TECHNICAL SUPPORT DOCUMENT
FOR
New COMAR 26.11.41

new Regulations .01 to .07 under new chapter COMAR 26.11.41 Control of Methane Emissions from the Natural Gas Industry

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I. PURPOSE OF REGULATORY ACTION

The purpose of this action is to propose new Regulations .01 to .07 under new chapter COMAR 26.11.41 Control of Methane Emissions from the Natural Gas Industry. Methane emissions from the natural gas industry account for approximately 30 percent of all methane emissions generated in Maryland. This action establishes requirements to reduce vented and fugitive emissions of methane from both new and existing natural gas facilities.

II. BACKGROUND

In 2009, the Maryland General Assembly adopted the Greenhouse Gas Emission Reduction Act (GGRA). This law required that the State develop and implement a plan to reduce greenhouse gas emissions by 25 percent by 2020, compared to the 2006 baseline. In 2015, the Maryland Commission on Climate Change (MCCC) was codified into law to provide guidance on helping the State achieve greenhouse gas reductions while supporting a healthy economy and creating new jobs. The MCCC recommended to the Maryland General Assembly that several enhancements be made to the 2009 GGRA. In 2016, Governor Larry Hogan signed an updated version of the GGRA, establishing a new benchmark to reduce greenhouse gas emissions in Maryland by 40 percent by 2030.

The MCCC, through its Mitigation Work Group, recommended that Maryland focus on reducing methane emissions from landfills, natural gas infrastructure (e.g. compressor stations and underground storage), and waste water treatment plants. Today's action focuses on reducing methane emissions from the natural gas infrastructure in Maryland to protect and restore the environment for the health and wellbeing of all Marylanders. Methane is the primary constituent of natural gas and is the second most prevalent greenhouse gas emitted by human activity in the U.S. While methane does not linger as long in the atmosphere as carbon dioxide, it is initially far more impactful to the climate because of how effectively it absorbs heat.

EPA also began to address methane emissions from the oil and natural gas industry. In June 2016, EPA finalized updates to its New Source Performance Standards, 40 CFR Part 60, Subpart OOOOa (or 2016 NSPS OOOOa[1]) for the oil and natural gas industry to reduce emissions of greenhouse gases. The 2016 NSPS OOOOa set emission limits for methane, which is the principal greenhouse gas emitted by equipment and processes in the oil and gas sector. The EPA final rule also requires owners/operators to find and repair leaks, also known as "fugitive emissions," which can be a significant source of both methane and volatile organic compound emissions.

On September 11, 2018, EPA proposed amendments to certain provisions of the 2016 NSPS

[1] Regulations.gov EPA–HQ–OAR–2010–0505

OOOOa. Among other proposed amendments, EPA considered relaxing the regulatory burden to industry by reducing the monitoring frequency of fugitive emissions and extending the required time for leaks to be repaired. On September 24, 2019, EPA proposed to further relax the 2016 NSPS OOOOa. EPA's new amendments propose to (1) remove sources in the transmission and storage segment from the affected source category and rescind the NSPS (including both the volatile organic compounds (VOC) and methane requirements) applicable to those sources, and (2) rescind the methane-specific requirements of the NSPS applicable to sources in the production and processing segments. The EPA is also proposing, as an alternative, to rescind the methane requirements of the NSPS applicable to all oil and natural gas sources, without removing any sources from the source category. The Maryland Department of the Environment (the Department) opposes these proposed amendments and any relaxation of NSPS OOOOa. The Department commented and documented opposition to the EPA's proposed rules in letters[2] on December 17, 2018 (federal register docket ID EPA-HQ-OAR-2017-0483[3]) and on November 25, 2019 (federal register docket ID EPA-HQ-OAR-2017-0757[4]). In response to EPA's reconsideration, Maryland is proposing standards for new and existing facilities in the State to control methane emissions from the natural gas industry.

Proposed Action Summary:

This action proposes requirements to mitigate methane emissions through fugitive emissions detection and repair, and establishes control measure requirements to limit emissions from compressors and pneumatic devices. Facility-wide greenhouse gas emission data will be required to be calculated and submitted to the Department annually. Additionally, owners and operators will be required to notify the Department and the public during "blowdown events", which are the release of pressurized natural gas from stations, equipment, or pipelines into the atmosphere so that maintenance, testing or other activities can take place.

The natural gas industry can be divided into four segments: (1) production; (2) gathering and processing; (3) transmission and storage; and (4) distribution. In the transmission and storage segment, compressors are used to maintain the pressure of the natural gas in transmission pipelines to deliver extracted gas to its eventual end-user. This action affects new and existing natural gas compressor stations, liquefied natural gas facilities, and underground storage facilities in the transmission and storage segment. In Maryland, there are four natural gas compressor stations, one liquefied natural gas import/export facility, and one underground storage facility.

Public Engagement:

This action represents development of regulations with extensive input from public community groups, environmental advocates, the industry and EPA.

[2] Appendix A – Maryland opposition letter's to EPA proposed regulations
[3] Regulations.gov EPA–HQ–OAR–2017-0483
[4] Regulations.gov EPA–HQ–OAR–2017-0757

The Department held Stakeholder meetings on June 29, 2017, July 10, 2018, March 6, 2019, June 28, 2019 and October 11, 2019[5]. Meeting announcements and presentations were posted https://mde.maryland.gov/programs/Regulations/air/Pages/ARMARegulationsStakeholders.aspx

The Department presented the proposed regulation to the Air Quality Control Advisory Council on December 16, 2019[6].

A public hearing will be held as announced in the Maryland Register and on the Department's website. https://mde.maryland.gov/programs/Regulations/air/Pages/reqcomments.aspx

III. SOURCES AFFECTED AND LOCATION

There are four natural gas compressor stations, one underground storage facility and one liquid natural gas (LNG) facility currently operating in Maryland that are subject to this regulation.

- The four compressor stations are: Dominion Myersville (Frederick County), Enbridge Texas Eastern (Garrett County), TC Energy (formerly TransCanada) Rutledge (Harford County), and Williams Transcontinental (Howard County),
- The one underground storage facility is Enbridge Texas Eastern (Garrett County)
- The one LNG facility is Dominion Cove Point (Calvert County).
- All new NG compressor stations, underground storage facilities, and LNG facilities will be subject to this regulation.

IV. REQUIREMENTS

The federal Clean Air Act provides that states may set more stringent standards and the proposed regulations are more stringent than existing federal rules. Maryland is proposing detection, testing, repair, reporting and record keeping requirements for all existing and new facilities in the State.

Leak Detection and Repair (LDAR):
Fugitive emissions can occur from leaking compressors, pipelines and other equipment components such as valves, connectors, pressure relief devices, and flanges. Unmonitored or faulty equipment with fugitive leaks exacerbates the methane emissions at a facility. Maryland's proposed regulations require owners/operators to do the following:

- Develop and submit a leak monitoring plan to the Department within 90 days of the adoption of the rule. New, modified, or reconstructed facilities will have up to 90 days to submit a methane emissions monitoring plan from the startup of the facility's operation.
- Conduct leak monitoring surveys at prescribed intervals using optical gas imaging (OGI) or EPA Method 21 as well as inspecting for leaks using audio, visual, and olfactory (AVO) observations. The Department will consider any new and/or emerging leak detection

[5] Appendix B – Stakeholder Meeting Presentation from Oct. 2019
[6] Appendix C – AQCAC Presentation from Dec. 2019

technology as an alternative practice to monitor for leaks.
• Repair or replace identified leaking component(s) within 30 days of leak discovery and verify that the leak has been successfully repaired. Owners/operators may submit a delay of repair request to the Department if the leaking component(s) requires a specialty part, is unsafe to repair during the operation of the unit, and/or would require a vent or compressor station blowdown.
• Follow applicable annual and quarterly recordkeeping and reporting requirements.
• New, modified, or reconstructed facilities will have up to 180 days to conduct an initial monitoring survey from the startup of the facility's operation.

LDAR - Facilities that use natural gas-powered equipment to compress natural gas and new liquefied natural gas (LNG) facilities:

• These facilities shall conduct quarterly inspections of fugitive emissions components using an OGI instrument or EPA's Method 21. The initial monitoring survey shall be conducted within 180 days of the adoption of the regulation.
• Weekly AVO inspection of all fugitive emissions components shall be conducted.

LDAR - Facilities that use electric-powered equipment to compress natural gas:

• Electric-powered equipment used to compress natural gas emits less methane than natural gas-powered equipment by eliminating the need for fuel gas. Furthermore, electric-powered compressors produce no exhaust byproduct.
• These facilities shall conduct annual inspections of fugitive emissions components using an OGI instrument or EPA's Method 21. The initial monitoring survey shall be conducted within 180 days of the adoption of the regulation
• Monthly AVO inspection of all fugitive emissions components shall be conducted.

LDAR - Natural gas underground storage fields that use electric-powered equipment to compress natural gas:

• These facilities shall conduct quarterly inspections of fugitive emissions components using an OGI instrument or EPA's Method 21. The initial monitoring survey shall be conducted within 180 days of the adoption of the regulation.
• Monthly AVO inspection of all fugitive emissions components shall be conducted.
• Additionally, every month, record the following measurements; the well-head pressure or water level measurement, as appropriate; the open flow on the annulus of the production casing or the annulus pressure if the annulus is shut in; a measurement of gas escaping the well if there is evidence of a gas leak; and evidence of progressive corrosion, rusting, or other signs of equipment deterioration.
• For each natural gas storage well with emissions that exceed 1,440 cubic feet per day[7], owners and operators shall: (1) Notify the Department within one business day of

[7] Annulus valve emission rate developed in coordination with Maryland source. Compare to 25 Pa. Code § 78.402

discovering the emission rate exceedance; and (2) File a written report within 10 days which shall include an explanation of the problem and corrective action taken or planned.

LDAR - Dominion Cove Point LNG facility:

Cove Point has two existing LDAR plans with equivalent stringency as this proposal;
(1) The leak detection and repair requirements as specified by the Climate Action Plan (CAP), which is defined, prepared, and approved under COMAR 26.09.02.06.B – E.; and
(2) The leak detection and repair plan defined and approved under the Certificate of Public Convenience and Necessity, issued by the Maryland Public Service Commission on May 30, 2014, Order No. 86372, Case No. 9318, as amended on February 6, 2018 with Order No. 88565, and Errata on February 23, 2018 Order No. 88565, as amended[8].

Natural Gas-Powered Pneumatic Devices:

Pneumatic devices are used for maintaining a process condition such as liquid level, pressure, or temperature. As part of normal operations, natural gas-powered pneumatic devices release or bleed natural gas to the atmosphere. The Department is proposing a phase-out of all high bleed continuous natural gas-powered devices. Additional requirements are summarized below:

- Beginning January 1, 2021, LDAR monitoring for all natural gas-powered pneumatic devices;
- By January 1, 2022, continuous bleed natural gas-powered pneumatic devices cannot have a bleed rate greater than 6 standard cubic feet per hour; and
- By January 1, 2023, continuous bleed natural gas-powered pneumatic devices shall be converted to electric or compressed air-powered devices.

The Department is proposing an exemption for continuous bleed natural gas-powered pneumatic devices with a low bleed rate that is needed for safety or operational purposes. Furthermore, this action includes recordkeeping and reporting requirements to the Department.

Reciprocating Compressors:

Reciprocating compressors are used to increase the pressure of the natural gas flowing through the transmission pipelines. Over time, rod packing systems within these reciprocating compressors can wear, resulting in leaking methane. Maryland's proposed rules provide two mitigation options for methane emissions from rod packing systems:

- Emissions from the rod packing shall be routed to a process or control device; or
- Rod packing flow rates shall be measured annually and rod packing systems with emissions greater than 1.0 standard cubic feet per minute (scfm) shall: (1) Be replaced; or (2) Be measured every 6 months until the rod packing flow rate reaches 2 scfm, at which point the rod packing shall be replaced.

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[8] See Appendix D - Cove Point - CAP and CPCN LDAR plans

Rod packing flow rates were determined after review of manufacturer-supplied data, California standard (2.00 scfm) and Canada standard (0.81 scfm)[9]. Reciprocating compressor's fugitive emission components shall be subject to LDAR requirements. This action also includes recordkeeping and reporting requirements to the Department.

Record Keeping and Reporting Requirements:

An annual report is due to the Department on April 1st of each year; owners and operators can combine reporting sections together into one report for greenhouse gas reporting.
LDAR reports are due to the Department either quarterly or annually based on the type of facility and compressor. Additional requirements for the LDAR report:.

- Quarterly LDAR reports will be accepted from a 3rd party if specific details are provided.
- The Department is proposing that an LDAR summary be publicly posted after each monitoring survey.

Blowdown Events and Reporting:

Blowdown events are common occurrences in which pressurized natural gas is released from stations, equipment, or pipelines into the atmosphere for maintenance and operational purposes. Maryland's rule requires owners and operators to notify the Department and the public whenever a blowdown activity with threshold of greater than 1.0 standard million cubic feet of methane will be released[10]. Owners and operators will be required to record all blowdown events greater than 50 standard cubic feet and report those blowdown emissions annually.

The following requirements apply to affected sources:
- Submit a blowdown notification plan to the Department for approval[11];
- Notification of planned blowdowns in the excess of 1 million scf should be given at least 7 days prior to the start of the event;
- Notification of emergency blowdowns should be given within one hour of the start of the event; and
- Owners and operators shall calculate and submit to the Department annually the total methane emissions from all blowdown events.

Greenhouse Gas Reporting:

Greenhouse gas emissions from the oil and natural gas industry account for approximately 20 percent of all greenhouse gas emissions in the United States. Natural gas facilities have the potential to emit greenhouse gases from a variety of sources, including fugitive emission components, stationary fuel combustion sources, and other site activities (e.g. blowdowns, maintenance, compressor startups, compressor shutdowns, etc.). On October 20, 2009, the EPA published a rule for the mandatory reporting of greenhouse gases from oil and natural gas

[9] See Appendix E – Rod Packing Threshold
[10] See Appendix F – Blowdown Operations
[11] See Appendix F for additional information

facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. Oil and natural gas facilities that emit less than the 25,000 metric tons threshold were exempted from EPA's rules. Maryland's proposed rule will require all facilities in the natural gas industry, regardless of their total greenhouse gas emissions, to report greenhouse gas emissions data to the Department. Maryland's proposed greenhouse gas emissions reporting requirements will require facilities to collect greenhouse gas data, calculate greenhouse gas emissions, and follow specified procedures for quality assurance, missing data, recordkeeping, and reporting. Maryland's requirements mirror EPA's Greenhouse Gas Reporting Program[12]to harmonize with federal rules and reduce regulatory burden. Example reporting forms can be located at EPA's electronic greenhouse gas reporting tool (E-GGRT). Calculation spreadsheets for subpart C- combustion and subpart W – petroleum and nat. gas can be used for the annual reporting[13].

V. PROJECTED EMISSION REDUCTIONS

The Department estimates the proposed regulations will minimize the release of methane emissions from the natural gas transmission and storage activities in the State. More specifically, the proposed rule is estimated to minimize the release of methane emissions from existing sources in the range of 600 to 5,000 metric tons per year through leak surveys, replacement of leaking equipment and components and inspection practices. The estimated methane emission reduction has the equivalent climate change mitigation benefit as reducing carbon dioxide emissions by 51,600-430,000 metric tons per year, using the 20-year global warming potential for methane.

Leak detection and repair (LDAR) surveys can produce varying results, but it is understood throughout the industry that technology is advancing to help minimize fugitive leaks. LDAR programs have the potential to lead to reduced emissions, valuable product recovery and increased safety of operations. A leak survey is most effective when performed on a routine basis to capture the unknown nature of unintentional poor performance.

The Department has reviewed literature on the proposed impacts of a fugitive leak detection and repair program from EPA, California, environmental advocates and the industry. The potential emissions reductions, quoted in the EPA 2015 Regulatory Impact Analysis[14] for the 2016 NSPS OOOOa, range from 40 — 80 percent depending on the frequency of surveys. Under California's rulemaking entitled "Greenhouse Gas Emission Standards For Crude Oil And Natural Gas Facilities" finalized in 2017[15], California assumes a 60 percent reduction in methane emissions due to quarterly LDAR. However, California also notes there can be a wide range of conditions that can disproportion data from an average assumption. It is understood that the industry has

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[12] EPA Code of Federal Regulations: 40 CFR part 98 – Mandatory Greenhouse Gas Reporting available electronically at https://www.law.cornell.edu/cfr/text/40/part-98

[13] See the following website https://ccdsupport.com/confluence/display/help/Optional+Calculation+Spreadsheet+Instructions

[14] EPA, Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector, EPA-452/R-15-002, August 2015 https://www3.epa.gov/ttn/ecas/docs/ria/oilgas_ria_proposed-nsps_2015-08.pdf

[15] CARB Rulemaking Activity https://ww3.arb.ca.gov/regact/2016/oilandgas2016/oilandgas2016.htm

skewed emissions distributions, where a small number of facilities can account for a large portion of emissions.

Vented methane emissions from reciprocating compressor engines and natural gas-driven pneumatic devices will be reduced by equipment monitoring, repair and replacement. EPA Natural Gas STAR Program Partner Reported Opportunities (PROs) Fact Sheets[16] and information from the equipment manufacturing industry estimate emissions reduction can be achieved up to 50 percent.

The nature of operations at each specific station determine the yearly emissions at a facility. The Department has used existing federal reporting figures through the Greenhouse Gas Reporting Rule (40 CFR Part 98) and figures from the Department's annual emission certification reports to estimate methane reductions in Maryland. The Department has calculated a range of potential methane reductions per year. The Department assumed a range of 40 to 80 percent reduction from the proposed regulation applied to recently reported methane emissions.

As the natural gas industry expands, any future sources located in Maryland which are in the production and transmission sector of the natural gas industry will be required to follow these state regulations, as well as federal rules. Advanced construction, maintenance and inspection practices will likely be utilized; therefore, large emission reductions will not be anticipated. Reporting is a key tool to understanding the emissions in the industry and the State. The documented mitigation strategies will be a tool to further analyze State and national inventories and industry emission factors.

VI. ECONOMIC IMPACT

Government and Industry Cost Estimate

The proposed regulation requires facilities in the natural gas industry to perform quarterly or annual leak surveys to identify and minimize unintentional fugitive emissions. The proposed regulation may require facilities to purchase, retrofit, and service capital equipment. The Department estimates affected facilities will be required to spend, on average, in 2018 dollars, $25,000 annually on leak surveys. Leak surveys require reporting with the survey plan. Repairs and maintenance may be an additional cost; however, product loss will be decreased. Some capital investment may be required and can vary in cost depending on the sophistication of the engineering design and the age of existing equipment but are estimated to range from $10,000 — $100,000. Affected facilities are also required to submit annual reports to the Department, which may result in additional reporting costs. However, since the proposed annual reporting requirements harmonize with the existing federal requirements, the Department estimates reporting costs to be minimal. The Department has reviewed literature on the proposed cost impacts of a fugitive leak detection and repair program from EPA, California, environmental

[16] https://www.epa.gov/natural-gas-star-program/recommended-technologies-reduce-methane-emissions

advocates and the industry. Additionally, the Department received cost estimates from manufacturers on equipment and maintenance[17].

The businesses in this industry are not small, therefore no economic impact is expected to small businesses.

Existing air compliance inspector staff at MDE will enforce these regulations.

Public Health and Environment

MDE's mission is to protect and restore the environment for the health and wellbeing of all Marylanders. Working to mitigate and adapt to climate change are main components of this mission authorized by the GGRA. Marylanders are already witnessing firsthand the impacts of climate change, from more frequent, severe flooding that threatens the state's agricultural sector, to more powerful heat waves that put lives at risk. That's why the State's GGRA Plan to cut greenhouse gas emissions 40 percent by 2030, and Governor Hogan's commitment to develop a clean and renewable energy standard, are so important. Maryland has made great progress on reducing air pollution and greenhouse gas emissions, and adapting to the potential consequences of climate change, while creating jobs and benefiting the economy. Comprehensive methane pollution regulation is a key part of making sure Maryland can continue to make progress and meet emission reduction goals.

The proposed regulation will have a positive effect on public health and the environment. Short-lived climate pollutants (SLCPs) are harmful air pollutants and potent climate forcers with a much shorter lifespan in the atmosphere than carbon dioxide. Reducing emissions of methane will combat the adverse impacts of climate change in Maryland.

More information on Maryland's climate change program's can be found at this website https://mde.maryland.gov/programs/Air/ClimateChange/Pages/index.aspx

VII. CORRESPONDING FEDERAL STANDARD

In compliance with Executive Order 01.01.1996.03, this proposed regulation is more restrictive or stringent than corresponding federal standards as follows:
(1) Regulation citation and manner in which it is more restrictive than the applicable federal standard:
New sources, which are facilities built, modified, or reconstructed after September 18, 2015, are subject to federal 2016 NSPS OOOOa requirements. The proposed regulations require both new and existing facilities to monitor and reduce methane emissions. Therefore, the proposed regulations are more stringent than the federal standard. However, Maryland has aligned requirements and reporting with the federal 2016 NSPS OOOOa whenever possible.
(2) Benefit to the public health, safety or welfare, or the environment:
Methane is a highly potent greenhouse gas that needs to be acted upon quickly because it is a

[17] Appendix G – Cost Impact Supporting Analysis

short-lived climate pollutant (SLCP). Methane emissions from the natural gas industry account for approximately 30 percent of all methane emissions generated in Maryland. Proposed methane reductions from this regulation can help to minimize greenhouse gases. Mitigation and adaption measures help minimize losses to Maryland businesses and communities from climate risk such as sea-level rise or heat-related stress.
(3) Analysis of additional burden or cost on the regulated person:
The Department estimates affected facilities will be required to spend, on average, in 2018 dollars, $25,000 annually on leak surveys. Additionally some capital investment may be required in the range from $10,000 -— $100,000. Affected facilities are required to report to the Department, which may result in additional reporting costs. However, since the proposed annual reporting requirements harmonize with the existing federal requirements, the Department estimates reporting costs to be minimal. Additional details follow are in the Department's technical support documents.
(4) Justification for the need for more restrictive standards:
The Maryland General Assembly adopted, and Governor Hogan signed, the 2016 Greenhouse Gas Emission Reduction Act (GGRA) reauthorization. Methane reductions from this natural gas sector reduce greenhouse gases. Additionally the EPA has proposed two separate rules relaxing standards for new sources under NSPS OOOOa. These relaxations will result in increased methane leakage. Due to the relaxations at the federal level, Maryland is proposing this regulation to strengthen methane mitigation practices.

VIII. OTHER STATE ACTIONS

In developing the proposed rules, the Department reviewed the requirements of various state methane reduction programs for sources in the oil and natural gas industry. The Department’s assessment was limited to state programs that were publicly available at the time of production of the proposed rules and may not include state programs that are currently being drafted or proposed. MDE identified the following states with methane emissions reduction programs for sources in the oil and natural gas industry[18]: California, Colorado, Montana, Pennsylvania, Texas, Utah, and Wyoming. Information and links to these state’s requirements for sources the oil and natural gas industry is below:

California

California’s Air Resources Board (CARB) finalized requirements for well sites and compressors stations on July 17, 2017, with an effective date of January 1, 2018. CARB’s regulations are available at https://ww2.arb.ca.gov/resources/documents/oil-and-gas-regulation.

Colorado

[18] MDE also utilized EPA’s Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa memorandum for our review, available at https://www.epa.gov/sites/production/files/2018-09/documents/equivalency_of_state_fugitive_emissions_programs_for_well_sites_and_compressor_stations.pdf

Colorado was the first state to establish methane reduction requirements for the oil and natural gas industry on April 14, 2014 in the state's Regulation 7. Colorado's regulations are available at https://www.sos.state.co.us/CCR/DisplayRule.do?action=ruleinfo&ruleId=2341&deptID=16&agencyID=7&deptNa.

Montana

Emission control requirements for oil and gas well facilities in Montana are provided in the Administrative Rules of Montana (ARM) Title 17, Chapter 8, Subchapters 16 and 17. Available at http://deq.mt.gov/DEQAdmin/dir/legal/Chapters/ch08-toc.

Pennsylvania

On June 7, 2018, the Pennsylvania Department of Environmental Protection (PADEP) finalized General Permits 5 and 5A for compressor stations and unconventional well sites, respectively, with an effective date of August 8, 2018. Information on General Permits 5 and 5A is available at http://www.dep.pa.gov/Business/Air/BAQ/Permits/Pages/GeneralPermits.aspx.

Texas

The Texas Commission on Environmental Quality established rules in Title 30, Texas Administrative Code, for controlling fugitive emissions of volatile organic compounds. The rule is available at https://www.tceq.texas.gov/airquality/stationary-rules/voc/fugitives.

Utah

The Utah Department of Environmental Quality (UDEQ) established requirements for oil and natural gas sources in the Utah Administrative Code, Title R307. The rule is available at https://rules.utah.gov/publicat/code/r307/r307.htm.

Wyoming

The Wyoming Department of Environmental Quality issued regulations in June 2015 for existing facilities, single-well oil and gas production facilities or sources, and all compressor stations that are located in the Upper Green River Basin (UGRB) ozone nonattainment area. Regulations are available at https://rules.wyo.gov/.

IX. PROPOSED REGULATIONS

Pre-publish version 07/23/2020

Title 26
DEPARTMENT OF THE ENVIRONMENT
Subtitle 11 AIR QUALITY
26.11.41 Control of Methane Emissions from the Natural Gas Industry

Authority: Environment Article, §§1-404, 2-103, 2-1202, and 2-1205, Annotated Code of Maryland

.01 Definitions.

A. In this chapter, the following terms have the meanings indicated.

B. Terms Defined.

(1) "Affected facilities" means any one of the following facilities:

(a) Cove Point Liquefied Natural Gas Facility;

(b) Myersville Natural Gas Compressor Station;

(c) Accident Natural Gas Compressor Station and Storage;

(d) Rutledge Natural Gas Compressor Station;

(e) Ellicott City Natural Gas Compressor Station; and

(f) Any new, modified, or reconstructed natural gas compressor station, natural gas underground storage facility, or liquefied natural gas facility.

(2) "Audio, visual, and olfactory inspection" means sensory monitoring to detect natural gas leaks utilizing a human ear, eyes, and nose.

(3) Blowdown.

(a) "Blowdown" means the release of pressurized natural gas from a station, equipment, or pipelines into the atmosphere conducted with the intent to lower the pressure in a vessel or pipeline.

(b) "Blowdown" does not include natural gas pneumatics emissions, fugitive components emissions, or pressure seal leakage.

(4) "Bubble test" means the alternative screening procedure as described at EPA Method 21 (40 CFR 60, Appendix A-7, §8.3.3).

(5) "Component" means a valve, fitting, flange, threaded-connection, process drain, stuffing box, pressure-vacuum valve, pressure-relief device, pipes, seal fluid system, diaphragm, hatch, sight-glass, meter, open-ended line, well casing, natural gas powered pneumatic device, natural gas powered pneumatic pump, reciprocating compressor rod packing/seal, metal to metal joint or seal of nonwelded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

(6) "Continuous bleed" means the continuous venting of natural gas from a gas-powered pneumatic device to the atmosphere.

(7) "Difficult-to-monitor" means fugitive emissions components that cannot be monitored for natural gas leakage without the monitoring personnel needing specialized equipment to reach components above the grade.

(8) "Direct measurement" means use of high volume sampling, calibrated bagging, a calibrated flow measuring instrument, or a temporary meter.

(9) "Fuel gas system" means components and equipment that collect and transfer natural gas to be used as a fuel source to on-site natural gas-powered equipment other than a vapor control device.

(10) Fugitive Emissions Component.

(a) "Fugitive emission component" means any component that has the potential to emit fugitive emissions of natural gas, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers, and vapor collection systems.

(b) "Fugitive emission component" does not include devices that vent as a part of normal operations, such as natural gas-driven pneumatic devices or annulus vents, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission.

(c) "Fugitive emission component" includes thief hatches or other openings on a storage vessel, compressor, instrument, natural gas-powered pneumatic device, or meter that are not venting.

(11) "Intermittent bleed" means a pneumatic controller that is designed to vent noncontinuously.

(12) "Leak detection and repair" or "LDAR" means the inspection of fugitive emissions components to detect leaks of total methane and the repair of components with leaks above the standards specified in this chapter and within the time frames specified in this chapter.

(13) "Leak or fugitive leak" means any visible emission from a fugitive emissions component observed by optical gas imaging or an instrument reading of 500 ppm or greater of methane using U.S. EPA Method 21 (40 CFR 60, Appendix A-7) or any emissions discovered from a fugitive emissions component observed using an auditory, visual, and olfactory inspection.

(14) "Liquefied natural gas" or "LNG" means natural gas or synthetic gas having methane as its major constituent which has been changed to a liquid.

(15) "LNG facility" means a pipeline facility that is used for liquefying natural gas or synthetic gas or transferring, storing, or vaporizing liquefied natural gas, and includes all components and stationary equipment within the fence line.

(16) "Natural gas" means a naturally occurring mixture or process derivative of hydrocarbon and nonhydrocarbon gases, which has methane as its major constituent.

(17) "Natural gas compressor station" means all equipment and components located within a facility fence line associated with moving natural gas from production fields or natural gas processing plants through natural gas transmission pipelines, or within natural gas storage fields.

(18) "Natural gas storage well" means a well located and used in a natural gas storage reservoir for injection or withdrawal purposes, or an observation well.

(19) "Natural gas underground storage" means all equipment and components associated with the temporary subsurface storage of natural gas in depleted crude oil or natural gas reservoirs or salt dome caverns, not including gas disposal wells.

(20) "Observation well" means a well used to monitor the operational integrity and conditions in a natural gas storage reservoir, the reservoir protective area, or the strata above or below the gas storage horizon.

(21) "Optical gas imaging" or "OGI" means an instrument that makes emissions visible to the naked eye that may otherwise be invisible.

(22) "Pneumatic device" means an automation device that uses natural gas or compressed air to control a process.

(23) "Process gas system" means components and equipment that collect and transfer the natural gas to be used through the intended process of the facility, including storage, transmission, or liquefaction.

(24) "Reciprocating natural gas compressor" means equipment that increases the pressure of natural gas by positive displacement of a piston in a compression cylinder and is powered by an internal combustion engine or electric motor with a horsepower rating designated by the manufacturer.

(25) "Reciprocating natural gas compressor rod packing" means a seal composed of a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that leaks into the atmosphere.

(26) "Reciprocating natural gas compressor seal" means any device or mechanism used to limit the amount of natural gas that leaks from a compression cylinder into the atmosphere.

(27) "Successful repair" means tightening, adjusting, or replacing equipment or a component for the purpose of stopping or reducing fugitive leaks below the minimum leak threshold or emission flow rate standard specified in this chapter.

(28) "Unsafe-to-monitor" means fugitive emissions components that cannot be monitored for natural gas leakage because monitoring personnel would be exposed to immediate danger while conducting a monitoring survey.

(29) "Vapor collection system" means equipment and components installed on pressure vessels, separators, tanks, sumps, piping, connections, reciprocating compressors, natural gas-powered pneumatic devices, and flow-inducing devices used to collect and route emission vapors to a processing gas system, fuel gas system, or vapor control device.

(30) "Vapor control device" means destructive or nondestructive equipment used to control otherwise vented emissions.

.02 Applicability.

The provisions of this chapter apply to an affected facility as that term is defined in Regulation .01B of this chapter.

.03 Leak Detection and Repair Requirements.

A. Affected facilities that are natural gas compressor stations or natural gas underground storage facilities and that use natural gas-powered equipment to compress natural gas shall comply with the following leak detection and repair requirements.

(1) Owners and operators of affected facilities subject to this section shall develop and submit to the Department an initial methane emissions monitoring plan that includes a technique for determining fugitive emissions (for example, EPA Method 21 at 40 CFR part 60, appendix A–7, or optical gas imaging).

(2) If an affected facility uses optical gas imaging for leak detection, the following information shall be included in the initial methane emissions monitoring plan:

(a) A list of the unsafe-to-monitor components;

(b) Procedures and time frames for identifying and repairing fugitive emissions components;

(c) A defined observation path throughout the site to confirm all components can be viewed and recorded;

(d) Manufacturer and model number of fugitive emissions detection equipment to be used; and

(e) Equipment specifications and procedures as specified in 40 CFR §60.5397a(c)(7), as published in July 2017.

(3) If an affected facility uses EPA Method 21 (40 CFR 60, Appendix A-7) for leak detection, the following information shall be included in the initial methane emissions monitoring plan:

(a) A list of all fugitive emission components, difficult-to-monitor components, and unsafe-to-monitor components at an affected facility;

(b) Procedures and time frames for identifying and repairing fugitive emission components; and

(c) Equipment specifications and procedures as specified in 40 CFR §60.5397a(c)(8), as published in July 2017.

(4) Each difficult-to-monitor and unsafe-to-monitor component shall be identified in the written initial methane monitoring plan explaining the location and why the fugitive emissions components are difficult-to-monitor and unsafe-to-monitor.

(5) Initial Methane Emissions Monitoring Plan Submission.

(a) Except for a new natural gas compressor station or natural gas underground storage facility, owners and operators of the affected facilities subject to this section shall submit the initial methane emissions monitoring plan required in §A(1)—(4) of this regulation to the Department within 90 days of the adoption of this regulation.

(b) Owners and operators of a new natural gas compressor station or natural gas underground storage facility subject to this section shall submit the initial methane emissions monitoring plan required in §A(1)—(4) of this regulation to the Department within 60 days of startup.

(6) Owners and operators of affected facilities that modify or reconstruct a natural gas compressor station or underground storage facility shall submit an initial monitoring plan with the elements in §A(1)—(4) of this regulation within 90 days of the facility startup operation for each new collection of fugitive emissions components at the modified or reconstructed compressor station or underground storage facility.

(7) Owners or operators of affected facilities subject to this section shall conduct an audio, visual, and olfactory inspection of all fugitive emission components for leaks or indications of leaks at least once per calendar week except for:

(a) Unsafe-to-monitor components; and

(b) Natural gas storage wells and observations, which shall conduct audio, visual, and olfactory inspections according to §A(10) of this regulation.

(8) Leak Monitoring Survey.

(a) Owners and operators of affected facilities shall follow the initial monitoring methane plan and shall inspect all fugitive emission components, except for unsafe-to-monitor components, for leaks using OGI or EPA Method 21 within 180 days of the adoption of this chapter and quarterly thereafter.

(b) Owners and operators of affected facilities that install any new, modified, or reconstructed natural gas compressor station or underground storage facility that uses natural gas-powered equipment to compress natural gas shall meet the requirements of §A(8)(a) of this regulation within 180 days of the startup of the facility's operations.

(c) At least annually, all difficult-to-monitor fugitive emissions components shall be inspected for leaks using an OGI camera.

(9) Repair Requirements.

(a) Any leaking fugitive emissions component identified during a leak monitoring survey or audio, visual, and olfactory inspection shall be successfully repaired, replaced, or removed from service as soon as practicable, but no later than 30 calendar days after leak detection.

(b) Fugitive Emissions Component Resurvey.

(i) Each repaired or replaced fugitive emissions component shall be resurveyed within 30 days after being repaired or replaced using either OGI or EPA Method 21 (40 CFR 60, Appendix A-7).

(ii) Owners and operators of facilities subject to this section that use EPA Method 21 (40 CFR 60, Appendix A-7) to resurvey the repaired or replaced fugitive emissions component shall consider the fugitive emissions component repaired when the EPA Method 21 (40 CFR 60, Appendix A-7) instrument indicates a concentration of less than 500 ppm of methane or when no soap bubbles are observed during a bubble test.

(iii) Owners and operators of affected facilities subject to this section that use OGI to resurvey the repaired or replaced fugitive emissions component shall consider the fugitive emissions component repaired when the OGI instrument shows no indication of visible emissions or when no soap bubbles are observed during a bubble test.

(c) A delay of repair may occur when, upon request, the owner or operator provides documentation to the Department that supports the following:

(i) The parts or equipment required to make necessary repairs will take longer than 30 days to be ordered and delivered, but the repair may not exceed 1 year;

(ii) The repair is unsafe to perform during the operation of the unit; or

(iii) The repair requires a blowdown or facility shutdown in order to complete.

(d) Leaking fugitive emission components awaiting repair or replacement under a delay of repair shall be clearly marked or identified in the facility's records.

(e) Leaking fugitive emission components under a delay of repair according to §A(9)(c)(i) of this regulation shall:

(i) Be repaired or replaced within 7 days after the owner or operator receives parts or equipment; or

(ii) Be repaired or replaced at the next vent or compressor station blowdown if the owner or operator has identified this fugitive emission component as needing a vent or compressor station blowdown.

(f) Fugitive emission components under a delay of repair according to §A(9)(c)(ii) and (iii) of this regulation shall be repaired or replaced within 1 year, at the next vent blowdown or facility shutdown, whichever occurs first.

(g) If a repair of a leak cannot be successfully completed according to this subsection, the owner or operator of the affected facility shall prepare a plan, for Department approval, that includes:

(i) An explanation of the technical difficulty;

(ii) A timeline to successfully repair the fugitive emission components;

(iii) A calculation of the additional methane that is expected to be released while on delay of repair; and

(iv) Upon written request from the Department, any other information that the Department determines is necessary to evaluate the plan.

(h) The owner or operator of the affected facility shall submit any plan required under §A(9)(g) of this regulation to the Department within 30 days from identifying the leak.

(10) Natural Gas Storage Field Inspections.

(a) Owners and operators of natural gas underground storage facilities shall conduct an audio, visual, and olfactory inspection of every natural gas storage well and observation well in the natural gas storage field at least once each month.

(b) For each inspection according to §A(10)(a) of this regulation, owners and operators shall record:

(i) The well-head pressure or water level measurement, as appropriate;

(ii) The open flow on the annulus of the production casing or the annulus pressure if the annulus is shut in;

(iii) A measurement of gas escaping the well if there is evidence of a gas leak; and

(iv) Evidence of progressive corrosion, rusting, or other signs of equipment deterioration.

(c) For each natural gas storage well with emissions that exceed 1,440 cubic feet per day, owners and operators shall:

(i) Notify the Department within 1 business day of discovering the emission rate exceedance; and

(ii) File a written report within 10 days which shall include an explanation of the problem and corrective action taken or planned.

(d) For each audio, visual, and olfactory inspection that detects a leaking fugitive emission component, the owner and operator shall comply with the repair requirements specified in §A(9) of this regulation, as applicable.

B. Affected facilities that are natural gas compressor stations and natural gas underground storage facilities, that exclusively use electric-powered equipment to compress natural gas, shall comply with the following leak detection and repair requirements.

(1) Owners and operators of facilities in this section shall meet the requirements of §A(1)—(6), (9), and (10) of this regulation.

(2) Except for unsafe-to-monitor components, owners or operators of facilities in this section shall conduct an audio, visual, and olfactory inspection of all fugitive emission components for leaks or indications of leaks at least once per calendar month.

(3) Leak Monitoring Survey.

(a) Except for unsafe-to-monitor components, owners and operators of affected facilities subject to this section shall inspect all fugitive emission components, including difficult-to-monitor components, for leaks using OGI or EPA Method 21 (40 CFR 60, Appendix A-7) within 180 days of the adoption of this chapter and annually thereafter.

(b) Owners and operators of affected facilities that install any new, modified, or reconstructed natural gas compressor station or underground storage facility that uses electric-powered equipment to compress natural gas shall meet the requirements of §B(3)(a) of this regulation within 180 days of the startup of the facility's operations.

C. Cove Point Liquefied Natural Gas facility shall comply with:

(1) The leak detection and repair requirements as specified by the Climate Action Plan, which is defined, prepared, and approved under COMAR 26.09.02.06.B — E; and

(2) The leak detection and repair plan defined and approved under the Certificate of Public Convenience and Necessity, issued by the Maryland Public Service Commission on May 30, 2014, Order No. 86372, Case No. 9318, as amended on February 6, 2018, with Order No. 88565, and Errata on February 23, 2018, Order No. 88565, as amended.

D. Any new liquefied natural gas facility that begins operations or repairs after the effective date of this chapter shall comply with §A of this regulation.

E. If an owner requests approval, the Department may approve a new technology or alternative practice to identify leaking fugitive emissions components as an equivalent substitution for the requirements in §A or B of this regulation.

.04 Natural Gas-Powered Pneumatic Devices Methane Emission Control Requirements.

A. Beginning January 1, 2021, each continuous and intermittent bleed natural gas-powered pneumatic device shall comply with the leak detection and repair requirements specified in Regulation .03 of this chapter, as applicable, when the device is idle and not controlling.

B. By January 1, 2022, continuous bleed natural gas-powered pneumatic devices shall not vent natural gas at a rate greater than 6 standard cubic feet per hour.

C. By January 1, 2023, all continuous bleed natural gas-powered pneumatic device shall be converted to use compressed air or electricity to operate unless an exemption is provided in §D of this regulation.

D. Exemption. Continuous bleed natural gas-powered pneumatic devices may be used if:

(1) The owner and operator collect all vented natural gas from the pneumatic device with the use of a vapor collection system according to Regulation .06 of this chapter; or

(2) The owner and operator submit justification for approval to the Department which demonstrates the need for the continuous bleed pneumatic device for safety or process purposes, as follows:

(a) Each continuous bleed pneumatic device that is approved for use shall be tagged with the month and year of installation, reconstruction, or modification and shall also have a permanent tag that identifies the natural gas flow rate as less than or equal to 6 standard cubic feet per hour; and

(b) The owner and operator shall:

(i) Inspect each continuous bleed pneumatic device on a monthly basis;

(ii) Perform necessary maintenance (including cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals and tuning to operate over a broader range of proportional band to eliminate unnecessary valve positioners);

(iii) Maintain the pneumatic device according to manufacturer specifications to ensure that the device's natural gas emissions are minimized;

(iv) By April 1, test each pneumatic device annually using a direct measurement method (high volume sampling, bagging, calibrated flow measuring instrument, etc.); and

(v) Successfully repair any device with a measured emissions flow rate that exceeds 6 standard cubic feet per hour within 14 calendar days from the date of the exceedance.

.05 Reciprocating Natural Gas Compressor Methane Emission Control Requirements.

A. All reciprocating natural gas compressor components at an affected facility shall comply with the leak detection and repair requirements in Regulation .03 of this chapter where applicable.

B. Control Measures for Reciprocating Natural Gas Compressor.

(1) By January 1, 2021, compressor vent stacks used to vent rod packing/seal emissions shall be controlled with the use of a vapor collection system as specified in Regulation .06 of this chapter; or

(2) By April 1, the reciprocating natural gas compressor rod packing/seal emission flow rate through the rod packing/seal vent stack shall be measured annually through direct measurement (high volume sampling, bagging, calibrated flow measuring instrument, etc.) while the compressor is operating at normal operating temperature.

(a) Direct measurements shall use one of the following methods:

(i) Vent stacks shall be equipped with a meter or instrumentation to measure the rod packing or seal emissions flow rate; or

(ii) Vent stacks shall be equipped with a clearly identified access port to measure individual or combined rod packing or seal emission flow rates.

(b) If the measurement is not obtained because the compressor is not operating for the scheduled test date, testing shall be conducted within 7 calendar days of resumed operation.

(3) A reciprocating natural gas compressor with a rod packing/seal with a measured emission flow rate that exceeds 1 standard cubic foot per minute, or a combined rod packing or seal emission flow rate that exceeds the number of compression cylinders multiplied by 1 standard cubic foot per minute shall:

(a) Be successfully repaired or replaced within 30 calendar days from the date of the exceedance; or

(b) Conduct natural gas compressor rod packing/seal emission flow rate measurements every 6 months or when the compressor resumes operation, whichever is later.

(4) A reciprocating natural gas compressor with a measured emission flow rate that exceeds 2 standard cubic feet per minute, or a combined rod packing or seal emission flow rate that exceeds the number of compression cylinders multiplied by 2 standard cubic feet per minute, shall be successfully repaired or replaced within 30 calendar days from the date of the exceedance.

C. Delay of Repair for Reciprocating Natural Gas Compressor.

(1) A delay of repair may occur provided the owner or operator provides documentation, upon request from the Department, that the delivery of parts or equipment required to make necessary repairs will take more than 30 days from the last emission flow rate measurement and that the parts have been ordered.

(2) A delay of repair to obtain parts or equipment may not exceed 60 days from the date of the last emission flow rate measurement unless the owner or operator notifies the Department, in writing, of the extended delay and provides an estimated time by which the repairs will be completed.

(3) A reciprocating natural gas compressor with a rod packing/seal emission flow rate measured above the standard specified in §B(4) of this regulation, and which has leaking parts deemed unsafe to monitor or requiring a facility shutdown, shall be successfully repaired by the end of the next planned process shutdown or within 12 months from the date of the flow rate measurement, whichever is sooner.

.06 Vapor Collection System and Vapor Control Devices.

A. Owners or operators of affected facilities that utilize vapor collection systems and vapor control device to comply with this chapter shall follow the requirements as specified in §§B and C of this regulation.

B. If a vapor collection system does not route all gases, vapors, and fumes to either a process gas system or a fuel gas system by January 1, 2021, a vapor control device shall be installed which meets the requirements of §E of this regulation.

C. The vapor collection system shall have no detectable emissions, as determined using auditory, visual, and olfactory inspections as specified in Regulation .03A(7) of this chapter.

D. The vapor collection system shall comply with the leak monitoring survey and repair requirements as specified in Regulation .03 of this chapter, where applicable.

E. Vapor control devices shall meet one of the following requirements:

(1) A nondestructive vapor control device manufacturer-designed to achieve at least 95 percent vapor control efficiency of methane emissions and may not result in emissions of nitrogen oxides (NOx); or

(2) A destructive vapor control device manufacturer-designed to achieve at least 95 percent vapor control efficiency of methane emissions and does not generate more than 15 parts per million volume (ppmv) NOx when measured at 3 percent oxygen; or require the use of supplemental fuel gas, other than gas required for a pilot burner, to operate.

.07 Record-Keeping and Reporting Requirements.

A. Owners or operators of affected facilities shall maintain, submit as described in this section, and make available upon request by the Department a copy of records necessary to verify compliance with the provisions of this chapter, as follows:

(1) For each leak monitoring survey and audio, visual, and olfactory inspection conducted according to Regulation .03 of this chapter, owners and operators shall:

(a) Submit a report to the Department within 60 days of each leak monitoring survey with the following information:

(i) Date of the survey;

(ii) A list of each fugitive emission and repair;

(iii) Any deviations from the initial methane monitoring plan or a statement that there were no deviations from the initial methane monitoring plan;

(iv) Number and type of components for which fugitive emissions were detected;

(v) Number and type of difficult-to-monitor fugitive emission components monitored;

(vi) Instrument reading of each fugitive emissions component that requires repair when EPA Method 21 (40 CFR 60, Appendix A-7) is used for monitoring;

(vii) Number and type of fugitive emissions components that were not repaired;

(viii) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair;

(ix) The date of successful repair of the fugitive emissions component; and

(x) Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding;

(b) Maintain, for a minimum of 5 years, record of each leak monitoring survey along with the following information:

(i) Reports submitted according to §A(1)(a) of this regulation;

(ii) Beginning and end time of the survey;

(iii) Name of operator(s) performing survey;

(iv) Monitoring instrument used, including the manufacturer, model number, serial number, and calibration documentation;

(v) When optical gas imaging is used to perform the survey, one or more digital photographs or videos, captured from the optical gas imaging instrument used for conduct of monitoring, of each required monitoring survey being performed;

(vi) Fugitive emissions component identification when EPA Method 21 (40 CFR 60, Appendix A-7) is used to perform the monitoring survey;

(vii) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey;

(viii) Any deviations from the initial methane monitoring plan or a statement that there were no deviations from the initial methane monitoring plan;

(ix) Proof that parts or equipment required to make necessary repairs, as required by this chapter, have been ordered;

(x) If a fugitive emissions component is not tagged, a digital photograph or video of each fugitive emissions component that could not be repaired during the leak monitoring survey at the time the fugitive emissions were initially found; and

(xi) Repair methods applied in each attempt to repair the fugitive emissions components;

(c) Post a quarterly report summary to a publicly available website of each leak monitoring survey, including the information required in §A(1)(a) of this regulation, 60 days after the leak monitoring survey; and

(d) Maintain records of audio, visual, and olfactory inspections for at least 5 years from the date of inspection.

(2) For each natural gas-powered continuous bleed pneumatic device, owners and operators shall:

(a) Maintain a record of the emission flow rate measurement and report annually beginning April 1, 2021, for at least 5 years from the date of each emissions flow rate measurement;

(b) Maintain records of the date, location, and manufacturer specifications for each continuous bleed pneumatic device constructed, modified, or reconstructed and report annually beginning April 1, 2021;

(c) Maintain records of the manufacturer's specifications indicating that the device is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour, if applicable;

(d) Maintain records of deviations in cases where the pneumatic device was not operated in compliance with the requirements specified in Regulation .04 of this chapter and report annually beginning April 1, 2021;

(e) Maintain purchase orders, work orders, or any in-house or third-party reports produced or provided to the affected facility relating to the device for at least 5 years; and

(f) Maintain a record of each continuous bleed pneumatic inspection and any corrective or maintenance action taken for at least 5 years.

(3) For each reciprocating natural gas compressor, owners and operators shall:

(a) Maintain a record of each rod packing leak concentration measurement found above the minimum leak threshold and report annually beginning April 1, 2021, for at least 5 years from the date of each leak concentration measurement;

(b) Maintain a record of each rod packing or seal emission flow rate measurement and report annually beginning April 1, 2021, for at least 5 years from the date of each emissions flow rate measurement;

(c) Maintain a record that documents the date(s) and hours of operation a compressor is operated in order to demonstrate compliance with the rod packing leak concentration or emission flow rate measurement in the event that the compressor is not operating during a scheduled inspection for at least 1 calendar year;

(d) Maintain records that provide proof that parts or equipment required to make necessary repairs required by this chapter have been ordered;

(e) Report annually the cumulative number of hours of operation or the number of months since initial startup or the previous reciprocating compressor rod packing replacement, whichever is later, beginning April 1, 2021;

(f) If applicable, submit a statement that emissions from the rod packing are being routed to applicable vapor control system under Regulation .06 of this chapter;

(g) Report records of deviations from this chapter that occurred during the reporting period annually, beginning April 1, 2021; and

(h) Maintain a record of purchase orders, work orders, or any in-house or third-party reports produced or provided to the affected facility necessary to demonstrate compliance with the delay of repair provisions of this chapter for at least 5 years.

