Commonwealth of Pennsylvania

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Technical Support Document

For the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268)

And the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267)

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IV. Abbreviations and Acronyms

A/F	Air-to-Fuel
AVO	Auditory, Visual, and Olfactory Inspections
BAT	Best Available Technology
bhp	Brake Horsepower
BMP	Best Management Practices
BTEX	Benzene, Toluene, Ethylbenzene, and Xylene
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPI	Consumer Price Index
DEA	Diethanolamine
DEP	Pennsylvania Department of Environmental Protection
EGR	Exhaust Gas Recirculation
EPA	U.S. Environmental Protection Agency
g/bhp-h	Grams per Brake Horsepower-Hour
GHG	Greenhouse Gas(es)
GP	General Plan Approval/General Operating Permit
GP-5	General Plan Approval/General Operating Permit for Natural Gas Compression Stations, Processing Plants, and Transmission Stations
GP-5A	General Plan Approval/General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations
H_2O	Water
H_2S	Hydrogen Sulfide
HAP	Hazardous Air Pollutant
HCHO	Formaldehyde
GPU	Gas Production Unit
MEA	Monoethanolamine
Mcf	Thousand Cubic Feet
MMBtu	Million British Thermal Units
MMBtu/h	Million British Thermal Units per Hour
N_2	Molecular Nitrogen
NAAQS	National Ambient Air Quality Standard
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGL	Natural Gas Liquid
NGStar	The Natural Gas Star Program
NMNEHC	Non-Methane, Non-Ethane Hydrocarbon
NO	Nitrogen Oxide
NO_2	Nitrogen Dioxide
NO_X	Oxides of Nitrogen
NSCR	Non-Selective Catalytic Reduction
NSPS	New Source Performance Standard
OGI	Optical Gas Imaging Camera
PennDOT	Pennsylvania Department of Transportation
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter with an Aerodynamic Diameter Less Than 2.5 Microns
PM_{10}	Particulate Matter with an Aerodynamic Diameter Less Than 10 Microns
ppmvd	Parts Per Million, Dry, by Volume

ppmv	Parts Per Million by Volume
PRO	Partner Reported Opportunities
PTE	Potential to Emit
RBLC	RACT/BACT/LAER Clearinghouse
REC	Reduced Emission Completion
scf	Standard Cubic Feet
SCR	Selective Catalytic Reduction
SI-RICE	Spark Ignition Reciprocating Internal Combustion Engine
SO_2	Sulfur Dioxide
SO_X	Oxides of Sulfur
THC	Total Hydrocarbons
tpy	Tons Per Year
TSD	Technical Support Document
VOC	Volatile Organic Compound

V. Executive Summary

This technical support document (TSD) was prepared by the Pennsylvania Department of Environmental Protection (Department or DEP) to include background information about the General Plan Approval and General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (GP-5A) and the General Plan Approval and General Operating Permit for Natural Gas Compression Stations, Processing Plants, and Transmission Stations (GP-5) released on *June 9, 2018*. The TSD includes the rationale for the air permitting requirements for air pollution sources and the associated air pollution controls covered by the General Permits. The TSD also describes sources common to all types of facilities, sources specific to GP-5A-eligible facilities, and sources specific to GP-5-eligible facilities.

According to 25 Pa. Code § 127.1, air contamination sources must be regulated to protect the public welfare, and new sources shall control air pollutant emissions to the maximum extent consistent with Best Available Technology (BAT) as determined by the Department. The federal New Source Performance Standards (NSPS) are incorporated into the Department's regulations by reference in 25 Pa. Code § 122.3, and the federal National Emissions Standards for Hazardous Air Pollutants (NESHAP) regulations are incorporated by reference in 25 Pa. Code § 127.35. Additionally, the current requirements of the U.S. Environmental Protection Agency's (EPA) NSPS for Crude Oil and Natural Gas Facilities (40 CFR Part 60, Subparts OOOO and OOOOa) and other federal requirements are incorporated by reference into the General Permits when the conditions are no different than the conditions determined by the Department to be BAT.

VI. Introduction

GP-5A and GP-5 have been developed under the authority of Section 6.1(f) of the Pennsylvania Air Pollution Control Act (APCA, 35 P.S § 4006.1) and under section 504(d) of the Clean Air Act (CAA, 42 U.S.C. § 7661c(d)) which authorizes the establishment of a general permit program to regulate air contamination sources. *See also* 25 Pa. Code Chapter 127, Subchapter H. Additionally, section 6.6(c) of the APCA, 35 P.S. § 4006.6(c), authorizes the Department to require new sources to control air pollution through the use of BAT at the time of plan approval. *See also* 25 Pa. Code § 127.1.

The Department's regulatory General Permit program and BAT provisions were established in 1994. (24 Pa.B. 5899 (November 26, 1994)). These regulations were subsequently approved by EPA as part of Pennsylvania's State Implementation Plan (SIP) in 1996. (61 Fed. Reg. 39594 (July 30, 1996)). Currently, the Department has 18 air quality General Permits that regulate air contamination sources in several industrial categories, including small boilers, burn off ovens, storage tanks, lithographic printing, mineral processing, petroleum dry cleaning, powder metal sintering furnaces, and natural gas production.

A General Permit is a pre-approved plan approval and operating permit which applies to a specific category of sources, if the Department determines that those sources can be adequately regulated using standardized specifications and conditions. (35 P.S. § 4006.1(f)). As part of the General Permit process, the Department establishes BAT requirements for new sources. Those BAT requirements can include equipment, devices, methods, or techniques as determined by the Department, which will prevent, reduce, or control air emissions to the maximum degree possible and which are available or may be made available. (25 Pa. Code § 121.1). BAT is not a regulation but an analysis of control techniques that are determined at the time of the issuance of a plan approval. The Pennsylvania Environmental Hearing Board (EHB) has indicated that the requirement to conduct a BAT analysis for new sources extends to greenhouse gases (GHGs), including methane. (*Snyder v. DEP*, 2015 EHB 027). Moreover, the Commonwealth Court has endorsed the Department's position that the General Assembly, through the APCA, gave the agency the authority to reduce GHG emissions. (*Wolf v. Funk*, 144 A.3d 228, 250 (Pa. Cmwlth. 2016)).

On September 21, 1996, the Department published the Air Quality Permit Exemptions, which specified sources or classes of sources that were determined to be exempt from the plan approval and permitting requirements of the APCA, 35 P.S. §4001 *et seq.* and 25 Pa. Code Chapter 127, which included crude oil and natural gas wells. The Department issued GP-5 on March 10, 1997, for natural gas production facilities. This established BAT for stationary natural gas-fired spark ignition reciprocating internal combustion engines (engines) rated from 100 brake horsepower (bhp) to 1,500 bhp and for glycol dehydrators with an uncontrolled potential to emit (PTE) volatile organic compounds (VOC) in excess of 10 tons per year (tpy) at natural gas production facilities. On July 27, 2006, DEP revised the GP-5 to expand the applicability to natural gas, coal bed methane, and gob gas production or recovery facilities, including gathering stations.

EPA has developed several regulations applicable to oil and natural gas production sites, natural gas compression stations, processing plants, and transmissions stations; these are 40 CFR Part 60, Subparts KKK, JJJJ, KKKK, OOOO, and OOOOa and 40 CFR Part 60 Subparts HH, HHH, and ZZZZ. Some of these regulations require the control of methane emissions from sources at these facilities. Other pollutants that are regulated under these standards include VOC and hazardous air pollutants (HAP). The federal regulations apply to all oil and gas operations in the U.S. The Department is required to implement these federal regulations under Section 4 of the APCA, 35 P.S. §4004. In addition, these federal regulations are incorporated by reference into the *Pennsylvania Code* and, as a result, are Pennsylvania law. *See* 25 Pa. Code §§122.1, 124.1, and 127.35(b).

On February 2, 2013, the Department changed the applicability of GP-5 to natural gas compression and/or processing facilities, and established BAT requirements for engines, stationary natural gas-fired simple cycle turbines (turbines), natural gas compressors, storage vessels, glycol dehydrators, natural gas fractionation units, equipment leaks, pneumatic controllers, and sweetening units. The Air Quality Permit Exemptions were amended by the Department on August 10, 2013, to change the unconditional exemption of all crude oil and natural gas wells to the unconditional exemption of sources located at conventional well sites and a conditional exemption for sources located at unconventional natural gas well sites.

In 2009, based on a large body of scientific evidence, EPA issued an "Endangerment Finding" under the Clean Air Act (CAA) section 202(a)(1), 42 U.S.C. § 7521(a)(1), related to GHGs.[1] EPA found that six well-mixed GHGs — carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride — endanger both the public health and the public welfare of current and future generations by causing or contributing to climate change.[2] New scientific assessments and observations strengthen the conclusions of this Endangerment Finding that GHGs endanger public health and the environment.[3] Methane traps 86 times more heat in the atmosphere than carbon dioxide in the short-term, increasing the consequences of climate change. Additionally, methane is often accompanied by toxic air pollutants such as benzene, formaldehyde, and ethylbenzene.

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[1] ''Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act,'' 74 Fed. Reg. 66496 (December 15, 2009) (''Endangerment Finding'').
[2] *Id.*
[3] "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources," 81 Fed. Reg. 35824 (June 3, 2016).

Methane is also a precursor to ground level ozone, which can cause a number of harmful effects on public health and the environment.[4] Exposure to ozone can cause respiratory system effects such as difficulty breathing and airway inflammation.[5] In addition, long-term exposure to ozone is likely to result in harmful respiratory effects, including respiratory symptoms and the development of asthma.[6]

There are also independent peer-reviewed studies which indicate that shale gas development is associated with the production of secondary pollutants such as tropospheric (ground-level) ozone, formed through the interaction of methane, VOC, and nitrogen oxides (NO_X) in the presence of sunlight.[7,8] Tropospheric ozone is a strong respiratory irritant associated with increased respiratory and cardiovascular morbidity and mortality.[9] Although toxicological data suggest that pure methane is not by itself health damaging (excluding its role as an asphyxiant and an explosive), it is a precursor to global tropospheric ozone.[10]

Based on all the information reviewed by the Department, which it adopts as its own, and incorporates by reference into this TSD, there is a strong scientific basis to show that methane meets the definition of air contaminant, air contamination, and air pollution under section 3 of the APCA. As a GHG and ozone precursor, methane is, among other things, inimical or may be inimical to the public health, safety, or welfare.

According to the U.S. Energy Information Agency (EIA), Pennsylvania was the nation's second-largest natural gas producer for the fourth consecutive year. The largest key sources of anthropogenic methane emissions in Pennsylvania include natural gas and oil systems (30.5 percent), coal mining (30.3 percent), landfills (21.1 percent), enteric fermentation from domestic livestock (9.9 percent), wastewater (3.9 percent), and manure management (2.3 percent). Of these major categories, natural gas and oil systems are the only areas that show significant growth, increasing threefold from the 1990s. The other major categories are either flat or slightly down from the 1990s. This shows that the oil and gas industry is therefore the largest category for methane emissions.

Based on information from the Department's emission inventory, there are approximately 31,224 sources at 4,960 well pad facilities and 4,285 sources at 493 compressor stations. The overall methane emissions from this source category in 2015 amounted to approximately 123,081 tons in Pennsylvania, which is an increase from 2014 levels. One peer-reviewed study indicates that new emissions data suggest that the recently instituted Pennsylvania methane emissions inventory substantially underestimates measured facility-level methane emissions by 10-40 times.[11]

Pennsylvania Governor Tom Wolf introduced a methane reduction strategy on January 19, 2016. The four-point plan included the following strategies:

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[4] *Id.*
[5] *Id.*
[6] *Id.*
[7] Shonoff, Hays, Finkel, *Environmental Health Dimensions of Shale and Tight Gas*, Environ Health Perspect., 2014 Aug; 122(8): 787–795.
[8] Jerrett M, Burnett RT, Pope CA III, Ito K, Thurston G, Krewski D, *et al*. *Long-term ozone exposure and mortality,* N Engl J Med 360:1085–1095, 2009 and *U.S. EPA Integrated Science Assessment for Ozone and Related Photochemical Oxidants* (EPA 600/R-10/076F) Available at: http://www.epa.gov/ncea/isa/ozone.htm, last accessed on May 9, 2018.
[9] Jerrett *et al*.
[10] Smith KR, Jerrett M, Anderson HR, Burnett RT, Stone V, Derwent R, *et al. Public health benefits of strategies to reduce greenhouse-gas emissions: health implications of short-lived greenhouse pollutants*. Lancet 374:2091–2103, 2009.
[11] Omara, *et al*., *Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Basin,* Environ. Sci. Technol. 2016, 50, 2099−2107.

- To reduce leaks at new unconventional natural gas well pads, DEP will develop a new General Permit for oil and gas exploration, development, and production facilities, requiring BAT for equipment and processes, better recordkeeping, and quarterly monitoring inspections.
- To reduce leaks at new compression stations and processing facilities, DEP will revise its current General Permit, updating BAT requirements and applying more stringent leak detection and repair (LDAR) and other requirements to minimize leaks.
- To reduce leaks at existing oil and natural gas facilities, DEP will develop a regulation for existing sources for consideration by the Environmental Quality Board.
- To reduce emissions along production, gathering, transmission and distribution lines, DEP will establish best management practices (BMP), including LDAR programs.

On February 4, 2017, the Department published notice in the *Pennsylvania Bulletin* of the availability of the Proposed General Plan Approval and/or General Operating Permit No. 5A for Unconventional Natural Gas Well Site Operations or Remote Pigging Stations ("GP-5A") and Proposed Modifications to General Plan Approval and/or General Operating Permit No. 5 for Natural Gas Compressor Stations, Processing Plants and Transmission Stations ("GP-5") and proposed revisions to the Air Quality Permit Exemptions document (TGD Document No. 275-2101-003) for public review and comment. (47 Pa.B. 733). The public comment period was originally scheduled to close on March 22, 2017. However, due to increased public and legislative interest, the comment period was extended until June 5, 2017. (47 Pa.B. 1235). Then on March 31, 2018, the Department published another *Pennsylvania Bulletin* notice announcing an additional opportunity to submit comments on the draft final GPs until May 15, 2018. (48 Pa.B. 1902).

The final General Permits set forth standardized terms and conditions related to BAT, compliance certification, notification, recordkeeping, reporting, and source testing requirements. In addition, the General Permits require permittees to comply with any applicable federal NSPS. Under the final GPs, the Department determined that BAT for certain new sources is more stringent than the applicable NSPS, and, in other cases, the Department determined that BAT is the same as the applicable NSPS limit for certain new sources. A BAT standard does not replace a NSPS, but is in addition to a NSPS. The Department made its determinations based on a technical and economic feasibility analysis contained in this TSD. For instance, under GP-5, the Department made 13 separate BAT determinations for 13 separate sources, nine of which were more stringent than the applicable NSPS. Under GP-5A, the Department made 11 separate BAT determinations for 11 separate sources, of which eight were more stringent than the applicable NSPS.

The BAT emission reductions in Table 1 and Table 2 below are from sources that may be located at an unconventional well site or a mid-stream compressor station and are scientifically-based estimates. Actual emissions at an individual site depend on a case-by-case analysis that accounts for: gas production or throughput; type of equipment; management practices; and composition of the gas or liquids. Estimates of reductions are based on changes due to BAT requirements from the previous GP-5 and Exemption 38 to the final GP-5A and GP-5.

The new GP-5A is applicable to the sources located at unconventional natural gas well site operations and remote pigging stations, and the revised GP-5 is applicable to sources located at natural gas compression stations, processing plants, and transmission stations. The use of the GP-5 and GP-5A are restricted to facilities with actual emissions less than 100 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 HAP, and less than 25 tpy of total HAPs. For facilities located in Philadelphia, Bucks, Chester, Montgomery, or Delaware Counties, the NO_X and VOC emissions thresholds are less than 25 tpy each.

While the terms and conditions of both General Permits incorporate both federal and state requirements, it is the duty of the Responsible Official to ensure that the facility is in compliance with all applicable federal, state, and local laws and regulations, including 25 Pa. Code, Subpart C, Article III. Nothing in these General Permits relieves the Responsible Official from this obligation to comply.

Table 1 - Emissions Reduction Estimates for Sources at Unconventional Natural Gas Wells Sites

Source	Emissions Reduction Estimate									
	CH_4 (tpy)		VOC (tpy)		HAP (lbpy)		NO_X (tpy)		CO (tpy)	
Glycol Dehydration Units	1.04[3]	29%	No Change		No Change		NA		NA	
Lean-Burn Engines (100 hp ≤ rating ≤ 500 hp)	NA		1.93	57%	NA		No Change		6.27	65%
Lean-Burn Engines (500 hp < rating < 2,370 hp)	NA		10.28	64%	NA		11.43	50%	40.00	88%
Lean-Burn Engines (rating ≥ 2,370 hp, 0.3 g/bhp-h NO_X)	NA		10.29	64%	NA		16.01	70%	40.01	88%
Lean-Burn Engines (rating ≥ 2,370 hp, SCR)	NA		10.29	64%	NA		21.72	95%	40.01	88%
Rich-Burn Engines (100 hp ≤ rating ≤ 500 hp)	NA		2.41	71%	NA		3.62	75%	8.20	85%
Rich-Burn Engines (rating > 500 hp)	NA		2.42	71%	NA		3.87	80%	8.22	85%
Reciprocating Compressors (EPA Emission Factors)	0.04	80%	0[4]	80%	0[4]	80%	NA		NA	
Reciprocating Compressors (UT Average Emission Factors)	3.03	80%	0.16	80%	0.07	80%	NA		NA	
Storage Vessels	1.04[3]	29%	No Change		No Change		NA		NA	
Fugitive Emissions Components	6.36	20%	0.33	20%	0.15	20%	NA		NA	
Pigging Operations[1] (Monthly Frequency)	No Change[5]									
Pigging Operations[1] (Monthly Frequency – BMP reduces pressure to 125 psi)	1.57	90%	0.08	90%	0.04	90%	NA		NA	
Pigging Operations[1] (Daily Frequency	50.41	95%	2.62	95%	1.18	95%	NA		NA	
Wellbore Liquids Unloading[2] (Monthly Frequency – BMP halves volume)	27.91	50%	1.45	50%	0.65	50%	NA		NA	
Wellbore Liquids Unloading[2] (Monthly Frequency – routed to control)	53.03	95%	2.76	95%	1.24	95%	NA		NA	

[1] Pigging Operations were assumed to emit a volume of 90 ft^3 at 1,250 psi.
[2] Wellbore Liquids Unloading Operations were assumed to emit a volume of 4,500 ft^3 at 800 psi.
[3] Methane emissions reductions based on assumed 93% destruction efficiency correlated to operating temperature for 95% VOC destruction efficiency.
[4] Even though the table shows zero tons reduced, emissions are reduced by the following percentage.
[5] Pigging Operations at the assumed volume and pressure to not exceed the control threshold at the monthly frequency.

Table 2 - Emissions Reduction Estimates for Sources at Natural Gas Compression Stations

Source	Emissions Reduction Estimate									
	CH_4 (tpy)		VOC (tpy)		HAP (lbpy)		NO_X (tpy)		CO (tpy)	
Glycol Dehydration Units	4.14[2]	61%	0.12[3]	46%	0.05[3]	46%	NA		NA	
Lean-Burn Engines (100 hp ≤ rating ≤ 500 hp)	NA		1.93	57%	NA		No Change		6.27	NA
Lean-Burn Engines (rating ≥ 2,370 hp, 0.3 g/bhp-h NO_X)	NA		No Change		NA		4.57	40%	No Change	
Lean-Burn Engines (rating ≥ 2,370 hp, SCR)	NA		No Change		NA		10.29	90%	No Change	
Storage Vessels	5.48[2]	68%	0.17[3]	55%	0.07[3]	55%	NA		NA	
Tanker Truck Load-Out Operations	0.83[3]	55%	0.04[3]	55%	0.02[3]	55%	NA		NA	
Pigging Operations[1] (Monthly Frequency)	No Change[4]									
Pigging Operations[1] (Monthly Frequency – BMP reduces pressure to 125 psi)	1.57	90%	0.08	90%	0.04	90%	NA		NA	
Pigging Operations[1] (Daily Frequency	50.41	95%	2.62	95%	1.18	95%	NA		NA	
Natural Gas-Fired Combustion Units (rating ≥ 10 MMBtu/h)	NA		NA		NA		0.80	50%	5.49	57%
Turbine (5,000 hp ≤ rating <15,900 hp)	NA		4.96	44%	NA		No Change		11.81	60%
Turbine (rating ≥ 15,900 hp – 9 ppm NO_X)	NA		No Change		NA		11.40	40%	No Change	
Turbine (rating ≥ 15,900 hp – SCR)	NA		No Change		NA		25.65	90%	No Change	
Centrifugal Compressor (Wet Seal Degassing Systems)	9.52[2]	29%	No Change		No Change		NA		NA	

[1] Pigging Operations were assumed to emit a volume of 90 ft^3 at 1,250 psi.
[2] Methane emissions reductions based on assumed 93% destruction efficiency correlated to operating temperature for 95% VOC destruction efficiency.
[3] Emissions reduction primarily based on reduction in control threshold.
[4] Pigging Operations at the assumed volume and pressure to not exceed the control threshold at the monthly frequency.

I. Definitions

Words and terms that are not otherwise defined in the General Permits 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 JJJJ, KKKK, OOOO, and OOOOa or 40 CFR Part 63 Subparts HH and ZZZZ also apply to these General Permits.

Coal bed methane – Methane that is extracted from a coal bed and the surrounding rock strata by extraction wells drilled in advance of a mining operation, which is typically of pipeline quality.

Fugitive Emissions Component – Any component that has the potential to emit fugitive emissions of methane, VOC, or HAP at a facility, but not limited to, valves, connectors, pressure relief devices, open-ended lines, flanges, compressors, instruments, meters, covers, and closed vent systems. Devices that vent as part of normal operations are not considered fugitive sources unless the emission originates from a place other than the vent.

Gob gas – Methane that is mixed with air from a mine ventilation system due to the mining operation reaching the area of an extraction well, which is typically below pipeline quality.

Leak – A leak is defined as any release of gaseous hydrocarbons that is detected by Auditory, Visual, or Olfactory (AVO) inspection; an optical gas imaging (OGI) camera calibrated according to 40 CFR §60.18 and a detection sensitivity level of 60 g/h; a gas leak detector that meets the requirements of 40 CFR Part 60, Appendix A-7, Method 21 that detects a concentration of 500 ppm calibrated as methane or greater; or other leak detection methods approved by the Department's Division of Source Testing and Monitoring. However, a release from any equipment or component designed by the manufacturer to protect the equipment, controller, or personnel or to prevent groundwater contamination, gas migration, or an emergency situation is not considered a leak.

Natural Gas Compression Station – A facility that compresses and/or processes natural gas, coal bed methane, or gob gas prior to the point of custody transfer using processes including, but not limited to, gas dehydration, compression, pigging, and storage.

Natural Gas Processing Plant – A facility that engages in the extraction of natural gas liquids from field gas, the fractionation of mixed natural gas liquids to natural gas products, or both extracts and fractionates natural gas liquids.

Natural Gas Transmission Station – A facility that compresses and/or processes natural gas after the point of custody transfer using processes including, but not limited to, gas dehydration, compression, pigging, and storage.

Pigging Operations – The process of removing and collecting condensed liquids including condensate, intermediate hydrocarbons, or produced water from a pipeline using a spherical or bullet-shaped device, known as a pig, forced through the pipeline by natural gas pressure. The liquids are then collected at their eventual destination in a storage tank, often referred to as a slug tank. This process also includes operation conducted for pipeline integrity evaluation.

Point of Custody Transfer – The location after the processing and/or treatment of natural gas in the production sector, typically after a natural gas processing plant, where control and/or ownership of the natural gas is transferred from one owner or operator to another.

Remote Pigging Station – A facility where pigging operations are conducted that is not located at an unconventional natural gas well site, natural gas compression station, natural gas processing plant, or natural gas transmission station and which meets or exceeds the exemption criteria in Category 38(c) of the Air Quality Permit Exemptions List.

Sour Gas – Natural gas where the Hydrogen Sulfide (H_2S) content is in excess of 4 ppmv at standard temperature and pressure.

Start of Production – The beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate, or produced water. A well whose owner or operator is selling gas through temporary equipment designed for flowback shall not be considered in production until either the sales continue through the temporary equipment for more than 30 days or the gas is routed to a permanent production separator.

Unconventional Natural Gas Well – A well drilled to produce natural gas from shale formations below the Elk Group or its geologic equivalent stratigraphic interval, where recovery of the resource is generally not economic without the bores being stimulated by hydraulic fracturing, multilateral well bores, or other techniques to expose more of the formation to the well bore.

Unconventional Natural Gas Well Site – A location with one or more unconventional natural gas wells at which unconventional natural gas well site operations are conducted.

Unconventional Natural Gas Well Site Operations – Equipment and processes at unconventional natural gas well sites including, but not limited to, well completion, gas dehydration, tanker truck load-out, wellbore liquids unloading, gas compression, pigging, and storage.

Wellbore Liquids Unloading – The process of removing accumulated liquids from a natural gas well in order to restore well pressure and natural gas production.

VII. Applicability/Scope

GP-5A authorizes the construction, modification, and/or operation of sources located at an unconventional natural gas well site or remote pigging station. The applicability of the GP-5A may include one or more of the following operations or emissions sources:

- Glycol Dehydration Units
- Stationary Natural Gas-Fired Spark Ignition Internal Combustion Engines
- Reciprocating Compressors
- Storage Vessels
- Tanker Truck Load-Out Operations
- Fugitive Emissions Components
- Controllers
- Pumps
- Enclosed Flares and Other Control Devices
- Pigging Operations
- Wellbore Liquids Unloading Operations

GP-5 authorizes the construction, modification, and/or operation of sources located at natural gas compression station, processing plant, or transmission station. The applicability of the GP-5 may include one or more of the following operations or emissions sources:

- Glycol Dehydration Units
- Stationary Natural Gas-Fired Spark Ignition Internal Combustion Engines
- Reciprocating Compressors
- Storage Vessels
- Tanker Truck Load-Out Operations
- Fugitive Emissions Components
- Controllers
- Pumps
- Enclosed Flares and Other Control Devices
- Pigging Operations
- Natural Gas-Fired Combustion Units
- Stationary Natural Gas-Fired Combustion Turbines
- Centrifugal Compressors

An Application for Authorization to Use GP-5 or GP-5A may be submitted for the operation of an eligible source if the source is exempted from plan approval requirements under 25 Pa. Code §127.14. If any source located at a facility cannot be regulated under the appropriate General Permit, a plan approval and/or an operating permit issued in accordance with 25 Pa. Code, Chapter 127, Subchapter B and/or Subchapter F will be required.

VIII. Prohibited Use of GP-5 and GP-5A

The proposed GP-5 and GP-5A are different from many other General Permits issued by the Department. The General Permit program typically establishes a general plan approval/general operating permit with requirements for a specific type of **source**, and can be used at Title V facilities when they are adding that type of source to the facility. However, GP-5 and 5A are eligible for sources located at non-major facilities. Since 1997, Authorizations to Use GP-5 issued for natural gas facilities were applicable only for sources located at non-major facilities. The sources located at Title V or major facilities must obtain a site-specific plan approval and operating permit.

In addition, because most of the natural gas production in the Marcellus Shale and Utica Shale Region is not sour gas, the GP-5 and 5A are prohibited for use by those facilities that produce or process sour gas. This removes the necessity to include the sweetening unit requirements and means many of the federal SO_2 requirements in 40 CFR Part 60 are presumptively met.

The owner or operator of a facility is also prohibited from circumventing the requirements for Title V applicability, the prevention of significant deterioration, or non-attainment new source review by allowing a pattern of ownership or development that conceals that the facility would otherwise be required to submit a plan approval or operating permit application. This includes specifically phasing, staging, delaying, or engaging in incremental construction over the geographical extent of the facility or using a device, stack height that exceeds good engineering practice, dispersion technique, or other technique to conceal or dilute emissions of air contaminants without reducing the amount of emissions in order to appear to qualify for the General Permit when the facility should actually be authorized under a plan approval or operating permit.

IX. Authorization to Use the General Permits

The general procedure to apply for an Authorization to Use the General Permit; the terms; expiration and reauthorization procedure; transfer of ownership; administrative amendment; and conditions relating to the modification, suspension, or revocation of the General Permit or an Authorization to Use the General Permit are detailed in Condition 6 of the General Permits. Application Instructions and Application Forms for the General Permits can be found in the Department's e-Library. In addition, electronic applications can be submitted using the Department's e-Permitting system, accessible through DEP's Greenport.

Another important modification to this Condition is the Transfer of Ownership procedure. In previous versions of the GP-5, the new owner or operator was required to submit a new application form within 30 days of the transfer of ownership. The new procedure, which is available in both GP-5 and GP-5A, is for the new owner or operator to file the appropriate form; for a transfer of ownership that does not modify any existing source, is not adding a new source, and is not subject to a new Single Source Determination the owner or operator may submit the Transfer of Ownership Form with the appropriate fee. For a transfer of ownership that does not modify any existing source, is not adding a new source, but requires a new Single Source Determination (i.e., equipment or activities located on the same site or on sites that share equipment and are within ¼ mile of each other) the new owner or operator shall submit an application for Authorization to Use the General Permit as a General Plan Approval with the appropriate fee. For a transfer of ownership that modifies an existing source or adds a new source, the new owner or operator shall submit an application for Authorization to Use the General Permit using the standard procedure.

X. General Permit Fees

The fees related to the General Permits are detailed in Condition 7. All fees are assessed in accordance with 25 Pa. Code Chapter 127 Subchapter I.

XI. Applicable Laws

The terms and conditions of the proposed GP-5 and 5A incorporate both federal and state requirements. It is the duty of the Responsible Official to ensure that the facility is in compliance with all applicable laws and regulations, and nothing in the General Permits relieves the Responsible Official of that duty. Therefore, it is suggested that owners and operators carefully review the listed sources and the federal, state, and local requirements applicable to them and compare them to the terms and conditions of the General Permit.

The Department's review has found that the applicable federal regulations include the following NSPS and NESHAP subparts:

(a) **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 internal combustion engines that commenced construction, modification or reconstruction after June 12, 2006, where the SI-RICE 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. The state BAT requirements for engines at natural gas compression and/or processing facilities under the current GP-5 are either equivalent or more stringent than the federal requirements.

(b) **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 with a heat input at peak load equal to or greater than 10 million British thermal units per hour (MMBtu/h) that commenced construction, modification or reconstruction after February 18, 2005. The pollutants regulated by this subpart are NO_X and sulfur dioxide (SO_2). However, the SO_2 requirements can be met by fuel composition analysis, and the prohibition of using the General Permits for facilities that produce or process sour gas ensures that the fuel composition analysis will be met.

(c) **40 CFR Part 60, Subpart OOOO – Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution for which Construction, Modification, or Reconstruction Commenced after August 23, 2011, and on or before September 18, 2015.** This subpart establishes emission standards and compliance schedules for the control of VOC and SO_2 emissions from affected facilities. In Subpart OOOO, the only SO_2 emission source is the sweetening unit typically located at natural gas processing plants. The prohibition of using the General Permits for facilities that produce or process sour gas makes it unlikely that a sweetening unit will produce significant SO_2 emissions, so the requirements for the sweetening unit were not included.

(d) **40 CFR Part 60, Subpart OOOOa – Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced After September 18, 2015.** This subpart establishes emission standards and compliance schedules for the control of the pollutant greenhouse gases (GHG). The GHG standard in this subpart is in the form of a limitation on emissions of methane. This subpart also establishes emission standards and compliance schedules for the control of VOC and SO_2 emissions. As for Subpart OOOO, the prohibition of using the General Permits for facilities that produce or process sour gas makes it unlikely that a sweetening unit will produce significant SO_2 emissions, so the requirements for the sweetening unit were not included.

(e) **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. Because the GP-5 and 5A require that the facility is non-major with respect to air pollution, only the area source requirements apply. Area sources are broken down into two categories, those located within an Urbanized Area (UA) plus offset or an Urbanized Cluster (UC) and those not located within a UA plus offset or UC.

(f) **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, in the context of these General Permits, only four-stroke engines above 500 bhp have BACT requirements; all others have work practice requirements. In addition, for engines that commenced construction, modification or reconstruction after June 12, 2006, compliance with 40 CFR Part 60, Subpart JJJJ meets the requirements of this subpart.

XII. Best Available Technology Requirements

New sources are required to control emissions of air pollutants to the maximum extent, consistent with BAT as determined by the Department as of the date of issuance of the plan approval for the new source as required under 25 Pa. Code §127.1. Condition 1 (BAT Compliance Requirements) in Sections B through L of GP-5A and in Sections B through N of GP-5 are determined to meet the BAT requirements.

