
Labor - $30/hr, 30 min/shift and supervisor - 15% of Labor)	$18,888.75	
Maintenance (5% of TCC - Most Vendors)	$32,487.95	
Overhead (60% of Maintenance - OAQPS)	$19,492.77	
PropertyTax+Ins.+Admn. (4% of TCC - OAQPS)	$25,990.36	
Capital Recovery (10 yrs @ 10%)	$105,260.97	
Total Annual Operating Cost (TAOC)	**$497,480.81**	
Uncontrolled NOx TPY (Calculated TPY is based on 0.5 g/hp-hr)	9.65	
NOx removed TPY (80% Eff.)	7.72	
Cost-Effectiveness ($/Ton NOx removed)	**$64,456.70**	
Cost Basis:		
Quote from Miratech from 1/13/1999		
Scaled to 2010 via CPI adjustment of 1.36		
Includes costs for catalyst housing, control system, reductant storage and delivery, installation, catalyst replacement, urea, and parts		

SCR Cost Analysis for 4000 BHP Natural Gas-Fired Lean-Burn Engine

		Miratech
HP	**4000**	**250**
Hrs	**8760**	**8760**
Capital Cost:		
SCR Catalyst Housing	$758,336.00	$47,396.00
Control System	$204,800.00	$12,800.00
Reductant Storage & Delivery	$40,000.00	$2,500.00
Insulation	$31,200.00	$1,950.00
Equipement Cost (EC)	$1,034,336.00	
Freight (6% of EC)	$62,060.16	
Total Equipment Cost (TEC)	**$1,096,396.16**	
Installation Cost	$101,561.00	$101,561.00
Total Capital Cost (TCC)	**$1,197,957.16**	
Annual Operating Cost:		
Catalyst replacement	$42,656.00	$2,666.00
Urea Cost	$495,264.00	$30,954.00
Parts Cost	$42,800.00	$2,675.00
On-Site Testing	$5,000.00	$5,000.00
Labor - $30/hr, 30 min/shift and supervisor - 15% of Labor)	$18,888.75	
Maintenance (5% of TCC - Most Vendors)	$59,897.86	
Overhead (60% of Maintenance - OAQPS)	$35,938.71	
PropertyTax+Ins.+Admn. (4% of TCC - OAQPS)	$47,918.29	
Capital Recovery (10 yrs @ 10%)	$194,069.06	
Total Annual Operating Cost (TAOC)	**$942,432.67**	
Uncontrolled NOx TPY (Calculated TPY is based on 0.5 gms/hp-hr)	19.30	
NOx removed TPY (80% Eff.)	15.44	
Cost-Effectiveness ($/Ton NOx removed)	**$61,053.71**	
Cost Basis:		
Quote from Miratech from 1/13/1999		
Scaled to 2010 via CPI adjustment of 1.36		
Includes costs for catalyst housing, control system, reductant storage and delivery, installation, catalyst replacement, urea, and parts		

Cost Analysis for NMNEHC control (CO Catalyst) for Lean-Burn engines 100 - 500 HP (0.7 gms/bhp-hr)

BHP	**500**	**Factors Used**
Hrs/Yr	**8760**	
Equipment Cost (Miratech) = (1)	$ 7,000.00	IQ-14-L1
Instrumentation / Control System = (2)	$0.00	N/A
Sales Tax (6% of EC) = (5)	$ 420.00	6% of EC
Freight (6% of EC) = (6)	$ 420.00	6% of EC
Purchase Equipment Cost = (7) = (1)+(2)+(3)+(4)+(5)	**$7,840.00**	
INSTALLATION COSTS		
Direct Installation		
Foundation and Support = (8)	0	
Handling and Erection = (9)	1,000	Unit weighs 103 lbs
Electrical = (10)	0	
Piping (11)	700	mating flange and welder (2 hours)
Painting (12)	0	
Total Direct Installation Cost = (13) = (8)+(9)+(10)+(11)+(12)	**$1,700.00**	
Site Preparation = (14)	**$0.00**	
Facilities, Buildings = (15)	**$0.00**	
Indirect Installation		
Engineering and Supervision = (16)	**$2,000.00**	
Construction, Field = (17)	**$392.00**	
Construction Fee = (18)	**$0.00**	
Startup = (19)	**$0.00**	No electronics, no startup
Total Indirect Cost = (20) = (14)+(15)+(16)+(17)+(18)+(19)	**$2,392.00**	
TOTAL CAPITAL COST (TCC)	**$4,092.00**	
ANNUAL OPERATING COST		
Annulized Capital Recovery Cost (10 yrs at 10%-OAQPS) = (21)	$662.90	0.162*TCC
Catalyst Replacement (costs/No. of years) = (24)	$2,333.33	every 3 years
Catalyst Disposal Costs (Costs/No. of years) = (25)	$0.00	
Contingencies (10% of PEC) = (26)	$784.00	
Administration (2% of TCC-OAQPS) = (27)	$81.84	2% of TCC (OAQPS)
Property Taxes (1% of TCC-OAQPS) = (28)	$40.92	1% of TCC (OAQPS)
Insurance (1% of TCC-OAQPS) = (29)	$40.92	1% of total EC (OAQPS)
Labor - $30/hr, 30 min/shift and supervisor - 15% of Labor = (30)	$18,888.75	8 hrs/shift, 1/2 hr/shift-labor@$50/hr, 15% Supervisory
Maintenance (10% of TCC) = (31)	$784.00	10% of PEC (OAQPS)
Overhead (60% of Maintenance-OAQPS) = (32)	0.6*	60% of Maintenance Cost (OAQPS)
TOTAL ANNUAL OPERATING COST = (33) = Sum from (21) through (32)	**$23,616.67**	
Uncontrolled HC TPY = (34)	3.38	Based on 0.7 gms/hp-hr
HC removed TPY (50% Eff.) = (35)	1.69	90% Efficient CO Catalyst Systems in practice
Cost-Effectiveness ($/Ton CO removed) = (36) = (33)/(35)	**$13,988**	

