AIR QUALITY PERMIT EXEMPTIONS – CATEGORY NO. 38
CURRENT INTERNAL IMPLEMENTATION INSTRUCTIONS

This document outlines implementation instructions to assist the Pennsylvania Department of Environmental Protection staff to consistently implement the provisions of Category No. 38 of the Air Quality Permit Exemption List (Document No. 275-2101-003). These instructions do not mandate specific inspections but provide instructions when inspections are conducted. Inspectors may be any DEP staff that are conducting inspections at the site and have been trained to understand the Category No. 38 instructions.

The provisions of Category No. 38 are printed in "bold" text with the explanatory instructions in regular font type.

38. Oil and gas exploration, development, and production facilities and associated equipment and operations meeting the following provisions:

a. Conventional wells, wellheads and all other associated equipment. A conventional well is any well that does not meet the definition of unconventional gas well in 58 PA.C.S § 3203.

The term "Unconventional gas well" is defined at 58 PA.C.S. § 3203 as follows:

"A bore hole drilled or being drilled for the purpose of or to be used for the production of natural gas from an unconventional formation."

The term "Unconventional formation" is defined at 58 PA.C.S. § 3203 as follows:

"A geological shale formation existing below the base of the Elk Sandstone or its geologic equivalent stratigraphic interval where natural gas generally cannot be produced at economic flow rates or in economic volumes except by vertical or horizontal well bores stimulated by hydraulic fracture treatments or by using multilateral well bores or other techniques to expose more of the formation to the well bore."

b. Well drilling, completion and work-over activities.

Well drilling and completion activities include but are not limited to horizontal or vertical drilling, well casing, well completion, lifting and well treatment, and other work-over activities.

This exemption allows the owner or operator to commence the activities related to well drilling, completion, and other activities without any permitting requirements when they comply with the permit exemption Category No. 38 criteria.

It should be noted that completion activities are subject to 40 CFR Part 60, Subpart OOOO and the owner or operator shall comply with the applicable requirements (such as Reduced Emissions Control (REC), Flare, etc.)

c. Non-road engines as defined in 40 CFR § 89.2.

(1) An internal combustion engine is a non-road engine if:

(i) It is used in or on a piece of equipment that is self-propelled or serves a dual purpose by both propelling itself and performing another function.

(ii) It is portable or transportable (i.e., designed to be or capable of being carried or moved from one location to another). Examples of transportability include, but are not limited to, wheels, skids, carrying handles, dollies, trailers, or platforms.

Some examples of non-road engines at a natural gas production facility are drilling rigs, portable generators, and hydraulic fracturing engines.

(2) An internal combustion engine is <u>not</u> a non-road engine if:

(i) It remains at a location for more than 12 consecutive months or if it remains at a location more than two years and operates more than 3 months per year. Any engine used to perform the same or similar function that replaces the engine in question has its time on site included in the consecutive time period; or

(ii) It is regulated by a Federal New Source Performance Standards promulgated under Section 111 of the Act.

Non-road engines are regulated in EPA's 40 CFR Part 89; for more details, see 40 CFR § 89.2. Part 89 includes emission standards and associated certification requirements for non-road engines.

a. Unconventional wells, wellheads, and associated equipment, provided the applicable exemption criteria specified in subparagraphs i, ii, iii, iv and v are met.

i. Within 60 days after the well is put into production, and annually thereafter, the owner/operator will perform a leak detection and repair (LDAR) program that includes either the use of an optical gas imaging camera such as a FLIR camera or a gas leak detector capable of reading methane concentrations in air of 0% to 5% with an accuracy of +/- 0.2% or other leak detection monitoring devices approved by the Department. LDAR is to be conducted on valves, flanges, connectors, storage vessels/storage tanks, and compressor seals in natural gas or hydrocarbon liquids service. Leaks are to be repaired no later than 15 days after leak detections unless facility shutdowns or ordering of replacement parts are necessary for repair of the leaks. The optical gas imaging camera or other Department-approved gas leak detection equipment must be operated in accordance with manufacturer-recommended procedures. For the storage vessel, any leak

detection and repair will be performed in accordance with 40 CFR Part 60, Subpart OOOO.