B. Blowdown Events and Reports.

(1) Within 90 days of the effective date of this chapter, affected facilities shall submit a blowdown notification plan to the Department for approval of any blowdown event in excess of 1,000,000 standard cubic feet.

(2) The blowdown notification plan according to §B(1) of this regulation shall include:

(a) The notification format (for example, website, email, robocall, text message, social media announcement, etc.) to local authorities, the Department, and interested parties for blowdown emissions in excess of 1,000,000 standard cubic feet;

(b) A public outreach plan to inform interested parties of the availability to be notified of blowdown events in excess of 1,000,000 standard cubic feet;

(c) The affected facility's responsible personnel for blowdown notifications; and

(d) A sitemap of the facility with clearly marked designated area(s) for blowdown emissions in excess of 1,000,000 standard cubic feet.

(3) For any blowdown event in excess of 1,000,000 standard cubic feet, affected facilities shall make information publicly available in accordance with the facility's approved blowdown notification plan, including notification to the Department, at least 7 days prior.

(4) For any blowdown event in excess of 1,000,000 standard cubic feet that is scheduled less than 7 days prior to the blowdown event, affected facilities shall, as soon as practicable:

(a) Make information publicly available in accordance with the facility's approved blowdown notification plan; and

(b) Provide an explanation to the Department of the reason for the blowdown event.

(5) For any emergency or unplanned blowdown event in excess of 1,000,000 standard cubic feet, affected facilities shall make information publicly available in accordance with the facility's approved blowdown notification plan and notify the Department within 1 hour of the emergency or unplanned blowdown event.

(6) When safety concerns preclude a facility from providing prior notification of an emergency or unplanned blowdown under §B(5) of this regulation, the facility shall send notice to the Department within 24 hours of the blowdown event indicating the reason(s) why prior notice was not possible.

(7) Affected facilities shall report the following information to the Department of blowdown emissions in excess of 50 standard cubic feet within the facility's fence line annually by April 1 of each year:

(a) Date and type (that is, planned or emergency) of each blowdown event;

(b) Methane emissions in metric tons released from each blowdown event; and

(c) Annual methane emissions in metric tons from all blowdown events.

(8) Methane emissions shall be calculated according to procedures in 40 CFR Part 98, Subpart W, §98.233.

C. Greenhouse Gas Emissions Reporting.

(1) Owners and operators of affected facilities shall report methane, carbon dioxide, and nitrous oxide mass emissions to the Department annually by April 1 of each year.

(2) Owners and operators of affected facilities shall follow the procedures for emission calculation, monitoring, quality assurance, missing data, record keeping, and reporting that are specified in 40 CFR Part 98, Subpart C, and 40 CFR Part 98, Subpart W.

(3) When reporting to the Department, owners and operators of affected facilities shall expand the fugitive emissions reporting requirements of 40 CFR Part 98, Subpart W, to include a Microsoft Excel format list providing calculations summarized by category under 40 CFR §98.232(e) — (h) as applicable.

(4) The reporting threshold in 40 CFR §§98.2, 98.31 and 98.231 of 25,000 metric tons of CO_2 equivalent does not exempt an affected facility from following the requirements of this section.

D. All required reports shall be submitted to the Industrial Compliance Division in written or electronic format and mailed to Maryland Department of the Environment, Air Quality Compliance Program, 1800 Washington Boulevard, 7th Floor, Baltimore, MD 21230, Attention: Industrial Compliance Division.

Appendix

Appendix A – Maryland opposition letter’s to EPA proposed regulations
Appendix B – Stakeholder Meeting Presentation Oct. 2019
Appendix C – Air Quality Control Advisory Council Dec. 2019
Appendix D – Cove Point – LDAR Climate Action Plan and CPCN
Appendix E – Rod Packing Thresholds
Appendix F – Blowdown Operations
Appendix G – Cost Impact Supporting Analysis
Appendix H – Public Hearing Documentation

Appendix A – Maryland opposition letter’s to EPA proposed regulations

Maryland
Department of
the Environment

Larry Hogan, Governor
Boyd K. Rutherford, Lt. Governor

Ben Grumbles, Secretary
Horacio Tablada, Deputy Secretary

Via Electronic Submission
United States Environmental Protection Agency
Docket ID Number: EPA–HQ–OAR–2017–0483

December 17, 2018

RE: Oil and Natural Gas Sector: Emissions Standards for New, Reconstructed, and Modified Sources Reconsideration, 83 Fed. Reg. 52056 (October 15, 2018)

To Whom It May Concern:

The Maryland Department of the Environment (MDE) appreciates the opportunity to comment on the Environmental Protection Agency's (EPA's) proposed rule *Oil and Natural Gas Sector: Emissions Standards for New, Reconstructed, and Modified Sources Reconsideration.* This action proposes reconsideration amendments to certain aspects of the new source performance standards (NSPS) at 40 Code of Federal Regulations part 60, subpart OOOOa (2016 NSPS OOOOa). Specifically, EPA proposes to reduce the monitoring frequency of fugitive emissions at compressor stations and to extend the allotted time for owners and/or operators of compressor stations to repair fugitive emission components. Additionally, EPA is seeking comment on extending the time period for owners and/or operators of well sites or compressor stations to conduct an initial monitoring survey and reoccurring leak inspections. MDE strongly opposes these proposed amendments.

MDE's mission is to protect and restore the environment for the health and well-being of all Marylanders. Working to improve air quality and mitigate and adapt to climate change are main components of this mission. Maryland, through Governor Hogan's Administration and MDE, has made great progress on reducing air pollution and greenhouse gas (GHG) emissions, and adapting to the potential consequences of climate change while creating jobs and benefiting the economy.

Natural gas use in the U.S. is growing and the growth is projected to continue over the next few decades. The U.S. Energy Information Administration estimates that through 2050, natural gas will account for the largest share of total energy production in the United States. Natural gas is a naturally occurring gas mixture, consisting mainly of methane. Methane that enters the atmosphere prior to combustion absorbs the sun's heat, warming the atmosphere. For this reason, it's considered a greenhouse gas, like carbon dioxide. While methane doesn't linger as long in the atmosphere as carbon dioxide, it is initially far more impactful to the climate because of how effectively it absorbs heat. In the first two decades after its release, methane is approximately 84 times more effective at trapping heat than carbon dioxide and over 100 years is 25 times more effective at trapping heat.

EPA expects increases in methane, VOC, and HAP emissions under the proposed action. Consequently, EPA states this increase in emissions will adversely affect human health. MDE shares this concern. MDE does not support the proposed action and has the following specific comments on the proposed action:

EPA is proposing to reduce the monitoring frequency of fugitive emissions at compressor stations from quarterly inspections to either semi-annual or annual inspections.

MDE does not support reducing the leak monitoring/survey frequency at natural gas compressor stations. Based on the proposed revision, leaking components that occur after a leak survey may potentially remain undiscovered for either six months (for semi-annual inspections) or up to a year (for annual inspections). The unnoticed fugitive emissions would increase the amount of potent methane into the atmosphere – thus, potentially posing a negative effect on the climate and public health.

MDE reviewed the Compressor Station Fugitive Emissions Monitoring data provided by GPA Midstream[1] along with EPA's analysis of the data. The data provided by GPA served as one of the bases for EPA's reconsideration for reducing fugitive emission monitoring frequencies. Based on MDE's assessment of the data, leak counts and leak percentages reported were inconsistent, changed vastly from survey-to-survey, and fluctuated between higher and lower values. For example, between May 2012 and September 2012, Station 1 of Company 1 had leak rate percentage values of 4.05, 3.01, 6.91, 7.01, and 1.82 respectively[2]. In another example, from January 2015 through June 2015, Site B of Company 2 showed the total number of new leaks found as 23, 4, 3, 8, 2, and 5, respectively[3]. Thus, though the data reveals an overall downward trend of total leak counts and leak percentage values, the inconsistencies between surveys should caution against action to reduce the number of surveys performed. The U.S. EPA's 2014 Greenhouse Gas Inventory indicates that a quarter of the methane emissions from the oil and natural gas industry come from the transmission and storage segments.

MDE believes that EPA should take into consideration other data such as the methane leak rate per component and time taken to repair leaking components. Less frequent inspections may potentially lead to more leaks, and more leaks translates directly into lost product and more environmental impacts. EPA's best practices guide[4] on leak detection and repair notes the importance of timely inspections: "To ensure that leaks are still being identified in a timely manner and that previously unidentified leaks are not worsening over time, implement a plan for more frequent monitoring for components that contribute most to equipment leak emissions". MDE suggests that EPA maintain the requirement for quarterly leak surveys.

EPA is proposing that a first attempt at repair must be completed within 30 days of identifying a component with fugitive emissions, with final repair completed within 60 days.

MDE supports the inclusion of a definition of "first attempt at repair" and the inclusion of a verification of repaired fugitive emissions as part of the "repaired" definition. MDE does not, however, support extending the time allotted for owners and/or operators of natural gas compressor stations to complete final repair. The length of time an identified leaking component remains in operation increases the amount of methane emitted from the source and poses a potential health, safety and environmental threat. MDE opposes the proposed rule; however, if EPA finalizes this proposed rule, MDE suggests revising it to require that first attempt at repair should be made no later than five days after a leak is detected (as recommended by EPA's leak detection and repair (LDAR) best practices guide[5]) and repairs should be made no longer than 30 days after the discovery of a leak. Based on discussion with facility

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[1,2,3] GPA Midstream Association Re: GPA Midstream OOOOa White Paper Supplemental Information, March 5, 2018, located at Docket ID No. EPA–HQ–OAR–2017–0483.

[4,5] Leak Detection and Repair, A Best Practices Guide EPA-305-D-07-001 October 2007

operators, MDE understands that fixing a leaking component may require specialty ordered parts or equipment. Therefore, MDE suggests that EPA adds language that grants a delay of repair provision for parts and/or equipment that need to be specially ordered to address fugitive components. Owners and operators should be required to submit reports that provide some form of proof that the parts needed to repair a leaking component have been ordered.

EPA is soliciting comment on whether to extend the leak inspections at well sites from being required every six months, to instead require leak inspections every year at minimum, with some of the smaller wells only requiring an inspection every two years.

MDE does not support reducing the frequency of leak inspections at well sites. More frequent surveys will detect methane emissions and provide companies opportunities to reduce leakage. Inspections occurring half as frequently allow leaks twice as long to go unnoticed and unrepaired. MDE believes reducing the number of leak inspections may potentially be problematic when a leak occurs immediately after an inspection. For example, if a leak occurs two months after an inspection, based on the proposed amendments, that leak will now be able to leak for 10 months instead of four months. MDE does not believe that just because a well site is low production it is a low methane emitter. In fact, at least one report[6], proves the opposite is true. The maintenance practices at a drilling site can greatly affect the potential for leaks and are a factor at all well sites, including low production well sites, as well as at any oil and gas production site. Well site emission records are very important to assist in inventory, modeling and climate predictions.

EPA is soliciting comment on whether to extend the period for conducting initial monitoring for well sites and compressor stations because additional time is needed to complete installation of equipment.

MDE does not support granting owners and operators of well sites and compressor stations additional time to conduct initial monitoring at well sites and natural gas compressor stations. As previously stated, unintended emission leaks can occur at any facility. Allowing more time before conducting an initial monitoring survey increases the probability of leaking methane emissions. It is especially important to review the performance of a new site process and new equipment to confirm that the design and integrity of the project has been constructed properly and is functioning at the designed efficiency. MDE recommends maintaining the initial monitoring deadline of 60 days with subsequent quarterly surveys.

For the reasons noted above, MDE opposes this proposed rule and recommends that EPA withdraw it and retain the existing NSPS at 40 Code of Federal Regulations part 60, subpart OOOOa. Thank you again for the opportunity to comment on EPA's proposed action and for your consideration. Should you have any questions, please contact me at george.aburn@maryland.gov or 410-537-3255.

Sincerely,

for Tad Aburn

George (Tad) S. Aburn, Jr., Director, Air and Radiation Administration

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[6] https://pubs.acs.org/doi/10.1021/acs.est.5b00133 Environmental Science and Technology Article: Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites.

Maryland
Department of
the Environment

Larry Hogan, Governor
Boyd K. Rutherford, Lt. Governor

Ben Grumbles, Secretary
Horacio Tablada, Deputy Secretary

November 25, 2019

Via Electronic Submission
United States Environmental Protection Agency
Docket ID Number: EPA–HQ–OAR–2017–0757

RE: Oil and Natural Gas Sector: Emissions Standards for New, Reconstructed, and Modified Sources Review, 84 Fed. Reg. 50244 (September 24, 2019)

To Whom It May Concern:

The Maryland Department of the Environment ("MDE") appreciates the opportunity to comment on the U.S. Environmental Protection Agency's ("EPA") proposed rule *Oil and Natural Gas Sector: Emissions Standards for New, Reconstructed, and Modified Sources Review*, 84 Fed. Reg. 50,244 (Sept. 24, 2019) ("Proposed Rule" or "Proposal"). As detailed in these comments, MDE oppose the Proposed Rule and continue to support EPA's 2016 emission standards for new, reconstructed, and modified sources in the oil and natural gas sector codified at 40 Code of Federal Regulations part 60, subpart OOOOa ("2016 Standard").[1]

This action proposes reconsideration amendments to the new source performance standards (NSPS) at 40 Code of Federal Regulations part 60, subpart OOOOa (2016 NSPS OOOOa). Specifically, EPA proposes to (1) remove sources in the transmission and storage segment from the affected source category and rescind the NSPS (including both the volatile organic compounds (VOC) and methane requirements) applicable to those sources, and (2) rescind the methane-specific requirements of the NSPS applicable to sources in the production and processing segments. The EPA is also proposing, as an alternative, to rescind the methane requirements of the NSPS applicable to all oil and natural gas sources, without removing any sources from the source category. Furthermore, the EPA is taking comment on alternative interpretations of its statutory authority to regulate pollutants under the Clean Air Act (CAA), and associated record and policy questions. MDE strongly opposes these proposed amendments that would result in increased emissions of climate-damaging methane pollution and that remove important public health protections by increasing emissions of ozone-smog precursors and hazardous air pollutants from the natural gas sector.

MDE's mission is to protect and restore the environment for the health and well-being of all Marylanders. Working to mitigate and adapt to climate change are main components of MDE's mission and is authorized by state legislation, specifically the Greenhouse gas Reduction Act (GGRA). Marylanders are already witnessing firsthand the impacts of climate change, from more frequent, severe flooding, which threatens the state's agricultural sector, to more powerful heat waves that put lives at risk. That is why the State's GGRA Plan to cut greenhouse gas emissions 40% by 2030, and Governor

[1] 81 Fed. Reg. 35,824 (June 3, 2016).

Hogan's commitment to develop a clean and renewable energy standard, are so important. Maryland has made great progress on reducing air pollution and greenhouse gas emissions, and adapting to the potential consequences of climate change while creating jobs and benefiting the economy. Comprehensive methane pollution regulation is a key part of making sure Maryland can continue to make progress and meet emission reduction goals.

Natural gas use in the U.S. is growing and the growth is projected to continue over the next few decades. The U.S. Energy Information Administration estimates that through 2050, natural gas will account for the largest share of total energy production in the United States. Cutting methane emissions from oil and gas infrastructure is one of the most cost-effective ways to mitigate the impacts of climate change. The International Energy Agency also estimates approximately half of global methane emissions can be cut at no net cost. Maryland believes that cost-effective methane regulation can go hand-in-hand with a positive economic growth and job creation. Natural gas is a naturally occurring gas mixture, consisting mainly of methane. Because methane is the main component of natural gas and a salable product, fugitive emissions mean lost revenue for the oil and gas sector. Continued action from EPA and regulations at the State level will curb emissions and mitigate impacts from climate change in a cost-effective way.

Under this proposal, EPA estimates increased emissions between the years 2019 - 2025 in the following amounts: 370,000 short tons of methane (equal to 8.4 MMTCO2e); 10,000 short tons of VOC; and 300 short tons of HAPs from these amendments. Consequently, EPA states this increase in emissions will adversely affect human health and the environment. MDE shares this concern. In addition, Clean Air Task Force (CATF) has modeled this proposed relaxation and shows even more potential increase in emissions than the EPA data shows.[2]

MDE is not alone in its concern over this proposal. MDE supports the comments prepared and submitted by National Association of Clean Air Agencies (NACAA). The expected increases in VOC and hazardous air pollutants (HAP) emissions under the proposed action will affect Maryland's ability to meet and maintain National Ambient Air Quality Standards. Without federal rules in place, each State will be subject to impacts from less stringent State controls. Federal rules better serve environmental protection and provide for industry certainty.

Section 111 of the CAA requires the EPA Administrator to list categories of stationary sources that, in his or her judgment, cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. MDE believes that the intent of the 1979 listing[3] was to broadly cover the natural gas industry, as EPA stated the same on September 13, 2015 in the 2016 NSPS OOOOa proposal.[4] The transmission and storage segment of the natural gas industry should be regulated as greenhouse gas emissions. Natural gas emissions from this segment are a significant portion of emissions in the natural gas industry. With the large expansion in natural gas production, processing,

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[2] Clean Air Task Force, White Paper titled "Memo: Modeled impacts from EPA methane rollbacks" https://www.catf.us/resource/memo-modeled-impacts-from-epa-methane-rollbacks/

[3] Priority List and Additions to the List of Categories of Stationary Sources, 44 FR 49222 (August 21, 1979) (''1979 Priority List'').

[4] 80 Fed. Reg. 56593

transmission and storage, emissions from this industry become more and more important to control. EPA was correct in their assumptions to include this segment in the 2016 NSPS OOOOa final rule.[5]

MDE submitted a comment letter on December 17, 2018, to Docket Number: EPA–HQ–OAR–2017–0483[6] to oppose EPA's previous NSPS reconsideration amendments[7] that proposed relaxation for leak detection survey monitoring frequency. MDE was worried about health and environmental impacts from that relaxation, while the removal of all leak detection survey monitoring for methane in the whole oil and gas transmission and storage segment under this proposal would be detrimental. EPA concedes that the proposed reconsideration amendments to NSPS Subpart OOOOa will result in additional emissions. Therefore, EPA's relaxation is inconsistent with the CAA's strict prohibition against backsliding.

EPA should not be reversing its obligation under Section 111(b) of the CAA to regulate methane under this natural gas industry. Maryland agrees that the statute is clear that the endangerment finding is made with respect to the source category; section 111(b)(1)(A) of the CAA does not provide that an endangerment finding is made as to specific pollutants, as EPA stated on September 13, 2015 in the 2016 NSPS OOOOa proposal. EPA did not introduce a new source category therefore a new endangerment finding is not warranted. Additionally we know methane emissions contribute to climate warming and endanger both the public health and the public welfare of current and future generations.

EPA should regulate existing sources in the oil and natural gas industry under Section 111(d) of the CAA. MDE disagrees that the number of existing sources in the U.S. will decline in the near future. For the same reasons as stated above, control of methane, VOC and HAPS is beneficial to improve air quality and mitigate climate change in Maryland and the nation. Should EPA's rollback of 2016 NSPS OOOOa be allowed, Maryland will still move ahead with a commitment to propose responsible, commonsense natural gas sector regulations. Climate action is something Marylanders have voiced support for, and the data are clear that comprehensive methane rules will deliver powerful benefits to communities throughout the State.

For the reasons noted above, MDE opposes this proposed rule and recommends that EPA withdraw it and retain the 2016 NSPS OOOOa final rule. Thank you again for the opportunity to comment on EPA's proposed action and for your consideration. Should you have any questions, please contact me at george.aburn@maryland.gov or 410-537-3255.

Sincerely,

George (Tad) S. Aburn, Jr., Director, Air and Radiation Administration

CC: Brian Hug, Program Manager ARA Planning Division
Chris Hoagland, Program Manager ARA Climate Division
Randy Mosier, Division Chief ARA Regulations Development

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[5] 81 Fed. Reg. 35824

[6] Docket EPA–HQ–OAR–2017–0483 Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration directly links to this Docket EPA–HQ–OAR–2017–0757 found at Regulations.gov

[7] 83 Fed. Reg. 52056

Appendix B – Stakeholder Meeting Presentation Oct. 2019

Maryland Department of the Environment

Minimizing Methane Emissions from Natural Gas Compressor Stations and other Related Equipment

Tad Aburn and Joshua Shodeinde, MDE - Stakeholder Meeting # 5 - October 11, 2019

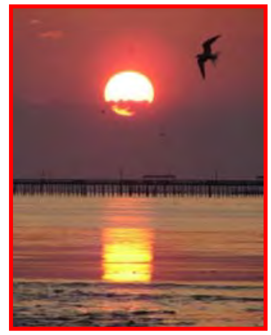
Today's Meeting

- We will focus mainly on comments received on discussion draft regulation
  - Priority to finalize regulation
  - Aiming for December 16th Air Quality Control Advisory Council (AQCAC)
- There will also be an update provided on voluntary program
- Different webinar format. Online participants will need to "raise hand" for comments and questions

2

Presentation Outline

- A Little Background for New Participants
- Comments Received/Addressed
- Draft Regulatory Requirements
- Discussion/Comments
- Next Steps

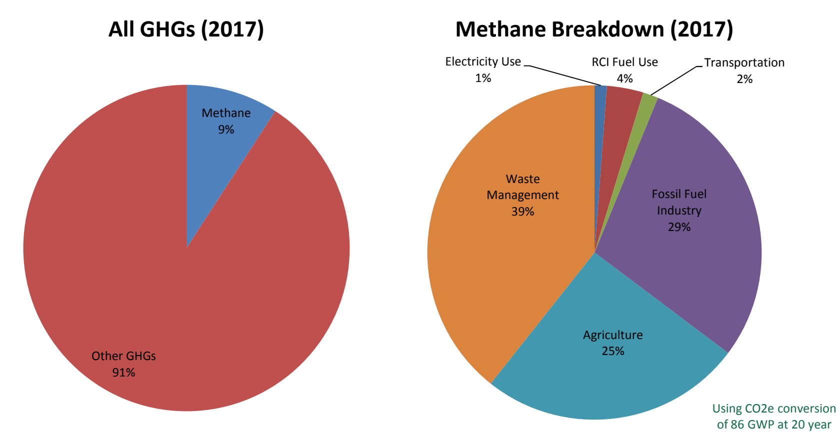


Why is MDE Pushing this Issue

- Maryland has one of the country's most aggressive programs to address climate change
- Methane is a highly potent greenhouse gas that needs to be acted upon quickly because it is a short-lived climate pollutant (SLCP)
- Leaking methane has been identified by researchers and regulators as a major issue that needs to be addressed
  – Reducing in-state methane leakage is a high priority

5

Methane Emissions in Maryland

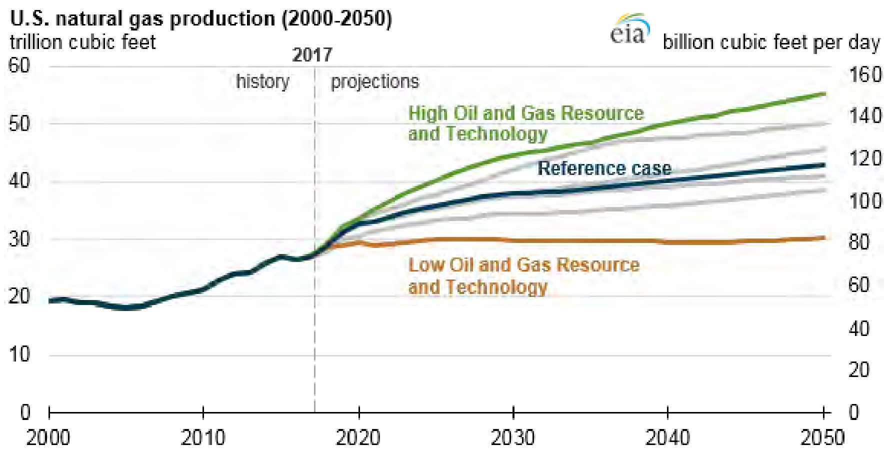


- MDE is also working on regulations to reduce leaking methane from landfills and wastewater treatment plants

6

Natural Gas - Continued Growth

US Natural Gas Production and Consumption are Expected to Keep Rising



Source: U.S. Energy Information Administration, Annual Energy Outlook 2018

7

Maryland's Climate Focus

- Greenhouse Gas Emission Reduction Act (GGRA)
  - 2009 aggressive reduction from 2006 baseline
  - 25 % Greenhouse Gas (GHG) Emission reduction by 2020
  - 2009 law reauthorized in 2016 … new goals added
  - 40 % GHG reduction by 2030
- Maryland Commission on Climate Change (MCCC)
  - Basic charge of the Commission: *Provide recommendations on how to reduce GHG emissions and adapt to the impacts of climate change, while considering economic impacts*
- US Climate Alliance
  - Basic mission…to meet the goals of the Paris Climate Agreement … at least 26-28 percent below 2005 levels by 2025
  - Multiple working groups - one on *Short-lived Climate Pollutants* (SLCP)

8

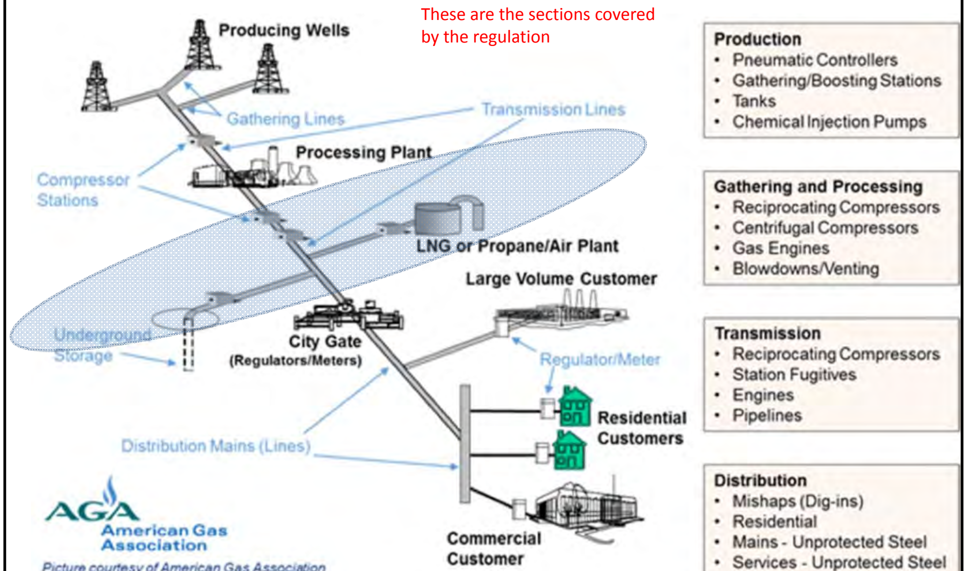
Shifting EPA Requirements

- From 2014 to 2016, EPA was working to tighten methane emission reduction requirements
  - 2016: NSPS OOOOa also called "Quad Oa"
  - 2016: Control Technology Guideline (CTG) for existing sources finalized
- More recently EPA has moved to relax emission reduction requirements
  - 2018 proposal to repeal 2016 CTG
  - 2018 and 2019 … EPA proposed relaxations to Quad Oa
- Maryland working with other states to challenge more recent relaxations
  - Reducing methane is not just a Maryland issue

9

Oil and Natural Gas Industry in General

These are the sections covered by the regulation



Source: https://www.epa.gov/natural-gas-star-program/overview-oil-and-natural-gasindustry#sources

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MDE's Stakeholder Process

MEETING 1 – June 29, 2017
Overview of the Natural Gas Industry

MEETING 2 – July 10, 2018
Regulatory and Voluntary Concepts - General

MEETING 3 – March 8, 2019
Regulatory and Voluntary Concepts - Specifics

MEETING 4 – June 28, 2019
Summary and Discussion of "Discussion Draft" of Regulation

Today – October 11, 2019
Respond to comments received and present updated "Discussion Draft"

- MDE has also been meeting with affected businesses, communities, environmental advocacy groups and other stakeholders in 1-on1 meetings or calls since 2017

11

Draft Regulatory Review

- Today's Review Process
- Joshua will go through the full summary of the "Discussion Draft"
- When you have a question … raise your hand … Carolyn will acknowledge and log your name and question
- After completing the presentation… we will address questions in the order they were logged in

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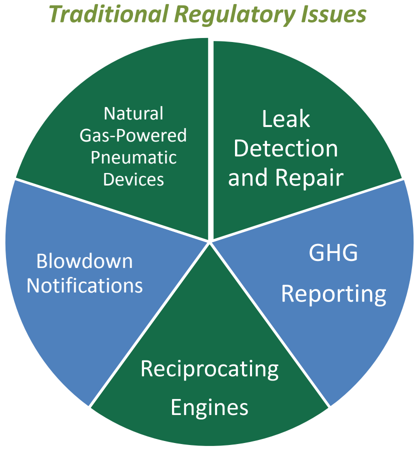
Overview of Requirements

Regulatory Requirements
Traditional Regulatory Issues



Built from OOOOa, and leading states with methane reduction programs such as Colorado and California

14

Applicability

No changes made

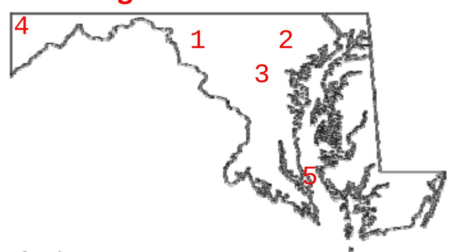
- Existing and “Any new, modified, or reconstructed natural gas compressor station, natural gas underground storage facility, or liquefied natural gas facility.”

- Four compressor stations
  1. Dominion, Myersville
  2. TC Energy, Rutledge
  3. Transco, Ellicott City
  4. Texas Eastern, Accident

- One underground storage facility
  – Texas Eastern, Accident

- One import and liquefaction/export facility
  5. Dominion, Cove Point

Existing facilities location



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Changes in Definitions

- “Fugitive emission component”
  – Includes “component”
  – Reflects EPA 40 CFR 60.5430a – when equipment is not actively venting as designed it can be a fugitive source
- “Process gas” instead of “Sale gas”
- Added “bubble test” and “intermittent bleed”
- Liquefied Natural Gas “Facility”, not “Station”
- Removed definitions not referenced

16

Leak Detection & Repair (LDAR): Comments Summary

Frequency	• More LDAR (monthly surveys) • Less LDAR (annual surveys) and audio, visual, olfactory (AVO) (monthly) • Apply same frequency to all facilities
Monitoring Plan	• LDAR steps should be clear for Optical Gas Imaging (OGI) vs. EPA Method 21 • Extend timeframe for submittal • Maintain component list requirement….other comments requested this provision to be removed
Repair times & Delay of Repair (DOR)	• Allow 1st attempt of repair to be done within 30 days, with 60 days to repair • Extend DOR to 30 days after receiving specialty ordered parts

Additional comment: Make plan and reporting for all facilities transparent and publicly available

17

Leak Detection & Repair (LDAR): MDE Response to Comments

2nd Discussion Draft - Reg .03 (pgs. 2/3)

Changes Made from 1st Draft	Remains the Same
• Initial monitoring plan for OGI vs. EPA method 21 separated for clarity • Extended submittal time for initial monitoring plan and initial leak survey by 30 days • Requirement for summary of fugitive emission components for OGI • Requirement for list of DTM & UTM components and explanation of why • DOR for specialty parts must be done within 7 days unless vent or compressor station blowdown needed and administrative amendments for clarity	• Quarterly surveys for facilities and annual surveys for facilities with electric compressors. Weekly AVOs • Repairs for leaks to be completed within 30 days unless placed on DOR • Cove Point to follow Certificate of Public Convenience and Necessity (CPCN) and Climate Action Plan – which will be made public • Allowance for new technology and practices to identify leaking components

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Leak Detection & Repair (LDAR): Summary of Requirements

2nd Discussion Draft - Reg .03 (pgs. 2/3)

- Facilities to submit initial methane emissions monitoring plan within 90 days of regulation adoption - *§A(5)*
  - Procedures, equipment and observation path
  - Include DTM and UTM components with explanation
- Weekly Audio/Visual/Olfactory (AVO) Inspections - *§A(7)*
- First LDAR monitoring survey due within 180 days of effective date of regulation. - *§A(8)(a)*
  - Within 180 days at the startup of new facility
- Quarterly monitoring survey using Optical Gas Imaging (OGI) or Method 21 - *§A(8)(a)*
  - Exception for electric engines (monthly AVO, annual LDAR inspections) - §.03(B)
- LNG specific requirements: Climate Action Plan and CPCN LDAR requirements - *§.0*3(C) – MDE will make these available

19

Leak Detection & Repair (LDAR): Summary of Requirements

2nd Discussion Draft – Reg .03 (pg. 3)

- *Repair Requirements - §A(9)*
- Repairs should be made and confirmed within 30 days of discovering a leak
- DOR provisions for documentation showing:
  - Repair will take longer than 30 days due to specialty part
  - Repair requires a vent or station blowdown
  - Repair is unsafe to repair due to the operation of unit
  - Repair can not be successfully completed, will require a plan to be approved by the Department

20

Pneumatic Devices: Comments Summary

1. Apply standards to continuous bleed devices and exempt intermittent pneumatic controllers
2. Consider exemption criteria for functional and safety needs as in OOOOa
3. Remove requirement for annual testing of continuous bleed devices
4. Extend phase out of continuous bleed devices to two years after rule effectiveness date

21

Pneumatic Devices: MDE Response to Comments

2nd Discussion Draft - Reg .04 (pgs. 3/4)

Changes Made from 1st Draft	Remains the Same
• Rearranged for clarity • Includes intermittent bleed device provisions • Added exemption criterion for continuous bleed device use after January 1, 2022, with additional requirements for those devices • No annual testing as devices will be phased-out. Monthly inspection for devices that will continually be in use	• Pneumatic devices subject to LDAR • Bleed rate shall be less than 6 standard cubic feet per hour (scfh) • Continuous bleed natural-gas powered pneumatics to be phased out beginning January 1, 2022 (unless exemption is granted)

22

Pneumatic Devices: Summary of Requirements

2nd Discussion Draft - Reg .04 (pgs. 3/4)

- Pneumatic devices will be subject to LDAR - *§B(1)*
- Bleed rate cannot exceed 6 standard cubic feet per hour - *§B(2)*
- Beginning Jan. 1, 2022 switch to electric or compressed air - *§C(1)*
- Additional requirements for exempt continuous bleed natural gas-powered devices - *§D(1)*:
  1. Use a vapor collection system; or
  2. Tag device, inspect monthly, and perform maintenance

23

Reciprocating Engines: Comments Summary

1. Use a time-based replacement schedule, similar to OOOOa, and not conditioned-base

2. Allow for a higher emission threshold for rod packing replacement....another commenter suggested leaving at lower threshold

24

Reciprocating Engines: MDE Response to Comments

2nd Discussion Draft - Reg .05 (pg. 4)

Changes Made from 1st Draft	Remains the Same
• Rearranged for clarity • Emission threshold for rod packing replacement changed to 1 scfm (MDE seeking comment and requesting additional real-world data on this standard)	• Two mitigation options for emissions are use of VCS or replace rod packing system • Condition-based maintenance schedule • DOR provisions

25

Reciprocating Engines: Summary of Requirements

2nd Discussion Draft - Reg .05 (pg. 4)

- Subject to LDAR - *§A*
- Two mitigation options:
  1. Vented gas is routed to a vapor control device - *§B(1);* OR
  2. Rod packing required to be measured annually and replaced if exceeds emission threshold of 1 scfm – *§B(2) and (3)*
     - Canada's threshold is 0.81 scfm (~0.04 scfm for equipment installed after January 2023)
     - California's threshold is 2 scfm
     - CATF threshold recommends 0.50 scfm

26

Vapor Collection System (VCS): Comments Summary

1. Non-destructive vapor control devices are ineffective at controlling methane

2. VCS and VCD should not be required as a methane control for all applications, e.g. pneumatic controllers

3. MDE should reexamine the NOx limits and fuel gas use for vapor recovery and control due to technical and economic feasibility issues.

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Vapor Collection System: Summary of Requirements

2nd Discussion Draft - Reg .06 (pg. 4/5)

NO CHANGES MADE

- Rearranged for clarity
- All gases collected with a VCS shall route all gases, vapors and fumes to:
  - Process gas system;
  - Fuel gas system; or
  - Vapor control device (VCD)
- VCS subject to LDAR and AVO inspections - §§ C and D
- VCD standards for destructive and non-destructive types - §E

28

Reporting and Blowdowns: Comments Summary

Reporting and Recordkeeping	• Reports should be submitted annually and not 60 days after LDAR surveys…other commenters requested reports be sent to MDE in a timely manner • Remove requirement to submit reports to MDE and instead be maintained in-house • Make reports publicly available
Blowdowns	• Establish reporting threshold for intentional and unplanned releases • Expand definition of blowdowns to include a wider range of operation activities • Communication signaling and notification for blowdowns…one commenter did not support blowdown notification • Focus on blowdowns within facility fence-line

Reporting and Blowdowns: MDE Response to Comments

2nd Discussion Draft - Reg .07 (pgs. 5/6)

Changes Made from 1st Draft	Remains the Same
• Industry to publicly post LDAR surveys monthly on their website • AVO and continuous bleed device inspection records to be maintained • Threshold for notifying and reporting blowdown emissions within the facility fence-line • Greenhouse gas emission reports to include expanded list of components	• LDAR survey report to be submitted to the Department within 60 days of completion • Blowdown event reporting • GHG emission reporting

Reporting and Recordkeeping: Summary of Requirements

2nd Discussion Draft - Reg .07 (pg. 5)

- LDAR reports to be publicly posted on company website and submitted to the Department
- LDAR is part of the annual GHG reporting
- DOR records on-site unless requested
- Recordkeeping requirements for AVO and continuous bleed natural gas-powered device inspections on-site

31

Blowdowns: Summary of Requirements

2nd Discussion Draft - Reg .07 (pg. 6)

- Significant blowdown events to be announced
  - Blowdowns in the excess of 1 million standard cubic feet (scf) to report to MDE and communities
  - Affected facilities shall notify the Department and make blowdown information publicly available at least 7 days prior to any planned blowdown event. Any planned blowdown less than 7 days before event should be explained
  - Emergency blowdowns notification within one hour of occurrence, if possible
- All blowdown events greater than 50 scf to be reported to MDE annually
  - Blowdown is required within the fence-line. All methane emissions from blowdown events shall be reported to the Department annually by April 1st

32

GHG Reporting: Summary of Requirements

2nd Discussion Draft - Reg .07 (pg. 6)

- All facilities, regardless of the size of GHG emissions, will be required to report their GHG emissions to the Department annually - §§ C(1) and (3)
- MDE's reporting requirements, calculation methodology, and procedures mirror EPA's Greenhouse Gas Reporting Program - § C(2)
- Maryland reporting requirement will harmonize reporting with federal rule with modification
  - Facilities will be required to provide back-up calculation details

33

Submitting Additional Comments

- To meet AQCAC deadlines, we are asking for any additional comments by October 28, 2019
  - Hard deadline because of Regulation Proposal requirements
- Requesting specific additional comments and data for:
  - Reciprocating engine rod packing replacement threshold
  - Format and threshold for blowdown notifications

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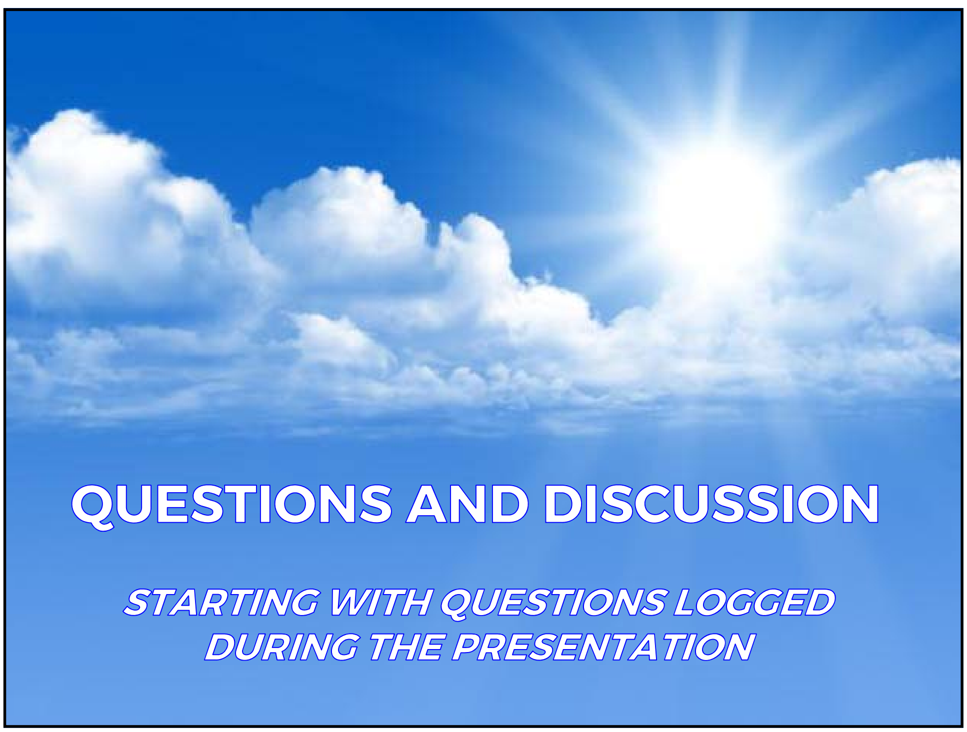
Schedule

- Stakeholder Meeting: Today
- Comments Due:
  October 28, 2019
- Air Quality Control Advisory Council:
  December 16, 2019
  - Public comment included
- Proposed Regulation in the Maryland Register: May 2020
- Public Hearing and final comment period: June 2020
- Rule Adoption and Effective: Fall 2020

35



Appendix C – Air Quality Control Advisory Council Dec. 2019

Maryland Department of the Environment

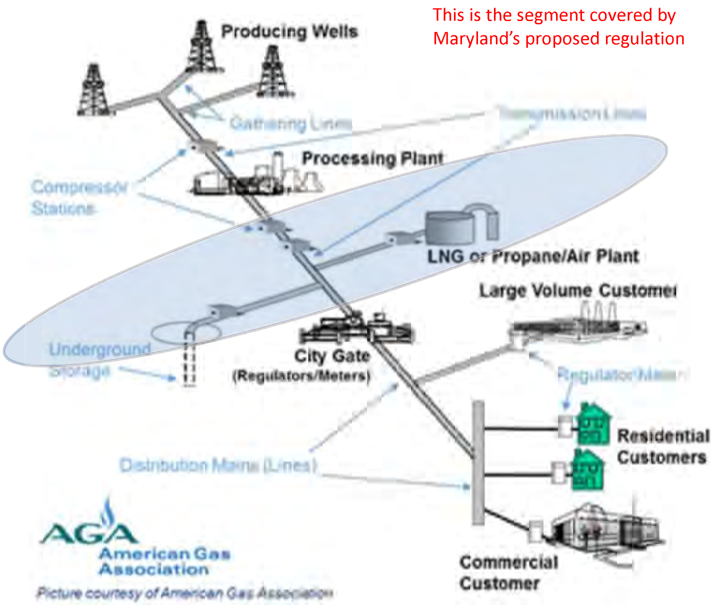
Minimizing Methane Emissions from Natural Gas Compressor Stations and other Related Equipment

Joshua Shodeinde, MDE - AQCAC - December 16, 2019

Presentation Outline

- Overview of Oil and Natural Gas Industry
- Federal New Source Performance Standards (NSPS)
- Proposed Regulatory Requirements
- Discussion/Questions

Oil and Natural Gas Industry in General



Production
- Pneumatic Controllers
- Gathering/Boosting Stations
- Tanks
- Chemical Injection Pumps

Gathering and Processing
- Reciprocating Compressors
- Centrifugal Compressors
- Gas Engines
- Blowdowns/Venting

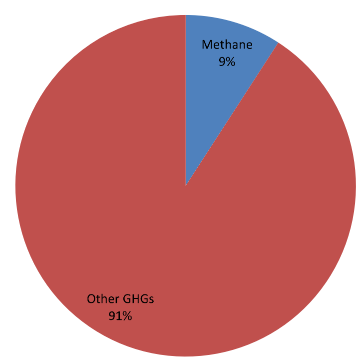
Transmission
- Reciprocating Compressors
- Station Fugitives
- Engines
- Pipelines

Distribution
- Mishaps (Dig-ins)
- Residential
- Mains - Unprotected Steel
- Services - Unprotected Steel

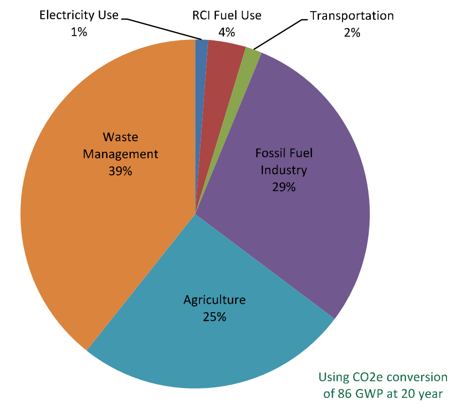
Source: https://www.epa.gov/natural-gas-star-program/overview-oil-and-natural-gasindustry#sources

Methane Emissions in Maryland

All GHGs (2017)



Methane Breakdown (2017)



Using CO2e conversion of 86 GWP at 20 year

- Fossil fuel industry methane emissions comprise of emissions in the transmission and storage segment and the distribution segment.

Shifting EPA Requirements

2016

- EPA finalized New Source Performance Standards (NSPS) OOOOa for the Oil and Natural Gas Industry to curb emissions of methane.
- EPA issued Control Technique Guidelines (CTG) for existing sources

2018

- EPA proposed relaxation of NSPS OOOOa requirements and withdrawal of the 2016 CTG

2019

- EPA reconsidering regulating methane and sources in the transmission and storage segment

- Maryland working with other states to challenge more recent relaxations
  - ➢ Reducing methane is not just a Maryland issue

MDE's Stakeholder Process

MEETING 1 – June 29, 2017
Overview of the Natural Gas Industry

MEETING 2 – July 10, 2018
Regulatory and Voluntary Concepts - General

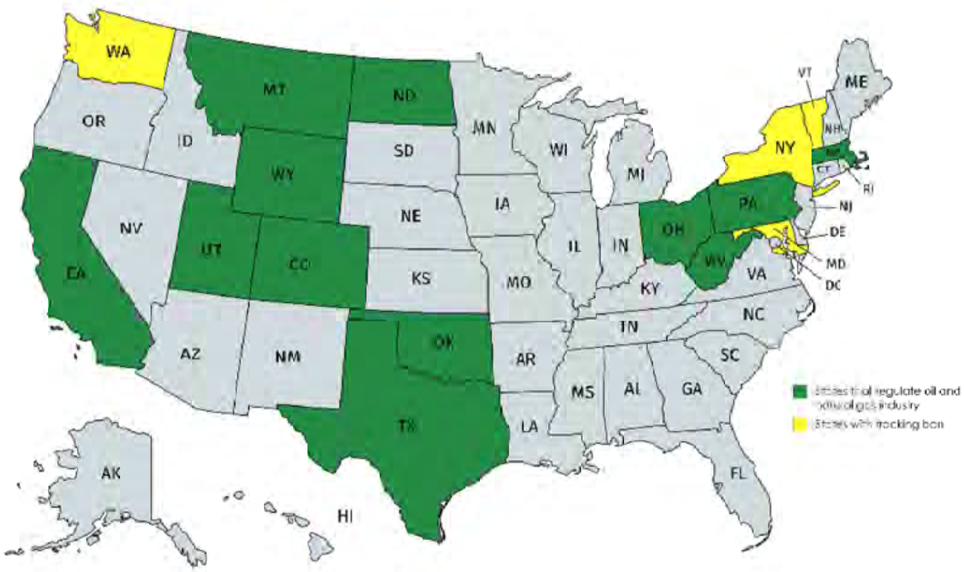
MEETING 3 – March 8, 2019
Regulatory and Voluntary Concepts - Specifics

MEETING 4 – June 28, 2019
Summary and Discussion of "Discussion Draft" of Regulation

MEETING 5 – October 11, 2019
Responded to comments received and presented updated "Discussion Draft"

- MDE has also been meeting with affected businesses, communities, environmental advocacy groups and other stakeholders in 1-on1 meetings or calls since 2017

Other State Programs



USCA also has working group on this issue

Overview of Requirements

Proposed Regulatory Requirements

- Built from 2016 NSPS OOOOa, and leading states with methane reduction programs such as Colorado and California

Applicability

- Existing and "Any new, modified, or reconstructed natural gas compressor station, natural gas underground storage facility, or liquefied natural gas facility."
- Four compressor stations
  1. Dominion, Myersville
  2. TC Energy, Rutledge
  3. Transco, Ellicott City
  4. Texas Eastern, Accident
- One underground storage facility
  – Texas Eastern, Accident
- One import and liquefaction/export facility
  5. Dominion, Cove Point

Existing facilities location

Overview of Requirements

Proposed Regulatory Requirements

Leak Detection & Repair (LDAR): Summary of Requirements

Reg .03 (pgs. 2-4)

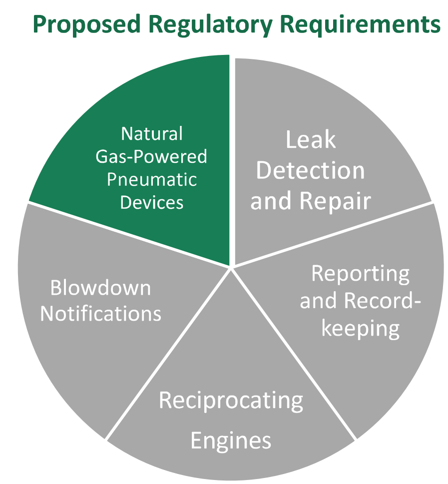
- Facilities to submit initial methane emissions monitoring plan within 90 days of regulation adoption - *§A(5)*
  - Procedures, equipment and observation path
  - Unsafe-to-monitor (UTM) and difficult-to-monitor (DTM) components with explanation
- First LDAR monitoring survey due within 180 days of effective date of regulation. - *§A(8)(a)*
  - Within 180 days at the startup of new facility
- Quarterly monitoring survey using Optical Gas Imaging (OGI) or Method 21 - *§A(8)(a)*
  - Exception for electric engines (monthly AVO, annual LDAR inspections) - §.03(B)
  - LNG specific requirements: Climate Action Plan and Maryland's Public Service Commission Certificate of Convenience and Public Necessity (CPCN) LDAR requirements - §.03(C)
- Weekly Audio/Visual/Olfactory (AVO) Inspections - *§A(7)*
  - Natural Gas Storage field specific requirements §A(10)

Leak Detection & Repair (LDAR): Summary of Requirements

Reg .03 (pg. 3) – Repair Requirements

- Repairs should be made and confirmed within 30 days of discovering a leak
- Delay of Repair (DOR) provisions for documentation showing:
  - Repair will take longer than 30 days due to need of specialty part
  - Repair requires a vent or station blowdown
  - Repair is unsafe to repair due to the operation of unit
  - Repair can not be successfully completed due to technical issue, will require a plan to be approved by the Department

Overview of Requirements



Pneumatic Devices: Summary of Requirements

Reg .04 (pg. 4)

January 2021
- All natural-gas powered pneumatic devices subject to LDAR

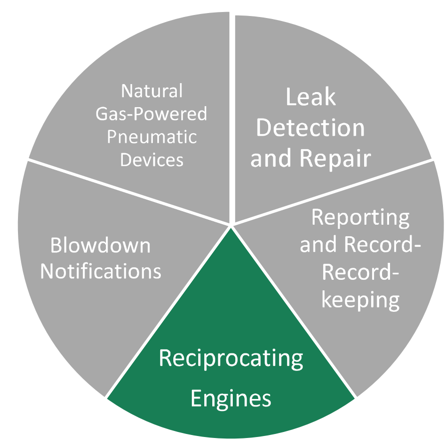
January 2022
- Continuous bleed natural gas-powered pneumatics cannot exceed 6 standard cubic feet per hour (scfh)

January 2023
- Continuous bleed pneumatics shall use compressed air or electricity to operate unless exempt

- Additional requirements for exempt continuous bleed natural gas-powered devices - *§D(1)*:
  1. Use a vapor collection system; or
  2. Tag device, inspect monthly, and perform maintenance

Overview of Requirements

Proposed Regulatory Requirements



Reciprocating Engines: Summary of Requirements

Reg .05 (pg. 4-5)

- Subject to LDAR - *§A*
- Two mitigation options:
  1. Vented gas is routed to a vapor control device - *§B(1);* OR
  2. Rod packing flow rate required to be measured annually and if exceeds emission threshold of 1 scfm:
     1. Replace rod packing; or
     2. Measure rod packing flow rate every six months until rod packing reaches 2 scfm, then replace within 30 days

Reciprocating Engines:
Rod Packing Replacement Schedule

Manufacturer Rod Packing Replacement Guidelines*	
Condition	Rod packing flow rate (scfm)
Past Normal lubed packing, New	0.2 – 0.5
Past Non-lube Packing, New	0.5 – 1.0
Past Normal lubed packing, Partially Worn	1.0 – 2.0
Recommended Alarm Set point	2.0 – 3.0
Recommended Shutdown Set point	4.0 – 5.0

- The Department also reviewed information used to establish California standard (2 scfm) and Canada standard (0.81 scfm).