Cost Analysis for CO Catalyst for Lean-Burn engines >500 HP (Baseline 2 gms/bhp-hr)

BHP	**500**	**Factors Used**
Hrs/Yr	**8760**	
Equipment Cost (Miratech) = (1)	$ 7,000.00	IQ-14-L1
Instrumentation / Control System = (2)	$0.00	N/A
Sales Tax (6% of EC) = (5)	$ 420.00	6% of EC
Freight (6% of EC) = (6)	$ 420.00	6% of EC
Purchase Equipment Cost = (7) = (1)+(2)+(3)+(4)+(5)	**$7,840.00**	
INSTALLATION COSTS		
Direct Installation		
Foundation and Support = (8)	0	
Handling and Erection = (9)	1,000	Unit weighs 103 lbs
Electrical = (10)	0	
Piping (11)	700	mating flange and welder (2 hours)
Painting (12)	0	
Total Direct Installation Cost = (13) = (8)+(9)+(10)+(11)+(12)	**$1,700.00**	
Site Preparation = (14)	**$0.00**	
Facilities, Buildings = (15)	**$0.00**	
Indirect Installation		
Engineering and Supervision = (16)	**$2,000.00**	
Construction, Field = (17)	**$392.00**	
Construction Fee = (18)	**$0.00**	
Startup = (19)	**$0.00**	No electronics, no startup
Total Indirect Cost = (20) = (14)+(15)+(16)+(17)+(18)+(19)	**$2,392.00**	
TOTAL CAPITAL COST (TCC)	**$4,092.00**	
ANNUAL OPERATING COST		
Annulized Capital Recovery Cost (10 yrs at 10%-OAQPS) = (21)	$662.90	0.162*TCC
Catalyst Replacement (costs/No. of years) = (24)	$2,333.33	every 3 years
Catalyst Disposal Costs (Costs/No. of years) = (25)	$0.00	
Contingencies (10% of PEC) = (26)	$784.00	
Administration (2% of TCC-OAQPS) = (27)	$81.84	2% of TCC (OAQPS)
Property Taxes (1% of TCC-OAQPS) = (28)	$40.92	1% of TCC (OAQPS)
Insurance (1% of TCC-OAQPS) = (29)	$40.92	1% of total EC (OAQPS)
Labor - $30/hr, 30 min/shift and supervisor - 15% of Labor = (30)	$18,888.75	8 hrs/shift, 1/2 hr/shift-labor@$50/hr, 15% Supervisory
Maintenance (10% of TCC) = (31)	$784.00	10% of PEC (OAQPS)
Overhead (60% of Maintenance-OAQPS) = (32)	0.6*	60% of Maintenance Cost (OAQPS)
TOTAL ANNUAL OPERATING COST = (33) = Sum from (21) through (32)	**$23,616.67**	
Uncontrolled CO TPY = (34)	9.65	Based on 2 gms/hp-hr
CO removed TPY (90% Eff.) = (35)	8.68	90% Efficient CO Catalyst Systems in practice
Cost-Effectiveness ($/Ton CO removed) = (36) = (33)/(35)	**$2,720**	

NSCR Cost Analysis for 50 BHP Spark Ignition Rich-Burn Engine

	Based on E - C/R INC's Cost-Analysis done for EPA in June 2010
HP	50
Hrs	8760
Total Capital Cost (TCC)	$14,363.00
Total Annual Operating Cost (TAOC)	$5,917.50
Uncontrolled NOx g/bhp-hr	11.41
Uncontrolled CO g/bhp-hr	17.00
Uncontrolled NMHC g/bhp-hr	1.50
Uncontrolled NOx tons per year	5.50
Uncontrolled CO tons per year	8.20
Uncontrolled NMHC tons per year	0.72
NOx removed TPY (90% Eff.)	4.95
CO removed TPY (90% Eff.)	7.38
NMHC removed TPY (50% Eff.)	0.36
Total NOx, CO, and NMHC removed	12.70
Cost-Effectiveness ($/Ton NOx removed)	**$1,194.60**
Cost-Effectiveness ($/Ton CO removed)	**$801.79**
Cost-Effectiveness ($/Ton NMHC removed)	**$3,945.00**
Cost-Effectiveness ($/Ton NOx, CO, NMHC removed)	**$466.10**

Uncontrolled NOx Emissions used for this cost analysis - 11.41 gms/bhp-hr
Uncontrolled CO Emissions used for this cost analysis - 17 gms/bhp-hr
Uncontrolled NMHC Emissions used for this cost analysis - 1.5 gms/bhp-hr