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

1. **No detectable emissions consistent with Method 21 specified in 40 CFR Part 60, Appendix A;**

2. **A concentration of 2.5% methane or less using a gas leak detector and a VOC concentration of 500 ppm or less;**

3. **No visible leak image when using an optical gas imaging camera;**

4. **No bubbling at leak interface using a soap solution bubble test specified in Method 21; or a procedure based on the formation of bubbles in a soap solution that is sprayed on a potential leak source may be used for those sources that do not have continuously moving parts and that do not have a surface temperature greater than the boiling point or less than the freezing point of the soap solution; or**

5. **Any other method approved by the Department.**

B. Leaks, repair methods and repair delays will be recorded and maintained for five years. If a gas leak detector is used, a leak is to be detected by placing the probe inlet at the surface of a component. The Department may grant an extension for leak detection deadlines or repairs upon the receipt of a written request from the owner or operator of the facility documenting the justification for the requested extension.

<u>LEAK DEFINITION</u>

Any leaks of gaseous hydrocarbons that can be detected by an optical gas imaging camera such as a FLIR camera or any other approved gas leak detection device is considered a leak.

A release by any equipment or component designed by the manufacturer to protect the equipment, controller, or personnel <u>or</u> to prevent ground water contamination, gas migration, or an emergency situation is <u>not</u> considered a leak.

<u>EQUIPMENT OR COMPONENTS TO BE MONITORED FOR LEAKS</u>

The scope of coverage of the equipment or components is dependent on the equipment or components that are located at natural gas wellheads such as valves, flanges, connectors, storage vessels/storage tanks, fittings, piping, etc.

In addition to an evaluation using a FLIR camera or gas leak detector or any other approved gas leak detection device, inspectors should search for signs of leakage from all equipment and components by:

(1) Examining the owner or operator's logs for gauge readings and compare the readings against current readings and previous results for indication of system leakage;

(2) Evaluating equipment for any wear and tear;

(3) Checking for spills of any fluids;

(4) Inspecting all equipment and components for signs of corrosion or leakage; and

(5) Inspecting floating roof in storage tank(s).

OPTICAL GAS IMAGING CAMERA

The Department does not endorse a specific manufacturer or model of optical gas imaging camera for leak detection. Inspectors should note that an owner or operator may use any optical gas imaging camera such as a FLIR camera that is designed and proven by the manufacturer to acceptably detect fugitive gaseous emissions of hydrocarbons from sources at natural gas production facilities and associated equipment. In order to ensure valid readings, the optical gas imaging camera needs to be operated in accordance with manufacturer recommended operating procedures.

QUANTIFICATION OF LEAKS NOT REGULATED BY 40 CFR PART 60 SUBPART OOOO

Using EPA method 21, the emissions are measured as organic compounds. VOC concentration may be computed from the measured organic emissions and the percent VOC in the gas stream. Inspectors should determine that an owner or operator quantifies any leaks by using the following equation:

$$TOC\ concentration \times ratio\ of\ VOC\ to\ TOC\ concentration = VOC\ concentration$$

For example, a facility showing a leak of a 0.5% TOC (0.5 ft^3 TOC/100 ft^3 of sample) gas stream of which 10% of the TOC is VOC by volume (10 ft^3 VOC/100 ft^3 TOC) resulting in a VOC concentration of:

$$\frac{0.5\ ft^3\ TOC}{100\ ft^3\ of\ sample} \times \frac{10\ ft^3\ VOC}{100\ ft^3\ TOC} = \frac{5\ ft^3\ VOC}{10{,}000\ ft^3\ of\ sample}$$

$$\frac{5\ ft^3\ VOC}{10{,}000\ ft^3\ of\ sample} \times \frac{100}{100} = \frac{500\ ft^3\ VOC}{1{,}000{,}000\ ft^3\ of\ sample} = 500\ ppm\ VOC$$

REPORTING OF LEAKS IN ANNUAL EMISSIONS REPORT AS REQUIRED BY CHAPTER 135.