XIII. Compliance Requirements and Compliance Certification

These General Permits function as a plan approval and operating permit only for a synthetic minor or natural minor facility. The Conditions of Section A lay out general terms and conditions to ensure that a facility remains a minor facility. The primary requirement to use these GPs is that the emissions from all sources and associated air pollution control equipment located at a facility must not exceed the major source thresholds on a 12-month rolling sum basis.

The owner or operator must constrain the facility throughput, hours of operation, and/or emissions from sources at the facility to ensure that the major source thresholds are not exceeded and keep records adequate to demonstrate compliance.

This Condition also contains requirements that all sources and associated air pollution control equipment are operated so as not to cause air pollution, operated and maintained in accordance with the manufacturer's specifications, operated and maintained in accordance with the fugitive emission requirements, and operated and maintained to limit the detection of malodors outside the property boundary. The addition of the fugitive emission requirements clause in the revised permit replaces the proposed version's Section B. Fugitive Particulate Matter, which was removed from both the GP-5 and GP-5A.

Another key compliance requirement is that the General Permits cannot be used to relax BAT previously established through the air quality permitting process. The owner and operator may not obtain a General Permit if BAT requirements in their current permit are more stringent than those in the revised General Permits. However, an owner or operator may elect to obtain a General Permit in lieu of their current plan approval or operating permit if they demonstrate they will be able to meet the applicable General Permit BAT requirements.

Finally, the Responsible Official must sign and submit a Certification of Compliance with the annual report.

XIV. Notification Requirements

There are several notifications that the owner or operator of a facility must perform, including a municipal notification to the local governments where the air pollution source is to be located. A copy of this notification is required to be included in the Application for Authorization to Use GP-5 or GP-5A. The notification to the local governments should include a description of the proposed sources and/or modification of existing sources to be authorized under the application.

Notifications to the Department for individual sources include prior notification of the commencement of operation of a source, which must include the completion of construction date. Notification of malfunctions are performed according to the GP-5 Malfunction Reporting Instructions (See Appendix I

– GP-5 Malfunction Reporting Instructions). All notices must be submitted to the Air Program Manager of the appropriate DEP Regional Office.

XV. Recordkeeping Requirements

Any records generated as part of the terms and conditions of the General Permits are required to be maintained on site or at the nearest local field office for a minimum of 5 years and may be maintained in electronic format. The key records generated and maintained by the owner or operator of a facility authorized under the General Permit are those that show the facility is in compliance with the facility-wide emission limits on a 12-month rolling basis. All records, reports, or other information obtained by the Department under the General Permit is publicly available unless the owner or operator of the facility shows cause that the information is confidential. Under no circumstance are records of emission data eligible for confidentiality as set forth in Section 13.2 of the APCA. 35 P.S. § 4013.2.

XVI. Reporting Requirements

In order to manage the federal and state reporting requirements, the Department merged all reporting requirements into a single annual report that is required to be sent to the Department no later than 60 days from the anniversary of the Authorization to Use the General Permit. The owner or operator may send a copy of the annual report to the EPA as all federal requirements are included, or the owner or operator may send a version that redacts all state requirements at their discretion. The annual report serves as the basis for the Compliance Certification, which the Responsible Official must sign. The annual report must be submitted either in electronic format or by hand-delivery, courier, or sent by certified mail, return receipt requested, to the Air Program Manager of the appropriate DEP Regional Office. The owner or operator of the facility must also submit an annual emissions inventory via AES*Online or AES*XML to the Department by March 1st of each year.

XVII. Source Testing Requirements

All submittals, including all reports, protocols, and test completion notifications and excluding periodic monitoring data, related to Source Testing must include one hard copy and one electronic copy sent to the Air Program Manager of the appropriate DEP Regional Office and one hard copy and one electronic copy sent to the PSIMS Administrator for the Source Testing Section in DEP Central Office.

The submission of a test protocol must be done at least 60 days prior to the performance of a source test to demonstrate compliance with the General Permits. An operator may request an approval from the Department for a test protocol that covers testing of all currently operated sources in service at that operator's various facilities. In such a request, the operator will submit the test protocol that includes a list of currently permitted sources and that meets the applicable requirements specified in the most current version of the Department's Source Testing Manual for review and approval. In the case that the owner or operator has a test protocol previously approved by the Department (including the testing contractor), a new test protocol is not required provided that there are no changes, and the owner or operator agrees to comply with all conditions of acceptance in the letter approving the protocol.

The frequency of the tests required is based on federal and state requirements. In most cases, the requirements are identical; however, in the case of engines, there are some discrepancies in the timing and frequency of the tests. These discrepancies are outlined in Table 3, with the caveats noted below the table.

Table 3 - Engine Source Testing Requirements

Engine Size	Initial Compliance Performance Test	Continuous Compliance Performance Test	Periodic Monitoring
<100 hp	None Required	None Required	Every 2,500 hours of operation
100 hp ≤ ER ≤ 500 hp	Within 180 days of startup of the engine	Within 180 days of each reauthorization	Every 2,500 hours of operation
>500 hp and not subject to 40 CFR Part 60 Subpart ZZZZ	Within 180 days of startup of the engine	Every 8,760 hours of operation **or** every three years **and** within 180 days of each reauthorization	Every 2,500 hours of operation
> 500 hp and subject to 40 CFR Part 60, Subpart ZZZZ	Not Applicable	Every year	Every 2,500 hours of operation

For an engine rated greater than or equal to 100 hp and less than or equal to 500 hp, if the engine is certified by the manufacturer in accordance with 40 CFR Part 60, Subpart JJJJ and the owner or operator operates and maintains the engine in accordance with the manufacturer's instructions, the performance testing requirements are waived.

For an engine rated greater than 500 hp, if the engine is certified by the manufacturer in accordance with 40 CFR Part 60, Subpart JJJJ and the owner or operator operates and maintains the engine in accordance with the manufacturer's instructions, the continuous compliance performance testing requirements every 8,760 hours of operation or every three years are waived.

There are also some differences between the federal and state requirements for testing for combustion turbines, primarily which pollutants are analyzed during the test. The Department requires testing for NO_X, CO, and NMNEHC (as propane) while the federal regulation requires testing of NO_X and SO_2 only. It is the Department's determination that SO_2 testing is not required based on 40 CFR §60.4415(a)(1) if the fuel used is either pipeline quality gas or field gas that does not meet the definition of sour gas. There is also a frequency difference in that the federal regulations require annual testing for turbines that do not use water or steam injection for NO_X control. The annual requirement can be waived if the owner or operator installs a continuous monitoring system.

In all cases and for all sources, the Department may alter the frequency of performance testing for reauthorization based on available performance data from the source, unless the performance tests are required by federal regulation.

XVIII. General Methodology of Determining Best Available Technology

New sources are required to control the emission of air pollutants to the maximum extent, consistent with 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 serve as minimum requirements for determining BAT. The resources utilized in the determination of BAT include the conditions established for similar sources in Category 38 of the Air Quality Permit Exemptions; the current GP-5; the data in EPA's RACT/BACT/LAER Clearinghouse (RBLC); case-by-case BAT determined in recently issued plan approvals; and permits recently issued by other states. The Department also evaluated vendors' guaranteed emission limits, available stack test data for the applicable sources, and documents related to EPA's Natural Gas Star (NGStar) program. The emission limitations included in the General Permits must be technically and economically feasible and must be sustainable during the life of the air pollution source.

The general classes of air emissions from the sources at facilities covered by GP-5 and GP-5A include NO_X, CO, VOC, HAP, SO_X, PM_{10}, $PM_{2.5}$, CO_2, and methane. These pollutants are described in more detail below.

A. Oxides of Nitrogen

Oxides of nitrogen are a family of compounds which includes nitrogen oxide (NO) and nitrogen dioxide (NO_2) that are produced as a byproduct of the combustion of fuel and air. The heat of combustion causes the molecular nitrogen (N_2) in the combustion air to disassociate and oxidize, forming NO and NO_2. NO_X is a criteria pollutant, but it is also a precursor to acid rain, ozone, and $PM_{2.5}$; NO_X emissions are typically expressed as NO_2.

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 and is heavily influenced by combustion temperature. Fuel NO_X results from oxidation of nitrogen contained in the fuel. Prompt NO_X is formed from molecular nitrogen in the air combining with fuel in fuel-rich conditions.

Strategies for the control of NO_X include combustion control and post-combustion control. In combustion control, the combustion temperature is lowered in order to limit the disassociation of molecular nitrogen through premixing, staging, or excess air. Post-combustion control typically includes an add-on device, such as nonselective catalytic reduction (NSCR) systems or selective catalytic reduction (SCR) systems. Both systems are described in greater detail in the individual source BAT analysis.

B. Carbon Monoxide

Carbon monoxide is a colorless, odorless gas that results from the incomplete combustion of carbon. CO is formed when insufficient oxygen or poor mixing interferes with the combustion reaction to produce CO_2. CO formation is greatest when the air-to-fuel (A/F) mixture is rich; however, CO also forms when a very fuel-lean mixture cannot sustain complete combustion.

Techniques for control of carbon monoxide also include combustion control and post-combustion controls. As for combustion control, a balance must be sought with NO_X control as lower combustion temperatures that prevent thermal NO_X formation can lead to incomplete combustion and therefore increase CO formation. Post-combustion controls include NSCR systems and oxidation catalysts. Individual source BAT analyses tend to favor minimizing NO_X production through combustion control techniques even though there may be an increase of CO, and then use post-combustion controls to mitigate the CO impact because Pennsylvania is a non-attainment state in the Ozone Transport Region.

C. Volatile Organic Compounds

VOCs are defined in 25 Pa Code §121.1. For engines and turbines, the Department uses non-methane, non-ethane hydrocarbons (NMNEHC) expressed as propane, excluding formaldehyde, in lieu of VOC. Also, the final General Permits include a separate emission limit for formaldehyde (HCHO), which is both a VOC and a HAP, for engines.

Techniques for the control of VOC are different depending on whether they are byproducts of combustion, due to venting or processing natural gas, or a result of fugitive emissions. Control techniques considered for the reduction of post-combustion VOC include NSCR systems and oxidation catalysts. The primary control technique considered for the reduction of venting or process emissions is the installation of a closed vent system routed to a process or a control. The primary control technique considered for the reduction of fugitive emissions is an LDAR program.

D. Hazardous Air Pollutants

HAPs are air pollutants known to cause cancer or to have other serious health impacts. There are currently 187 listed HAPs. While combustion accounts for a portion of HAP emissions, HAPs are also released through fugitive emissions, venting, and the processing of natural gas. The HAPs of primary concern at unconventional natural gas well site operations, remote pigging stations, natural gas compression stations, processing plants, and transmission stations are n-hexane; benzene, toluene, ethylbenzene, xylenes (collectively known as BTEX); and formaldehyde. Formaldehyde is of interest because it is the predominant HAP component of combustion emissions, resulting from the incomplete combustion of methane.

Similar to the control of VOC, the techniques for mitigating HAP emissions are dependent on whether the emissions are byproducts of combustion, due to venting or processing natural gas, or a result of fugitive emissions. The techniques to reduce HAP in these cases are the same as those used to reduce VOCs.

E. Oxides of Sulfur

Oxides of sulfur are the byproduct of combustion of a fuel that contains sulfur. In the Marcellus Shale region, natural gas does not contain sulfur above trace amounts. The Department has determined that for a typical combustion process using natural gas, SO_2 emissions are of minor significance. Therefore, neither GP-5 nor GP-5A include SO_2 emission limitations or SO_2 stack testing requirements for combustion sources. An example of this determination of minor significance is given in the calculation below.

$$\left|\frac{4\ lb\cdot mol\ H_2S}{10^6\ lb\cdot mol\ natural\ gas}\right|\left|\frac{lb\cdot mol\ SO_2}{lb\cdot mol\ H_2S}\right|\left|\frac{64.07\ lb\ SO_2}{lb\cdot mol\ SO_2}\right|\left|\frac{lb\cdot mol\ natural\ gas}{386.8\ scf\ natural\ gas}\right|\left|\frac{scf\ natural\ gas}{1{,}030\ Btu}\right|\left|\frac{10^6\ Btu}{MMBtu}\right|$$
$$= 6.42\times 10^{-4}\,\frac{lb\ SO_2}{MMBtu} < 6.00\times 10^{-2}\ \frac{lb\ SO_2}{MMBtu}\left(40\ CFR\ \S 60.4330(a)(2)\right)$$

Another example is the sweetening unit sulfur feed rate, where the lowest applicable limit is two long tons per day. Using the equations provided in 40 CFR §60.5406a(b)(1) and assuming the 4 ppm H_2S limit, the “acid gas” flow rate would have to be nearly 13,500 MMscf/day to reach a sulfur feed rate of two long tons of sulfur per day. According to a EIA report,[12] an average transmission station moves approximately 700 MMscf/day and the largest compression station at the time moves as much as 4,600 MMscf/day. Neither type of facility would reach the required sulfur feed rate for control under 40 CFR §60.5405(a). This is also true for gathering stations as they are generally smaller than transmission stations.

F. Particulate Matter

There are many types of particulate matter emissions, with classifications based on size (i.e., PM_{10} and $PM_{2.5}$) and state (i.e., filterable and condensable). Some particles are emitted directly from a source, such as construction sites, unpaved roads, or combustion, and are called primary particles. Others are formed in complicated reactions in the atmosphere from SO_2 and NO_X and are called secondary particles. The clearing, grading, and construction of a site as well as the drilling of a well can create primary particle emissions. The combustion of natural gas produces very little primary particle emissions, and the control of precursor emissions helps reduce secondary particle emissions. Because the primary particle emissions from combustion sources are of minor significance, and the primary precursor emissions are either of minor significance or well controlled, GP-5 and GP-5A do not include PM emission limitations or stack testing requirements from most combustion sources.[13]

G. Carbon Dioxide

Carbon dioxide is sometimes present in natural gas in significant quantities and is also a primary byproduct of combustion. CO_2 is a greenhouse gas; however, since the explicit control of CO_2 emissions such as carbon capture and sequestration (CCS) from minor facilities such as sources covered by these General Permits are not readily available. However, many of the BMP, maintenance requirements, and operating limitations included in the General Permits have the co-benefit of increasing the source's efficiency and therefore reducing CO_2 on an output basis.

H. Methane

Methane is the primary component of natural gas and represents a major portion of the emissions from unconventional natural gas well site operations, remote pigging stations, natural gas compression stations, processing plants, and transmission stations. While methane is harmless in low concentrations, it can explode when the concentration reaches the lower explosive limit. Methane is also a greenhouse gas and a precursor to ground level ozone.

Based on the 2015 Air Emissions Inventory for unconventional natural gas operations, methane emissions from 2011 through 2015 ranged from 107,375 tpy to 122,589 tpy. The sources of methane emissions included dehydration units, fugitive sources such as connectors, flanges, pump lines, pump seals, valves, heaters, pneumatic pumps, stationary engines, tanks, venting, blowdowns, well completions and pigging operations. Details of methane emissions from the above sources are shown in Table 4 and Table 5.

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[12] Technical Report: Natural Gas Compressor Stations on the Interstate Pipeline Network: Developments Since 1996, November 2007, Energy Information Administration, Office of Oil and Gas.

[13] Technical Report: Development of Fine Particulate Emission Factors and Speciation Profiles for Oil and Gas-fired Combustion Systems, Update: Critical Review of Source Sampling and Analysis Methodologies for Characterizing Organic Aerosol and Fine Particulate Source Emission Profiles, February 2004, Gas Research Institute, *et.al.*

The Exemption 38, finalized in 2013, required 95% control of any emission unit exceeding emission thresholds of 2.7 tpy of VOC, 0.5 tpy of single HAP, and 1.0 tpy of total HAP. It should be noted that not a single plan approval was submitted for an unconventional natural gas well site despite the requirement to install 95% VOC control on storage vessels and other equipment. This means either the installation of control is cost effective, or that the sources in question emit less than 2.7 tpy of VOC, 0.5 tpy of single HAP, and 1.0 tpy of total HAP.

The control of methane emissions in the earlier GP-5s and Exemption 38 were addressed as a collateral benefit due to the control of VOC emissions; however, because of the great success with the 2.7 tpy VOC threshold in Exemption 38, the Department decided to do something similar with methane related to a cost-effective control threshold under BAT. In addition, the leak definition for oil and gas operations included in GP-5 and Exemption 38 expressly addressed methane emissions from fugitive sources. As previously discussed in the Introduction, Governor Wolf's Methane Reduction Strategy sought to explicitly address the control of methane from the oil and gas industry. Also, as previously discussed in the Introduction, the EHB indicated to the Department that BAT also applies to GHG. Therefore, BAT for methane control was determined for sources authorized under the final General Permits to satisfy both regulatory and policy requirements.

Table 4 - Methane Emissions from Unconventional Well Site Operations in Pennsylvania

Source Type	2012		2013		2014		2015		2016	
	(tpy)		(tpy)		(tpy)		(tpy)		(tpy)	
Blowdown Vent	2,483	3%	3,745	7%	13,336	23%	12,527	21%	12,090	22%
Well Completion	39,449	54%	12,101	24%	2,237	4%	6,237	11%	7,071	13%
Dehydration Units	8,130	11%	6,402	13%	11,630	20%	6,112	10%	5,531	10%
Drilling Rigs	47	0%	33	0%	105	0%	20	0%	8	0%
Engines	3	0%	79	0%	102	0%	2	0%	26	0%
Fugitive Emissions	3,675	5%	6,081	12%	6,708	11%	11,136	19%	8,561	16%
Heaters	127	0%	12	0%	10	0%	33	0%	33	0%
Pumps	15,270	21%	19,157	38%	22,716	39%	22,007	37%	20,688	38%
Tanks	3,626	5%	3,041	6%	1,544	3%	1,169	2%	853	2%
Total	**72,809**	**100%**	**50,650**	**100%**	**58,388**	**100%**	**59,244**	**100%**	54,860	100%

Table 5 - Methane Emissions from Midstream Gas Compression and Processing Facilities in Pennsylvania

Source Type	2012		2013		2014		2015		2016	
	(tpy)		(tpy)		(tpy)		(tpy)		(tpy)	
Blowdown Vent	5,572	12%	10,575	19%	8,883	20%	16,640	26%	17,731	30%
Dehydration Units	14,259	29%	24,846	44%	16,066	36%	11,705	19%	12,290	20%
Engines	3,916	8%	5,731	10%	8,574	19%	11,418	18%	7,706	13%
Fugitive Emissions	2,930	6%	3,320	6%	4,032	9%	8,813	14%	7,429	12%
Heaters	5	0%	13	0%	8	0%	1,054	2%	769	1%
Pigging	NA	NA	NA				997	2%	192	0%

Pumps	8,102	17%	9,810	17%	4,309	10%	9,382	15%	12,410	21%
Tanks	13,638	28%	2,602	5%	2,490	6%	2,998	5%	1,450	2%
Total	**48,424**	**100%**	**56,897**	**100%**	**44,363**	**100%**	**63,007**	**100%**	59,976	100%

The Department originally proposed a BAT methane control threshold of 200 tpy based on calculating the amount of methane based on the VOC control threshold and an average gas composition as shown in Table 15 of Appendix A – Average Gas Composition Analysis. To calculate the BAT methane control threshold, the Department used a standard mass-balance calculation; the general methodology for determining the methane control threshold was to calculate the amount of methane in a natural gas release relative to the amount of VOC that reaches the VOC control threshold. Using twelve different gas samples, the BAT methane control thresholds ranged from a minimum of 21.2 tpy to a maximum of 1,615.3 tpy. The average of the twelve calculated control thresholds is 714.9 tpy, which is 17,872 tpy of CO_{2e}. This value is nearly 25% of the 75,000 tpy of CO_{2e} major modification facility threshold for greenhouse gases.

Therefore, the Department calculated an average gas composition from the twelve samples and followed the same methodology for determining the methane control threshold with a result of 191.6 tpy. The Department conservatively used 200 tpy methane to account for the scientific uncertainty due to the limited number of gas samples used in the calculation, which is equivalent to 5,000 tpy CO_{2e}. This is approximately 7% of the facility greenhouse gas threshold.

Several commentators stated that the Department's calculated average gas composition was not representative of natural gas in Pennsylvania because of its small sample size and limited geographic scope. To improve the average gas composition calculation, the Department decided to expand the scope of the analysis; for every county with wells displayed on eMapPA, the Department attempted to obtain at least five reasonable representative gas analyses, two from compressor stations or processing plants, and three from unconventional natural gas well sites. The Department then calculated a county average gas composition for each county, and a state average gas composition by averaging the county average gas compositions.

The average composition for the counties with at least one representative gas analysis and the calculated state average gas composition are shown in Table 16 of Appendix A – Average Gas Composition Analysis. The Department believes that this state average gas composition is representative of the regions where oil and gas operations are occurring. The same process was followed as in the previous analysis, where methane emissions were calculated based on a standard mass-balance and the VOC control threshold of 2.7 tpy for each county. The methane control thresholds ranged from 5.8 tpy for Mercer County and 1,474.8 tpy for Somerset County with an average methane control threshold of 444.0 tpy. While this value is lower than the 714.9 tpy value of the previous analysis, the Department determined that it is unreasonable to be used as a control threshold; this is because it is approximately 15% of the major modification facility threshold for GHG. For the calculated state average composition, the methane control threshold is calculated to be 51.9 tpy; this is lower than in the previous calculation because there were more representative gas analyses with VOC weight percentages higher than 2%.

In the first analysis, there were only two samples with VOC weight percentages over 2% and one of them was questionable due to the high nitrogen content; this means only 10% - 17% of the samples had a VOC weight percentage over 2%. In the second analyses, approximately 25% of the samples had VOC weight percentages over 2%; half of those samples had VOC weight percentages over 5% and one had a VOC weight percentage over 25%. This higher VOC weight percentage had the effect of lowering the methane emissions calculated from the mass-balance and increasing the VOC weight percentage of the state average gas composition from 1.25% in the first analysis to 4.47% in the second analysis. The 51.9 tpy methane control threshold calculated from the state average gas composition is approximately 2% of the major modification facility threshold for GHG meaning it is appropriate to use it as a control threshold in the permit. However, as is shown in the analysis in Appendix D – Cost Analysis for Combustion Control Devices, control of methane at 51.9 tpy is not cost-effective.

The average gas composition determined in the second analysis is comparable to other sources such as E $^{C}/_{R}$ Incorporated's memorandum[14] to EPA, which was used in establishing the requirements of 40 CFR Part 60 Subparts OOOO and OOOOa. In most cases the cost-effectiveness threshold for methane control was determined to be $1,000/ton of methane reduced, which is based on an analysis of EPA's technical support document for Subpart OOOOa where the cost-effectiveness threshold appeared to be $1,000/ton based on which methane control techniques were implemented and which were not. The $1,000/ton of methane reduced also coincides with the central estimate of the Social Cost of Methane as determined by EPA in 2012.

As shown in Appendix D – Cost Analysis for Combustion Control Devices, the BAT methane control is cost-prohibitive at $2,239/ton of methane reduced when considering the 51.9 tpy calculated control threshold. Even though methane control is cost-effective at approximately 163 tpy methane based on the $1,000/ton reduced threshold based on a linear interpolation, the 200 tpy BAT methane control threshold previously proposed is maintained for new or modified unconventional natural gas sources at $581/ton of methane reduced. One reason for conservatively establishing the BAT methane control threshold is due to the scientific uncertainty inherent in any analysis, including the second analysis discussed above and in Appendix A – Average Gas Composition Analysis and the site-specific uncertainty in the control costs from Appendix D – Cost Analysis for Combustion Control Devices. BAT control measures for methane must be implemented for sources with emissions that meet or exceed 200 tpy methane; this requirement is also included in the exemption criteria for facilities seeking exemption under Category 38(c). For those sources that wish to forgo controls, they can use methods or techniques to reduce methane emissions below the BAT control threshold.

Another reason in establishing the BAT 200 tpy methane control threshold is that, according to the Air Emissions Inventory, between 2012 and 2016 various sources at natural gas production, compression, and processing facilities have emissions exceeding 200 tpy of methane. While the number of sources fluctuate, generally speaking the number of sources have increased from year to year; details are shown in Table 6.

Table 6 - Reported Methane Emissions Greater Than 200 tpy

Source	Number of Sources				
	2012	2013	2014	2015	2016
Pumps	9	12	5	8	22
Heaters				2	1
Pigging				2	
Blowdowns	4	6	14	25	17
Completions	52	10	1	6	11
Dehydrators	33	40	37	28	30

[14] Memorandum on Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking, E $^{C}/_{R}$ Incorporated, July 28, 2011.

Fugitive			3	9	7

It should be noted, however, that even when not explicitly stated for control of methane, such as for sources that were constructed prior to August 8, 2018, the BMP, maintenance requirements, operating limitations, and control requirements often have a co-benefit of reducing methane emissions. As an illustration of this co-benefit, assume the 95% control requirement for VOC from a storage vessel authorized under Category Number 38(b) is met using an enclosed flare. Assuming a pre-control VOC emission rate of 10 tpy, the updated average gas composition as determined in Table 16 of Appendix A – Average Gas Composition Analysis, a methane destruction efficiency of 95%, and that 100% of the destroyed methane becomes CO_2, it is possible to calculate the greenhouse gas reduction in CO_{2e}. The following equation shows the amount of methane emissions that coincide with the 10 tpy VOC assumption:

$$\left|\frac{10\ \text{ton VOC}}{\text{year}}\right|\left|\frac{1\ \text{ton natural gas}}{0.0447\ \text{ton VOC}}\right|\left|\frac{0.8603\ \text{ton CH}_4}{1\ \text{ton natural gas}}\right| = 192.5\ \text{tpy CH}_4$$

The next calculation shows the amount of CO_2 generated by combusting the methane in the control device, using the 95% destruction efficiency and 100% conversion assumptions:

$$\left|\frac{192.5\ \text{tons CH}_4}{\text{year}}\right|\left|\frac{2000\ \text{lb CH}_4}{1\ \text{ton CH}_4}\right|\left|\frac{1\ \text{lb}\cdot\text{mol CH}_4}{16.04\ \text{lb CH}_4}\right|\left|\frac{0.95\ \text{lb}\cdot\text{mol CH}_4}{1\ \text{lb}\cdot\text{mol CH}_4}\right|\left|\frac{1\ \text{lb}\cdot\text{mol CO}_2}{1\ \text{lb}\cdot\text{mol CH}_4}\right|\left|\frac{44.02\ \text{lb CO}_2}{\text{lb}\cdot\text{mol CO}_2}\right|\left|\frac{1\ \text{ton CO}_2}{2000\ \text{lb CO}_2}\right|$$
$$= 501.8\ \text{tpy CO}_2\ \text{produced from the combustion of methane}$$

The final equation shows the total amount of CO_{2e} reduced by showing the amount of CO_{2e} equivalent to the reduced methane and subtracting the CO_{2e} of the CO_2 emissions produced in the combustion process:

$$(0.95)(192.5\ \text{tpy CH}_4)\left(\frac{25\ \text{tpy CO}_{2e}}{1\ \text{tpy CH}_4}\right) - (501.8\ \text{tpy CO}_2)\left(\frac{1\ \text{tpy CO}_{2e}}{1\ \text{tpy CO}_2}\right)$$
$$= 4{,}070.1\ \text{tpy CO}_{2e}\ \text{eliminated by the combustion of methane}$$

Techniques for the control of methane emissions differ depending on whether they are due to venting, processing natural gas, or fugitive emissions. The primary control technique considered for the reduction of venting or process emissions is the installation of a closed vent system routed to a process or control. The primary control technique considered for the reduction of fugitive emissions is an LDAR program.

XIX. Sources Common to GP-5 and GP-5A

A. Glycol Dehydration Units and Associated Equipment

All natural gas well streams contain water vapor as they leave the reservoir, and this water is produced along with the natural gas. As the natural gas travels up the well bore, it cools as a result of pressure reduction and the conduction of heat through the casing 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 water-lean 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 allows for the easy removal of water from the glycol. The water-lean 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 BTEX and 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 hydrocarbons (containing BTEX and heavier VOC), then decant the hydrocarbons 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 the atmosphere or to the regenerator firebox, other heaters, or a flare. Emissions from water-rich glycol flash tank vents are often controlled by combustion or by recycling back to low-pressure inlet gas streams. These systems have been shown to recover 90 to 99 percent of methane that would otherwise be flared into the atmosphere.[15]

1. *Emission Limits for Glycol Dehydrators*

a. Existing Glycol Dehydrators

The owner or operator of each existing glycol dehydrator located at an unconventional natural gas well site, remote pigging station, natural gas compression station, natural gas processing plant, or natural gas transmission station shall comply with the applicable requirements established in 40 CFR Part 63, Subpart HH, which are incorporated by reference in the General Permits. It is important to note that the locations listed in the technical support documents of 40 CFR Part 63, Subpart HH as urbanized areas and urban clusters were updated in the 2010 Census. The new list can be found in Appendix F.

The owner or operator of each existing glycol dehydrator installed prior to February 2, 2013, which has a total uncontrolled PTE of VOC in excess of 10 tpy, shall be controlled by at least 85% with a condenser, enclosed flare, or other air cleaning device approved by the Department.

The owner or operator of each existing glycol dehydrator installed on or after February 2, 2013, but before August 8, 2018 at a natural gas compression station or processing plant, which has a total

[15] NaturalGas.org, last accessed on May 24, 2018.

uncontrolled PTE of VOC in excess of 5 tpy, shall be controlled by at least 95% with a condenser, enclosed flare or other air cleaning device approved by the Department.

The owner or operator of each existing glycol dehydrator installed on or after August 10, 2013, but before August 8, 2018 at an unconventional natural gas well site or remote pigging station, which has a total uncontrolled VOC emission rate greater than or equal to 2.7 tpy, an uncontrolled single HAP emission rate greater than or equal to 0.5 tpy, or a total HAP emission rate greater than or equal to 1.0 tpy, shall be controlled by at least 95%.

b. New Glycol Dehydrators

The owner or operator of each new glycol dehydrator located at an unconventional natural gas well site, remote pigging station, natural gas compression station, processing plant, or transmission station shall comply with the applicable requirements established in 40 CFR Part 63, Subpart HH, which are incorporated by reference in the General Permits.

For new glycol dehydrators whose emissions are greater than or equal to the control thresholds for methane of 200 tpy, VOC of 2.7 tpy, single HAP of 0.5 tpy, **or** combined HAP of 1.0 tpy, emission must be controlled by at least 95%. A cost analysis was done by the Department for sources that emit above the control thresholds and included in Appendix D – Cost Analysis for Combustion Control Devices. A revised analysis was done based on comments received and is also included in Appendix D – Cost Analysis for Combustion Control Devices. The control requirements are summarized in Table 7.

Table 7 - Glycol Dehydrator Control Thresholds and Control Requirements

Uncontrolled VOC PTE	Still Vent Control Level
Permitted Under GP-5 Prior to Feb 2, 2013	
>10 tpy	85%
Permitted Under GP-5 On or After Feb 2, 2013 but Prior to Aug 8, 2018	
>5 tpy	95%
Permitted on or After Aug 8, 2018	
≥2.7 tpy	95%

B. Stationary Natural Gas-Fired Spark Ignition Internal Combustion Engines

In an 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 precise 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.

In the natural gas industry, engines are used as prime movers to drive compressors or vapor recovery units and as electric generators. Both rich-burn and lean-burn engines are used in the natural gas industry.

1. Emissions from Lean-Burn and Rich-Burn Engines

The main pollutants emitted from the exhaust of SI-RICE are NO_X, CO, NMNEHC, formaldehyde, SO_X, PM, and methane, depending on the composition of the fuel used. Natural gas is the only fuel authorized by GP-5A and GP-5.

2. Emission Control Technology

Control technologies that may be used on engines primarily fall into two categories, combustion control and post-combustion control.

a. <u>Combustion Control</u>

Control of combustion temperature is the principal focus of combustion process control in natural gas-fired engines. Combustion control requires tradeoffs – higher temperatures favor complete consumption of the fuel and lower residual hydrocarbons and CO but result in increased NO_X formation. Lean combustion dilutes the fuel mixture and reduces combustion temperatures and therefore reduces 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 and incomplete combustion may occur, increasing CO and VOC emissions.[16]

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 most common strategy for NO_X 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.