** November 7, 2019 e-mail from Cook Compression*

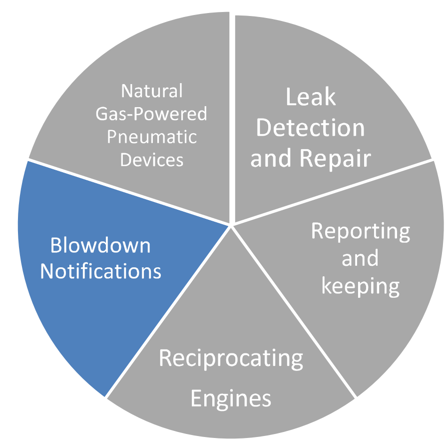
Vapor Collection System: Summary of Requirements

Reg .06 (pg. 5)

- All gases collected with a VCS shall route all gases, vapors and fumes to:
  - Process gas system;
  - Fuel gas system; or
  - Vapor control device (VCD)
- VCS subject to LDAR and AVO inspections - §§ C and D
- VCD standards for destructive and non-destructive types - §E

Overview of Requirements

Proposed Regulatory Requirements



Blowdowns: Summary of Requirements

Reg .07 (pg. 6-7)

- Affected facilities shall submit blowdown notification plan to the Department for blowdown events in the excess of 1 million standard cubic feet (scf). Plans shall include:
  - Notification format (e.g. website, e-mail, text message, social media announcement)
  - Public outreach plan
- Affected facilities shall notify the Department and make blowdown information publicly available at least 7 days prior to any planned blowdown event. Any planned blowdown less than 7 days before event should be explained
  - Emergency blowdowns notification within one hour of occurrence, if possible
- All blowdown events within the facility fence-line that is greater than 50 scf shall be reported to MDE annually
  - Reporting format similar to EPA's Greenhouse Gas Reporting Program.

Overview of Requirements

Proposed Regulatory Requirements

Reporting and Recordkeeping: Summary of Requirements

Reg .07 (pg. 5)

- LDAR report summary to be publicly posted on company website and submitted to the Department
- LDAR is part of the annual GHG reporting
- DOR records on-site unless requested
- Recordkeeping requirements

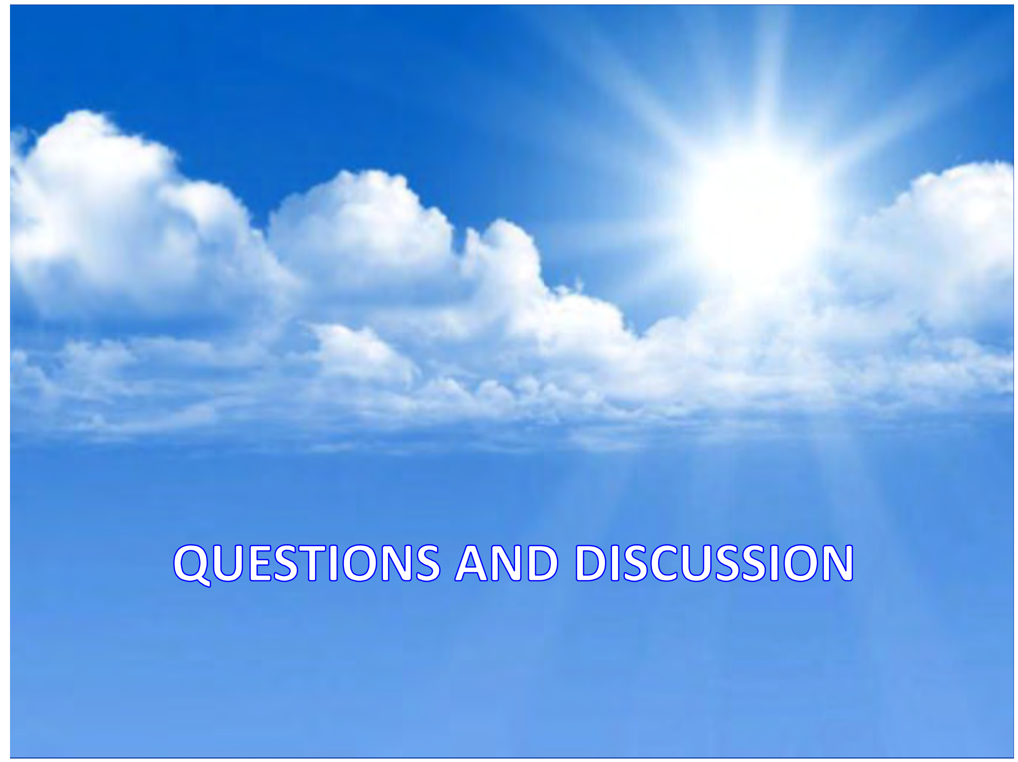
GHG Reporting: Summary of Requirements

Reg .07 (pg. 7)

- All facilities, regardless of the size of GHG emissions, will be required to report their GHG emissions to the Department annually - §§ C(1) and (3)
- MDE's reporting requirements, calculation methodology, and procedures mirror EPA's Greenhouse Gas Reporting Program - § C(2)
- Maryland reporting requirement will harmonize reporting with federal rule with modification
  - Facilities will be required to provide back-up calculation details

Tentative Schedule

- Air Quality Control Advisory Council: Today
- Proposed Regulation in the Maryland Register: May 2020
- Public Hearing and final comment period: June 2020
- Rule Adoption and Effective: Fall 2020



Facts About ...

New Regulations under new Chapter COMAR 26.11.41

Control of Methane Emissions from the Natural Gas Industry

12/2/2019

Purpose

The purpose of this action is to propose new Regulations .01 to .08 under new chapter COMAR 26.11.41 Control of Methane Emissions from the Natural Gas Industry. Methane Emissions from the natural gas industry account for approximately 30% of all methane emissions in Maryland. This action establishes requirements to reduce vented and fugitive emissions of methane from both new and existing natural gas facilities.

Submission to EPA as Revision to Maryland's State 111(d) Plan

The proposed regulations pertaining to methane reductions for Natural Gas Compression Stations and LNG Facilities will be submitted to the U.S. Environmental Protection Agency (EPA) for approval as part of Maryland's State Plan under CAA section 111(d).

Background

In 2009, the Maryland General Assembly adopted the Greenhouse Gas Emission Reduction Act (GGRA). This law required that the State develop and implement a plan to reduce greenhouse gas emissions by 25% by 2020. In 2015, the Maryland Commission on Climate Change (MCCC) was codified into law to provide guidance on greenhouse gas reductions while supporting a healthy economy and creating new jobs. The MCCC recommended to the Maryland General Assembly that several enhancements be made to the 2009 GGRA. In 2016, Governor Larry Hogan signed an updated version of the GGRA, establishing a new benchmark to reduce greenhouse gas emissions in Maryland by 40% by 2030.

The MCCC, through its Mitigation Working Group, recommended that Maryland focus on reducing methane emissions from landfills, natural gas infrastructure (e.g. compressor stations and underground storage), and waste water treatment plants. This action focuses on reducing methane emissions from the natural gas infrastructure in Maryland to protect and restore the environment for the health and wellbeing of all Marylanders.

Methane is the primary constituent of natural gas and is the second most prevalent greenhouse gas emitted by human activity in the U.S. While methane doesn't linger as long in the atmosphere as carbon dioxide, it is initially far more impactful to the climate because of how effectively it absorbs heat. Maryland began taking steps to restrict methane emissions from oil and natural gas operations by establishing law to ban hydraulic fracturing in the state. Hydraulic fracturing, a form of drilling to extract natural gas from underground depositories, poses the risk of emitting greenhouse gases into the atmosphere. The ban on hydraulic fracturing eliminates this environmental risk.

EPA also began to address methane emissions from the oil and natural gas industry. In June 2016, EPA finalized updates to its New Source Performance Standards (40 CFR Part 60, Subpart OOOOa or 2016 NSPS OOOOa) for the oil and natural gas industry to reduce emissions of greenhouse gases. The 2016 NSPS OOOOa set emission limits for methane, which is the principal greenhouse gas emitted by equipment and processes in the oil and gas sector. The EPA final rule also requires owners/operators to find and repair leaks, also known as “fugitive emissions,” which can be a significant source of both methane and volatile organic compound emissions.

On September 11, 2018, however, EPA proposed reconsideration amendments to certain provisions of the 2016 NSPS OOOOa. Among other proposed amendments, EPA considered relaxing the regulatory burden to industry by reducing the monitoring frequency of fugitive emissions and extending the required time for leaks to be repaired.

On September 24, 2019, EPA proposed to further relax the 2016 NSPS OOOOa. EPA’s new reconsideration amendments propose to (1) remove sources in the transmission and storage segment from the affected source category and rescind the NSPS (including both the volatile organic compounds (VOC) and methane requirements) applicable to those sources, and (2) rescind the methane-specific requirements of the NSPS applicable to sources in the production and processing segments. The EPA is also proposing, as an alternative, to rescind the methane requirements of the NSPS applicable to all oil and natural gas sources, without removing any sources from the source category. The Department strongly opposes these proposed amendments and any relaxation of NSPS OOOOa. In response, Maryland is proposing standards for new facilities and existing in the State to control methane emissions from the natural gas industry.

Specifically, this action proposes requirements to mitigate methane emissions through fugitive emissions detection and repair, and control measure requirements to limit emissions from compressors and pneumatic devices. Facility-wide greenhouse gas emission data will be required to be calculated and submitted to the Department annually. Additionally, owners and operators will be required to notify the Department and the public during “blowdown events” which are the release of pressurized natural gas from stations, equipment, or pipelines into the atmosphere so that maintenance, testing or other activities can take place.

The natural gas industry can be divided into four segments: (1) production; (2) gathering and processing; (3) transmission and storage; and (4) distribution. In the transmission and storage segment, compressors are used to maintain the pressure of the natural gas in transmission pipelines to deliver extracted gas to its eventual end-user. This action affects new and existing natural gas compressor stations, liquefied natural gas facilities, and underground storage facilities in the transmission and storage segment. In Maryland, there are four natural gas compressor stations, one liquefied natural gas import/export facility, and one underground storage facility. This action represents development of regulations with extensive input from public community groups, environmental advocates, the industry and EPA.

Sources Affected and Location

- There are four natural gas compressor stations, one underground storage facility and one liquid natural gas (LNG) facility currently operating in Maryland that are subject to this regulation.
- The four compressor stations are: Dominion Myersville (Frederick County), Enbridge Texas Eastern (Garrett County), TC Energy (previously Transcanada) Rutledge (Harford County), and Williams Transcontinental (Howard County),
- The one underground storage facility is Enbridge Texas Eastern (Garrett County)
- The one LNG facility is Dominion Cove Point (Calvert County).
- All new NG compressor stations, underground storage facilities, and LNG facilities will be subject to this regulation.

Requirements

The federal Clean Air Act provides that States may set more stringent standards and the proposed regulations are more stringent than existing federal rules. Maryland is proposing detection, testing, repair, reporting and record keeping requirements for all existing and new facilities in the State,

Leak Detection and Repair (LDAR)

Fugitive emissions can occur from leaking compressors, pipelines and other equipment components such as valves, connectors, pressure relief devices, and flanges. Unmonitored or faulty equipment with fugitive leaks exacerbates the methane emissions at a facility.

Maryland's proposed regulations require owners/operators to do the following:

- Develop and submit a leak monitoring plan to the Department within 90 days of the adoption of the rule. New, modified, or reconstructed facilities will have up to 90 days to submit a methane emissions monitoring plan from the startup of the facility's operation.
- Conduct leak monitoring surveys at prescribed intervals using optical gas imaging (OGI) or EPA Method 21 as well as inspecting for leaks audibly, visually, and olfactorily (AVO). The Department will consider any new and/or emerging leak detection technology as an alternative practice to monitor for leaks.
- Repair or replace identified leaking component(s) within 30 days of leak discovery and verify that the leak has been successfully repaired. Owners/operators may submit a delay of repair request to the Department if the leaking component(s) requires a

specialty part, is unsafe to repair during the operation of the unit, and/or would require a vent or compressor station blowdown.

- Follow applicable annual and quarterly recordkeeping and reporting requirements.

Facilities that use natural gas-powered equipment to compress natural gas and new liquefied natural gas (LNG) facilities:

- These facilities shall conduct quarterly inspections of fugitive emissions components using an OGI instrument or EPA's Method 21. The initial monitoring survey shall be conducted within 180 days of the adoption of the regulation. New, modified, or reconstructed facilities will have up to 180 days to conduct an initial monitoring survey from the startup of the facility's operation.
- Weekly audio, visual, and olfactory inspection of all fugitive emissions components shall be conducted.

Natural gas underground storage fields that use electric-powered equipment to compress natural gas:

- These facilities shall conduct quarterly inspections of fugitive emissions components using an OGI instrument or EPA's Method 21. The initial monitoring survey shall be conducted within 180 days of the adoption of the regulation. New, modified, or reconstructed facilities will have up to 180 days to conduct an initial monitoring survey from the startup of the facility's operation.
- Electric- Monthly AVO inspections will be required for components at natural gas storage fields with additional monitoring and recordkeeping requirements.

Facilities that use electric-powered equipment to compress natural gas:

- Electric-powered equipment used to compress natural gas emits less methane than natural gas-powered equipment by eliminating the need for fuel gas. Furthermore, electric-powered compressors produce no exhaust byproduct.
- These facilities shall conduct annual inspections of fugitive emissions components using an OGI instrument or EPA's Method 21. The initial monitoring survey shall be conducted within 180 days of the adoption of the regulation. New, modified, or reconstructed facilities will have up to 180 days to conduct an initial monitoring survey from the startup of the facility's operation.
- Monthly audio, visual, and olfactory inspection of all fugitive emissions components shall be conducted.

Dominion Cove Point LNG facility:

- Cove Point has two existing LDAR plans with equivalent stringency as this proposal; The facility will be required to follow:
  (a) The leak detection and repair requirements as specified by the Climate Action Plan, which is defined, prepared, and approved under COMAR 26.09.02.06.B – E.; and

(b) The leak detection and repair plan defined and approved under the Certificate of Public Convenience and Necessity, issued by the Maryland Public Service Commission on June 2, 2014, Order No. 88565, Case No. 9318, as amended.

Natural Gas-Powered Pneumatic Devices

Pneumatic devices are used for maintaining a process condition such as liquid level, pressure, or temperature. As part of normal operations, natural gas-powered pneumatic devices release or bleed natural gas to the atmosphere. The Department is proposing a phase-out of all high bleed continuous natural gas-powered devices over. Additional requirements are summarized below:

- Beginning January 1, 2021, LDAR monitoring for all natural gas-powered pneumatic devices;
- Beginning January 1, 2022, continuous bleed natural gas-powered pneumatic devices cannot have a bleed rate greater than 6 standard cubic feet per hour; and
- Beginning January 1, 2023, continuous bleed natural gas-powered pneumatic devices shall be converted to electric or compressed air-powered devices.

The Department is proposing an exemption for continuous bleed natural gas-powered pneumatic devices with a low bleed rate that is needed for safety or operational purposes.

Furthermore, this action includes recordkeeping and reporting requirements to the Department.

Reciprocating Compressors

Reciprocating compressors are used to increase the pressure of the natural gas flowing through the transmission pipelines. Over time, rod packing systems within these reciprocating compressors can wear, resulting in leaking methane. Maryland's proposed rules provide two mitigation options for methane emissions from rod packing systems:

- Emissions from the rod packing shall be routed to a process or control device; or
- Rod packing flow rates shall be measured annually and rod packing systems with emissions greater than 1.0 standard cubic feet per minute (scfm) shall:
    - Be replaced; or
    - Measured every 6 months until the rod packing flow rate reaches 2 scfm, at which point the rod packing must be replaced.

Reciprocating compressor's fugitive emission components shall be subject to LDAR requirements. This action also includes recordkeeping and reporting requirements to the Department.

Record Keeping and Reporting Requirements

An annual report is due to the Department on April 1st of each year, owners and operators can combine reporting sections together into one report for greenhouse gas reporting.
LDAR reports are due to the Department either quarterly or annually based on the regulatory section identified throughout Regulation .03.

- Quarterly LDAR reports are accepted from a 3rd party if the details are provided.
- The Department is requiring an LDAR summary be publicly posted after each monitoring survey.

Blowdown Events & Reporting

Blowdown events are common occurrences in which pressurized natural gas is released from stations, equipment, or pipelines into the atmosphere for maintenance and operational purposes. Maryland's rule requires owners and operators to notify the Department and the public whenever a blowdown activity with threshold of greater than 1.0 million cubic feet of methane will be released. Owners and operators will be required to record all blowdown events greater than 50 standard cubic feet and report annually. The following requirements apply to affected sources:

- Submit a public notification plan to the Department for approval;
- Notification of planned blowdowns in the excess of 1 million scf should be given at least 7 days prior to the start of the event;
- Notification of emergency blowdowns should be given within one hour of the start of the event; and
- Owners and operators shall calculate and submit to the Department annually the total methane emissions from all blowdown events.

Greenhouse Gas Emissions Reporting

Greenhouse gas emissions from the oil and natural gas industry account for approximately 20% of all greenhouse gas emissions in the United States. On October 20, 2009, the EPA published a rule for the mandatory reporting of greenhouse gases from oil and natural gas facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. Oil and natural gas facilities that emit less than the 25,000 metric tons threshold were exempted from EPA's rules.

Maryland's proposed rule will require all facilities in the natural gas industry, regardless of their greenhouse gas emissions threshold, to report greenhouse gas emissions data to the Department. Natural gas facilities have the potential to emit greenhouse gases from a variety of sources, including fugitive emission components, stationary fuel combustion sources, and other site activities (i.e. blowdowns, maintenance, compressor startups, compressor shutdowns, etc.).

Maryland's greenhouse gas emissions reporting requirements will require facilities to collect greenhouse gas data, calculate greenhouse gas emissions, and follow specified procedures for quality assurance, missing data, recordkeeping, and reporting. Maryland's requirements mirror EPA's Greenhouse Gas Reporting Program (40 CFR Part 98) to harmonize with federal rules and reduce regulatory burden.

Projected Emission Reductions

MDE estimates the proposed regulations will minimize the release of methane emissions from the natural gas transmission and storage activities in the State. The proposed rule will minimize the release of methane emissions from existing sources in the range of 600 to 5,000 metric tons per year through leak surveys, replacement of leaking equipment and components and inspection practices.

Leak detection and repair (LDAR) surveys can produce varying results, but it is understood throughout the industry that technology is advancing to help minimize fugitive leaks. LDAR leads to reduced emissions, valuable product recovery and increased safety of operations. A leak survey is most effective when performed on a routine basis so as to capture the unknown nature of unintentional poor performance.

The Department has reviewed literature on the proposed impacts of a fugitive leak detection and repair program from EPA, California, environmental advocates and the industry. The potential emissions reductions, quoted in the EPA 2015 Regulatory Impact Analysis for the 2016 NSPS OOOOa, range from 40% — 80% depending on the frequency of surveys. Under California's rule-making for "Greenhouse Gas Emission Standards For Crude Oil And Natural Gas Facilities" finalized in 2017, CA assumes a 60% reduction in methane emissions due to quarterly LDAR. However they also note there can be a wide range of conditions that can disproportion data from an average assumption. It is understood that the industry has skewed emissions distributions, where a small number of facilities can account for a large portion of emissions.

Vented methane emissions from reciprocating compressor engines and gas driven pneumatic devices will be reduced by equipment monitoring, repair and replacement. EPA Natural Gas STAR Program Partner Reported Opportunities (PROs) Fact Sheets and information from the equipment manufacturing industry estimate emissions reduction can be achieved up to 50%.

The operations at each specific station determine the yearly emissions at a facility. The Department has used existing federal reporting figures through the Greenhouse Gas Reporting Rule (40 CFR Part 98) and figures from the Department's annual emission certification reports to estimate methane reductions in Maryland. The Department has calculated a range of potential methane reductions per year. The Department assumed a range of 40% to 80% reduction from the proposed regulation applied to recently reported methane emissions.

Facts About …

New Regulations under new Chapter COMAR 26.11.41

Control of Methane Emissions from the Natural Gas Industry

As the natural gas industry expands, any future sources in the production and transmission sector of the natural gas industry will be required to follow these state regulations, as well as federal rules. Advanced construction, maintenance and inspection practices will be utilized, and therefore large emission reductions will not be anticipated. Reporting is a key tool to understanding the emissions in the industry and the State. The documented mitigation strategies will be a tool to further analyze State and national inventories and industry emission factors.

Methane is a highly potent greenhouse gas that needs to be acted upon quickly because it is a short-lived climate pollutant (SLCP). Proposed methane reductions from this regulation can help to minimize greenhouse gases. Mitigation and adaption measures help minimize losses to Maryland businesses and communities from climate risk such as severe weather events.

Economic Impact on Affected Sources, the Department, other State Agencies, Local Government, other Industries or Trade Groups, the Public

The proposed regulation requires facilities in the natural gas industry to perform quarterly or annual leak surveys to identify and minimize unintentional fugitive emissions. The proposed regulation may require facilities to purchase, retrofit, and service capital equipment. Maryland estimates affected facilities will be required to spend, on average, in 2018 dollars, $25,000 annually on leak surveys. Repairs and maintenance may be an additional cost; however, product loss will be decreased. Some capital investment may be required and can vary in cost depending on the sophistication of the engineering design and the age of existing equipment but are estimated to range from $10,000 -— $100,000. Affected facilities are required to report to the Department however the LDAR survey includes reporting costs and the annual report harmonizes with the existing federal requirements therefore minimal expense for reporting were estimated.

MDE's mission is to protect and restore the environment for the health and wellbeing of all Marylanders. Working to mitigate and adapt to climate change are main components of this mission authorized by the GGRA. Marylanders are already witnessing firsthand the impacts of climate change, from more frequent, severe flooding that threatens the state's agricultural sector, to more powerful heat waves that put lives at risk. That's why the State's GGRA Plan to cut greenhouse gas emissions 40% by 2030, and Governor Hogan's commitment to develop a clean and renewable energy standard, are so important. Maryland has made great progress on reducing air pollution and greenhouse gas emissions, and adapting to the potential consequences of climate change while creating jobs and benefiting the economy. Comprehensive methane pollution regulation is a key part of making sure Maryland can continue to make progress and meet emission reduction goals.

Facts About …

New Regulations under new Chapter COMAR 26.11.41

Control of Methane Emissions from the Natural Gas Industry

Economic Impact on Small Businesses

The proposed action has minimal or no economic impact on small businesses.

Comparison to Federal Standards

New sources, which are facilities built, modified, or reconstructed after September 18, 2015, are subject to federal 2016 NSPS OOOOa requirements. The proposed regulations require both new and existing facilities to monitor and reduce methane emissions. Therefore, the proposed regulations are more stringent than the federal standard. However, Maryland has tried to align requirements and reporting with the federal 2016 NSPS OOOOa whenever possible.

Title 26

DEPARTMENT OF THE ENVIRONMENT

Subtitle 11 AIR QUALITY

Chapter 41 Control of Methane Emissions from the Natural Gas Industry

Authority: Environment Article, §§ 1-404, 2-103, 2-1202 and 2-1205, Annotated Code of Maryland

All New Text

.01 Definitions.

A. In this chapter, the following terms have the meanings indicated.

B. Terms Defined.

(1) "Affected facilities" means any one of the following facilities:

(a) Cove Point Liquefied Natural Gas Facility;

(b) Myersville Natural Gas Compressor Station;

(c) Accident Natural Gas Compressor Station and Storage;

(d) Rutledge Natural Gas Compressor Station;

(e) Ellicott City Natural Gas Compressor Station; and

(f) Any new, modified, or reconstructed natural gas compressor station, natural gas underground storage facility, or liquefied natural gas facility.

(2) "Audio, visual, olfactory inspection" means sensory monitoring to detect natural gas leaks utilizing a human ear, eyes, and nose.

(3) "Bubble test" means the alternative screening procedure as described at EPA Method 21 (40 CFR 60, Appendix A-7, Section 8.3.3)

(4) Blowdown.

(a) "Blowdown" means the release of pressurized natural gas from station, equipment, or pipelines into the atmosphere conducted with the intent to lower the pressure in a vessel or pipeline.

(b) "Blowdown" does not refer to natural gas pneumatics, fugitive components, or pressure seal leakage.

(5) "Component" means a valve, fitting, flange, threaded-connection, process drain, stuffing box, pressure-vacuum valve, pressure-relief device, pipes, seal fluid system, diaphragm, hatch, sight-glass, meter, open-ended line, well casing, natural gas powered pneumatic device, natural gas powered pneumatic pump, reciprocating compressor rod packing/seal, metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

(6) "Continuous bleed" means the continuous venting of natural gas from a gas powered pneumatic device to the atmosphere.

(7) "Difficult-to-monitor" means fugitive emissions components that cannot be monitored for natural gas leakage without the monitoring personnel needing specialized equipment to reach components above the grade.

(8) "Direct measurement" means use of high volume sampling, calibrated bagging, calibrated flow measuring instrument, or a temporary meter.

(9) "Fuel gas system" means components and equipment that collect and transfer natural gas to be used as a fuel source to on-site natural gas powered equipment other than a vapor control device.

(10) Fugitive Emissions Component.

(a) "Fugitive emission component" means any component that has the potential to emit fugitive emissions of natural gas, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers, vapor collection systems.

(b) "Fugitive emission component" does not include devices that vent as a part of normal operations, such as natural gas-driven pneumatic device, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission.

(c) "Fugitive emission component" includes thief hatches or other openings on a storage vessel, compressor, instrument, natural-gas powered pneumatic device, or meter, that are not venting.

(11) "Intermittent bleed" means a pneumatic controller that is designed to vent non-continuously.

(12) "Leak or fugitive leak" means any visible emission from a fugitive emissions component observed by optical gas imaging or an instrument reading of 500 ppm or greater of methane using U.S. EPA Method 21 (40 CFR 60, Appendix A-7) or any emissions discovered from a fugitive emissions component observed using an auditory, visual or olfactory inspection.

(13) "Leak detection and repair" or "LDAR" means the inspection of fugitive emissions components to detect leaks of total methane and the repair of components with leaks above the standards specified in this chapter and within the timeframes specified in this chapter.

(14) “Liquefied natural gas” or “LNG” means natural gas or synthetic gas having methane as its major constituent which has been changed to a liquid.

(15) “LNG facility” means a pipeline facility that is used for liquefying natural gas or synthetic gas or transferring, storing, or vaporizing liquefied natural gas, and includes all components and stationary equipment within the fence-line.

(16) “Natural gas” means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases, which has methane as its major constituent.

(17) “Natural gas compressor station” means all equipment and components located within a facility fence-line associated with moving natural gas from production fields or natural gas processing plants through natural gas transmission pipelines, or within natural gas storage fields.

(18) “Natural gas storage well” means a well located and used in a natural gas storage reservoir for injection or withdrawal purposes, or an observation well.

(19) “Natural gas underground storage” means all equipment and components associated with the temporary subsurface storage of natural gas in depleted crude oil or natural gas reservoirs or salt dome caverns, not including gas disposal wells.

(20) “Observation well” means a well used to monitor the operational integrity and conditions in a natural gas storage reservoir, the reservoir protective area, or strata above or below the gas storage horizon.

(21) “Optical gas imaging or OGI” means an instrument that makes emissions visible to the naked eye that may otherwise be invisible.

(22) “Pneumatic device” means an automation device that uses natural gas or compressed air to control a process.

(23) “Process gas system” means components and equipment that collect and transfer the natural gas to be used through the intended process of the facility, including storage, transmission, or liquefaction.

(24) “Reciprocating natural gas compressor” means equipment that increases the pressure of natural gas by positive displacement of a piston in a compression cylinder and is powered by an internal combustion engine or electric motor with a horsepower rating designated by the manufacturer.

(25) “Reciprocating natural gas compressor rod packing” means a seal comprising of a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that leaks into the atmosphere.

(26) “Reciprocating natural gas compressor seal” means any device or mechanism used to limit the amount of natural gas that leaks from a compression cylinder into the atmosphere.

(27) "Successful repair" means tightening, adjusting, or replacing equipment or a component for the purpose of stopping or reducing fugitive leaks below the minimum leak threshold or emission flow rate standard specified in this chapter.

(28) “Unsafe-to-monitor” means fugitive emissions components that cannot be monitored for natural gas leakage because monitoring personnel would be exposed to immediate danger while conducting a monitoring survey.

(29) “Vapor collection system” means equipment and components installed on pressure vessels, separators, tanks, or sumps including piping, connections, reciprocating compressors, natural gas-powered pneumatic devices, and flow-inducing devices used to collect and route emission vapors to a processing gas, or fuel gas system; or to a vapor control device.

(30) “Vapor control device” means destructive or non-destructive equipment used to control otherwise vented emissions.

.02 Applicability.

The provisions of this chapter apply to an affected facility as that term is defined in Regulation .01B of this chapter.

.03 Leak Detection and Repair Requirements.

A. Affected facilities that are natural gas compressor stations or natural gas underground storage facilities, that use natural gas-powered equipment to compress natural gas, shall comply with the following leak detection and repair requirements.

(1) Owners and operators of affected facilities subject to this section shall develop and submit to the Department an initial methane emissions monitoring plan that includes a technique for determining fugitive emissions (e.g., EPA Method 21 at 40 CFR part 60, appendix A–7, or optical gas imaging).

(2) If an affected facility uses optical gas imaging for leak detection, the following information shall be included in the initial methane emissions monitoring plan:

(a) A list of the unsafe-to-monitor components;

(b) Procedures and timeframes for identifying and repairing fugitive emissions components;

(c) A defined observation path throughout the site to confirm all components can be viewed and recorded; and

(d) Manufacturer and model number of fugitive emissions detection equipment to be used.

(e) Equipment specifications and procedures as specified in 40 CFR §60.5397a (c)(7), as published in July 2017.

(3) If an affected facility uses EPA Method 21 (40 CFR 60, Appendix A-7) for leak detection, the following information shall be included in the initial methane emissions monitoring plan:

(a) A list of all fugitive emission components, difficult-to-monitor components, and unsafe-to-monitor components at an affected facility;

(b) Procedures and timeframes for identifying and repairing fugitive emission components; and

(c) Equipment specifications and procedures as specified in 40 CFR §60.5397a (c)(8), as published in July 2017.

(4) Each difficult-to-monitor and unsafe-to-monitor component shall be indentified in the written initial methane monitoring plan explaining the location and why the fugitive emissions components are difficult-to-monitor and unsafe-to-monitor.

(5) Owners and operators of the affected facilities subject to this section shall submit the initial methane emissions monitoring plan required in §A(1)—(4) to the Department within 90 days of the adoption of this regulation.

(6) Owners and operators of affected facilities that modify or reconstruct a natural gas compressor station or underground storage facility shall submit an initial monitoring plan with the elements in §A(1)—(4) of this regulation within 90 days of the facility startup operation for each new collection of fugitive emissions components at the modified or reconstructed compressor station or underground storage facility.

(7) Except for unsafe-to-monitor components, owners or operators of affected facilities subject to this section shall conduct an audio, visual, and olfactory inspection of all fugitive emission components for leaks or indications of leaks at least once per calendar week.

(8) Leak Monitoring Survey.

(a) Owners and operators of affected facilities shall follow the initial monitoring methane plan and shall inspect all fugitive emission components, except for unsafe-to-monitor components, for leaks using OGI or EPA Method 21 within 180 days of the adoption of this regulation and quarterly thereafter.

(b) Owners and operators of affected facilities that install any new, modified, or reconstructed natural gas compressor station or underground storage facility that uses natural gas-powered equipment to compress natural gas shall meet the requirements of §A(8)(a) of this regulation within 180 days of the startup of the facility's operations.

(c) At least annually, all difficult-to-monitor fugitive emissions components shall be inspected for leaks using an OGI camera.

(9) Repair Requirements.

(a) Any leaking fugitive emissions component identified during a leak monitoring survey shall be successfully repaired, replaced, or removed from service as soon as practicable, but no later than 30 calendar days after leak detection.

(b) Each repaired or replaced fugitive emissions component shall be resurveyed within 30 days after being repaired or replaced using either OGI or EPA Method 21 (40 CFR 60, Appendix A-7).

(i) Owners and operators of facilities subject to this section that use EPA Method 21 (40 CFR 60, Appendix A-7) to resurvey the repaired or replaced fugitive emissions component shall consider the fugitive emissions component repaired when the EPA Method 21 (40 CFR 60, Appendix A-7) instrument indicates a concentration of less than 500 ppm of methane or when no soap bubbles are observed during a bubble test.

(ii) Owners and operators of affected facilities subject to this section that use OGI to resurvey the repaired or replaced fugitive emissions component shall consider the fugitive emissions component repaired when the OGI instrument shows no indication of visible emissions or when no soap bubbles are observed during a bubble test.

(c) A delay of repair may occur when, upon request, the owner or operator provides documentation to the Department that supports the following:

(i) The parts or equipment required to make necessary repairs will take longer than 30 days to be ordered and delivered, but said repair shall not exceed one year;

(ii) The repair is unsafe to perform during the operation of the unit; or

(iii) The repair requires a blowdown or facility shutdown in order to complete.

(d) Leaking fugitive emission components awaiting repair or replacement under a delay of repair shall be clearly marked or identified in the facility's records

(e) Leaking fugitive emission components under a delay of repair according to §A(9)(c)(i) of this regulation must:

(i) Be repaired or replaced within 7 days after the owner or operator receives parts or equipment; or

(ii) Be repaired or replaced at the next vent or compressor station blowdown if the owner or operator has identified this fugitive emission component as needing a vent or compressor station blowdown.

(f) Fugitive emission components under a delay of repair according to §A(9)(c)(ii) and (iii) of this regulation must be repaired or replaced within one year, at the next vent blowdown or facility shutdown, whichever occurs first.

(g) If a repair of a leak cannot be successfully completed according to this subsection, the owner or operator of the affected facility shall prepare a plan, for Department approval, that includes:

(i) An explanation of the technical difficulty;

(ii) A timeline to successfully repair the fugitive emission components;

(iii) A calculation of the additional methane that is expected to be released while on delay of repair; and

(iv) Upon written request from the Department, any other information that the Department determines is necessary to evaluate the plan.

(h) The owner or operator of the affected facility shall submit any plan required under §A(9)(g) of this regulation to the Department within 30 days from identifying the leak.

(10) Natural Gas Storage Field Inspections.

(a) Owners and operators of natural gas underground storage facilities shall inspect every natural gas storage well and observation well in the natural gas storage field at least once each month.

(b) For each inspection according to §A(10)(a), owners and operators shall record:

(i) The well-head pressure or water level measurement, as appropriate;

(ii) The open flow on the annulus of the production casing or the annulus pressure if the annulus is shut in;

(iii) A measurement of gas escaping the well if there is evidence of a gas leak; and

(iii) Evidence of progressive corrosion, rusting, or other signs of equipment deterioration.

(c) For each natural gas storage well with emissions that exceed 5,000 cubic feet per day, owners and operators shall:

(i) Notify the Department within one business day of discovering the leak; and

(ii) File a written report within 10 days which shall include an explanation of the problem and corrective action taken or planned.

B. Affected facilities that are natural gas compressor stations and natural gas underground storage facilities, that exclusively use electric-powered equipment to compress natural gas, shall comply with the following leak detection and repair requirements.

(1) Owners and operators of facilities in this section shall meet the requirements of §A(1)— (6) and (9) of this regulation.

(2) Except for unsafe-to-monitor components, owners or operators of facilities in this section shall conduct an audio, visual, and olfactory inspection of all fugitive emission components for leaks or indications of leaks at least once per calendar month.

(3) Leak Monitoring Survey

(a) Except for unsafe-to-monitor components, owners and operators of affected facilities subject to this section shall inspect all fugitive emission components, including difficult-to-monitor components , for leaks using OGI or EPA Method 21 (40 CFR 60, Appendix A-7) within 180 days of the adoption of this regulation and annually thereafter.

(b) Owners and operators of affected facilities that install any new, modified, or reconstructed natural gas compressor station or underground storage facility that uses electric-powered equipment to compress natural gas shall meet the requirements of §B(3)(a) within 180 days of the startup of the facility's operations.

C. Cove Point Liquefied Natural Gas facility shall comply with:

(a) The leak detection and repair requirements as specified by the Climate Action Plan, which is defined, prepared, and approved under COMAR 26.09.02.06.B – E.; and

(b) The leak detection and repair plan defined and approved under the Certificate of Public Convenience and Necessity, issued by the Maryland Public Service Commission on June 2, 2014, Order No. 88565, Case No. 9318, as amended.

D. Any new liquefied natural gas facility that begins operations or repairs after the effective date of this chapter shall comply with §A of this regulation.

E. If an owner requests approval, the Department may approve a new technology or alternative practice to identify leaking fugitive emissions components as an equivalent substitution for the requirements in §§A or B of this regulation.

.04 Natural Gas-Powered Pneumatic Devices Methane Emission Control Requirements.

A. Beginning January 1, 2021, each continuous and intermittent bleed natural gas-powered pneumatic device shall comply with the leak detection and repair requirements specified in Regulation .03 of this chapter, as applicable, when the device is idle and not controlling.

B. Beginning January 1, 2022, continuous bleed natural gas-powered pneumatic devices shall not vent natural gas at a rate greater than six (6) standard cubic feet per hour.

C. Beginning January 1, 2023, each continuous bleed natural gas-powered pneumatic device shall use compressed air or electricity to operate unless an exemption is provided in §D of this regulation.

D. Exemption. Continuous bleed natural gas-powered pneumatic devices may be used if:

(1) The owner and operator collect all vented natural gas from the pneumatic device with the use of a vapor collection system according to Regulation .06 of this chapter; or

(2) The owner and operator submit justification for approval to the Department which demonstrates the need for the continuous bleed pneumatic device for safety or process purposes.

(a) Each continuous bleed pneumatic device that is approved for use shall be tagged with the month and year of installation, reconstruction, or modification and shall also have a permanent tag that identifies the natural gas flow rate as less than or equal to six (6) standard cubic feet per hour; and

(b) The owner and operator must:

(i) Inspect each continuous bleed pneumatic device on a monthly basis;

(ii) Perform necessary maintenance (including cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band to eliminate unnecessary valve positioners);

(iii) Maintain the pneumatic device according to manufacturer specifications to ensure that the device's natural gas emissions are minimized;

(iv) By April 1st, test each pneumatic device annually using a direct measurement method (high volume sampling, bagging, calibrated flow measuring instrument); and

(v) Successfully repair any device with a measured emissions flow rate that exceeds six (6) standard cubic feet per hour within 14 calendar days from the date of the exceedance.

.05 Reciprocating Natural Gas Compressor Methane Emission Control Requirements.

A. All reciprocating natural gas compressor components at an affected facility shall comply with the leak detection and repair requirements in Regulation .03 of this chapter where applicable.

B. Control Measures for Reciprocating Natural Gas Compressor.

(1) Beginning January 1, 2021, compressor vent stacks used to vent rod packing/seal emissions shall be controlled with the use of a vapor collection system as specified in Regulation .06 of this chapter; or

(2) By April 1st,the reciprocating natural gas compressor rod packing/seal emission flow rate through the rod packing/seal vent stack shall be measured annually through direct measurement (high volume sampling, bagging, calibrated flow measuring instrument) while the compressor is operating at normal operating temperature.

(a) Direct measurements shall use one of the following methods:

(i) Vent stacks shall be equipped with a meter or instrumentation to measure the rod packing or seal emissions flow rate; or

(ii) Vent stacks shall be equipped with a clearly identified access port to measure individual or combined rod packing or seal emission flow rates.

(b) If the measurement is not obtained because the compressor is not operating for the scheduled test date, testing shall be conducted within seven calendar days of resumed operation.

(3) A reciprocating natural gas compressor with a rod packing/seal with a measured emission flow rate that exceeds 1.0 standard cubic feet per minute, or a combined rod packing or seal emission flow rate that exceeds the number of compression cylinders multiplied by 1.0 standard cubic feet per minute shall:

(a) Be successfully repaired or replaced within 30 calendar days from the date of the exceedance; or

(b) Conduct natural gas compressor rod packing/seal emission flow rate measurements every 6 months or when the compressor resumes operation, whichever is later.

(4) A reciprocating natural gas compressor with a measured emission flow rate that exceeds 2.0 standard cubic feet per minute, or a combined rod packing or seal emission flow rate that exceeds the number of compression cylinders multiplied by 2.0 standard cubic feet per minute, shall be successfully repaired or replaced within 30 calendar days from the date of the exceedance.

C. Delay of Repair for Reciprocating Natural Gas Compressor.

(1) A delay of repair may occur provided the owner or operator provides documentation, upon request from the Department, that the delivery of parts or equipment required to make necessary repairs will take more than 30 days from the last emission flow rate measurement and that the parts have been ordered.

(2) A delay of repair to obtain parts or equipment shall not exceed 60 days from the date of the last emission flow rate measurement unless the owner or operator notifies the Department, in writing, of the extended delay and provides an estimated time by which the repairs will be completed.

(3) A reciprocating natural gas compressor with a rod packing/seal emission flow rate measured above the standard specified in §B(2) of this regulation, and which has leaking parts deemed unsafe to monitor or requiring a facility shutdown, shall be successfully repaired by the end of the next planned process shutdown or within 12 months from the date of the flow rate measurement, whichever is sooner.

.06 Vapor Collection System and Vapor Control Devices.

A. Owners or operators of affected facilities that utilize vapor collection systems and vapor control device to comply with this chapter shall follow the requirements as specified in §§B and C of this regulation.

B. If a vapor collection system does not route all gases, vapors, and fumes to either a process gas system or a fuel gas system, beginning January 1, 2021, a vapor control device shall be installed which meets the requirements of §E of this regulation.

C. The vapor collection system shall have no detectable emissions, as determined using auditory, visual, and olfactory inspections as specified in Regulation .03A(7) of this chapter.

D. The vapor collection system shall comply with the leak monitoring survey and repair requirements as specified in Regulation .03 of this chapter, where applicable.

E. Vapor control devices shall meet one of the following requirements:

(1) A non-destructive vapor control device manufacturer-designed to achieve at least 95 percent vapor control efficiency of methane emissions and shall not result in emissions of nitrogen oxides (NOx); or,

(2) A destructive vapor control device manufacturer-designed to achieve at least 95 percent vapor control efficiency of methane emissions and not more than 15 parts per million volume (ppmv) NOx when measured at 3 percent oxygen; and does not require the use of supplemental fuel gas, other than gas required for a pilot burner, to operate.

.07 Record Keeping and Reporting Requirements

A. Owners or operators of affected facilities shall maintain, submit as described in this section, and make available upon request by the Department a copy of records necessary to verify compliance with the provisions of this chapter.

(1) For each leak monitoring survey and audio, visual, olfactory inspection conducted according to Regulation .03 of this chapter, owners and operators shall:

(a) Submit a report to the Department within 60 days of each leak monitoring survey with the following information:

(i) Date of the survey;

(i) A list of each fugitive emission and repair;

(ii) Any deviations from the initial methane monitoring plan or a statement that there were no deviations from the initial methane monitoring plan;

(iii) Number and type of components for which fugitive emissions were detected;

(iv) Number and type of difficult-to-monitor fugitive emission components monitored;

(v) Instrument reading of each fugitive emissions component that requires repair when EPA Method 21 (40 CFR 60, Appendix A-7) is used for monitoring;

(vi) Number and type of fugitive emissions components that were not repaired;

(vii) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair;

(viii) The date of successful repair of the fugitive emissions component; and

(ix) Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(b) Maintain, for a minimum of five (5) years, record of each leak monitoring survey along with the following information:

(i) Reports submitted according to §A(1)(a) of this regulation;

(ii) Beginning and end time of the survey;

(iii) Name of operator(s) performing survey;

(iv) Monitoring instrument used including the manufacturer, model number, serial number, and calibration documentation;

(v) When optical gas imaging is used to perform the survey, one or more digital photographs or videos, captured from the optical gas imaging instrument used for conduct of monitoring, of each required monitoring survey being performed;

(vi) Fugitive emissions component identification when EPA Method 21 (40 CFR 60, Appendix A-7) is used to perform the monitoring survey;

(vii) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey;

(viii) Any deviations from the initial methane monitoring plan or a statement that there were no deviations from the initial methane monitoring plan;

(ix) Proof that parts or equipment required to make necessary repairs, as required by this chapter, have been ordered;

(x) If a fugitive emissions component is not tagged, a digital photograph or video of each fugitive emissions component that could not be repaired during the leak monitoring survey at the time the fugitive emissions were initially found; and

(xi) Repair methods applied in each attempt to repair the fugitive emissions components;

(c) Post a quarterly report summary to a publicly available website of each leak monitoring survey, including the information required in §A(1)(a) of this regulation, 60 days after the leak monitoring survey.

(d) Maintain records of audio, visual, and olfactory inspections for at least five (5) years from the date of inspection.

(2) For each natural gas-powered continuous bleed pneumatic device, owners and operators shall:

(a) Maintain a record of the emission flow rate measurement and report annually beginning April 1, 2021 for at least five (5) years from the date of each emissions flow rate measurement;

(b) Maintain records of the date, location and manufacturer specifications for each continuous bleed pneumatic device constructed, modified or reconstructed and report annually beginning April 1, 2021;

(c) Maintain records of the manufacturer's specifications indicating that the device is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour, if applicable;

(d) Maintain records of deviations in cases where the pneumatic device was not operated in compliance with the requirements specified in Regulation .04 of this chapter and report annually beginning April 1, 2021;

(e) Maintain purchase orders, work orders, or any in-house or third-party reports produced or provided to the affected facility relating to the device for at least five (5) years; and

(f) Maintain, record of each continuous bleed pneumatic inspection and any corrective or maintenance action taken for at least five (5) years.