NOx Control Efficiency 90% (EPA)
CO Control Efficiency 90% (EPA)
HC Control Efficiency 50% (EPA)

NSCR Cost Analysis for 100 BHP Spark Ignition Rich-Burn Engine

	Based on E - C/R INC's Cost-Analysis done for EPA in June 2010
HP	**100**
Hrs	**8760**
Total Capital Cost (TCC)	$15,608.00
Total Annual Operating Cost (TAOC)	$6,156.00
Uncontrolled NOx g/bhp-hr	11.41
Uncontrolled CO g/bhp-hr	17.00
Uncontrolled NMHC g/bhp-hr	1.50
Uncontrolled NOx tons per year	11.01
Uncontrolled CO tons per year	16.40
Uncontrolled NMHC tons per year	1.45
NOx removed TPY (90% Eff.)	9.91
CO removed TPY (90% Eff.)	14.76
NMHC removed TPY (50% Eff.)	0.72
Total NOx, CO, and NMHC removed	25.39
Cost-Effectiveness ($/Ton NOx removed)	**$621.37**
Cost-Effectiveness ($/Ton CO removed)	**$417.05**
Cost-Effectiveness ($/Ton NMHC removed)	**$4,104.00**
Cost-Effectiveness ($/Ton NOx, CO, NMHC removed)	**$242.44**

Uncontrolled NOx Emissions used for this cost analysis - 11.41 gms/bhp-hr
Uncontrolled CO Emissions used for this cost analysis - 17 gms/bhp-hr
Uncontrolled NMHC Emissions used for this cost analysis - 1.5 gms/bhp-hr

NOx Control Efficiency 90% (EPA)
CO Control Efficiency 90% (EPA)
HC Control Efficiency 50% (EPA)

SCR Cost Analysis for 1000 BHP Natural Gas-Fired Turbine

HP	**1000**
Hrs	**8760**
Total Capital Investment (TCI)	**$234,478.56**
Annual Operating Cost:	
Operating Labor	$42,752.00
Superviosry Labor	$6,412.80
Maintenance	$11,271.56
Catalyst Replacement	$19,828.89
Catalyst Disposal	$363.03
Reagent	$1,123.39
Dilution Sream	$667.25
Performance Loss	$2,959.26
Blower	$295.93
Overhead	$13,420.32
Taxes, Insurance, and Administration	$9,386.68
Capital Recovery (10 yrs @ 10%)	$37,985.53
Total Annual Cost (TAC)	**$146,466.61**
Uncontrolled NOx TPY (Calculated TPY is based on 25 ppm)	2.93
NOx removed TPY (80% Eff.)	2.34
Cost-Effectiveness ($/Ton NOx removed)	**$62,543.72**

Uncontrolled Emisson Calcuation

25 ppm
0.091911765 lb/MMBtu
1000 HP Output
2857.142857 HP Input
7.271428571 MMBtu/hr
0.668329832 lb/hr
2.927284664 ton/yr

Cost Basis:
EPA's ACT Document (January 1993)
Scaled from 1990 to 2010 via CPI adjustment of 1.67
Costs are based for a 4,430 bhp turbine
Includes all costs except for capital recovery

1000 HP Turbine Catalyst Cost Calculations with uncontrolled CO Emission of 25 ppm and UHC emission of 25 ppm

Uncontrolled CO Emission Rate ppm	25	(Caterpillar)			
Controlled Emission Rate ppm	5				
Control Efficiency	80%				
Uncontrolled CO Emissions tons/year	2.22	(Caterpillar)			
CO Emission Reduction tons/year	1.78				
Uncontrolled UHC Emission Rate ppm	25	(Caterpillar)			
Controlled UHC Emission Rate ppm	2				
Control Efficiency	92%				
Uncontrolled UHC Emissions tons/year	1.27	(Caterpillar)			
UHC Emission Reduction tons/year	1.17				
Total CO and UHC removed	2.95				
Direct Costs (DC)	**COST FACTOR**		**REFERENCE**	**COST**	
Purchased Equipment Costs (PEC)					
Major Equipment					
Oxidation Catalyst & Auxiliary Equipment, (A)			Vendor*	$ 200,000	
Instrumentation	0.10	x A	EPA Manual	$ 20,000	
Total Major Equipment (PEC), (B)				$ 220,000	
State Sales Tax	6.0%	x B	State of PA	$ 13,200	
Freight	0.05	x B	EPA Manual	$ 11,000	
Total PEC, (C)				$ 244,200	
Direct Installation Costs (DIC)					
Foundation and supports	0.08	x C	EPA Manual	$ 19,536	
Handling and Erection	0.14	x C	EPA Manual	$ 34,188	
Electrical	0.04	x C	EPA Manual	$ 9,768	
Piping	0.02	x C	EPA Manual	$ 4,884	
Insulation	0.01	x C	EPA Manual	$ 2,442	
Painting	0.01	x C	EPA Manual	$ 2,442	
Total Direct Costs (DC)				$ 317,460	
Indirect Costs (IC)					
Engineering	0.12	x C	Estimate	$ 29,304	
Construction Overhead	0.05	x C	EPA Manual	$ 12,210	
Contractor Fees	0.10	x C	EPA Manual	$ 24,420	
Start-up	0.02	x C	EPA Manual	$ 4,884	
Performance Testing	0.01	x C	EPA Manual	$ 2,442	
Process Contingencies	0.05	x C	EPA Manual	$ 12,210	
Simple Interest during Construction	5.5%	x C	Estimate	$ 13,431	
Total IC				$ 98,901	
Total Capital Investment (IC+DC), (D)				$ 416,361	
Project Contingency	0.15	x D		62,454	
Total Installed Cost (E)				$ 478,815	