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

- 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.

b. <u>Post-Combustion Emission Reduction Technology for Rich-Burn Engines</u>

i. Three-Way Catalyst (for NO_X, CO, and NMNEHC reduction)

In rich-burn engines, an after-treatment system such as NSCR, also known as a three-way catalyst, can be added to reduce NO_X, CO, and NMNEHC 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

[16] Technical Report: Technology Characterization: Reciprocating Engines, March 2015, Prepared by Darrow, K. *et al.*, of ICF International on behalf of the EPA and US DOE.

to oxidize the CO and NMNEHC. 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%. For this analysis, the Department has determined that an NSCR is economically feasible for engines if the cost per ton of NO_X, CO, and NMNEHC removal is approximately $5,000; see Appendix C – Oxidation Catalyst and NSCR Cost Analysis for Engines and Turbines.

c. Post-Combustion Emission Reduction Technology for Lean-Burn Engines

i. Oxidation Catalyst (for CO and NMNEHC reduction)

On lean-burn engines, oxidation catalysts using platinum and palladium are effective for lowering CO and NMNEHC levels in exhaust emissions. Methane that is not combusted in the engine is exhausted with the other products of combustion; however, methane is difficult to oxidize at exhaust temperatures provided by lean-burn engines. Therefore, the control efficiency for methane using an oxidation catalyst can be very low, and no specific emission limit for methane is included in the final General Permits for engines. No A/F ratio control system is required with this type of catalyst and it can be applied to either rich-burn or lean-burn engines. For this analysis, the Department has determined that an oxidation catalyst is economically feasible for engines if the cost per ton of CO and NMNEHC removal is approximately $5,000; see Appendix C – Oxidation Catalyst and NSCR Cost Analysis for Engines and Turbines.

ii. Selective Catalytic Reduction (for NO_X 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. On closed-loop control systems SCR can reduce natural gas-fired engine NO_X emissions by 90% as per the SCR system manufacturers.[17]

In the GP-5 issued on February 2, 2013, the Department required add-on control for CO emissions which also controls VOC and HCHO emissions. The Department also established an uncontrolled NO_X emission limit of 0.5 grams per brake horsepower-hour (g/bhp-h) for lean-burn engines rated at greater than 500 brake horsepower (bhp) based on vendor's guaranteed emission rates. The Department evaluated the economic feasibility of SCR for engines and determined that SCR is economically cost-prohibitive for engines rated below 4,000 bhp. The Department did not evaluate SCR for larger engines at that time because the information received from natural gas compression facility owners led us to believe that the typical engine sizes were between 1,300 bhp and 4,000 bhp.

The Department has reviewed the manufacturers' current guaranteed level for NO_X emissions for lean-burn engines and found that some manufacturers now offer a guaranteed emissions rate of 0.30 g/bhp-h NO_X for certain engines rated greater than or equal to 1,875 bhp. For the current analysis, the Department has determined that SCR is economically feasible for engines if the cost per ton of NO_X removal is approximately $10,000; see the updated Appendix B – SCR Cost Analysis for Engines and Turbines.

[17] Emails from Vendor A and Vendor B, as referenced in Appendix B – SCR Cost Analysis for Engines and Turbines of this document.

3. *Engine Size Grouping*

The Department chose the engine size groups based on information for various engine makes and models available. The General Permits group the engines into the following categories:

- Less than 100 bhp;
- Greater than or equal to 100 bhp and less than 500 bhp;
- Greater than or equal to 500 bhp and less than 2,370 bhp; and
- Greater than or equal to 2,370 bhp.

The groupings are comparable to the bhp categories in 40 CFR Part 60, Subpart JJJJ. The Department made BAT determinations for these categories.

4. *Engine Emission Limits*

The BAT for most of the engine size categories in the proposed GP-5A and GP-5 is adapted from the current GP-5 for Natural Gas Compression and/or Processing Facilities, revised January 16, 2015. For engines rated above a certain size, the Department evaluated uncontrolled emissions, control efficiency of various controls and associated costs, and stack test results for SI-RICE to establish BAT.

It should be noted that there were engines permitted through GP-5 prior to February 2, 2013, which could include sources at natural gas well sites. The scope of the revised GP-5, issued on February 2, 2013, did not include sources at natural gas well sites. Therefore, specific categories for these existing engines authorized to operate under previous versions of GP-5 and their emissions limits have been included in GP-5A.

a. <u>Rich-Burn Engines Less Than 100 bhp</u>

Due to the limited available emissions data for rich-burn engines less than 100 hp, the Department determined BAT for rich-burn engines less than 100 bhp equivalent to the emissions standards specified in 40 CFR Part 60 Subpart JJJJ. The emission limits included in the final General Permits are 1.0 g/bhp-h of NO_X, 2.0 g/bhp-h of CO, and 0.70 g/bhp-h of NMNEHC.

b. <u>Rich-Burn Engines Greater Than or Equal To 100 bhp but Less Than 500 bhp</u>

Vendor data for rich-burn engines greater than or equal to 100 bhp but less than 500 bhp indicate weighted average emission rates[18] of 15.9 g/bhp-h for NO_X, 8.3 g/bhp-h for CO, 1.5 g/bhp-h for THC, and 0.3 g/bhp-h for NMNEHC. Both the weighted average emission rates and BAT emission rates were used in the BAT analysis.

All NSCR cost estimations were based on an analysis by E $^C/_R$ Incorporated[19], where they determined total annual costs based on vendor data. The equations are for retrofitted technology and give the cost in 2009 dollars. The total annual cost in the cost analysis was then multiplied by the consumer price index (CPI) of 1.12 for inflating 2009 dollars to 2016 dollars. Because the equations were designed as a retrofit, it is assumed that it is a conservative cost estimate for new installations. It was assumed that the control efficiencies for NO_X and CO are 95% and for NMNEHC is 50%.

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[18] The weighted average emission rates for all engine categories is based on data gathered by the Department and included in the Excel Spreadsheet titled GP-5 NG Engine Data 03152018.
[19] Memorandum on Control Costs for Existing Stationary SI-RICE, E $^C/_R$ Incorporated, June 29, 2010.

Using the weighted average emission rates and the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for rich-burn engines greater than or equal to 100 bhp but less than 500 bhp is estimated between $138 and $11,480 per ton of pollutants reduced. The $11,480 per ton of pollutants reduced figure is for a 100 hp engine operating at the BAT emissions rate, which presumes installation of NSCR. Discarding this point, the control cost for an NSCR is then estimated to be between $138 and $5,126 per ton of pollutant reduced, which are within the cost-effectiveness benchmark (~$5,000/ton of pollutant removed). Therefore, the Department determines NSCR to be BAT for rich-burn engines greater than or equal to 100 bhp but less than 500 bhp where emission limits of 0.25 g/bhp-h for NO_X, 0.30 g/bhp-h for CO, and 0.20 g/bhp-h for NMNEHC remains as in the previously issued GP-5.

c. Rich-Burn Engines Greater Than or Equal To 500 bhp

Vendor data for rich-burn engines greater than or equal to 500 bhp indicate uncontrolled weighted average emission rates of 15.4 g/bhp-h for NO_X, 8.2 g/bhp-h for CO, 1.7 g/bhp-h for THC, and 0.3 g/bhp-h for NMNEHC. Both the weighted average emission rates and BAT emission rates were used in the BAT analysis.

Using the weighted average emission rates and the BAT emissions rates, the assumed control efficiencies, and assuming full-year operation, the control cost for rich-burn engines greater than or equal to 500 bhp is estimated between $30 and $3,256 per ton of pollutants reduced, which are within the cost-effectiveness benchmark (~$5,000/ton of pollutant removed). Therefore, the Department determines NSCR to be BAT for rich-burn engines greater than or equal to 500 bhp where emission limits of 0.20 g/bhp-h for NO_X, 0.30 g/bhp-h for CO, and 0.20 g/bhp-h for NMNEHC remains as in the previously issued GP-5.

d. Lean-Burn Engines Less Than 100 bhp

Due to the limited available emissions data for lean-burn engines less than 100 hp, the Department determined BAT for lean-burn engines less than 100 bhp equivalent to the emissions standards specified in 40 CFR Part 60 Subpart JJJJ. The emission limits included in the final General Permits are 1.0 g/bhp-h of NO_X, 2.0 g/bhp-h of CO, and 0.70 g/bhp-h of NMNEHC.

e. Lean-Burn Engines Greater Than or Equal To 100 bhp but Less Than 500 bhp

Vendor data for lean-burn engines greater than or equal to 100 bhp but less than 500 bhp indicate uncontrolled weighted average emission rates of 7.8 g/bhp-h for NO_X, 6.7 g/bhp-h for CO, 1.9 g/bhp-h for THC, and 0.6 g/bhp-h for NMNEHC. Both the weighted average emission rates and BAT emission rates were used in the BAT analysis.

Using the weighted average emission rates and BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for lean-burn engines greater than or equal to 100 bhp but less than 500 bhp is estimated between $286 and $1,956 per ton of pollutants reduced, which are within the cost-effectiveness benchmark (~$5,000/ton of pollutant removed). Therefore, the Department determines oxidation catalyst to be BAT for lean-burn engines greater than 100 bhp but less than 500 bhp with emission limits of 0.70 g/bhp-h for CO and 0.30 g/bhp-h for NMNEHC based on the weighted average emission factors and the given control efficiencies.

In the previous analysis, using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for lean-burn engines greater than or equal to 100 bhp but less than 500 bhp is estimated between $25,843 and $62,940 per ton of NO_X reduced. In the revised analysis, using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for lean-burn engines greater than or equal to 100 bhp but less than 500 bhp is estimated between $22,183 and $71,821 per ton of NO_X reduced. The Department maintains the determination that SCR is not BAT for lean-burn engines greater than or equal to 100 bhp but less than 500 bhp because it is not economically feasible; therefore, the Department established emission limit of 1.00 g/bhp-h NO_X remains as in the previously issued GP-5.

f. Lean-Burn Engines Greater Than or Equal To 500 bhp but Less Than 2,370 bhp

Vendor data for lean-burn engines greater than or equal to 500 bhp but less than 2,370 bhp indicate uncontrolled weighted average emission rates of 1.4 g/bhp-h for NO_X, 2.0 g/bhp-h for CO, 4.0 g/bhp-h for THC, and 0.5 g/bhp-h for NMNEHC. Both the weighted average emission rates and the current uncontrolled BAT for NO_X were used in the BAT analysis.

In the previous analysis, using the weighted average emission rates and BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for lean-burn engines greater than or equal to 500 bhp but less than 1,875 bhp is estimated between $232 and $2,081 per ton of pollutants reduced. Under the new category, using the previous analysis, the control cost for an oxidation catalyst for lean-burn engines greater than or equal to 500 bhp but less than 2,370 bhp is estimated between $185 and $2,081 per ton of pollutants reduced, which are within the cost-effectiveness benchmark (~$5,000/ton of pollutant removed). Therefore, the Department maintains the determination that oxidation catalyst is BAT for engines greater than 500 bhp but less than 2,370 bhp with an emission limit of 0.25 g/bhp-h for CO based on the weighted average emission factor and the given control efficiencies and an emission limit of 0.25 g/bhp-h for NMNEHC as in the previously issued GP-5.

In the previous analysis, using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for lean-burn engines greater than or equal to 500 bhp but less than 1,875 bhp is estimated between $10,466 and $13,477 per ton of NO_X reduced. In the revised analysis, using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for lean-burn engines greater than or equal to 500 bhp but less than 2,370 bhp is estimated between $11,792 and $24,541 per ton of NO_X reduced. Therefore, the Department determines that SCR is not BAT for lean-burn engines greater than or equal to 500 bhp but less than 2,370 bhp because it is not economically feasible, and the emission limit remains 0.50 g/bhp-h for NO_X as in the previously issued GP-5.

g. Lean-Burn Engines Greater Than or Equal To 2,370 bhp

Vendor data for lean-burn engines greater than or equal to 2,370 bhp indicate uncontrolled weighted average emission rates of 0.7 g/bhp-h for NO_X, 2.1 g/bhp-h for CO, 5.7 g/bhp-h for THC, and 0.8 g/bhp-h for NMNEHC.

In the previous analysis, using the weighted average emission rates and BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for lean-burn engines greater than or equal to 1,875 bhp is estimated between $123 and $873 per ton of pollutants reduced. Under the new category, using the previous analysis, the control cost for an oxidation catalyst for lean-burn engines greater than or equal to 2,370 bhp is estimated between $123 and $781 per ton of pollutants reduced, which are within the cost-effectiveness benchmark (~$5,000/ton of pollutant removed). Therefore, the Department determined oxidation catalyst to be BAT for lean-burn engines greater than 2,370 bhp with an emission limit of 0.25 g/bhp-h for CO based on the weighted average emission factor and the given control efficiency and an emission limit of 0.25 g/bhp-h for NMNEHC as in the previously issued GP-5.

In the previous analysis, using the BAT emission rate of 0.50 g/bhp-h as baseline, the assumed control efficiency, and assuming full-year operation, the control cost effectiveness for SCR for lean-burn engines greater than 1,875 bhp was estimated to be less than $8,818 per ton of NO_X reduced. In the revised analysis, lean-burn engines rated below 2,370 bhp were included in the previous category. However, the Department learned in recent conversations with Caterpillar that engines rated at 1,875 bhp are from a special class of engine designed to emit 0.30 g NO_X/bhp-h. Engines of the same model designation, but not of the same class as the 1,875 bhp model, are rated at 1,775 bhp. SCR is estimated to be $11,792 per ton of NO_X reduced for the 1,775 bhp model and $19,178 per ton of NO_X reduced for the 1,875 bhp model, therefore, SCR is a cost-prohibitive option for lean-burn engines designed to emit 0.30 g NOx/bhp-h. This was one reason for changing the engine categories.

The Department previously relied on stack test data that shows that approximately 33% of engines rated greater than or equal to 1,875 bhp are capable of achieving a NO_X emissions rate of 0.35 g/bhp-h uncontrolled. Therefore, the Department performed the previous analysis using 0.35 g/bhp-h of NO_X as a baseline, the assumed control efficiency, and assuming full-year operation, and found the control cost effectiveness for SCR for lean-burn engines rated greater than or equal to 1,875 bhp but less than 3,000 bhp is estimated to increase to between $10,241 and $12,597. The control cost effectiveness for SCR for engines rated greater than or equal to 3,000 bhp, using a NO_X emissions rate of 0.35 g/bhp-h as the baseline, the assumed control efficiency, and assuming full-year operation, is estimated to be less than $9,064. The Department therefore determined that lean-burn engines greater than or equal to 1,875 bhp but less than 3,000 bhp would have a dual BAT where engines with a NO_X emission rate of 0.50 g/bhp-h required SCR and engines with a NO_X emission rate of 0.35 g/bhp-h did not require SCR based on economic feasibility. However, as many of the commentators pointed out, relying on stack test data to establish an uncontrolled emission rate based on 33% of sources tested basically means that two in three engines, or an engine in two out of three tests, would be incapable of meeting that emission rate. This was another reason for changing the engine categories.

The Department conducted a revised analysis based on available engine models. For engines with a NO_X emission rate of 0.50 g/bhp-h, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for lean-burn engines greater than or equal to 2,370 bhp is estimated between $7,611 and $10,451 per ton of NO_X reduced. This was the final reason for changing the engine categories.

For engines with a NO_X emission rate of 0.30 g/bhp-h, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for lean-burn engines greater than or equal to 2,370 bhp is estimated between $13,706 and $17,072 per ton of NO_X reduced. The Department therefore determined that lean-burn engines greater than or equal to 2,370 bhp have a dual BAT where engines with a NO_X emission rate of 0.50 g/bhp-h require SCR and engines with a NO_X emission rate of 0.30 do not require SCR based on economic feasibility. Based on the comments received, the Department has revised the ammonia slip limit to 10 ppmvd corrected to 15% O2 in the final general permits.

The BAT emission limits for the proposed General Permits are summarized in Table 8 and Table 9.

Table 8 - BAT Emission Limits for Existing SI-RICE

Engine Type	Rated bhp	NO_X	CO	NMNEHC as propane (excluding HCHO)	HCHO
Permitted Under GP-5 Prior to Feb 2, 2013					
NG-fired Lean- and Rich-Burn Engines	<1,500	2.0 g/bhp-h	2.0 g/bhp-h	2.0 g/bhp-h	
Permitted Under GP-5 On or After Feb 2, 2013 but Prior to Aug 8, 2018					
NG-fired Lean- and Rich-burn Engines	≤100	2.0 g/bhp-h	2.0 g/bhp-h	-	-
NG-fired Lean-burn Engines	>100 to ≤500	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	-
NG-fired Lean-burn Engines	>500	0.50 g/bhp-h	47 ppmvd @ 15% O_2 **or** 93% reduction	0.25 g/bhp-h	0.05 g/bhp-h
NG-fired Rich-burn Engines	>100 to ≤500	0.25 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	
NG-fired Rich-burn Engines	>500	0.20 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	2.7 ppmvd @ 15% O_2 **or** 76% reduction

Table 9 - Proposed BAT Emission Limits for New SI-RICE

Engine Type	Rated bhp	NO_X	CO	NMNEHC as propane (excluding HCHO)	HCHO
Permitted on or After Aug 8, 2018					
New NG-fired Lean-burn Engines	≤100	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	-
New NG-fired Lean-burn Engines	>100 to ≤500	1.0 g/bhp-h	0.70 g/bhp-h	0.30 g/bhp-h	-
New NG-fired Lean-burn Engines	>500 to <2,370	0.50 g/bhp-h	0.25 g/bhp-h	0.25 g/bhp-h	0.05 g/bhp-h
New NG-fired Lean-burn Engines	≥2,370	0.30 g/bhp-h Uncontrolled **or** 0.05 g/bhp-h with Control	0.25 g/bhp-h	0.25 g/bhp-h	0.05 g/bhp-h
New NG-fired Rich-burn Engines	≤100	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	-
New NG-fired Rich-burn Engines	>100 to ≤500	0.25 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	
New NG-fired Rich-burn Engines	>500	0.20 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	2.7 ppmvd @ 15% O_2 **or** 76% reduction

In addition, the engines shall comply with all applicable requirements specified in 40 CFR Part 60, Subpart JJJJ and 40 CFR Part 63, Subpart ZZZZ. For engines constructed on or after June 12, 2006, compliance with the requirements in Table 10 guarantees compliance with the requirements of 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63 Subpart ZZZZ.

Table 10 - 40 CFR Part 60 Subpart JJJJ Requirements

Engine Size	Manufacture Date	NO_x	NMNEHC (as propane) excluding HCHO	CO
≤25 bhp and <225 cc displacement	7/1/2008	12 g/bhp-h		387 g/bhp-h
	1/1/2012	7.5 g/bhp-h		455 g/bhp-h
≤25 bhp and ≥225 cc displacement	7/1/2008	10. g/bhp-h		387 g/bhp-h
	1/1/2011	6.0 g/bhp-h		455 g/bhp-h
25 bhp < ER < 100 bhp	1/1/2007	2.8 g/bhp-h		4.9 g/bhp-h
	1/1/2011	1.0 g/bhp-h	0.70 g/bhp-h	2.0 g/bhp-h
100 hp ≤ ER < 500 bhp	7/1/2008	2.0 g/bhp-h	1.0 g/bhp-h	4.0 g/bhp-h
	1/1/2011	1.0 g/bhp-h	0.70 g/bhp-h	2.0 g/bhp-h
≥500 bhp	7/1/2007	2.0 g/bhp-h	1.0 g/bhp-h	4.0 g/bhp-h
	7/1/2010	1.0 g/bhp-h	0.70 g/bhp-h	2.0 g/bhp-h

The Department's proposed BAT requirements are at least as or more stringent than those listed in the table above. Therefore, by complying with the Department's BAT requirements, the owner or operator of an engine will be guaranteed compliant with the applicable emission limits of 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63 Subpart ZZZZ for new engines.

For engines constructed prior to June 12, 2006, compliance with the requirements in Table 11 guarantees compliance with the requirements of 40 CFR Part 63 Subpart ZZZZ:

Table 11 - 40 CFR Part 63 Subpart ZZZZ Requirements

Engine Category	Oil and Filter Change	Spark Plug Inspection, Plugs Replaced as Necessary	Hose Inspection, Hoses Replaced as Necessary
Emergency SI-RICE; 4SRB and 4SLB > 500 hp that operate ≤ 24 hours per year	500 hours or annually	1,000 hours or annually	500 hours or annually
4SRB and 4SLB > 500 hp in remote locations	2,160 hours or annually	2,160 hours or annually	2,160 hours or annually
4SLB > 500 hp	Install Oxidation Catalyst to Reduce HAP Emissions		
4SRB > 500 hp	Install NSCR to Reduce HAP Emissions		
4SRB and 4SLB ≤ 500 hp	1,440 hours or annually	1,440 hours or annually	1,440 hours or annually
2SLB	4,320 hours or annually	4,320 hours or annually	4,320 hours or annually

Visible emissions shall not meet or exceed 10% opacity for a period or periods aggregating more than three minutes in any one hour nor meet or exceed 30% opacity at any time.

C. Reciprocating Natural Gas Compressors

Fluids, such as natural gas, travel naturally from areas of high pressure to areas of low pressure. Natural gas compressors take advantage of this property by increasing the pressure of natural gas at one location in a pipeline in order to promote the movement of the gas to a lower pressure area downstream. The pipeline pressure tends to drop over the length of a pipeline due to friction. This decrease in pressure is the reason why compression stations are located along the length of the pipeline.

Reciprocating natural gas compressors provide this increase of pressure by using a piston and cylinder arrangement. As the piston moves through the chamber, the pressure at the forward edge of the piston is increased as the volume in the cylinder is decreased. The high-pressure gas is then forced through a valve into the high-pressure section of the pipeline. On the reverse stroke, the pressure at the trailing edge of the piston is decreased as the volume in the cylinder is increased. This reduction in pressure allows the low-pressure gas in the pipeline to be drawn into the cylinder. The piston is connected to its prime mover by a rod, and the rod utilizes rod packings to reduce wear on the compressor components and to seal in the gas pressure. Over time, these packings can wear, resulting in methane, VOC, and HAP emissions.

It is not typical for reciprocating compressors to be installed at an unconventional natural gas well site. According to 40 CFR Part 60, Subparts OOOO and OOOOa, reciprocating compressors located at well sites are not affected facilities. Since reciprocating compressors located at well sites are air contaminant sources subject to BAT requirements, the final GP-5A requires reciprocating compressors located at well sites to meet the same requirements for reciprocating compressors located at compression stations as BAT; see Appendix H – Well Site Rod Packing Replacement Cost-Effectiveness Analysis.

1. Existing Reciprocating Natural Gas Compressors

40 CFR Part 60, Subpart OOOO provides two options for controlling VOC emissions from reciprocating natural gas compressors. The first is to replace the rod packings either 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 second is to utilize a rod packing emissions collection system that operates under negative pressure to route the rod packing emissions to a process through a closed vent system.

The previous GP-5 required the owner or operator of reciprocating compressors to meet the requirements of 40 CFR Part 60, Subpart OOOO. Therefore, the owner or operator of an existing reciprocating natural gas compressor shall continue to comply with the applicable requirements specified in 40 CFR Part 60, Subpart OOOO, which are incorporated by reference in the General Permit.

2. New Reciprocating Natural Gas Compressors

EPA finalized NSPS OOOOa on June 3, 2016, which requires reciprocating natural gas compressors to replace the rod packing on or before 26,000 hours of operation or 36 calendar months or route emissions from the rod packing to a process through a closed vent system under negative pressure. Based on the Department's evaluation, no additional requirements are needed. Therefore, the Department determines that the recently promulgated requirements of 40 CFR Part 60, Subpart OOOOa are determined to be BAT. Therefore, the owner or operator of a new reciprocating natural gas compressor at natural gas compression stations, processing plants, and transmission stations shall comply with the applicable requirements specified in 40 CFR Part 60, Subpart OOOOa, which are incorporated by reference in the GP-5.

The Department examined whether the rod-packing replacement requirements of 40 CFR Part 60, Subpart OOOOa could also be applied to reciprocating compressors at unconventional natural gas well sites. Reciprocating compressors at these facilities are exempt based on EPA's determination in their Technical Support Document for Subpart OOOOa.[20] In their TSD, EPA determined that the cost to replace the rod-packings is $1,620 per cylinder in 2008 dollars. Adjusting to 2016 dollars using the CPI, using EPA's base assumptions for emissions and number of cylinders, and assuming 7% for future worth calculations, the Department calculates that the cost per ton of methane reduced and cost per ton of pollutant reduced is $15,802 and $12,365, respectively, based on the 0.271 scf/h emission factor from the TSD.

However, a more recent study by the University of Texas[21] (UT) lists compressor seal emission factors from different sources in Table 1-4 on pages 16 and 17 of the report including calculated emission factors from measurements conducted during the study. Table 1-4 of UT's report also includes EPA's methane emission factor of 0.271 scf/h for production sources, a natural gas emission factor of 0.343 scf/h per cylinder calculated from the methane emission factor using a default methane content of 78.8 mol%, and a natural gas emission factor of 42.2 scf/h per cylinder from a 1992 study by Picard. The UT study found the average rod packing emissions to be 241 Mscf/year, which translates to 27.5 scf/h per cylinder.

In Appendix H – Well Site Rod Packing Replacement Cost-Effectiveness Analysis, the costs associated with rod-packing replacement requirements identical to those in EPA's TSD for 40 CFR Part 60, Subpart OOOOa were reevaluated for unconventional natural gas well sites based on the additional natural gas emission factors from the UT study. Based on the emissions estimate using average emissions from the UT study, the requirement of rod-packing replacement was determined to be cost effective as BAT. The Center for Responsible Shale Development (CRSD) certifies participants, which includes energy companies such as Chevron, CNX, EQT, and Shell Appalachia, that conform to their performance standards. CRSD standard #14 also requires rod-packing replacement every 36 months or every 26,000 hours of operation at all new and existing sites, including those at the wellhead. The voluntary participation of natural gas producers in the CRSD performance standards supports the Department's determination that the rod-packing replacement requirement is technically and economically feasible and therefore BAT.

D. Storage Vessels

Storage vessels are used to collect and store condensate (also known as natural gas liquids or NGLs) and/or produced water that are byproducts of natural gas production. Most storage vessels in the natural gas industry are fixed-roof structures and are equipped with a variety of pressure equalization devices to protect the structural integrity of the tank.

There are several federal regulations that pertain to storage vessels including requirements found in 40 CFR Part 60, Subparts K, Ka, Kb, OOOO, and OOOOa and 40 CFR Part 63, Subpart HH. In addition, state regulations found in 25 Pa. Code §§ 129.56 and 129.57 have applicable requirements. 40

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[20] E $^{C}/_{R}$ Incorporated/US Environmental Protection Agency. Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Facilities. Background Technical Support Document for the Proposed Standards 40 CFR Part 60, Subpart OOOOa. August 2015.

[21] URS Corporation/University of Texas at Austin. 2011. Natural Gas Industry Methane Emission Factor Improvement Study, Final Report. December 2011. https://dept.ceer.utexas.edu/ceer/GHG/files/FReports/XA_83376101_Final_Report.pdf, last accessed May 24, 2018.

CFR Part 60, Subparts OOOO and OOOOa include inspection and monitoring requirements for storage vessels which are incorporated in the final General Permits by reference.

1. Emission Limits for Storage Vessels

a. <u>Existing Storage Vessels</u>

Existing storage vessels at crude oil and natural gas production (except unconventional natural gas facilities constructed on or after August 10, 2013 but prior to August 8, 2018), transmission, and distribution facilities constructed on or after August 23, 2011, but prior to August 8, 2018, with uncontrolled potential VOC emissions greater than or equal to 6.0 tpy are required to be controlled by 95% or more, install a fixed-roof tank with an internal floating roof, an external floating roof, or maintain the actual uncontrolled VOC emissions below 4.0 tpy as required by 40 CFR Part 60 Subparts OOOO and OOOOa.

Existing storage vessels at unconventional natural gas facilities constructed on or after August 10, 2013 but prior to August 8, 2018 are required to meet the conditions in Category 38(b) of the Air Quality Permit Exemptions document. This means that existing storage vessels at unconventional natural gas well sites shall be equipped with controls achieving VOC emission reductions of 95% or greater unless the facility's uncontrolled VOC emissions for all sources are below 2.7 tpy. If the storage vessels' HAP emissions are uncontrolled, they must also be included in the facility-wide uncontrolled single HAP emissions limit of 0.5 tpy and total uncontrolled HAP emissions limit of 1.0 tpy. The facility-wide uncontrolled emission limits do not include emissions from any source that is equipped with emission controls.

In addition, the owner or operator of any storage vessel, without regard to when it was constructed, must meet the applicable requirements of 25 Pa. Code §§129.56 and 129.57, which are incorporated by reference in the General Permits.

b. <u>New Storage Vessels</u>

Storage vessels at unconventional natural gas well sites constructed on or August 8, 2018, must meet the requirements of Category 38(c) of the Air Quality Permit Exemptions document.

Because the Department has not issued any plan approval for sources located at any unconventional natural gas well site, either the VOC and HAP emissions from each storage vessel installed at well sites on or after August 10, 2013 are below the control threshold requirement or emissions are being reduced by 95% or more. Therefore, based on the updated cost analysis in Appendix D – Cost Analysis for Combustion Control Devices and the lack of plan approvals for sources located at any unconventional natural gas well site, the Department has determined BAT for the General Permits to be the reduction of methane, VOC, and HAP emissions by 95% or more for a storage vessel that exceeds any control threshold of 200 tpy methane, 2.7 tpy VOC, 0.5 tpy of a single HAP, or 1.0 tpy of total HAP.

In addition, the owner or operator of any storage vessel, without regard to when it was constructed, must meet the applicable requirements of 25 Pa. Code §§129.56 and 129.57, which is incorporated by reference in the General Permits.

<u>E. Tanker Truck Load-Out Operations</u>

The storage tanks at unconventional natural gas well sites, natural gas compression facilities, and natural gas processing facilities must be unloaded on occasion. This is done by loading the liquids from the tanks into tanker trucks so the liquids may be transported to a processing facility. The unloading process may emit methane, VOC, and HAP based on the composition of the liquids.

Since August 10, 2013, in accordance with Category 38 of the Air Quality Permit Exemptions document tanker truck load out operations are required to be equipped with controls achieving VOC, and HAP emissions reductions of 95% or greater unless their uncontrolled VOC, single HAP, and total HAP emissions are below the control thresholds of 2.7 tpy, 0.5 tpy, and 1.0 tpy, respectively. Because the Department has not issued any plan approval for tanker truck load out operations, either VOC and HAP emissions from each tanker truck load out operation on or after August 10, 2013 is below the control threshold requirement or emissions are being reduced by 95% or more.

All tanker truck load-out operations were required to use a vapor recovery load-out system that meets the closed vent system requirements in Section N, Enclosed Flares and Other Control Devices, in the originally proposed General Permits. This was an error, which was pointed out by several commentators, as there should be no requirement to use a vapor recovery load-out system for tanks that handle produced water. This was not the Department's intent, and to be consistent with Exemption 38 and the Internal Implementation Instructions for Exemption Category No. 38, a source that is below the control thresholds is not required to install controls.

Therefore, in the final General Permits, only tanker truck load-out operations that take liquids from storage vessels with emissions above the control thresholds are required to use a vapor balancing system and ensure each truck used to unload liquids has passed one of the annual leak checks below.

When calculating the emissions from tanker truck load-out operations, the collection efficiency may be assumed to be 99.2% for tanker trucks that pass the MACT-level annual leak test and 98.7% for tanker trucks that pass the NSPS-level annual test. The MACT-level leak test is passed if the tanker does not indicate more than a 1" H_2O pressure change within 5 minutes after being pressurized to 18" H_2O and after being depressurized to 6" H_2O vacuum. The NSPS-level leak test is passed if the tanker does not indicate more than a 3" H_2O pressure change within 5 minutes after being pressurized to 18" H_2O and after being depressurized to 6" H_2O vacuum. A leak test performed in accordance with 49 CFR §180.407 – *Requirements for Test and Inspection of Specification Cargo Tanks*, or EPA Method 27 – *Determination of Vapor Tightness of Gasoline Delivery Tank Using Pressure Vacuum Test*, will be accepted as equivalent to an NSPS-level collection efficiency (i.e., 98.7%).

Originally, the Department required the owner or operator to keep records of the entire fleet of tanker trucks that collect liquids from the facility, including the date and rating of each leak test and an identification number for each truck. However, based on comments received, the Department decided to drop this recordkeeping requirement. Instead, the load-out records will identify the truck performing the load-out, identify the leak test classification, the date and time the load-out occurred, and the type and volume of liquids loaded. These records can then be used to calculate emissions due to the load-out operations for the emissions inventory.