(3) For each reciprocating natural gas compressor, owners and operators shall:

(a) Maintain a record of each rod packing leak concentration measurement found above the minimum leak threshold and report annually beginning April 1, 2021 for at least five (5) years from the date of each leak concentration measurement,;

(b) Maintain a record of each rod packing or seal emission flow rate measurement and report annually beginning April 1, 2021for at least five (5) years from the date of each emissions flow rate measurement;

(c) Maintain a record that documents the date(s) and hours of operation a compressor is operated in order to demonstrate compliance with the rod packing leak concentration or emission flow rate measurement in the event that the compressor is not operating during a scheduled inspection for at least one calendar year;

(d) Maintain records that provide proof that parts or equipment required to make necessary repairs required by this chapter have been ordered;

(e) Report annually the cumulative number of hours of operation or the number of months since initial startup or the previous reciprocating compressor rod packing replacement, whichever is later, beginning April 1, 2021;

(f) If applicable, submit a statement that emissions from the rod packing are being routed to applicable vapor control system under Regulation .06 of this chapter;

(g) Report records of deviations from of this chapter that occurred during the reporting period annually beginning April 1, 2021; and

(h) Maintain a record of purchase orders, work orders, or any in-house or third-party reports produced or provided to the affected facility necessary to demonstrate compliance with the delay of repair provisions of this regulation for at least five (5) years.

B. Blowdown Events and Reports.

(1) Within 90 days of the effective date of this regulation, affected facilities shall submit a blowdown notification plan to the Department for approval f of any blowdown event in excess of one million standard cubic feet.

(2) The blowdown notification plan according to §B(1) of this regulation shall include:

(a) The notification format (e.g. website, e-mail, robocall, text message, social media announcement) to local authorities, the Department, and interested parties for blowdown emissions in excess of one million standard cubic feet;

(b) A public outreach plan to inform interested parties of the availability to be notified of blowdown events in excess of one million standard cubic feet;

(c) The affected facility's responsible personnel for blowdown notifications; and

(d) A sitemap of the facility with clearly marked designated area(s) for blowdown emissions in excess of one million standard cubic feet;

(3) For any blowdown event in excess of one million standard cubic feet affected facilities shall make information publicly available in accordance with the facility's approved blowdown notification plan, including notification to the Department, at least seven (7) days prior.

(4) For any blowdown event in excess of one million standard cubic feet that is scheduled less than seven (7) days prior to the blowdown event, affected facilities shall, as soon as practicable:

(a) Make information publicly available in accordance with the facility's approved blowdown notification plan; and

(b) Provide an explanation to the Department of the reason for the blowdown event.

(5) For any emergency or unplanned blowdown event in excess of one million standard cubic feet, affected facilities shall make information publicly available in accordance with the facility's approved blowdown notification plan and notify the Department within one hour of the emergency or unplanned blowdown event.

(6) When safety concerns preclude a facility from providing prior notification of an emergency or unplanned blowdown under §B(5) of this regulation, the facility shall send notice to the Department within 24 hours indicating the reason(s) why prior notice was not possible.

(7) Affected facilities shall report the following information to the Department of blowdown emissions in excess of 50 standard cubic feet within the facility's fence-line annually by April 1 of each year:

(a) Date and type (i.e. planned or emergency) of each blowdown event;

(b) Methane emissions in metric tons released from each blowdown event; and

(c) Annual methane emissions in metric tons from all blowdown events.

(8) Methane emissions shall be calculated according to procedures in 40 CFR Part 98 Subpart W §98.233.

C. Greenhouse Gas Emissions Reporting.

(1) Owners and operators of affected facilities shall report methane, carbon dioxide, and nitrous oxide mass emissions to the Department annually by April 1 of each year.

(2) Owners and operators of affected facilities shall follow the procedures for emission calculation, monitoring, quality assurance, missing data, recordkeeping, and reporting that are specified in 40 CFR Part 98 Subpart C and 40 CFR Part 98 Subpart W.

(3) When reporting to the Department, Owners and operators of affected facilities shall expand the fugitive emissions reporting requirements of 40 CFR Part 98 Subpart W to include a Microsoft Excel format list providing calculations summarized by category under 40 CFR §98.232(e) – (h) as applicable.

(4) The reporting threshold in 40 CFR §98.2, §98.31 and §98.231 of 25,000 metric tons of CO2 equivalent does not exempt an affected facility from following the requirements in §C(1) and (2) of this regulation.

D. All required reports shall be submitted to the Industrial Compliance Division in written or electronic format:

Maryland Department of the Environment
Air Quality Compliance Program
1800 Washington Boulevard, 7th floor
Baltimore MD 21230
Attention: Industrial Compliance Division

Appendix D – Cove Point LDAR – Climate Action Plan and CPCN Proposed regulations for COMAR 26.11.41 TSD dated July 2020

Dominion Energy Services, Inc.
5000 Dominion Boulevard, Glen Allen, VA 23060

www.dominionenergy.com

December 19, 2019

BY U.S. MAIL, RETURN RECEIPT REQUESTED
7018 2290 0000 9542 5279

John Artes
Air Quality Permits Program
Air and Radiation Management Administration
Maryland Department of the Environment
1800 Washington Boulevard
Baltimore, MD 21230

RE: Dominion Energy Cove Point LNG, LP
Liquefaction Facility, CPCN Case 9318, Order 88565
LDAR Plan Submittal – Revision 4 Update

Dear Mr. Artes:

Dominion Energy Cove Point LNG, LP (DECP) is submitting the enclosed Revision 4 update of the Leak Detection and Repair (LDAR) Plan pertaining to the DECP Liquefaction Facility in Lusby, MD for your review and approval. The attached LDAR plan is required to be submitted and approved under the Revised Condition A-IX-3 of the February 6, 2018 amended Certificate of Public Convenience and Necessity (CPCN), updated February 23, 2018.

If you require any additional information, please contact Joseph Pietro at (804) 273-4175 or via email at Joseph.J.Pietro@dominionenergy.com.

Sincerely,

Thomas N. Effinger
Director, Environmental Services

Enclosure

cc: John Artes, MDE (john.artes@maryland.gov)
BY U.S. MAIL, RETURN RECEIPT REQUESTED
7018 2290 0000 9542 5255
Administrator, Compliance Program
Air and Radiation Management Administration
Maryland Department of the Environment
1800 Washington Boulevard
Baltimore, MD 21230

Enclosure

jjp

Document Certification

Facility Name: Dominion Energy Cove Point LNG, LP
(formerly known as Dominion Cove Point LNG, LP)

Facility Location: 2100 Cove Point Road, Lusby, Maryland 20657

County: Calvert

Type of Submittal: Dominion Energy Cove Point LNG, LP
Liquefaction Facility, CPCN Case 9318, Order 88565
LDAR Plan Submittal – Revision 4 Update

Certification: As required under COMAR 26.11.03, I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Name of Responsible Official: Frank N. Brayton

Title: Director, LNG Operations (Authorized Representative)

Signature: ____________

Date: 12.16.19

Dominion Energy Cove Point LNG, LP
Lusby, Maryland

Leak Detection and Repair (LDAR) Monitoring Plan

Cove Point Liquefaction Export Facility

December 2019 (Rev. 4)

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Appendix E: AVO Inspection and Repair Procedures
Appendix F: Leak Identification and Work Flow Diagrams
Appendix G: LDAR Monitoring Plan Revision Log

LDAR Acronyms and Abbreviations

AVO	Audio/Visual/Olfactory
°C	degrees Celsius
°F	degrees Fahrenheit
AWP	Alternative Work Practice
BACT	Best Available Control Technology
CFR	Code of Federal Regulations
CH_4	chemical symbol for Methane
CO_2	chemical symbol for Carbon Dioxide
COMAR	Code of Maryland Regulations
CPCN	Certificate of Public Convenience and Necessity
DECP	Dominion Energy Cove Point LNG, LP
DEES	Dominion Energy Environment and Sustainability
DEGIG	Dominion Energy Gas Infrastructure Group
DOR	Delay of Repair
DTM	Difficult to monitor
E_{DOR}	Total daily mass emission rate from all components on DOR within the gas circuit multiplied by the number of days until the next scheduled shutdown of the gas circuit
E^*_{DOR}	Total daily mass emission rate from all components on DOR within the gas circuit multiplied by the number of days until the early scheduled shutdown of the gas circuit
$E_{SHUTDOWN}$	Pollutant emissions from shutdown of the gas circuit
EPA	Environmental Protection Agency
FID	Flame Ionization Detector
GHG	Greenhouse Gas
GV	Gas/Vapor
H&MB	Heat & Material Balance
HFC	Hydrofluorocarbons
kPa	kilopascal
LAER	Lowest Achievable Emission Rate
LDAR	Leak Detection and Repair
LL	Light Liquid
LMS	Learning Management System
LNG	Liquid Natural Gas
LOTO	Lock-out/tag-out
MDE	Maryland Department of the Environment
MOC	Management of Change
NEIC	National Enforcement Investigation Center
N_2O	chemical symbol for Nitrous Oxide
NSPS	New Source Performance Standards
NSR	New Source Review
O&G Avg. EF	Oil & Gas Average Emission Factor
OEL	Open-ended line
OGIC	Optical Gas Imaging Camera
P&IDs	Piping and instrumentation diagrams
PFC	Perfluorocarbons
PFD	Process Flow Diagram

PID	Photoionization Detector
PPMV	Parts per Million by Volume
QA	Quality Assurance
QC	Quality Control
RF	Response Factor
TAP	Toxic Air Pollutant
T-BACT	Best Available Control Technology for Toxics
TCEQ	Texas Commission on Environmental Quality
TOC	Total Organic Compounds
TOC ER	Total Organic Compounds Emission Rate
UTM	Unsafe to Monitor
VOC	Volatile Organic Compounds

1.1 PURPOSE

Dominion Energy Cove Point LNG, LP (DECP) operates the Cove Point Liquefied Natural Gas (LNG) Terminal (Cove Point) located in Lusby, Maryland. The Cove Point Liquefaction Facility (the Export Facility) was constructed at Cove Point under authorization of the Certificate of Public Convenience and Necessity (CPCN) Order No. 86372 (PSC Case No. 9318), issued on May 30, 2014 and amended on February 6, 2018, Order No. 88565. The Export Facility is subject to the Leak Detection and Repair (LDAR) requirements described in the CPCN under Condition A-IX, as well as the Permit to Operate (PTO), issued December 1, 2017. The CPCN requires DECP to develop and implement an LDAR Monitoring Program following the procedures outlined in the Texas Commission on Environmental Quality (TCEQ) 28LAER LDAR protocol. The procedures to be followed under the LDAR Monitoring Program for the Export Facility, including monitoring requirements, leak definitions, repair procedures, and emissions calculation methodologies, are outlined in this LDAR Monitoring Plan. DECP is required to submit the plan to the Maryland Department of the Environment (MDE) for approval within 30 days after issuance of Order No. 88565, by March 8, 2018.

This LDAR Monitoring Plan is applicable to the Cove Point Liquefaction Export Facility and does not apply to the Cove Point LNG Import Facility. More specifically, the LDAR Monitoring Program applies to piping and equipment components[1] at the Export Facility, as referenced under Condition A-IX of the CPCN, with the potential to emit fugitive emissions of volatile organic compounds (VOCs) and/or greenhouse gases (GHGs) pursuant to the requirements of CPCN Conditions A-IX-3 and A-IX-2, respectively. In addition, the VOC LDAR Monitoring Program satisfies MDE best available control technology (BACT) requirements for toxic air pollutants (TAPs)[2] (T-BACT) as required by CPCN Condition A-IX-4. For components containing TAPs in addition to VOC and/or GHG, compliance with the T-BACT will be met through compliance with the portions of the LDAR Monitoring Program applicable to VOCs and/or GHGs. For components in TAP-only service, the procedures contained in this LDAR Monitoring Plan that were designed specifically for TAP-only components will apply. These TAP-only LDAR procedures are potentially applicable to the components in TAP-only service associated with the following streams as identified in Exhibit E of the CPCN Amendment Application: booster comp feed, amine/ammonium hydroxide, aqueous ammonia, citric acid, sodium bisulfite, and sodium hypochlorite. However, only the amine/ammonium hydroxide and aqueous ammonia streams are anticipated to result in fugitive air emissions from leaking components and will continue to be monitored at the facility via the TAP-only LDAR procedures. The other TAP-only streams are low vapor pressure liquid streams and therefore are not anticipated to result in fugitive air emissions due to leaking components. These streams were monitored during the first quarter of the LDAR monitoring program to ensure the lines were installed without leaks.

A list of definitions for commonly used terms is provided at the end of the Monitoring Plan, prior to the Appendices.

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[1] "Piping and equipment components" may include, but are not limited to, valves, flanges, connectors, instruments, and other piping and mechanical installations.

[2] TAPs include a Maryland-specific list of pollutants, available in MDE's Tox-a-Matic spreadsheet which can be found online at: http://mde.maryland.gov/programs/Permits/AirManagementPermits/Documents/Tox-a-matic-2012b.xls. The specific TAPs relevant to the Export Facility and subject to T-BACT requirements are listed in Exhibit C to the September 2017 CPCN Amendment Application.

1.2 APPLICABILITY BACKGROUND

The Export Facility must implement an LDAR Monitoring Program consistent with the requirements in the CPCN, which are outlined in Table 1.2-1. The TCEQ 28LAER program and Alternative Work Practice (AWP) for Monitoring Equipment Leaks, codified at 40 CFR §60.18, were used as guides in developing this LDAR Monitoring Plan along with reasonable engineering/scientific principles. It should be noted that TCEQ 28LAER and the AWP do not prescribe exact methodologies for all situations that are encountered at the Export Facility.

Table 1.2-1 LDAR Applicability Overview

Process Area	Applicable LDAR Requirements	Component Applicability Threshold
Piping and Equipment Components Associated with the Export Facility	CPCN Condition A-IX-1 and COMAR 26.11.19.16	Any in-service components that contain VOCs
	CPCN Condition A-IX-3 and TCEQ 28LAER (VOC LAER)	Any in-service components that contain VOCs[3]
	CPCN Condition A-IX-2 and TCEQ 28LAER (GHG BACT)	Any in-service components that contain GHGs (i.e., methane and carbon dioxide)
	CPCN Condition A-IX-4 (T-BACT)	Any in-service components that contain TAPs (either applicable TAP-only components or TAP components containing VOCs or GHGs)

MDE regulations at COMAR 26.11.19.16 include requirements to visually inspect components in VOC service for leaks on a monthly basis and repair leaking components observed during the inspections within a specified timeframe. The requirements of this regulation, which are included under Condition A-IX-1 of the CPCN, may differ from the requirements of TCEQ 28LAER.[4] To limit the impact of these potential differences between COMAR 26.11.19.16 and TCEQ 28LAER, this LDAR Monitoring Plan limits the incorporation of COMAR 26.11.19.16 requirements to those leaks identified during audio, visual, and olfactory (AVO) inspections of components in VOC service, consistent with the requirement.

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[3] TCEQ 28 LAER provides an exemption from certain requirements for components containing VOCs with aggregate partial pressure or vapor pressure less than 0.044 psi at 68°F. This exemption is intended to be applied to liquid streams. Details on exceptions are provided in the relevant sections of this LDAR Monitoring Program. Components excluded based on this condition will be identified in the LDAR Monitoring Database.

[4] For example, delaying the repair of a leaking component is allowed under TCEQ 28LAER when a shutdown would be required to repair the component and emissions from the shutdown would result in more emissions than allowing the component to leak until the next scheduled shutdown. If emissions from the leaking components exceed emissions from a unit shutdown, MDE must be notified and an early shutdown may be required. Under the COMAR regulations and CPCN Condition A-IX-1(g), if the repair of a leaking component would require a shutdown, the repair may be delayed until the next scheduled shutdown regardless of emissions from the leaking component.

1.3 LDAR MONITORING PROGRAM PERSONNEL

The roles and responsibilities of personnel under the LDAR Monitoring Program are outlined in Table 1.3-1.

Table 1.3-1 LDAR Monitoring Plan Roles and Responsibilities

Role	Person Responsible
Ensure overall compliance of LDAR Monitoring Plan by ensuring necessary and appropriate resources have been allocated.	Director, LNG Operations
Management of required component repairs/replacements.	Maintenance Manager/Supervisor
Performing required component repairs/replacements.	Maintenance Personnel (multiple, may be internal or contracted)
Performing audio, visual, and olfactory (AVO) inspections.	Designated Operations Personnel (multiple)
Performing Environmental Protection Agency (EPA) Method 21 and Optical Gas Imaging (OGI) instrument monitoring.	Third-Party LDAR Monitoring Contractor (LDAR Monitoring Contractor)
Managing the LDAR emissions calculation software and performing quality assurance activities.	LDAR Monitoring Contractor
Daily oversight and management of LDAR monitoring contractor.	DECP LDAR Coordinator
Performing review of monthly emissions calculations performed by LDAR emissions calculation software and performing additional calculations, as needed, using LDAR monitoring contractor data.	Dominion Energy Environment and Sustainability (DEES) Air Specialist
Assisting the LDAR Coordinator and DEES Air Specialist with LDAR Program data review and decision making.	Dominion Energy Gas Infrastructure Group (DEGIG) LDAR Coordinator, Cove Point Environmental Staff, including Environmental Compliance Coordinator(s).

2 LDAR MONITORING PROGRAM REQUIREMENTS

The primary requirements of the LDAR Monitoring Program at the Export Facility are described in this section.

2.1 LEAK MONITORING AND INSPECTION TECHNIQUES

The leak monitoring and inspection techniques that will be used under the LDAR Monitoring Program are as follows:

For VOC and/or GHG components:

- Optical Gas Imaging Camera (OGIC) – An OGIC capable of viewing fugitive emissions may be used to monitor components in VOC and/or GHG service in accordance with the AWP. The type of OGIC used will depend on the stream composition associated with the components being monitored. For example, a FLIR® GF 320 may be used to monitor components containing hydrocarbons (e.g., methane, ethane, etc.) and a FLIR® GF 343 may be used to monitor components containing CO_2.
- EPA Method 21 Monitoring – Components in VOC and/or GHG hydrocarbon service may be monitored using a gas analyzer that conforms to requirements listed in Method 21 of 40 CFR Part 60, Appendix B (Method 21). The Method 21 Soap Bubble test may be used, where appropriate, for remonitoring purposes to demonstrate that a component has been successfully repaired and is no longer leaking (See Section 4.2.4).
- AVO Inspections – Routine observations will be made to detect audible, visible, or olfactory evidence of a leak from VOC and/or GHG components.

For TAP-only components:

- AVO Inspections – Routine observations will be made to detect audible, visible, or olfactory evidence of a leak from TAP-only components.
- EPA Method 21 Soap Bubble test may be used, where appropriate, for remonitoring of TAP-only components to demonstrate that a component has been successfully repaired and is no longer leaking (See Section 4.2.4).

Each of these monitoring and inspection techniques are discussed in more detail throughout this LDAR Monitoring Plan. **The term "monitoring" (or "monitored") as used herein refers to the use of an OGIC or Method 21 instrument and the term "inspection" (or "inspected") refers to the use of an AVO inspection.**

2.2 LEAK DEFINITIONS

The Export Facility will adhere to the following leak definitions for each monitoring and inspection technique:

For GHG and/or VOC components:

- OGIC – A leak is defined as any emissions observed through the OGIC.
- EPA Method 21 monitoring – A leak is defined as any instrument reading of 500 parts per million by volume (ppmv) or greater based on an instrument calibrated with methane.[5]

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[5] TCEQ 28LAER Section F requires that the Method 21 approved instrument be calibrated using methane.

- EPA Method 21 Soap Bubble Test – A leak exists if the formation of bubbles is observed when using the Method 21 Soap Bubble test for remonitoring.
- AVO inspections – A leak is defined as any audible, visible, or olfactory indications of a leak (e.g., visual indications of liquids dripping).

For TAP-only components:

- AVO inspections – A leak is defined as any audible, visible, or olfactory indications of a leak (e.g., visual indications of liquids dripping).
- EPA Method 21 Soap Bubble Test – A leak exists if the formation of bubbles is observed.

2.3 MONITORING AND INSPECTION FREQUENCY

Monitoring and inspections will be performed in accordance with the frequencies set forth in this section. Initial monitoring of all components at the Export Facility must be completed within 180 days after the first production of LNG.[6]

2.3.1 AWP Monitoring

OGIC will be used to monitor VOC and/or GHG components at the minimum frequency established under the AWP, which is dependent upon the selected detection sensitivity levels as summarized in Table 2.3-1.

Table 2.3-1. Detection Sensitivity Levels and Monitoring Frequencies for AWP[7]

Minimum Monitoring Frequency[8]	Detection Sensitivity Level (grams/hour)
Bi-Monthly	60
Semi-Quarterly	85
Monthly	100

Components that are designated for monitoring under the AWP must be monitored annually using a Method 21 instrument as required by 40 CFR §60.18(h)(7) unless inaccessible (e.g., insulated) or unsafe to monitor (UTM). Initial Method 21 instrument monitoring of the population of components designated for monitoring under the AWP must be completed within 12 calendar months after commencing monitoring under the LDAR Monitoring Program, with subsequent annual Method 21 instrument monitoring being completed every 12 calendar months thereafter.[9] A component that is monitored using a Method 21 instrument during the applicable period established pursuant to Table 2.3-1 need not be monitored with an OGIC during that period. Skip periods or reductions in monitoring frequency are not applicable to components for which the AWP is used.

[6] Reference September 17, 2015 email exchange from Duane King, MDE to Paul Dickson, DECP.
[7] 40 CFR Part 60, Subpart A, Table 1.
[8] Bi-monthly means once every two calendar months. Semi-quarterly means twice every three calendar months. Monthly means one per calendar month.
[9] For example, if monitoring under the LDAR Monitoring Program commences on June 1, 2018, initial Method 21 instrument monitoring of all affected components must be completed by June 1, 2019. Subsequent Method 21 instrument monitoring must be completed by June 1 of each year. The timeframes for completing Method 21 instrument monitoring under the AWP apply to the population of components designated for the AWP, not on an individual component basis.

2.3.2 Method 21 Monitoring

Components subject to the monitoring requirements of the LDAR Monitoring Program that are not designated for monitoring under the AWP (e.g., VOC and/or GHG components containing organic material that do not meet the minimum detection sensitivity levels of the OGIC based on stream composition) will be monitored using a Method 21 instrument on a quarterly basis. Components subject to quarterly Method 21 instrument monitoring will be designated as such in the LDAR Monitoring Database. The Method 21 Soap Bubble Test may only be used for remonitoring of components deemed appropriate following a repair attempt and may be used for VOC and/or GHG components, as well as TAP-only components.

2.3.3 AVO Inspections

AVO inspections are to be conducted on a monthly basis[10](once per calendar month) for all affected components, including TAP-only components, except for connectors, which will be inspected on a weekly basis.[11]

2.4 DIFFICULT-TO-MONITOR AND UNSAFE-TO-MONITOR COMPONENTS

Components are exempt from the monitoring frequencies of Table 2.3.1 and Section 2.3 if they are designated as difficult-to-monitor (DTM) or unsafe-to-monitor (UTM). A DTM component is one that cannot be monitored without elevating the monitoring personnel more than two meters above a permanent support surface or that requires a permit for confined space entry.[12] UTM is a component that cannot be monitored because monitoring personnel would be exposed to an immediate danger as a consequence of the monitoring activities.[13] DTM components must be monitored annually (at least once every 12 months) and safe access must be provided during the annual monitoring event. If a UTM component is not considered safe to monitor during a calendar year, it shall be monitored as soon as it is safe to do so. Components designated as DTM or UTM will be designated as such within the LDAR Monitoring Database. UTM/DTM designations will include date designated (or last monitored) and an explanation for why the components are DTM or UTM in the LDAR Monitoring Database.

The classification of a component as DTM depends on whether the component is designated for monitoring under the AWP or designated for monitoring using Method 21. A component that is DTM with Method 21 may not be DTM with an OGIC. As such, DTM designations within the LDAR Monitoring Database are considered specific to the monitoring approach that will be used. [14]

AVO inspections of DTM and UTM components subject to the LDAR Monitoring Program will be performed in accordance with Section 2.3.3 in a manner that ensures safety while maximizing the efficacy of the AVO inspections. For example, a component that cannot be safely accessed for visual inspection may be able to be inspected via audio and/or olfactory means.

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[10] Reference: CPCN Final License Condition A-IX-1 (a)
[11] Reference: TCEQ, Section 1.E.
[12] Reference: 30 TAC 115.352(7)
[13] Reference: 30 TAC 115.354(1)(C)
[14] see 73 FR 78205.

2.5 DESIGN, MONITORING, AND INSPECTION REQUIREMENTS BY COMPONENT TYPE

The design, monitoring, and inspection requirements applicable to components in VOC and/or GHG service under this LDAR Monitoring Plan, based on TCEQ 28LAER requirements and commitments made in the CPCN application, are summarized in Table 2.5-1. These requirements do not apply to TAP-only components.

Table 2.5-1. Affected Component Design, Monitoring, and Inspection Requirements for Components in VOC and/or GHG Service

Component Type:	Design Requirement	Applicable Monitoring/Inspection Requirement [1]
Agitator Seals Compressor Seals Pump Seals	All new and replacement pumps, compressors, and agitators shall be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. These seal systems need not be monitored and may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored. All other pump, compressor, and agitator seals shall be monitored in accordance with the schedule set forth in Section 2.3, including all other aspects of this plan. (TCEQ 28LAER, 1.G).	AVO
Pressure Relief Valves	In accordance with TCEQ 28LAER, 1.F, relief valves vented to a control device are not subject to monitoring. Relief valves with a rupture disc and pressure-sensing device upstream are also not subject to monitoring, so long as the reading of the pressure-sensing device is checked on a quarterly basis and recorded in a maintenance log (or equivalent). The quarterly recordkeeping requirement does not apply to pressure-sensing devices that are continuously monitored and equipped with alarms to notify operators of a failure in disc integrity. All pressure relief valves subject to the LDAR Monitoring Program shall be vented to a control device, equipped with a rupture disc and pressure-sensing device, or monitored in accordance with the LDAR Monitoring Plan (CPCN application and TCEQ 28LAER, 1.F).	AVO
Leakless Valves	Sealless/leakless valves may include diaphragm valves and valves with welded bonnet bellows. Valves may not be buried. (TCEQ 28LAER, 1.C and 1.F). Note: TCEQ 28LAER does not require all valves to be sealless/leakless.	AVO
Open-ended lines	Unless an open-ended line is required for safety reasons, each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. Except during sampling, both valves shall be closed. See Section 3.4.5. (TCEQ 28LAER, 1.E).	AVO
Components in Vacuum Service	> 0.725 psi below ambient (TCEQ 28LAER, 1.A). Such components will be documented in the LDAR Monitoring Database.	AVO

Component Type:	Design Requirement	Applicable Monitoring/Inspection Requirement [1]
Components in Heavy Liquid Service	In accordance with TCEQ 28LAER, 1.A, components containing a liquid with a VOC aggregate partial pressure or vapor pressure of less than 0.044 psia are exempt from the monitoring requirements of the LDAR Monitoring Program and the design requirements for pumps, compressors, and agitators. Such components will be documented in the LDAR Monitoring Database.	AVO
Other, non-leakless, valves (including check valves)	Valves may not be buried. (TCEQ 28LAER, 1.C and 1.F).	AWP (or Method 21) and AVO
Connectors	Connectors shall be welded or flanged. Screwed connectors are permissible only on piping smaller than two inches in diameter. Buried connectors shall be welded. New and re-worked piping connections shall be pressure tested at no less than operating pressure prior to placing into service or monitored within 15 days of returning to service. (TCEQ 28LAER, 1.C and 1.E.).	AWP (or Method 21) and AVO (Non-Welded Connectors), AVO (Welded Connectors) [2]
Insulated Components	Not applicable.	AWP/AVO [3]
Other components with potential to emit fugitive emissions of VOCs and GHGs.	Components should be designed such that they are reasonably accessible for monitoring to the extent that good engineering practices will permit. (TCEQ 28LAER, 1.D).	AWP (or Method 21) and AVO

Notes:

[1] This table summarizes the monitoring and inspection requirements generally applicable to each type of component. Alternate monitoring and inspection requirements may apply to individual components as discussed elsewhere in this LDAR Monitoring Plan.

[2] Connectors are exempt from the monitoring if they are welded together around their circumference so that the flanges cannot be unbolted. These connectors are still subject to AVO inspection requirements.

[3] Insulated components are exempt from Method 21 monitoring insofar as the insulation inhibits the Method 21 instrument probe from accessing the potential leak interface. If the leak interface is accessible, it is subject to monitoring/inspection.

2.6 DETERMINATION OF STREAM COMPOSITIONS

The composition of individual process streams containing VOC and/or GHG has been determined based on the Heat and Material Balance (H&MB) derived from process simulation modeling performed for the Export Facility's "design" scenario. The process streams delineated on the Process Flow Diagrams (PFDs) were manually correlated with the lines on the Process and Instrumentation Diagrams (P&IDs). Stream compositions were assigned to individual components based on engineering judgement. Stream compositions for each component subject to the monitoring requirements of the LDAR Monitoring Program are stored in the LDAR Monitoring Database and will be used to:

- Calculate the detection sensitivity levels to be used in the performance of OGIC daily instrument checks (see Section 3.2.2).
- Calculate the response factor to be used in assessing the leak concentration measured with a Method 21 instrument (see Section 5.4.1).
- Calculate fugitive emissions of VOC and GHG from components subject to the LDAR Monitoring Program (see Section 5).

When a new component is added at the Export Facility, a similar approach will be followed to assign a stream composition to the new component based on the "design" scenario H&MB (see Section 6.3). [15] Updates to the stream composition database may be made periodically based on updated engineering information. Updating the stream composition information will not be retroactive, but will only apply to calculations moving forward from the update.

2.7 LDAR MONITORING DATABASE

LDAR Monitoring Program data will be stored within the LDAR Monitoring Database, which is contained and managed within LDAR software. Each VOC and/or GHG component subject to monitoring under the LDAR Monitoring Program is assigned a unique LDAR ID that corresponds to data stored within the LDAR Monitoring Database, including but not limited to: Export Facility identification numbers, physical component data (e.g., component type), stream composition information (i.e., Stream ID), monitoring method, monitoring results, and repair records. The LDAR Monitoring Database will be used to track monitoring requirements, repair schedules, emissions, and other pertinent information. As data from the field is entered into the LDAR Monitoring Database, the software has the ability to run emissions estimates based on the monitoring result and pre-defined information such as emissions factors, component gas stream composition, and previous monitoring/inspection results. TAP-only component leaks and repairs will be tracked through the LDAR Monitoring Database. Although not required under the LDAR Monitoring Program, a complete index of TAP-only components may also be included in the LDAR Monitoring Database.

[15] Note that this LDAR Monitoring Plan does not address determination of stream composition for TAP-only components.

The Export Facility must perform monitoring of components in VOC and/or GHG service in accordance with the AWP and/or Method 21. Only personnel, including 3rd party vendors, properly trained to use the OGIC or Method 21 instrument shall perform the monitoring (see Section 6.2). Additionally, the Export Facility must perform AVO inspections of components in VOC and/or GHG service, as well as components in TAP-only service. Performing AVO inspections requires limited training as it does not involve the use of any instrumentation. This section describes the procedures to be used for monitoring and inspections performed under the LDAR Monitoring Program.

3.1 COMPONENT FIELD IDENTIFICATION

Each component that is subject to monitoring under the LDAR Monitoring Program (i.e., components in VOC and/or GHG service) is assigned a unique LDAR ID that is used to identify component information stored within the LDAR Monitoring Database (see Section 2.7). Components may be identified in the field by weatherproof and readily-visible tags that are stamped with the LDAR ID. Alternatively, components may be identifiable in relation to a nearby tagged component.[16] LDAR ID tags may be physically affixed to components or hung in a location that is proximate to the component.[17] Any changes to the process or equipment will be reflected in updated P&IDs as part of the Management of Change process and appropriate changes to field tagging, database setup, and other aspects of the LDAR Monitoring Plan will be made (see Section 6.3).

TAP-only component repairs and leaks will be tracked through the LDAR Monitoring Database. Although not required under the LDAR Monitoring Program, a complete index of TAP-only components may also be included in the LDAR Monitoring Database. If a TAP-only component is included in the LDAR Monitoring Database, the database will clearly identify the component as a TAP-only component. If a leak is identified during an AVO inspection, personnel performing the inspection will take actions to confirm that the component is a TAP-only component. Such actions may include but are not limited to:

- Checking for the presence of an LDAR tag on the leaking component or on components upstream/downstream from the leaking component.
- Checking the LDAR Monitoring Database to see if the component has an LDAR ID using the leaking component's Export Facility/SAP ID number.
- Checking the LDAR Monitoring Database to see if the component has been identified as a TAP-only component using the leaking component's Export Facility/SAP ID number.
- Consulting the P&IDs.

[16] A valve that is tagged with an LDAR ID tag may be used to identify a nearby component that is not tagged. For example, the following record could be included in the LDAR database to identify a flanged connection associated with a valve that has LDAR ID 1001: *LDAR ID 1001.1, flanged connection downstream of valve 1001*.

[17] Examples of instances where a tag may not be physically affixed to the component include, but are not limited to: an LDAR ID tag for an overhead valve may be hung on the railing of the walkway beneath the valve; an LDAR ID tag for a component with moving parts may be hung upstream or downstream of the component, or some other proximate location, so as not to interfere with the operation of the component; the LDAR ID tags for the valves associated with a four-valve manifold may be clustered together and affixed to the manifold rather than to each individual valve.

3.2 OGIC MONITORING

3.2.1 OGIC Monitoring Equipment

The gas visualization functionality of OGICs is based on the absorption of electromagnetic radiation in the infrared wavelength of the gas being monitored. Given that different gases emit infrared radiation at different wavelengths, the type of OGIC that can be used depends on the characteristics of the fluid being monitored. Based on the composition of process streams subject to the LDAR Monitoring Program, two different OGICs will be required: one to monitor hydrocarbon (organic) streams and one to monitor carbon dioxide streams.

The OGICs will meet the following minimum instrument specifications from 40 CFR §60.18(i)(1).

- Provide the operator with an image of the potential leak points for each piece of equipment at the detection sensitivity level, within the distance used in the daily instrument check; and
- Provide a date and time stamp for video records of every monitoring event.

The cameras will be operated and maintained in accordance with manufacturer specification and as specified in this LDAR Monitoring Plan.

3.2.2 Daily Instrument Checks

Unlike Method 21 instruments, OGICs do not require calibration before use. Rather, a daily instrument check on days the instrument will be used is performed to verify that the OGIC is capable of imaging emissions from the components to be monitored at the detection sensitivity level, and within the maximum distance, to be encountered during the monitoring survey. The detection sensitivity level and maximum monitoring distance depend on the fluid stream being monitored. The LDAR Monitoring Contractor may repeat the daily instrument check to establish a different maximum monitoring distance for specific process streams to increase the efficiency of monitoring, as desired.

The instrument check must be performed on a daily basis, prior to beginning any leak monitoring work, for each camera configuration (e.g., different lens options) that is to be used, and for each individual operating the OGIC, during the monitoring survey. The procedures for performing daily instrument checks are provided in Appendix A. Records of the daily instrument checks will be maintained within the LDAR Monitoring Database. Records to be maintained are summarized in Appendix D.

During the daily instrument check, the camera must be used to view emissions from a gas cylinder at a flow rate calculated using the standard detection sensitivity levels for the defined monitoring frequency (see Section 2.3.1), as well as the lowest mass fraction of detectable chemicals within the stream(s) to be monitored. The mass fraction of the detectable chemicals for each stream is obtained from the H&MB described in Section 2.6. See Appendix A for further instructions on how to calculate the daily instrument check mass flow rate.

3.2.3 OGIC Monitoring Procedures

The OGIC will be operated to image every component designated for OGIC monitoring in accordance with the instrument manufacturer's operating parameters. OGIC monitoring will be performed in accordance with the AWP as outlined in this LDAR Monitoring Plan. The AWP is designed to be implemented by experienced, knowledgeable technicians and as such does not anticipate every possible monitoring scenario. The monitoring personnel must determine how to implement the monitoring to achieve the intended results, which is to identify the presence of leaks.

All emissions imaged by the OGI instrument on LDAR components in VOC and/or GHG service are considered leaks and are subject to repair. When a leak is identified with the OGIC, the leak concentration may be assessed using a Method 21 instrument.

3.3 METHOD 21 MONITORING

The Export Facility may use an appropriate Method 21 instrument for monitoring of most components in VOC and/or GHG organic material service. Method 21 instruments are unable to detect inorganic materials, such as carbon dioxide. GHG components in inorganic-only material service will be monitored using OGIC techniques (see Section 3.2).

3.3.1 Method 21 Monitoring Equipment

The Method 21 monitoring equipment used at the Export Facility will meet the requirements of Method 21 as outlined in this section.

3.3.1.1 Method 21 Monitoring Instruments

The Method 21 instruments used in the LDAR Monitoring Program will meet the following minimum criteria:

- The monitoring instrument will be capable of responding to the compounds in the process streams monitored.
- The monitoring instrument will be capable of measuring the leak definition concentration (i.e., 500 ppmv, as methane).
- The scale of the monitoring instrument meter will be readable to ±2.5 percent of the leak definition concentration (i.e., ±12.5 ppmv).
- The monitoring instrument shall be equipped with an electrically-driven pump to ensure that a sample is provided to the detector at a constant flow rate. The nominal sample flow rate, as measured at the sample probe tip, shall be 0.1 to 3.0 liters per minute (L/min) when the probe is fitted with a glass wool plug or filter that may be used to prevent plugging of the instrument. Neither Method 21 nor TCEQ 28LAER prescribe a methodology to be used to document compliance with this flow rate requirement. As such, compliance will be assumed based on manufacturer's documentation of the pump flow rate and acceptable response time test results.
- The monitoring instrument shall be equipped with a probe or probe extension that will meet the manufacturer's specifications and not exceed 6.4 millimeters (mm) (1/4 inch) in outside diameter.
- The monitoring instrument shall be intrinsically safe for operation in explosive atmospheres as defined by the National Electrical Code by the National Fire Prevention Association or other applicable regulatory code for operation in any explosive atmospheres that may be encountered during use. The instrument shall, at a minimum, be intrinsically safe for Class 1, Division 1 conditions, and/or Class 2, Division 1 conditions, as appropriate, as defined by the applicable code. The instrument shall not be operated with any safety device removed.

Types of monitoring instruments that may be used include catalytic oxidation detectors, flame ionization detectors (FIDs), infrared absorption detectors, and photoionization detectors (PIDs). All instrument(s) will be maintained in good working condition and operated according to the manufacturer's specifications.

3.3.1.2 Calibration Gases

Calibration gases used at the Export Facility shall meet the following minimum requirements.

- Zero gas that contains less than 10 ppmv VOC;
- 500 ppmv (28LAER leak definition) calibration gases of methane balanced with air;
- Calibration gases will be analyzed and certified by the manufacturer within ±2% accuracy;
- Shelf lives will be specified for all calibration gases and expired calibration gases will not be used unless reanalyzed and recertified;
- Certification sheets for each cylinder of gas will be available and maintained for at least five (5) years after the cylinder has been emptied or the expiration date of the cylinder; and
- A unique lot number will be on each cylinder that can be referenced to the certification (or recertification).

3.3.1.3 Method 21 Soap Solution

The following minimum requirements apply to soap solution used in the performance of the Method 21 Soap Bubble Test.

- The soap solution will be a commercially available leak detection solution (e.g., Snoop) or will be prepared using concentrated detergent (e.g., common dishwashing detergent) and water.
- A pressure sprayer or squeeze bottle will be used to dispense the solution.

3.3.2 Method 21 Instrument Calibration and Performance Evaluation

Instrument quality assurance activities shall be performed according to the minimum frequencies shown in Table 3.3-1.

Table 3.3-1. Frequencies of Quality Assurance Activities

Activity	Frequency	Acceptability Criteria
Instrument Calibration	At the start of each monitoring shift.	Instrument reading must be adjusted to the calibration gas value.
Calibration Precision Test	Prior to placing the instrument into service and at 3-month intervals. If instrument is not used for more than 3 months, it must be tested prior to being placed into service.	The calibration precision shall be equal to or less than 10 percent of the calibration gas value.
Response Time Test	Prior to placing the instrument into service and after any change in instrument flow configuration (e.g., extension probe).	The response time shall be less than or equal to 30 seconds.
Response Factor Test	Prior to placing the instrument into service, unless response factors are determined through published reference sources. The response factor tests do not need to be repeated at subsequent intervals.	The response factor shall be less than 10 for each individual VOC to be measured.

The procedures for performing these quality assurance activities are provided in Appendix B. These activities are recorded in the LDAR Monitoring Database. Records to be maintained are listed in Appendix D.

3.3.2.1 Calibration Drift Assessments

A calibration drift assessment is a tool that may be used to verify that the Method 21 instrument is functioning properly and helps to identify potential monitoring equipment issues. Method 21 does not specifically require the performance of calibration drift assessments. Where calibration drift assessments are required, they are prescribed by the underlying regulation, e.g., 40 CFR Part 60, Subpart VVa. The regulatory programs underpinning the LDAR Monitoring Program at the Export Facility, i.e., TCEQ 28LAER and COMAR, do not require calibration drift assessments. Therefore, calibration drift assessments are considered a best management practice to be performed at the discretion of the LDAR Monitoring Contractor rather than a regulatory requirement. Calibration drift assessments may be performed mid-way through each monitoring shift and/or at the end of the monitoring shift. The procedures for a calibration drift assessment are provided in Appendix B. The calibration drift results, if conducted, are recorded in electronic form in the LDAR Monitoring Database. Records to be maintained are listed in Appendix D.

The Cove Point Environmental Staff or DECP LDAR Coordinator shall be notified if any drift assessment results in a greater than 10% variance from the previous calibration value. Re-monitoring of components monitored since the later of the most recent calibration or calibration drift assessment may be performed at the discretion of the Export Facility.

3.3.3 Method 21 Monitoring Procedure

When Method 21 is used, the component monitoring at the Export Facility will be performed according to *Type I - Leak Definition Based on Concentration* shown in section 8.3.1 of EPA Method 21, which states:

Place the probe inlet at the surface of the component interface where leakage could occur. Move the probe along the interface periphery while observing the instrument readout. If an increased meter reading is observed, slowly sample the interface where leakage is indicated until the maximum meter reading is obtained. Leave the probe inlet at this maximum reading location for approximately two times the instrument response time

Provided below are some technical clarifications on the method described above.

3.3.3.1 Leak Interfaces

It is important to correctly identify and monitor at the interfaces "where leakage could occur". The leak interfaces are generally definable and not subjective. Monitoring personnel must be familiar with the leak interfaces of the components that are being monitored. If the LDAR Monitoring Contractor is unsure if an interface encountered is a leak interface, the interface is to be monitored until the personnel obtain clarification that it is not a leak interface. In addition, monitoring personnel should not monitor unnecessary interfaces (i.e., interfaces with no potential to leak). Openings on devices that are intended to vent as a part of their normal operation (e.g., pneumatic equipment) are not considered leak interfaces for the purposes of this LDAR Monitoring Plan, and should not be monitored.

3.3.3.2 Probe Placement

The intent of Method 21 is to utilize a probe placement and orientation that provides for the highest possible concentration reading. To this end, the probe should be positioned so that it is touching the leak interface unless doing so would present a safety hazard, the interface is wet, or the interface is moving. Where these conditions exist, attempts should be made to place the probe inlet no farther than 1 centimeter (cm) (0.4 inches) away from the leak interface. The probe should not be inserted into a location that cannot be visually observed to assess the presence of potential safety hazards, wet or moving parts, or materials that could contaminate the probe/instrument. If a leak interface is observed to be contaminated to a degree that would interfere with monitoring, monitoring personnel should first attempt to remove the contamination, and if unable to adequately remove the contamination, schedule maintenance to remove the contamination.

3.3.3.3 Probe Movement

The rate of probe movement should be considered when monitoring based on the equipment size and the response rate of the instrument to the process fluid. Method 21 does not prescribe a required probe movement rate, nor would it be feasible to establish one under this LDAR Monitoring Plan. The probe movement rate used in practice will be up to the discretion of the LDAR Monitoring Contractor.

3.3.3.4 Increased and Maximum Meter Readings

Both "increased meter reading" and "maximum meter reading" are referred to in the Type I procedure in EPA Method 21. Whether an increased meter reading is observed should be decided by trained monitoring personnel considering the components being monitored and the conditions encountered during the monitoring survey. It is not feasible to set a specific threshold that correlates to an "increased meter reading". The technician must be aware of the level of background "noise" and allow the meter to reach a maximum when an increase has occurred.

When an increased meter reading is observed, the LDAR Monitoring Contractor should slowly move the probe along the leak interface in the vicinity of the increased meter reading until the location of the highest meter reading is identified. The probe must be left at this location for approximately two (2) times the instrument's response time and until the maximum meter reading is obtained at that location.

3.3.3.5 Background Correction

Instrument readings may be corrected for background, as appropriate, for Method 21 monitoring performed at the Export Facility. Any concentration adjustments will be performed in accordance with the "no detectable emissions" provisions in Section 8.3.2 of Method 21. Background correction is to be performed by monitoring personnel for instances where zero emissions are occurring, but where the Method 21 instrument is detecting low organic compound concentrations during Method 21 due to organic material in the ambient air or general equipment fluctuations. Background correction is performed at the discretion of monitoring personnel.

3.4 COMPONENT-SPECIFIC CLARIFICATIONS

The following subsections describe specific component clarifications for the Export Facility. These clarifications are in no way intended to limit the scope of the LDAR Monitoring Program. Refer to Section 2.5 for LDAR Monitoring Program requirements specific to component type.

3.4.1 Valves

Valves are considered to include the valve body, stem, bonnet, gate, packing, and handle. Valves do not include the connector(s) on either side of the valve. Those connectors are separate components for monitoring purposes. The bonnet is not to be identified separately as a connector in the LDAR Monitoring Database. Any interfaces resulting from anything inserted into the valve body is subject to monitoring and inspection.

3.4.2 Second Valves

Second valves following normally closed valves are included in the LDAR Monitoring Plan and are not considered exempt from monitoring and/or inspection.

3.4.3 Check Valves

Check valves are considered valves under the LDAR Monitoring Program, even though they have no stem. Most check valves have a bonnet, and this is included as part of the valve. There may be connectors at the points where the check valve is attached to the piping. These connectors are separate components for monitoring and inspection purposes.

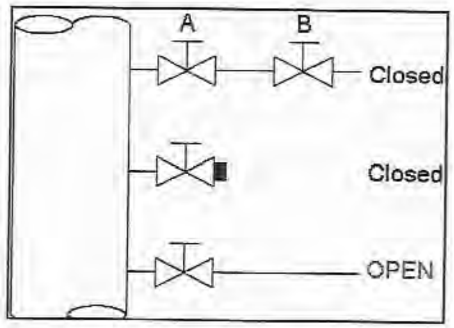
3.4.4 Plugs and Caps

Plugs and caps attached to normally closed valves are identified in the LDAR Monitoring Database as components but are not required to be monitored. Such plugs and caps are subject only to the AVO inspection requirements of the LDAR Monitoring Program. See Section 3.4.5 for the requirements applicable to open-ended lines. Plugs and caps other than those downstream of a normally closed valve must be monitored as per this monitoring plan.

3.4.5 Open-Ended Lines

An open-ended line is any valve having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through piping.[18] Except for those that are part of an emergency shutdown system, each open-ended line shall be equipped with a cap, blind flange, plug, or a second valve as shown in the illustration below (Figure 3.4-1).

Figure 3.4-1: Open-Ended Line Example



The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended line, or during maintenance. If a second valve or cap/plug is installed, the component is not an open-ended line. DECP's policy is to not permit open-ended lines, unless necessary for safety systems.

If the isolation of equipment for hot work or the removal of a component for repair or replacement results in an open-ended line, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 72 hours during maintenance activities. If the repair or replacement is not completed within 72 hours, either of the following actions must be completed:

- A cap, blind flange, plug, or second valve must be installed on the line; or
- The OEL shall be monitored once for leaks for a plant or unit turnaround lasting up to 45 days with an approved gas instrument and the results recorded. For all other situations, the OEL shall be monitored once by the end of the 72 hour period following the creation of the OEL and once per month thereafter with an approved gas instrument and the results recorded. For all situations, leaks are indicated by readings of 500 ppmv and must be repaired within 24 hours, or a cap, blind flange, plug, or second valve must be installed on the line or valve.

If any open-ended lines are discovered on subject lines, a cap, blind flange, plug, or a second valve will be placed upon discovery at the end of the open-ended line unless: operations are occurring that require process

[18] This definition of "open-ended line" is not provided in TCEQ 28LAER. The definition given herein is from 40 CFR Part 60, Subpart VV. A similar definition is used in other regulatory programs requiring LDAR.

fluid flow through the line; maintenance is occurring on the line; or, the open-ended line is a part of the emergency shutdown system. Note that these requirements only apply to VOC and/or GHG components and do not apply to TAP-only components.

3.4.6 Connectors

Connectors have many different configurations. The LDAR Monitoring Contractor must be familiar with the different shapes and configurations of connectors at the Export Facility to understand where leakage could occur. The complete circumference of each interface must always be monitored. Connectors (including tubing connections) in streams containing VOCs and/or GHGs as well as TAP-only components will be monitored and inspected regardless of size.

3.4.7 Insulated Components

Insulated components are generally not accessible for monitoring using a Method 21 instrument. As such, insulated components that are inaccessible for monitoring using Method 21 (i.e., leak interface is not accessible due to insulation materials) will be monitored using an OGIC. If the OGIC indicates a leak passing through an opening in the insulation, the insulation in the vicinity of the leak will be removed, if practicable, and the underlying components monitored in an attempt to identify the leaking component. A component that has a non-leak interface penetration (e.g., valve handle) in the insulation is not required to be monitored via Method 21 at the penetration. Monitoring with a Method 21 instrument at a penetration in insulation may be done for investigative purposes.

3.5 AVO INSPECTIONS

AVO inspections involve the use of sensory methods (i.e., audio, visual, and/or olfactory) to identify a potential leak to the atmosphere. AVO inspections apply to all components subject to the LDAR Monitoring Program, even if such components are exempt from Method 21 and/or OGIC monitoring (e.g., TAP-only components). The repair requirements applicable to leaks identified during AVO inspections are discussed in Section 4. The procedure for AVO inspections and repair can be found in Appendix E.