Operating Cost Factors for the Catalyst			Capital Recovery Factor (CRF)		
Interest Rate	5.50%				
Catalyst Life	3	yrs	0.371		
Equipment Life	10	yrs	0.133		
Direct Annual Costs	**COST FACTOR**		**REFERENCE**	**COST**	**CALCULATION METHOD**
Power Loss Due to Pressure Drop			Estimate	$ 7,974	Derate kW 0.14% per inch x 2 inches
Labor and Maintenance Materials					
Operating Labor			Estimate	$ 25,550	$35/hr x 1hr/shift x 2 shifts/day x 365 day/yr
Supervisory Labor			EPA Manual	$ 3,833	15% of operating labor
Maintenance Labor	0.015	x B	EPA Manual	$ 3,300	
Maintenance Materials	0.015	x B	EPA Manual	$ 3,300	100% of Maintenance Labor
Subtotal Labor and Maintenance Materials (F)				$ 35,983	
Catalyst Replacement Cost					
Catalyst Replacement Labor			Vendor	$ 1,400	40 hrs
Catalyst Replacement			Vendor	$ 6,000	
State Tax	6.0%		State of PA	$ 360	
Total Catalyst Replacement Costs, (G)				$ 7,760	
Capital Recovery	0.371	x G		$ 2,879	Total Catalyst Replacement Costs x CRF
Total Direct Annual Costs				$ 46,835	
Indirect Annual Costs					
Overhead	0.6	x F	EPA Manual	$ 21,590	60% of labor costs and maintenance materials
Property Tax	0.01	x E	EPA Manual	$ 4,788	1% of Total Plant Cost, (E)
Insurance and Administration	0.04	x E	EPA Manual	$ 19,153	4% of Plant Cost (E)
Capital Recovery	0.133	x (E-G)		$ 62,650	
Total Indirect Annual Costs				$ 108,181	
Total Annual Costs				$ 155,016	
Annual CO +UHC Reduction				2.95	
Cost Effectiveness				**$ 52,626**	

*Source: Penn State University Application

5000 HP Turbine Catalyst Cost Calculations with uncontrolled CO Emission of 25 ppm and UHC emission of 25 ppm

Uncontrolled CO Emission Rate ppm	25	(Caterpillar)		
Controlled Emission Rate ppm	5			
Control Efficiency	80%			
Uncontrolled CO Emissions tons/year	11.10	(Caterpillar)		
CO Emission Reduction tons/year	8.88			
Uncontrolled UHC Emission Rate ppm	25	(Caterpillar)		
Controlled UHC Emission Rate ppm	2			
Control Efficiency	92%			
Uncontrolled UHC Emissions tons/year	6.36	(Caterpillar)		
UHC Emission Reduction tons/year	5.85			
Total CO and UHC removed	**14.73**			
Direct Costs (DC)	**COST FACTOR**		**REFERENCE**	**COST**
Purchased Equipment Costs (PEC)				
Major Equipment				
Oxidation Catalyst & Auxiliary Equipment, (A)			Vendor*	$ 200,000
Instrumentation	0.10	x A	EPA Manual	$ 20,000
Total Major Equipment (PEC), (B)				$ 220,000
State Sales Tax	6.0%	x B	State of PA	$ 13,200
Freight	0.05	x B	EPA Manual	$ 11,000
Total PEC, (C)				**$ 244,200**
Direct Installation Costs (DIC)				
Foundation and supports	0.08	x C	EPA Manual	$ 19,536
Handling and Erection	0.14	x C	EPA Manual	$ 34,188
Electrical	0.04	x C	EPA Manual	$ 9,768
Piping	0.02	x C	EPA Manual	$ 4,884
Insulation	0.01	x C	EPA Manual	$ 2,442
Painting	0.01	x C	EPA Manual	$ 2,442
Total Direct Costs (DC)				**$ 317,460**
Indirect Costs (IC)				
Engineering	0.12	x C	Estimate	$ 29,304
Construction Overhead	0.05	x C	EPA Manual	$ 12,210
Contractor Fees	0.10	x C	EPA Manual	$ 24,420
Start-up	0.02	x C	EPA Manual	$ 4,884
Performance Testing	0.01	x C	EPA Manual	$ 2,442
Process Contingencies	0.05	x C	EPA Manual	$ 12,210
Simple Interest during Construction	5.5%	x C	Estimate	$ 13,431
Total IC				**$ 98,901**
Total Capital Investment (IC+DC), (D)				**$ 416,361**
Project Contingency	0.15	x D		62,454
Total Installed Cost (E)				**$ 478,815**