F. Fugitive Emissions Components

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. However, a release from any equipment or component designed by the manufacturer to protect the equipment, controller, or personnel or to prevent groundwater contamination, gas migration, or an emergency situation is not considered a leak. The following requirements have been included to minimize and/or eliminate the equipment leaks.

In accordance with the Department's requirements under the previous version of GP-5, the owner or operator of a natural gas compression facility and/or natural gas processing facility shall, at a minimum on a monthly basis, perform an LDAR program which includes AVO inspections. This requirement is to be extended to unconventional natural gas well sites, remote pigging stations, and natural gas transmission stations covered by the final General Permits.

In the previous version of the GP-5, the owner or operator of the facility was required to use an OGI camera or other leak detection device to conduct an LDAR program inspection within 180 days after the initial startup of a source and at a minimum of once a quarter thereafter. This requirement has been changed to within 60 days after the initial startup of a source to meet the 40 CFR Part 60 Subpart OOOOa requirement and align with the LDAR requirements for unconventional natural gas well sites, which are required to perform an LDAR program inspection within 60 days of the start of production.

Based upon the cost-effectiveness analysis of Appendix E – LDAR Cost Analysis, the Department determined that quarterly inspections are BAT for unconventional natural gas well sites and remote pigging stations. An owner or operator of an unconventional natural gas well site or remote pigging station may track the number of leaking components in the LDAR program and reduce the inspection interval from once per quarter to semi-annually if the percentage of leaking components is less than 2.0% for two consecutive inspections. If the percentage of leaking components is higher than 2.0% in any inspection, the quarterly LDAR inspection interval must be resumed or maintained.

Consistent with 40 CFR Part 60, Subparts KKK, OOOO, and OOOOa, the LDAR requirements for natural gas processing plants are to use Method 21. As per 40 CFR §65.7(e), when a Method 21 inspection is required in any subpart of Parts 60, 61, 63, and 65, OGI camera inspections are an accepted alternative work practice for monitoring equipment for leaks. Therefore, the Department requires that all LDAR inspections covered by GP-5 and GP-5A use the same criteria, including those at natural gas processing plants under 40 CFR §§60.484 and 60.484a.

A leak is defined as any positive indication, whether audible, visual, or odorous, determined during an AVO inspection, any visible emission detected by an OGI camera calibrated according to 40 CFR §60.18 and a detection sensitivity level of 60 g/h, or a concentration of 500 ppm or greater calibrated as methane detected by an instrument that meets the requirements of 40 CFR Part 60, Appendix A-7, Method 21, regardless of source. However, a release from any equipment or component designed by the manufacturer to protect the equipment, controller, or personnel or to prevent groundwater contamination, gas migration, or an emergency situation is not considered a leak.

If any leak is detected, the owner or operator of the facility shall make a first attempt of repair within five days of the detection of the leak. The leak must be repaired no later than 15 days after the leak is detected, unless the repair requires the ordering of parts, in which case the repair must be completed no later than 10 days after receipt of the parts, or if the repair is technically infeasible without a vent blowdown, facility shutdown, or well shut-in or would be unsafe to repair during operation of the unit, in which case the repair must be completed at the earliest of the next scheduled facility shutdown, after a planned vent blowdown, or within two years.

Several commentators were concerned over the requirement that a repair that is technically infeasible without a blowdown, shutdown, or shut-in must be completed during an unscheduled blowdown. This was consistent with EPA's requirement in 40 CFR Part 60 Subpart OOOOa. The commentators were concerned that if the facility undergoes an emergency shutdown and parts are not on hand to complete the repair, the facility would have to remain shut down until the repair is completed. The commentators petitioned the EPA to change the requirement, which was granted; subsequently, the Department amended the final General Permits to reflect the change.

A leak is considered repaired if one of the following can be demonstrated:

- No detectable emissions consistent with 40 CFR Part 60, Appendix A-7, Method 21 Section 8.3.2;
- A concentration of less than 500 ppm calibrated as methane is detected when the gas leak detector probe inlet is placed at the surface of the component;
- No visible leak image when using an OGI camera calibrated in accordance with 40 CFR §60.18 with a detection sensitivity of 60 g/h; or
- No bubbling at leak interface using a soap solution bubble test specified in Section 8.3.3 of 40 CFR Part 60, Appendix A-7, Method 21.

LDAR is considered to have a fugitive emission control rate based on the frequency of the inspection. According to EPA and Colorado[22] the emissions reductions from annual LDAR is 40% and from quarterly LDAR is 60%. In 40 CFR Part 60, Subpart OOOOa, LDAR is required semi-annually for well pads and quarterly for compression stations and processing plants. Using 50% emissions reduction for semi-annual LDAR and 60% emission reduction for quarterly LDAR programs, the Department evaluated cost-effectiveness. As shown in Appendix E – LDAR Cost Analysis, the cost-effectiveness is $516 for well pad and $144 for transmission facilities. Therefore, the final GP-5A requires quarterly LDAR for sources at unconventional natural gas well sites or remote pigging stations and the final GP-5 requires quarterly LDAR for sources at natural gas compression, processing, and transmission facilities to minimize fugitive emissions.

The Department determined that the VOC and methane emissions remaining after the implementation of BAT requirements, including LDAR, are of minor significance with regard to causing air pollution, and will not, on their own merits, be preventing or interfering with the attainment or maintenance of an ambient air quality standard.

G. Controllers

Controllers are automated instruments used for maintaining liquid levels, pressure, and temperature at unconventional natural gas well sites, remote pigging stations, natural gas compression stations, natural gas processing plants, and natural gas transmission stations. These controllers often are powered by high-pressure natural gas and may release methane, VOC, and HAP with every valve movement (i.e., intermittent bleed), or continuously (i.e., continuous bleed) as part of their normal operations.

Existing controllers shall comply with the applicable requirements specified in 40 CFR Part 60, Subpart OOOO. For pneumatic controllers located at unconventional natural gas well sites, remote pigging stations, natural gas compression stations, and natural gas transmission stations this means they must be low-bleed controllers with an emission rate less than or equal to 6.0 standard cubic feet per hour unless a higher bleed rate is required for operational reasons such as speed, safety, or positive actuation.

[22] ICF International, Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, March 2014.

The Department originally proposed that new controllers constructed on or after the effective date of the final General Permits should either be an electric controller if the facility has access to electricity on site or meet the requirements of 40 CFR Part 60 Subpart OOOOa if electricity is not available on site. Several commentators pointed out that electric controllers can compromise facility reliability because electric power can fail; using electric controllers could compromise safety. The Department removed the requirement to install electric controllers at facilities based on these safety and reliability concerns. However, pneumatic controllers must comply with Subpart OOOOa when located at unconventional natural gas well sites, remote pigging stations, natural gas compression stations, and natural gas transmission stations. This means they must be low-bleed controllers with an emission rate less than or equal to 6.0 standard cubic feet per hour unless a higher bleed rate is required for operational reasons as above.

The owner or operator of new and existing controllers located at a natural gas processing plant shall employ no-bleed pneumatic controllers. These can be electrically actuated controllers or pneumatic controllers driven by instrument air. Natural gas actuated controllers that route the emissions into the downstream pipeline can also be used.

H. Pumps

Pumps are primarily used at unconventional natural gas well sites, remote pigging stations, natural gas compression stations, processing plants, and transmission stations for glycol circulation or for injecting chemicals used in normal operations. Pneumatic pumps use pressurized air or natural gas to operate the pump; at natural gas facilities, it is common to use natural gas from the production stream to operate the pumps. The pressurized natural gas, after being used to operate the pump, is often vented to the atmosphere through the exhaust port. There are many options available to reduce or eliminate emissions to the atmosphere.

Pneumatic pumps had no standards in 40 CFR Part 60, Subpart OOOO other than the LDAR requirements for pumps at natural gas processing facilities. In 40 CFR Part 60, Subpart OOOOa, natural gas-driven diaphragm pumps have control requirements for GHG and VOC depending upon the type of facility at which they are located and the number of days they are operated. Subpart OOOOa does not have a requirement for pumps located at natural gas compression stations.

In the proposed GPs, the Department required that electric pumps be used at any facility other than a natural gas processing plant that has access to electricity on site. For facilities that do not have access to electricity on site, the Department proposed that the requirements of 40 CFR Part 60, Subpart OOOOa, which were detailed in the General Permit, are BAT for pumps located at unconventional natural gas well sites and natural gas processing plants. The Department also proposed that the requirements for pumps at well sites are also BAT for pumps located at remote pigging stations, natural gas compression stations, and transmission stations. The Department also proposed to collect information on other types of pneumatic pumps by having notification, recordkeeping, and reporting requirements for all pneumatic pumps.

However, based on comments received, and the current challenges to Subpart OOOOa, the Department reevaluated the requirements for pumps. Based on the cost analysis in Appendix D – Cost Analysis for Combustion Control Devices, the Department determined that pumps with emissions greater than or equal to the control thresholds for methane of 200 tpy, VOC of 2.7 tpy, a single HAP of 0.5 tpy, or combined HAP of 1.0 tpy must control methane, VOC, and HAP emissions by 95%. For pumps with methane, VOC, and HAP emissions below the control thresholds, they must meet the applicable requirements of 40 CFR Part 60 Subpart OOOOa. These requirements were incorporated into the General Permits by reference.

I. Enclosed Flares and Other Control Devices

Most of the BAT requirements for emissions sources are dependent on a control to reduce those emissions to the atmosphere. The conditions for operating, maintaining, and performance testing those control devices are included in this section of the General Permits. The proposed General Permits required 98% control efficiency which was based on the economic feasibility of combustion control devices, as shown in Appendix D – Cost Analysis for Combustion Control Devices. In addition, the Department demonstrated that at a combustion zone temperature of 1,600 °F a methane destruction of 98% is achievable.

However, in 40 CFR Part 60 Subparts OOOO and OOOOa, the operators have the option to purchase manufacturer-tested models, which require 95% VOC control efficiency. Therefore, the Department revised the methane, VOC, and HAP destruction efficiency required from 98% to 95% to enable the owners or operators to comply with the federal requirements and terms and conditions of the general permits using manufacturer-tested models. Even so, the manufacturer-tested models generally achieve higher than 95% destruction. The manufacturer-tested models also minimize the amount of performance tests required to be performed by the owner or operator relying instead on parametric monitoring to ensure compliance.

J. Pigging Operations

Pigging operations are undertaken to remove accumulated water and condensate liquids in natural gas gathering pipelines or to conduct pipeline integrity checks. These operations are done as necessary to maintain the optimal pressure in the pipeline that keeps the natural gas flowing and to push valuable condensate to tanks where it can be transported to a processing plant and ensure pipeline safety. The "pig" is a spherical or bullet-shaped device that travels through the pipeline to push the liquids to their eventual destination.

A pig must be loaded into the pipeline at a launching station and recovered at a receiving station. When the pig is launched and recovered, some of the natural gas in the chamber is vented to the atmosphere. This venting can be reduced by routing the gas to a vapor recovery unit, flare, or other control device. It can also be minimized in high-pressure pipelines by equalizing the high-pressure chamber with a low-pressure line before venting. Some of these technologies and techniques are employed in practice by MarkWest for their pigging operations. The EPA's Partner Reported Opportunities (PRO) for Reducing Methane Emissions, also called NGStar, PRO Fact Sheet No. 505, gives information on other ways to minimize emissions from pigging operations.

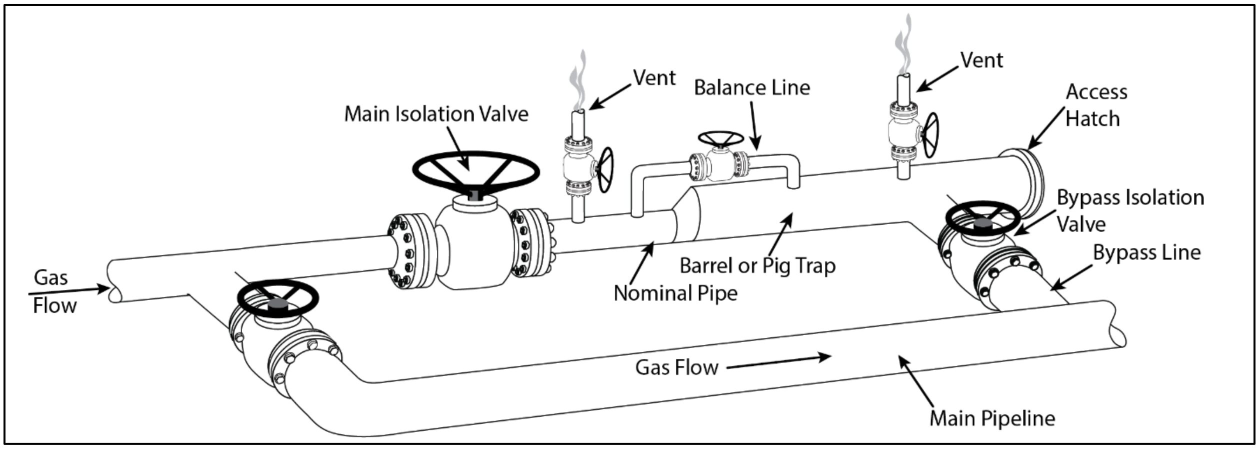

Figure 1: Drawing of a barrel type design of a pig launcher and receiver equipped with uncontrolled depressurization vents.[23]

Even though EPA is familiar with pigging operations through the NGStar program, they did not address emissions from pigging operations in 40 CFR Part 60 Subpart OOOOa. However, the Department has evaluated and set requirements for pigging operations. As part of the Annual Emissions Inventory reporting requirements, the Department requires that the owner or operator of each pigging-affected facility calculate the total annual emissions of VOC and methane using the Pigging Emissions Spreadsheet.

The owner or operator of a pigging operation shall minimize all emissions to the atmosphere to the highest extent possible. Originally, the Department required all pig receiver chambers to be equipped with a liquids drain and that all high-pressure pig launcher and receiver chambers be vented to a low-pressure pipeline or vessel if available in addition to any other best management practices (BMP) the operator decides to employ. The Department received comments recommending that DEP remove the proposed specific requirements and allow owners and operators to select all of the BMP they will implement for a specific operation. However, an owner or operator of a pigging operation whose emissions, after the application of BMP, still exceed the control thresholds for methane of 200 tpy, the total VOC of 2.7 tpy, the single HAP of 0.5 tpy, or the combined HAP of 1.0 tpy shall control methane, VOC, and HAP emissions by at least 95%.

XX. Sources Specific to GP-5A

A. Site Preparation, Well Drilling and Hydraulic Fracturing Operations

The first step in establishing a natural gas well is site preparation, which entails clearing, grading, and constructing access roads at the well site. This involves construction equipment which uses non-road engines that must meet the applicable non-road engine standards. The next step is the drilling phase; this typically entails drilling the wellbore in stages using either a diesel engine rig or a natural gas engine rig. Because the drill rig is on-site for a short period of time, the only standards that apply are that any drill rig engine must meet the applicable non-road engine standards. The owner or operator must provide at least 24 hours advance notification to the Department's Office of Oil and Gas Management before drilling. After the wellbore is completed and encased, the wellhead or "Christmas Tree" is installed.

[23] *Quantifying the Potential Impact of Natural Gas Condensate Holdup on Uncontrolled Volatile Organic Compound Emissions from Pig Receivers During Depressurization in Wet Gas Gathering Operations*, EPA Discussion Draft, May 2016.

After the installation of the wellhead, the well is ready for hydraulic fracturing. Large volumes of water mixed with chemicals and proppants are pumped into the formation to create and hold open fractures in the shale; this fracturing technique greatly enhances natural gas production. Again, the owner or operator must provide at least 24 hours advance notification to the Department's Office of Oil and Gas Management before fracture. The trucks responsible for mixing the fracturing fluid and pumping underground also use non-road engines and must meet the applicable non-road engine standards. These are summarized in the tables in Appendix G – Non-road Engine Standards.

Several commentators informed the Department that these temporary operations may be carried out a year or more in advance of the installation of any permanent air emissions source. The well drilling and hydraulic fracturing typically lasts from a few weeks to a few months. In addition, except for California, States are preempted from establishing emission standards for non-road engines under Section 209 of the CAA. However, these engines must comply with applicable EPA non-road engine standards at 40 CFR Parts 89, 1039, and 1048. Therefore, the Department has removed requirements related to site preparation, well drilling, hydraulic fracturing, and well completion from the final GP-5A and maintained the exemption for these temporary operations in Category 38(c) of the Air Quality Permit Exemptions document.

B. Well Completion Operations

After a natural gas well is hydraulically fractured, the well must be prepared to produce natural gas by removing the fluid used in the fracturing process from the well. During this process, equipment such as a separator is used to separate and remove the sand and water from the natural gas stream. The separated gas, instead of being vented, is either captured and routed to a sales pipeline, or is flared. By not directly venting the gas to the atmosphere, both methane and VOC emissions are greatly reduced. This method of completing a natural gas well is called reduced emission completion (REC) or green completion.

The owner or operator shall use REC methods in accordance with requirements specified in 40 CFR Part 60, Subpart OOOOa. Also, any existing well that is refractured after the applicability date of Subpart OOOOa subjects existing sources at a facility to the fugitive emissions components requirements in the final GP-5A. As stated above, these operations are also temporary in nature. While well completion is likely to occur much closer to the installation of permanent air emission sources, there may still be significant time between when the completion occurs and when air contamination sources are due to be installed. This could lead to inaccurate applications being submitted and many reauthorizations of the General Permit, increasing the administrative burden on the industry and the Department. Because the requirements for well completion operations are no different than those required by state and federal regulations, the Department removed these temporary operations from the final GP-5A and maintained the exemption for them in the Category 38(c). Even though these operations will not require an air permit, the operators will still be required to meet the applicable state and federal regulations, including notifying both the Air Program Manager of the appropriate Regional Office and the Department's Office of Oil and Gas Management 24 hours prior to the start of flowback.

C. Wellbore Liquids Unloading

Over time, liquids may accumulate in a producing natural gas well and may reduce the well pressure to the point where production is reduced, especially in wells located in the wet gas areas. When this happens, the accumulated fluids need to be removed in order to restore production through a process called liquids unloading. There are many techniques that can be used to accomplish this, including venting, soaping, swabbing, and using a plunger lift system. As indicated in EPA's white paper on Oil and Natural Gas Sector Liquids Unloading Processes[24], the use of technologies like a plunger lift system can reduce the frequency of liquids unloading operations.

However, the basic criteria for the installation of a plunger lift, as found in EPA's NGStar program[25], are as follows:

- Wells must produce at least 400 scf of gas per barrel of fluid per 1,000 feet of depth.
- Wells with shut-in wellhead pressure that is 1.5 times the sales line pressure.
- Wells with scale or paraffin buildup.

These conditions may not be found at all wells covered by the GP-5A, so plunger lift systems remain an option but not a requirement for wellbore liquids unloading. Furthermore, in comments to EPA in the rulemaking for 40 CFR Part 60 Subpart OOOOa, the American Petroleum Institution (API) states that it is a misconception that plunger lift systems are the single emission control action for wells where venting for liquids unloading occurs.

> "This misconception is exacerbated by a lack of understanding, even among those purporting plunger lift systems as *the* solution to liquids unloading, of liquids loading or plunger lift systems and their appropriate uses, limitations, and efficacy. Plungers work by providing a mechanical barrier between a small volume of water and the gas that is used to transport it up the well-bore. The mechanical barrier isolates the gas from the liquids, prevents gas from moving up through the liquids hence making better use of the gas energy, and helps prevent liquids from falling back into the well-bore. If the gas could flow faster, then that mechanical barrier would not be necessary or helpful.
>
> Although plungers are among the most common tools used in middle stage deliquification, there is a misconception that plungers eliminate the need to vent to atmosphere. In many cases, wells are vented to atmosphere to generate the differential pressure necessary to lift the plunger and liquid column up the well-bore. While this can be controlled and minimized, it cannot be eliminated.
>
> As the API/ANGA report and the GHGRP data show, venting of wells to aid liquids unloading occurs in both plunger equipped wells and non-plunger equipped wells with plunger equipped wells having higher reported emissions overall."

There was another EPA white paper[26] that detailed other alternatives to repeated well venting to remove accumulated liquids including surfactants, velocity tubing, manual plunger lifts, automated plunger lifts, and downhole pumps. However, EPA did not address emissions from wellbore liquids unloading operations in 40 CFR Part 60 Subpart OOOOa. However, the Department evaluated emissions from

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[24] U.S. EPA Office of Air Quality Planning and Standards, *Report for Oil and Natural Gas Sector Liquids Unloading Processes Review Panel,* April 2014, located at http://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-liquids-unloading.pdf, last accessed on May 24, 2018.

[25] U.S. EPA's Natural Gas STAR Program, *Lessons Learned from Natural Gas STAR Partners: Installing Plunger Lift Systems in Gas Wells,* October 2006, located at https://www.epa.gov/sites/production/files/2016-06/documents/ll_plungerlift.pdf, last accessed on May 24, 2018.

[26] U.S. EPA's Natural Gas STAR Program, *Lessons Learned from Natural Gas STAR Partners: Options for Removing Accumulated Fluid and Improving Flow in Gas Wells*, 2011, located at https://www.epa.gov/sites/production/files/2016-06/documents/ll_options.pdf, last accessed on May 24, 2018.

wellbore liquid operations to determine BAT. In general, there has been great support in the comments for including wellbore liquids unloading operations in the GP-5A.

The Department learned through conversations with some industry representatives, that one of the largest factors in emissions from wellbore liquids unloading events is the length of time that flow is directed to atmospheric pressure. Therefore, one of the most effective methods to reduce the time venting to atmospheric pressure would be to ensure that an operator remains on site for the duration of a manual unloading operation. However, one commentator stressed that the requirement to have an operator onsite for the entire duration of a wellbore liquids unloading operation is burdensome, especially to small businesses. An unloading operation can take a significant amount of time, which is typically spent by an operator travelling to another site to initiate another unloading operation. The operator then travels back to each site, ending each unloading operation in turn. The time spent by an operator onsite would necessitate hiring significant additional staff that small businesses cannot easily afford.

Therefore, the Department has removed the requirement that the owner or operator shall ensure that an operator remains on site for the duration of a manual unloading operation. The requirement that the owner or operator use BMP including, but not limited to, a plunger lift system, soaping, swabbing, or venting to atmospheric pressure to minimize methane and VOC emissions during wellbore liquids unloading operations to mitigate emissions. In all cases, where technically feasible, the owner or operator shall direct the gas to a separator, storage vessel, or control device, unless it is necessary to vent to the atmosphere for safety.

XXI. Sources Specific to GP-5

A. *Natural Gas-Fired Combustion Units*

There are many different combustion units used at natural gas production and processing facilities. Some are small integrated units, typically rated at less than 2.5 MMBtu/h, such as those found on gas production units (GPU), heated flash separators, or glycol dehydration units. Others are large units, some larger than 10 MMBtu/h, such as the fractionation column heaters found at natural gas processing plants.

Often when natural gas first exits the wellbore, it contains free water, condensate, and water vapor that must be removed from the natural gas stream. GPUs perform this task, and many have small boilers that facilitate the removal of natural gas from the liquids stream through flashing, which volatilizes the gas from the liquids. In dry-gas regions, the liquid is primarily water, and is referred to as produced water. In rich-gas regions, the high percentage of condensate in the natural gas stream often requires further processing to ensure that the water and condensate are separated. Heated flash separator units are used for this purpose and are also equipped with small boilers to facilitate the condensate removal from the water by flashing. The flow of the natural gas and liquids through the GPUs and heated flash separator units are often controlled by integrated controllers and pumps.

Combustion units with a rated capacity of less than 10 MMBtu/h of heat input fired on natural gas supplied by a public utility are exempt from plan approval and operating permit requirements by the Air Quality Permit Exemptions document. Under Category 39 of the final Air Quality Permit Exemptions document, combustion units rated at less than 10 MMBtu/h firing natural gas supplied by an independent producer shall be exempt from plan approval, and the General Permits may function as the required operating permit. Even though the combustion units are exempt from plan approval and/or operating permits, the owner or operator will be required to list these sources in the *Application for*

Authorization to Use GP-5 or GP-5A for reference purposes to ensure compliance with the facility emissions limits. Any associated fugitive emissions components, controllers, and pumps will be subject to their respective requirements of the General Permit.

Table 12 identifies the applicable BAT emission limitations for combustion units rated greater than or equal to 10 MMBtu/h and less than or equal to 50 MMBtu/h:

Table 12 - BAT Emission Limits for Natural Gas-Fired Combustion Units

Constructed After:	NO_X (ppmvd @ 3% O_2)	CO (ppmvd @ 3% O_2)	PM (lb/MMBtu)	Opacity (No more than 3 minutes in an hour)	Opacity (At any time)
December 2, 1995	30	300	0.4	20%	60%
August 8, 2018	30	130	0.4	10%	30%

1. NO_X Limit

The Department has found that there are few vendors that offer natural gas-fired combustion units with a NOx emission rate of lower than 30 ppmvd corrected at 3% oxygen. These units are typically used in production facilities for producing steam. However, GP-5 includes combustion units including, but not limited to, heated flash separator units, evaporator units, fractionation column heaters, and glycol dehydrator reboilers. Typically, these combustion units are rated at less than 10 MMBtu/hr, which are exempted from permitting. Due to the availability of limited emissions data for units operating at natural gas production, compression and transmission facilities, the Department has established a NOx emission limit for natural gas-fired combustion units at 30 ppmvd corrected @ 3% oxygen. The Department will continue to evaluate NOx emissions data from these units.

2. CO Limit

The CO emission limit of 130 ppmvd corrected to 3% oxygen is consistent with the CO limit established in 40 CFR Part 63 Subpart DDDDD. Specifically, Table 1, Item 16 in Subpart DDDDD establishes for new or reconstructed boilers and process heaters the above-noted CO limit for "units designed to burn light liquid fuel." While this limit is specific to light liquid fuels, like No. 2 fuel oil, the Department proposed this limit for both No. 2 fuel oil and natural gas.

B. Natural Gas-Fired Simple Cycle Turbines

A simple cycle turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. A turbine is composed of three major components: the compressor, the combustor, and the power turbine. In the compressor section, ambient air is drawn in and compressed up to 30 times the ambient pressure and directed to the combustor section where fuel is injected, ignited, and burned. The resultant gases are diluted with additional air from the compressor section and are expanded through the power turbine section, which consists of a series of rotors and stators to extract mechanical work via a shaft. A portion of the generated shaft power is used to drive the internal compressor; the rest is directed to external load. At natural gas compression stations, natural gas processing facilities, and natural gas transmission stations, turbines are used mainly as prime movers to drive centrifugal compressors or generators.

1. *Emissions from Natural Gas-Fired Turbines*

Natural gas-fired turbines produce many of the same pollutants as SI-RICE which are emitted from the exhaust, depending on the composition of the fuel used. In addition, PM emissions are an issue for turbines due to the high exhaust flows. Since formaldehyde emissions from natural gas-fired turbines are on the order of 7.10×10^{-4} lb/MMBtu uncontrolled as per EPA's AP-42 Emissions Factors, a 30,000 hp simple cycle turbine may emit approximately 0.6 tpy. However, this size turbine is required to install an oxidation catalyst, which would also reduce formaldehyde by 85-90%. Therefore, the Department has not established a formaldehyde limit for simple cycle turbines. Natural gas is the primary fuel used by the natural gas industry and is the only fuel authorized by GP-5.

2. *Emission Control Technology*

Several technologies may be used to control emissions from turbines. They primarily fall into two categories: combustion control and post-combustion control.

a. Combustion Control

Control of combustion temperature has been the principal focus of combustion process control in turbines. 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.

Because the NO_X produced by combustion turbines is primarily thermal NO_X, reducing the combustion temperature will result in less NO_X production. Thus, the most common strategy for NO_X control is to control the combustion temperature. This is often done by using wet methods, such as steam or water injection, or dry methods, such as lean combustion or two-stage combustion.

i. Steam or Water Injection

Steam or water injection has been demonstrated to effectively suppress NO_X emissions from turbines. The effect of steam or water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. Steam or water 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% or more. Both CO and VOC emissions are increased by steam or water injection, and the level of increase will depend on the water-to-fuel weight ratio.

ii. Dry Controls

Since thermal NO_X is a function of both temperature and time, the basis of dry controls is to either lower the combustor temperature using lean mixtures of air and fuel, fuel staging, or decreasing the residence time of the combustor. A combination of these methods may also be used to reduce NO_X emissions.

Lean combustion involves increasing the A/F 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 also reduces residence time at peak temperatures.

Two-stage combustion can be broken down into lean/lean and rich/lean staging, which both serve to reduce NO_X. In lean/lean staging, the combustor is a fuel-staged premixed combustor that operates at an extremely lean A/F ratio. A small stoichiometric pilot flame ignites the premixed gas to provide flame stability. Because the NO_X emissions from the high temperature pilot flame are insignificant and the combustor is designed to operate at lower flame temperatures and to avoid localized "hot spots," low NO_X emission levels are achieved. In rich/lean staging, the combustor is an air-staged premixed combustor where the primary zone is operated fuel rich and the secondary zone is fuel lean. The fuel-rich zone operates at an A/F ratio less than one, which produces higher concentrations of CO and decreases the amount of NO_X due to a lack of available oxygen and lower flame temperatures. The exhaust from the primary zone is then quenched and mixed with large amounts of air, creating a lean mixture which is pre-ignited and introduced to the secondary zone where combustion is completed. The lower temperature and lean mixture results in low NO_X emission levels. Staged combustion is identified through a variety of names, including Dry-Low NO_X (DLN), Dry-Low Emissions (DLE), or $SoLoNO_X$.

b. <u>Post-Combustion Emission Reduction Technology for Turbines</u>

i. Oxidation Catalyst (for CO and NMNEHC reduction)

Oxidation catalysts using platinum and palladium are effective for lowering CO, NMNEHC, and formaldehyde levels in exhaust emissions from turbines. For this analysis, the Department has determined that an oxidation catalyst is economically feasible for turbines if the cost per ton of CO and NMNEHC removal is approximately $5,000; see Appendix C – Oxidation Catalyst and NSCR Cost Analysis for Engines and Turbines.

ii. Selective Catalytic Reduction (for NO_X reduction)

SCR is technically feasible on turbine exhaust streams, and the systems operate much like they do on engine exhaust streams. Urea or ammonia is typically used in SCR systems that control turbine NO_X emissions, which also results in ammonia emissions. For this analysis, the Department has determined that SCR is economically feasible for turbines if the cost per ton of NO_X removal is approximately $10,000; see Appendix B – SCR Cost Analysis for Engines and Turbines.

3. Turbine Size Grouping

The Department chose to slightly alter the turbine size groups for natural gas compression stations, natural gas processing plants, and natural gas transmission stations. In the previous GP-5, the turbines were placed into the following categories:

- Greater than or equal to 1,000 bhp but less than 5,000 bhp;
- Greater than or equal to 5,000 bhp but less than 15,000 bhp; and
- Greater than or equal to 15,000 bhp.

In the final GP-5, the turbines were placed into the following categories:

- Greater than or equal to 1,000 bhp but less than 5,000 bhp;
- Greater than or equal to 5,000 bhp but less than 15,900 bhp; and
- Greater than or equal to 15,900 bhp.

4. Turbine Emission Limits

New sources are required to control the emission of air pollutants to the maximum extent, consistent with BAT as determined by the Department. The Department evaluated uncontrolled emissions, control efficiency of various controls and associated costs, and stack test results for turbines to establish BAT. In the following sections, all references to the pollutant concentrations are given as ppm @ 15% O_2.

a. Turbines Rated Greater Than or Equal To 1,000 bhp but Less Than 5,000 bhp

Vendor data for turbines greater than or equal to 1,000 bhp but less than 5,000 bhp gave uncontrolled emission rates of 25 ppm NO_X, 25 ppm CO, and 25 ppm THC as methane. This was the basis of the BAT from the previous GP-5, and the THC emission rate was converted to NMNEHC as propane, establishing an emission rate of 9 ppm NMNEHC as propane.

SCR cost estimations were based on vendor quotes, cited as from Vendor A and Vendor B. It was assumed that the control efficiency for SCR is 90% for NO_X. All oxidation catalyst cost estimations were based on vendor data, with the costs quoted in 2007 dollars. The costs in the analysis were then multiplied by the CPI of 1.16 for inflating 2007 dollars to 2016 dollars. It was assumed that the control efficiencies for oxidation catalysts are 93% for CO and 50% for NMNEHC. See Appendix B – SCR Cost Analysis for Engines and Turbines and Appendix C – Oxidation Catalyst and NSCR Cost Analysis for Engines and Turbines for the analyses.