When a leak is identified during an AVO inspection, the leak concentration may be assessed using a Method 21 instrument.

4 LEAK IDENTIFICATION AND REPAIR PROCEDURES

The procedures for leak identification and repair are outlined in this section. Work flow diagrams depicting the leak identification and repair requirements of this LDAR Monitoring Plan are provided in Appendix F.

4.1 LEAK IDENTIFICATION

Components found to be leaking will be identified as leaking via a weatherproof and readily visible leak tag (e.g., SAP Notification). The leak tag may be physically affixed to the leaking component or hung at a location in proximity to the leaking component.[19] In instances where the leak tag is not physically affixed to the leaking component, the tag and/or leak record in the database will contain information sufficient to identify the leaking component. Leak tags must include the following information: unique identification number (e.g. component LDAR ID or SAP ID); the name of the personnel who identified the leak; and, the date that the leak was identified. All tags will remain in place until, at a minimum, the information necessary to track and identify the leaking component has been entered into the LDAR Monitoring Software and/or SAP, as appropriate. See Section 4.2.4 for details on remonitoring.

The following procedures will be used to supplement the identification of leaking components through tagging. The intent of these procedures is to assist personnel with locating a leaking component for repair.

- For leaks identified through OGIC monitoring, a video and/or image of the leaking component will be captured and recorded in the LDAR Monitoring Database.
- For all leaks identified via monitoring or AVO inspections, the leak record uploaded into the LDAR Monitoring Database will include the unique component LDAR ID (if applicable) and a description of the leak location (e.g., upstream flange on the suction isolation valve of equipment ID XXX).
- Records to be maintained for all leaking components are identified in Section 6.6 of this LDAR Monitoring Plan and summarized in Appendix D.

4.2 LEAK REPAIRS

When a leak is identified, it shall be repaired according to the procedures outlined below. All repairs at the Export Facility are to be performed by maintenance personnel under the direction of the Maintenance Manager or Maintenance Supervisor. First attempts at repair may be made by other personnel.

If a repair of a leak cannot be successfully completed according to this plan, other than for safety reasons (see Section 4.2.2 for safety concerns), DECP shall submit a plan prior to extending a repair past allowed timeframes for MDE approval. The leaking component will remain on DOR until an MDE determination has been made. The submitted plan shall include the following:

i) An explanation of the technical difficulty;
ii) A timeline to successfully repair the leaking component; and
iii) A calculation on the additional VOC or GHG, for GHG-only components, that is expected to be released due to the extension beyond allowed timeframes, i.e. additional emissions from end of allowed timeframe to planned successful leak repair.

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[19] Examples of instances where a leak tag may not be physically affixed to the leaking component include, but are not limited to: the leak tag for a leaking overhead component may be affixed to the railing of the walkway beneath the component; the leak tag for a leaking component that is located behind other equipment such that hanging the tag on the leaking component would render it not "readily visible" may be hung in a nearby visible location.

4.2.1 Directed Maintenance

Maintenance personnel and the LDAR Monitoring Contractor should maintain close coordination/communication to address leaking components as soon as practicable. As required by TCEQ 28LAER, repair of leaking components in VOC and/or GHG service will be performed using directed maintenance. Directed maintenance may be employed, but is not specifically required for TAP-only components. Directed maintenance involves the use of monitoring concurrent with repair to assess the impact that the repair/maintenance activity has on leak magnitude. In this way, directed maintenance informs maintenance personnel on the actions that have the greatest impact on fugitive emissions from the leaking component such that a minimum concentration of fugitive emissions may be achieved. The assessment of repair activities performed under directed maintenance may be quantitative (e.g., using a Method 21 instrument) or qualitative (e.g., using an OGIC or Method 21 Soap Bubble Test).

4.2.2 First Attempt at Repair

The actions taken during a first attempt at repair may vary depending on the situation (type of component, location of the leak on the component, etc.). A first attempt at repair may include, but is not limited to, the following:

- Tightening the bonnet bolts;
- Replacing the bonnet bolts;
- Tightening the packing gland nuts; and,
- Injecting lubricant into the lubricating packing.

These actions are provided as guidance only. The appropriate action to be taken during a first attempt at repair will be determined by the personnel performing the repair attempt. For equipment required to remain insulated during operation for safety reasons, or other instances where first attempt at repair would cause a safety concern (e.g., the time needed to safely build scaffolding to safely access an elevated component), first attempt at repair will be postponed until it is safe to perform the first attempt at repair. The decision to postpone the first attempt at repair due to safety reasons will be documented, including the basis for such decision.

4.2.3 Repair Timeframe

When a leaking component is identified via monitoring or AVO inspection, the component shall be repaired in accordance with the timeframes outlined in this section unless it is placed on DOR pursuant to Section 4.3.

4.2.3.1 Leaks Identified via Monitoring

First attempts at repair for leaking components found by instrument monitoring should be performed no later than 5 calendar days after initial leak source identification, unless otherwise postponed as described in Section 4.2.2. If the first repair attempt is not successful, the component should be repaired within 15 calendar days after initial leak source identification unless the component has been depressurized or qualifies for placement on DOR (See Section 4.3). A repair is not considered successful until remonitoring has been performed to verify the success of the repair.

4.2.3.2 VOC Leaks Identified via AVO Inspection

For leaking components in VOC service that are identified by AVO inspection, a first attempt at repair must be performed no later than 48 hours after initial leak source identification, unless otherwise postponed as described in Section 4.2.2. If the first repair attempt is not successful, the component should be repaired within 15 calendar days after initial leak source identification unless the component has been depressurized. If a replacement part is required, the part must be ordered within 3 calendar days after initial leak identification and the leak shall be repaired within 48 hours after receiving the part, unless the component has been depressurized. The LDAR Monitoring Contractor may perform Method 21 monitoring prior to and following each repair attempt to assess the leak concentration for emissions calculation purposes and to evaluate the success of the repair attempt.

4.2.3.3 GHG-Only Leaks Identified via AVO Inspection

For leaking components in GHG-only service (non-VOC, non-TAP) that are identified by AVO inspection, a first attempt at repair must be performed no later than 5 calendar days after initial leak source identification, unless otherwise postponed as described in Section 4.2.2. If the first repair attempt is not successful, the component should be repaired within 15 calendar days after initial leak source identification unless the component has been depressurized. The component will be considered repaired only when it has been remonitored successfully.

4.2.3.4 TAP-Only Leaks Identified via AVO Inspection

For leaking components in TAP-only service (non-VOC, non-GHG) that are identified by AVO inspection, a first attempt at repair must be performed no later than 5 calendar days after initial leak source identification, unless otherwise postponed as described in Section 4.2.2. If the first repair attempt is not successful, the component should be repaired within 15 calendar days after initial leak source identification unless the component has been depressurized. A follow-up AVO inspection or Method 21 Soap Bubble Test will be performed to evaluate the success of each repair attempt.

4.2.4 Leak Repair Verification

The procedures to be followed for verifying that a leak has been repaired are outlined below. No component shall be deemed repaired until it has been remonitored or reinspected.

4.2.4.1 VOC and GHG Remonitoring

After performing a repair attempt of a VOC and/or GHG component from which a leak has been identified by means of monitoring and/or inspection, the component will be remonitored using a Method 21 instrument, an OGIC, or the Method 21 Soap Bubble Test. For leaks discovered via an AVO inspection for low vapor pressure, liquid systems (e.g., glycol), remonitoring will be conducted using a follow up AVO inspection. A leak is considered repaired when the results of remonitoring indicate that the leak has been eliminated (refer to the leak definitions in Section 2.2).

4.2.4.2 TAP-Only Reinspection

After repairing a TAP-only component from which a leak has been identified, the component will be reinspected. Either a follow-up AVO inspection or a Method 21 Soap Bubble Test will be used for reinspection. A leak is considered repaired when the results of reinspection indicate that the leak has been eliminated (refer to the leak definitions in Section 2.2).

4.3 DELAY OF REPAIR

Leaking components that cannot be repaired without a process unit/gas circuit shutdown may be placed on DOR until the next scheduled shutdown if an early shutdown would create more emissions than the repair would eliminate. A leaking component may also be placed on DOR if approved for DOR status under Section 4.2 or was determined to be a safety concern under Section 4.2.2. In the event of a safety concern, the DOR will not be extended beyond 24 months. The following process will be used to determine if a component is eligible for DOR based on emission calculations:

- Export Facility engineering personnel, the Environmental Compliance Coordinator, and/or the DECP LDAR Coordinator will coordinate with the lock-out/tag-out (LOTO) team to define the boundary of the gas circuit (i.e., the "LOTO boundary") that would need to be shutdown to repair the component being considered for DOR.
- A list of all components currently on DOR within the gas circuit will be obtained by conducting a walkthrough of the gas circuit to look for DOR tags, review of the LDAR Monitoring Database to look for DOR records, or other available methods.
- The total VOC or GHG, for GHG-only service, daily mass emission rate from the component being considered for DOR, as well as all other leaking components on DOR within the gas circuit, will be calculated using the methodologies described in Section 5. Emission rates for all components on DOR are calculated and maintained within the LDAR Software or a similar database.
- The total daily pollutant mass emission rate from all components on DOR within the gas circuit will be multiplied by the number of days until the next scheduled shutdown of the gas circuit (E_{DOR}).
- Pollutant emissions from shutdown of the gas circuit ($E_{SHUTDOWN}$) will be estimated by Export Facility engineering personnel in coordination with the LOTO team, the Environmental Compliance Coordinator, the DECP LDAR Coordinator, and the DEGIG LDAR Coordinator, as needed. $E_{SHUTDOWN}$ will be calculated taking into account control device efficiency, and emissions from subsequent clearing and startup of the gas circuit, as applicable. Emissions of nitrogen oxides (NOx) that may be generated as a result of the action (e.g., flaring of emissions during a gas circuit shutdown) may be considered during the evaluation. NOx and VOC emissions will be treated as having a one-to-one tradeoff for the purposes of this evaluation.[20]

If $E_{SHUTDOWN}$ is greater than or equal to E_{DOR}, the component may be placed on DOR. If E_{DOR} is greater than $E_{SHUTDOWN}$, DECP will either make a decision to shut down the associated gas circuit for repairs within 15 days or will notify MDE within 15 days of completing the DOR emissions calculations. During this time of MDE review, the component will be placed on DOR, pending MDE determination. DECP will coordinate with MDE to determine whether an early shutdown or other appropriate action is required, based on the severity of leaks from components on DOR awaiting shutdown of the gas circuit. If the MDE determines that an early shutdown is needed, the date for the early shutdown of the gas circuit will be established such that E^*_{DOR}[21] remains below $E_{SHUTDOWN}$, as practicable. Records of calculations of $E_{SHUTDOWN}$, E_{DOR}, and E^*_{DOR} including the basis for the calculations, any assumptions made, as well as any related communications between DECP and MDE, will be maintained.

[20] For example, if E_{DOR} is estimated to be 10 pounds of VOC and flaring of the gas vented from the gas circuit during shutdown would result in 25 pounds of NOx emissions, there is a net environmental impact of 15 pounds of NOx associated with the shutdown. As such, the components should remain on delay of repair until the next scheduled shutdown of the gas circuit.

[21] E^*_{DOR} is the total daily mass emission rate from all components on DOR within the gas circuit multiplied by the number of days until the early scheduled shutdown of the gas circuit.

The calculations, analyses, and reporting process described above are not required if leaking components are isolated from the process and do not remain in service (depressurized). Such components may be placed on the DOR list indefinitely. Components that are depressurized to atmospheric pressure need not be purged to meet this criterion. All DOR components will be identified by tagging in the field, as described in Section 4.1, and within the LDAR Monitoring Database. Upon repressurization of the system, the leaking component will be remonitored within 15 days to confirm leak(s) have been repaired.

Emissions from shutdown of certain gas circuits may be routed to a flare, which will reduce VOC and increase GHG due to the CO_2 generated from the combustion process. As such, in some instances $E_{SHUTDOWN}$ may be higher than E_{DOR} for GHG while the opposite may be true for VOC. Thus, in performing the analysis described in this section, the following approach will be employed depending on the composition of the process stream:

- Components in VOC and GHG service – The analysis will be completed for VOC only.
- Components in VOC-only service – The analysis will be completed for VOC only.
- Components in GHG-only service – The analysis will be completed for GHG only. GHG mass emissions will be converted to a CO_2 equivalent basis for comparison of $E_{SHUTDOWN}$ to E_{DOR}.
- Components in TAP-only service – The analysis will be completed for TAPs only.

Given that emissions from TAP-only components are not quantified as a part of the LDAR Monitoring Program, the evaluation of $E_{SHUTDOWN}$ and E_{DOR} will be performed qualitatively using engineering judgement for components in TAP-only service.

In addition to the above, leaking component repairs not covered for requiring parts under Section 4.2.3.2 may be placed on DOR for a period of up to one year due to requiring replacement parts or specialty equipment or services. The leaking component must be repaired within 7 days of receiving the required parts or specialty equipment or services unless otherwise eligible for DOR status under other aspects of the LDAR Monitoring Program.

5.1 EMISSION CALCULATION REQUIREMENTS

Fugitive emissions of VOC and GHG from components subject to the LDAR Monitoring Program will be estimated to satisfy the following requirements:

- Assess when an early process unit shutdown may be required based on total emissions from all components on the DOR list within the process unit exceeding emissions from early shutdown of the process unit (see Section 4.3).
- Maintain a 12-month rolling sum of VOC and GHG emissions from components subject to the LDAR Monitoring Program for comparison to the applicable emission limits (CPCN Conditions A-III-4, A-IX-2, and A-IX-3, PTO conditions B(4)).

Procedures to be used to satisfy these requirements are outlined below. Note that emissions estimates for TAP-only components are not required under the LDAR Monitoring Program.

Pursuant to TCEQ guidance, components in liquid service where the liquid has an aggregate VOC partial pressure of less than 0.002 psia at 68 °F are expected to have such low emissions that emissions quantification is not required.[22, 23] Such components are exempt from the emissions quantification requirements of this LDAR Monitoring Plan and may be placed on DOR as necessary without emissions quantification. These components will be designated as exempt from emissions quantification requirements in the LDAR Monitoring Database based on the process stream assignment. These components are also exempt from Method 21 and/or OGI monitoring per TCEQ 28LAER.

5.2 EMISSION CALCULATION METHODOLOGIES

CPCN Condition A-IX-5 stipulates that emissions from component leaks will be calculated based on the results of gas analyzer monitoring and through the use of emission factors in Table 2-4 of the EPA document entitled "Protocol for Equipment Leak Emission Estimates" ("EPA Protocol", EPA-453/R-95-017). The calculation methodologies from the EPA Protocol to be used under the LDAR Monitoring Program include:

- **EPA Correlation Equations:** The Petroleum Industry Leak Rate/Screening Value Correlations (Correlation Equations) from Table 2-10 of the EPA Protocol will be used to estimate the mass emission rate from individual components based on component type and the concentration of emissions measured via a Method 21 instrument. The use of the Correlation Equations is the preferred approach and will be used to estimate fugitive emissions of VOC and GHG under this LDAR Monitoring Program, except as follows:
  - When the Method 21 instrument reading is zero (i.e. Zero Leak Factors).
  - When the Method 21 instrument reading is "pegged" (e.g., ≥100,000 ppmv).
  - When a component is not monitored using a Method 21 instrument.

The methodologies to be used under these scenarios are outlined below.

[22] Air Permit Technical Guidance for Chemical Sources: Fugitive Guidance, TCEQ (APDG 6422v1, Revised 12/17)

[23] An example of components taking this exemption includes, but is not limited to, components in water/glycol service, where the aggregate VOC partial pressure is approximately 0.0004 psia at 68°F.

- **Average Emission Factors:** The Oil and Gas Average Emission Factors (O&G Avg. EFs) from Table 2-4 of the EPA Protocol can be used to estimate the mass emission rate from a population of components based on component type and service type. No monitoring data is required to estimate emissions using this approach. This approach will be used to estimate emissions from components that are not monitored using a Method 21 instrument.

- **Pegged Emission Factors:** The 100,000 ppmv Screening Value Pegged Emission Rates for the Petroleum Industry (Pegged Emission Factors) from Table 2-14 of the EPA Protocol are used to estimate the mass emission rate from components where the Method 21 instrument reading is "pegged". The 100,000 ppmv Pegged Emission Factors should be used to estimate emissions where the Method 21 instrument reading is above the upper range of the Method 21 instrument where it can still meet the detection resolution required by Method 21. For example, the Bascom-Turner Gas Rover meter can measure the VOC concentration up to 40,000 ppmv, at which time the resolution decreases to greater than 2.5% of the leak definition. Therefore, above 40,000 ppmv, the 100,000 ppmv Screening Value Pegged Emission Rate are used for measurements using the Bascom-Turner Gas Rover meter.

- **Zero-Leak Factors:** The Default-Zero Values: Petroleum Industry (Zero-Leak Factors) from Table 2-12 of the EPA Protocol are used to estimate the mass emission rate from components where the concentration measured using a Method 21 instrument is zero. The Zero-Leak Factors may only be used when the minimum detection limit of the Method 21 instrument is less than or equal to one ppmv. If the minimum detection limit of the Method 21 instrument is greater than one ppmv, emissions will be estimated using the Correlation Equations and a concentration equal to one half of the Method 21 instrument minimum detection limit.

The Correlation Equations, Average Emission Factors, Pegged Emission Factors, and Zero-Leak Factors are provided in Appendix C.

The LDAR Monitoring Program at the Export Facility will utilize periodic OGIC monitoring accompanied by annual Method 21 monitoring as required by the AWP. The CPCN requires monthly VOC and GHG emission calculations. The specific emission calculation approach used to estimate VOC and GHG emissions from components will depend on the methods used for component monitoring and the results of such monitoring as outlined in Table 5.2-1.

Table 5.2-1. Calculation Approach Summary for Components in VOC and/or GHG Service

Monitoring Result	Calculation Approach	Duration of Emissions
Non-Leaking	• Utilize O&G Avg. EFs and the TCEQ 28LAER control efficiencies until a Method 21 instrument reading is collected (e.g., during annual Method 21 monitoring, if applicable). • Once a Method 21 instrument reading is collected for a component, use the Correlation Equations or Factors, as applicable, to estimate emissions from the component.	• Assume that emissions have occurred at the calculated rate since the last monitoring event. • Once a Method 21 instrument reading is collected for the component, the rate calculated using the Correlation Equations or Zero-Leak Factors will be used until such time that a leak is identified from the component or the next annual Method 21 monitoring event, whichever comes first.
Leaking	• Emissions from leaking components identified during OGIC monitoring or AVO inspections may be monitored with a Method 21 instrument. Emissions would then be estimated using the Correlation Equations or Pegged Emission Factors, as applicable. • Emissions from leaking components identified during annual Method 21 monitoring will be estimated using the Correlation Equations or Pegged Emission Factors, as applicable. • Emissions from leaking components that are not monitored using a Method 21 instrument (e.g., components in CO_2 service) will be estimated using the O&G Avg. EFs and the TCEQ 28LAER control efficiencies.[3]	• Per TCEQ policy[1] assume that emissions have occurred at the calculated rate since the midpoint between the last monitoring event and the current monitoring event and until the time the component is remonitored to verify successful repair. A necessary outcome from applying this TCEQ policy and the CPCN requirement to calculate fugitive emissions on a monthly basis is that emission calculations are subject to change based on the results of future monitoring events.[2] Past emissions calculated from a leak will be attributed to the facility wide rolling emissions on the day the leak was found. Previous monthly facility totals will not be updated with past emissions.

Note:
[1] *Technical Supplement 3: Fugitive Emissions from Piping Components*, TCEQ Publication RG-360/17, January 2018 Revision.
[2] As an example, assume that a component is monitored during a bi-monthly monitoring event and no leaks are observed. At the end of the month (Month 1), emissions from the component would be estimated based on the daily emission rate (calculated using the "non-leaking" calculation approach described above) and the number of days during the month since the monitoring event. The same calculation would be performed in the following month (Month 2). Assume that the same component is found to be leaking during the next bi-monthly monitoring event (e.g., 60 days from the previous monitoring event). The Export Facility would estimate emissions from the component using the daily emission rate (calculated using the "leaking" calculation approach described above) and assuming a leak duration from the mid-point between the current monitoring event and the previous monitoring event (30 days) to the date that the repair is made and component remonitored (e.g., 15 days from leak identification). Thus, emissions from the component calculated for Month 2 would change.
[3] If a component is found to be leaking and is placed on DOR, the TCEQ 28LAER control efficiencies will not be applied.

5.3 LDAR MONITORING PROGRAM CONTROL EFFICIENCIES

The O&G Avg. EFs are used to estimate "uncontrolled emissions", or emissions from a population of components without LDAR requirements. TCEQ has developed control efficiencies that can be applied to emissions estimated using the O&G Avg. EFs for the purposes of estimating emissions from a population of components subject to LDAR in accordance with TCEQ 28LAER. The use of the TCEQ 28 LAER control efficiencies is subject to the following limitations:

- Control efficiencies will only be used when the O&G Avg. EFs are used to estimate uncontrolled emissions. The use of control efficiencies does not apply to emission estimates performed using the Correlation Equations, Pegged Emission Factors, or Zero-Leak Factors.
- Control efficiencies will not be applied to unmonitored components, except that 100% control efficiencies may be assumed for the following component types that are exempt from monitoring based on applicable design requirements as outlined in Table 2.5-1[24].
    - Relief valves that are routed to a properly operating control device, or equipped with a rupture disc and pressure sensing device (between the valve and the disc) to monitor for disc integrity;
    - Pumps that are designed to be leakless, such as canned pumps, magnetic drive pumps, diaphragm-type pumps, pumps with double mechanical seals and the use of a barrier fluid at a higher pressure than the process fluid pressure, or pumps with double mechanical seals and that vent the barrier fluid seal pot to a control device;
    - Valves that are: bellows valves with bellows welded to both the bonnet and stem, diaphragm-type valves, or seal-welded, magnetically actuated, packless, hermetically sealed control valves;
    - Connections that are welded together around their circumference so that the flanges cannot be unbolted; and
    - Compressors designed with enclosed distance pieces and if the crankcase vents to a control device.
- A 75% control efficiency may be applied for components that are designated as DTM as long as those components are monitored using Method 21 at least once per 12-month period and repaired if found to be leaking, as required by this LDAR Monitoring Plan.[25]
- Control efficiencies will not be applied to components placed on the DOR list or components designated as UTM, as such components are not subject to routine monitoring and repair. The incidental monitoring or inspection of a UTM component (OGIC monitoring or AVO inspections) does not qualify for the application of a control efficiency insofar as the components are unsafe to access for repair.

The TCEQ 28LAER control efficiencies are included in Appendix C of this LDAR Monitoring Plan.

[24] TCEQ Technical Supplement 3: Fugitive Emissions from piping Components, TCEQ Publication RG-360/17, January 2018 Revision

[25] Reference – Air Permit Technical Guidance for Chemical Sources Fugitive Guidance, Air Permits Division Texas Commission on Environmental Quality (TCEQ (APDG 6422v1, Revised December 2017)

5.4 CORRECTIONS BASED ON STREAM COMPOSITION

Data corrections that are applied during the emissions calculation process are outlined in this section.

5.4.1 Response Factor Correction

A response factor is the ratio of the actual concentration of a VOC to the concentration reading of a Method 21 instrument calibrated with methane. The response factor of the instrument for specific VOCs will be determined pursuant to the requirements of Method 21. If a mixture of VOCs is being monitored, the response factor of the mixture will be calculated for the average composition of the process fluid. A calculated average response factor of the mixture is not required when all of the compounds in the mixture have a response factor less than 10 using methane. Calculation of average response factors of mixtures is further discussed in Appendix B.

Response factors may be obtained for specific gases and Method 21 instrument types from reference sources, instrument manufacturers, or via the performance of reference factor tests. In accordance with the EPA Protocol, if the response factor of a mixture of gases is below three (3) at 500 ppmv and 10,000 ppmv, the response factors need not be applied unless otherwise desired. If the response factor is above three (3) at either 500 ppmv or 10,000 ppmv, the Method 21 instrument reading should be adjusted using the response factor prior to using the concentration in the Correlation Equations. A response factor curve may be used to account for variability across a range of gas concentrations.

5.4.2 Normalizing Stream Compositions

The O&G Avg. EFs provide estimates of total leak emission rates. In this case, average total organic compound (TOC) emission rates can be calculated using the weight fraction of TOC in the streams, using the following equation:

$$E_{TOC} = F_A \times WF_{TOC}$$

E_{TOC} = Emission rate of TOC from all equipment in the stream of a given equipment type (kg/hr);
F_A = Applicable O&G Avg. EFs for the equipment type (kg/hr/source)
WF_{TOC} = Average Weight Fraction of TOC in the stream

Correlation Equations, Pegged Emission Factors, and Zero-Leak Factors all provide estimates of TOC emission rates.

To estimate VOC and GHG emissions using the calculated TOC emission rate, the process stream composition information must be normalized to remove any non-TOC chemicals (e.g., nitrogen, water, etc.). The example provided in Table 5.4-1 illustrates the stream normalization process.

Table 5.4-1. Example Normalized Stream Composition

Total Stream Composition		TOC Constituents		Normalized TOC Stream	
Propane	30%	Propane	30%	Propane	31.58%
Methane	50%	Methane	50%	Methane	52.63%
Butane	15%	Butane	15%	Butane	15.79%
Carbon Dioxide	5%				
Total =	100%	Total =	95%	Total =	100%
Example Calculation: Propane = 30% * 100%/95% = 31.58%					

Once the stream has been normalized, the normalized individual VOC component concentrations are summed and multiplied by the estimated TOC emission rate to estimate the VOC emission rate. Similarly, the methane emission rate is estimated by multiplying the normalized methane concentration by the TOC emission rate.

In cases where the process stream contains very little hydrocarbon, this normalization process may result in an overestimate of emissions. Engineering judgement will be used to identify process streams that need not be normalized.

5.4.3 Estimating CO_2 Emissions

CO_2 emissions are not accounted for in the TOC emission estimates produced using the O&G Avg. EFs, Correlation Equations, Pegged Emission Factors, and Zero-Leak Factors. As such, CO_2 emissions will need to be calculated in accordance with the following equation:

$$CO_2\ emissions = TOC\ ER * \frac{CO_2\ concentration}{TOC\ concentration}$$

Where:

- TOC ER is the TOC emission rate estimated using the O&G Avg. EFs, Correlation Equations, Pegged Emission Factors, or Zero-Leak Factors, as applicable.
- The CO_2 concentration is the concentration, by weight, of CO_2 in the process stream (5% in the example provided in Table 5.4-1).
- The TOC concentration is the sum of the concentrations, by weight, of all constituents in the process stream that are considered organic compounds (95% in the example provided in Table 5.4-1).

This approach does not apply in streams containing no organic compounds as the denominator in the above equation would be zero. In such cases, the O&G Avg. EFs may be assumed to represent the total leak rate, with CO_2 emissions estimated by multiplying the total leak rate by the concentration, by weight, of CO_2 in the process stream.

6.1 QUALITY ASSURANCE (QA)/QUALITY CONTROL (QC)

The Quality Assurance (QA)/Quality Control (QC) procedures employed by the Export Facility may include the following:

- The development of and adherence to this written LDAR Monitoring Plan (Note: revisions are documented in Appendix G);
- Training of affected/involved personnel as described in Section 6.2 (this is considered a best management practice, not a requirement, as it is not required under TCEQ 28LAER);
- Periodic third-party or internal assessments/audits of the LDAR Monitoring Plan as described in Section 6.4 (this is considered a best management practice, not a requirement, as it is not required under TCEQ 28LAER).

6.2 TRAINING

Two types of training may be performed at or provided by the Export Facility, as described below. This training may be classroom, online, or self-study training.

- General training to inform all personnel who may have an impact on or be affected by the LDAR Monitoring Plan of the general requirements contained therein.
- More detailed training for those personnel actually performing the day-to-day operations of the LDAR Monitoring Plan, including: LDAR contractors, maintenance personnel responsible for compliance with leak repair requirements, environmental staff responsible for oversight, and others, as necessary, based on job responsibilities.

Impacted personnel may be assigned the required training in DECP's Learning Management System (LMS) upon employment or a change in job requiring LDAR training. Note that the training requirements of this LDAR Monitoring Plan are considered a Best Management Practice and are not a regulatory requirement.

6.3 MANAGEMENT OF CHANGE

Management of Change (MOC) at the Export Facility in the context of this LDAR Monitoring Plan involves the updating of this document and ancillary information, such as component inventories, calculation procedures, stream compositions, etc. as changes occur at the Export Facility. The Export Facility will utilize the MOC process in line with standard company procedures. These procedures apply to equipment added or removed from service and the LDAR Monitoring Plan. The specific form includes line items related to additions, deletions, and other changes made to equipment in the LDAR Monitoring Plan. All changes will be evaluated for impacts to the LDAR Monitoring Plan and must be approved by the DECP LDAR Coordinator, Senior Environmental Compliance Coordinator, Director, LNG Operations, and/or other appropriate DECP personnel.

With reference to new and reworked piping connections, TCEQ 28LAER prescribes that gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to initiating or returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being initiated or returned to service. Adjustments shall be made as necessary to obtain leak-free performance.

There are cases where initial monitoring is required for existing components that have a change of service and are now required to be monitored as per the applicable frequency. These components will typically be associated with a specific portion of a process line or plant. For implementing this LDAR Monitoring Plan, a monitoring team will typically work its way through the various sections of the plant by adhering to a schedule that will ensure that every component is monitored as per applicable frequency. It is conceivable that a component will re-enter service after the monitoring team has departed that portion of the plant. In this particular case, it is acceptable that this particular component is not monitored until the monitoring team is scheduled to monitor that portion of the plant again, as long as it is monitored within the next cycle of monitoring, as per applicable frequency.[26]

6.4 LDAR AUDITS

The scope of the LDAR Monitoring Plan assessments/audits at the Export Facility may include, but is not limited to the following:

- Reviewing whether any pieces of equipment that are required to be in the LDAR Monitoring Plan are not included;
- Observing Method 21 instrument calibration and monitoring techniques;
- Observing OGIC daily instrument checks and monitoring techniques;
- Verifying that equipment was monitored at the appropriate frequency, including normal, inaccessible, DTM, and UTM components;
- Analyzing monitoring data and equipment counts (e.g., number of pieces of equipment monitored per day, time between monitoring events) for feasibility and unusual trends;
- Ensuring that repairs have been performed within the required time periods;
- Verifying that proper documentation and sign-offs have been recorded for equipment placed on the DOR list;
- Reviewing the Export Facility's MOC procedures to ensure that LDAR components are being added, deleted, or changed appropriately;
- Verifying that proper calibration records and monitoring instrument maintenance information are maintained;
- Evaluating LDAR Monitoring Plan equipment, software, training records, and workspace resources; and
- Verifying that other LDAR Monitoring Plan records are maintained, as required.

As previously mentioned, assessments/audits of the LDAR Monitoring program are considered a BMP as they are not specifically required by any applicable regulation.

6.5 ELECTRONIC MONITORING AND STORAGE OF DATA

The Export Facility will maintain LDAR monitoring software for collection, management, storage, analysis, and reporting of the LDAR data.

6.6 RECORDKEEPING

[26] Reference – Air Permit Technical Guidance for Chemical Sources Fugitive Guidance, Air Permits Division Texas Commission on Environmental Quality (TCEQ (APDG 6422v1, Revised December 2017)

Records of instrument monitoring will indicate dates, times, name of the person conducting the monitoring, the monitoring and inspection methods employed, and instrument readings. The instrument monitoring record will include the time that monitoring took place for no less than 95% of the instrument readings recorded[27]. OGIC video records, including each daily instrument check, must be kept for five years. Records of AVO inspections shall be noted in the operator's log or an equivalent hardcopy or electronic form and shall be maintained for at least five years. Records of calibration, instrument performance, response factors, and maintenance, as applicable, will be maintained by the LDAR Monitoring Contractor for at least five years. Examples of the types of information that will be recorded are provided in Appendix D.

For any leaks identified during monitoring, the following information will be recorded in the LDAR software by the LDAR Monitoring Contractor for not less than five years from the date of their occurrence:

- The instrument and the component identification numbers and the operator name, initials, or identification number. The SAP notification number should also be recorded, if available.
- If using a Method 21 instrument, the maximum instrument reading.
- The date the leak source was detected and the date of the first attempt to repair. A first attempt is required within 5 days of leaks source identification for all leaks identified by monitoring, for TAP-only and GHG-only leak sources identified via AVO inspection, and 48 hours of leak source identification for a VOC leak identified by AVO inspection.
- If a decision is taken to postpone the first attempt at repair due to safety reasons, the decision will be documented, including the basis for the decision.
- The date of successful repair of the leak.
- Results of remonitoring after the component is successfully repaired or when determined to be non-repairable.
- Indication if the component is given the status of "repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak source. This may be recorded in a DOR list outside of the LDAR software.

Records of repairs shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for components. All component repair records are managed in SAP and electronic records are maintained to demonstrate compliance.

6.7 REPORTING

The Export Facility will incorporate component fugitive emissions data calculated pursuant to this LDAR Monitoring Plan in its rolling 12-month emission calculations and will report this data in quarterly reports to the MDE, as required under the CPCN and PTO. The rolling 12-month emission calculations are compared to Project-wide GHG and VOC limits in CPCN Condition A-III-4. The CPCN does not contain emission limits specific to component fugitive emissions.

A record will be developed by the 15th of each month showing the monthly mass emissions of VOCs and GHGs from fugitive emissions during the prior monthly period. The record will be generated using data from the LDAR monitoring software and validated by the LDAR Monitoring Contractor.

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[27] Reference: TCEQ 28 LAER, Section 1.I.

Starting in 2019, by April 1st of each year DECP shall notify the MDE of any updates to or deviations from this LDAR Monitoring Plan occurring during the previous calendar year unless an alternative reporting schedule is approved by MDE.

6.8 MONITORING PLAN REVISIONS LOG

A log to track all revisions made to this LDAR Monitoring Plan is provided in Appendix G. The controlled copy of this LDAR Monitoring Plan will be managed by the DECP LDAR Coordinator in accordance with the Export Facility's document control procedures. All hardcopies of the LDAR Monitoring Plan are considered uncontrolled. Records and logs may be maintained in hardcopy or electronic form.

As mentioned in Section 6.7, DECP must notify the MDE of any updates to this LDAR Monitoring Plan on an annual basis starting in 2019. This LDAR Monitoring Plan, and any subsequent revisions, are considered final and effective on the date of issuance. DECP will issue revisions to the LDAR Monitoring Plan, incorporating changes requested by MDE, within 90 days of receiving a request for changes.

DEFINITIONS

LDAR Definitions Notes:

- Definitions are taken verbatim from the referenced regulation, unless specified otherwise.
- If a definition varies between or among the different applicable LDAR regulations, each regulatory definition is provided. When definitions are the same in different regulations, each regulation utilizing that definition is referenced in the table.
- Not all potentially applicable definitions are included.
- Regulations identified in the table are the *source* of the definition, which may not be the only regulation for which the definition is applicable.
- Definitions are provided for reference only. Inclusion of a definition herein does not necessarily suggest applicability of the referenced regulation(s).

Legend:

Regulatory Source Definition Legend	
TCEQ	Texas Administrative Code Chapter 115
28LAER	TCEQ's 28LAER Control Efficiencies for TCEQ Leak Detection and Repair Programs
VV	40 CFR Part 60, Subpart VV
KKK	40 CFR Part 60, Subpart KKK
COMAR	Code of Maryland Regulations 26.11.19.16
M21	EPA Method 21 of Appendix A
NA	Non-Regulatory Definition
GHG	Title 40, Chapter I, Subchapter C, Part 98

Term	Definition	Regulatory Source of Definition
Audio, visual, olfactory (AVO)	A method of sensory leak detection that anyone can use to detect the presence of a leak based on sight, sound, and/or smell.	NA
Calibration Drift	The difference in the reading from the initial calibration response to a calibration value after a period of operation during which no maintenance, repair, or adjustment took place (i.e., shift in the instrument's reference point).	NA
Calibration Gas	The VOC compound used to adjust the instrument meter reading to a known value. The calibration gas is usually the reference compound at a known concentration approximately equal to the leak definition concentration.	M21
Calibration Precision	The degree of agreement between measurements of the same known value, expressed as the relative percentage of the average difference between the meter readings and the known concentration to the known concentration.	M21
Connector	A flanged, screwed, or other joined fitting used to connect two pipe lines or a pipe line and a piece of equipment. The term connector does not include joined fittings welded completely around the circumference of the interface. A union connecting two pipes is considered to be one connector.	TCEQ
Component	Equipment which has the potential to leak volatile organic compounds (VOCs), including process equipment, storage tanks, pumps, compressors, valves, flanges and other pipeline fittings, pressure relief valves, process drains, and open-ended pipes.	COMAR
Delay of Repair (DOR)	This targets equipment for which leaks have been identified but cannot be repaired within the 15-day requirement because the repair would require shutting down a process unit or causing an increase in emissions during the repair. Any equipment that is placed on DOR generally must be repaired by the end of the next process unit shutdown in which the leak is located.	NA
Difficult-to-monitor (DTM)	DTM is a component that cannot be inspected without elevating the monitoring personnel more than two meters above a permanent support surface or that requires a permit for confined space entry.	TCEQ
Distance piece	An open or enclosed casing through which the piston rod travels, separating the compressor cylinder from the crankcase.	VV
Double block and bleed system	Two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.	VV
Equipment	Each pump, pressure relief device, open-ended valve or line, valve, agitator, compressor, and flange or other connector.	28LAER
First attempt at repair	To take action for the purpose of stopping or reducing leakage of organic material to the atmosphere using best practices.	VV
Flame Ionization Detector	A flame ionization detector (FID) is a scientific instrument that measures the concentration of organic species in a gas stream using a hydrogen-air flame.	NA

Term	Definition	Regulatory Source of Definition
Fugitive Emissions	Fugitive emissions means those emissions that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.	COMAR
Greenhouse Gas	Means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and other fluorinated greenhouse gases.	GHG
Heavy Liquid	Volatile organic compounds that have a true vapor pressure equal to or less than 0.044 pounds per square inch absolute (0.3 kilopascal) at 68 °F (20 degrees Celsius).	TCEQ
Hydrocarbon	A compound of hydrogen and carbon, such as any of those that are the chief components of petroleum and natural gas.	NA
In vacuum service	Equipment's operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure.	28LAER
Leak	An unintended liquid or vapor release of VOC from a component into the ambient air or into a building.	COMAR
Leak definition concentration	The local VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is present. The leak definition is an instrument meter reading based on a reference compound.	M21
Light Liquids	Volatile organic compounds that have a true vapor pressure greater than 0.044 pounds per square inch absolute (0.3 kilopascal) at 68 degrees Fahrenheit (20 degrees Celsius), and are a liquid at operating conditions.	TCEQ
Liquids dripping	Any visible leakage from the seal including spraying, misting, clouding, and ice formation	VV
Management of Change (MOC)	A procedure used to provide the process for initiating, reviewing, and approving proposed changes within the Export Facility. The procedure is a requirement for covered processes under OSHA 1910.119 and within the Process Safety Code of Responsible Care. This procedure applies to all covered changes that may affect the safety of the community or Export Facility personnel, compliance with laws and regulations, or the quality of the product. It is designed to "manage" the change process and to ensure the impact of a change is properly reviewed and approved before the change is implemented.	NA
National Enforcement Investigation Center (NEIC)	The only environmental forensic center accredited for environmental data measurement activities. The Center has a unique role in conducting complex criminal and civil enforcement investigations and applied research and development to support science for enforcement. (http://www.epa.gov/compliance/neic/index.html)	NA
Natural gas liquids	The hydrocarbons, such as ethane, propane, butane, and pentane, that are extracted from field gas.	KKK
Natural gas processing Facility (gas plant)	Any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.	KKK
Open-ended valve or line	Any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.	VV
Percent Leaking	The percentage of any given equipment type that is found to be leaking according to the leak definition of the applicable regulation. Some regulations allow the frequency of monitoring to vary based on percent leaking performance. For actual calculation, see the TCEQ 28LAER permit.	NA

Term	Definition	Regulatory Source of Definition
Pressure release	The emission of materials resulting from system pressure being greater than set pressure of the pressure relief device.	VV
Process improvement	The smallest set of process equipment that can operate independently and includes all operations necessary to achieve its process objective.	VV
Process unit	Equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.	TCEQ
Process unit shutdown	Shutdown or turnaround- For the purposes of this chapter, a work practice or operational procedure that stops production from a process unit or part of a unit during which time it is technically feasible to clear process material from a process unit or part of a unit consistent with safety constraints, and repairs can be accomplished. The term shutdown or turnaround does not include a work practice that would stop production from a process unit or part of a unit: for less than 24 hours; or for a shorter period of time than would be required to clear the process unit or part of the unit and start up the unit. Operation of a process unit or part of a unit in recycle mode (i.e., process material is circulated, but production does not occur) is not considered shutdown.	TCEQ
Quality assurance/quality control (QA/QC)	Those activities you undertake to demonstrate the accuracy (how close to the real result you are) and precision (how reproducible your results are) of your monitoring. Quality Assurance (QA) generally refers to a broad plan for maintaining quality in all aspects of a program. Quality Control (QC) consists of the steps you will take to determine the validity of specific monitoring procedures.	NA
Quarter	A 3-month period with the first month being of the calendar quarter.	NA
Reciprocating compressor	A piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.	KKK
Reference compound	The VOC species selected as the instrument calibration basis for specification of the leak definition concentration. For the TCEQ 28LAER permit, a leak definition concentration is 500 ppm as methane, so that any source emission that results in a local concentration that yields a meter reading of 500 or greater on an instrument meter calibrated with methane would be classified as a leak. The leak definition concentration is 500 ppm and the reference compound is methane.	M21
Repaired	For the purposes of this subpart, equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in the applicable sections of this subpart and, except for leaks identified in accordance with 40 CFR §§60.482-2(b)(2)(ii) and (d)(6)(ii) and (iii), 60.482-3(f), and 60.48210(f)(1)(ii), is re-monitored as specified in 40 CFR §60.485(b) to verify that emissions from the equipment are below the applicable leak definition.	VV
Replacement cost	The capital needed to purchase all the depreciable components in a Facility.	VV

Term	Definition	Regulatory Source of Definition
Response factor (RF)	The ratio of the known concentration of a VOC compound to the observed meter reading when measured using an instrument calibrated with the reference compound specified in the applicable regulation.	M21
Response time	The time interval from a step change in VOC concentration at the input of the sampling system to the time at which 90 percent of the corresponding final value is reached as displayed on the instrument readout meter.	M21
Rupture Disk	A diaphragm held between flanges for the purpose of isolating a volatile organic compound from the atmosphere or from a downstream pressure relief valve.	TCEQ
Sampling connection system	An assembly of equipment within a process unit used during periods of representative operation to take samples of the process fluid. Equipment used to take non-routine grab samples is not considered a sampling connection system.	VV
Sensor	A device that measures a physical quantity or the change in a physical quantity such as temperature, pressure, flow rate, pH, or liquid level.	VV
Title V permit	Any permit issued, renewed, or revised pursuant to Federal or State regulations established to implement title V of the Act (42 U.S.C. 7661). A title V permit issued by a State permitting authority is called a part 70 permit in this part.	A
Unsafe-to-monitor (UTM)	Classification determined by the owner or operator for certain equipment because monitoring personnel would be exposed to an immediate danger as a consequence of complying with the applicable LDAR monitoring, inspection, and/or repair requirements.	VV
Volatile organic compound (VOC)	For the purposes of this subpart, any reactive organic compounds as defined in 40 CFR §60.2 Definitions, and further clarified in 40 CFR §51.100(s).	EPA/VV

APPENDIX A: OGIC REFERENCE INFORMATION AND DOCUMENTS

Daily Instrument Check Procedure

1. An OGIC performance check will be performed on a daily basis prior to OGIC monitoring surveys, and at other times as needed, in accordance with the following procedure.

2. Start the OGIC according to the manufacturer's instructions, ensuring that all appropriate settings conform to the manufacturer's instructions.

3. After the OGIC start-up process is completed and the OGIC is set to the intended settings, view the viewfinder to ensure that the image is clear. If the image is unclear or grainy, follow proper lens cleaning procedure from the manufacturer, if necessary.

4. Calculate the mass flow rate to be used in the daily instrument check by the following method:
   a. Determine the piece of equipment in contact with the lowest mass fraction of detectable chemicals, within the distance at or below the standard detection sensitivity level.
   b. Multiply the standard detection sensitivity level by the mass fraction of chemicals from the stream to determine the mass flow rate to be used in the daily instrument check using the following equation:

   $$E_{DIC} = (E_{SDS}) \cdot \Sigma(X)$$

   Where:

   E_{DIC} = Mass flow rate for the daily instrument check (grams per hour)
   E_{SDS} = Standard detection sensitivity level from Table 1 to Subpart A, (grams per hour)
   X = Mass fraction of detectable chemical(s) seen by the optical gas imaging instrument, within the operating distance at or below the E_{SDS}.
   c. To determine the daily instrument check mass flow rate for streams with multiple constituents, refer to the memo at the end of this appendix (Appendix A).

5. Prior to the beginning of the monitoring survey, test the OGIC as follows:
   a. As a best management practice, the technician may choose to record ambient air temperature as measured from an onsite temperature gauge or local weather station.
   b. As a best management practice, the technician may choose to record average, estimated local wind speed or the recorded average wind speed from an onsite or local weather station.
   c. Install a regulator on a gas cylinder containing a gas that is visible by the OGIC (e.g., methane or CO2). The regulator flow rate and gas cylinder composition shall be selected to represent the process stream(s) to be surveyed on that day. Place the cylinder in the area where the OGIC monitoring survey will take place or where similar environmental (wind, rain, etc.) conditions exist. If the wind speed increases during the monitoring survey, repeat the OGIC daily verification check.
   d. Set up the OGIC at a distance (D_{max}) from the outlet of the cylinder regulator that is less than or equal to the actual distance between the OGIC and the components that will be encountered during the monitoring survey. Refer to the defined observation path for assistance determining D_{max}.

e. Open the valve on the regulator and set the flow rate to the flow calculated in Step 3 while observing the gas flow through the OGIC instrument viewfinder. When an image of the emission is seen through the viewfinder for a minimum duration of 10 seconds, the OGIC daily verification check is complete.

TORA CONSULTING

Confidential Memorandum

Date:	16 August 2018
To:	Matthew Ballantine – Dominion Energy Cove Point (DECP)
From:	Brandon Mogan, PE – Tora Consulting LLC
Subject:	Determining the Mass Flow Rate for Daily Instrumentation Check

BACKGROUND

Dominion Energy Cove Point (DECP) is using the Alternative Work Practice (AWP) for leak monitoring at the liquefaction facility. At a selected detection sensitivity level of 60 grams per hour, the AWP requires bi-monthly monitoring using an optical gas imaging camera (OGIC). Prior to each monitoring day when the OGIC is used, monitoring personnel must perform a daily instrument check following the procedure in Appendix A of the Leak Detection and Repair (LDAR) Monitoring Plan. During the daily instrument check, personnel use the OGIC to observe gas being emitted from a pressurized gas cylinder at a mass flow rate equal to or less than the rate calculated using the procedures in 40 CFR §60.18(i)(2)(i), which are incorporated into Appendix A of the LDAR Monitoring Plan.

The purpose of this memorandum is to document the mass flow rates from gas cylinders of varying composition and equipped with varying flow regulators.

DETERMINATION OF MASS FLOW RATE FOR DAILY INSTRUMENT CHECKS

The mass flow rate emitted from a gas cylinder equipped with a flow regulator can be calculated using the ideal gas law (Equation 1).

$$P \times V = \frac{mass}{MW} \times R \times T \qquad \text{(Equation1)}$$

Where,

P =	Pressure (atm)
V =	Volume (l)
mass =	mass of CH_4 (g)
MW =	Molecular weight of CH4 (g/mol).
R =	Gas Constant $\left(\frac{atm \times l}{mol \times K}\right)$
T =	Temperature (K)

Dividing Equation 1 by time (t), gives:

$$P \times Q = \frac{M}{MW} \times R \times T \quad \text{(Equation 2)}$$

Where,

Q =	Volumetric Flow Rate (l/hr)
M =	Mass Flow Rate (g/hr)

Rearranging Equation 2 to solve for mass flow rate (M) results in:

$$M = \frac{P \times Q \times MW}{R \times T} \quad \text{(Equation 3)}$$

The results of these calculations for various methane (CH_4) and carbon dioxide (CO_2) gas cylinder compositions and volumetric flow rates are summarized in Table 1.

Calculations have been performed to determine the maximum allowable daily instrument check mass flow rates for all process streams identified in the heat and material balance. These calculations are included in the version of the HMB provided to Dominion by Geosyntec (dated 17 April 2018). A summary of these calculated mass flow rates is included herewith as Table 2.

The calculations summarized in Table 1 indicate that a daily instrument check performed using a 100% pure CH_4 gas cylinder with a 0.5 l/min flow regulator would be valid for all process streams where the requisite hydrocarbon mass flow rate is equal to or greater than 20 g/hr. The only non-exempt process streams with a required hydrocarbon mass flow rate less than 20 g/hr, based on the Geosyntec HMB, are: 14 (Amine Regen OH), 17 (Amine Reboiler Vapor), 22 (Acid Gas to Blower), 23 (SRU Effluent to Thermal Oxidizer), and 59 (GT Exhaust). Of these, the stream with the lowest mass fraction of CO_2 is 17 (Amine Reboiler Vapor), with a calculated maximum daily instrument check mass flow rate of 3.89 g/hr CO_2. DECP could utilize a FLIR GF343 (CO2 OGIC) to monitor these streams. According to the data in Table 1, CO2 cylinder composition and regulator combinations that would be sufficient for streams 14, 17, 22, 23, and 59 include but are not limited to: a 35% CO2 gas cylinder equipped with a 0.1 l/min flow regulator and a 6% CO2 gas cylinder equipped with a 0.5 l/min regulator.