Operating Cost Factors for the Catalyst			Capital Recovery Factor (CRF)		
Interest Rate	5.50%				
Catalyst Life	3	yrs	0.371		
Equipment Life	10	yrs	0.133		
Direct Annual Costs	**COST FACTOR**		**REFERENCE**	**COST**	**CALCULATION METHOD**
Power Loss Due to Pressure Drop			Estimate	$ 7,974	Derate kW 0.14% per inch x 2 inches
Labor and Maintenance Materials					
Operating Labor			Estimate	$ 25,550	$35/hr x 1hr/shift x 2 shifts/day x 365 day/yr
Supervisory Labor			EPA Manual	$ 3,833	15% of operating labor
Maintenance Labor	0.015	x B	EPA Manual	$ 3,300	
Maintenance Materials	0.015	x B	EPA Manual	$ 3,300	100% of Maintenance Labor
Subtotal Labor and Maintenance Materials (F)				**$ 35,983**	
Catalyst Replacement Cost					
Catalyst Replacement Labor			Vendor	$ 1,400	40 hrs
Catalyst Replacement			Vendor	$ 30,000	
State Tax	6.0%		State of PA	$ 1,800	
Total Catalyst Replacement Costs, (G)				**$ 33,200**	
Capital Recovery	0.371	x G		$ 12,317	Total Catalyst Replacement Costs x CRF
Total Direct Annual Costs				**$ 56,274**	
Indirect Annual Costs					
Overhead	0.6	x F	EPA Manual	$ 21,590	60% of labor costs and maintenance materials
Property Tax	0.01	x E	EPA Manual	$ 4,788	1% of Total Plant Cost, (E)
Insurance and Administration	0.04	x E	EPA Manual	$ 19,153	4% of Plant Cost (E)
Capital Recovery	0.133	x [E-G]		$ 59,267	
Total Indirect Annual Costs				**$ 104,797**	
Total Annual Costs				$ 161,071	
Annual CO +UHC Reduction				14.73	
Cost Effectiveness				**$ 10,936**	

*Source: Penn State University Application

SCR Cost Analysis for 5000 BHP Natural Gas-Fired Turbine (25 ppm)

HP	5000
Hrs	8760
Total Capital Investment (TCI)	**$1,172,392.78**
Annual Operating Cost:	
Operating Labor	$42,752.00
Superviosry Labor	$6,412.80
Maintenance	$56,357.79
Catalyst Replacement	$99,144.47
Catalyst Disposal	$1,815.14
Reagent	$5,616.93
Dilution Sream	$3,336.23
Performance Loss	$14,796.28
Blower	$1,479.63
Overhead	$67,101.58
Taxes, Insurance, and Administration	$46,933.41
Capital Recovery (10 yrs @ 10%)	$189,927.63
Total Annual Cost (TAC)	**$535,673.87**
Uncontrolled NOx TPY (Calculated TPY is based on 25 ppm)	14.64
NOx removed TPY (80% Eff.)	11.71
Cost-Effectiveness ($/Ton NOx removed)	**$45,748.36**

Uncontrolled Emisson Calcuation

25	ppm
0.091911765	lb/MMBtu
5000	HP Output
14285.71429	HP Input
36.35714286	MMBtu/hr
3.34164916	lb/hr
14.63642332	ton/yr

Cost Basis:
EPA's ACT Document (January 1993)
Scaled from 1990 to 2010 via CPI adjustment of 1.67
Costs are based for a 4,430 bhp turbine
Includes all costs except for capital recovery