Using the uncontrolled and BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for turbines greater than or equal to 1,000 bhp but less than 5,000 bhp is estimated between $8,142 and $13,810 per ton of pollutants reduced. The Department determines that an oxidation catalyst is not economically feasible based on the cost-effectiveness benchmark of approximately $5,000 per ton of pollutant reduced. Therefore, BAT for turbines greater than or equal to 1,000 bhp but less than 5,000 bhp are emission limits of 25 ppm for CO and 9 ppm for NMNEHC as in the previously issued GP-5.

Using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for turbines greater than or equal to 1,000 bhp but less than 5,000 bhp is estimated between $11,622 and $18,853 per ton of NO_X reduced. The Department determines SCR is not BAT for turbines greater than or equal to 1,000 bhp but less than 5,000 bhp because it is not economically feasible based on a cost-effectiveness benchmark of $10,000 per ton of NO_X reduced and the emission limit remains 25 ppm for NO_X as in the previously issued GP-5.

b. Turbines Rated Greater Than or Equal To 5,000 bhp but Less Than 15,900 bhp

Vendor data for turbines greater than or equal to 5,000 bhp but less than 15,900 bhp gave uncontrolled emission rates of 25 ppm NO_X, 25 ppm CO, and 25 ppm THC as methane. This was the basis of the BAT from the previous GP-5 for CO and NMNEHC, and the THC emission rate was converted to NMNEHC as propane, establishing an emission rate of 9 ppm NMNEHC as propane. BAT for NO_X was established as 15 ppm based on stack test results.

Using the uncontrolled and BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for turbines greater than or equal to 5,000 bhp but less than 15,900 bhp is estimated between $4,836 and $6,612 per ton of pollutants reduced. However, according to stack test data, emission rates of 10 ppm CO and 5 ppm NMNEHC are achievable without control. Using the stack test emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for turbines greater than or equal to 5,000 bhp but less than 15,900 bhp is estimated between $11,082 and $15,153 per ton of pollutants reduced. Therefore, it is the Department's determination that turbines greater than 5,000 bhp but less than 15,900 bhp have BAT criteria with emission limits of 10.00 ppm for CO and 5.00 ppm for

NMNEHC whether attained through use of an oxidation catalyst or good combustion engineering practices.

Using the uncontrolled emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for turbines greater than or equal to 5,000 bhp but less than 15,900 bhp is estimated between $7,714 and $9,810 per ton of NO_X reduced. Using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for turbines greater than or equal to 5,000 bhp but less than 15,900 bhp is estimated between $12,858 and $16,351 per ton of NO_X reduced. Therefore, it is the Department's determination that turbines greater than 5,000 bhp but less than 15,900 bhp have BAT criteria with emission limits of 15.00 ppm for NO_X whether attained through use of an SCR or good combustion engineering practices.

c. Turbines Rated Greater Than or Equal To 15,900 bhp

Vendor data for turbines greater than or equal to 15,900 bhp gave uncontrolled emission rates of 25 ppm NO_X, 25 ppm CO, and 25 ppm THC as methane. This was the basis of establishing oxidation catalysts as BAT from the previous GP-5 for CO and NMNEHC, and the THC emission rate was converted to NMNEHC as propane, establishing an emission rate of 9 ppm NMNEHC as propane. An alternative BAT of 10 ppm CO and 5 ppm NMNEHC based on stack test results was offered in the previous GP-5. BAT for NO_X was established as 15 ppm also based on stack test results.

Using the uncontrolled emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for turbines greater than or equal to 15,900 bhp is estimated between $3,576 and $4,321 per ton of pollutants reduced. Using the alternative BAT emission rates, the assumed control efficiencies, and assuming a full year of operation, the control cost for an oxidation catalyst for turbines greater than or equal to 15, 900 bhp is estimated between $8,243 and $9,903 per ton of pollutants reduced. Therefore, it is the Department's determination that turbines greater than 15,900 bhp have dual BAT criteria with emission limits of 10.00 ppm for CO uncontrolled or 1.75 ppm for CO through use of an oxidation catalyst. It is the Department's determination that turbines greater than 15,900 bhp have BAT criteria with emission limits of 5.00 ppm for NMNEHC whether attained through use of an oxidation catalyst or good combustion engineering practices.

Using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for turbines greater than or equal to 15,900 bhp is estimated to be less than $11,466 per ton of NO_X reduced. The Department determines SCR is BAT for turbines greater than or equal to 15,900 bhp. However, recently issued permits and plan approval applications show turbines greater than or equal to 15,900 bhp are capable of achieving 9.0 ppm for NO_X uncontrolled. Using the 9.0 ppm emission rate, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for turbines greater than or equal to 15,900 bhp is estimated to be between $16,946 and $19,106 per ton of NO_X reduced.

Most SCR vendors guarantee NO_X emissions reduction of 90% or more and therefore, with an uncontrolled baseline NOx emission rate of 15 ppmvd corrected to 15% oxygen, which is established as achievable, the Department proposed a NO_X emission limit of 1.5 ppmvd @ 15% O_2. The Department has permitted several turbines equipped with SCR with emission limits of 2 to 2.5 ppmvd NO_X @ 15% O_2. The stack test results for these turbines show NOx emissions range from 1.6 to 1.8 ppmvd. Therefore, the Department has determined that 2.0 ppmvd NO_X @ 15% O_2 is BAT in the final GP-5 for turbines rated greater than or equal to 15, 900 hp.

Therefore, it is the Department's determination that turbines greater than or equal to 15,900 bhp have dual BAT criteria with emission limits of 9.00 ppmvd for NO_X uncontrolled and 2.0 ppmvd for NO_X through use of SCR.

Table 13 - BAT Emission Limits for Existing Turbines

Turbine Rating (bhp)	NO_X (ppmvd @ 15% O_2)	CO (ppmvd @ 15% O_2)	NMNEHC (as propane) (ppmvd @ 15% O_2)	Total PM (lbs/MMBtu)
1,000 ≤ TR < 5,000	25	25	9.0	0.03
5,000 ≤ TR < 15,000	15	25	9.0	0.03
≥ 15,000	15	10. **or** 93% reduction	5.0 **or** 50% reduction	0.03

Table 14 - Proposed BAT Emission Limits for New Turbines

Turbine Rating (bhp)	NO_X (ppmvd @ 15% O_2)	CO (ppmvd @ 15% O_2)	NMNEHC (as propane) (ppmvd @ 15% O_2)	Total PM (lbs/MMBtu)
1,000 ≤ TR < 5,000	25	25	9.0	0.03
5,000 ≤ TR < 15,900	15	10.	5.0	0.03
≥ 15,900	9.0 Uncontrolled or 2.0 with Control	10. Uncontrolled or 1.8 with Control	5.0	0.03

In addition, the turbines shall comply with all applicable requirements specified in 40 CFR Part 60, Subpart KKKK.

However, for all previous versions of the GP-5, the Department's BAT requirements are more stringent than those required under Subpart KKKK. Therefore, by complying with the Department's BAT requirements, the owner or operator of a turbine will be guaranteed compliant with the applicable requirements of 40 CFR Part 60 Subpart KKKK.

Visible emissions shall not meet or exceed 10% opacity for a period or periods aggregating more than three minutes in any one hour nor meet or exceed 30% opacity at any time.

Based on the comments received, the Department added a provision that the owner or operator shall also operate the turbine and air pollution control equipment consistent with good air pollution control practices during periods of low ambient air temperature (at or below 0 °F) during which times the emission standards do not apply. This is consistent with the requirements of 40 CFR Part 60 Subpart KKKK.

5. Turbine Core Replacement

A turbine core must be done in accordance with the terms and conditions of the GP-5; these terms and conditions are consistent with turbine core replacement requirements established for landfill gas-fired turbines in GP-22.

C. Centrifugal Natural Gas Compressors

Like reciprocating natural gas compressors, centrifugal natural gas compressors are used to increase the pressure of natural gas in a pipeline in order to take advantage of the property of fluids moving from high-pressure to low-pressure areas. In a centrifugal compressor, however, rotary motion from the prime mover is used to drive an impeller that imparts energy into the gas which serves to increase its pressure. There can be multiple stages of impellers that can generate a large change in pressure.

Like the reciprocating natural gas compressor, the centrifugal compressor has a shaft that must be sealed to reduce wear and maintain gas pressure. These seals can be either dry or wet; the wet seal uses an oil film in its operation. However, the oil used in a wet seal system collects natural gas, which must be removed in order to maintain the seal effectiveness.

It is not typical for centrifugal compressors to be installed at an unconventional natural gas well site. According to 40 CFR Part 60, Subparts OOOO and OOOOa, centrifugal compressors located at well sites are not affected facilities. The Department is therefore not proposing to authorize centrifugal compressors at unconventional well sites or remote pigging stations through the GP-5A; centrifugal compressors at natural gas compression stations, processing plants, and transmission stations are authorized in the GP-5.

1. Existing Centrifugal Natural Gas Compressors

The owner or operator of an existing wet seal centrifugal natural gas compressor shall continue to comply with the 95% control and other applicable requirements specified in 40 CFR Part 60, Subpart OOOO, which are incorporated by reference in the GP-5.

2. New Centrifugal Natural Gas Compressors

40 CFR Part 60, Subpart OOOOa requires centrifugal compressor to be equipped with dry seal or wet seal where methane and VOC emissions from the wet seal degassing system is reduced by 95% or more. Based on the Department’s evaluation, no additional requirements are needed. Therefore, the Department determines that the recently promulgated requirements of 40 CFR Part 60, Subpart OOOOa are determined to be BAT.

D. Natural Gas Fractionation Process Units

Condensates, or NGLs, are an important product of natural gas production. In much of the production segment, the condensates are separated from the natural gas stream and stored in tanks before eventually being shipped to a processing plant via truck. However, condensates are still part of the natural gas stream and may fall out during transport in a pipeline. The fluid buildup can cause flow problems, which are typically cleaned through a pigging operation. In this case, the NGLs can be sent to a tank called a slug catcher which may be located at a compression station or processing plant. The liquids at a compression station are also commonly transported via a truck.

Natural gas fractionation is the process of separating the various hydrocarbons in NGLs by extracting them in sequence in heated columns. Any methane, which is the lightest of the hydrocarbons, remaining in the condensate is separated first, and put into the pipeline for transmission and storage. Then ethane, propane, and butane are removed in turn and sent to their respective storage tanks; butane may be further divided into isobutane and n-butane. The heavier NGLs are called natural gasoline and will typically be sent to another plant for further refinement.

Potential emissions from natural gas fractionation units are from the process heaters and the fugitive emissions associated with piping, valves, flanges, pumps, compressors, and pressure relief devices. Process heaters for fractionation columns eligible for authorization under the GP-5 range in size up to 50 MMBtu/h. Combustion units rated less than 2.5 MMBtu/h are exempt from plan approval by 25 Pa. Code §127.14(a). Under Category 39 of the Air Quality Permit Exemptions document, combustion units rated less than 10 MMBtu/h firing natural gas supplied by an independent producer shall be given the same consideration given to similarly sized sources that fire natural gas provided by a public utility. Even though the process heaters described are exempt, these sources will be listed in the permit for reference purposes. However, emissions from these exempt units must be included in the facility emissions totals for tracking compliance with the General Requirements (i.e., the 12-month rolling sum must remain below the major source emissions thresholds) and in the annual emissions inventory.

Natural gas processing, which includes fractionation, is subject to federal requirements under 40 CFR Part 60, Subpart KKK for units which were constructed, reconstructed, or modified after January 20, 1984, and on or before August 23, 2011. After August 23, 2011, and on or before September 18, 2015, fractionation process units are subject to the requirements of 40 CFR Part 60, Subpart OOOO. After September 18, 2015, fractionation process units are subject to the requirements of 40 CFR Part 60, Subpart OOOOa. In all cases, the primary standards are monitoring for equipment leaks using 40 CFR Part 60, Appendix A-7, Method 21.

Because potential emission sources associated with natural gas fractionation are addressed individually, i.e. in the sections related to combustion units and fugitive emissions components, a separate section for natural gas fractionation units was not incorporated into the final General Permit.

E. Sweetening Units

Natural gas from some wells contains sulfur and carbon dioxide, which must be removed to protect personnel, the environment, and equipment. Sulfur typically exists in natural gas in the form of hydrogen sulfide (H_2S), and natural gas where the H_2S content exceeds 4 ppm is referred to as sour gas. The process for removing H_2S from sour gas is called sweetening the gas.

The primary process for sweetening sour gas is similar to the process of glycol dehydration. An amine solution is used to remove the H_2S by passing the sour gas through a tower where it contacts the solution and is absorbed. There are two primary amine solutions used, monoethanolamine (MEA) and diethanolamine (DEA). Either of these compounds, in liquid form, will absorb sulfur compounds and CO_2 from the sour gas leaving the effluent gas virtually free of these contaminants. Both MEA and DEA can be regenerated and the resultant gases can be used to feed a Claus process, which involves using thermal and catalytic reactions to extract elemental sulfur from the hydrogen sulfide solution.[27]

Potential emissions from sweetening units are from the process heaters; the fugitive emissions associated piping, valves, flanges, pumps, compressors, and pressure relief devices; and the tail gas of

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[27] NaturalGas.org, last accessed on May 24, 2018.

the Claus process. Process heaters for sweetening units are eligible for authorization under the GP-5 up to 50 MMBtu/h in size. Combustion units rated less than 2.5 MMBtu/h are exempt from plan approval by 25 Pa. Code §127.14(a). Under Category 39 of the Air Quality Permit Exemptions document, combustion units rated less than 10 MMBtu/h firing natural gas supplied by an independent producer shall be given the same consideration given to similarly sized sources that fire natural gas provided by a public utility. Even though the described process heaters are exempt, these sources will be listed in the permit for reference purposes. However, emissions from these exempt units must be included in the facility emissions totals for tracking compliance with the General Requirements (i.e., the 12-month rolling sum must remain below the major source emissions thresholds) and in the annual emissions inventory.

Sweetening units are subject to federal requirements under 40 CFR Part 60, Subpart LLL for units which were constructed, reconstructed, or modified after January 20, 1984, and on or before August 23, 2011. After August 23, 2011, and on or before September 18, 2015, sweetening units are subject to the requirements of 40 CFR Part 60, Subpart OOOO. After September 18, 2015, sweetening units are subject to the requirements of 40 CFR Part 60, Subpart OOOOa. The standards are for a target control efficiency for SO_2 emissions based on sulfur production.

Because the Authorization to Use the GP-5 and GP-5A cannot be granted to facilities that produce or process sour gas as shown in the basic calculations in the section on Oxides of Sulfur in General Methodology of Determining Best Available Technology, the SO_2 emissions limits from the federal regulations were not included in the General Permits. Should a sweetening unit be needed to remove excess CO_2, the potential emissions sources from the sweetening unit are addressed individually, i.e., in the sections on combustion units and fugitive emissions components, and therefore a separate section on sweetening units was not incorporated into the General Permits.

XXII. Appendix A – Average Gas Composition Analysis

Table 15 - Methane de Minimis Calculations

	Average Gas Composition	Donald R. Bowser #1M-207	Roundwood Wyo	Martin Sanders 1M	Liberty	Kenneth L. Crosby #1M-69	Petraitis	Boyanowski Wyo	Jack Wyo	Lopatofsky Wyo	Fanclaire Wyo	Susan Sus	Delhagen Sus
Methane	88.78%	63.08%	93.85%	83.21%	93.51%	70.94%	91.37%	93.90%	94.52%	95.41%	94.32%	95.49%	95.72%
Ethane	5.93%	7.91%	4.94%	4.98%	4.48%	17.15%	6.69%	4.77%	4.44%	3.86%	4.58%	3.71%	3.60%
Propane	0.88%	1.53%	0.36%	0.55%	0.36%	5.64%	0.73%	0.34%	0.26%	0.18%	0.31%	0.17%	0.15%
Butane (iso- and n-)	0.27%	0.44%	0.05%	0.03%	0.05%	2.30%	0.13%	0.07%	0.04%	0.01%	0.05%	0.01%	0.01%
Pentane (iso- and n-)	0.05%	0.09%	0.00%	0.00%	0.00%	0.49%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Hexane and above	0.05%	0.00%	0.00%	0.00%	0.00%	0.62%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Carbon Dioxide	0.21%	0.16%	0.05%	0.30%	0.75%	0.17%	0.66%	0.06%	0.05%	0.06%	0.05%	0.07%	0.10%
Molecular Nitrogen	3.85%	26.78%	0.74%	10.93%	0.41%	3.32%	0.41%	0.83%	0.69%	0.48%	0.65%	0.54%	0.42%
Sum of Parts	100.01%	99.99%	99.99%	100.00%	99.56%	100.63%	100.03%	99.97%	100.00%	100.00%	99.96%	99.99%	100.00%
VOC (sum of propane and above)	1.25%	2.06%	0.41%	0.58%	0.41%	9.05%	0.90%	0.41%	0.30%	0.19%	0.36%	0.18%	0.16%
VOC de minimis (TPY)	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Methane de minimis (TPY)	191.6	82.7	618.0	387.4	615.8	21.2	274.1	618.4	850.7	1,355.8	707.4	1,432.4	1,615.3
Average of Columns (C through N) Methane de minimis (TPY)					714.9								

The general methodology for determining the methane control threshold is to calculate the amount of methane in a natural gas release relative to the amount of VOC that reaches the VOC control threshold using a standard mass-balance calculation. Using twelve different gas samples, the methane control thresholds ranged from a minimum of 21.2 tpy to a maximum of 1,615.3 tpy. The average of the twelve calculated control thresholds is 714.9 tpy, which is 17,872 tpy of CO_{2e}. This value is nearly 25% of the 75,000 tpy CO_{2e} major modification facility threshold for greenhouse gases.

Therefore, the Department calculated an average gas composition from the twelve samples and followed the same methodology for determining the methane control threshold with a result of 191.6 tpy. The Department conservatively used 200 tpy methane to account for the scientific uncertainty due to the limited number of gas samples used in the calculation, which is equivalent to 5,000 tpy CO_{2e}. This is approximately 7% of the facility greenhouse gas threshold and is much more reasonable to use as the methane control threshold.

However, several commentators stated that the Department's calculated average gas composition was not representative of natural gas in Pennsylvania because of its small sample size and limited geographic scope. To improve the average gas composition calculation, the Department decided to expand the scope of the analysis. For every county with wells displayed on eMapPA, the Department attempted to obtain at least five reasonable representative gas analyses, two from compressor stations or processing plants, and three from unconventional natural gas well sites. The sample included 59 representative gas analyses across all of the regions with oil and gas activity including the Southwest, Northwest, North Central, and Northeast Regions of Pennsylvania. The Department then calculated a county average gas composition for each county, and a state average gas composition by averaging the county average gas compositions. Therefore, the Department reduced the scope of scientific uncertainty based on geographic location.

Table 16 - Average Gas Composition Data

County	Allegheny	Armstrong	Beaver	Bradford	Butler	Cambria	Clarion	Crawford	Fayette	Greene	Indiana	Lawrence	Lycoming	Mercer	Somerset	Sullivan	Susquehanna	Tioga	Washington	Westmoreland	Wyoming	Appendix A Table 11 of the TSD	Appendix A Table 11 of the TSD Discarding Bowers and Sanders	New Analysis
	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%
Methane	92.65%	83.91%	79.23%	94.06%	81.42%	87.18%	76.96%	88.62%	93.18%	91.51%	95.15%	75.50%	95.14%	54.26%	95.60%	94.46%	95.22%	94.71%	67.26%	93.29%	94.92%	88.78%	91.90%	86.03%
Ethane	6.18%	10.13%	11.39%	4.79%	11.58%	3.71%	12.29%	5.04%	4.21%	6.38%	2.93%	15.37%	4.07%	19.53%	2.81%	4.60%	3.87%	4.40%	17.08%	4.42%	4.13%	5.93%	5.82%	7.93%
Propane	0.41%	2.46%	4.56%	0.34%	3.40%	0.54%	4.79%	1.05%	0.60%	0.68%	0.24%	4.88%	0.24%	11.89%	0.14%	0.32%	0.19%	0.25%	8.09%	0.53%	0.23%	0.88%	0.85%	2.42%
Butane (iso- and n-)	0.08%	0.92%	2.20%	0.05%	1.42%	0.19%	2.43%	0.54%	0.28%	0.13%	0.08%	2.25%	0.03%	7.33%	0.04%	0.08%	0.02%	0.02%	4.14%	0.20%	0.02%	0.27%	0.27%	1.21%
Pentane (iso- and n-)	0.00%	0.24%	0.80%	0.01%	0.44%	0.00%	1.05%	0.48%	0.13%	0.02%	0.01%	0.50%	0.00%	3.24%	0.00%	0.00%	0.00%	0.00%	1.82%	0.06%	0.00%	0.05%	0.05%	0.48%
Hexane and above	0.00%	0.28%	0.50%	0.00%	0.21%	0.02%	1.30%	0.21%	0.17%	0.01%	0.05%	0.39%	0.01%	2.78%	0.00%	0.00%	0.00%	0.00%	0.61%	0.10%	0.00%	0.05%	0.06%	0.36%
Carbon Dioxide	0.19%	0.26%	0.65%	0.08%	1.21%	7.48%	0.09%	0.00%	0.63%	0.82%	0.57%	0.65%	0.04%	0.27%	0.74%	0.05%	0.14%	0.15%	0.37%	0.56%	0.05%	0.21%	0.20%	0.72%
Molecular Nitrogen	0.49%	1.80%	0.66%	0.65%	0.32%	0.87%	1.01%	4.05%	0.80%	0.46%	0.94%	0.46%	0.46%	0.70%	0.65%	0.49%	0.55%	0.45%	0.58%	0.82%	0.62%	3.85%	0.85%	0.85%
Molecular Oxygen	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.07%	0.00%	0.00%	0.00%	0.02%	0.00%	0.00%	0.00%	0.02%	0.00%	0.00%	0.01%	0.03%	0.02%	0.02%	0.00%	0.00%	0.01%
Benzene	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Toluene	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%
Ethylbenzene	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Xylene	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Sum of Parts	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.01%	100.01%	100.00%
VOC (sum of propane and above)	0.49%	3.90%	8.06%	0.41%	5.47%	0.76%	9.57%	2.29%	1.17%	0.84%	0.38%	8.02%	0.28%	25.25%	0.18%	0.41%	0.22%	0.28%	14.67%	0.89%	0.25%	1.25%	1.24%	4.47%
VOC de minimis (TPY)	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Methane de minimis (TPY)	506.8	58.0	26.5	616.3	40.2	310.3	21.7	104.4	214.5	295.0	667.9	25.4	907.0	5.8	1,474.8	629.5	1,189.3	924.9	12.4	282.2	1,012.1	191.6	200.6	51.9
Density of Gas (lb/lb-mol)	16.63	17.41	18.13	16.51	17.81	17.31	18.42	17.01	16.63	16.75	16.44	18.48	16.42	22.05	16.40	16.48	16.41	16.46	19.69	16.60	16.43	16.95	16.71	17.36
Density of Gas (lb/cf)	0.0423	0.0443	0.0461	0.0420	0.0453	0.0441	0.0469	0.0433	0.0423	0.0426	0.0418	0.0470	0.0418	0.0561	0.0417	0.0419	0.0418	0.0419	0.0501	0.0422	0.0418	0.0431	0.0425	0.0442
Average of per County Methane De Minimis					444.0																			

The average composition for the counties with at least one representative gas analysis and the calculated state average gas composition are shown in Table 16. The Department believes that this state average gas composition is representative of the regions where oil and gas operations are occurring. The same process was followed as in the previous analysis, where methane emissions were calculated based on a standard mass-balance and the VOC control threshold of 2.7 tpy for each county. The methane control thresholds ranged from 5.8 tpy for Mercer County and 1,474.8 tpy for Somerset County with an average methane control threshold of 444.0 tpy. While this value is lower than the 714.9 tpy value of the previous analysis, the Department determined that it is unreasonable to be used as a control threshold; this is because it is approximately 15% of the major modification facility threshold for GHG. For the calculated state average composition, the methane control threshold is calculated at 51.9 tpy; this is lower than in the previous calculation because there were more representative gas analyses with VOC weight percentages higher than 2%.

In the first analysis, there were only two samples with VOC weight percentages over 2% and one of them was questionable due to the high nitrogen content; this means only 10% - 17% of the samples had a VOC weight percentage over 2%. In the second analyses, approximately 25% of the samples had VOC weight percentages over 2%; half of those samples had VOC weight percentages over 5% and one had a VOC weight percentage over 25%. This higher VOC weight percentage had the effect of lowering the methane emissions calculated from the mass-balance and increasing the VOC weight percentage of the state average gas composition from 1.25% in the first analysis to 4.47% in the second analysis. The 51.9 tpy methane control threshold calculated from the state average gas composition is approximately 2% of the major modification facility threshold for GHG meaning it is appropriate to use it as a control threshold in the permit. However, as is shown in the analysis in Appendix D for Combustion Control Devices, control of methane at 51.9 tpy is not cost-effective.

XXIII. Appendix B – SCR Cost Analysis for Engines and Turbines

Table 17 - SCR Cost Analysis for 1,380 hp Engine

(All dollar values in 2016 dollars)	Vendor A @ 0.50 g/bhp-h (2016 Quote)	Vendor B @ 0.50 g/bhp-h (2016 Quote)	Vendor C @ 0.50 g/bhp-h (2016 Quote)	Vendor A @ 0.35 g/bhp-h (2016 Quote)	Vendor B @ 0.35 g/bhp-h (2016 Quote)	Vendor C @ 0.35 g/bhp-h (2016 Quote)
SCR Purchased Equipment Costs	$107,000	$150,000		$107,000	$150,000	
Reductant Tank Purchased Equipment Costs	$11,000	$30,000		$11,000	$30,000	
Total Purchased Equipment Costs	$118,000	$180,000	$146,000	$118,000	$180,000	$146,000
Freight	$5,900	$9,000	$7,300	$5,900	$9,000	$7,300
Commissioning Costs	$0	$0	$11,500	$0	$0	$11,500
Total Indirect Installation Costs	$23,600	$36,000	$29,200	$23,600	$36,000	$29,200
Project Contingency	$21,240	$32,400	$26,280	$21,240	$32,400	$26,280
Total Plant Cost	$168,740	$257,400	$220,280	$168,740	$257,400	$220,280
Preproduction Cost	$3,375	$5,148	$4,406	$3,375	$5,148	$4,406
Inventory Capital - Initial Fill of Reductant	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500
Total Capital Investment	$174,615	$265,048	$227,186	$174,615	$265,048	$227,186
Operating and Supervisory Labor Costs	$886	$886	$6,716	$886	$886	$6,716
Maintenance Cost	$2,619	$3,347	$3,408	$2,619	$3,347	$3,408
Reductant Consumption Cost	$18,540	$18,540	$24,090	$18,540	$18,540	$24,090
Annual Electricity Cost	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000
Annual Catalyst Replacement Cost	$11,525	$11,525	$22,500	$11,525	$11,525	$22,500
Direct Annual Costs	$38,570	$39,297	$61,714	$38,570	$39,297	$61,714
Indirect Annual Costs	$16,482	$25,019	$21,445	$16,482	$25,019	$21,445
Total Annual Costs	$55,052	$64,316	$83,158	$55,052	$64,316	$83,158
TPY of NO_X Emissions Reduced	5.99	5.99	5.99	4.19	4.19	4.19
Cost Per Ton	$9,189	$10,735	$13,880	$13,127	$15,336	$19,829

Table 18 - SCR Cost Analysis for 4,735 hp Engine

(All dollar values in 2016 dollars)	Vendor A @ 0.50 g/bhp-h (2016 Quote)	Vendor B @ 0.50 g/bhp-h (2016 Quote)	Vendor A @ 0.35 g/bhp-h (2016 Quote)	Vendor B @ 0.35 g/bhp-h (2016 Quote)
SCR Purchased Equipment Costs	$105,000	$225,000	$105,000	$225,000
Reductant Tank Purchased Equipment Costs	$20,000	$50,000	$20,000	$50,000
Total Purchased Equipment Costs	$125,000	$275,000	$125,000	$275,000
Freight	$6,250	$13,750	$6,250	$13,750
Commissioning Costs	$0	$0	$0	$0
Total Indirect Installation Costs	$25,000	$55,000	$25,000	$55,000
Project Contingency	$22,500	$49,500	$22,500	$49,500
Total Plant Cost	$178,750	$393,250	$178,750	$393,250
Preproduction Cost	$3,575	$7,865	$3,575	$7,865
Inventory Capital - Initial Fill of Reductant	$2,172	$2,172	$2,172	$2,172
Total Capital Investment	$184,497	$403,287	$184,497	$403,287
Operating and Supervisory Labor Costs	$1,771	$1,771	$1,771	$1,771
Maintenance Cost	$2,767	$6,694	$2,767	$6,694
Reductant Consumption Cost	$37,080	$37,080	$37,080	$37,080
Annual Electricity Cost	$5,000	$5,000	$5,000	$5,000
Annual Catalyst Replacement Cost	$23,050	$23,050	$23,050	$23,050
Direct Annual Costs	$69,668	$73,595	$69,668	$73,595
Indirect Annual Costs	$17,415	$38,067	$17,415	$38,067
Total Annual Costs	$87,083	$111,662	$87,083	$111,662
TPY of NO_X Emissions Reduced	20.56	20.56	14.39	14.39
Cost Per Ton	$4,236	$5,432	$6,052	$7,760

Table 19 - SCR Cost Analysis for Turbines

(All dollar values in 2016 dollars)	Vendor A 1,590 HP 25 ppm NO_X (2016 Quote)	Vendor A 30,000 HP 25 ppm NO_X (2016 Quote)	Vendor B 30,000 HP 25 ppm NO_X (2016 Quote)	Vendor A 30,000 HP 15 ppm NO_X (2016 Quote)	Vendor B 30,000 HP 15 ppm NO_X (2016 Quote)	Vendor A 30,000 HP 9 ppm NO_X (2016 Quote)	Vendor B 30,000 HP 9 ppm NO_X (2016 Quote)
SCR Purchased Equipment Costs	$514,600	$932,800	$2,000,000	$932,800	$2,000,000	$932,800	$2,000,000
Reductant Tank Purchased Equipment Costs	$15,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000
Total Purchased Equipment Costs	$529,600	$992,800	$2,060,000	$992,800	$2,060,000	$992,800	$2,060,000
Freight	$26,480	$49,640	$103,000	$49,640	$103,000	$49,640	$103,000
Commissioning Costs	$0	$0	$0	$0	$0	$0	$0
Total Indirect Installation Costs	$105,920	$198,560	$412,000	$198,560	$412,000	$198,560	$412,000
Project Contingency	$95,328	$178,704	$370,800	$178,704	$370,800	$178,704	$370,800
Total Plant Cost	$730,848	$1,419,704	$2,945,800	$1,419,704	$2,945,800	$1,419,704	$2,945,800
Preproduction Cost	$14,617	$28,394	$58,916	$28,394	$58,916	$28,394	$58,916
Inventory Capital - Initial Fill of Reductant	$203	$1,408	$1,408	$1,408	$1,408	$1,408	$1,408
Total Capital Investment	$745,668	$1,449,506	$3,006,124	$1,449,506	$3,006,124	$1,449,506	$3,006,124
Operating and Supervisory Labor Costs	$6,716	$6,716	$6,716	$6,716	$6,716	$6,716	$6,716
Maintenance Cost	$11,185	$21,743	$45,092	$21,743	$45,092	$21,743	$45,092
Reductant Consumption Cost	$2,467	$17,150	$17,150	$17,150	$17,150	$17,150	$17,150
Annual Electricity Cost	$1,545	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501
Annual Catalyst Replacement Cost	$20,741	$138,216	$138,216	$138,216	$138,216	$138,216	$138,216
Direct Annual Costs	$42,654	$201,326	$224,675	$201,326	$224,675	$201,326	$224,675
Indirect Annual Costs	$70,386	$136,823	$283,757	$136,823	$283,757	$136,823	$283,757
Total Annual Costs	$113,040	$338,149	$508,432	$338,149	$508,432	$338,149	$508,432
TPY of NO_X Emissions Reduced	6.00	69.38	69.38	41.62	41.62	24.98	24.98
Cost Per Ton	$18,853	$4,874	$7,329	$8,124	$12,215	$13,538	$20,355

Because the quotes furnished to the Department by the vendors were determined based on the assumption of 8,760 hours of operation, the Department proposes to determine cost effectiveness of the control of NO_X with an SCR system without regard to variability of hours of operation.