Table 1: CH_4 and CO_2 Mass Flow Rates For Various Gas Cylinders

Gas		CH4	CO2				
Concentration		100%	100%	50%	35%	25%	7%
Flow Rate (Q)		Mass Flow (M)	Mass Flow (M)				
(l/min)	(l/hr)	(g/hr)	(g/hr)				
0	**0**	0.00	0.00	0.00	0.00	0.00	0.00
0.1	**6**	4.00	10.98	5.49	3.84	2.74	0.66
0.25	**15**	10.00	27.44	13.72	9.61	6.86	1.65
0.5	**30**	20.01	54.89	27.44	19.21	13.72	3.29
0.75	**45**	30.01	82.33	41.17	28.82	20.58	4.94
1	**60**	40.01	109.78	54.89	38.42	27.44	6.59
1.25	**75**	50.01	137.22	68.61	48.03	34.31	8.23
1.5	**90**	60.02	164.67	82.33	57.63	41.17	9.88
1.75	**105**	70.02	192.11	96.06	67.24	48.03	11.53
2	**120**	80.02	219.56	109.78	76.85	54.89	13.17
2.25	**135**	90.02	247.00	123.50	86.45	61.75	14.82
2.5	**150**	100.03	274.45	137.22	96.06	68.61	16.47
2.75	**165**	110.03	301.89	150.95	105.66	75.47	18.11
3	**180**	120.03	329.34	164.67	115.27	82.33	19.76
3.25	**195**	130.03	356.78	178.39	124.87	89.20	21.41
3.5	**210**	140.04	384.23	192.11	134.48	96.06	23.05
3.75	**225**	150.04	411.67	205.84	144.08	102.92	24.70

TABLE 2: Maximum Daily Instrument Check Flow Rates From Geosyntec HMB

Stream No.	Stream Name	Maximum Flow Rate for TOC (e.g., when using GF320 camera) (TOC * Detection Sensitivity)	Maximum Flow Rate for CO2 (e.g., when using GF343 camera) (CO2 * Detection Sensitivity)
1	Feed Gas at B/L	55.56	2.96
2	Heated Feed Gas	55.56	2.96
3	HP Makeup Fuel Gas	55.56	2.96
4	Feed to Pretreat- ment	55.56	2.96
5	Demer-curizer Feed	55.56	2.96
6	AGRU Feed	55.56	2.96
7	Sweet Gas	58.34	0.00
8	Cooled Sweet Gas	58.35	0.00
9	Sweet Gas Conden- sate	EXEMPT	EXEMPT
10	Dehydra-tion Filter Separator Feed	58.40	0.00
11	AGRU Flash Gas	55.53	1.62
12	Flashed Rich Amine	EXEMPT	EXEMPT
13	Heated Rich Amine	27.96	4.76
14	Amine Regen OH	0.07	43.70
15	Amine Regen Reflux	EXEMPT	EXEMPT
16	Amine Reboiler Feed	EXEMPT	EXEMPT
17	Amine Reboiler Vapor	0.69	3.89
18	Lean Amine (Regen Btm)	EXEMPT	EXEMPT
19	Lean Amine (from HX)	EXEMPT	EXEMPT
20	Lean Amine (to filters)	EXEMPT	EXEMPT
21	Lean Amine (to Absorber)	EXEMPT	EXEMPT
22	Acid Gas to Blower	0.10	58.94
23	SRU Effluent to Thermal Oxidizer	0.10	58.95
50	BOG from Existing Facility (Note 2)	48.07	0.00
51	Heated BOG (Note 2)	48.07	0.00
52	LP Fuel Gas from KO Drum (Note 2)	41.37	0.00
53	LP Fuel Gas to Users (Note 2)	41.37	0.00
54	Fuel Gas Compres-sor Suction (Note 2)	41.37	0.00
55	Stabilizer OH to Fuel Gas Comp.	59.98	0.02
56	Fuel Gas Compres- sor Disch. (Note 2)	42.85	0.00
57	HP Makeup Fuel after letdown (Note 2)	55.56	2.96
58	Fuel Gas to Gas Turbines (Note 2)	47.42	1.07
59	GT Exhaust	0.00	4.87
60	Fuel gas to Flare Pilot	55.56	2.96
101	Feed to HRU (APCI, Note 1)	58.45	0.01
103	Rich Gas from 5E507	58.45	0.01
104	HRU Separator Vapor	58.42	0.01
105	HRU Separator Liquid	59.89	0.00
107	HRU Reflux Feed	58.42	0.01
115	Lean Gas Booster Comp Feed	58.41	0.01

Stream No.	Stream Name	Maximum Flow Rate for TOC (e.g., when using GF320 camera) (TOC * Detection Sensitivity)	Maximum Flow Rate for CO2 (e.g., when using GF343 camera) (CO2 * Detection Sensitivity)
116	NG Feed to MCHE	58.43	0.01
117	Booster Comp Feed	EXEMPT	EXEMPT
121	Lean Gas Booster Compr Discharge	58.41	0.01
122	HRU Side Reboiler Feed	59.99	0.01
123	HRU Side Reboiler Effluent	59.99	0.01
124	HRU Bottoms	60.00	0.00
126	Stabilizer OH Liquid	60.00	0.00
127	Stabilizer OH to Fuel	59.98	0.02
130	Stabilized NGL Conden- sate	60.00	0.00
132	Rich Gas from 5E523	58.45	0.01
133	CH4 Makeup to MR	58.41	0.01
134	HRU OH	58.41	0.01
135	HRU Turbo Exp Disch.	58.42	0.01
136	Feed Gas to C3 Chillers	58.43	0.01
137	HRU Reboiler Inlet	59.99	0.01
138	HRU Reboiler Effluent	59.99	0.01
139	Stabilizer Reboiler Inlet	60.00	0.00
140V	Stabilizer Reboiler Vapor Effluent	60.00	0.00
140L	Stabilizer Reboiler Liquid Effluent	60.00	0.00
141	Stabilizer OH	60.00	0.00
142	Stabilizer Reflux Drum Inlet	60.00	0.00
154	LNG Exit MCHE	58.43	0.01
156	N2 Stripper Feed	58.43	0.01
158	N2 Stripper Reboiler Inlet	59.13	0.01
159	N2 Stripper Reboiler Outlet	59.07	0.01
160	LNG Product to Storage	59.50	0.01
170	N2 Stripper OH	38.42	0.00
171	End Flash Gas to Fuel	38.42	0.00
201	MR Return from MCHE	57.54	0.00
202	Combined MR Makeup	57.54	0.00
204	LP MR Comp A Suction	57.54	0.00
207	MP MR Comp A Suction (Note 5)	57.54	0.00
211	HP MR Comp A Suction (Note 5)	57.54	0.00
214	HP MR Comp A Discharge (Note 5)	57.54	0.00
217	MR Comp A Losses (Note 5)	57.54	0.00
219	MR to HHP C3 Cooler	57.54	0.00
220	MR to HP C3 Cooler	57.53	0.00
221	MR to MP C3 Cooler	57.50	0.00
222	MR to LP C3 Cooler	57.46	0.00
223	MR To MR Separator	57.42	0.00
225	MRV to MCHE Bottom	52.40	0.00
227	MRL to MCHE Bottom	58.95	0.00

Stream No.	Stream Name	Maximum Flow Rate for TOC (e.g., when using GF320 camera) (TOC * Detection Sensitivity)	Maximum Flow Rate for CO2 (e.g., when using GF343 camera) (CO2 * Detection Sensitivity)
230	MRV to Flash Gas Exchanger	52.40	0.00
231	MRV from Flash Gas Exchanger	52.40	0.00
250	MRL to MR Expander	58.95	0.00
301	C3 Comp A Dicharge (Note 4)	60.00	0.00
302	C3 Comp A Losses	60.00	0.00
305	C3 Cond Inlet (Note 4)	60.00	0.00
306	C3 Cond Outlet (Note 4)	60.00	0.00
310	C3 Subcooler Outlet (Note 4)	60.00	0.00
311	C3 to 5E514 LC Valve (Note 4)	60.00	0.00
312	C3 to 5E514 (Note 4)	60.00	0.00
314	C3 Liquid from 5E514 (Note 4)	60.00	0.00
315	C3 Vapor from 5E514 (Note 4)	60.00	0.00
316	C3 to 5E515 (Note 4)	60.00	0.00
317	C3 Vapor from 5E515 (Note 4)	60.00	0.00
318	C3 Liquid from 5E515	60.00	0.00
320	C3 to 5E516	60.00	0.00
321	C3 Vapor from 5E516	60.00	0.00
323	C3 Liquid from 5E516	60.00	0.00
324	C3 to 5E517	60.00	0.00
325	C3 Vapor from 5E517	60.00	0.00
326	C3 to BOG Heater (Note 4)	60.00	0.00
330	C3 to 5E501 LC Valve	60.00	0.00
331	C3 to 5E501	60.00	0.00
334	C3 Vapor from 5E501	60.00	0.00
335	C3 Liquid from 5E501	60.00	0.00
336	C3 to 5E502	60.00	0.00
337	C3 Vapor from 5E502	60.00	0.00
339	C3 Liquid from 5E502	60.00	0.00
340	C3 to 5E503	60.00	0.00
341	C3 Vapor from 5E503	60.00	0.00
343	C3 Liquid from 5E503	60.00	0.00
344	C3 to 5E504	60.00	0.00
345	C3 Vapor from 5E504	60.00	0.00
378	C3 Makeup	60.00	0.00
381	LP C3 Comp A Suction	60.00	0.00
382	MP C3 Comp A Suction	60.00	0.00
385	HP C3 Comp A Suction (Note 4)	60.00	0.00
388	HHP C3 Comp A Suction (Note 4)	60.00	0.00
HHCA	Heavy Hydrocarbon with Amine	EXEMPT	EXEMPT
GLYW	Water/Glycol Stream	EXEMPT	EXEMPT
LPF	Low Pressure Flare	55.33	2.40
HPF	High Pressure Flare	56.57	1.29

Stream No.	Stream Name	Maximum Flow Rate for TOC (e.g., when using GF320 camera) (TOC * Detection Sensitivity)	Maximum Flow Rate for CO2 (e.g., when using GF343 camera) (CO2 * Detection Sensitivity)
CF	Cold Flare	58.51	0.26

APPENDIX B: METHOD 21 REFERENCE INFORMATION AND DOCUMENTS

Instrument Calibration Procedure

1. Visually inspect filters. Clean and replace, as needed.
2. Verify that filters are in place, clean, and not damaged.
3. Make sure connections, both sample line and electrical, are secure and not damaged. It is important that the sample line connections are tightened.
4. Check that the detector cap and flame arrestor are in place, if applicable.
5. Ensure that the battery is adequately charged. Refer to instrument manufacturer's specifications for the appropriate charge and how to determine the charge. (For FIDs: Ensure there is sufficient hydrogen supply (>1,500 psi preferably). Do not calibrate when the hydrogen is <500 psi.)
6. Turn on the pump and the detector.
7. Perform a quick qualitative leak check by briefly blocking the probe tip with a finger. Listen for the sound of the pump to indicate the need for air or allow the pump to come to a near stop and then release finger. If the sound of the pump doesn't change or if the pump doesn't stop, this indicates that there may be a leak, or the probe fittings aren't tight.
8. Allow the instrument to warm up per manufacturer's specifications. Performing zero air warm up may be done with a zero air gas cylinder if there is concern about target gases in the ambient environment and is recommended, but not required for daily calibrations.
9. Prepare the calibration gases for use. Gases must be certified to ± 2% accuracy of the requested ppmv value and not past their expiration date.
10. If using sample bags, make sure each bag is completely empty and then fill it to no more than 90% of the bag capacity with fresh calibration gas prior to each calibration.
11. Once the warm-up period is complete, calibrate using the manufacturer's specific instructions using the zero air and the selected methane/air standard(s). Using zero gas between the different calibration gases is recommended to clear the instrument of calibration gas between calibration points, but is not a requirement. Allow sufficient duration during calibration to ensure each calibration is cleared before placing next gas in line for calibration.
12. Record calibration gas lot numbers, expiration dates, and other information contained on the calibration record.
13. If the calibration fails, as indicated by the meter, do not perform monitoring. Troubleshoot the cause. Monitoring will not be done with the meter until a passing calibration is obtained.

Performance Evaluation Procedure - Calibration Precision Test

1. Perform the calibration precision test prior to placing an instrument in service, whenever maintenance is performed on the instrument, and at subsequent 3-month intervals.
2. Complete the calibration procedure.
3. Perform this evaluation with the 500 ppmv calibration gas.
4. Introduce the zero gas into the instrument at the probe tip.
5. Once the instrument response has stabilized, quickly introduce the 500 ppmv calibration gas into the instrument at the probe tip.
6. Allow the instrument to stabilize to the 500 ppmv calibration gas.
7. Record the stable instrument response to the calibration gas on the performance evaluation form.
8. Perform steps 4 through 6 with the 500 ppmv calibration gas for a total of three times.
9. Subtract each actual calibration gas value from each stable instrument response and record this value. If a negative actual is calculated, record the reading as a positive value (i.e., take the absolute value).
10. Average the three absolute value differences for the calibration gas vs. instrument reading and record this value.
11. Divide the average difference by the actual calibration gas value and multiply by 100 to obtain the calibration precision as a percentage. The calibration precision is required to be within ±10% per EPA Method 21.
12. Perform steps 4 through 11 with the 10,000 ppmv calibration gas rather than 500 ppmv calibration gas, if necessary, based on the required leak definition utilized.

Performance Evaluation Procedure - Response Time Test

1. Perform the response time test prior to placing an instrument in service and any time changes or maintenance is performed on the instrument pump or a probe extension is added/changed.
2. Complete the calibration procedure.
3. Perform this evaluation with the 500 ppmv calibration gas.
4. Introduce the zero gas into the instrument at the probe tip.
5. Once the instrument response has stabilized to approximately zero, quickly introduce the 500 ppmv calibration gas into the instrument at the probe tip.
6. Measure the time required to attain 90% of the final stable reading (or 450 ppmv).
7. Record this time on the performance evaluation form. This is the response time.
8. Perform steps 4 through 7 with the 500 ppmv calibration gas for a total of three times.
9. Average the three response times for the calibration gas and record this value. The average response time is required to be equal to or less than 30 seconds per EPA Method 21.
10. Perform steps 4 through 9 with the 10,000 ppmv calibration gas rather than 500 ppmv calibration gas, if necessary, based on the required leak definition utilized.
11. If an extension probe will be used periodically, perform this entire procedure again with the probe attached as if performing the procedure for a separate instrument.

Response Factor Test

1. Complete the calibration procedure.
2. Introduce the calibration gas mixture to the analyzer at the probe tip and record the observed meter reading.
3. Introduce the zero gas into the instrument at the probe tip.
4. Once the instrument response has stabilized, reintroduce the calibration gas into the instrument at the probe tip and record the observed meter reading.
5. Make a total of three measurements by alternating between the calibration gas and zero gas.
6. Calculate the response factor for each repetition by taking the actual concentration of the calibration gas and dividing it by the instrument reading. Average the response factors from each repetition to get the response factor for the calibration gas.
7. The response factor shall be less than 10.
8. For Process Streams/Mixtures:

   a. Repeat steps 2 through 7 for each VOC to be measured within the process stream.
   b. Each response factor shall be less than 10 for each individual VOC to be measured. If Response factor of any individual VOC is greater than 10, then calculate the response factor of the mixture.
   c. To find the response factor for a specific process stream or gas mixture, use the following equation:

$$RF_m = \frac{1}{\sum_{i=1}^{n}\left(\frac{x_i}{RF_i}\right)}$$

Where:

RF_m=Response factor of the process stream;
n=Number of components in the mixture;
x_i=Mole fraction of constituent i in the mixture;
RF_i=Response factor of constituent i in the mixture.

Note: If response factors have been published for the compounds of interest for the instrument or detector type, the response factor determination is not required, and existing results may be referenced.

Calibration Drift Assessment

1. Prepare the certified 500 ppmv calibration gas for use.
2. Without making any adjustments or recalibrations of the instrument, introduce the gas at the probe tip until a stable instrument response is obtained.
3. Record the stable instrument response. Take off the calibration gas and introduce zero gas at the probe tip.
4. Repeat steps 2 and 3 two more times recording each reading.
5. Average the three readings.
6. Calculate the calibration drift for the average response as shown below:

$$CD = ((C_F - C_I) \div C_I) \times 100$$

Where:

CD = Calibration Drift (%)
C_F = Final Calibration Value (ppmv) from Step 3 of the calibration drift assessment procedure
C_I = Initial Calibration Value (ppmv) from daily calibration performed at the beginning of the monitoring shift
100 = Percentage conversion factor

7. If the calculated calibration drift for any of the calibration gases shows a negative drift of more than 10%, perform some or all of the following:
   a. All connections and ensure the probe is tightly secured.
   b. Check and clean filters. Replace filters if necessary.
   c. Check the probe for cleanliness and use pipe cleaner to clean the probe tip.
   d. Check the sample line for signs of contamination and damage, especially near the connection at the instrument.
   e. Check the battery level and plug instrument in if low.
   f. Check the hydrogen supply and refill if low.
   g. Repeat Steps 2 through 6 after making adjustments.
8. If the calculated calibration drift still shows a negative drift of more than 10% following Step 5, re-monitor in accordance with section 9 and 10 below equipment that was monitored since the last daily calibration or a successful calibration drift assessment.
9. If there is a negative drift of more than 10%, record the drift result and perform re-monitoring for any component with a Method 21 reading within the calibration drift percentage of the applicable leak threshold (i.e., for a leak definition of 500 ppmv and a calibration drift of 10%, re-monitor all components measured at 450 to 499 ppmv). After completing the necessary re-monitoring, make a note on the calibration record showing that the necessary equipment was re-monitored.
10. If there is a positive drift, record the drift result on the calibration record. Re-monitoring is not required because results in the field would have been biased too high. However, re-monitoring may be warranted to ensure over reporting of leaks does not occur. If re-monitoring is conducted, note on the calibration record that the re-monitoring was conducted.

APPENDIX C: EMISSION CALCULATION INFORMATION

Oil & Gas Average Emission Factors Table (EPA-453/R-95-017 Page 2-15)

TABLE 2-4. OIL AND GAS PRODUCTION OPERATIONS AVERAGE EMISSION FACTORS (kg/hr/source)

Equipment Type	Service[a]	Emission Factor (kg/hr/source)[b]
Valves	Gas	4.5E-03
	Heavy Oil	8.4E-06
	Light Oil	2.5E-03
	Water/Oil	9.8E-05
Pump seals	Gas	2.4E-03
	Heavy Oil	NA
	Light Oil	1.3E-02
	Water/Oil	2.4E-05
Others[c]	Gas	8.8E-03
	Heavy Oil	3.2E-05
	Light Oil	7.5E-03
	Water/Oil	1.4E-02
Connectors	Gas	2.0E-04
	Heavy Oil	7.5E-06
	Light Oil	2.1E-04
	Water/Oil	1.1E-04
Flanges	Gas	3.9E-04
	Heavy Oil	3.9E-07
	Light Oil	1.1E-04
	Water/Oil	2.9E-06
Open-ended lines	Gas	2.0E-03
	Heavy Oil	1.4E-04
	Light Oil	1.4E-03
	Water/Oil	2.5E-04

[a] Water/Oil emission factors apply to water streams in oil service with a water content greater than 50%, from the point of origin to the point where the water content reaches 99%. For water streams with a water content greater than 99%, the emission rate is considered negligible.

[b] These factors are for total organic compound emission rates (including non-VOC's such as methane and ethane) and apply to light crude, heavy crude, gas plant, gas production, and off shore facilities. "NA" indicates that not enough data were available to develop the indicated emission factor.

[c] The "other" equipment type was derived from compressors, diaphrams, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, relief valves, and vents. This "other" equipment type should be applied for any equipment type other than connectors, flanges, open-ended lines, pumps, or valves.

Petroleum Industry Emission Factor Table for Screening Value Correlations (EPA-453/R-95-017 Page 2-27)

TABLE 2-10. PETROLEUM INDUSTRY LEAK RATE/SCREENING VALUE CORRELATIONS[a]

Equipment type/service	Correlation[b,c]
Valves/all	Leak rate (kg/hr) = 2.29E-06 × $(SV)^{0.746}$
Pump seals/all	Leak rate (kg/hr) = 5.03E-05 × $(SV)^{0.610}$
Others[d]	Leak rate (kg/hr) = 1.36E-05 × $(SV)^{0.589}$
Connectors/all	Leak rate (kg/hr) = 1.53E-06 × $(SV)^{0.735}$
Flanges/all	Leak rate (kg/hr) = 4.61E-06 × $(SV)^{0.703}$
Open-ended lines/all	Leak rate (kg/hr) = 2.20E-06 × $(SV)^{0.704}$

[a]The correlations presented in this table are revised petroleum industry correlations.

[b]SV = Screening value in ppmv.

[c]These correlations predict total organic compound emission rates (including non-VOC's such as methane and ethane).

[d]The "other" equipment type was derived from instruments, loading arms, pressure relief valves, stuffing boxes, and vents. This "other" equipment type should be applied to any equipment type other than connectors, flanges, open-ended lines, pumps, or valves.

Petroleum Industry Emission Factor Table for Pegged Screening Values (EPA-453/R-95-017 Page 2-37)

TABLE 2-14. 10,000 ppmv and 100,000 PPMV SCREENING VALUE PEGGED EMISSION RATES FOR THE PETROLEUM INDUSTRY

Equipment type/service	10,000 ppmv pegged emission rate (kg/hr/source)[a,b]	100,000 ppmv pegged emission rate (kg/hr/source)[a]
Valves/all	0.064	0.140
Pump seals/all	0.074	0.160[c]
Others[d]/all	0.073	0.110
Connectors/all	0.028	0.030
Flanges/all	0.085	0.084
Open-ended lines/all	0.030	0.079

[a]The petroleum industry pegged emission rates are for total organic compounds (including non-VOC's such as methane and ethane).

[b]The 10,000 ppmv pegged emission rate applies only when a dilution probe cannot be used or in the case of previously-collected data that contained screening values reported pegged at 10,000 ppmv. The 10,000 ppmv pegged emission rate was based on components screened at greater than or equal to 10,000 ppmv; however, in some cases, most of the data could have come from components screened at greater than 100,000 ppmv, thereby resulting in similar pegged emission rates for both the 10,000 and 100,000 pegged levels (e.g., connector and flanges).

[c]Only 2 data points were available for the pump seal 100,000 pegged emission rate; therefore the ratio of the pump seal 10,000 pegged emission rate to the overall 10,000 ppmv pegged emission rate was multiplied by the overall 10,000 ppmv pegged emission rate to approximate the pump 100,000 ppmv pegged emission rate.

[d]The "other" equipment type was developed from instruments, loading arms, pressure relief valves, stuffing boxes, vents, compressors, dump lever arms, diaphrams, drains, hatches, meters, and polished rods. This "other" equipment type should be applied to any equipment type other than connectors, flanges, open-ended lines, pumps, and valves.

TCEQ 28 LAER Control Efficiencies (TCEQ Air Permit Technical Guidance for Chemical Sources: Fugitive Guidance)

Table V: Control Efficiencies for LDAR

Equipment/Service	28M	28RCT	28VHP	28MID	28LAER	28CNTQ	28CNTA	28PI	28AVO[9]
Valves[1]									97%
Gas/Vapor	75%	97%	97%	97%	97%			30%	
Light Liquid	75%	97%	97%	97%	97%			30%	
Heavy Liquid[5]	0%[5]	0%[5]	0%[6]	0%[5]	30%[6, 8]			30%[8]	
Pumps[1]									93%
Light Liquid	75%	75%	85%	93%	93%			30%	
Heavy Liquid[5]	0%	0%[7]	0%[7]	0%[8, 10]	30%[8]			30%[8]	
Flanges/Connectors[1]	30%	30%	30%	30%				30%	97%
Gas/Vapor					97%	97%	75%		
Light Liquid					97%	97%	75%		
Heavy Liquid[5]					30%	30%	30%		
Compressors[1]	75%	75%	85%	95%	95%			30%	95%
Relief Valves[1, 2] (Gas/Vapor)	75%	97%	97%	97%	97%			30%	97%
Sampling Connection[3] (pounds per hour per sample taken)	0%	0%	0%	0%	0%			0%	0%
Open Ended Lines[1, 4]									

It should be noted in the application and added to the permit conditions if any of the footnotes are applicable. For example, if components in heavy liquid service are monitored, then the application should include the monitored concentration and the concentration of saturation, in ppmv and such monitoring will be added as a separate condition.

Endnotes Table V

1. **Control efficiencies apply only to components that are actually monitored. Control efficiencies do not apply to components that are difficult or unsafe-to-monitor on the standard schedule. However, difficult-to-monitor gas or light liquid valves under the 28RCT, 28VHP, 28MID, or 28LAER programs that are monitored once per year may apply a 75% reduction credit.**
2. **100% control may be taken if a relief valve vents to an operating control device or if it is equipped with a rupture disc and a pressure-sensing device between the valve and disc to monitor for disc integrity. For new facilities, BACT guidelines generally require that all relief valves vent to a control device. When there are safety reasons that the relief valve cannot achieve 100% control, the relief valve can be monitored under the LDAR programs for the credit listed. This monitoring must be performed regardless of whether the relief valve is considered accessible, difficult-to-monitor or unsafe-to-monitor. Relief valves that do not achieve 100% control should not be built in locations that are unsafe-to-monitor.**
3. **Sampling connection control efficiencies are covered under other equipment and services. Sampling emissions are based on the number of samples taken per year as opposed to the number of connections. Fugitives for a closed loop sampling system are based on the component count.**
4. **Good design criteria for special chemicals handling and most LDAR programs require open-ended lines to be equipped with an appropriately sized cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit. Regardless of the lines given 100% credit, these lines should be mentioned in permit applications. Exceptions to the LDAR program criteria may be made for safety reasons with the approval of TCEQ management.**

EPA Protocol Control Efficiencies (EPA-453/R-95-017 Page 5-3)

TABLE 5-1. SUMMARY OF EQUIPMENT MODIFICATIONS

Equipment type	Modification	Approximate control efficiency (%)
Pumps	Sealless design	100[a]
	Closed-vent system	90[b]
	Dual mechanical seal with barrier fluid maintained at a higher pressure than the pumped fluid	100
Compressors	Closed-vent system	90[b]
	Dual mechanical seal with barrier fluid maintained at a higher pressure than the compressed gas	100
Pressure relief devices	Closed-vent system	c
	Rupture disk assembly	100
Valves	Sealless design	100[a]
Connectors	Weld together	100
Open-ended lines	Blind, cap, plug, or second valve	100
Sampling connections	Closed-loop sampling	100

[a]Sealless equipment can be a large source of emissions in the event of equipment failure.

[b]Actual efficiency of a closed-vent system depends on percentage of vapors collected and efficiency of control device to which the vapors are routed.

[c]Control efficiency of closed vent-systems installed on a pressure relief device may be lower than other closed-vent systems, because they must be designed to handle both potentially large and small volumes of vapor.

APPENDIX D: TYPES OF INFORMATION TO BE RECORDED

The following records associated with the LDAR Monitoring Program will be maintained in hardcopy or electronic form. Electronic records will be maintained in the LDAR Monitoring Database or other electronic systems:

- Records of the daily instrument checks and calibration drift results:
    - Instrument type (OGIC or M21) and make/model.
    - Test type, such as Daily Calibration, Calibration Precision Test, Response Time and Factor Test, and Calibration Drift Test.
    - Type of test gas, test gas concentration, and cylinder ID and expiration date.
    - Time of test,
    - Result of test, and
    - Other comments.
- AVO inspections:
    - Date and time that the AVO inspection was performed.
    - Name of the individual performing the AVO inspection.
    - Description of the area(s) included in the AVO inspection.
    - If a leak is found during the AVO inspection:
        - Date and Time the leak was found.
        - Name of the individual who found the leak.
        - LDAR ID (or other identifying information) and description of the leak location.

- Method 21 and OGIC monitoring:
    - For annual or quarterly (where required) Method 21 monitoring:
        - The LDAR ID of each component monitored.
        - The Method 21 measured concentration, in ppmv, for each component monitored.
        - If adjusting for background (optional), the background concentration reading, in ppmv, for each component monitored (if and when applicable).
    - For all monitoring:
        - The type of monitoring instrument used (e.g., OGIC, CO_2 OGIC, M21).
        - Make/model of the instrument used.
        - Name of personnel performing the monitoring.
        - Date of monitoring event.
        - Any deviations from the LDAR Monitoring Plan.
    - For all OGIC monitoring:
        - Complete video record of each monitoring event and daily instrument check.
    - When a leak is identified:
        - Date and time the leak was identified.
        - The type of equipment used to identify the leak.
        - The LDAR ID and/or other identifying information and description of the leak location.
    - For each repair attempt:
        - Date of repair attempt.
        - Methods employed to affect the repair.
        - Methods used to verify the success of the repair attempt (e.g., OGIC, M21 Soap Bubble Test, etc.) and the associated result.
        - Date of component remonitoring that verifies the repair was successful.

- Information on DOR components will be maintained in the LDAR Monitoring Database or other electronic recordkeeping system:
  - The LDAR ID and/or other identifying information (Component ID, SAP Notification, etc.).
  - Name of person approving the DOR.
  - Date that the component was placed on DOR.
  - Date of the next scheduled shutdown of the gas circuit.
  - Documentation of the analysis performed to determine whether emissions from leaking components within a gas circuit exceed emissions from gas circuit shutdown.
  - Records of correspondence with MDE related to DOR.

- A list of DTM and UTM components will be maintained within the LDAR Monitoring Database:
  - LDAR ID and/or other identifying information.
  - Whether component is DTM or UTM.
  - Justification for DTM or UTM designation.

- A list of components that are exempt from the monitoring requirements of this plan (e.g., in vacuum service, in heavy liquid service). The list shall include the LDAR ID and basis for exemption.

- A list of components that are exempt from calculation requirements because they are in liquid service and the liquid contains VOC with an aggregate partial pressure or vapor pressure of less than 0.002 psia at 68 °F.

APPENDIX E: AVO INSPECTION AND REPAIR PROCEDURES

AVO Inspections, and repair of leaking components identified during AVO inspections, will be performed in accordance with the following procedures:

- AVO inspections will be documented in electronic or hardcopy forms or logs. Records to be maintained are included in Appendix D of this LDAR Monitoring Plan.
- AVO inspections can be performed by the LDAR Monitoring Contractor or Designated Operations Personnel familiar with and trained in the LDAR Monitoring Plan.
- During an AVO inspection:
    - Observe components that may have visible leakage including dripping, spraying, misting, clouding, puddling, or staining. Observe all necessary safety practices and do not enter an area if you suspect a hazardous condition due to a leak.
    - Listen for abnormal hissing or other sounds that may indicate a leak. Do not remove any required hearing protection.
    - Use the olfactory senses to detect abnormal odors that may indicate a leak of process fluids. Olfactory observations should be performed in the course of normal breathing.

- A leak notification tag shall be attached to leaking components identified during an AVO inspection (see Section 4.1).
- All completed AVO inspections will be documented and such documentation will be filed electronically or in hardcopy form and the DECP LDAR Coordinator will review them periodically.
- The Operations personnel or the DECP LDAR Coordinator or their designee will generate an SAP notification to track repairs for all components identified as leaking and they will be identified in the notification based on component ID and/or location.
- A work order will be generated in SAP for each leak identified during an AVO inspection based on the notification. The SAP work order(s) will be assigned to the appropriate maintenance personnel.
- Maintenance personnel may coordinate with the LDAR Monitoring Contractor to have the leaking component monitored with a Method 21 instrument or OGIC prior to, during, and/or after repair attempts for the purposes of assessing the leak concentration (if applicable) and/or verifying the success of the repair.
- After successful repair, maintenance personnel will close the work order. Information to be included in work history should include a description of work performed to repair the leak and the leak monitoring results following repair.
- Maintenance will close the SAP work order, record the completion of the repair, and provide a copy of the completed work order to the LDAR Monitoring Contractor.
- The LDAR Monitoring Contractor will document the leak and associated repair(s) within the LDAR Monitoring Database.
- The DECP LDAR Coordinator will maintain a hardcopy or electronic log that includes the name of the person conducting each inspection, the date on which leak inspections are made, the findings of the inspections, and a list of leaks by tag identification number. The log shall be made available to regulatory agencies upon request.

Leak records shall be maintained for a period of not less than 5 years from the date of their occurrence.

APPENDIX F: LEAK IDENTIFICATION AND REPAIR WORK FLOW DIAGRAMS

LDAR WORK FLOW PROCESS

LDAR Coordinator (LC)

Operations

Planner/Scheduler

Maintenance Personnel (MP)

LOTO Coordinator

Environmental Personnel

Engineering

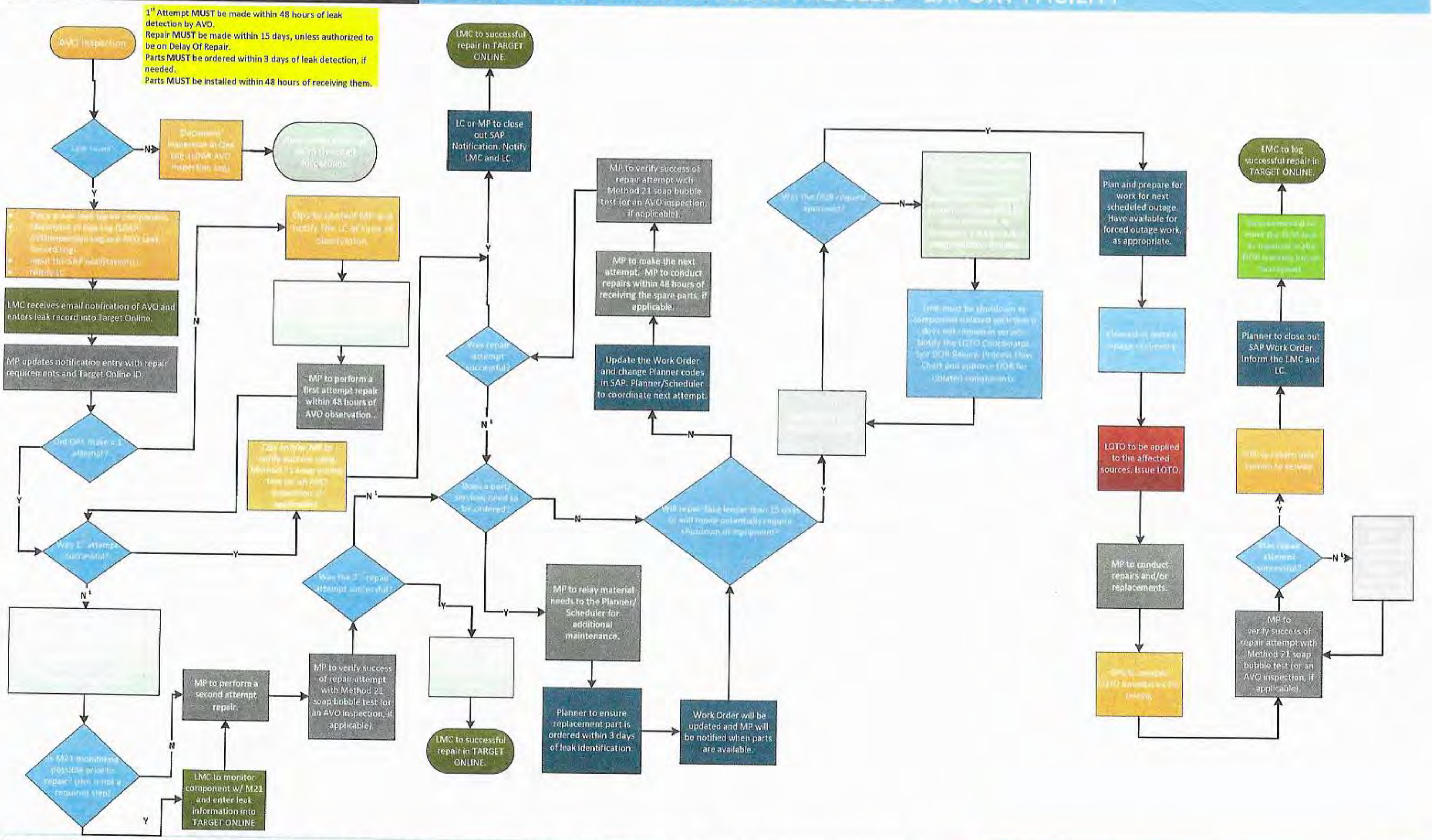
LDAR Monitoring Contractor (LMC)

Key Repair Milestones:

- 1st Attempt **MUST** be made within 5 days of leaks detected via monitoring and 48 hours for leaks detected via an AVO inspection.
- Repair **MUST** be made within 15 days, unless authorized to be on Delay Of Repair.
- Parts **MUST** be ordered within 3 days of leak detection for AVO-discovered leaks, where a replacement part is required.
- Parts **MUST** be installed within 48 hours of receiving them for AVO-discovered leaks.

DOMINION ENERGY COVE POINT

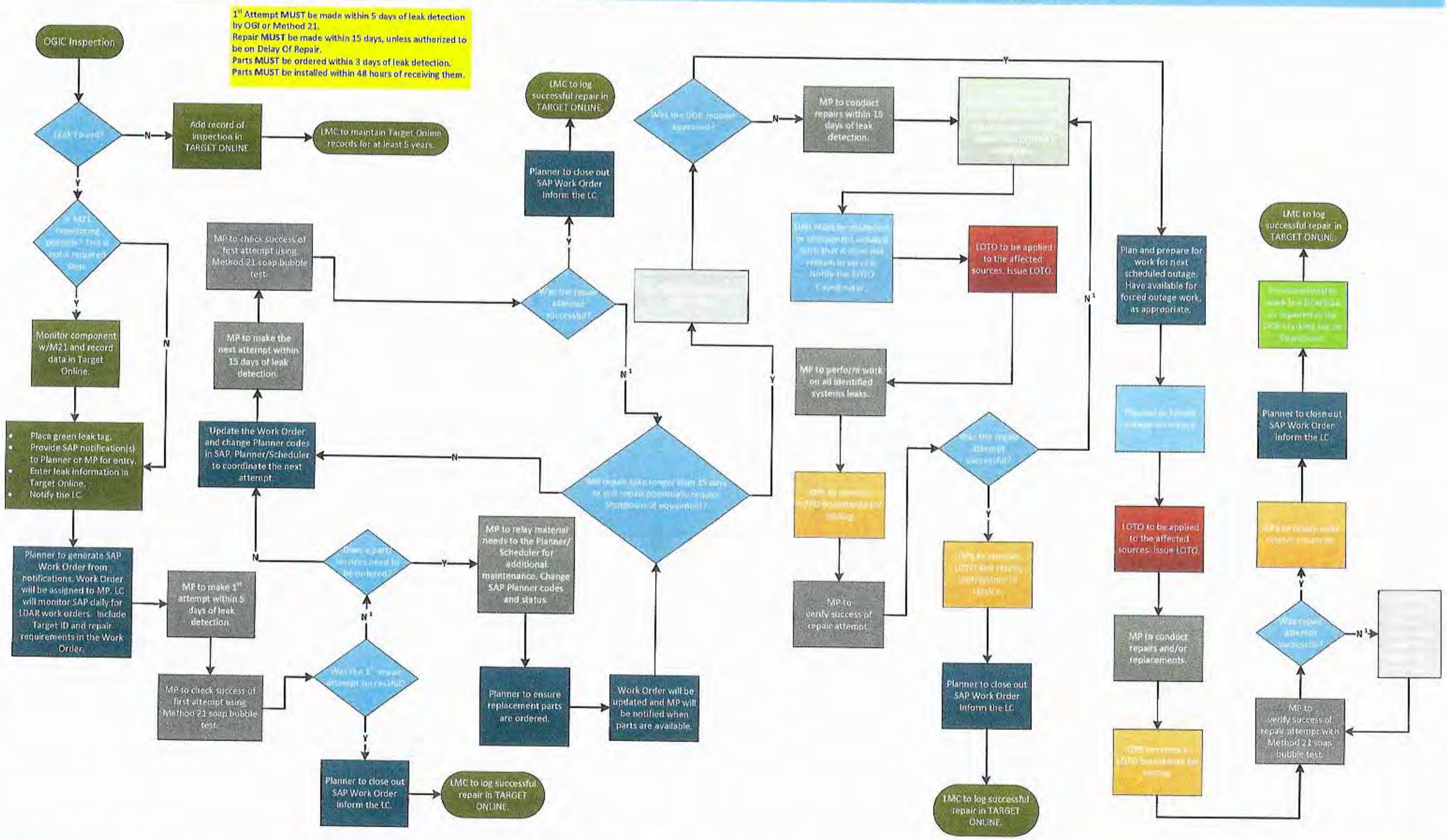
AVO INSPECTION WORK FLOW PROCESS – EXPORT FACILITY



[1] For each unsuccessful attempt at repair, the LC will update the work order with repair details. MP will perform evaluation of additional actions required and updated the work order. The LC will work with Operations to develop repair plan, understand LOTO requirements, etc. and will relay this to the Planner. The Planner will coordinate all field work and schedule MP based on repair requirements and due dates. The Planner will submit LOTO request, if required.

DOMINION ENERGY COVE POINT

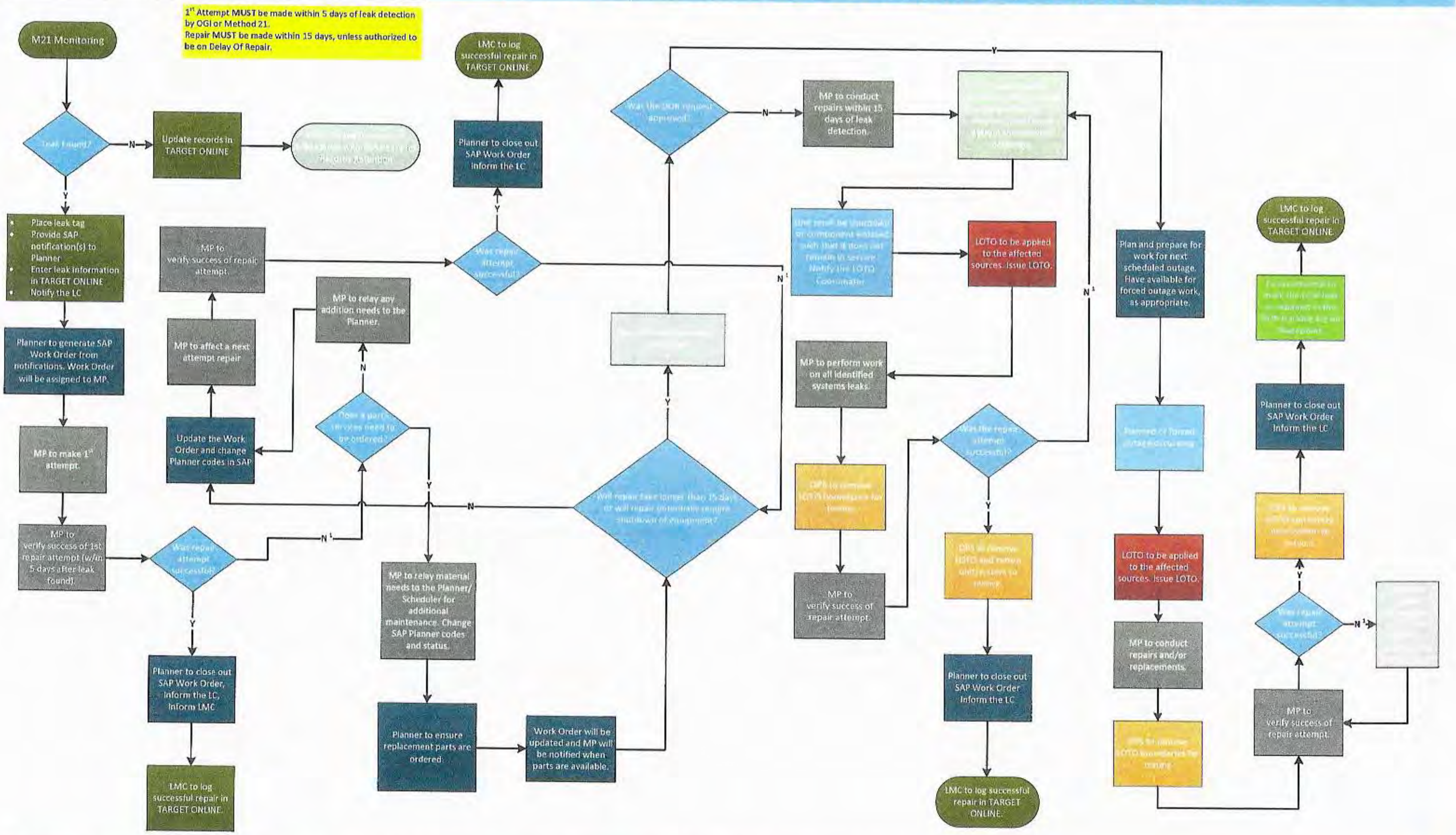
OGIC LDAR MONITORING WORK FLOW – EXPORT FACILITY



[1] For each unsuccessful attempt at repair, the LC will update the work order with repair details. MP will perform evaluation of additional actions required and updated the work order. The LC will work with Operations to develop repair plan, understand LOTO requirements, etc. and will relay this to the Planner. The Planner will coordinate all field work and schedule MP based on repair requirements and due dates. The Planner will submit LOTO request, if required.

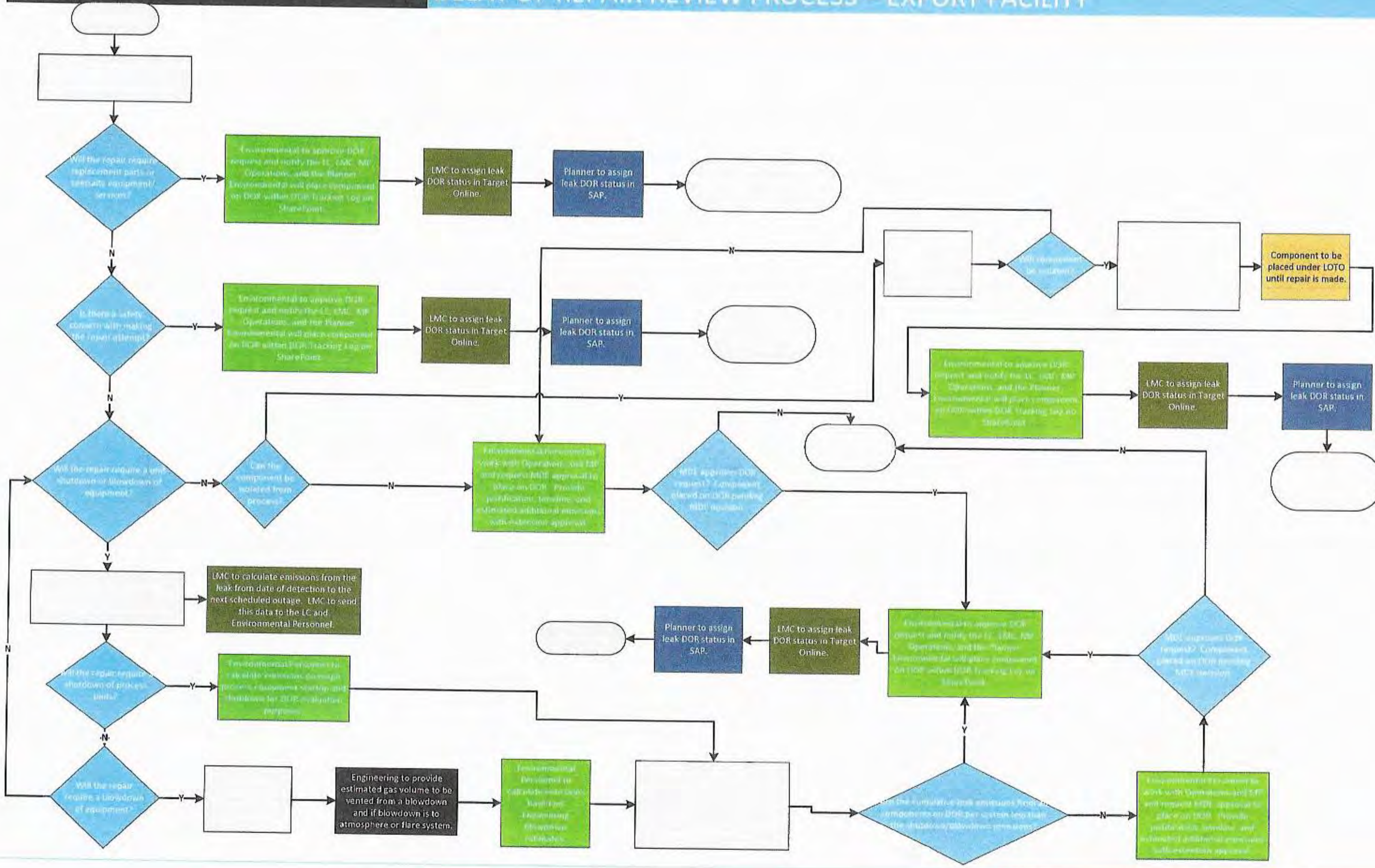
DOMINION ENERGY COVE POINT

METHOD 21 MONITORING WORK FLOW PROCESS – EXPORT FACILITY



[1] For each unsuccessful attempt at repair, the LC will update the work order with repair details. MP will perform evaluation of additional actions required and updated the work order. The LC will work with Operations to develop repair plan, understand LOTO requirements, etc. and will relay this to the Planner. The Planner will coordinate all field work and schedule MP based on repair requirements and due dates. The Planner will submit LOTO request, if required.