14000 HP Turbine Catalyst Cost Calculations with uncontrolled CO Emission of 25 ppm and UHC emission of 25 ppm

Uncontrolled CO Emission Rate ppm	25	(Caterpillar)				Operating Cost Factors for the Catalyst			Capital Recovery Factor (CRF)		
Controlled Emission Rate ppm	5					Interest Rate	5.50%				
Control Efficiency	80%					Catalyst Life	3	yrs	0.371		
Uncontrolled CO Emissions tons/year	31	(Caterpillar)				Equipment Life	10	yrs	0.133		
CO Emission Reduction tons/year	24.80										
Uncontrolled UHC Emission Rate ppm	25	(Caterpillar)									
Controlled UHC Emission Rate ppm	2										
Control Efficiency	92%										
Uncontrolled UHC Emissions tons/year	18	(Caterpillar)									
UHC Emission Reduction tons/year	16.56			17							
Total CO and UHC removed	41.36										
Direct Costs (DC)	**COST FACTOR**		**REFERENCE**	**COST**		**Direct Annual Costs**	**COST FACTOR**		**REFERENCE**	**COST**	**CALCULATION METHOD**
Purchased Equipment Costs (PEC)						Power Loss Due to Pressure Drop			Estimate	$ 7,974	Derate kW 0.14% per inch x 2 inches
Major Equipment						**Labor and Maintrenance Materials**					
Oxidation Catalyst & Auxiliary Equipment, (A)			Vendor*	$ 200,000		Operating Labor			Estimate	$ 25,550	$35/hr x 1hr/shift x 2 shifts/day x 365 day/yr
Instrumentation	0.10	x A	EPA Manual	$ 20,000		Supervisory Labor			EPA Manual	$ 3,833	15% of operating labor
Total Major Equipment (PEC), (B)				$ 220,000		Maintenance Labor	0.015	x B	EPA Manual	$ 3,300	
State Sales Tax	6.0%	x B	State of PA	$ 13,200		Maintenance Materials	0.015	x B	EPA Manual	$ 3,300	100% of Maintenance Labor
Freight	0.05	x B	EPA Manual	$ 11,000		**Subtotal Labor and Maintenance Materials (F)**				$ 32,883	
Total PEC, (C)				$ 244,200		**Catalyst Replacement Cost**					
Direct Installation Costs (DIC)						Catalyst Replacement Labor			Vendor	$ 1,400	40 hrs
Foundation and supports	0.08	x C	EPA Manual	$ 19,536		Catalyst Replacement			Vendor	$ 90,000	
Handling and Erection	0.14	x C	EPA Manual	$ 34,188		State Tax	6.0%		State of PA	$ 5,400	
Electrical	0.04	x C	EPA Manual	$ 9,768		**Total Catalyst Replacement Costs, (G)**				$ 96,800	
Piping	0.02	x C	EPA Manual	$ 4,884		Capital Recovery	0.371	x G		$ 35,913	Total Catalyst Replacement Costs x CRF
Insulation	0.01	x C	EPA Manual	$ 2,442		**Total Direct Annual Costs**				$ 76,636	
Painting	0.01	x C	EPA Manual	$ 2,442		**Indirect Annual Costs**					
Total Direct Costs (DC)				$ 317,460		Overhead	0.6	x F	EPA Manual	$ 19,610	60% of labor costs and maintenance materials
Indirect Costs (IC)						Property Tax	0.01	x E	EPA Manual	$ 4,788	1% of Total Plant Cost, (E)
Engineering	0.12	x C	Estimate	$ 29,304		Insurance and Administration	0.04	x E	EPA Manual	$ 19,153	4% of Plant Cost (E)
Construction Overhead	0.05	x C	EPA Manual	$ 12,210		Capital Recovery	0.133	x [E-G]		$ 50,808	
Contractor Fees	0.10	x C	EPA Manual	$ 24,420		**Total Indirect Annual Costs**				$ 94,359	
Start-up	0.02	x C	EPA Manual	$ 4,884		Total Annual Costs				$ 170,995	
Performance Testing	0.01	x C	EPA Manual	$ 2,442		Annual CO +UHC Reduction				41.36	
Process Contingencies	0.05	x C	EPA Manual	$ 12,210		**Cost Effectiveness**				**$ 4,134**	
Simple Interest during Construction	5.5%	x C	Estimate	$ 13,431							
Total IC				$ 98,901							
Total Capital Investment (IC+DC), (D)				$ 416,361							
Project Contingency	0.15	x D		62,454							
Total Installed Cost (E)				$ 478,815							

*Source: Penn State University Application

15000 HP Turbine Catalyst Cost Calculations with uncontrolled CO Emission of 10 ppm and UHC emission of 5 ppm

Uncontrolled CO Emission Rate ppm	10	(Caterpillar)
Controlled Emission Rate ppm	2	
Control Efficiency	80%	
Uncontrolled CO Emissions tons/year	13.3	(Caterpillar)
CO Emission Reduction tons/year	10.64	
Uncontrolled UHC Emission Rate ppm	5	(Caterpillar)
Controlled UHC Emission Rate ppm	0.4	
Control Efficiency	92%	
Uncontrolled UHC Emissions tons/year	3.8	(Caterpillar)
UHC Emission Reduction tons/year	0.30	
Total CO and UHC removed	**10.94**	

Operating Cost Factors for the Catalyst			Capital Recovery Factor (CRF)
Interest Rate	5.50%		
Catalyst Life	3	yrs	0.371
Equipment Life	10	yrs	0.133

Direct Costs (DC)	COST FACTOR		REFERENCE	COST
Purchased Equipment Costs (PEC)				
Major Equipment				
Oxidation Catalyst & Auxiliary Equipment, (A)			Vendor*	$ 200,000
Instrumentation	0.10	x A	EPA Manual	$ 20,000
Total Major Equipment (PEC), (B)				$ 220,000
State Sales Tax	6.0%	x B	State of PA	$ 13,200
Freight	0.05	x B	EPA Manual	$ 11,000
Total PEC, (C)				**$ 244,200**
Direct Installation Costs (DIC)				
Foundation and supports	0.08	x C	EPA Manual	$ 19,536
Handling and Erection	0.14	x C	EPA Manual	$ 34,188
Electrical	0.04	x C	EPA Manual	$ 9,768
Piping	0.02	x C	EPA Manual	$ 4,884
Insulation	0.01	x C	EPA Manual	$ 2,442
Painting	0.01	x C	EPA Manual	$ 2,442
Total Direct Costs (DC)				**$ 317,460**
Indirect Costs (IC)				
Engineering	0.12	x C	Estimate	$ 29,304
Construction Overhead	0.05	x C	EPA Manual	$ 12,210
Contractor Fees	0.10	x C	EPA Manual	$ 24,420
Start-up	0.02	x C	EPA Manual	$ 4,884
Performance Testing	0.01	x C	EPA Manual	$ 2,442
Process Contingencies	0.05	x C	EPA Manual	$ 12,210
Simple Interest during Construction	5.5%	x C	Estimate	$ 13,431
Total IC				**$ 98,901**
Total Capital Investment (IC+DC), (D)				**$ 416,361**
Project Contingency	0.15	x D		62,454
Total Installed Cost (E)				**$ 478,815**