The Department proposed to use the average of the total annual costs for each engine size as determined in Table 17 and Table 18 above as a point on a line to determine the cost effectiveness of SCR for sizes for which a quote was not obtained. The reason for using the average total annual cost versus the average cost in dollars per ton is that the emission limit for NO_X emissions for engines rated equal to or less than 500 hp is 1.0 g/bhp-h while for engines rate greater than 500 hp the emission limit for NO_X is 0.5 g/bhp-h. This difference in emission limits would not be reflected using the average cost in dollars per ton, as can be seen in Table 20 below.

Table 20 - Calculated Cost per Ton NO_X Reduced vs Average Cost per Ton NO_X Reduced for Engines

Engine HP (All dollar values in 2016 dollars)	100	250	500	1,000	1,380	1,500	1,875	2,500	3,000	4,735	5,500
Average Total Annual Costs	$54,650	$56,097	$58,509	$63,334	$67,000	$68,158	$71,777	$77,807	$82,632	$99,373	$106,754
TPY of NO_X Emissions Reduced	0.87	2.17	4.34	4.34	5.99	6.51	8.14	10.85	13.02	20.56	23.88
Cost Per Ton	$62,940	$25,843	$13,477	$14,588	$11,183	$10,466	$8,818	$7,169	$6,344	$4,834	$4,471
Average Cost Per Ton	$13,603	$13,320	$12,847	$11,901	$11,182	$10,955	$10,245	$9,063	$8,117	$4,834	$3,387
TPY of NO_X Emissions Reduced, Alternative BAT							5.70	7.60	9.12	14.39	16.71
Alternative Cost Per Ton							$12,597	$10,241	$9,064	$6,906	$6,387

The Department proposed that installing an SCR system on lean-burn engines rated at or above 1,875 hp is BAT if the uncontrolled emission rate is 0.50 g/bhp-h, resulting in an emission limit of 0.05 g/bhp-h. However, engine stack test data shows that engines in this size range are capable of achieving an uncontrolled emissions rate of 0.35 g/bhp-h. As can be seen in Table 20 above, SCR is not economically feasible for an engine with uncontrolled emissions rate of 0.35 g/bhp-h until an engine is rated at or above 3,000 hp. Therefore, the Department proposed dual BAT criteria for lean-burn engines rated at or above 1,875 hp and less than 3,000 hp of 0.35 g/bhp-h uncontrolled or 0.05 g/bhp-h with control. The Department proposed a BAT criterion for lean-burn engines rated at or above 3,000 hp of 0.05 g/bhp-h.

Based on additional information submitted and comments received, the Department determined that the installation of SCR should be reevaluated for cost effectiveness. One of the issues raised is that the original BAT cost estimates did not include direct installation costs. Even though the EPA's Air Pollution Control Cost Manual 6th Edition Section 4.2 did not include direct installation costs in Table 2.5, and the 7th Edition Section 4.2 calculates the TCI based on operational parameters, the Department used vendor quotes and the standard cost estimate method from Section 1 of the 6th Edition to calculate cost effectiveness. There appears to be little difference in the method in Section 1 of the 7th Edition except for the use of the bank prime rate of 4.25% for the annualization of capital costs. The Department continues to use the 7% rate from the previous analysis for consistency.

Table 21 - Revised SCR Cost Analyses

(All dollar values in 2016 dollars)[A]	Vendor A 1,380 hp @ 0.50 g/bhp-h	Vendor B 1,380 hp @ 0.50 g/bhp-h	GCA Vendor C[1,2] 1,380 hp @ 0.50 g/bhp-h	Vendor C 1,380 hp @ 0.50 g/bhp-h	Vendor A 1,380 hp @ 0.35 g/bhp-h	Vendor B 1,380 hp @ 0.35 g/bhp-h	Vendor C 1,380 hp @ 0.35 g/bhp-h	Cardinal[1,2,3] 1,775 hp @ 0.50 g/bhp-h	Cardinal 1,775 hp @ 0.50 g/bhp-h	GCA[1,2] 1,775 hp @ 0.50 g/bhp-h	GCA 1,775 hp @ 0.50 g/bhp-h	Vendor A 4,735 hp @ 0.50 g/bhp-h	Vendor B 4,735 hp @ 0.50 g/bhp-h	GCA[4] 4,735 hp @ 0.50 g/bhp-h	GCA 4,735 hp @ 0.50 g/bhp-h
SCR System	$107,000	$150,000	$146,000	$146,000	$107,000	$150,000	$146,000	$152,484	$152,484	$130,000	$130,000	$105,000	$225,000	$495,685	$495,685
Reductant Tank and Other Auxiliary Equipment	$11,000	$30,000	$0	$0	$11,000	$30,000	$0	$37,043	$37,043	$0	$0	$20,000	$50,000	$58,257	$58,257
Customer Supplied Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Instrumentation	$0	$0	$14,600	$0	$0	$0	$0	$16,110	$0	$13,000	$0	$0	$0	$0	$0
Initial Fill of Reductant	$711	$711	$2,500	$3,960	$498	$498	$3,960	$5,000	$5,000	$2,500	$3,600	$2,440	$2,440	$9,750	$3,024
Freight	$5,936	$9,036	$7,300	$7,498	$5,925	$9,025	$7,498	$10,532	$9,726	$6,500	$6,680	$6,372	$13,872	$13,750	$27,848
Total Purchased Equipment Costs	$124,647	$189,747	$170,400	$157,458	$124,423	$189,523	$157,458	$221,169	$204,253	$152,000	$140,280	$133,812	$291,312	**$577,442**	$584,814
Total Direct Installation Costs	$162,041	$246,671	$131,400	$204,695	$161,750	$246,380	$204,695	$144,989	$265,529	$117,000	$182,364	$173,956	$378,706	$0	$760,259
Commissioning Costs	$0	$0	$11,500	$11,500	$0	$0	$11,500	$100,000	$100,000	$11,500	$11,500	$0	$0	$0	$0
Total Indirect Installation Costs	$38,640	$58,821	$58,878	$48,812	$38,571	$58,752	$48,812	$113,030	$63,319	$52,450	$43,487	$41,482	$90,307	$463,072	$181,292
Total Capital Investment	$200,681	$305,492	$372,178	$265,007	$200,321	$305,132	$265,007	$548,284	$428,848	$332,950	$237,351	$215,437	$469,012	$1,040,514	$941,551
Operating and Supervisory Labor Costs	$5,009	$2,362	$65,000	$5,009	$5,009	$2,362	$5,009	$62,400	$5,009	$65,000	$5,009	$5,009	$4,723	$21,000	$5,009
Maintenance Cost	$9,583	$3,347	$3,722	$9,583	$9,583	$3,347	$9,583	$8,224	$9,583	$3,330	$9,583	$9,583	$6,694	$37,500	$9,583
Reductant Consumption Cost	$4,326	$18,540	$24,090	$24,090	$3,028	$18,540	$24,090	$8,760	$8,760	$24,090	$21,900	$14,843	$37,080	$18,396	$14,843
Annual Electricity Cost	$3,524	$3,524	$5,000	$3,524	$3,524	$3,524	$3,524	$5,807	$3,993	$5,000	$3,993	$10,551	$10,551	$5,000	$10,551
Annual Catalyst Replacement Cost	$14,248	$11,614	$22,500	$14,248	$14,023	$11,614	$14,023	$20,000	$8,078	$18,000	$14,827	$22,371	$23,227	$47,388	$22,371
Direct Annual Costs	$36,690	$39,387	$120,312	$56,454	$35,167	$39,387	$56,229	$105,191	$35,423	$115,420	$55,312	$62,357	$82,275	$129,284	$62,357
Overhead	$11,351	$14,549	$0	$23,209	$10,572	$14,549	$23,209	$0	$14,011	$0	$21,895	$17,661	$29,098	$0	$17,661
Administrative Charges	$4,014	$6,110	$0	$5,300	$4,006	$6,103	$5,300	$0	$8,577	$0	$4,747	$4,309	$9,380	$0	$18,831
Property Tax	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Insurance	$2,007	$3,055	$0	$2,650	$2,003	$3,051	$2,650	$0	$4,288	$0	$2,374	$2,154	$4,690	$0	$9,416
Capital Recovery	$18,942	$28,835	$40,861	$25,014	$18,908	$28,801	$25,014	$89,233	$40,479	$36,555	$22,404	$20,335	$44,270	$98,214	$88,873
Indirect Annual Costs	$36,314	$52,550	$40,861	$56,173	$35,490	$52,505	$56,173	$89,233	$67,356	$36,555	$51,419	$44,459	$87,439	$98,214	$134,781
Total Annual Costs	$73,004	$91,937	$161,173	$112,627	$70,657	$91,892	$112,402	$194,424	$102,779	$151,975	$106,731	$106,816	$169,714	$227,498	$197,138
TPY of NO_X Emissions Reduced	5.99	5.99	5.99	5.99	4.19	4.19	4.19	7.71	7.71	7.71	7.71	20.56	20.56	20.56	20.56
Cost Per Ton	$12,185	$15,345	$26,902	$18,799	$16,848	$21,911	$26,802	$25,230	$13,337	$19,722	$13,850	$5,196	$8,256	$11,067	$9,590
TPY of All Polutants Emissions Reduced								55.63	55.63						
Cost Per Ton								$3,495	$1,848						

[1] Quote included instrumentation.

[2] Company used interest rate and/or equipment life different than EPA directed 7.0% interest rate and 20 years equipment life.

[3] Quote included oxidation catalyst.

[4] Company made arithmetic error; listed PEC as $517,942 when $495,685 + $58,257 = $553,942.

[A] The Department orginially used the Capital Cost Factors from Table 2.5 in the October 2000 version of the Control Cost Manual. The updated chapter uses a base equation to calculate TCI. The Department uses the base OAQPS calculation method in the reanalysis, which may result in an overestimation of cost.

Table 22 - Revised SCR Cost Analyses

(All dollar values in 2016 dollars)[A]	INGAA 1[1,2,5,6,7] 4,735 hp @ 0.35 g/bhp-h	INGAA 1 4,735 hp @ 0.35 g/bhp-h	INGAA 2[1,2,5,6,7] 4,735 hp @ 0.35 g/bhp-h	INGAA 2 4,735 hp @ 0.35 g/bhp-h	Vendor A 4,735 hp @ 0.35 g/bhp-h	Vendor B 4,735 hp @ 0.35 g/bhp-h	GCA[4,7] 4,735 hp @ 0.30 g/bhp-h	GCA 4,735 hp @ 0.30 g/bhp-h	MarkWest[1,2,3,7,8] 5,350 hp @ 0.30 g/bhp-h	MarkWest[9] 5,350 hp @ 0.30 g/bhp-h	MarkWest[1,2,7,8,10] 5,350 hp @ 0.30 g/bhp-h Revised	MarkWest[9,10] 5,350 hp @ 0.30 g/bhp-h	MarkWest[1,2,7,10] 5,350 hp @ 0.30 g/bhp-h No OxyCat	MarkWest[9,10] 5,350 hp @ 0.30 g/bhp-h No OxyCat
SCR System	$225,000	$225,000	$277,000	$227,000	$105,000	$225,000	$495,685	$495,685	$245,790	$245,790	$226,290	$226,290	$226,290	$226,290
Reductant Tank and Other Auxiliary Equipment	$0	$50,000	$0	$50,000	$20,000	$50,000	$58,257	$58,257	$13,253	$15,593	$13,253	$15,593	$13,253	$15,593
Customer Supplied Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$28,200	$28,200	$28,200	$25,963	$28,200	$25,963
Instrumentation	$85,000	$0	$27,700	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Initial Fill of Reductant	$0	$1,708	$0	$1,708	$1,708	$1,708	$9,750	$1,464	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000
Freight	$11,250	$13,835	$0	$13,935	$6,335	$13,835	$13,750	$27,770	$15,000	$14,729	$15,000	$13,642	$15,000	$13,642
Total Purchased Equipment Costs	$330,550	$290,543	$304,700	$292,643	$133,043	$290,543	**$577,442**	$583,176	$307,243	$309,312	$287,743	$286,488	$287,743	$286,488
Total Direct Installation Costs	$429,715	$377,706	$987,700	$380,436	$172,956	$377,706	$0	$758,129	$365,981	$454,847	$365,981	$420,991	$313,240	$372,434
Commissioning Costs	$0	$0	$0	$0	$0	$0	$0	$0	$30,875	$30,875	$30,875	$28,426	$30,875	$30,875
Total Indirect Installation Costs	$69,416	$90,068	$157,173	$90,719	$41,243	$90,068	$463,072	$180,785	$133,945	$95,887	$133,945	$88,811	$133,945	$88,811
Total Capital Investment	$499,131	$467,775	$1,144,873	$471,156	$214,200	$467,775	$1,040,514	$938,914	$838,044	$581,609	$818,544	$538,228	$765,803	$492,121
Operating and Supervisory Labor Costs	$14,375	$5,009	$14,375	$5,009	$5,009	$5,009	$21,000	$5,009	$0	$5,009	$0	$5,009	$0	$5,009
Maintenance Cost	$17,500	$9,583	$17,500	$9,583	$9,583	$9,583	$37,500	$9,583	$0	$9,583	$0	$9,583	$0	$9,583
Reductant Consumption Cost	$37,000	$10,390	$37,000	$10,390	$10,390	$10,390	$18,396	$8,906	$0	$17,520	$0	$17,520	$0	$17,520
Annual Electricity Cost	$5,000	$10,551	$5,000	$10,551	$10,551	$10,551	$5,000	$10,551	$0	$11,856	$0	$11,856	$0	$11,856
Annual Catalyst Replacement Cost	$23,050	$21,984	$23,050	$21,984	$21,984	$21,984	$47,388	$21,855	$0	$37,668	$0	$37,668	$0	$18,834
Direct Annual Costs	$116,925	$57,517	$116,925	$57,517	$57,517	$57,517	$129,284	$55,904	$85,000	$81,636	$85,000	$81,636	$85,000	$62,802
Overhead	$19,125	$14,989	$19,125	$14,989	$14,989	$14,989	$0	$14,099	$0	$19,267	$0	$19,267	$0	$19,267
Administrative Charges	$9,983	$9,355	$22,897	$9,423	$4,284	$9,355	$0	$18,778	$0	$11,632	$0	$10,765	$0	$9,842
Property Tax	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Insurance	$4,991	$4,678	$11,449	$4,712	$2,142	$4,678	$0	$9,389	$0	$5,816	$0	$5,382	$0	$4,921
Capital Recovery	$81,234	$44,153	$186,328	$44,472	$20,218	$44,153	$98,214	$88,624	$0	$54,898	$0	$50,803	$0	$46,451
Indirect Annual Costs	$120,321	$73,176	$251,243	$73,596	$41,634	$73,176	$98,214	$130,890	$134,386	$91,613	$166,483	$86,217	$159,235	$80,482
Total Annual Costs	$237,246	$130,693	$368,168	$131,113	$99,151	$130,693	$227,498	$186,794	$219,386	$173,249	$251,483	$167,853	$244,235	$143,284
TPY of NO_X Emissions Reduced	13.70	14.39	13.70	14.39	14.39	14.39	11.74	12.33	12.90	13.94	12.90	13.94	12.90	13.94
Cost Per Ton	$17,315	$9,082	$26,869	$9,112	$6,890	$9,082	$19,370	$15,145	$17,009	$12,432	$19,497	$12,045	$18,935	$10,282
TPY of All Polutants Emissions Reduced									133.27	134.31				
Cost Per Ton									$1,646	$1,290				

[1] Quote included instrumentation.

[2] Company used interest rate and/or equipment life different than EPA directed 7.0% interest rate and 20 years equipment life.

[3] Quote included oxidation catalyst.

[4] Company made arithmetic error; listed PEC as $517,942 when $495,685 + $58,257 = $553,942.

[5] Company included sales tax in their calculation. Under 61 Pa. Code §32.35, pollution control devices are exempt from tax in mining operations, which includes oil and gas drilling. Under 61 Pa. Code §155.11, pollution control devices are deductable from property tax calculations.

[6] Company included $20,000 Testing and QA/QC costs in the Direct Annual Costs.

[7] Calculated NO_X reduction to limit of 0.05 g/bhp-h rather than by 90% control.

[8] Site Preparation Costs of $52,741 were included.

[9] The Department included the additional $2,340 for the Maintenance Pack listed in the scope of supply.

[10] The oxidation catalyst costs were removed from the system cost; however, the company did not pro-rate any other costs in their analysis. The Department prorated all costs based on the ratio of costs for the oxidation catalyst to the SCR system.

[A] The Department orginially used the Capital Cost Factors from Table 2.5 in the October 2000 version of the Control Cost Manual. The updated chapter uses a base equation to calculate TCI. The Department uses the base OAQPS calculation method in the reanalysis, which may result in an overestimation of cost.

Table 23 - Derivation of Average Total Annual Cost Parameters

Quote Source	Purchased Equipment Costs	Engine Rating (HP)	NOx Emission Factor (g/bhp-h)	SCR Control Efficiency	Interest Rate	Equipment Life (years)	Total Annual Cost	Estimation Method	NOx Emissions Reduced (tons)	Cost Effectiveness ($/ton reduced)	Total Emissions Reduced (tons)	Cost Effectiveness ($/ton reduced)
Vendor A	$118,000	1,380	0.50	90.0%	7.0%	20	$55,052	First TSD Analysis	5.99	**$9,189**		
Vendor A	$118,000	1,380	0.50	90.0%	7.0%	20	$73,004	OAQPS (Revised)	5.99	$12,185		
Vendor B	$180,000	1,380	0.50	90.0%	7.0%	20	$64,316	First TSD Analysis	5.99	$10,735		
Vendor B	$180,000	1,380	0.50	90.0%	7.0%	20	$91,937	OAQPS (Revised)	5.99	$15,345		
GCA Vendor C	$146,000	1,380	0.50	90.0%	7.0%	**15**	$161,173	Company OAQPS Based	5.99	$26,902		
Vendor C	$146,000	1,380	0.50	90.0%	7.0%	20	$83,158	First TSD Analysis	5.99	$13,880		
Vendor C	$146,000	1,380	0.50	90.0%	7.0%	20	$112,627	OAQPS (Revised)	5.99	$18,799		
Vendor A	$118,000	1,380	0.35	90.0%	7.0%	20	$55,052	First TSD Analysis	4.19	$13,127		
Vendor A	$118,000	1,380	0.35	90.0%	7.0%	20	$70,657	OAQPS (Revised)	4.19	$16,848		
Vendor B	$180,000	1,380	0.35	90.0%	7.0%	20	$64,316	First TSD Analysis	4.19	$15,336		
Vendor B	$180,000	1,380	0.35	90.0%	7.0%	20	$91,892	OAQPS (Revised)	4.19	$21,911		
Vendor C	$146,000	1,380	0.35	90.0%	7.0%	20	**$83,158**	First TSD Analysis	4.19	$19,829		
Vendor C	$146,000	1,380	0.35	90.0%	7.0%	20	$112,402	OAQPS (Revised)	4.19	$26,802		
Cardinal	**$189,527**	1,775	0.50	90.0%	**10.0%**	**10**	$194,424	Company Quote	7.71	$25,230	55.11	$3,528
Cardinal	**$189,527**	1,775	0.50	90.0%	7.0%	20	$102,779	OAQPS (Revised)	7.71	$13,338	55.11	$1,865
GCA	$130,000	1,775	0.50	90.0%	7.0%	**15**	$151,975	Company Quote	7.71	$19,722		
GCA	$130,000	1,775	0.50	90.0%	7.0%	20	$106,731	OAQPS (Revised)	7.71	$13,850		
Vendor A	$125,000	4,735	0.50	90.0%	7.0%	20	$87,083	TSD	20.56	**$4,236**		
Vendor A	$125,000	4,735	0.50	90.0%	7.0%	20	$106,816	OAQPS (Revised)	20.56	**$5,196**		
Vendor B	$275,000	4,735	0.50	90.0%	7.0%	20	$111,662	TSD	20.56	**$5,432**		
Vendor B	$275,000	4,735	0.50	90.0%	7.0%	20	$169,714	OAQPS (Revised)	20.56	**$8,256**		
GCA	**$553,942**	4,735	0.50	90.0%	7.0%	20	$227,498	Company TSD Method	20.56	$11,067		
GCA	$553,942	4,735	0.50	90.0%	7.0%	20	$197,138	OAQPS (Revised)	20.56	**$9,590**		
INGAA	$310,000	4,735	0.35	**85.7%**	**10.0%**	**10**	$237,246	Company OAQPS Based	13.70	$17,315		
INGAA	$275,000	4,735	0.35	90.0%	7.0%	20	$130,693	OAQPS (Revised)	14.39	**$9,082**		
INGAA	$304,700	4,735	0.35	**85.7%**	**10.0%**	**10**	$368,168	Company Quote	13.70	$26,869		
INGAA	$277,000	4,735	0.35	90.0%	7.0%	20	$131,113	Company Quote	14.39	**$9,112**		
Vendor A	$125,000	4,735	0.35	90.0%	7.0%	20	$87,083	TSD	14.39	**$6,052**		
Vendor A	$125,000	4,735	0.35	90.0%	7.0%	20	$99,151	OAQPS (Revised)	14.39	**$6,890**		
Vendor B	$275,000	4,735	0.35	90.0%	7.0%	20	$111,662	TSD	14.39	**$7,760**		
Vendor B	$275,000	4,735	0.35	90.0%	7.0%	20	$130,693	OAQPS (Revised)	14.39	**$9,082**		
GCA	**$553,942**	4,735	0.30	**85.7%**	7.0%	20	$227,498	Company TSD Method	11.74	$19,370		
GCA	$553,942	4,735	0.30	90.0%	7.0%	20	$186,794	OAQPS (Revised)	12.33	$15,145		
MarkWest	**$287,243**	5,350	0.30	**83.3%**	**6.0%**	20	$219,386	Company Quote	12.90	$17,009	133.27	$1,646
MarkWest	**$289,583**	5,350	0.30	90.0%	7.0%	20	$173,249	OAQPS (Revised)	13.94	$12,432	134.31	$1,290
MarkWest	$267,743	5,350	0.30	**83.3%**	7.0%	20	$251,483	Company Revised Quote	12.90	$19,497		
MarkWest	$267,846	5,350	0.30	90.0%	7.0%	20	$167,853	OAQPS (Revised)	13.94	$12,045		
MarkWest	$267,743	5,350	0.30	**83.3%**	7.0%	20	$244,235	Company Revised Quote	12.90	$18,935		
MarkWest	$267,846	5,350	0.30	90.0%	7.0%	20	$143,284	OAQPS (Revised)	13.94	**$10,282**		

Engine Rating (HP)	Average Total Annual Cost
1,380	$86,057
1,380	$79,798
1,775	$138,977
1,775	$104,755
4,735	$163,126
4,735	$143,186
5,530	$199,915
5,530	$196,021

m	$28.01
b	$41,150

Table 24 - Calculated SCR Cost Effectiveness

Engine Rating (HP)	Caterpillar Model	Emission Rate	Emissions Reduced (90% Reduction)	Estimated Annual Cost	$/ton reduced
100		1.0	0.87	$43,951	$50,618
145	G3306	0.5	0.63	$45,211	$71,821
250		1.0	2.17	$48,153	$22,183
255	G3408	0.5	1.11	$48,293	$43,622
425	G3408C	0.5	1.85	$53,054	$28,754
500		1.0	4.34	$55,155	$12,704
524	G3508	0.5	2.27	$55,827	$24,541
690	G3508B	0.5	3.00	$60,477	$20,189
790	G3512	0.5	3.43	$63,278	$18,450
1,000		0.5	4.34	$69,160	$15,930
1,035	G3512B	0.5	4.49	$70,140	$15,610
1,380	*G3516B*	*0.5*	*5.99*	*$79,804*	*$13,320*
1,480	G3520B	0.5	6.43	$82,605	$12,856
1,500		0.5	6.51	$83,165	$12,771
1,775	G3606	0.5	7.71	$90,868	$11,792
1,875	G3606A4	0.3	4.88	$93,669	$19,178
2,370	G3608	0.5	10.29	$107,534	**$10,451**
2,500	G3608A4	0.3	6.51	$111,175	$17,072
3,000		0.5	13.02	$125,180	**$9,611**
3,550	G3612	0.5	15.41	$140,586	**$9,122**
3,750	G3612A4	0.3	9.77	$146,188	$14,966
4,735	*G3616*	*0.5*	*20.56*	*$173,777*	***$8,454***
5,350	G3616A4	0.3	13.94	$191,004	$13,706
5,500		0.5	23.88	$195,205	**$8,175**
6,135	G12CM34	0.5	26.63	$212,991	**$7,997**
8,180	G16CM34	0.5	35.51	$270,272	**$7,611**
6,135		0.3	15.98	$212,991	$13,328
8,180		0.3	21.31	$270,272	$12,684

Based on the costs determined in Table 24 above, and the cost-effectiveness threshold of $10,000 per ton of NO_X reduced, SCR is cost effective for engines greater than or equal to 2,370 hp if the starting NO_X emission rate is 0.50 g/bhp-h. Installation of SCR becomes economically infeasible for engines greater than or equal to 2,370 hp if the starting NO_X emission rate is 0.30 g/bhp-h. For this reason, the Department proposes a dual BAT criterion for lean burn engines greater than or equal to 2,370 hp of 0.30 g/bhp-h NO_X uncontrolled, or 0.05 g/bhp-h NO_X with control.

Following the original methodology described above for engines with the turbine data results in cost per ton and average cost per ton as summarized in Table 5 below. The BAT emissions limits of 25 ppm for NO_X for turbines below 5,000 bhp, of 15 ppm for turbines 5,000 bhp and above were used in the analysis.

Table 25 - Calculated Cost per Ton NO_X Reduced vs Average Cost per Ton NO_X Reduced for Turbines using BAT Emissions

Turbine HP (All dollar values in 2016 dollars)	1,000	1,590	3,000	5,000	6,130	7,500	11,150	15,900	17,500	20,000	25,000	30,000
Average Total Annual Costs	$107,277	$113,040	$130,449	$153,621	$166,713	$182,586	$224,875	$279,908	$298,446	$327,411	$385,341	$423,291
TPY of NO_X Emissions Reduced, Uncontrolled	6.79	6.00	11.22	15.66	18.95	21.21	29.15	42.75	43.39	48.93	60.02	69.38
Uncontrolled Cost Per Ton	$15,804	$18,853	$11,622	$9,810	$8,799	$8,611	$7,714	$6,547	$6,879	$6,691	$6,420	$6,101
Average Cost Per Ton	$15,912	$15,933	$15,987	$16,062	$16,104	$16,155	$16,292	$16,470	$16,530	$16,624	$16,812	$16,999
TPY of NO_X Emissions Reduced, BAT	6.79	6.00	11.22	9.40	11.37	12.72	17.49	25.65	26.03	29.36	36.01	41.62
BAT Cost Per Ton	$15,804	$18,853	$11,622	$16,351	$14,665	$14,352	$12,858	$10,913	$11,466	$11,153	$10,701	$10,170
TPY of NO_X Emissions Reduced, Alternative BAT								15.39	15.62	17.62	21.61	24.98
Alternative Cost Per Ton								$18,184	$19,106	$18,585	$17,832	$16,946

For turbines rated at 5,000 hp and above with uncontrolled emissions of 25 ppm NO_X, SCR is cost effective. However, for turbines rated 5,000 hp and above but below 15,900 hp and operating at 15 ppm NO_X uncontrolled, SCR is not cost effective. Therefore, for turbines rated at or above 5,000 hp and below 15,900 hp, the Department proposes an emission limit of 15 ppm NO_X. For turbines rated at or above 15,900 hp, SCR is cost effective even when the uncontrolled emission rate is 15 ppm NO_X. However, a recently issued permit in New York establishes a NO_X emission limit of 9 ppm for two Solar Mars Turbines which, according to the Solar Turbines website, are rated at 15,900 bhp. A recent plan approval application to the Department also proposes 9 ppm NO_X for combustion turbines. Based on the availability of these low-emission models, the Department proposes an emission limit of 9 ppm NO_X uncontrolled or 1.5 ppm NO_X with control for turbines greater than 15,900 hp.

XXIV. Appendix C – Oxidation Catalyst and NSCR Cost Analysis for Engines and Turbines

Unlike the methodology used in Appendix B – SCR Cost Analysis for Engines and Turbines for SCR, the Department relied on a memorandum from E $^{C}/_{R}$ Incorporated dated June 29, 2010, to Melanie King at EPA OAQPS/SPPD/ESG for engine emission control devices. The memorandum determined a linear equation for total annual cost for oxidation catalysts for lean-burn engines. The Department then calculated the cost per ton based on weighted average emission rates and on BAT emission rates.

Table 26 - Oxidation Catalyst Cost Analysis for Lean-Burn Engines - Weighted Average Emissions

Engine HP (All dollar values in 2016 dollars)	100	250	500	1,000	1,380	1,500	1,875	2,370	2,500	3,500	4,735	5,500
Total Annual Costs	$4,058	$4,362	$4,869	$5,882	$6,653	$6,896	$7,656	$8,660	$8,923	$10,950	$13,454	$15,005
TPY of CO Emissions Reduced	5.82	14.54	8.68	17.37	23.96	26.05	34.19	43.21	45.58	63.82	86.34	100.29
TPY of NMNEHC Emissions Reduced	0.29	0.72	1.21	2.41	3.33	3.62	7.24	9.15	9.65	13.51	18.27	21.22
Cost Per Ton	$664	$286	$492	$297	$244	$232	$185	$165	$162	$142	$129	$123

Table 27 - Oxidation Cost Analysis for Lean-Burn Engines - BAT Emissions

Engine HP (All dollar values in 2016 dollars)	100	250	500	1,000	1,380	1,500	1,875	2,370	2,500	3,500	4,735	5,500
Total Annual Costs	$4,058	$4,362	$4,869	$5,882	$6,653	$6,896	$7,656	$8,660	$8,923	$10,950	$13,454	$15,005
TPY of CO Emissions Reduced	1.74	4.34	1.74	3.47	4.79	5.21	6.51	8.23	8.68	12.16	16.45	19.10
TPY of NMNEHC Emissions Reduced	0.34	0.84	0.60	1.21	1.66	1.81	2.26	2.86	3.01	4.22	5.71	6.63
Cost Per Ton	$1,956	$841	$2,081	$1,257	$1,030	$983	$873	$781	$763	$669	$607	$583

The same memorandum also determined a linear equation for the total annual cost for NSCR for rich-burn engines. As for lean-burn engines, the Department calculated the cost per ton for NSCR on rich-burn engines using the cost per ton based on weighted average emission rates and on BAT emission rates.

Table 28 - NSCR Cost Analysis for Rich-Burn Engines - Weighted Average Emissions

Engine HP (All dollar values in 2016 dollars)	100	250	500	1,000	1,380	1,500	2,500	3,500	4,735	5,500
Total Annual Costs	$6,895	$7,696	$9,032	$11,703	$13,733	$14,374	$19,716	$25,059	$31,657	$35,744
TPY of NO_X Emissions Reduced	14.57	36.43	70.57	141.14	194.78	211.72	352.86	494.00	668.32	776.29
TPY of CO Emissions Reduced	7.61	19.02	37.58	75.15	103.71	112.73	187.89	263.04	355.86	413.35
TPY of NMNEHC Emissions Reduced	0.14	0.36	0.72	1.45	2.00	2.17	3.62	5.06	6.85	7.96
Cost Per Ton	$309	$138	$83	$54	$46	$44	$36	$33	$31	$30

Table 29 - NSCR Cost Analysis for Rich-Burn Engines - BAT Emissions

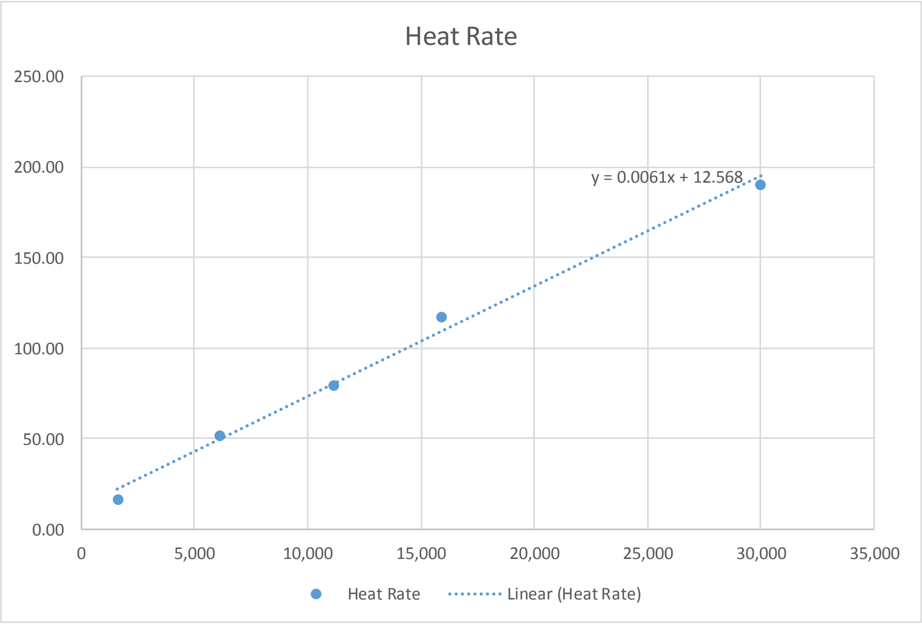
Engine HP (All dollar values in 2016 dollars)	100	250	500	1,000	1,380	1,500	2,500	3,500	4,735	5,500
Total Annual Costs	$6,895	$7,696	$9,032	$11,703	$13,733	$14,374	$19,716	$25,059	$31,657	$35,744
TPY of NO_X Emissions Reduced	0.23	0.57	0.92	1.83	2.53	2.75	4.58	6.42	8.68	10.08
TPY of CO Emissions Reduced	0.27	0.69	1.37	2.75	3.79	4.12	6.87	9.62	13.02	15.12
TPY of NMNEHC Emissions Reduced	0.10	0.24	0.48	0.96	1.33	1.45	2.41	3.38	4.57	5.31
Cost Per Ton	$11,480	$5,126	$3,256	$2,110	$1,794	$1,727	$1,422	$1,291	$1,205	$1,172

For lean-burn engines, using both the weighted average emissions and the BAT emissions, the cost effectiveness of control was less than the cost-effectiveness threshold of $5,000 per ton of pollutant reduced was shown for engines rated at 100 bhp and above. Therefore, the Department determines that oxidation catalysts are required for all lean-burn engines rated greater than or equal to 100 bhp.