DELAY OF REPAIR REVIEW PROCESS – EXPORT FACILITY



Appendix G: LDAR Monitoring Plan Revision Log

Revision Number	Date	Revised by:	Comments
0	March 2018	Geosyntec Consultants, Inc.	Final (Rev. 0) Submitted to MDE for Approval.
1	June 2018	Dominion Energy, Inc.	General format corrections; update to Table 2.5-1 and Section 5.1. Final (Rev. 1) Submitted to MDE for Approval.
2	September 2018	Dominion Energy, Inc.	Updated Acronyms, Sections 1.1 & 4.1, Tables 1.2-1 & 5.2-1, and Appendices A & D. Submitted to MDE for Approval.
3	February 2019	Dominion Energy, Inc.	Updated Section 3.4.7, 4.2.4.1, and Appendices A, B, and F. Submitted to MDE in Annual Report
4	December 2019	Dominion Energy, Inc.	Updated Sections 3.3.1.2, 4.2, 4.2.2, 4.2.3.1, 4.3, 5.2, Table 2.5-1, & Appendices B, D, & E. Submitted to MDE for Approval.

Dominion Energy Services, Inc.
5000 Dominion Boulevard, Glen Allen, VA 23060

Website: www.dominionenergy.com

December 19, 2019

BY U.S. MAIL, RETURN RECEIPT REQUESTED
7018 2290 0000 9542 5262

John Artes
Air Quality Permits Program
Air and Radiation Management Administration
Maryland Department of the Environment
1800 Washington Boulevard
Baltimore, MD 21230

**RE: Dominion Energy Cove Point LNG, LP (Import Facility)
Greenhouse Gas Monitoring and Repair Plan**

Dear Mr. Artes:

Dominion Energy Cove Point LNG, LP (DECP) is submitting the following update to the Greenhouse Gas Monitoring and Repair Plan (GHG Plan) for the Cove Point LNG Import Facility in compliance with the Maryland Department of the Environment's (MDE's) November 17, 2017 approval of the DECP Climate Action Plan. This GHG Plan is submitted for MDE review and approval.

If you require any additional information, please contact Joseph Pietro at (804) 273-4175 or via email at Joseph.J.Pietro@dominionenergy.com.

Sincerely,

Thomas N. Effinger
Director, Environmental Services

Enclosure

cc: Christopher Beck, MDE (christopher.beck@maryland.gov)
Luke Wisniewski, MDE (luke.wisniewski@maryland.gov)
John Artes, MDE (john.artes@maryland.gov)

jjp

Document Certification

Facility Name: Dominion Energy Cove Point LNG, LP
(formerly known as Dominion Cove Point LNG, LP)

Facility Location: 2100 Cove Point Road, Lusby, Maryland 20657

County: Calvert

Type of Submittal: Dominion Energy Cove Point LNG, LP:
Greenhouse Gas Monitoring and Repair Plan Update

Certification: As required under COMAR 26.11.03, I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Name of Responsible Official: Frank N. Brayton

Title: Director, LNG Operations (Authorized Representative)

Signature:

Date: 12.16.19

CO_2 Authorized Account Representative Document Certification

Facility Name:	Dominion Energy Cove Point LNG, LP (formerly known as Dominion Cove Point LNG, LP)
Facility Location:	2100 Cove Point Road, Lusby, Maryland 20657
County:	Calvert
Type of Submittal:	Dominion Energy Cove Point LNG, LP: Greenhouse Gas Monitoring and Repair Plan Update

Certification: As required under COMAR 26.09.01.04(G), I am authorized to make the submission on behalf of the owners or operators of the CO_2 budget sources or CO_2 budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in the document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name of Responsible Official: Frank N. Brayton

Title: Director, LNG Operations (Alternate CO_2 Authorized Account Representative)

Signature:

Date: 12.16.19

Dominion Energy Cove Point LNG, LP
Lusby, Maryland

Greenhouse Gas Monitoring and Repair Plan

Cove Point LNG Import Facility

December 2019 (Rev. 2)

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1 INTRODUCTION

1.1 PURPOSE

Dominion Energy Cove Point LNG, LP (DECP) operates the Cove Point Liquefied Natural Gas (LNG) Storage and Terminal (the Import Facility) located in Lusby, Maryland. DECP is required under the DECP Climate Action Plan (CAP) to implement this Greenhouse Gas (GHG) Monitoring and Repair Plan (herein referred to as "the GHG Plan") to monitor and reduce fugitive GHG emissions from the Import Facility equipment. The scope of this document does not cover equipment associated with the Liquefaction Project (Export Facility), which is collocated with the Import Facility. The GHG Plan outlines recommended procedures and practices to be followed to monitor components for GHG emissions from the Import Facility equipment, as well as relevant repair procedures. This GHG Plan was developed using sound and reasonable engineering/scientific principles and overall aims to identify and reduce GHG emissions, such as carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O), from the Import Facility.

DECP is required, as part of the CAP, to maintain a GHG Plan for the Import Facility in order to minimize GHG emissions from the existing Import Facility equipment. The CAP was submitted to MDE on November 7, 2017 and subsequently approved by MDE on November 17, 2017. The GHG Plan is not related to the actual reporting of GHG emissions under EPA's Greenhouse Gas Reporting Rule of 40 CFR Part 98.

DECP maintains a separate leak detection and repair (LDAR) Monitoring Plan which applies to the Liquefaction Project Export Facility piping and equipment to evaluate applicable components for leaks of volatile organic compounds (VOCs), GHGs, and toxic air pollutants (TAPs), as required by Certificate of Public Convenience and Necessity (CPCN) Order No. 86372 issued May 30, 2014. The GHG Plan for the Import Facility is separate from the LDAR Monitoring Plan that is required for the Liquefaction Project Export Facility. The GHG Plan applies only to the Import Facility equipment and specifically applies only to GHG fugitive emissions.

The roles and responsibilities of personnel under this GHG Plan are outlined in Table 1.1.

Table 1.1 GHG Plan Roles and Responsibilities

Role	Person Responsible
Promotes the best practices laid out in the GHG Plan by ensuring necessary and appropriate resources have been allocated.	Director, LNG Operations
Management of component repairs/replacements.	Maintenance Manager
Performs component repairs/replacements.	Maintenance Personnel
Performs audio, visual, and olfactory (AVO) inspections.	Designated Operations Personnel (multiple)

Performs Optical Gas Imaging (OGI) instrument monitoring.	Third-Party Monitoring Contractor
Daily oversight and management of monitoring contractor.	GHG Plan Coordinator
Program Oversight	Corporate Air Specialist Station Environmental Compliance Coordinator

2 GHG MONITORING AND REPAIR PROCESS

The primary components of the GHG Plan are described in this section.

2.1 LEAK MONITORING AND INSPECTION TECHNIQUE

The leak monitoring and inspection techniques that may be used under the GHG Plan are as follows:

- OGI Monitoring – As the primary method to monitor components for fugitive GHG emissions, an OGI camera will be used. OGI monitoring will be performed on a quarterly basis, based on generally accepted industry standards.
- AVO Inspection – Leaks of GHG fugitive emissions may also be observed via the use of sensory methods (i.e., sound, sight, and/or smell) during operator rounds, and will be conducted on a monthly basis, based on general guidance from COMAR 26.11.19.16C(1).
- EPA Method 21 Soap Bubble Test – After the Import Facility attempts to repair leaking components, the Soap Bubble Test, conducted in accordance with EPA Method 21 procedures, may be used to confirm that the repair attempts were successful.

2.2 LEAK DEFINITIONS

Since DECP is implementing the practices laid out in this GHG Plan as a site-specific effort under the DECP CAP to reduce GHG emissions, DECP will generally follow the leak definitions for each monitoring and inspection technique as provided below:

- OGI Monitoring – A leak is defined as any emissions observed through the OGI camera.
- AVO Inspection – A leak is defined as any audible, visible, or olfactory indication of a leak (e.g., visual indications of liquids dripping).
- EPA Method 21 Soap Bubble Test – A leak exists if the formation of bubbles is observed when using the soap bubble test to confirm a repair.

2.3 DIFFICULT-TO-ACCESS AND UNSAFE-TO-ACCESS COMPONENTS

Components may not be monitored and/or repaired if the components cannot be accessed in a routine and safe manner. Determinations of difficult-to-access (DTA) and unsafe-to-access (UTA) components will be made on a case-by-case basis utilizing input from environmental, operations, and maintenance personnel. If leaks are observed during OGI monitoring for components determined to be DTA or UTA, repairs will be made when it is possible and safe to do so. Components that are found to be leaking and deemed to be DTA or UTA will be recorded, including the reasoning for the DTA or UTA determination, and the appropriate records will be maintained. DTA and UTA components awaiting repair will be placed on delay of repair, as referenced in Section 4.3.

3 FIELD PROCEDURES

Monitoring for fugitive emissions of GHGs may be performed at the Import Facility as discussed in the following sections.

3.1 OGI MONITORING

OGI monitoring will be performed on a quarterly basis by a third-party contractor. The OGI monitoring contractor is responsible for maintaining the OGI camera according to manufacturer's recommendations and performing OGI monitoring according to generally accepted industry standards. The repair procedures applicable to leaks identified during OGI monitoring are discussed in Section 4.

3.2 AVO INSPECTIONS

AVO inspections involve the use of sensory methods (i.e., sound, sight, and/or smell) to identify a potential leak to the atmosphere. Leaks may also be observed via AVO methods during routine operator rounds at the Import Facility. During AVO inspections, facility personnel will check for AVO indications of a leak (e.g., liquids dripping from a component) using the following best practices:

- Observe components that may have visible leakage including dripping, spraying, misting, clouding, puddling, or staining.
- Listen for abnormal hissing or other sounds that may indicate a leak. Any required hearing protection should not be removed.
- Use the olfactory senses to detect abnormal odors that may indicate a leak of process fluids. Olfactory observations should be performed in the course of normal breathing.

The repair procedures applicable to leaks identified during AVO inspections are discussed in Section 4.

3.3 EPA METHOD 21 SOAP BUBBLE TEST

The EPA Method 21 Soap Bubble Test may be used to confirm that repair attempts to a leaking component were successful. To perform the EPA Method 21 Soap Bubble Test, the Import Facility will apply a soap solution to the component of interest. The soap solution will be a commercially available leak detection solution (e.g., Snoop) or will be prepared using concentrated detergent (e.g., common dishwashing detergent) and water. A pressure sprayer or squeeze bottle will be used to dispense the solution onto the component of interest. Then, potential leak sites will be observed to determine if bubbles are formed. If no bubbles are observed, the component is not leaking, and the repair attempt was successful. The EPA Method 21 Soap Bubble Test will not be used on components, or portions thereof, that have continuously moving parts, have surface temperatures that will boil or freeze the soap solution, have open areas to the atmosphere that the soap solution cannot bridge, or that exhibit evidence of liquid leakage. If bubbles are observed, the component is still leaking. The repair procedures applicable to leaks identified during the EPA Method 21 Soap Bubble Test are discussed in Section 4.

4 LEAK IDENTIFICATION AND REPAIR PROCEDURES

The procedures for leak identification and repair are outlined in this section.

4.1 LEAK IDENTIFICATION AND DOCUMENTATION

Components found to be leaking through the procedures described in Section 3 will be initially tagged, if possible (e.g. a pressure relief valve on top of an LNG tank is not expected to be tagged), with a weatherproof and readily visible identification tag (i.e., leaker tag). A leaker tag is still required to be completed independent of the ability to physically hang the tag. The leaker tag is meant to identify leaking equipment for the appropriate maintenance personnel, but more importantly, is the mechanism for the leak to be entered into SAP. The identified leak will then be logged into an electronic database. A notification is entered into SAP, which notifies the GHG Plan Coordinator and maintenance personnel of the leak. Once the leak is entered into SAP, any leaker tag need not be maintained. The SAP notification will include the component tag number, if applicable, and the leaking component location description (e.g., upstream flange on the suction isolation valve of equipment ID XXX). As a best practice, the SAP notification should include the following:

- Unique component tag number, if applicable;
- Description of the leaking component's location;
- Date and time leak was discovered; and
- Date and time a first repair attempt was made and a note if the first attempt was successful.

4.2 LEAK REPAIRS

When a leak is identified, it will be repaired according to the procedures outlined below. Repairs at the Import Facility are typically performed by maintenance personnel under the direction of the Maintenance Manager. DECP strives to repair leaking components in accordance with the repair time frames provided in the sections below. Note that the leak repair time frames discussed below are guidelines and not required by regulation. DECP aims to perform work within these time frames as a best management practice in order to address all GHG leaks in a timely manner. If additional time is required, maintenance personnel should document the reason and the updated timeline for repair in an electronic database.

Repairs to identified leaks will be documented in an electronic database.

4.2.1 First Attempt at Repair

The actions taken during a first attempt at repair may vary depending on the situation (type of component, location of the leak on the component, etc.). A first attempt at repair may include, but is not limited to, the following:

- Tightening the bonnet bolts;
- Replacing the bonnet bolts;
- Tightening the packing gland nuts; and,

- Injecting lubricant into the lubricating packing.

These actions are provided as guidance only. Based on operating conditions and safety concerns, the appropriate action to be taken during a first attempt at repair will be at the sole discretion of Operations personnel.

First repair attempts of equipment required to be insulated for operations must be postponed until the repair can be done in a safe manner. This also applies to any component that is DTA or UTA during operations. Each repair currently postponed due to the equipment being required to be insulated for operation will be included in the CAP annual progress report due February 28th of each year.

4.2.2 Leaks Identified via OGI Monitoring

First attempts at repair for leaking equipment found by OGI monitoring should be performed within five (5) calendar days after each leak is detected, if it is safe to do so. If the first repair attempt is not successful, efforts should be made to repair the component within 15 calendar days after initial leak identification, if possible. If repair is not feasible (e.g. unavailability of parts, delay of repair, operating conditions, safety concerns, etc.) within this time frame, the component may be placed on the delay of repair list, as discussed in Section 4.3. A follow-up leak repair verification (e.g., EPA Method 21 Soap Bubble Test or OGI monitoring) will be performed to evaluate the success of each repair attempt.

4.2.3 Leaks Identified via AVO Inspection

For leaking components identified by AVO inspection, a first attempt at repair should be performed within 48 hours after initial leak identification, if it is safe to do so. If the first attempt at repair is not successful or is not safe to perform, the component should be repaired within 15 calendar days after initial leak identification, if possible. If repair is not feasible (e.g. unavailability of parts, delay of repair, operating conditions, safety concerns, etc.) within this time frame, the component may be placed on the delay of repair list, as discussed in Section 4.3. A follow-up leak repair verification (e.g. EPA Method 21 Soap Bubble Test or OGI monitoring) will be performed to evaluate the success of each repair attempt.

4.3 DELAY OF REPAIR

Components that cannot be repaired within the target time frames provided above may be placed on the delay of repair list as follows:

- Components that are isolated from the process and do not remain in service (i.e., no process fluid remaining within the piping) may be placed on the delay of repair list indefinitely.
- Components remaining in service, the repair of which would require a process unit shutdown, may be placed on the delay of repair list until the next scheduled shutdown.
- Components for which necessary parts are unavailable may be placed on the delay of repair list until these parts are ordered and received.
- Components in cryogenic service will be placed on delay of repair if it is unsafe to work on the component until the next planned outage.

- Leaks identified on DTA and UTA components will be placed on delay of repair until repairs can be made safely. A list of the DTA and UTA components currently on delay of repair will be included in the CAP annual progress report due February 28th of each year, including the reasoning of the DTA or UTA determination and the schedule for each repair.
- If a repair of a leak cannot be successfully completed according to this GHG Plan, DECP shall submit a plan prior to extending a repair past allowed timeframes for MDE approval. The leaking component will remain on delay of repair until an MDE determination has been made. The submitted plan shall include the following:
    - An explanation of the technical difficulty;
    - A timeline to successfully repair the leaking component; and
    - A calculation on the additional GHG emissions, that is expected to be released due to the extension beyond allowed timeframes, i.e. additional emissions from end of allowed timeframe to planned successful leak repair.

As a best practice, DECP will elect to utilize SAP, an electronic database, or other program approved by Dominion Energy Environmental Services to track delay of repair items. The final decision for placing a component on the delay of repair list is the responsibility of maintenance personnel and will be made following coordination with the Station Environmental Coordinator and the GHG Plan Coordinator.

5 GHG PLAN REVISION LOG

Revision Number	Date	Revised by:	Comments
0	January 2018	Dominion Energy, Inc.	Submitted to MDE for Approval.
1	February 2018	Dominion Energy, Inc.	Updated Sections 1.1, 2.1, 2.3, 4.1, 4.2.1, and 4.3. Submitted to MDE for Approval.
2	December 2019	Dominion Energy, Inc.	Updated 4.3 and added Section 5. Submitted to MDE for Approval.

Appendix E – Rod Packing Threshold

APPENDIX E - ROD PACKING THRESHOLD

In order to develop the proposed emissions standard for reciprocating compressors, Staff reviewed the EPA new source performance standards (NSPS), California's and Canada's rod packing replacement requirements, and contacted a reciprocating engine service provider.

EPA's current NSPS establishes a prescribed time-based requirement for replacement rod packing systems. The NSPS requires new or modified compressors used at gathering and boosting stations and natural gas processing plants to replace rod packing systems within 26,000 hours or 36 months of operation, regardless of the condition of the rod packing[1]. California and Canada prescribe a condition-based requirement for replacement rod packing systems. California establishes a 2 scfm threshold for rod packing replacement[2], while Canada's Environment and Climate Change Canada (ECCC) sets a much lower threshold for repair of rod packing at 0.023 m^3 per minute[3], which is about 0.8 scfm.

In addition to reviewing the above, the Department contacted a service provider for reciprocating compressors to gather information and manufacturer guidelines for replacing faulty or defective rod packing systems. The guidelines provided below, are described in terms of a natural gas flow rate of emissions from the vent near the piston rod-packing on the reciprocating compressor.

Table 1 – Rod Packing Guidelines[4]

Condition	Rod packing flow rate measured in scfm
Past Normal Lubed Packing, New	0.2 – 0.5
Past Non-Lube Packing, New	0.5 – 1.0
Past Normal Lubed Packing, Partially Worn	1.0 – 2.0
Recommended Alarm Setpoint	2.0 – 3.0
Recommended Shutdown Setpoint	4.0 – 5.0

[1] https://www.govinfo.gov/content/pkg/FR-2016-06-03/pdf/2016-11971.pdf
[2] https://ww2.arb.ca.gov/resources/documents/oil-and-gas-regulation
[3] https://laws-lois.justice.gc.ca/eng/regulations/SOR-2018-66/page-3.html#docCont
[4] Cook Compression, 2019. E-mail from Craig Martin of Cook Compression to Joshua Shodeinde of MDE. November 7, 2019.

Appendix F – Blowdown Operations

Appendix F - Blowdown Operations

Maryland Department of Environment ARA staff regulation development for COMAR 26.11.41 blowdown reporting. Compressor stations and associated piping and equipment must periodically be taken offline for maintenance, stand-by, or emergency shutdown testing, and as a result, the gas within the compressors and associated piping is vented to the atmosphere. This operational practice of depressurizing and releasing natural gas into the atmosphere, known as blowdowns, allows operators to remove the natural gas quickly and safely from the equipment and pipeline.

Community and environmental advocacy groups raised concerns about blowdown emissions and requested that MDE consider requiring potentially affected sources to notify the public whenever blowdowns occur. The Department evaluated blowdown requirements in other jurisdictions and discovered only one state program, Louisiana[5], with established blowdown notification requirements. At the federal level, the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) requires the reporting of *unintentional* releases of natural gas[6]. Research was limited to the federal and state programs publicly available at the time of the production of the proposed rules, and may not reflect federal or state programs that may have been proposed or finalized since that time[7].

The Department is proposing that owners and operators of affected sources notify the public, local authorities and the Department for any blowdown releases that exceed 1.0 million scf with a seven-day advanced notice for planned blowdown events. For unplanned blowdowns, the proposed rules will require affected sources to notify the public and relevant authorities within one hour of occurrence. Additionally, the Department is proposing annual emissions reporting for all blowdown events greater than 50 scf. The Department expects the required reporting of blowdown activities will provide a better sense of how blowdowns are conducted, along with emissions data. This information will serve as a guide for future regulatory action and may provide opportunity to strengthen the proposed standards.

Blowdown Notification Plan

The proposed action includes requirements for natural gas facility owners and operations to submit a blowdown notification plan for approval by the Department. The blowdown notification plan should include:

- The notification format (for example, website, email, robocall, text message, social media announcement);
- A public outreach plan to inform interested parties of the availability to be notified for blowdown events that exceeds 1 million scf;
- The responsible personnel for blowdown notification; and
- A sitemap of locations where blowdown events occur.

[5] Louisiana Administrative Code, Title 33, Part III, Section 309.
[6] 49 CFR Part 191. Note that PHMSA's requirements do not apply to intentional and controlled releases
[7] After establishing the proposed standards, the Department received information of another state permit with a lower blowdown reporting threshold from the Environmental Integrity Project on February 12, 2020.

Regarding the notification form, the proposed requirements afford owners and operators the flexibility to determine, for approval, the appropriate avenue to inform interested parties. Additionally, to provide for the public record, all submitted plans will be available.

Appendix G – Cost Impact Supporting Analysis

APPENDIX G – Cost Impact Supporting Analysis

Maryland Department of Environment ARA staff regulation development for COMAR 26.11.41 cost impacts. In order to develop the estimated cost impacts, the Department reviewed literature on the proposed cost impacts of methane control strategies and fugitive leak detection and repair programs from EPA, California, environmental advocates and the industry. Additionally, the Department received cost estimates from manufacturers on equipment and maintenance.

The proposed regulation requires facilities in the natural gas industry to perform quarterly or annual leak surveys to identify and minimize unintentional fugitive emissions. The proposed regulation may require facilities to purchase, retrofit, and service capital equipment. The Department estimates affected facilities will be required to spend, on average, in 2018 dollars, $25,000 annually on leak surveys. Repairs and maintenance may be an additional cost; however, product loss will be decreased. Some capital investment may be required and can vary in cost depending on the sophistication of the engineering design and the age of existing equipment but are estimated to range from $10,000 — $100,000. Affected facilities are also required to submit annual reports to the Department, which may result in additional reporting costs. However, since the proposed annual reporting requirements harmonize with the existing federal requirements, the Department estimates reporting costs to be minimal.

The proposed regulation will have a positive effect on public health and the environment. Short-lived climate pollutants (SLCPs) are harmful air pollutants and potent climate forcers with a much shorter lifespan in the atmosphere than carbon dioxide. Reducing emissions of methane will combat the adverse impacts of climate change in Maryland.

Businesses in this industry do not meet the size criterion to qualify as small businesses, therefore no economic impact is expected to small businesses. Facilities may hire a small business to perform LDAR so an indeterminate benefit could be seen.

Existing air compliance inspector staff at MDE will enforce these regulations.

SUPPORTING STATEMENTS TO COST IMPACT ANALYSIS:

I. Reciprocating Natural Gas Compressors

The affected facilities with reciprocating natural gas compressors will be required to measure and report leak concentration from rod packings or seals. Existing and new facilities have the option to either replace rod packing after the leak rate is measured at 1 scfm, or increase the frequency of testing until the leak rate 2 scfm per cylinder, and then replace the rod packing. Alternatively, affected sources may employ a vapor collection and control system for reciprocating compressor.

To estimate the potential cost impacts of the proposed requirements pertaining to owners and operators of reciprocating natural gas compressors, the Department utilized the cost analysis from California's Air Resources Board (CARB), EPA's NSPS OOOOa, and EPA's Natural Gas STAR program. The utilization of each cost analysis is outlined below.

A. CARB

In 2017, CARB finalized and established its "Greenhouse Gas Emissions Standards from Crude Oil and Natural Gas Facilities" regulations[8]. CARB requires rod packing replacement when the leak rate is measured over 2 scfm.

According to CARB's Initial Statement of Reasons (ISOR)[9], CARB estimated that there are 325 reciprocating compressors in CARB affected by their 2 scfm standard; CARB's analysis excludes compressors under 250 hp which were assumed to be production field compressors, and are included in the LDAR program only. To estimate the portion of the 325 reciprocating compressors that may be over the proposed standard of 2 scfm per cylinder, CARB's staff relied on data provided by industry. CARB's data includes 68 reciprocating compressors at transmission stations, and estimate an average reciprocating compressor has 3 rod packings. Additionally, CARB's data reflects measurements from rod packing vents for 55 reciprocating compressors taken over a four-year period. According to the data, about 14% of the measurements indicated a leak rate of over 2 scfm per cylinder. Based on the data, CARB staff estimated that 46 out of 325 non-production reciprocating compressors would have a leak rate of over 2 scfm each year, and would require a rod packing replacement to comply with the proposed regulation. CARB staff estimated that for each of these 46 compressors, two of the rod packings would need to be replaced to bring the leak rate into compliance. In total, 92 rod packings would need to be replaced each year to comply with the proposed regulation.

According to ICF, the cost of replacing a single rod packing on a reciprocating compressor is estimated to be $6,000[10]. Using the information presented above:

Cost of Rod packing replacement for CA = numbers of devices x cost per device x capital recovery factor. Where,
Number of devices = 92 rod packing replacements per year
Cost per Device = $6,000 per Rod Packing Replacement (ICF, 2014)
Capital Recovery Factor = .367 from Table B-3, Appendix B of Initial Statement of Reasoning Staff Report
Thus total cost of rod packing replacement for CA estimated to be = 92 X $6,000 X 0.367 = $202,548 per year

Applying CARB's cost evaluation to Maryland:
MDE staff used the following assumptions to calculate cost impacts for Maryland: In Maryland there are 4 existing facilities that have natural gas reciprocating compressors and each facility has 2 to 12 units, so a total 18 units; assuming each unit has 3 rod packings; and assuming 1/3 of the rod packings will measure over 2 scfm per cylinder and require replacement each year.

[8] https://ww3.arb.ca.gov/regact/2016/oilandgas2016/ogfro.pdf
[9] CARB ISOR Appendix B, located at https://ww3.arb.ca.gov/regact/2016/oilandgas2016/oilgasappb.pdf
[10] Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF, 2014)

Thus, the total cost of rod packing replacement for MD estimated to be = 18 X \$6,000 X 0.367 = \$39,636 per year

B. EPA NSPS OOOOa

EPA's NSPS finalized in 2016 requires rod packing replacement after 26,000 hours of operation while the compressor is pressurized. Unlike MDE's proposal and CARB's oil and natural gas rules, no measurement of leak rate is required; facilities are required to keep records for the number of hours of operation.

The potential control options reviewed for reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas past the piston rod packing. This includes replacement of the compressor rod packing, replacement of the piston rod, and the refitting or realignment of the piston rod. EPA data states the cost to replace rod packing rings is \$1,620 per cylinder[11]. Also, EPA summarizes reciprocating compressors rod packing replacement total cost, for the transmission sector, for a year, to be equal to \$5,346 in 2008[12].

C. EPA Natural Gas STAR Lessons Learned[13]

EPA's Natural Gas STAR Lesson Learned document states the following: "Costs of replacing packing rings and piston rods vary between compressors. For packing ring replacements, variables include the number of compressor cylinders and the type of replacement ring. A Natural Gas STAR Partner reported that costs for a typical Teflon or molybased, 8 to10 cup ring set for a three-inch rod will range from \$135 to \$170 per cup, or about \$1,350 to \$1,700 total. Another source stated that a set of rings may vary between \$675 and \$1,080, or \$2,025 to \$3,375 if the cups and cases are included. Factors affecting equipment costs for rod replacements include rod dimension and type of rod. Estimates of the costs of rods can range from \$2,430 to \$4,725. Special coatings, such as ceramic, tungsten carbide, or chromium, can increase costs by \$1,350 or more—the cost of some rods may be as high as \$12,150 to \$13,500.

Installation costs vary as well, depending on site location and difficulties encountered during replacement. Both Partners and manufacturers estimate that installation costs are roughly equal to equipment costs. One Partner spent an average of \$1,420 per packing ring set for purchase and installation."

D. Additional Sources Used in Reciprocating Natural Gas Compressor Cost Analysis

- One Maryland facility operator estimated the cost of one compressor with 4-8 rods needing replacement and labor, to be approximately \$40,000[14].

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[11] EPA NSPS OOOOa TSD, **EPA-453/R-11-002,** July 2011, page 6-16, The cost of rod packing ring replacement is from the EPA NG Star "Reducing Methane Emissions from Compressor Rod Packing Systems Lessons Learned paper" dated 2006.

[12] Ibid, Table 6-7

[13] https://www.epa.gov/sites/production/files/2016-06/documents/ll_rodpack.pdf

[14] Email from Enbridge dated November 8, 2019

- A manufacturer's quote for an existing pre-2010 compressor with a single compression cylinder would cost $4,405[15].

II. Pneumatic Devices

The affected facilities all have various pneumatic control devices. The proposed regulation requires a phase-out of all high bleed continuous natural gas-powered devices. Additionally:

• Beginning January 1, 2021, LDAR monitoring for all natural gas-powered pneumatic devices;
• By January 1, 2022, continuous bleed natural gas-powered pneumatic devices cannot have a bleed rate greater than 6 standard cubic feet per hour; and
• By January 1, 2023, continuous bleed natural gas-powered pneumatic devices shall be converted to electric or compressed air-powered devices.

To estimate the potential cost impacts of the proposed requirements pertaining to owners and operators with natural gas-powered pneumatic devices, the Department utilized the cost analysis data from EPA and CARB. The utilization of each cost analysis is outlined below.

A. EPA

EPA data from NSPS OOOOa states that replacing high bleed with low bleed devices is below $200 per unit in 2008 dollars[16]. According to EPA the average cost for a low bleed pneumatic is $2,553, while the average cost for a high bleed is $2,338. Thus, the incremental cost of installing a low-bleed device instead of a high-bleed device is on the order of $165 per device. Installation cost is shown to be similar.

Furthermore, EPA data states that the primary costs associated with conversion to instrument air systems are the initial capital expenditures for installing compressors and related equipment and the operating costs for electrical energy to power the compressor motor. This equipment includes a compressor, a power source, a dehydrator and a storage vessel. It is assumed that in either an instrument air solution or a natural gas pneumatic solution, gas supply piping, control instruments, and valve actuators of the gas pneumatic system are required. The total cost, including installation and labor, of three representative sizes of compressors were evaluated based on assumptions found in the Natural Gas STAR document, "Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air" and summarized in Table 5-10. Capital costs range from and annualized costs (10-year life cycle) for an instrument air system range from $11,000 - $80,000 in 2008 dollars.

[15] Ibid
[16] EPA NSPS OOOOa TSD, TSD, **EPA-453/R-11-002,** July 2011

B. CARB

CARB's cost analysis for pneumatic devices[17] quotes the EPA's Natural Gas STAR document[18] and estimates the cost of a no bleed mechanical device to be $3,000 per device.

III. Vapor Collection and Vapor Recovery Devices

When compressors and/or pipeline segments are taken out of service for operational or maintenance purposes, it is a common practice to depressurize the natural gas to the atmosphere. Partners report saving this gas and reducing methane emissions by depressurizing to a connected or nearby low-pressure fuel or product system and/or installing a vapor collection system that controls emissions. A vapor collection or recovery system can also be applied to tanks or a pneumatic device that is designed to vent.

Two sources were used to perform a cost analysis for vapor recovery systems: EPA's Natural Gas STAR program and CARB. The use of each cost analysis is outlined below

A. EPA Natural Gas STAR

EPA states: To collect gas from blowdown or depressurizing operations, facility expenditures may be necessary to add piping from compressors to the low-pressure mains. Capital costs range from $1,000 - $10,000 for piping systems[19].

B. CARB

CARB regulations require VRU for tank systems with VOC emissions over 10 metric tons per year and include a vapor recovery system option for venting gas at production and transmission stations[20].

CARB states that the total cost of installing a vapor recovery system on a wet seal centrifugal compressor is estimated to be $6,475 per year[21]. The cost is amortized over a period of 10 years, which matches the methodology used by ICF[22].

Vapor recovery for separators and tanks requires the installation of a piping system and requires the gas to be routed to an existing or new combustion device. In order to meet

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[17],[38] CARB Initial Statement of Reasons, Appendix B – Cost Analysis, located at https://ww3.arb.ca.gov/regact/2016/oilandgas2016/oilgasappb.pdf

[18] EPA Natural Gas STAR - Convert Pneumatics to Mechanical Controls (EPA, 2011)

[19] EPA Natural Gas STAR PRO 401 - https://www.epa.gov/sites/production/files/2016-06/documents/injectblowdowngas.pdf

[20] https://ww3.arb.ca.gov/regact/2016/oilandgas2016/ogfro.pdf

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

stringent permitting requirements, it is anticipated that the combustion device must meet a NOx standard; therefore, a current flare would need to be replaced by a low-NOx incinerator.

CA staff determined a capital cost estimate range for an incinerator to be from $160,000 to $295,000, depending on size, that can operate with a capacity of up to 380,000 scf per day[23] According to CARB, the installation of the system ranged from $80,000 - $148,000, and the cost to remove an existing flare was calculated to be approximately $36,000.

CARB regulations require uncontrolled systems above the 10 metric tons per year threshold to utilize a vapor recovery system. CARB quotes in their Economic Analysis: "In cases where only the water tank is uncontrolled, the new vapor recovery system for the water tank would route to the existing vapor recovery and control system. For each of these systems, an appropriately sized vapor recovery system was chosen based on estimates from EPA's Gas STAR Document "Installing Vapor Recovery Units on Storage Tanks" (EPA, 2006b). The cost of these vapor recovery units ranged from about $20,000 to $26,000 in capital costs, and about $15,000 to $20,000 in installation costs."[24]

Applying CARB's economic estimates to Maryland would require an analysis of existing infrastructure and site-specific design. A new vapor collection system could connect to existing site recovery units or require new piping and destruction systems; therefore the cost could range from $50,000 - $480,000.

IV. Leak Detection and Repair Requirements

The proposed regulations require affected Maryland facilities to perform LDAR and AVO surveys; the frequency of the survey depends on the nature of the facility's operations and the type of compressors present at the facility. MDE staff relied on information from EPA, one fugitive emission management services vendor, and one natural gas owner/operator to estimate the cost of the LDAR and AVO requirements. Information utilized is outlined below.

A. EPA Natural Gas STAR

EPA through a lessoned learned paper "estimates LDAR survey average cost to be $6,900[25]. Natural Gas STAR Partners have found that follow-up surveys in an ongoing directed inspection and maintenance (DI&M) program cost 25 percent to 40 percent less than the initial survey because subsequent surveys focus only on the components that are likely to leak and are economic to repair. Component repair cost ranged from $10 - $5,600 and total estimated repair cost per compressor station ranged from to $100 - $50,000.This paper also

[23] CARB Initial Statement of Reasons, Appendix B – Cost Analysis, located at https://ww3.arb.ca.gov/regact/2016/oilandgas2016/oilgasappb.pdf
[24] https://ww3.arb.ca.gov/regact/2016/oilandgas2016/oilgasappb.pdf
[25] Directed Inspection and Maintenance at Compressor Stations Lessons Learned paper located at https://www.epa.gov/sites/production/files/2016-06/documents/ll_dimcompstat.pdf

discusses a dollar value savings due to less product loss; however, facilities in Maryland in the transmission sector do not typically own the gas, so the estimated savings cannot be applied to Maryland facilities.. Therefore, no estimates were considered in this analysis.

B. Discussions with fugitive emission management vendor

Based on discussions with a fugitive emission management vendor, MDE staff estimates that an optical gas imaging (OGI) leak survey, recording and reporting is approximately $8,000 for an average size facility (assumed 2-3 compressors with standard access).

C. One Maryland Facility Owner

MDE obtained the estimated cost for AVO survey for underground storage wells at one Maryland-based facility[26]. The geographic spread of the storage wells requires a very labor-intensive process due to the number of well heads and spread across approximately 20 square miles of noncontiguous property. Weekly inspections were estimated to cost approximately $100,000 per year for labor and equipment. Monthly inspections reduce this cost by 75%.

V. Record-Keeping and Reporting

The proposed regulations require affected facilities to provide LDAR reports and annual greenhouse gas emissions reports including blowdown emissions. MDE utilized calculations conducted by CARB, which also has record-keeping and reporting requirements in their oil and natural gas rules, to conduct a cost analysis of the proposed requirements.

> CARB's cost analysis states: A recordkeeping event, or keeping inspection and repair records for LDAR, a flash test, a liquids unloading calculation, or a recording of a leak rate for reciprocating compressors was assigned a cost of $48. These estimated costs of recordkeeping and reporting are in line with costs used with EPA's recordkeeping cost estimate for their proposed emission standards in the oil and natural gas sector (EPA, 2015). Recording keeping and reporting requirements impact 272 CA businesses. For each of the business impacted, an annual report to ARB was estimated to cost $144, or take 3 hours at $48 per hour.
> Recordkeeping and Reporting Cost = 272 x 144 = $39,168

In Maryland's cost analysis of record-keeping and reporting, records for LDAR are assumed as part of the survey costs. Blowdown notification plans will be devised so that companies can utilize existing public forums to provide notification and existing staff that currently monitoring performance and emissions. Initial coordination with the Department will be necessary. Annual greenhouse gas reporting follows the federal Part 98 structure and excel spreadsheets developed for that reporting can be used to report to the Department.

[26] Email from Enbridge dated November 8, 2019

Recording keeping and reporting requirements impact 5 Maryland businesses. For each of the business impacted, an annual report was estimated to cost $768, or take 16 hours at $48 per hour.
Annual Recordkeeping and Reporting Cost = 5 x 768 = $3,840

REFERENCES AND RESOURCES USED TO DETERMINE COST IMPACT:

- State of California Air Resources Board (ARB) Oil and Gas Regulation development https://ww3.arb.ca.gov/regact/2016/oilandgas2016/oilandgas2016.htm
    - Final Regulation Order – Subarticle 13 – Greenhouse Gas Emsission Standards for Crude Oil and Natural Gas Facilities, Sections 95665 - 95677, Appendix A, Appendix B, and Appendix C https://ww3.arb.ca.gov/regact/2016/oilandgas2016/ogfro.pdf
    - California ARB Staff Report: FINAL STATEMENT OF REASONS (FSOR) REGULATION FOR GREENHOUSE GAS EMISSION STANDARDS FOR CRUDE OIL AND NATURAL GAS FACILITIES DATE OF RELEASE: May 2017
    - California ARB Staff Report: INITIAL STATEMENT OF REASONS (ISOR), Date of release: May 31, 2016, scheduled for consideration: July 21, 2016. Also includes Appendix A – E.
    - California ARB Staff Report: Attachment 2: 15-day Notice Supplemental, February 3, 2017
- EPA Natural Gas STAR Program: Recommended Technologies to Reduce Methane Emissions: **Lessons Learned Studies and Partner Reported Opportunities (PRO) Fact Sheets**
    - Lessons Learned “Directed Inspection and Maintenance at Compressor Stations” Office of Air and Radiation: Natural Gas Star. Washington, DC. 2006” https://www.epa.gov/sites/production/files/2016-06/documents/ll_dimcompstat.pdf
    - Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry. Office of Air and Radiation: Natural Gas Star. Washington, DC. February 2004 https://www.epa.gov/sites/production/files/2016-06/documents/ll_pneumatics.pdf
    - Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air. Office of Air and Radiation: Natural Gas Star. Washington, DC. October 2006 https://www.epa.gov/sites/production/files/2016-06/documents/ll_instrument_air.pdf
    - Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems. Office of Air and Radiation: Natural Gas Star. Washington, DC. October 2006 https://www.epa.gov/sites/production/files/2016-06/documents/ll_rodpack.pdf
    - PRO 401: Inject Blowdown Gas into Low Pressure Mains or Fuel Gas System, 2011. https://www.epa.gov/sites/production/files/2016-06/documents/injectblowdowngas.pdf

    - Lessons Learned: Installing Vapor Recovery Units on Storage Tanks. Office of Air and Radiation: Natural Gas Star. Washington, DC. October 2006 https://www.epa.gov/sites/production/files/2016-06/documents/ll_final_vap.pdf
- EPA Oil and Natural Gas Sector -- New Source Performance Standards, National Emission Standards for Hazardous Air Pollutants, and Control Techniques Guidelines – Regulation development with various supporting documents found at regulatios.gov under EPA-HQ-OAR-2010-0505. https://www.regulations.gov/docket?D=EPA-HQ-OAR-2010-0505
    - EPA " Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Technical Support Document for Proposed Standards, EPA-453/R-11-002, July 2011" regulatios.gov **EPA-HQ-OAR-2010-0505-0045**
    - EPA " Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Facilities. Background Technical Support Document for Proposed New Source Performance Standards 40 CFR Part 60, subpart OOOOa, August 2015" regulatios.gov **EPA-HQ-OAR-2010-0505-5120**
    - EPA " Regulatory Impact Analysis Regulatory Impact Analysis of the Proposed: Emission Standards for New, Reconstructed, and Modified Sources in the Oil and Natural Gas Sector, EPA-452/R-15-002, August 2015" regulatios.gov **EPA-HQ-OAR-2010-0505-5258**
    - EPA " Regulatory Impact Analysis of the Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, EPA-452/R-16-002, May 2016" regulatios.gov **EPA-HQ-OAR-2010-0505-7630**
- Maryland Facility Owner provided cost impacts
- Maryland staff discussions with Target Emissions Services Inc.
- Manufacture data on rod packing replacement costs

Appendix H – Public Hearing Documentation

Notice of public hearing/comment concerning Control of Methane from the NG Industry

Please Note: The Maryland Department of the Environment is proposing new Regulations .01 - .07 under new Chapter COMAR 26.11.41 Control of Methane from the Natural Gas Industry. This action proposes requirements to reduce vented and fugitive emissions of methane from both new and existing natural gas facilities. This action will not be submitted to the U.S. Environmental Protection Agency (EPA) as part of Maryland's State Implementation Plan (SIP) at this time.

The full text of the proposed new regulation will appear in the Maryland Register on **July 31, 2020. (See attached)**

Hearing Date: Mon, Aug 31, 2020 10:00 AM (EDT)

Due to the ongoing COVID-19 pandemic, a virtual public hearing will be held in accordance with Governor Hogan's State of Emergency proclamation[1] and Executive Order[2]prohibiting events and gatherings of ten (10) people or more.

Hearing Location: Virtual – gotomeeting

Virtual Hearing Connection Information:
Join online: https://global.gotomeeting.com/join/316465965
You can also dial in using your phone.
United States (Toll Free): 1 866 899 4679
Event Access Code: 316-465-965
New to GoToMeeting? Get the app now and be ready when your first meeting starts
https://global.gotomeeting.com/install/316465965

Deadline for Comments: September 3, 2020, 5:00 pm

Comments may be mailed or emailed to the addresses listed below or be submitted verbally during the hearing. If you would like to give a statement at the hearing we request that you notify Mr. Randy Mosier at randy.mosier@maryland.gov by Thursday August 27th.

We ask that oral comments be limited to 3 minutes, this is for respect of all participants' time, however written comments may be as detailed as necessary.
For more information or to submit comments:
Randy Mosier, Chief, Regulation Development Division
Air Quality Planning Program
Air and Radiation Administration
Maryland Department of the Environment
1800 Washington Boulevard, Suite 730
Baltimore, Maryland 21230-1720
Email: randy.mosier@maryland.gov

For questions by telephone: (410) 537-4488, 1-(800) 633-6101 ext. 4488

Information is also published on the Department's website
https://mde.maryland.gov/programs/Regulations/air/Pages/reqcomments.aspx

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[1] https://governor.maryland.gov/wp-content/uploads/2020/03/Proclamation-COVID-19.pdf
[2] https://governor.maryland.gov/wp-content/uploads/2020/03/Gatherings-FOURTH-AMENDED-3.30.20.pdf

Subtitle 79 APPLICATIONS CONCERNING THE CONSTRUCTION OR MODIFICATION OF GENERATING STATIONS, *QUALIFIED GENERATOR LEAD LINES*, AND OVERHEAD TRANSMISSION LINES

20.79.03 Details of Filing Requirements — Generating Stations

Authority: Public Utilities Article, §§*2-113*, 2-121, and 7-205—7-208, Annotated Code of Maryland

Notice of Proposed Action

[20-140-P]

The Maryland Public Service Commission proposes to adopt new Regulations **.03** and **.04** and recodify existing Regulation **.03** to be Regulation **.05** under **COMAR 20.79.03 Details of Filing Requirements — Generating Stations**. This action was considered by the Maryland Public Service Commission at a scheduled rule-making (RM 69) meeting held on May 21, 2020, notice of which was given under General Provisions Article, §3-302, Annotated Code of Maryland.

Statement of Purpose

The purpose of this action is to amend the Code of Maryland Regulations governing the filing requirements for an application for a Certificate of Public Convenience and Necessity (CPCN), for a qualifying fossil fuel generating station that is greater than 70 megawatts (MW) in nameplate capacity.

Comparison to Federal Standards

There is no corresponding federal standard to this proposed action.

Estimate of Economic Impact

The proposed action has no economic impact.

Economic Impact on Small Businesses

The proposed action has minimal or no economic impact on small businesses.

Impact on Individuals with Disabilities

The proposed action has an impact on individuals with disabilities as follows:

The proposed action does not directly impose any requirements or obligations on individuals with disabilities. In a broader sense, the proposed action could have an indirect, positive impact, qualitatively, on individuals with disabilities insofar as it requires the CPCN applicant to certify its efforts to meaningfully engage those affected communities—that is, communities most likely affected by the siting of the qualifying generating station (as that term is defined under proposed COMAR 20.79.01.02)—with regard to discussing the project before the CPCN application is filed. The proposed regulation would also require the applicant to describe any terms, incentives, or resolutions reached as a result of this engagement. Affected community members would include residents and individuals with disabilities located within the defined geographic radius of the proposed facility, consistent with the term "affected community" as defined in proposed COMAR 20.79.01.02.

Opportunity for Public Comment

Comments may be sent to Andrew S. Johnston, Executive Secretary, Maryland Public Service Commission, 6 St. Paul Street, Baltimore, MD 21202, or call 410-767-8067, or fax to 410-333-6495. Comments will be accepted through August 31, 2020. A public hearing has not been scheduled.

.03 EJSCREEN Reports.

An application for a proposed qualifying generating station shall be accompanied by:

A. A copy of the applicant's EJSCREEN Standard Report, or comparable report if the EJSCREEN is unavailable, which shall be based on a 3-mile circular buffer centered at the Geographic Information System coordinates of the proposed qualifying generating station and shall include a statement of the numerical thresholds applied to generate the report as required under COMAR 20.79.01.04; and

B. A copy of the applicant's EJSCREEN ACS Report, which shall be based on the same 3-mile circular buffer as the EJSCREEN Standard Report and shall utilize the U.S. Census Bureau American Community Survey data available through EJSCREEN.

.04 Statement of Public Engagement and Participation Certification.

An application for a proposed qualifying generating station shall be accompanied by a signed statement of public engagement and participation, which shall include:

A. A description of the time, place, and manner in which the applicant held the public meeting with members of the affected communities;

B. A description of the manner in which the applicant provided notice to the affected communities of the proposed public meeting with members of the affected communities;

C. A copy of any meeting sign-in sheet voluntarily indicating persons of interest; and

D. A description of any terms, incentives, or resolutions reached between the applicant and the affected communities.

ANDREW S. JOHNSTON
Executive Secretary

Title 26 DEPARTMENT OF THE ENVIRONMENT

Subtitle 11 AIR QUALITY

26.11.41 Control of Methane Emissions from the Natural Gas Industry

Authority: Environment Article, §§1-404, 2-103, 2-1202, and 2-1205, Annotated Code of Maryland

Notice of Proposed Action

[20-137-P]

The Secretary of the Environment proposes to adopt new Regulations **.01 — .07** under a new chapter, **COMAR 26.11.41 Control of Methane Emissions from the Natural Gas Industry**.

Statement of Purpose

The purpose of this action is to propose new Regulations .01 — .07 under new chapter COMAR 26.11.41 Control of Methane Emissions from the Natural Gas Industry. Methane emissions from the natural gas industry account for approximately 30 percent of all methane emissions generated in Maryland. This action establishes requirements to reduce vented and fugitive emissions of methane from both new and existing natural gas facilities.

Background

In 2009, the Maryland General Assembly adopted the Greenhouse Gas Emission Reduction Act (GGRA). This law required that the State develop and implement a plan to reduce greenhouse gas emissions by 25 percent by 2020, compared to the 2006 baseline. In 2015, the Maryland Commission on Climate Change (MCCC) was codified into law to provide guidance on greenhouse gas reductions while supporting a healthy economy and creating new jobs. The MCCC recommended to the Maryland General Assembly that several enhancements be made to the 2009 GGRA. In 2016, Governor Larry Hogan signed an updated version of the GGRA, establishing a new benchmark to reduce greenhouse gas emissions in Maryland by 40 percent by 2030.

The MCCC, through its Mitigation Work Group, recommended that Maryland focus on reducing methane emissions from landfills, natural gas infrastructure (for example, compressor stations and underground storage), and waste water treatment plants. This action focuses on reducing methane emissions from the natural gas infrastructure in Maryland to protect and restore the environment for the health and wellbeing of all Marylanders.

Methane is the primary constituent of natural gas and is the second most prevalent greenhouse gas emitted by human activity in the U.S. While methane does not linger as long in the atmosphere as carbon dioxide, it is initially far more impactful to the climate because of how effectively it absorbs heat.

EPA also began to address methane emissions from the oil and natural gas industry. In June 2016, EPA finalized updates to its New Source Performance Standards (40 CFR Part 60, Subpart OOOOa or 2016 NSPS OOOOa) for the oil and natural gas industry to reduce emissions of greenhouse gases. The 2016 NSPS OOOOa set emission limits for methane, which is the principal greenhouse gas emitted by equipment and processes in the oil and gas sector. The EPA final rule also requires owners/operators to find and repair leaks, also known as "fugitive emissions," which can be a significant source of both methane and volatile organic compound emissions.

On September 11, 2018, EPA proposed amendments to certain provisions of the 2016 NSPS OOOOa. Among other proposed amendments, EPA considered relaxing the regulatory burden to industry by reducing the monitoring frequency of fugitive emissions and extending the required time for leaks to be repaired.