Direct Annual Costs	COST FACTOR		REFERENCE	COST	CALCULATION METHOD
Power Loss Due to Pressure Drop			Estimate	$ 7,974	Derate kW 0.14% per inch x 2 inches
Labor and Maintenance Materials					
Operating Labor			Estimate	$ 25,550	$35/hr x 1hr/shift x 2 shifts/day x 365 day/yr
Supervisory Labor			EPA Manual	$ 3,833	15% of operating labor
Maintenance Labor	0.015	x B	EPA Manual	$ 3,300	
Maintenance Materials	0.015	x B	EPA Manual	$ 3,300	100% of Maintenance Labor
Subtotal Labor and Maintenance Materials (F)				**$ 32,683**	
Catalyst Replacement Cost					
Catalyst Replacement Labor			Vendor	$ 1,400	40 hrs
Catalyst Replacement			Vendor	$ 90,000	
State Tax	6.0%		State of PA	$ 5,400	
Total Catalyst Replacement Costs, (G)				**$ 96,800**	
Capital Recovery	0.371	x G		$ 35,913	Total Catalyst Replacement Costs x CRF
Total Direct Annual Costs				**$ 76,636**	
Indirect Annual Costs					
Overhead	0.6	x F	EPA Manual	$ 19,610	60% of labor costs and maintenance materials
Property Tax	0.01	x E	EPA Manual	$ 4,788	1% of Total Plant Cost, (E)
Insurance and Administration	0.04	x E	EPA Manual	$ 19,153	4% of Plant Cost (E)
Capital Recovery	0.133	x [E-G]		$ 50,808	
Total Indirect Annual Costs				**$ 94,359**	
Total Annual Costs				$ 170,995	
Annual CO +UHC Reduction				10.94	
Cost Effectiveness				**$ 15,625**	

*Source: Penn State University Application

15000 HP Turbine Catalyst Cost Calculations with uncontrolled CO Emission of 25 ppm and UHC emission of 25 ppm

Uncontrolled CO Emission Rate ppm	25	(Caterpillar)				Operating Cost Factors for the Catalyst			Capital Recovery Factor (CRF)		
Controlled Emission Rate ppm	5					Interest Rate	5.50%				
Control Efficiency	80%					Catalyst Life	3	yrs	0.371		
Uncontrolled CO Emissions tons/year	33.3	(Caterpillar)				Equipment Life	10	yrs	0.133		
CO Emission Reduction tons/year	26.64										
Uncontrolled UHC Emission Rate ppm	25	(Caterpillar)									
Controlled UHC Emission Rate ppm	2										
Control Efficiency	92%										
Uncontrolled UHC Emissions tons/year	19.07	(Caterpillar)									
UHC Emission Reduction tons/year	17.54										
Total CO and UHC removed	**44.18**										
Direct Costs (DC)	**COST FACTOR**		**REFERENCE**	**COST**		**Direct Annual Costs**	**COST FACTOR**		**REFERENCE**	**COST**	**CALCULATION METHOD**
Purchased Equipment Costs (PEC)						Power Loss Due to Pressure Drop			Estimate	$ 7,974	Derate kW 0.14% per inch x 2 inches
Major Equipment						**Labor and Maintrenance Materials**					
Oxidation Catalyst & Auxiliary Equipment, (A)			Vendor*	$ 200,000		Operating Labor			Estimate	$ 25,550	$35/hr x 1hr/shift x 2 shifts/day x 365 day/yr
Instrumentation	0.10	x A	EPA Manual	$ 20,000		Supervisory Labor			EPA Manual	$ 3,833	15% of operating labor
Total Major Equipment (PEC), (B)				**$ 220,000**		Maintenance Labor	0.015	x B	EPA Manual	$ 3,300	
State Sales Tax	6.0%	x B	State of PA	$ 13,200		**Maintenance Materials**	0.015	x B	EPA Manual	$ 3,300	100% of Maintenance Labor
Freight	0.05	x B	EPA Manual	$ 11,000		**Subtotal Labor and Maintenance Materials (F)**				**$ 32,883**	
Total PEC, (C)				**$ 244,200**		**Catalyst Replacement Cost**					
Direct Installation Costs (DIC)						Catalyst Replacement Labor			Vendor	$ 1,400	40 hrs
Foundation and supports	0.08	x C	EPA Manual	$ 19,536		Catalyst Replacement			Vendor	$ 90,000	
Handling and Erection	0.14	x C	EPA Manual	$ 34,188		State Tax	6.0%		State of PA	$ 5,400	
Electrical	0.04	x C	EPA Manual	$ 9,768		**Total Catalyst Replacement Costs, (G)**				**$ 96,800**	
Piping	0.02	x C	EPA Manual	$ 4,884		Capital Recovery	0.371	x G		$ 35,913	Total Catalyst Replacement Costs x CRF
Insulation	0.01	x C	EPA Manual	$ 2,442		**Total Direct Annual Costs**				**$ 76,636**	
Painting	0.01	x C	EPA Manual	$ 2,442		**Indirect Annual Costs**					
Total Direct Costs (DC)				**$ 317,480**		Overhead	0.6	x F	EPA Manual	$ 19,810	60% of labor costs and maintenance materials
Indirect Costs (IC)						Property Tax	0.01	x E	EPA Manual	$ 4,788	1% of Total Plant Cost, (E)
Engineering	0.12	x C	Estimate	$ 29,304		Insurance and Administration	0.04	x E	EPA Manual	$ 19,153	4% of Plant Cost (E)
Construction Overhead	0.05	x C	EPA Manual	$ 12,210		Capital Recovery	0.133	x [E-G]		$ 50,808	
Contractor Fees	0.10	x C	EPA Manual	$ 24,420		**Total Indirect Annual Costs**				**$ 94,359**	
Start-up	0.02	x C	EPA Manual	$ 4,884		Total Annual Costs				$ 170,995	
Performance Testing	0.01	x C	EPA Manual	$ 2,442		Annual CO +UHC Reduction				44.18	
Process Contingencies	0.05	x C	EPA Manual	$ 12,210		**Cost Effectiveness**				**$ 3,870**	
Simple interest during Construction	5.5%	x C	Estimate	$ 15,431							
Total IC				**$ 98,901**							
Total Capital Investment (IC+DC), (D)				**$ 416,381**							
Project Contingency	0.15	x D		62,454							
Total Installed Cost (E)				**$ 478,815**							