For rich-burn engines, using the BAT emissions shows that NSCR is not cost effective below 250 hp; however, NSCR was previously established as BAT for rich-burn engines rated greater than or equal to 100 bhp. Therefore, the Department determines that NSCR is required for all rich burn engines rated greater than or equal to 100 bhp.

Table 30 - Turbine Characteristics and Emissions Data

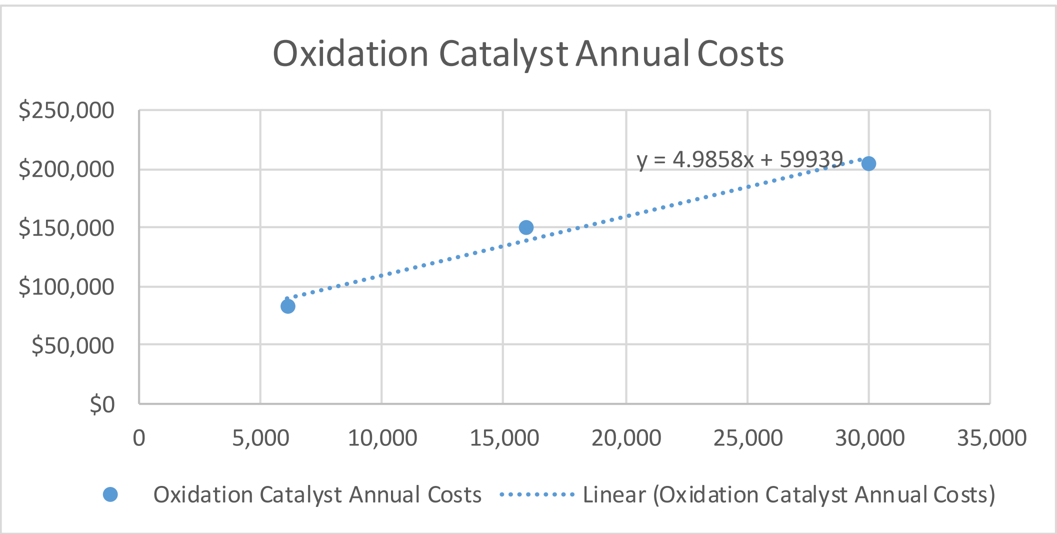
	Turbine A	Turbine B	Turbine C	Turbine D	Tubine E
Power (bhp)	1,590	6,130	11,150	15,900	30,000
Heat Rate (Btu/bhp-h)	10,370	8,500	7,190	7,395	6,360
Exhaust Flow (lb/h)	51,615	149,380	215,990	337,850	541,590
Exhaust Temperature (°F)	970	960	935	905	865
Heat Input (MMBtu/h)	16.49	52.11	80.17	117.58	190.80
Exhaust Flow (scfh)	720,747	2,085,927	3,016,063	4,717,703	7,562,708
Exhaust Flow (acfm)	32,411	93,145	132,308	202,505	315,113
NO_X Emission Rate (ppm)	2.50E-05	1.50E-05	1.50E-05	9.00E-06	9.00E-06
NO_X Emission Rate (lb/MMBtu)	0.09224	0.05534	0.05534	0.03321	0.03321
NO_X Emission Rate (tpy)	6.66	12.63	19.43	17.10	27.75
CO Emission Rate (ppm)	2.50E-05	2.50E-05	2.50E-05	1.00E-05	1.00E-05
CO Emission Rate (lb/MMBtu)	0.05607	0.05607	0.05607	0.02243	0.02243
CO Emission Rate (tpy)	4.05	12.80	19.69	11.55	18.74
NMNEHC Emission Rate (ppm)	9.00E-06	9.00E-06	9.00E-06	5.00E-06	5.00E-06
NMNEHC Emission Rate (lb/MMBtu)	0.03179	0.03179	0.03179	0.01766	0.01766
NMNEHC Emission Rate (tpy)	2.30	7.25	11.16	9.09	14.76



Unfortunately, a convenient analysis for oxidation catalysts for turbines was not found. Instead, the Department relied on vendor quotes and performed an analysis similar to the one for SCR in Appendix B – SCR Cost Analysis for Engines and Turbines. Three independent quotes were given for different sized turbines, and those formed the basis for the extrapolation of total annual costs for turbines of other sizes.

Table 31 - Oxidation Catalyst Cost Data for Turbines

(All dollar values in 2016 dollars)	6,130	15,900	30,000
Oxidation Catalyst Purchased Equipment Costs	$96,785	$205,918	$215,090
Direct Installation Costs (0.30PEC)	$29,035	$61,775	$64,527
Total Indirect Installation Costs (0.27PEC)	$26,132	$55,598	$58,074
Project Contingency (0.15(DIC+IIC))	$8,275	$17,606	$18,390
Total Capital Investment	$160,227	$340,897	$356,082
Operating and Supervisory Labor Costs	$18,889	$18,889	$18,889
Maintenance Cost	$2,904	$6,178	$6,453
Natural Gas Penalty	$12,553	$28,325	$45,964
Catalyst Disposal	$130	$338	$637
Annual Catalyst Replacement Cost	$14,204	$36,841	$69,512
Direct Annual Costs	$48,679	$90,570	$141,454
Indirect Annual Costs	$34,609	$60,854	$63,060
Total Annual Costs	$83,288	$151,424	$204,514



The uncontrolled emissions rates assume 25 ppm for CO and total hydrocarbons, which when adjusted to NMNEHC as propane becomes 9 ppm. The BAT emissions rates, in ppm, were taken from the previous GP-5. The values for CO and NMNEHC are used in the table below for the turbine oxidation catalyst cost analysis.

Table 32 – Oxidation Catalyst Cost Analysis for Turbines - Uncontrolled Emissions

Turbine HP (All dollar values in 2016 dollars)	1,000	1,590	3,000	5,000	6,130	7,500	11,150	15,900	17,500	20,000	25,000	30,000
Total Annual Costs	$64,925	$67,866	$74,896	$84,868	$83,288	$97,333	$115,531	$151,424	$147,191	$159,655	$184,584	$204,514
TPY of CO Emissions Reduced	4.26	3.77	7.05	9.84	11.90	13.32	18.31	26.85	27.25	30.73	37.70	43.58
TPY of NMNEHC Emissions Reduced	1.30	1.15	2.15	3.00	3.63	4.06	5.58	8.19	8.31	9.37	11.49	13.62
Cost Per Ton	$11,670	$13,810	$8,142	$6,612	$5,363	$5,600	$4,836	$4,321	$4,139	$3,981	$3,752	$3,576

Table 33 - Oxidation Catalyst Cost Analysis for Turbines - BAT Emissions

Turbine HP (All dollar values in 2016 dollars)	1,000	1,590	3,000	5,000	6,130	7,500	11,150	15,900	17,500	20,000	25,000	30,000
Total Annual Costs	$64,925	$67,866	$74,896	$84,868	$83,288	$97,333	$115,531	$151,424	$147,191	$159,655	$184,584	$204,514
TPY of CO Emissions Reduced	4.26	3.77	7.05	9.84	11.90	13.32	18.31	10.74	10.90	12.29	15.08	17.43
TPY of NMNEHC Emissions Reduced	1.30	1.15	2.15	3.00	3.63	4.06	5.58	4.55	4.61	5.20	6.38	7.38
Cost Per Ton	$11,670	$13,810	$8,142	$6,612	$5,363	$5,600	$4,836	$9,903	$9,486	$9,123	$8,599	$8,243
TPY of CO Emissions Reduced, Alternative BAT				3.93	4.76	5.33	7.32					
TPY of NMNEHC Emissions Reduced, Alternative BAT				1.67	2.02	2.26	3.10					
Cost Per Ton				$15,153	$12,291	$12,834	$11,082					

As can be seen in Table 32 and Table 33 above, oxidation catalysts for turbines greater than or equal to 1,000 hp but less than 5,000 hp are not cost-effective; for turbines greater than or equal to 5,000 hp, oxidation catalysts are cost-effective based on a cost-effectiveness threshold of $5,000 per ton of pollutant reduced. It is important to point out that for turbines less than 15,000 hp, the uncontrolled emissions and the BAT emissions are identical, with identical results.

For turbines greater than or equal to 15,900 hp, oxidation catalysts are cost-effective if one considers the uncontrolled emission rates of 25 ppm CO and 9 ppm NMNEHC as propane as a baseline. However, if one considers the alternative BAT emissions rate established in the previous GP-5 of 10 ppm CO and 5 ppm NMNEHC, oxidation catalysts are not cost-effective. Oxidation catalysts are also cost prohibitive for turbines rated greater than or equal to 5,000 hp but less than 15,900 hp with uncontrolled emissions rates of 10 ppm CO and 5 ppm NMNEHC, which is achievable according to stack test data. Therefore, it is the Department's determination that turbines greater than or equal to 5,000 hp but less than 15,900 hp have BAT criteria of 10 ppm CO and 5 ppm NMNEHC and that turbines greater than or equal to 15,900 hp have dual BAT criteria with BAT of 10 ppm CO uncontrolled and 1.75 ppm CO with control and 5 ppm NMNEHC.

XXV. Appendix D – Cost Analysis for Combustion Control Devices

Table 34 - Combustion Control Device Cost Analysis

(All dollar values in 2016 dollars)	Vendor A	Sensitivity Analysis			
Combustor	$19,186				
Auto Ignitor	$1,740				
Surveilannce System	$4,176				
Total Purchased Equipment Cost	$25,102				
Freight and Design	$1,740				
Installation	$7,371				
Total Capital Investment	$34,213	$40,000	$50,000	$75,000	$100,000
Pilot Fuel	$2,201	$2,573	$3,216	$4,824	$6,432
Maintenance Cost	$2,320	$2,712	$3,391	$5,086	$6,781
Data Management	$1,160	$1,356	$1,695	$2,543	$3,391
Direct Annual Costs	$5,681	$6,641	$8,302	$12,453	$16,603
Indirect Annual Costs	$3,756	$4,392	$5,490	$8,235	$10,979
Total Annual Costs (7% Intrest, 15 Year Life)	$9,437	$11,033	$13,791	$20,687	$27,583
TPY of Methane	200.00	200.00	200.00	200.00	200.00
TPY of VOC	2.70	2.70	2.70	2.70	2.70
TPY of HAP	1.00	1.00	1.00	1.00	1.00
Cost Per Ton (95% Reduction)	$49	$57	$71	$107	$143
Cost Per Ton (95% Reduction, Excluding Methane)	$2,685	$3,139	$3,924	$5,885	$7,847
Cost Per Ton (98% Reduction)	$47	$55	$69	$104	$138
Cost Per Ton (98% Reduction, Excluding Methane)	$2,603	$3,043	$3,803	$5,705	$7,607

As can be seen from the table above, it is cost effective for a combustion control device that controls methane, VOC, and HAP based on the vendor quote and assuming an emission rate at the control threshold. In the sensitivity analysis, it is assumed that the annual costs scale relative to the increased total capital investment. If the cost-effectiveness threshold including methane is considered, it is cost-effective to install a combustion control device with a total capital investment of $100,000 (and arguably much more) because it is much less than the $1,000 per ton of pollutant reduced. If the cost-effectiveness threshold excluding methane is considered, combustion control devices are cost-effective up to a total capital investment of $75,000 because it is close to the $5,000 per ton of pollutant reduced.

Many commentators provided additional information on combustion control devices capabilities and cost, and so the Department conducted another cost analysis based on the new information. One aspect the Department explored was the effect of gas composition on the number of hours of operation an enclosed flare of the given characteristics would take to reach the proposed control thresholds. As seen in Table 35 below, the time varies for each pollutant, and establishes a range of operating hours. In Table 36 below, the emissions calculations were done based on the gas composition and the minimum and maximum operating hours calculated in Table 35.

Table 35 - Operating Hours to Reach Control Thresholds

Gas Composition Analysis	Original TSD Average Gas Composition	TSD Reanalysis Average Gas Composition	Rich Gas - Washington County Average	Dry Gas - Susquehanna County Average
Methane (vol%)			82.6%	97.4%
Methane (wt%)	88.8%	86.0%	67.3%	95.1%
VOC (vol%)			5.65%	0.08%
VOC (wt% as propane)	1.3%	4.5%	12.7%	0.2%
HAP (vol%)			0.0024%	0.0000%
HAP (wt% as hexane)	0.0500%	0.0000%	0.0105%	0.0000%
Total Weight of Gas (lb/cf gas)	0.0453	0.0442	0.0501	0.0418
Enclosed Flare Statistics				
Gas Throughput (lb/h)	4,800	4,800	4,800	4,800
Gas Throughput (Mcf/h)	106	109	96	115
Number of Pilots	3	3	3	3
Pilot Fuel Consumption (cf/h)	65	65	65	65
Annual Pilot Fuel Consumption (Mcf/yr)	1,708	1,708	1,708	1,708
Natural Gas Price ($/Mcf)	$2.50	$2.50	$2.50	$2.50
Power Consumption (kWh/yr)	616	616	616	616
Electricity Price ($/kWh)	$0.07	$0.07	$0.07	$0.07
Control Efficiency	95%	95%	95%	95%
Operational Assumptions				
Estimated Hours to Reach Control Threshold for Methane	94	97	124	88
Estimated Hours to Reach Control Threshold for VOC	90	25	9	524
Estimated Hours to Reach Control Threshold for Single HAP	417	-	1,983	-
Estimated Hours to Reach Control Threshold for Total HAP	833	-	3,967	-
Minimum Estimated Hours of Operation	90	25	9	88
Maximum Estimated Hours of Operation	833	97	3,967	524

Table 36 - Cost Sensitivity to Gas Composition and Hours of Operation

Gas Composition Analysis	Original TSD Average Gas Composition	TSD Reanalysis Average Gas Composition	Rich Gas - Washington County Average	Dry Gas - Susquehanna County Average
Maximum Emission Reductions				
Methane Reduced (tpy)	1,687	190	6,083	1,136
VOC Reduced (tpy)	23.75	9.87	1,144.39	2.57
Total HAP Reduced (tpy)	0.95	0.00	0.95	0.00
Minimum Emission Reductions				
Methane Reduced (tpy)	182	49	14	190
VOC Reduced (tpy)	2.57	2.57	2.57	0.43
Total HAP Reduced (tpy)	0.10	0.00	0.00	0.00
Emission Reductions from Control Thresholds				
Methane Reduced (tpy)	190	190	190	190
VOC Reduced (tpy)	2.57	2.57	2.57	2.57
Single HAP Reduced (tpy)	0.48	0.48	0.48	0.48
Total HAP Reduced (tpy)	0.95	0.95	0.95	0.95
Dollars Per Ton of Methane Reduced ($/ton)	$581	$581	$581	$581
Dollars Per Ton of VOC Reduced ($/ton)	$43,047	$43,047	$43,047	$43,047
Dollars Per Ton of Single HAP Reduced ($/ton)	$232,453	$232,453	$232,453	$232,453
Dollars Per Ton of Total HAP Reduced ($/ton)	$116,226	$116,226	$116,226	$116,226
Dollars Per Ton of All Pollutants Reduced Maximum ($/ton)	$65	$552	$15	$97
Dollars Per Ton of All Pollutants Reduced Minimum ($/ton)	$598	$2,126	$6,816	$580

The cost effectiveness for all pollutants at both the minimum and maximum hours of operation show that regardless of gas composition, an enclosed combustion device is economically feasible for the control of methane, VOC, and HAP.

Another commentator pointed out that control devices need to be sized for the worst-case scenario, which drives up the cost of the system based on the maximum gas flow to the control. The commentator provided operational data, summarized in Table 37 below, that gives both volume flow rates and mass flow rates as well as hours of operation.

Table 37 - Gas Flow Rates and Annual Hours of Operation

	Purge Gas	Closed Drain Vapors	Pigging Vapors (30" Receiver)	Pigging Vapors (12" C3+ Launcher)	Amine Unit Flash Gas	Total Maximum Flow Rate		Total Minimum Flow Rate	
						scfh	Mscfd	scfh	Mscfd
Volume Flow Rate (scfh)	434	26	120,000	48,135	2,154	170,749	4,098	2,588	62
Volume Flow Rate %	0.25%	0.02%	70.28%	28.19%	1.26%				
Mass Rate (lb/h)	18.68	1.43	6,723.53	6,885.81	177.91	13,807		197	
Annual Hours of Operation	8,760	2,190	12	1	8,760				

Another consideration is the effect of the previously calculated methane control threshold versus the newly calculated methane control threshold; as seen in Table 38 below, there is a significant increase in the cost per ton of methane reduced, as well as the cost per ton of all pollutants reduced. Cost-effectiveness on the basis of methane alone at 51.9 tpy is significantly beyond EPA's threshold of approximately $1,000 per ton of methane reduced;

Table 38 - Cost-Effectiveness of Proposed vs. Recalculated Control Thresholds for Enclosed Combustion Devices

(All dollar values in 2016 dollars)	MSC Enclosed Oxidizer @ 250 Mscfd CH_4	MSC Enclosed Oxidizer @ 250 Mscfd CH_4	Vendor D Enclosed Flare @ 2,606 Mscfd	Vendor D Enclosed Flare @ 2,606 Mscfd	Vendor D Enclosed Flare @ 26,064 Mscfd	Vendor D Enclosed Flare @ 26,064 Mscfd
Total Annual Costs	$68,059	$68,059	$110,415	$110,415	$445,745	$445,745
TPY of CH_4 Emissions Reduced	190.00	49.31	190.00	49.31	190.00	49.31
Cost Per Ton	$358	$1,380	$581	$2,239	$2,346	$9,041
TPY of VOC Emissions Reduced	2.57	2.57	2.57	2.57	2.57	2.57
Cost Per Ton	$26,534	$26,534	$43,047	$43,047	$173,780	$173,780
TPY of HAP Emissions Reduced	0.95	0.95	0.95	0.95	0.95	0.95
Cost Per Ton	$71,641	$71,641	$116,226	$116,226	$469,206	$469,206
TPY of All Pollutants Emissions Reduced	193.52	52.82	193.52	52.82	193.52	52.82
Cost Per Ton	$352	$1,289	$571	$2,090	$2,303	$8,439

ranging from $1,380 to $9,041 per ton of methane reduced. However, considering all pollutants, an enclosed combustion device is still cost effective based on the cost-effectiveness threshold of $5,000 per ton of pollutant reduced, ranging from $1,289 to $8,439 per ton of pollutant reduced. The Department must maintain, however, that the control threshold of 51.9 tpy is cost-prohibitive because for dry gas regions, methane is the likely trigger for control, and as there are insignificant amounts of VOC and HAP in the gas stream, only the cost per ton of methane reduced should be considered for determining the cost-effectiveness. Performing a linear interpolation between the 51.2 tpy control threshold and the 200 tpy control threshold for the 2,606 Mscfd enclosed flare, the $1,000 per ton of methane reduced threshold is approximately 163 tpy methane. This would provide a range from $441 to $2,886 per ton of methane reduced. However, the Department determines that BAT control measures for methane must be implemented for sources with emissions that meet or exceed 200 tpy methane; this requirement is also included in the exemption criteria for facilities seeking exemption under Category 38(c). One reason for conservatively establishing the methane control threshold at 200 tpy instead of 163 tpy is due to the inherent scientific uncertainty in the second analysis control threshold calculation discussed in Appendix A – Average Gas Composition Analysis and the site-specific uncertainty in the control costs from Appendix D – Cost Analysis for Combustion Control Devices.

For the primary BAT analysis, the Department determined the total annual flow through the enclosed flare based on the operational information from Table 37 and the average natural gas composition as determined in Table 16 of Appendix A – Average Gas Composition Analysis. Where the flow was given as a volume of methane, the Department used the methane density of 0.0416 lb/scf and the average gas composition density of 0.0442 lb/scf to determine the adjusted flow rate. For Vendor D, the flow was given in lb/h; the Department used the average gas composition density to determine the volume flow. The Department used EPA's Air Pollution Control Cost Manual to determine the total capital investment and total annual costs based on the purchased equipment prices provided by the commentators. The results can be seen in Table 39 below.

Table 39 - BAT Analysis for Enclosed Flare

(All dollar values in 2016 dollars)	MSC Enclosed Oxidizer @ 20 Mscfd CH_4	MSC Enclosed Oxidizer @ 50 Mscfd CH_4	MSC Enclosed Oxidizer @ 100 Mscfd CH_4	MSC Enclosed Oxidizer @ 250 Mscfd CH_4	MSC Enclosed Oxidizer @ 500 Mscfd CH_4	MSC Enclosed Oxidizer @ 1,000 Mscfd CH_4	Vendor D Enclosed Flare @ 2,606 Mscfd	MSC Enclosed Oxidizer @ 3,000 Mscfd CH_4	MSC Enclosed Oxidizer @ 5,000 Mscfd CH_4	Vendor D Enclosed Flare @ 26,064 Mscfd
Control Flow Rate (Mscfh)	0.88	2.21	4.43	11.07	22.13	44.27	108.60	132.81	221.35	1,085.97
Control Equipment Costs	$50,500	$90,900	$111,100	$146,450	$212,100	$373,700	$300,000	$479,750	$757,500	$1,500,000
Instrumentation	$5,050	$9,090	$11,110	$14,645	$21,210	$37,370	$30,000	$47,975	$75,750	$150,000
Freight	$2,778	$5,000	$6,111	$8,055	$11,666	$20,554	$16,500	$26,386	$41,663	$82,500
Total Purchased Equipment Costs	$58,328	$104,990	$128,321	$169,150	$244,976	$431,624	$346,500	$554,111	$874,913	$1,732,500
Total Direct Installation Costs	$91,574	$164,834	$201,463	$265,565	$384,612	$677,649	$544,005	$869,955	$1,373,613	$2,720,025
Total Indirect Installation Costs	$20,415	$36,746	$44,912	$59,202	$85,741	$151,068	$121,275	$193,939	$306,219	$606,375
Total Capital Investment	$111,989	$201,580	$246,375	$324,768	$470,353	$828,717	$665,280	$1,063,894	$1,679,832	$3,326,400
Operating and Supervisory Labor Costs	$5,009	$5,009	$5,009	$5,009	$5,009	$5,009	$5,009	$5,009	$5,009	$5,009
Maintenance Cost	$9,583	$9,583	$9,583	$9,583	$9,583	$9,583	$9,583	$9,583	$9,583	$9,583
Pilot Gas Cost	$4,271	$4,271	$4,271	$4,271	$4,271	$4,271	$4,271	$4,271	$4,271	$8,541
Annual Electricity Cost	$43	$43	$43	$43	$43	$43	$43	$43	$43	$86
Direct Annual Costs	$18,906	$18,906	$18,906	$18,906	$18,906	$18,906	$18,906	$18,906	$18,906	$23,219
Overhead	$8,755	$8,755	$8,755	$8,755	$8,755	$8,755	$8,755	$8,755	$8,755	$8,755
Administrative Charges	$2,240	$4,032	$4,928	$6,495	$9,407	$16,574	$13,306	$21,278	$33,597	$66,528
Insurance	$1,120	$2,016	$2,464	$3,248	$4,704	$8,287	$6,653	$10,639	$16,798	$33,264
Capital Recovery	$10,571	$19,027	$23,255	$30,655	$44,397	$78,223	$62,796	$100,421	$158,559	$313,979
Indirect Annual Costs	$22,685	$33,830	$39,402	$49,153	$67,262	$111,839	$91,509	$141,093	$217,710	$422,526
Total Annual Costs	$41,591	$52,735	$58,307	$68,059	$86,168	$130,745	$110,415	$159,999	$236,615	$445,745
Total Annual Gas Flow (TPY)	2.76	6.91	13.85	34.60	69.18	138.38	339.43	415.12	691.85	3,394.31
TPY of CH_4 Emissions Reduced	2.25	5.65	11.32	28.28	56.54	113.10	277.41	339.27	565.44	2,774.12
Cost Per Ton	$18,462	$9,341	$5,152	$2,406	$1,524	$1,156	$398	$472	$418	$161
TPY of VOC Emissions Reduced	0.12	0.29	0.59	1.47	2.94	5.88	14.41	17.63	29.38	144.14
Cost Per Ton	$355,329	$179,782	$99,151	$46,315	$29,334	$22,249	$7,660	$9,076	$8,054	$3,092
TPY of HAP Emissions Reduced	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.03
Cost Per Ton	$1,579,159,879	$798,991,326	$440,647,863	$205,835,023	$130,364,846	$98,879,212	$34,044,084	$40,337,559	$35,792,683	$13,743,595
TPY of All Pollutants Emissions Reduced	2.37	5.94	11.91	29.75	59.47	118.98	291.83	356.90	594.83	2,918.29
Cost Per Ton	$17,550	$8,880	$4,897	$2,288	$1,449	$1,099	$378	$448	$398	$153

Table 40 – Cost-Effectiveness of Proposed vs. Recalculated Control Thresholds for Open Flares

(All dollar values in 2016 dollars)	Vendor D Open Flare @ 2,606 Mscfd	Vendor D Open Flare @ 2,606 Mscfd	Vendor D Open Flare @ 26,064 Mscfd	Vendor D Open Flare @ 26,064 Mscfd
Total Annual Costs	$38,563	$38,563	$53,779	$53,779
TPY of CH_4 Emissions Reduced	190.00	49.31	190.00	49.31
Cost Per Ton	$203	$782	$283	$1,091
TPY of VOC Emissions Reduced	2.57	2.57	2.57	2.57
Cost Per Ton	$15,034	$15,034	$20,966	$20,966
TPY of HAP Emissions Reduced	0.95	0.95	0.95	0.95
Cost Per Ton	$40,593	$40,593	$56,609	$56,609
TPY of All Pollutants Emissions Reduced	193.52	52.82	193.52	52.82
Cost Per Ton	$199	$730	$278	$1,018

As can be seen in Table 40, open flares are less expensive and have lower annual operating costs than enclosed flares, ranging from $203 to $283 per ton of methane reduced for the 200 tpy methane control threshold. At the recalculated 51.9 tpy methane control threshold, the costs range from $782 to $1,091 per ton of methane reduced which just meets EPA's Social Cost of Methane. However, the Department determines that BAT control measures for methane must be implemented for sources with emissions that meet or exceed 200 tpy methane; this requirement is also included in the exemption criteria for facilities seeking exemption under Category 38(c). One reason for conservatively establishing the methane control threshold at 200 tpy instead of 51.9 tpy is due to the inherent scientific uncertainty in the second analysis control threshold calculation discussed in Appendix A – Average Gas Composition Analysis and the site-specific uncertainty in the control costs from Appendix D – Cost Analysis for Combustion Control Devices.

For the primary BAT analysis, the Department determined the total annual flow through the open flare based on the operational information from Table 37 and the average natural gas composition as determined in Table 16 of Appendix A – Average Gas Composition Analysis. Where the flow was given as a volume of methane, the Department used the methane density of 0.0416 lb/scf and the average gas composition density of 0.0442 lb/scf to determine the adjusted flow rate. For Vendor D, the flow was given in lb/h; the Department used the average gas composition density to determine the volume flow. The Department used EPA's Air Pollution Control Cost Manual to determine the total capital investment and total annual costs based on the purchased equipment prices provided by the commentators. The results can be seen in Table 41 below.

Open flares are only authorized to be used at remote facilities and with infrequent operations.

Table 41 - BAT Analysis for Open Flare

(All dollar values in 2016 dollars)	Vendor D Open Flare @ 2,606 Mscfd	Vendor D Open Flare @ 26,064 Mscfd
Control Flow Rate (Mscfh)	108.60	1,085.97
Control Equipment Costs	$50,000	$100,000
Instrumentation	$5,000	$10,000
Freight	$2,750	$5,500
Total Purchased Equipment Costs	$57,750	$115,500
Total Direct Installation Costs	$90,668	$181,335
Total Indirect Installation Costs	$20,213	$40,425
Total Capital Investment	$110,880	$221,760
Operating and Supervisory Labor Costs	$5,009	$5,009
Maintenance Cost	$9,583	$9,583
Pilot Gas Cost	$1,424	$2,847
Annual Electricity Cost	$0	$0
Direct Annual Costs	$16,016	$17,439
Overhead	$8,755	$8,755
Administrative Charges	$2,218	$4,435
Insurance	$1,109	$2,218
Capital Recovery	$10,466	$20,932
Indirect Annual Costs	$22,548	$36,340
Total Annual Costs	$38,563	$53,779
Total Annual Gas Flow (TPY)	339.43	3,394.31
TPY of CH_4 Emissions Reduced	277.41	2,774.12
Cost Per Ton	$139	$19
TPY of VOC Emissions Reduced	14.41	144.14
Cost Per Ton	$2,675	$373
TPY of HAP Emissions Reduced	0.00	0.03
Cost Per Ton	$11,890,087	$1,658,157
TPY of All Pollutants Emissions Reduced	291.83	2,918.29
Cost Per Ton	$132	$18

XXVI. Appendix E – LDAR Cost Analysis

ICF has conducted two analyses on LDAR, one for the Environmental Defense Fund (EDF) in March of 2014[28] and one for ONE Future Inc. in May of 2016[29]. In both analyses, they broke down the costs associated with an LDAR program into an hourly cost number. This was an adaptation of the analysis used by Colorado in their rulemaking. In the March 2014 analysis, the determination was that the total cost as an hourly rate was $101.64 and that inspections would be performed on a quarterly basis. This resulted in an LDAR cost that ranged between $2.15 and $7.60 per Mcf of methane reduced, which approximates to between $95 and $336 per ton of methane reduced, when not counting the recovered gas value. In the May 2016 analysis, the determination was that the total cost as an hourly rate was $142.06 and that inspections would be performed annually. This resulted in an LDAR cost that ranged between $1.41 and $6.94 per Mcf of methane reduced, which approximates to between $62 and $306 per ton of methane, when not counting the recovered gas value.

The Department conducted two independent LDAR cost analyses, the first using the ICF analyses as a basis and a second based on two vendors' quotes. The Department's assumptions in the first analysis included a semi-annual and quarterly survey interval for unconventional natural gas well sites and a quarterly survey interval for natural gas compression stations, processing plants, and transmission stations. The semi-annual frequency is assumed to result in a 50% emissions reduction and the quarterly frequency is assumed to result in a 60% emissions reduction. The Department favored the ONE Future Equipment Costs as the basis of the cost analysis as it includes a high-flow system for leak quantification in the analysis.

Table 42 and Table 43 below represent the Department's assumptions on frequency with the respective assumptions on emissions and hours for each survey from the two ICF analyses.