Inspectors should determine if an owner or operator quantifies and includes the emissions from leaks in the annual emissions inventory report which is submitted in accordance with 25 Pa. Code Chapter 135. The emissions may be determined using any generally accepted model or calculation methodology using emission factors.

REPAIR

The term "repair" means that equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in the applicable sections of the federal regulations or as defined in the exemption criteria.

For the equipment subject to exemption criteria a leak is considered repaired if one of the following can be demonstrated:

(1) There are no detectable emissions consistent with Method 21 of 40 CFR Part 60, Appendix A;

(2) There is a concentration of 2.5% methane or less using a gas leak detector and a VOC concentration of 500 ppm or less;

(3) There is no visible leak image when using an optical gas imaging camera;

(4) There is no bubbling at leak interface using a soap solution bubble test specified in Method 21 which may only be used for those sources that do not have continuously moving parts, that do not have surface temperature greater than the boiling point or less than the freezing point of the soap solution; or

(5) There are no detectable emissions by any other method approved by the Department.

Using EPA Method 21, the emissions are measured as organic compounds. VOC concentration may be computed from the measured organic emissions and the percent VOC in the organic (carbon) stream.

For closed vent systems controlling storage vessels, repair must be performed in accordance with 40 CFR Part 60, Subpart OOOO. Subpart OOOO requires closed vent systems controlling storage vessels to be operated with no detectable emissions. Such demonstrations are required to be conducted using EPA Method 21. A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined is less than 500 parts per million by volume.

A first attempt of repair should be made within 5 days of detection of leak. Leaks are to be repaired as soon as practicable, but not later than 15 days after detection, unless repair may require a facility or process shutdown or require new parts for repairs.

COMPLIANCE DEMONSTRATION

Inspectors should determine if an owner or operator demonstrates compliance with the Category No. 38 exemption criteria using any generally accepted model or calculation methodology within 180 days after the well completion or installation of a source. This initial compliance demonstration to the Department may be submitted through electronic or regular mail to the appropriate Regional Air Program Manager. Inspectors are reminded that owners or operators need to maintain the records of demonstration of compliance for at least 5 years and be made available upon request.

Compliance with the exemption criteria for a gas wellhead may be demonstrated with a photograph that contains the following:

(1) Date of photograph;

(2) Longitude and latitude of the well site embedded within or stored with the photograph (or separate GIS device visible in frame); and

(3) Picture of equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to gas flow line, and the completion combustion device connected to and operating at each completion operation.

Compliance with the exemption criteria for storage vessels may be demonstrated by:

(1) An initial performance test and a periodic performance test within 60 months of a previous test;

(2) Maintaining daily average control device parameters above (or below) the minimum (or maximum) level established during the performance test;

(3) Preparing a site-specific monitoring plan for a continuous monitoring system; and

(4) Conducting initial and annual inspections of covers and closed vent systems for leaks or defects.

RECORDKEEPING, NOTIFICATION AND REPORTING

Inspectors should verify that an owner or operator is in compliance with all applicable state and federal requirements including notification, recordkeeping, and reporting requirements as specified in 40 CFR 60, Subpart OOOO.

Inspectors should verify that an owner or operator performing completions after hydraulic fracturing at gas wellheads commencing after January 1, 2015, employs reduced emissions completions (REC) and routes all salable quality gas to the gas flow line as soon as practicable. Inspectors should verify that an owner or operator documents compliance with this provision through a photograph of the recovery and completion combustion equipment that contains the location of the wellhead and the date of the completion operations.

Inspectors should verify that an owner or operator notified the EPA and the Department no later than two days prior to the commencement of each well completion. The notification can be submitted in writing or via email. As provided in 40 CFR § 60.5420, the owner and operator may send a copy of the 24-hour advance notice required under Pennsylvania's Oil and Gas Law (Act 13 of 2012) for well completions to the Air Program Manager in the appropriate DEP regional office.