On September 24, 2019, EPA proposed to further relax the 2016 NSPS OOOOa. EPA's new amendments propose to (1) remove sources in the transmission and storage segment from the affected source category and rescind the NSPS (including both the volatile organic compounds (VOC) and methane requirements) applicable to those sources, and (2) rescind the methane-specific requirements of the NSPS applicable to sources in the production and processing segments. EPA is also proposing, as an alternative, to rescind the methane requirements of the NSPS applicable to all oil and natural gas sources, without removing any sources from the source category. The Maryland Department of the Environment (the Department) opposes these proposed amendments and any relaxation of NSPS OOOOa. The Department commented and documented opposition to EPA's proposed rules in letters on December 17, 2018 (federal register docket ID EPA-HQ-OAR-2017-0483) and on November 25, 2019 (federal register docket ID EPA-HQ-OAR-2017-0757). In response, Maryland is proposing standards for new and existing facilities in the State to control methane emissions from the natural gas industry.

Specifically, this action proposes requirements to mitigate methane emissions through fugitive emissions detection and repair, and establishes control measure requirements to limit emissions from compressors and pneumatic devices. Facility-wide greenhouse gas emission data will be required to be calculated and submitted to the Department annually. Additionally, owners and operators will be required to notify the Department and the public during "blowdown events", which are the release of pressurized natural gas from stations, equipment, or pipelines into the atmosphere so that maintenance, testing, or other activities can take place.

The natural gas industry can be divided into four segments: (1) production; (2) gathering and processing; (3) transmission and storage; and (4) distribution. In the transmission and storage segment, compressors are used to maintain the pressure of the natural gas in transmission pipelines to deliver extracted gas to its eventual end-user. This action affects new and existing natural gas compressor stations, liquefied natural gas facilities, and underground storage facilities in the transmission and storage segment. In Maryland, there are four natural gas compressor stations, one liquefied natural gas import/export facility, and one underground storage facility. This action represents development of regulations with extensive input from public community groups, environmental advocates, the industry, and EPA.

Sources Affected and Location

• There are four natural gas compressor stations, one underground storage facility and one liquid natural gas (LNG) facility currently operating in Maryland that are subject to this regulation.

• The four compressor stations are: Dominion Myersville (Frederick County), Enbridge Texas Eastern (Garrett County), TC Energy (formerly TransCanada) Rutledge (Harford County), and Williams Transcontinental (Howard County),

• The one underground storage facility is Enbridge Texas Eastern (Garrett County)

• The one LNG facility is Dominion Cove Point (Calvert County).

• All new NG compressor stations, underground storage facilities, and LNG facilities will be subject to this regulation.

Requirements

The federal Clean Air Act provides that states may set more stringent standards, and the proposed regulations are more stringent than existing federal rules. Maryland is proposing detection, testing, repair, reporting, and record-keeping requirements for all existing and new facilities in the State.

Leak Detection and Repair (LDAR):

Fugitive emissions can occur from leaking compressors, pipelines, and other equipment components such as valves, connectors, pressure relief devices, and flanges. Unmonitored or faulty equipment with fugitive leaks exacerbates the methane emissions at a facility.

Maryland's proposed regulations require owners/operators to do the following:

• Develop and submit a leak monitoring plan to the Department within 90 days of the adoption of the rule. New, modified, or reconstructed facilities will have up to 90 days to submit a methane emissions monitoring plan from the startup of the facility's operation.

• Conduct leak monitoring surveys at prescribed intervals using optical gas imaging (OGI) or EPA Method 21 as well as inspecting for leaks using audio, visual, and olfactory (AVO) observations. The Department will consider any new and/or emerging leak detection technology as an alternative practice to monitor for leaks.

• Repair or replace identified leaking component(s) within 30 days of leak discovery and verify that the leak has been successfully repaired. Owners/operators may submit a delay of repair request to the Department if the leaking component(s) requires a specialty part, is unsafe to repair during the operation of the unit, and/or would require a vent or compressor station blowdown.

• Follow applicable annual and quarterly record-keeping and reporting requirements.

• New, modified, or reconstructed facilities will have up to 180 days to conduct an initial monitoring survey from the startup of the facility's operation.

Facilities that use natural gas-powered equipment to compress natural gas and new liquefied natural gas (LNG) facilities:

• These facilities shall conduct quarterly inspections of fugitive emissions components using an OGI instrument or EPA's Method 21. The initial monitoring survey shall be conducted within 180 days of the adoption of the regulation.

• Weekly AVO inspection of all fugitive emissions components shall be conducted.

Facilities that use electric-powered equipment to compress natural gas:

• Electric-powered equipment used to compress natural gas emits less methane than natural gas-powered equipment by eliminating the need for fuel gas. Furthermore, electric-powered compressors produce no exhaust byproduct.

• These facilities shall conduct annual inspections of fugitive emissions components using an OGI instrument or EPA's Method 21. The initial monitoring survey shall be conducted within 180 days of the adoption of the regulation

• Monthly AVO inspection of all fugitive emissions components shall be conducted.

Natural gas underground storage fields and wellheads:

• These facilities shall conduct quarterly inspections of fugitive emissions components using an OGI instrument or EPA's Method 21. The initial monitoring survey shall be conducted within 180 days of the adoption of the regulation.

• Monthly AVO inspection of all fugitive emissions components shall be conducted.

• Additionally, every month, record the following measurements: the well-head pressure or water level measurement, as appropriate; the open flow on the annulus of the production casing or the annulus pressure if the annulus is shut in; a measurement of gas escaping the well if there is evidence of a gas leak; and evidence of progressive corrosion, rusting, or other signs of equipment deterioration.

• For each natural gas storage well with emissions that exceed 1,440 cubic feet per day, owners and operators shall: (1) notify the Department within 1 business day of discovering the emission rate exceedance; and (2) file a written report within 10 days which shall include an explanation of the problem and corrective action taken or planned.

Dominion Cove Point LNG facility:

Cove Point has two existing LDAR plans with equivalent stringency as this proposal:

(1) The leak detection and repair requirements as specified by the Climate Action Plan, which is defined, prepared, and approved under COMAR 26.09.02.06.B — E.; and

(2) The leak detection and repair plan defined and approved under the Certificate of Public Convenience and Necessity, issued by the Maryland Public Service Commission on May 30, 2014, Order No. 86372, Case No. 9318, as amended on February 6, 2018, with Order No. 88565, and Errata on February 23, 2018, to Order No. 88565, as amended.

Natural Gas-Powered Pneumatic Devices:

Pneumatic devices are used for maintaining a process condition such as liquid level, pressure, or temperature. As part of normal operations, natural gas-powered pneumatic devices release or bleed natural gas to the atmosphere. The Department is proposing a phase-out of all high bleed continuous natural gas-powered devices. Additional requirements are summarized below:

• Beginning January 1, 2021, LDAR monitoring for all natural gas-powered pneumatic devices;

• By January 1, 2022, continuous bleed natural gas-powered pneumatic devices cannot have a bleed rate greater than 6 standard cubic feet per hour; and

• By January 1, 2023, continuous bleed natural gas-powered pneumatic devices shall be converted to electric or compressed air-powered devices.

The Department is proposing an exemption for continuous bleed natural gas-powered pneumatic devices with a low bleed rate that is needed for safety or operational purposes. Furthermore, this action includes record-keeping and reporting requirements to the Department.

Reciprocating Compressors:

Reciprocating compressors are used to increase the pressure of the natural gas flowing through the transmission pipelines. Over time, rod packing systems within these reciprocating compressors can wear, resulting in leaking methane. Maryland's proposed rules provide two mitigation options for methane emissions from rod packing systems:

• Emissions from the rod packing shall be routed to a process or control device; or

• Rod packing flow rates shall be measured annually and rod packing systems with emissions greater than 1 standard cubic foot per minute (scfm) shall: (1) Be replaced; or (2) Be measured every 6 months until the rod packing flow rate reaches 2 scfm, at which point the rod packing shall be replaced.

Reciprocating compressor's fugitive emission components shall be subject to LDAR requirements. This action also includes record-keeping and reporting requirements to the Department.

Record-Keeping and Reporting Requirements:

An annual report is due to the Department on April 1 of each year, owners and operators can combine reporting sections together into one report for greenhouse gas reporting.

LDAR reports are due to the Department either quarterly or annually based on the regulatory section identified throughout COMAR 26.11.41.03.

• Quarterly LDAR reports are accepted from a 3rd party if the details are provided.

• The Department is requiring an LDAR summary be publicly posted after each monitoring survey.

Blowdown Events and Reporting:

Blowdown events are common occurrences in which pressurized natural gas is released from stations, equipment, or pipelines into the atmosphere for maintenance and operational purposes. Maryland's rule requires owners and operators to notify the Department and the public whenever a blowdown activity with threshold of greater than 1,000,000 standard cubic feet of methane will be released. Owners and operators will be required to record all blowdown events greater than 50 standard cubic feet and report those blowdown emissions annually. The following requirements apply to affected sources:

• Submit a public notification plan to the Department for approval;

• Notification of planned blowdowns in the excess of 1,000,000 scf should be given at least 7 days prior to the start of the event;

• Notification of emergency blowdowns should be given within 1 hour of the start of the event; and

• Owners and operators shall calculate and submit to the Department annually the total methane emissions from all blowdown events.

Greenhouse Gas Emissions Reporting:

Greenhouse gas emissions from the oil and natural gas industry account for approximately 20 percent of all greenhouse gas emissions in the United States. Natural gas facilities have the potential to emit greenhouse gases from a variety of sources, including fugitive emission components, stationary fuel combustion sources, and other site activities (for example, blowdowns, maintenance, compressor startups, compressor shutdowns, etc.). On October 20, 2009, EPA published a rule for the mandatory reporting of greenhouse gases from oil and natural gas facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. Oil and natural gas facilities that emit less than the 25,000 metric tons threshold were exempted from EPA's rules. Maryland's proposed rule will require all facilities in the natural gas industry, regardless of their greenhouse gas emissions threshold, to report greenhouse gas emissions data to the Department. Maryland's greenhouse gas emissions reporting requirements will require facilities to collect greenhouse gas data, calculate greenhouse gas emissions, and follow specified procedures for quality assurance, missing data, record keeping, and reporting. Maryland's requirements mirror EPA's Greenhouse Gas Reporting Program (40 CFR Part 98) to harmonize with federal rules and reduce regulatory burden.

Projected Emission Reductions

The Department estimates the proposed regulations will minimize the release of methane emissions from the natural gas transmission and storage activities in the State. The proposed rule will minimize the release of methane emissions from existing sources in the range of 600 to 5,000 metric tons per year through leak surveys, replacement of leaking equipment and components, and inspection practices. That has the equivalent climate change mitigation benefit as reducing carbon dioxide emissions by 51,600 — 430,000 metric tons per year, using the 20-year global warming potential for methane.

Leak detection and repair (LDAR) surveys can produce varying results, but it is understood throughout the industry that technology is advancing to help minimize fugitive leaks. LDAR leads to reduced emissions, valuable product recovery, and increased safety of operations. A leak survey is most effective when performed on a routine basis to capture the unknown nature of unintentional poor performance.

The Department has reviewed literature on the proposed impacts of a fugitive leak detection and repair program from EPA, California, environmental advocates, and the industry. The potential emissions reductions, quoted in the EPA 2015 Regulatory Impact Analysis for the 2016 NSPS OOOOa, range from 40 — 80 percent depending on the frequency of surveys. Under California's rule making for "Greenhouse Gas Emission Standards For Crude Oil And Natural Gas Facilities" finalized in 2017, California assumes a 60 percent reduction in methane emissions due to quarterly LDAR. However California also notes there can be a wide range of conditions that can disproportion data from an average assumption. It is understood that the industry has skewed emissions distributions, where a small number of facilities can account for a large portion of emissions.

Vented methane emissions from reciprocating compressor engines and natural gas driven pneumatic devices will be reduced by equipment monitoring, repair, and replacement. EPA Natural Gas STAR Program Partner Reported Opportunities (PROs) Fact Sheets and information from the equipment manufacturing industry estimate emissions reduction can be achieved up to 50 percent.

The nature of operations at each specific station determine the yearly emissions at a facility. The Department has used existing federal reporting figures through the Greenhouse Gas Reporting Rule (40 CFR Part 98) and figures from the Department's annual emission certification reports to estimate methane reductions in Maryland. The Department has calculated a range of potential methane reductions per year. The Department assumed a range of 40 to 80 percent reduction from the proposed regulation applied to recently reported methane emissions.

As the natural gas industry expands, any future sources in the production and transmission sector of the natural gas industry will be required to follow these State regulations, as well as federal rules. Advanced construction, maintenance, and inspection practices will be utilized, and therefore large emission reductions will not be anticipated. Reporting is a key tool to understanding the emissions in the industry and the State. The documented mitigation strategies will be a tool to further analyze State and national inventories and industry emission factors.

Comparison to Federal Standards

In compliance with Executive Order 01.01.1996.03, this proposed regulation is more restrictive or stringent than corresponding federal standards as follows:

(1) Regulation citation and manner in which it is more restrictive than the applicable federal standard:

New sources, which are facilities built, modified, or reconstructed after September 18, 2015, are subject to federal 2016 NSPS OOOOa requirements. The proposed regulations require both new and existing facilities to monitor and reduce methane emissions. Therefore, the proposed regulations are more stringent than the federal standard. However, Maryland has aligned requirements and reporting with the federal 2016 NSPS OOOOa whenever possible.

(2) Benefit to the public health, safety, or welfare, or the environment:

Methane is a highly potent greenhouse gas that needs to be acted upon quickly because it is a short-lived climate pollutant (SLCP). Methane emissions from the natural gas industry account for approximately 30 percent of all methane emissions generated in Maryland. Proposed methane reductions from this regulation can help to minimize greenhouse gases. Mitigation and adaption measures help minimize losses to Maryland businesses and communities from climate risk such as sea-level rise or heat-related stress.

(3) Analysis of additional burden or cost on the regulated person:

The Department estimates affected facilities will be required to spend, on average, in 2018 dollars, $25,000 annually on leak surveys. Additionally some capital investment may be required in the range from $10,000 — $100,000. Affected facilities are also required to submit annual reports to the Department, which may result in additional reporting costs. However, since the proposed annual reporting requirements harmonize with the existing federal requirements, the Department estimates reporting costs to be minimal. Additional details follow in the section below and the Department's technical support documents.

(4) Justification for the need for more restrictive standards:

The Maryland General Assembly adopted, and Governor Hogan signed, the 2016 Greenhouse Gas Emission Reduction Act (GGRA) reauthorization. Methane reductions from this natural gas sector reduce greenhouse gases. Additionally EPA has proposed two separate rules relaxing standards for new sources under NSPS OOOOa. These relaxations will result in increased methane leakage. Due to the relaxations at the federal level, Maryland is proposing this regulation to strengthen methane mitigation practices.

Estimate of Economic Impact

I. Summary of Economic Impact. The proposed regulation requires facilities in the natural gas industry to perform quarterly or annual leak surveys to identify and minimize unintentional fugitive emissions. The proposed regulation may require facilities to purchase, retrofit, and service capital equipment. The Department estimates affected facilities will be required to spend, on average, in 2018 dollars, $25,000 annually on leak surveys. Leak surveys require reporting with the survey plan. Repairs and maintenance may be an additional cost; however, product loss will be decreased. Some capital investment may be required and can vary in cost depending on the sophistication of the engineering design and the age of existing equipment but are estimated to range from $10,000 — $100,000. Affected facilities are also required to submit annual reports to the Department, which may result in additional reporting costs. However, since the proposed annual reporting requirements harmonize with the existing federal requirements, the Department estimates reporting costs to be minimal. The Department has reviewed literature on the proposed cost impacts of a fugitive leak detection and repair program from EPA, California, environmental advocates, and the industry. Additionally, the Department received cost estimates from manufacturers on equipment and maintenance. The businesses in this industry are not small.

MDE's mission is to protect and restore the environment for the health and wellbeing of all Marylanders. Working to mitigate and adapt to climate change are main components of this mission authorized by the GGRA. Marylanders are already witnessing firsthand the impacts of climate change, from more frequent, severe flooding that threatens the State's agricultural sector, to more powerful heat waves that put lives at risk. That's why the State's GGRA Plan to cut greenhouse gas emissions 40 percent by 2030 and Governor Hogan's commitment to develop a clean and renewable energy standard are so important. Maryland has made great progress on reducing air pollution and greenhouse gas emissions, and adapting to the potential consequences of climate change, while creating jobs and benefiting the economy. Comprehensive methane pollution regulation is a key part of making sure Maryland can continue to make progress and meet emission reduction goals.

II. Types of Economic Impact.	Revenue (R+/R-) Expenditure (E+/E-)	Magnitude
A. On issuing agency:		
State agency inspection	(E+)	Minimal
B. On other State agencies:	NONE	
C. On local governments:	NONE	

	Benefit (+) Cost (-)	Magnitude
D. On regulated industries or trade groups:		
Affected facilities	(-)	$10,000 — $100,000
F. Direct and indirect effects on public:		
Environmental protection/public health	(+)	Indeterminable

III. Assumptions. (Identified by Impact Letter and Number from Section II.)

A. Existing air compliance inspector staff will enforce these regulations.

D. Affected facilities will be required to spend, on average, in 2018 dollars, $25,000 annually on leak surveys. Some capital investment is estimated to range from $10,000 — $100,000.

F. The proposed regulation will have a positive effect on public health and the environment. Short-lived climate pollutants (SLCPs) are harmful air pollutants and potent climate forcers with a much shorter lifespan in the atmosphere than carbon dioxide. Reducing emissions of methane will combat the adverse impacts of climate change in Maryland.

Economic Impact on Small Businesses

The proposed action has minimal or no economic impact on small businesses.

Impact on Individuals with Disabilities

The proposed action has no impact on individuals with disabilities.

Opportunity for Public Comment

The Department of the Environment will hold a virtual public hearing on the proposed action on August 31, 2020, at 10 a.m. See the Department's website for virtual hearing information (https://mde.maryland.gov/programs/Regulations/air/Pages/reqcomments.aspx). Interested persons are invited to attend and express their views. Comments may be sent to Mr. Randy Mosier, Chief of the Regulation Division, Air and Radiation Administration, Department of the Environment, 1800 Washington Boulevard, Suite 730, Baltimore, MD 21230, or email to randy.mosier@maryland.gov. Comments must be received by no later than 5 p.m. on Sept. 3, 2020, or be submitted at the hearing. For more information, call Randy Mosier at 410-537-4488.

.01 Definitions.

A. In this chapter, the following terms have the meanings indicated.

B. Terms Defined.

(1) "Affected facilities" means any one of the following facilities:

(a) Cove Point Liquefied Natural Gas Facility;

(b) Myersville Natural Gas Compressor Station;

(c) Accident Natural Gas Compressor Station and Storage;

(d) Rutledge Natural Gas Compressor Station;

(e) Ellicott City Natural Gas Compressor Station; and

(f) Any new, modified, or reconstructed natural gas compressor station, natural gas underground storage facility, or liquefied natural gas facility.

(2) "Audio, visual, and olfactory inspection" means sensory monitoring to detect natural gas leaks utilizing a human ear, eyes, and nose.

(3) Blowdown.

(a) "Blowdown" means the release of pressurized natural gas from a station, equipment, or pipelines into the atmosphere conducted with the intent to lower the pressure in a vessel or pipeline.

(b) "Blowdown" does not include natural gas pneumatics emissions, fugitive components emissions, or pressure seal leakage.

(4) "Bubble test" means the alternative screening procedure as described at EPA Method 21 (40 CFR 60, Appendix A-7, §8.3.3).

(5) "Component" means a valve, fitting, flange, threaded-connection, process drain, stuffing box, pressure-vacuum valve, pressure-relief device, pipes, seal fluid system, diaphragm, hatch, sight-glass, meter, open-ended line, well casing, natural gas powered pneumatic device, natural gas powered pneumatic pump, reciprocating compressor rod packing/seal, metal to metal joint or seal of nonwelded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

(6) "Continuous bleed" means the continuous venting of natural gas from a gas-powered pneumatic device to the atmosphere.

(7) "Difficult-to-monitor" means fugitive emissions components that cannot be monitored for natural gas leakage without the monitoring personnel needing specialized equipment to reach components above the grade.

(8) "Direct measurement" means use of high volume sampling, calibrated bagging, a calibrated flow measuring instrument, or a temporary meter.

(9) "Fuel gas system" means components and equipment that collect and transfer natural gas to be used as a fuel source to on-site natural gas-powered equipment other than a vapor control device.

(10) Fugitive Emissions Component.

(a) "Fugitive emission component" means any component that has the potential to emit fugitive emissions of natural gas, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers, and vapor collection systems.

(b) "Fugitive emission component" does not include devices that vent as a part of normal operations, such as natural gas-driven pneumatic devices or annulus vents, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission.

(c) "Fugitive emission component" includes thief hatches or other openings on a storage vessel, compressor, instrument, natural gas-powered pneumatic device, or meter that are not venting.

(11) "Intermittent bleed" means a pneumatic controller that is designed to vent noncontinuously.

(12) "Leak detection and repair" or "LDAR" means the inspection of fugitive emissions components to detect leaks of total methane and the repair of components with leaks above the standards specified in this chapter and within the time frames specified in this chapter.

(13) "Leak or fugitive leak" means any visible emission from a fugitive emissions component observed by optical gas imaging or an instrument reading of 500 ppm or greater of methane using U.S. EPA Method 21 (40 CFR 60, Appendix A-7) or any emissions discovered from a fugitive emissions component observed using an auditory, visual, and olfactory inspection.

(14) "Liquefied natural gas" or "LNG" means natural gas or synthetic gas having methane as its major constituent which has been changed to a liquid.

(15) "LNG facility" means a pipeline facility that is used for liquefying natural gas or synthetic gas or transferring, storing, or vaporizing liquefied natural gas, and includes all components and stationary equipment within the fence line.

(16) "Natural gas" means a naturally occurring mixture or process derivative of hydrocarbon and nonhydrocarbon gases, which has methane as its major constituent.

(17) "Natural gas compressor station" means all equipment and components located within a facility fence line associated with moving natural gas from production fields or natural gas processing plants through natural gas transmission pipelines, or within natural gas storage fields.

(18) "Natural gas storage well" means a well located and used in a natural gas storage reservoir for injection or withdrawal purposes, or an observation well.

(19) "Natural gas underground storage" means all equipment and components associated with the temporary subsurface storage of natural gas in depleted crude oil or natural gas reservoirs or salt dome caverns, not including gas disposal wells.

(20) "Observation well" means a well used to monitor the operational integrity and conditions in a natural gas storage reservoir, the reservoir protective area, or the strata above or below the gas storage horizon.

(21) "Optical gas imaging" or "OGI" means an instrument that makes emissions visible to the naked eye that may otherwise be invisible.

(22) "Pneumatic device" means an automation device that uses natural gas or compressed air to control a process.

(23) "Process gas system" means components and equipment that collect and transfer the natural gas to be used through the intended process of the facility, including storage, transmission, or liquefaction.

(24) "Reciprocating natural gas compressor" means equipment that increases the pressure of natural gas by positive displacement of a piston in a compression cylinder and is powered by an internal combustion engine or electric motor with a horsepower rating designated by the manufacturer.

(25) "Reciprocating natural gas compressor rod packing" means a seal composed of a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that leaks into the atmosphere.

(26) "Reciprocating natural gas compressor seal" means any device or mechanism used to limit the amount of natural gas that leaks from a compression cylinder into the atmosphere.

(27) "Successful repair" means tightening, adjusting, or replacing equipment or a component for the purpose of stopping or reducing fugitive leaks below the minimum leak threshold or emission flow rate standard specified in this chapter.

(28) "Unsafe-to-monitor" means fugitive emissions components that cannot be monitored for natural gas leakage because monitoring personnel would be exposed to immediate danger while conducting a monitoring survey.

(29) "Vapor collection system" means equipment and components installed on pressure vessels, separators, tanks, sumps, piping, connections, reciprocating compressors, natural gas-powered pneumatic devices, and flow-inducing devices used to collect and route emission vapors to a processing gas system, fuel gas system, or vapor control device.

(30) "Vapor control device" means destructive or nondestructive equipment used to control otherwise vented emissions.

.02 Applicability.

The provisions of this chapter apply to an affected facility as that term is defined in Regulation .01B of this chapter.

.03 Leak Detection and Repair Requirements.

A. Affected facilities that are natural gas compressor stations or natural gas underground storage facilities and that use natural gas-powered equipment to compress natural gas shall comply with the following leak detection and repair requirements.

(1) Owners and operators of affected facilities subject to this section shall develop and submit to the Department an initial methane emissions monitoring plan that includes a technique for determining fugitive emissions (for example, EPA Method 21 at 40 CFR part 60, appendix A–7, or optical gas imaging).

(2) If an affected facility uses optical gas imaging for leak detection, the following information shall be included in the initial methane emissions monitoring plan:

(a) A list of the unsafe-to-monitor components;

(b) Procedures and time frames for identifying and repairing fugitive emissions components;

(c) A defined observation path throughout the site to confirm all components can be viewed and recorded;

(d) Manufacturer and model number of fugitive emissions detection equipment to be used; and

(e) Equipment specifications and procedures as specified in 40 CFR §60.5397a(c)(7), as published in July 2017.

(3) If an affected facility uses EPA Method 21 (40 CFR 60, Appendix A-7) for leak detection, the following information shall be included in the initial methane emissions monitoring plan:

(a) A list of all fugitive emission components, difficult-to-monitor components, and unsafe-to-monitor components at an affected facility;

(b) Procedures and time frames for identifying and repairing fugitive emission components; and

(c) Equipment specifications and procedures as specified in 40 CFR §60.5397a(c)(8), as published in July 2017.

(4) Each difficult-to-monitor and unsafe-to-monitor component shall be identified in the written initial methane monitoring plan explaining the location and why the fugitive emissions components are difficult-to-monitor and unsafe-to-monitor.

(5) Initial Methane Emissions Monitoring Plan Submission.

(a) Except for a new natural gas compressor station or natural gas underground storage facility, owners and operators of the affected facilities subject to this section shall submit the initial methane emissions monitoring plan required in §A(1)—(4) of this regulation to the Department within 90 days of the adoption of this regulation.

(b) Owners and operators of a new natural gas compressor station or natural gas underground storage facility subject to this section shall submit the initial methane emissions monitoring plan required in §A(1)—(4) of this regulation to the Department within 60 days of startup.

(6) Owners and operators of affected facilities that modify or reconstruct a natural gas compressor station or underground storage facility shall submit an initial monitoring plan with the elements in §A(1)—(4) of this regulation within 90 days of the facility startup operation for each new collection of fugitive emissions components at the modified or reconstructed compressor station or underground storage facility.

(7) Owners or operators of affected facilities subject to this section shall conduct an audio, visual, and olfactory inspection of all fugitive emission components for leaks or indications of leaks at least once per calendar week except for:

(a) Unsafe-to-monitor components; and

(b) Natural gas storage wells and observations, which shall conduct audio, visual, and olfactory inspections according to §A(10) of this regulation.

(8) Leak Monitoring Survey.

(a) Owners and operators of affected facilities shall follow the initial monitoring methane plan and shall inspect all fugitive emission components, except for unsafe-to-monitor components, for leaks using OGI or EPA Method 21 within 180 days of the adoption of this chapter and quarterly thereafter.

(b) Owners and operators of affected facilities that install any new, modified, or reconstructed natural gas compressor station or underground storage facility that uses natural gas-powered equipment to compress natural gas shall meet the requirements of §A(8)(a) of this regulation within 180 days of the startup of the facility's operations.

(c) At least annually, all difficult-to-monitor fugitive emissions components shall be inspected for leaks using an OGI camera.

(9) Repair Requirements.

(a) Any leaking fugitive emissions component identified during a leak monitoring survey or audio, visual, and olfactory inspection shall be successfully repaired, replaced, or removed from service as soon as practicable, but no later than 30 calendar days after leak detection.

(b) Fugitive Emissions Component Resurvey.

(i) Each repaired or replaced fugitive emissions component shall be resurveyed within 30 days after being repaired or replaced using either OGI or EPA Method 21 (40 CFR 60, Appendix A-7).

(ii) Owners and operators of facilities subject to this section that use EPA Method 21 (40 CFR 60, Appendix A-7) to resurvey the repaired or replaced fugitive emissions component shall consider the fugitive emissions component repaired when the EPA Method 21 (40 CFR 60, Appendix A-7) instrument indicates a concentration of less than 500 ppm of methane or when no soap bubbles are observed during a bubble test.

(iii) Owners and operators of affected facilities subject to this section that use OGI to resurvey the repaired or replaced fugitive emissions component shall consider the fugitive emissions component repaired when the OGI instrument shows no indication of visible emissions or when no soap bubbles are observed during a bubble test.

(c) A delay of repair may occur when, upon request, the owner or operator provides documentation to the Department that supports the following:

(i) The parts or equipment required to make necessary repairs will take longer than 30 days to be ordered and delivered, but the repair may not exceed 1 year;

(ii) The repair is unsafe to perform during the operation of the unit; or

(iii) The repair requires a blowdown or facility shutdown in order to complete.

(d) Leaking fugitive emission components awaiting repair or replacement under a delay of repair shall be clearly marked or identified in the facility's records.

(e) Leaking fugitive emission components under a delay of repair according to §A(9)(c)(i) of this regulation shall:

(i) Be repaired or replaced within 7 days after the owner or operator receives parts or equipment; or

(ii) Be repaired or replaced at the next vent or compressor station blowdown if the owner or operator has identified this fugitive emission component as needing a vent or compressor station blowdown.

(f) Fugitive emission components under a delay of repair according to §A(9)(c)(ii) and (iii) of this regulation shall be repaired or replaced within 1 year, at the next vent blowdown or facility shutdown, whichever occurs first.

(g) If a repair of a leak cannot be successfully completed according to this subsection, the owner or operator of the affected facility shall prepare a plan, for Department approval, that includes:

(i) An explanation of the technical difficulty;

(ii) A timeline to successfully repair the fugitive emission components;

(iii) A calculation of the additional methane that is expected to be released while on delay of repair; and

(iv) Upon written request from the Department, any other information that the Department determines is necessary to evaluate the plan.

(h) The owner or operator of the affected facility shall submit any plan required under §A(9)(g) of this regulation to the Department within 30 days from identifying the leak.

(10) Natural Gas Storage Field Inspections.

(a) Owners and operators of natural gas underground storage facilities shall conduct an audio, visual, and olfactory inspection of every natural gas storage well and observation well in the natural gas storage field at least once each month.

(b) For each inspection according to §A(10)(a) of this regulation, owners and operators shall record:

(i) The well-head pressure or water level measurement, as appropriate;

(ii) The open flow on the annulus of the production casing or the annulus pressure if the annulus is shut in;

(iii) A measurement of gas escaping the well if there is evidence of a gas leak; and

(iv) Evidence of progressive corrosion, rusting, or other signs of equipment deterioration.

(c) For each natural gas storage well with emissions that exceed 1,440 cubic feet per day, owners and operators shall:

(i) Notify the Department within 1 business day of discovering the emission rate exceedance; and

(ii) File a written report within 10 days which shall include an explanation of the problem and corrective action taken or planned.

(d) For each audio, visual, and olfactory inspection that detects a leaking fugitive emission component, the owner and operator shall comply with the repair requirements specified in §A(9) of this regulation, as applicable.

B. Affected facilities that are natural gas compressor stations and natural gas underground storage facilities, that exclusively use electric-powered equipment to compress natural gas, shall comply with the following leak detection and repair requirements.

(1) Owners and operators of facilities in this section shall meet the requirements of §A(1)—(6), (9), and (10) of this regulation.

(2) Except for unsafe-to-monitor components, owners or operators of facilities in this section shall conduct an audio, visual, and olfactory inspection of all fugitive emission components for leaks or indications of leaks at least once per calendar month.

(3) Leak Monitoring Survey.

(a) Except for unsafe-to-monitor components, owners and operators of affected facilities subject to this section shall inspect all fugitive emission components, including difficult-to-monitor components, for leaks using OGI or EPA Method 21 (40 CFR 60, Appendix A-7) within 180 days of the adoption of this chapter and annually thereafter.

(b) Owners and operators of affected facilities that install any new, modified, or reconstructed natural gas compressor station or underground storage facility that uses electric-powered equipment to compress natural gas shall meet the requirements of §B(3)(a) of this regulation within 180 days of the startup of the facility's operations.

C. Cove Point Liquefied Natural Gas facility shall comply with:

(1) The leak detection and repair requirements as specified by the Climate Action Plan, which is defined, prepared, and approved under COMAR 26.09.02.06.B — E; and

(2) The leak detection and repair plan defined and approved under the Certificate of Public Convenience and Necessity, issued by the Maryland Public Service Commission on May 30, 2014, Order No. 86372, Case No. 9318, as amended on February 6, 2018, with Order No. 88565, and Errata on February 23, 2018, Order No. 88565, as amended.

D. Any new liquefied natural gas facility that begins operations or repairs after the effective date of this chapter shall comply with §A of this regulation.

E. If an owner requests approval, the Department may approve a new technology or alternative practice to identify leaking fugitive emissions components as an equivalent substitution for the requirements in §A or B of this regulation.

.04 Natural Gas-Powered Pneumatic Devices Methane Emission Control Requirements.

A. Beginning January 1, 2021, each continuous and intermittent bleed natural gas-powered pneumatic device shall comply with the leak detection and repair requirements specified in Regulation .03 of this chapter, as applicable, when the device is idle and not controlling.

B. By January 1, 2022, continuous bleed natural gas-powered pneumatic devices shall not vent natural gas at a rate greater than 6 standard cubic feet per hour.

C. By January 1, 2023, all continuous bleed natural gas-powered pneumatic device shall be converted to use compressed air or electricity to operate unless an exemption is provided in §D of this regulation.

D. Exemption. Continuous bleed natural gas-powered pneumatic devices may be used if:

(1) The owner and operator collect all vented natural gas from the pneumatic device with the use of a vapor collection system according to Regulation .06 of this chapter; or

(2) The owner and operator submit justification for approval to the Department which demonstrates the need for the continuous bleed pneumatic device for safety or process purposes, as follows:

(a) Each continuous bleed pneumatic device that is approved for use shall be tagged with the month and year of installation, reconstruction, or modification and shall also have a permanent tag that identifies the natural gas flow rate as less than or equal to 6 standard cubic feet per hour; and

(b) The owner and operator shall:

(i) Inspect each continuous bleed pneumatic device on a monthly basis;

(ii) Perform necessary maintenance (including cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals and tuning to operate over a broader range of proportional band to eliminate unnecessary valve positioners);

(iii) Maintain the pneumatic device according to manufacturer specifications to ensure that the device's natural gas emissions are minimized;

(iv) By April 1, test each pneumatic device annually using a direct measurement method (high volume sampling, bagging, calibrated flow measuring instrument, etc.); and

(v) Successfully repair any device with a measured emissions flow rate that exceeds 6 standard cubic feet per hour within 14 calendar days from the date of the exceedance.

.05 Reciprocating Natural Gas Compressor Methane Emission Control Requirements.

A. All reciprocating natural gas compressor components at an affected facility shall comply with the leak detection and repair requirements in Regulation .03 of this chapter where applicable.

B. Control Measures for Reciprocating Natural Gas Compressor.

(1) By January 1, 2021, compressor vent stacks used to vent rod packing/seal emissions shall be controlled with the use of a vapor collection system as specified in Regulation .06 of this chapter; or

(2) By April 1, the reciprocating natural gas compressor rod packing/seal emission flow rate through the rod packing/seal vent stack shall be measured annually through direct measurement (high volume sampling, bagging, calibrated flow measuring instrument, etc.) while the compressor is operating at normal operating temperature.

(a) Direct measurements shall use one of the following methods:

(i) Vent stacks shall be equipped with a meter or instrumentation to measure the rod packing or seal emissions flow rate; or

(ii) Vent stacks shall be equipped with a clearly identified access port to measure individual or combined rod packing or seal emission flow rates.

(b) If the measurement is not obtained because the compressor is not operating for the scheduled test date, testing shall be conducted within 7 calendar days of resumed operation.

(3) A reciprocating natural gas compressor with a rod packing/seal with a measured emission flow rate that exceeds 1 standard cubic foot per minute, or a combined rod packing or seal emission flow rate that exceeds the number of compression cylinders multiplied by 1 standard cubic foot per minute shall:

(a) Be successfully repaired or replaced within 30 calendar days from the date of the exceedance; or

(b) Conduct natural gas compressor rod packing/seal emission flow rate measurements every 6 months or when the compressor resumes operation, whichever is later.

(4) A reciprocating natural gas compressor with a measured emission flow rate that exceeds 2 standard cubic feet per minute, or a combined rod packing or seal emission flow rate that exceeds the number of compression cylinders multiplied by 2 standard cubic feet per minute, shall be successfully repaired or replaced within 30 calendar days from the date of the exceedance.

C. Delay of Repair for Reciprocating Natural Gas Compressor.

(1) A delay of repair may occur provided the owner or operator provides documentation, upon request from the Department, that the delivery of parts or equipment required to make necessary repairs will take more than 30 days from the last emission flow rate measurement and that the parts have been ordered.

(2) A delay of repair to obtain parts or equipment may not exceed 60 days from the date of the last emission flow rate measurement unless the owner or operator notifies the Department, in writing, of the extended delay and provides an estimated time by which the repairs will be completed.

(3) A reciprocating natural gas compressor with a rod packing/seal emission flow rate measured above the standard specified in §B(4) of this regulation, and which has leaking parts deemed unsafe to monitor or requiring a facility shutdown, shall be successfully repaired by the end of the next planned process shutdown or within 12 months from the date of the flow rate measurement, whichever is sooner.

.06 Vapor Collection System and Vapor Control Devices.

A. Owners or operators of affected facilities that utilize vapor collection systems and vapor control device to comply with this chapter shall follow the requirements as specified in §§B and C of this regulation.

B. If a vapor collection system does not route all gases, vapors, and fumes to either a process gas system or a fuel gas system by January 1, 2021, a vapor control device shall be installed which meets the requirements of §E of this regulation.

C. The vapor collection system shall have no detectable emissions, as determined using auditory, visual, and olfactory inspections as specified in Regulation .03A(7) of this chapter.

D. The vapor collection system shall comply with the leak monitoring survey and repair requirements as specified in Regulation .03 of this chapter, where applicable.

E. Vapor control devices shall meet one of the following requirements:

(1) A nondestructive vapor control device manufacturer-designed to achieve at least 95 percent vapor control efficiency of methane emissions and may not result in emissions of nitrogen oxides (NOx); or

(2) A destructive vapor control device manufacturer-designed to achieve at least 95 percent vapor control efficiency of methane emissions and does not generate more than 15 parts per million volume (ppmv) NOx when measured at 3 percent oxygen; or require the use of supplemental fuel gas, other than gas required for a pilot burner, to operate.

.07 Record-Keeping and Reporting Requirements.

A. Owners or operators of affected facilities shall maintain, submit as described in this section, and make available upon request by the Department a copy of records necessary to verify compliance with the provisions of this chapter, as follows:

(1) For each leak monitoring survey and audio, visual, and olfactory inspection conducted according to Regulation .03 of this chapter, owners and operators shall:

(a) Submit a report to the Department within 60 days of each leak monitoring survey with the following information:

(i) Date of the survey;

(ii) A list of each fugitive emission and repair;

(iii) Any deviations from the initial methane monitoring plan or a statement that there were no deviations from the initial methane monitoring plan;

(iv) Number and type of components for which fugitive emissions were detected;

(v) Number and type of difficult-to-monitor fugitive emission components monitored;

(vi) Instrument reading of each fugitive emissions component that requires repair when EPA Method 21 (40 CFR 60, Appendix A-7) is used for monitoring;

(vii) Number and type of fugitive emissions components that were not repaired;

(viii) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair;

(ix) The date of successful repair of the fugitive emissions component; and

(x) Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding;

(b) Maintain, for a minimum of 5 years, record of each leak monitoring survey along with the following information:

(i) Reports submitted according to §A(1)(a) of this regulation;

(ii) Beginning and end time of the survey;

(iii) Name of operator(s) performing survey;

(iv) Monitoring instrument used, including the manufacturer, model number, serial number, and calibration documentation;

(v) When optical gas imaging is used to perform the survey, one or more digital photographs or videos, captured from the optical gas imaging instrument used for conduct of monitoring, of each required monitoring survey being performed;

(vi) Fugitive emissions component identification when EPA Method 21 (40 CFR 60, Appendix A-7) is used to perform the monitoring survey;

(vii) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey;

(viii) Any deviations from the initial methane monitoring plan or a statement that there were no deviations from the initial methane monitoring plan;

(ix) Proof that parts or equipment required to make necessary repairs, as required by this chapter, have been ordered;

(x) If a fugitive emissions component is not tagged, a digital photograph or video of each fugitive emissions component that could not be repaired during the leak monitoring survey at the time the fugitive emissions were initially found; and

(xi) Repair methods applied in each attempt to repair the fugitive emissions components;

(c) Post a quarterly report summary to a publicly available website of each leak monitoring survey, including the information required in §A(1)(a) of this regulation, 60 days after the leak monitoring survey; and

(d) Maintain records of audio, visual, and olfactory inspections for at least 5 years from the date of inspection.

(2) For each natural gas-powered continuous bleed pneumatic device, owners and operators shall:

(a) Maintain a record of the emission flow rate measurement and report annually beginning April 1, 2021, for at least 5 years from the date of each emissions flow rate measurement;

(b) Maintain records of the date, location, and manufacturer specifications for each continuous bleed pneumatic device constructed, modified, or reconstructed and report annually beginning April 1, 2021;

(c) Maintain records of the manufacturer's specifications indicating that the device is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour, if applicable;

(d) Maintain records of deviations in cases where the pneumatic device was not operated in compliance with the requirements specified in Regulation .04 of this chapter and report annually beginning April 1, 2021;

(e) Maintain purchase orders, work orders, or any in-house or third-party reports produced or provided to the affected facility relating to the device for at least 5 years; and

(f) Maintain a record of each continuous bleed pneumatic inspection and any corrective or maintenance action taken for at least 5 years.

(3) For each reciprocating natural gas compressor, owners and operators shall:

(a) Maintain a record of each rod packing leak concentration measurement found above the minimum leak threshold and report annually beginning April 1, 2021, for at least 5 years from the date of each leak concentration measurement;

(b) Maintain a record of each rod packing or seal emission flow rate measurement and report annually beginning April 1, 2021, for at least 5 years from the date of each emissions flow rate measurement;

(c) Maintain a record that documents the date(s) and hours of operation a compressor is operated in order to demonstrate compliance with the rod packing leak concentration or emission flow rate measurement in the event that the compressor is not operating during a scheduled inspection for at least 1 calendar year;

(d) Maintain records that provide proof that parts or equipment required to make necessary repairs required by this chapter have been ordered;

(e) Report annually the cumulative number of hours of operation or the number of months since initial startup or the previous reciprocating compressor rod packing replacement, whichever is later, beginning April 1, 2021;

(f) If applicable, submit a statement that emissions from the rod packing are being routed to applicable vapor control system under Regulation .06 of this chapter;

(g) Report records of deviations from this chapter that occurred during the reporting period annually, beginning April 1, 2021; and

(h) Maintain a record of purchase orders, work orders, or any in-house or third-party reports produced or provided to the affected facility necessary to demonstrate compliance with the delay of repair provisions of this chapter for at least 5 years.

B. Blowdown Events and Reports.

(1) Within 90 days of the effective date of this chapter, affected facilities shall submit a blowdown notification plan to the Department for approval of any blowdown event in excess of 1,000,000 standard cubic feet.

(2) The blowdown notification plan according to §B(1) of this regulation shall include:

(a) The notification format (for example, website, email, robocall, text message, social media announcement, etc.) to local authorities, the Department, and interested parties for blowdown emissions in excess of 1,000,000 standard cubic feet;

(b) A public outreach plan to inform interested parties of the availability to be notified of blowdown events in excess of 1,000,000 standard cubic feet;

(c) The affected facility's responsible personnel for blowdown notifications; and

(d) A sitemap of the facility with clearly marked designated area(s) for blowdown emissions in excess of 1,000,000 standard cubic feet.

(3) For any blowdown event in excess of 1,000,000 standard cubic feet, affected facilities shall make information publicly available in accordance with the facility's approved blowdown notification plan, including notification to the Department, at least 7 days prior.

(4) For any blowdown event in excess of 1,000,000 standard cubic feet that is scheduled less than 7 days prior to the blowdown event, affected facilities shall, as soon as practicable:

(a) Make information publicly available in accordance with the facility's approved blowdown notification plan; and

(b) Provide an explanation to the Department of the reason for the blowdown event.

(5) For any emergency or unplanned blowdown event in excess of 1,000,000 standard cubic feet, affected facilities shall make information publicly available in accordance with the facility's approved blowdown notification plan and notify the Department within 1 hour of the emergency or unplanned blowdown event.

(6) When safety concerns preclude a facility from providing prior notification of an emergency or unplanned blowdown under §B(5) of this regulation, the facility shall send notice to the Department within 24 hours of the blowdown event indicating the reason(s) why prior notice was not possible.

(7) Affected facilities shall report the following information to the Department of blowdown emissions in excess of 50 standard cubic feet within the facility's fence line annually by April 1 of each year:

(a) Date and type (that is, planned or emergency) of each blowdown event;

(b) Methane emissions in metric tons released from each blowdown event; and

(c) Annual methane emissions in metric tons from all blowdown events.

(8) Methane emissions shall be calculated according to procedures in 40 CFR Part 98, Subpart W, §98.233.

C. Greenhouse Gas Emissions Reporting.

(1) Owners and operators of affected facilities shall report methane, carbon dioxide, and nitrous oxide mass emissions to the Department annually by April 1 of each year.

(2) Owners and operators of affected facilities shall follow the procedures for emission calculation, monitoring, quality assurance, missing data, record keeping, and reporting that are specified in 40 CFR Part 98, Subpart C, and 40 CFR Part 98, Subpart W.

(3) When reporting to the Department, owners and operators of affected facilities shall expand the fugitive emissions reporting requirements of 40 CFR Part 98, Subpart W, to include a Microsoft Excel format list providing calculations summarized by category under 40 CFR §98.232(e) — (h) as applicable.

(4) The reporting threshold in 40 CFR §§98.2, 98.31 and 98.231 of 25,000 metric tons of CO_2 equivalent does not exempt an affected facility from following the requirements of this section.

D. All required reports shall be submitted to the Industrial Compliance Division in written or electronic format and mailed to Maryland Department of the Environment, Air Quality Compliance Program, 1800 Washington Boulevard, 7th Floor, Baltimore, MD 21230, Attention: Industrial Compliance Division.

BENJAMIN H. GRUMBLES
Secretary of the Environment

Title 30 MARYLAND INSTITUTE FOR EMERGENCY MEDICAL SERVICES SYSTEMS (MIEMSS)

Subtitle 01 GENERAL

30.01.02 Documents Incorporated by Reference

Authority: Education Article, §§*13-509 and* 13-516, Annotated Code of Maryland

Notice of Proposed Action

[20-136-P-I]

The State Emergency Medical Services Board proposes to amend Regulation **.01** under **COMAR 30.01.02 Documents Incorporated by Reference**. This action was considered and approved by the State Emergency Medical Services Board at its regular meeting held on June 9, 2020, notice of which was given by publication on the Maryland Institute for Emergency Medical Services Systems website, www.mimess.org, from December 2019, through June 9, 2020 (virtual information posted June 1, 2020), pursuant to General Provisions Article, §3-302, Annotated Code of Maryland.

Statement of Purpose

The purpose of this action is to incorporate by reference the current Maryland Medical Protocols for Emergency Medical Services and the current Maryland State Trauma Registry Data Dictionary for Burn Patients.

Comparison to Federal Standards

There is no corresponding federal standard to this proposed action.

Estimate of Economic Impact

The proposed action has no economic impact.

Economic Impact on Small Businesses

The proposed action has minimal or no economic impact on small businesses.

Impact on Individuals with Disabilities

The proposed action has no impact on individuals with disabilities.

Opportunity for Public Comment

Comments may be sent to E. Fremont Magee, Assistant Attorney General, Maryland Institute for Emergency Medical Services Systems, 653 West Pratt Street, Baltimore, MD 20201, or call 410-706-8531, or email to fmagee@miemss.org, or fax to 410-706-2138. Comments will be accepted through August 31, 2020. A public hearing has not been scheduled.

Editor's Note on Incorporation by Reference

Pursuant to State Government Article, §7-207, Annotated Code of Maryland, Maryland Medical Protocols for Emergency Medical Services (MIEMSS August 1, 2020 Edition) and Maryland State Trauma Registry Data Dictionary for Burn Patients (MIEMSS May 21, 2020 Edition) have been declared documents generally available to the public and appropriate for incorporation by reference. For this reason, they will not be printed in the Maryland Register or the Code of Maryland Regulations (COMAR). Copies of these documents are filed in special public depositories located throughout the State. A list of these depositories was published in 47:1 Md. R. 9 (January 3, 2020), and is available online at www.dsd.state.md.us. These documents may also be inspected at the office of the Division of State Documents, 16 Francis Street, Annapolis, Maryland 21401.

.01 Incorporation by Reference.

A. (text unchanged)

B. Documents Incorporated.

(1) "Maryland Medical Protocols for Emergency Medical Services **[**Providers**]** (MIEMSS **[**July 1, 2019**]** *August 1, 2020* Edition)". This document can be obtained through the Maryland Institute for Emergency Medical Services Systems at 653 W. Pratt Street, Baltimore, Maryland 21201 (410-706-4449).

(2)—(3) (text unchanged)

(4) "Maryland State Trauma Registry Data Dictionary for Burn Patients (MIEMSS **[**September 7, 2012,**]** *May 21, 2020* Edition)". This document can be obtained through the Maryland Institute for Emergency Medical Services Systems at 653 W. Pratt Street, Baltimore, Maryland 21201 (410-706-4449).

THEODORE R. DELBRIDGE, M.D., M.P.H.
Executive Director