Table 42 - LDAR Costs with ONE Future Equipment Costs and EDF Assumptions

	Wellpads	Wellpads	Gathering	Processing	Transmission
Methane (Mcf/yr)	440	440	1,676	2,448	4,671
% Reduction	50%	60%	60%	60%	60%
Reduction (Mcf)	220	264	1,006	1,469	2,803
Hours each Inspection	2.7	2.7	8.0	8.0	8.0
Frequency per Year	2	4	4	4	4
Annual Inspection Cost	$767	$1,534	$4,546	$4,546	$4,546
Initial Set-Up	$77	$153	$455	$455	$455
Repair Labor Cost	$575	$1,151	$3,409	$3,409	$3,409
Total Cost per Year	$1,419	$2,838	$8,410	$8,410	$8,410
Cost of Reduction ($/Mcf)	$6.45	$10.75	$8.36	$5.73	$3.00
Cost of Reduction ($/ton)	$309.39	$515.65	$401.11	$274.62	$143.92

[28] Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, ICF International on behalf of the Environmental Defense Fund, March 2014.
[29] Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems, ICF International on behalf of ONE Future Inc., May 2016.

Table 43 - LDAR Costs with ONE Future Equipment Costs and Assumptions

	Wellpads	Wellpads	Gathering	Processing	Transmission
Methane (Mcf/yr)	3,057	3,057	3,605	5,986	3,605
% Reduction	50%	60%	60%	60%	60%
Reduction (Mcf)	1,529	1,834	2,163	3,592	2,163
Hours each Inspection	5.5	5.5	32.0	40.0	32.0
Frequency per Year	2	4	4	4	4
Annual Inspection Cost	$1,563	$3,125	$18,184	$22,730	$18,184
Initial Set-Up	$156	$313	$1,818	$2,273	$1,818
Repair Labor Cost	$1,172	$2,344	$13,638	$17,047	$13,638
Total Cost per Year	$2,891	$5,782	$33,640	$42,050	$33,640
Cost of Reduction ($/Mcf)	$1.89	$3.15	$15.55	$11.71	$15.55
Cost of Reduction ($/ton)	$90.71	$151.19	$745.92	$561.53	$745.92

As can be seen in the tables, the cost of reduction in both cases is well within the cost-effective range of $1,000 per ton of methane reduced.

A. *The Department's Independent LDAR Cost Analysis*

Since the number of leaking components, amount of leakage from individual components, duration, and frequency is uncertain at an individual facility, it is impractical to perform a generic cost-analysis for LDAR requirements for static and rotating components (flanges, valves, joints, packing of compressor rods, etc.) at well sites, natural gas compression, processing or transmission facilities.

However, the Department contacted representatives of two companies that offer services for LDAR for the sources at well sites, and natural gas compression, processing or transmission facilities, to determine the estimated costs for leak detection, quantification, and repair tasks. Neither company offered quotes for repair costs since the costs for repairs vary significantly, depending on which components are leaking and what type of maintenance is required to repair the leaks. Therefore, the analysis is based only on the quoted costs for methane gas leak detections and quantifications.

According to the representative of the first company, a dry natural gas well pad contains approximately 1,000 components. Wet gas well pads, and compression, processing, or transmission facilities contain approximately 2,000 components. Typically, it takes one person and one day (10 hours) to complete the leak detection task using an OGI camera for a dry gas well pad. It takes one person two days to complete the leak detection using an OGI camera for a wet gas well pad, or natural gas compression, processing, or transmission station. The company charges $75 per hour for manpower, $400 per day for travel costs, $150 per day for camera rental, and $300 per day for gas leak detection device rental.

The company charges the same amount for labor for leak quantification, and assuming all components are leaking it takes two people three days to quantify leaks from all 1,000 components at a dry gas well pad, and two people six days to quantify leaks from all 2,000 components at a wet gas well pad, or natural gas compression, processing, or transmission facility. This yields a labor rate of 0.06 man-hours per component that is leaking, and in the analysis the Department will round up to the nearest full day.

The Department also contacted representatives of the second company to determine their costs for LDAR services, and they echoed the cost that was suggested by the first company. According to the company representatives, typically it costs $750 - $1,500 for any well pad or natural gas compression station for leak detection and quantification.

Based on the above information, the Department performed cost-effectiveness analysis for leak detection and quantification requirements stated for sources located at well pads, and natural gas compression, processing, or transmission facilities. The costs for leak detection were assumed to be at the full quoted cost and the costs for leak quantification were based on the amount of time to survey 1%, 2%, and 3% of the components rounded up to the nearest full day for sources at dry gas well pads, wet gas well pads, and natural gas compression, processing, and transmission facilities.

According to Method 21, the detector must have a sampling rate between $3.53x10^{-3}$ and 0.11 cf/min. At the maximum sampling rate, a 500 ppm indication on a Method 21 detector would be approximately equivalent to a 0.08 cf/day emission rate for a component if it is assumed that 100% of the leak is captured. For leaks above 500 ppm, it is less likely that 100% of the leak is captured, but for purposes of this analysis, it is assumed the detector does capture all of the emissions up to the 100,000 ppm level for a calculated leak rate of 15.84 cf/day. For any leak above 100,000 ppm on a Method 21 device, a high-flow sampler must be used for quantification. A high-flow device has a sampling rate of 10 cf/min and can detect leaks between 0.05 cf/min and 8.00 cf/min. This results in leak emission rates of 72.00 cf/day and 11,520 cf/day, respectively.

Based on the several leak studies, one vendor informed the Department that the majority of leak emissions come from a small percentage of "super-emitters." The Department assumes the "super-emitters" emit at the 11,520.00 cf/day rate and the total daily emission rate is based on the equation:

$$E = \frac{(P_{SE})(C_l)\left(11{,}520\ \frac{cf}{day}\right)}{(P_E)}$$

Where:

E = Total Daily Emission Rate
P_{SE} = Percentage of "Super-Emitters"
C_l = Number of Leaking Components
P_E = Percentage of Total Emissions Attributed to "Super-Emitters"

The following table outlines the calculated total daily emission rate for 1% of the total components at a dry gas well site found leaking.

Table 44 - Super-Emitter Study Data and LDAR Costs[30]

Study Author	Percent "Super-Emitters" (P_{SE})	Percent of Total Emissions (P_E)	Calculated Total Daily Emission Rate (E) (cf/day)	Annual Emissions (Mcf/y)	Annual Avoided Emissions (TPY)	Cost per Ton of Methane Reduced ($/ton)
Brandt, et. al.	5.00%	50%	11,520.00	4,204.80	52.6	$228.13
Rella, et. al.	6.60%	50%	15,206.40	5,550.30	69.4	$172.82
	22%	80%	9,642.60	3,519.50	44	$272.54
Clearstone Engineering	0.06%	58%	119.2	43.5	0.5	$22,047.27
British Columbia Oil & Gas	6.00%	80%	8,640.00	3,153.60	39.5	$304.17

The ONE Future emissions estimate from well sites is 3,057 Mcf/y, and the EDF emission estimate from well sites is 440 Mcf/y. Assuming the Department's costs and that the emissions estimates are from 1% of the total components, this results in costs of $313.78 per ton of methane reduced and $2,180.07 per ton of methane reduced, respectively. The British Columbia Oil & Gas and the Rella, *et al.* top 22% of leaks responsible for 80% of total emissions estimates are in line with ONE Future's emissions estimates from well sites.

Brandt, *et al.* and the Rella, *et al.* top 6.6% responsible for 50% of total emissions estimates are nearly 80% higher than ONE Future's emissions estimates. This serves to drive down the cost per ton of methane reduced. The Clearstone Engineering emissions estimate is approximately 1.5% of the ONE Future emission estimate, which serves to significantly drive up the cost per ton of methane reduced. The Department therefore focused on the British Columbia and Rella, *et al.* 22% cases in the cost analysis.

Based on our independent analysis, the Department determines that quarterly LDAR is technically and economically feasible for the control of methane emissions. The Department preserves the off-ramp originally proposed if less than 2% of components are found to be leaking in two consecutive inspections to help small businesses that operate effectively to reduce the frequency of inspections, and thereby reduce costs.

[30] The second line under Rella, et. al. is calculated assuming that 6.6% emit at the 11,520 cf/day rate and the remaining 15.4% emit at the 72.0 cf/day rate.

Table 45 - LDAR Costs from Vendor Quotes

TOTAL ANNUAL COST FOR LEAK DETECTION										
Facility	~No. of Components	Leak Detection Duration (Days)	Labor Cost Per Man-Hour	Number of Hours/Day	Manpower	Travel Cost ($400/Day-Man)	Equipment Rental (OGI) ($150/Day-Man)	Contingency ($200/Day-Man)	Frequency per Year	Annual Cost for Leak Detection
Wellpad (Dry Gas)	1,000	1	$75	10	1	$400	$150	$200	4	$6,000
Wellpad (Wet Gas), Compressor Station, Processing Plant, or Transmission Station	2,000	2	$75	10	1	$800	$300	$400	4	$12,000

TOTAL ANNUAL COST FOR LEAK QUANTIFICATION											
Facility	Percent Leaking Components	~No. of Components Leaking	Leak Quantification Duration (Days)	Labor Cost Per Man-Hour	Number of Hours/Day	Manpower	Travel Cost ($400/Day-Man)	Equipment Rental (Method 21) ($150/Day-Man)	Contingency ($200/Day-Man)	Frequency per Year	Annual Cost for Leak Quantification
Wellpad (Dry Gas)	1.0%	10	1	$75	10	1	$400	$150	$200	4	$6,000
	2.0%	20	1	$75	10	1	$400	$150	$200	4	$6,000
	3.0%	30	1	$75	10	1	$400	$150	$200	4	$6,000
Wellpad (Wet Gas), Compressor Station, Processing Plant, or Transmission Station	1.0%	20	1	$75	10	1	$400	$150	$200	4	$6,000
	2.0%	40	1	$75	10	1	$400	$150	$200	4	$6,000
	3.0%	60	1	$75	10	1	$400	$150	$200	4	$6,000

Table 46 - LDAR Cost Analysis Based on Rella *et al.* and British Columbia Emissions Assumptions

TOTAL ANNUAL COST FOR LEAK DETECTION AND LEAK QUANTIFICATION												
Facility	Percent Leaking Components	Total Annual Cost	Rella et. al.					British Columbia Oil and Gas				
			Total Flow Rate (CF/Day)	Undetected Annual PTE (CFY)	Avoided Emissions (CFY)	Mass of Avoided Emissions (TPY)	$/ton	Total Flow Rate (CF/Day)	Undetected Annual PTE (CFY)	Avoided Emissions (CFY)	Mass of Avoided Emissions (TPY)	$/ton
Wellpad (Dry Gas)	1.0%	$12,000	9,643	3,519,549	2,111,729	44.03	$272.54	8,640	3,153,600	1,892,160	39.45	$304.17
	2.0%	$12,000	19,285	7,039,098	4,223,459	88.06	$136.27	17,280	6,307,200	3,784,320	78.90	$152.09
	3.0%	$12,000	28,928	10,558,647	6,335,188	132.09	$90.85	25,920	9,460,800	5,676,480	118.35	$101.39
Wellpad (Wet Gas), Compressor Station, Processing Plant, or Transmission Station	1.0%	$18,000	19,285	7,039,098	4,223,459	88.06	$204.41	17,280	6,307,200	3,784,320	78.90	$228.13
	2.0%	$18,000	38,570	14,078,196	8,446,918	176.12	$102.20	34,560	12,614,400	7,568,640	157.81	$114.06
	3.0%	$18,000	57,856	21,117,294	12,670,376	264.18	$68.14	51,840	18,921,600	11,352,960	236.71	$76.04

B. The Department's Revised LDAR Cost Analysis

Based on comments received, the Department has performed a brief reanalysis of LDAR costs, which are summarized in Table 47 below. Even with a leak rate at 0.13% of production or throughput, the mass and volume of emissions are very high. The corresponding costs, which are based on the Annual Costs for Leak Detection in Table 45, the assumed leak rate, and the assumed production and throughput rates yield cost effectiveness numbers well below EPA's Social Cost of Methane. Based on our revised analysis, the Department determines that quarterly LDAR is technically and economically feasible for the control of methane emissions. The Department preserves the off-ramp originally proposed if less than 2% of components are found to be leaking in two consecutive inspections to help small businesses that operate effectively to reduce the frequency of inspections, and thereby reduce costs.

Table 47 - Revised LDAR Cost Analysis

TOTAL ANNUAL COST FOR LEAK DETECTION[1]						
Facility	**Total Annual Cost**	**Total Flow Rate (CF/Day)**	**Undetected Annual PTE (CFY)**	**Avoided Emissions (CFY)**	**Mass of Avoided Emissions (TPY)**	**$/ton**
Wellpad (Dry Gas)[2]	$6,000	13,000	4,745,000	2,847,000	59.36	$101.08
Wellpad (Wet Gas)[2]	$12,000	13,000	4,745,000	2,847,000	59.36	$202.16
Compressor Station, Processing Plant, or Transmission Station[3]	$12,000	910,000	332,150,000	199,290,000	4,155.20	$2.89

[1] The Annual Cost reflects only leak detection, as the leak quantification requirements were removed.

[2] The assumed production was 10 MMcf/d, with an assumed leak rate of 0.13% of production.

[3] The assumed throughput was 700 MMcf/d based on the previously referenced U.S. EIA report (see page 26), with an assumed leak rate of 0.13% of throughput.

XXVII. Appendix F – Urbanized Areas and Urban Clusters from the 2010 Census

Albion, PA Urban Cluster (2010)
Allentown, PA--NJ Urbanized Area (2010)
Altoona, PA Urbanized Area (2010)
Ashland, PA Urban Cluster (2010)
Bedford, PA Urban Cluster (2010)
Bellefonte, PA Urban Cluster (2010)
Belvidere, NJ--PA Urban Cluster (2010)
Binghamton, NY--PA Urbanized Area (2010)
Blairsville, PA Urban Cluster (2010)
Bloomsburg--Berwick, PA Urbanized Area (2010)
Bonneauville, PA Urban Cluster (2010)
Bradford, PA--NY Urban Cluster (2010)
Brockway, PA Urban Cluster (2010)
Brookville, PA Urban Cluster (2010)
Burgettstown, PA Urban Cluster (2010)
Butler, PA Urban Cluster (2010)
Cambridge Springs, PA Urban Cluster (2010)
Chambersburg, PA Urbanized Area (2010)
Clarion, PA Urban Cluster (2010)
Cresson, PA Urban Cluster (2010)
Cumberland, MD--WV--PA Urbanized Area (2010)
East Liverpool, OH--WV--PA Urban Cluster (2010)
East Prospect, PA Urban Cluster (2010)
East Stroudsburg, PA--NJ Urbanized Area (2010)
Edinboro, PA Urban Cluster (2010)
Ellwood City, PA Urban Cluster (2010)
Emmitsburg, MD--PA Urban Cluster (2010)
Emporium, PA Urban Cluster (2010)
Erie, PA Urbanized Area (2010)
Everett, PA Urban Cluster (2010)
Fairdale, PA Urban Cluster (2010)
Franklin (Venango County), PA Urban Cluster (2010)
Greenville, PA Urban Cluster (2010)
Grove City, PA Urban Cluster (2010)
Hagerstown, MD--WV--PA Urbanized Area (2010)
Hanover, PA Urbanized Area (2010)
Harrisburg, PA Urbanized Area (2010)
Hazleton, PA Urbanized Area (2010)
Honesdale, PA Urban Cluster (2010)
Houtzdale, PA Urban Cluster (2010)
Huntingdon, PA Urban Cluster (2010)
Jersey Shore, PA Urban Cluster (2010)
Jim Thorpe, PA Urban Cluster (2010)
Johnstown, PA Urbanized Area (2010)
Kutztown, PA Urban Cluster (2010)
Lake Meade, PA Urban Cluster (2010)
Lancaster, PA Urbanized Area (2010)
Lebanon, PA Urbanized Area (2010)
Lewistown, PA Urban Cluster (2010)
Ligonier, PA Urban Cluster (2010)
Littlestown, PA Urban Cluster (2010)
Lock Haven, PA Urban Cluster (2010)
Lykens, PA Urban Cluster (2010)
Mansfield, PA Urban Cluster (2010)
Martinsburg, PA Urban Cluster (2010)
Masontown, PA Urban Cluster (2010)
Meadville, PA Urban Cluster (2010)
Mercer, PA Urban Cluster (2010)
Meyersdale, PA Urban Cluster (2010)
Mifflinburg, PA Urban Cluster (2010)
Mifflintown, PA Urban Cluster (2010)
Milford, NJ--PA Urban Cluster (2010)
Millersburg, PA Urban Cluster (2010)
Millsboro, PA Urban Cluster (2010)
Milton--Lewisburg, PA Urban Cluster (2010)
Monessen--California, PA Urbanized Area (2010)
Montgomery, PA Urban Cluster (2010)
Moscow, PA Urban Cluster (2010)

Mount Holly Springs, PA Urban Cluster (2010)
Mount Union, PA Urban Cluster (2010)
Muncy, PA Urban Cluster (2010)
Nanty-Glo, PA Urban Cluster (2010)
New Castle, PA Urban Cluster (2010)
New Freedom--Shrewsbury, PA--MD Urban Cluster (2010)
New Wilmington, PA Urban Cluster (2010)
North East, PA Urban Cluster (2010)
Northern Cambria, PA Urban Cluster (2010)
Oil City, PA Urban Cluster (2010)
Orwigsburg, PA Urban Cluster (2010)
Philadelphia, PA--NJ--DE--MD Urbanized Area (2010)
Philipsburg, PA Urban Cluster (2010)
Pine Grove, PA Urban Cluster (2010)
Pittsburgh, PA Urbanized Area (2010)
Portage, PA Urban Cluster (2010)
Pottstown, PA Urbanized Area (2010)
Pottsville, PA Urban Cluster (2010)
Punxsutawney, PA Urban Cluster (2010)
Quarryville, PA Urban Cluster (2010)
Reading, PA Urbanized Area (2010)
Reynoldsville, PA Urban Cluster (2010)
Ridgway, PA Urban Cluster (2010)
Roaring Spring, PA Urban Cluster (2010)
Saw Creek, PA Urban Cluster (2010)
Sayre--Waverly, PA--NY Urban Cluster (2010)
Scranton, PA Urbanized Area (2010)
Shamokin--Mount Carmel, PA Urban Cluster (2010)
Shippensburg, PA Urban Cluster (2010)
Sierra View--Indian Mountain Lake, PA Urban Cluster (2010)
Slippery Rock, PA Urban Cluster (2010)
Somerset, PA Urban Cluster (2010)
State College, PA Urbanized Area (2010)
Stewartstown, PA Urban Cluster (2010)
Susquehanna Depot, PA Urban Cluster (2010)
Titusville, PA Urban Cluster (2010)
Towanda, PA Urban Cluster (2010)
Treasure Lake, PA Urban Cluster (2010)
Tunkhannock, PA Urban Cluster (2010)
Tyrone, PA Urban Cluster (2010)
Union City, PA Urban Cluster (2010)
Uniontown--Connellsville, PA Urbanized Area (2010)
Waynesboro, PA--MD Urban Cluster (2010)
Waynesburg, PA Urban Cluster (2010)
Weirton--Steubenville, WV--OH--PA Urbanized Area (2010)
Williamsport, PA Urbanized Area (2010)
Williamstown, PA Urban Cluster (2010)
Youngstown, OH--PA Urbanized Area (2010)
Youngsville, PA Urban Cluster (2010)

XXVIII. Appendix G – Non-road Engine Standards

The emission limits in the following tables are expressed in g/bhp-h.

Table 48 - Non-Road Compression Ignition Engine Emission Standards

<table>
<tr><th rowspan="2"></th><th colspan="5">Tier 1</th><th colspan="5">Tier 2</th><th colspan="5">Tier 3</th><th colspan="5">Tier 4i</th><th colspan="5">Tier 4f</th></tr>
<tr><th>Model Year</th><th>NO_X</th><th>HC</th><th>CO</th><th>PM</th><th>Model Year</th><th>NO_X</th><th>HC</th><th>CO</th><th>PM</th><th>Model Year</th><th>NO_X</th><th>HC</th><th>CO</th><th>PM</th><th>Model Year</th><th>NO_X</th><th>HC</th><th>CO</th><th>PM</th><th>Model Year</th><th>NO_X</th><th>HC</th><th>CO</th><th>PM</th></tr>
<tr><td>HP < 11</td><td>2000</td><td colspan="2">7.83</td><td>5.97</td><td>0.75</td><td>2005</td><td colspan="2">5.59</td><td>5.97</td><td>0.6</td><td rowspan="4" colspan="5"></td><td>2008</td><td colspan="2">5.59</td><td>5.97</td><td>0.3</td><td>2014</td><td colspan="2">5.59</td><td>5.97</td><td>0.3</td></tr>
<tr><td>11 ≤ HP < 25</td><td>2000</td><td colspan="2">7.08</td><td>4.92</td><td>0.75</td><td>2005</td><td colspan="2">5.59</td><td>4.92</td><td>0.6</td><td>2008</td><td colspan="2">5.59</td><td>4.92</td><td>0.3</td><td>2014</td><td colspan="2">5.59</td><td>4.92</td><td>0.3</td></tr>
<tr><td rowspan="2">25 ≤ HP < 50</td><td rowspan="2">1999</td><td rowspan="2" colspan="2">7.08</td><td rowspan="2">4.1</td><td rowspan="2">0.75</td><td rowspan="2">2004</td><td rowspan="2" colspan="2">5.59</td><td rowspan="2">4.1</td><td rowspan="2">0.45</td><td>2008</td><td colspan="2">5.59</td><td>4.1</td><td>0.22</td><td rowspan="2">2014</td><td rowspan="2" colspan="2">3.5</td><td rowspan="2">4.1</td><td rowspan="2">0.02</td></tr>
<tr><td>2013</td><td colspan="2">3.5</td><td>3.73</td><td>0.02</td></tr>
<tr><td>50 ≤ HP < 75</td><td rowspan="2">1998</td><td rowspan="2">6.86</td><td rowspan="3" colspan="3"></td><td rowspan="2">2004</td><td rowspan="2" colspan="2">5.59</td><td rowspan="2">3.73</td><td rowspan="2">0.3</td><td rowspan="2">2008</td><td rowspan="2" colspan="2">3.5</td><td rowspan="2">3.73</td><td rowspan="2">0.3</td><td>2013</td><td colspan="2">3.5</td><td>3.73</td><td>0.02</td><td>2014</td><td colspan="2">3.5</td><td>3.73</td><td>0.01</td></tr>
<tr><td>75 ≤ HP < 100</td><td>2014</td><td>0.3</td><td>0.14</td><td>3.73</td><td>0.01</td><td rowspan="2">2014</td><td rowspan="2">0.3</td><td rowspan="2">0.14</td><td rowspan="2">3.73</td><td rowspan="2">0.01</td></tr>
<tr><td>100 ≤ HP < 175</td><td>1997</td><td>6.86</td><td>2003</td><td colspan="2">4.92</td><td>3.73</td><td>0.22</td><td>2007</td><td colspan="2">2.98</td><td>3.73</td><td>0.22</td><td>2014</td><td>0.3</td><td>0.14</td><td>3.73</td><td>0.01</td></tr>
<tr><td>175 ≤ HP < 300</td><td>1996</td><td>6.86</td><td>0.97</td><td>8.5</td><td>0.4</td><td>2003</td><td colspan="2">4.92</td><td>2.61</td><td>0.15</td><td>2006</td><td colspan="2">2.98</td><td>2.61</td><td>0.15</td><td rowspan="3">2014</td><td rowspan="3">0.3</td><td rowspan="3">0.14</td><td rowspan="3">2.61</td><td rowspan="3">0.01</td><td rowspan="3">2014</td><td rowspan="3">0.3</td><td rowspan="3">0.14</td><td rowspan="3">2.61</td><td rowspan="3">0.01</td></tr>
<tr><td>300 ≤ HP < 600</td><td>1996</td><td>6.86</td><td>0.97</td><td>8.5</td><td>0.4</td><td>2001</td><td colspan="2">4.77</td><td>2.61</td><td>0.15</td><td>2006</td><td colspan="2">2.98</td><td>2.61</td><td>0.15</td></tr>
<tr><td>600 ≤ HP ≤ 750</td><td>1996</td><td>6.86</td><td>0.97</td><td>8.5</td><td>0.4</td><td>2002</td><td colspan="2">4.77</td><td>2.61</td><td>0.15</td><td>2006</td><td colspan="2">2.98</td><td>2.61</td><td>0.15</td></tr>
<tr><td>750 < HP ≤ 1205</td><td rowspan="3">2000</td><td rowspan="3">6.86</td><td rowspan="3">0.97</td><td rowspan="3">8.5</td><td rowspan="3">0.54</td><td rowspan="3">2006</td><td rowspan="3" colspan="2">4.77</td><td rowspan="3">2.61</td><td rowspan="3">0.15</td><td rowspan="3" colspan="5"></td><td>2014</td><td>2.61</td><td>0.3</td><td>2.61</td><td>0.07</td><td>2014
Gen Set</td><td>0.5</td><td>0.14</td><td>2.61</td><td>0.02</td></tr>
<tr><td rowspan="2">1205 < HP</td><td>2014
Gen Set</td><td>0.5</td><td>0.3</td><td>2.61</td><td>0.07</td><td rowspan="2">2014
Other</td><td rowspan="2">2.61</td><td rowspan="2">0.14</td><td rowspan="2">2.61</td><td rowspan="2">0.03</td></tr>
<tr><td>2014
Other</td><td>2.61</td><td>0.3</td><td>2.61</td><td>0.07</td></tr>
</table>

Table 49 - Non-Road Spark Ignition Engine Emission Standards

		General Emission Standards		Severe-Duty Engine Emission Standards	
		NO_X + HC	CO	NO_X + HC	CO
Certification and Production-Line Testing	Tier 1 Model Year 2004-2006	2.98	37.29	2.98	96.94
Field Testing		4.03	37.92	4.03	96.94
Steady-State Testing	Tier 2 Model Year 2007-	2.01	3.28	2.01	96.94
Transient Testing		2.01	3.28		
Field Testing		2.83	4.85	2.83	149.14

XXIX. Appendix H – Well Site Rod Packing Replacement Cost-Effectiveness Analysis

Table 50 - Rod Packing Cost Analysis with Revised Emission Factors

(All dollar values in 2016 dollars)	EPA TSD Production	UT Methane Emission Factor Production - low	UT Methane Emission Factor Production - high	UT Methane Emission Factor Production - measured	UT Methane Emission Factor Production - average
Packing Replacement Costs (Materials and Installation)	$1,814	$1,814	$1,814	$1,814	$1,814
Annualized Packing Replacement Cost	$698	$698	$698	$698	$698
Total Annualized Costs	$698	$698	$698	$698	$698
TPY of CH_4 Emissions Reduced	0.0456	0.0456	5.6104	0.9144	2.1901
TPY of VOC Emissions Reduced	0.0024	0.0024	0.2915	0.0475	0.1138
TPY of HAP Emissions Reduced	0.0000	0.0000	0.0001	0.0000	0.0000
Cost Per Ton Pollutant	$14,551	$14,551	$118	$726	$303
Cost Per Ton Methane	$15,307	$15,307	$124	$763	$319
Cost Per Ton VOC	$294,603	$294,603	$2,395	$14,692	$6,134
Cost Per Ton HAP	$1,316,877,281	$1,316,877,281	$10,703,529	$65,671,548	$27,418,845

XXX. Appendix I – GP-5 Malfunction Reporting Instructions

GP-5 Malfunction Reporting Instructions

1. **Malfunction reporting to the PA Department of Environmental Protection (DEP or Department) under GP-5 must be conducted as follows:**

   a. The owner/operator authorized to use GP-5 shall report to DEP each malfunction that results in a potential exceedance of the GP-5 emissions limits. For GP-5 purposes, the term malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control or process equipment, or, operating in a non-permitted manner, which results in, or may possibly be resulting in, the emission of air contaminants in excess of any applicable limitations specified in GP-5.

   b. The notification, recordkeeping and reporting requirements relating to performance testing, work practice and monitoring standards, equipment leaks or fugitive emissions noted in GP-5 are not subject to the malfunction reporting requirements.

   c. When the malfunction or incident poses an imminent and substantial danger to the public health and safety, and/or potential harm to the environment, the owner/operator shall report the incident to the Department and the County Emergency Management Agency immediately after the discovery of an incident. The owner/ operator shall submit a written report of instances of such malfunctions or incidents to the Department within three (3) business days of the telephone report.

      i. The Report shall include the following:
         a) name and location of the facility;
         b) nature and cause of the malfunction or incident;
         c) time when the malfunction, incident or breakdown was first observed;
         d) expected duration of increased emissions; and
         e) estimated rate of emissions

      ii. The Owner/Operator shall notify the Department immediately when corrective measures have been accomplished.

   d. Incidents covered by the notification, recordkeeping and reporting requirements relating to performance testing, work practice and monitoring standards, equipment leaks or fugitive emissions noted in this general permit are not subject to the reporting requirements of this section.

   e. Any malfunction or incident that is not subject to the notice requirements of paragraph (c) of this document shall be reported to the Department by telephone within 24 hours (or by 4:00 PM of the next business day, whichever is later) of discovery and in writing or e-mail within five days of discovery of the incident. The report shall contain the same information required by paragraph (c)(i).

   f. The Department may require, when a malfunction or other incident results in citizen complaints, the Owner/Operator to report the incident immediately to the Department. The Department will review the incident and determine if a written follow up report including corrective action is needed.

   g. Malfunctions shall be reported to the appropriate DEP Regional Office Air Program Manager.

2. **Examples of Malfunctions or Incidents are provided below.**

a. Malfunctions or incidents posing an imminent and substantial danger to the public health and safety.

i. Reportable
a) Fire;
b) Explosion; or
c) Explosive or other condition that may impact outside of the fence-line or require evacuations.

b. Malfunctions or incidents that do not pose an imminent and substantial danger to public health and safety but may result in an exceedance of GP-5 emissions limits.

i. Reportable Malfunctions or Incidents
a) Process equipment incidents, or air pollution control equipment shutdown or reduction in control which results in VOC, NOX, CO, HAP, or Formaldehyde emissions in excess of the General Permit's emissions limits or permit requirements.
b) Equipment or operation failure, or malfunctions in process or pollution control equipment that result in fugitive particulate emission or odor beyond the facility boundary.

ii. Non-reportable Malfunctions or Incidents
a) Air Pollution Control equipment shutdowns that are rectified by automatic restarts, other adjustments of the operation as per the manufacturer.
b) Air Pollution Control equipment shutdowns which are manually restarted within one hour of the malfunction and do not result in emissions in excess of GP limitations.
c) Malfunctions in process or pollution control equipment which result in odor or fugitive dust emissions which are contained within the facility's fence-line.
d) Building fire eyes or gas detector trips that pose no harm to the public.
e) False fire eyes or other safety device trips which do not pose harm to the public.
f) Upset conditions within the site boundaries which do not pose a threat to the public provided that they do not result in a potential exceedance of the GP-5 emissions limits.

c. Emergency Releases

i. Reportable Releases
a) Unplanned Emergency Shut-down events that result in a potential exceedance of permit emission limits or create an offsite risk.
b) Relief valves that stay open, or frequently relieve and may result in a potential exceedance of permit limits.

ii. Non- Reportable Releases
a) Vents from pressure safety relief valves (PSVs) that do not result in a potential exceedance of permit limits or create an offsite risk. However, DEP should be notified by telephone if there is noise from the release that results in community complaints to the facility owner/operator, or there are multiple PSV incidents.

d. Planned Compressor Vents, Engine Starters and Other Emissions Included in the Application

i. Non-Reportable Releases
a) Venting from compressors as described in the GP-5 Application that do not result in an exceedance of emission limits.

b) Gas from engine starters as described in the application that do not result in an exceedance of emission limits. Planned or required ESDs included in the application that do not result in an exceedance of emission limits.

c) Rod packing or crankcase vent emissions – source of minor significance normally detailed in the permit application.

e. Malfunctions or Other Incidents That Result in Citizen Complaints – Courtesy Reporting

i. Incident Reporting

a) Noise from pressure relief valves or other safety devices that result in community complaints to the facility owner/operator.

b) Odors from an off-site source when detected in the area.

c) Issues that have received prior community complaints.

d) Emergency Response Drills held at the facility where a number of emergency vehicles may be present.

f. Dehydrators

i. Reportable Incidents

a) Still vent bypass or flash tank venting from freezing or process malfunction that has the potential to exceed permit emission limitations.

b) Malfunctions of process controls that may or may not result in exceedances of permit limits.

ii. Non-Reportable Incidents

a) Still vent or flash tank bypass of oxidizers or other controls during automated restart sequence, without any potential to exceed permit emission limits.

NOTE: Emissions (including emissions from malfunctions) from all sources must be included in the source reports submitted to DEP by March 1st each year as prescribed in 25 Pa. Code Chapter 135 (relating to reporting of sources).