The well completion notification must include the following:

(1) Contact information for the owner or operator;

(2) Anticipated date of well completion;

(3) API well number;

(4) Latitude/Longitude (5 decimal places);

(5) Planned date for beginning of flowback;

(6) Type of well (Normal, Wildcat, Delineation, Low Pressure);

(7) Type of emission control used (REC, Flaring, Neither); and

(8) If emission control used is identified as "neither," reasons why.

During every day of the well completion activity, the owner/operator maintains a daily log book containing the following information for each well completion:

(1) Location;

(2) API well number;

(3) Duration of flowback (hours);

(4) Duration of venting (hours);

(5) Reasons for venting to atmosphere;

(6) Duration of recovery to the flow line (hours); and

(7) Duration of combustion (hours).

Inspectors should verify that the owner or operator submitted an annual report for affected facilities. The annual report is due 30 days from the date the compliance period ends, with subsequent annual reports due on the same date. Owners or operators may submit a combined report for all affected facilities. The annual reports, which must be certified by a responsible official, must contain identification of affected facilities, and deviations from work practice or emission/operating limits.

Information required in annual reports must contain the following:

Wellheads: Location, API well number, duration of flowback, duration of recovery to the flow line, duration of combustion, duration of venting, specific reasons for venting, documentation for exception from control/recovery, and digital photographs, if applicable.

Pneumatic controllers: Date, location, and manufacturer's specifications.

Storage vessels: Emission calculations, records of deviation, and number of consecutive days a skid mounted or mobile source mounted storage vessel is located at a site in the oil and natural gas production segment. If a vessel is removed from a site and, within 30 days, is either returned to or replaced by another vessel at the site to serve the same or similar function, then the entire period since the original vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

Inspectors are reminded that an owner or operator may record and maintain the data in electronic form or written log. Electronic monitoring and storage of LDAR data provides accuracy, an effective means for QA/QC, and helps retrieve records in a timely manner for review purposes.

The log must include the following:

(1) The equipment or component, date of leak detection, detection method and measurement data or visual image;

(2) The number of repairs not completed within 15 days. A list of all equipment or components currently on the "Delay of Repair" list, the date each component was placed on the list, reasons and the scheduled dates of repairs; and

(3) The number of equipment or components that could not be repaired and reason, if applicable.

Inspectors are also reminded that an owner or operator needs to maintain the record for leaks, repair methods and repair delays for five years and make available to the Department upon request.

ii. Storage vessels/storage tanks or other equipment equipped with VOC emission controls achieving emissions reduction of 95% or greater. Compliance will be demonstrated consistent with 40 CFR Part 60, Subpart OOOO or an alternative test method approved by the Department

VOC emissions from storage vessels or storage tanks can be controlled at more than 95% by control devices such as an enclosed combustion device or vapor recovery device, along with a cover that meets requirements established in 40 CFR § 60.5395.

Inspectors should note that an owner or operator demonstrate compliance with 95% VOC reduction requirements of storage vessels in accordance with § 60.5413.

Inspectors should note that an owner or operator may demonstrate compliance with 95% VOC reduction requirements of other equipment such as tanker truck load-outs, consistent with § 60.5413 or alternate test methods as approved by the Department.

Measures to reduce tanker truck load-outs emissions include the application of vapor recovery equipment or enclosed flare. As per EPA's AP-42, Compilation of Air Pollutant Emission Factors, the collection efficiency may be assumed to be 99.2 percent for tanker trucks passing the MACT-level annual leak test (not more than 1 inch water column pressure change in 5 minutes after pressurizing to 18 inches water followed by pulling a vacuum of 6 inches water). A collection efficiency of 98.7 percent (a 1.3 percent leakage rate) may also be assumed for tanker trucks passing the NSPS-level annual test (3 inches pressure change). If Method 27 – Determination of Vapor Tightness of Gasoline Delivery Tank Using Pressure-Vacuum Test is used for annual leak testing, it will be determined as equivalent to NSPS-level annual testing, and no additional approval is required from the Department. The leak testing performed in accordance with Department Of Transportation regulations 49 CFR 180.407 - Requirements for test and inspection specifications for cargo tanks will be determined as equivalent to NSPS-level annual testing.