*Source: Penn State University Application

SCR Cost Analysis for 15,000 BHP Natural Gas-Fired Turbine

HP	**15000**
Hrs	**8760**
Total Capital Investment (TCI)	**$3,517,178.33**
Annual Operating Cost:	
Operating Labor	$42,752.00
Superviosry Labor	$6,412.80
Maintenance	$169,073.36
Catalyst Replacement	$297,433.41
Catalyst Disposal	$5,445.41
Reagent	$16,850.79
Dilution Sream	$10,008.69
Performance Loss	$44,388.83
Blower	$4,438.88
Overhead	$201,304.74
Taxes, Insurance, and Administration	$140,800.23
Capital Recovery (10 yrs @ 10%)	$569,782.89
Total Annual Cost (TAC)	**$1,508,692.02**
Uncontrolled NOx TPY (Calculated TPY is based on 15 ppm)	26.35
NOx removed TPY (80% Eff.)	21.08
Cost-Effectiveness ($/Ton NOx removed)	**$71,581.89**

Uncontrolled Emisson Calcuation

15	ppm
0.055147059	lb/MMBtu
15000	HP Output
42857.14286	HP Input
109.0714286	MMBtu/hr
6.014968487	lb/hr
26.34556197	ton/yr

Cost Basis:
EPA's ACT Document (January 1993)
Scaled from 1990 to 2010 via CPI adjustment of 1.67
Costs are based for a 4,430 bhp turbine
Includes all costs except for capital recovery

SCR Cost Analysis for 50,000 BHP Natural Gas-Fired Turbine

HP	**50000**
Hrs	**8760**
Total Capital Investment (TCI)	**$11,723,927.77**
Annual Operating Cost:	
Operating Labor	$42,752.00
Superviosry Labor	$6,412.80
Maintenance	$563,577.88
Catalyst Replacement	$991,444.70
Catalyst Disposal	$18,151.35
Reagent	$56,169.30
Dilution Sream	$33,362.30
Performance Loss	$147,962.75
Blower	$14,796.28
Overhead	$671,015.80
Taxes, Insurance, and Administration	$469,334.09
Capital Recovery (10 yrs @ 10%)	$1,899,276.30
Total Annual Cost (TAC)	**$4,914,255.54**
Uncontrolled NOx TPY (Calculated TPY is based on 15 ppm)	87.82
NOx removed TPY (80% Eff.)	70.25
Cost-Effectiveness ($/Ton NOx removed)	**$69,949.00**

Uncontrolled Emisson Calcuation

15 ppm
0.055147059 lb/MMBtu
50000 HP Output
142857.1429 HP Input
363.5714286 MMBtu/hr
20.04989496 lb/hr
87.81853992 ton/yr

Cost Basis:
EPA's ACT Document (January 1993)
Scaled from 1990 to 2010 via CPI adjustment of 1.67
Costs are based for a 4,430 bhp turbine
Includes all costs except for capital recovery

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(5) Technical Report: Horn, Nuss-Warren. *Cost-Effective Reciprocating Engine Emissions Control and Monitoring for E&P Field and Gathering Engines*, Kansas State University, 2011

(6) Technical Report: Technical Support document for controlling NOx emissions from stationary reciprocating internal combustion engines and turbines, Illinois Environmental Protection Agency Air Quality Planning Section Division of Air Pollution Control Bureau of Air, March 19, 2007.

(7) Technical Report: Colorado Department of Public Health and Environment - Air Pollution Control Division, *Reasonable Progress Evaluation for RICE Source Category*, 2011

(8) Technical Document: US EPA, AP-42, Vol. I, 3.1: Stationary Gas Turbines

(9) Web Site: KW International, http://www.kwintl.com/glycol-dehydrators.html.

(10) Web Site: www.naturalgas.org