iii. Combined VOC emissions from all the sources at the facility less than 2.7 tons on a 12-month rolling basis. If the VOCs include HAPs, the HAP exemption criteria in this paragraph will be met. Compliance with this criterion is to be determined using any generally accepted model or calculation methodology. Combined HAP emissions [not including Polychlorinated Biphenyls (PCBs), Chromium (Cr), Mercury (Hg), Lead (Pb), Polycyclic Organic Matter (POM), Dioxins and Furans] at the facility less than 1000 lbs of a single HAP or one ton of a combination of HAPs in any consecutive 12-month period. The emission criteria do not include emissions from sources which are approved by the Department in plan approvals, or the general plan approvals/general operating permits at the facility and the emissions from sources meeting the exemption criteria in subparagraphs i, ii, and iv.

Generally accepted models or calculation methodologies for the estimation of emissions include, but are not limited to, vendors' data, source test data from identical sources or EPA emission factors. The supporting documentation must be kept for at least 5 years and be made available to the Department upon request.

iv. Flaring activities as outlined below:

A. Flaring used at exploration wells to determine whether oil and/or gas exists in geological formations or to appraise the physical extent, reserves and likely production rate of an oil or gas field.

B. Flaring used for repair, maintenance, emergency or safety purposes.

C. Flaring used for other operations at a wellhead or facility to comply with 40 CFR Part 60, Subpart OOOO requirements.

D. Enclosed combustion device including enclosed flare will be used for all permanent flaring operations at a wellhead or facility. These flaring operations will be designed and operated in accordance with the requirements of 40 CFR § 60.18.

For a flare, inspectors shall visually examine the following:

(i) That the flare is operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours using Method 22 of Appendix A of 40 CFR Part 60. Temporary flares used as a completion combustion device is not subject to Method 22 Visible emission observations.

(ii) That the flare is operated with a flame present at all times, as indicated by thermocouple or other equivalent device. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback

(iii) That flare is operated at all time when emissions are vented to it.

For further requirements regarding heat content specifications, maximum tip velocity, flare diameter, hydrogen content, etc., refer to 40 CFR§ 60.18.

As defined in 40 CFR § 60.5430, the term "completion combustion device" means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Temporary flares used as completion combustion devices are not required to meet 40 CFR§ 60.18 as subpart OOOO excludes these devices from the flare requirements.

REPORTING OF EMISSIONS FROM FLARING OPERATIONS

Inspectors should determine that an owner or operator quantified and included the emissions from flaring operations in the annual emissions inventory report which is submitted in accordance with 25 Pa. Code Chapter 135. The emissions must be determined using any generally accepted model or calculation methodology using emission factors.

v. Combined NOx emissions from the stationary internal combustion engines at wells, and wellheads less than 100 lbs./hr., 1000 lbs./day, 2.75 tons per ozone season (the period beginning May 1 of each year and ending on September 30 the same year), and 6.6 tons per year on a 12-month rolling basis. The emissions criteria do not include emissions from sources which are approved by plan approvals or general permits at the facility.

The combined NOx emission thresholds are applicable only for sources located at wells and wellheads. Compliance with this criterion shall be determined using any generally accepted model or calculation methodology for the estimation of emissions, including, but not limited to, vendors' data, source test data from identical sources, or EPA emission factors. The supporting documentation must be kept for at least 5 years and be made available to the Department upon request.

ANNUAL EMISSION INVENTORY REPORTING

The annual emissions inventory report required to be submitted in accordance with 25 Pa. Code Chapter 135 must also include the emissions from sources which are exempted from permitting requirements.