SG.17.1.2

# TECHNICAL GUIDANCE DOCUMENT NUMBER 2:

# FUGITIVE COMPONENT AND EQUIPMENT LEAKS

## Introduction

This document provides technical guidance to Partners of the CCAC Oil and Gas Methane Partnership (OGMP). It is one in a series describing a core source of methane emissions from oil and natural gas production, gathering, and processing operations. This guidance document introduces suggested methodologies for identifying and repairing methane emissions from a unique source and describes established mitigation options that Partners should reference when determining if the source is "mitigated."[1] The OGMP recognizes that the equipment and emissions described in this document are found in all oil and gas operations, including onshore, offshore, and remote operations, and the way in which the emissions are detected and mitigated may vary across locations and operational environments. As such, operational conditions, as well as logistical, safety and cost considerations, must be evaluated on a case-by-case basis. The OGMP assumes that methane emission mitigation actions that require shut-downs of non-redundant equipment/processes (e.g., that would result in a stoppage of operations) would be carried out during regularly scheduled maintenance activities, unless the Partner deems the corrective action to be worthy of an early/additional shut-down.

## Description of Source

Fugitive emissions arise from unintentional leaks from equipment used in oil and gas operations. Potential components or sources of leaks from this equipment include flanges, screw and compression fittings, stem packing in valves, pump seals, compressor components[2], through-valve leaks in pressure relief devices that vent to the atmosphere, tank thief hatches, meters, and open-ended lines. For the purposes of this core source, emissions from equipment designed to vent as part of normal operations, such as gas-driven pneumatic controllers, are not considered leaks.

Methane leaks are typically caused by poor construction, corrosion or wear of mechanical joints, seals, and rotating surfaces over time. Fugitive emissions can also occur from devices that are not operating properly such as intermittent pneumatic devices that are malfunctioning and continuously bleeding gas, or stuck dump valves on separators[3]. Common sources of leaks from process equipment/components are presented below in Table 2.1.

[1] For reporting purposes as described in the CCAC Oil and Gas Methane Partnership Framework, Section 3.
[2] Leaks from compressor seals fall under the compressor-related source described in TGD 3 *Centrifugal Compressors with Wet (Oil) Seals* and TGD 4 *Reciprocating Compressors*.
[3] See TGD 1, *Natural Gas Driven Pneumatic Controllers and Pumps*

**Table 2.1: Sources of Equipment/Component Leaks**[4]

| Process Equipment/Component, Exhibit A | Common Source/Reason for Leak(s) |
|---|---|
| Pumps | Typically occur at the drive shaft seal. |
| Valves | Commonly occur at the stem seal of the valve and are commonly caused by a deterioration of the valve stem packing, grease packing, or rubber O-ring. |
| Connectors/Flanges | Usually caused from gasket failure and improperly torqued bolts on flanges. |
| Sampling Connections | Typically a through-valve leak at the outlet of the sampling valve caused by fouling, corrosion, or over-torqueing. |
| Compressors | All compressors, centrifugal and reciprocating, periodically develop leaks around gaskets, flanges, valves, and connectors as the unit commonly experiences vibrations and temperature/pressure fluctuations.[5] |
| Pressure Relief Devices that vent to the atmosphere | Usually occur if the valve plug is not seated properly, is operating too close to the set point, or if the seal is worn, damaged, or fouled with process debris. Leaks from rupture disks can occur around the disk gasket if the gasket is not properly installed. |
| Open-Ended Lines | Occur from through-valve leakage of a shut-off valve that vents or drains process equipment through a line open to the atmosphere. It is often caused by the valve not being closed tightly or debris fouling the valve seat. |
| Scrubber Dump Valves | Gas/liquid separator and compressor scrubber dump valve emissions result from gas that is leaking through a dump valve that is not tightly closed, and might manifest themselves from vents or atmospheric pressure relief devices on the tank roof. |

Due to the high number of valves, instruments, piping and tubing connections, pumps, and other components within oil and gas operations, fugitive emissions – even if individually small – can collectively become a substantial fraction of a site methane emissions inventory. Component and equipment leaks

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[4] EPA, *Leak Detection and Repair: A Best Practices Guide*, page 4. February 2014.. https://www.epa.gov/sites/production/files/2014-02/documents/ldarguide.pdf

[5] Other compressor emissions can result from seal oil de-gassing of wet seal centrifugal compressors or reciprocating compressor rod packing leakage (1) around packing case through nose gasket, (2) between the packing cups, (3) around the packing rings, and (4) between the packing rings and shaft. Please see separate TGD 3 *Centrifugal Compressors with Wet (Oil) Seals* and TGD 4 *Reciprocating Compressors* for more details on these emissions sources.

are unintended and random, and therefore require dedicated study with specialized equipment to find and repair the associated emissions. Leaks should be repaired as soon as feasible (e.g., on the spot or during the next planned maintenance shutdown). Because leaks can reappear at any time, 'Partners' operations/assets must undergo directed inspection and maintenance (DI&M) surveys to report operation/asset status annually as "mitigated"/"unmitigated." An annual frequency, at minimum, is recommended; Partners should, however, define the right frequency for their specific assets according to a risk assessment.

**Table 2.2: Configurations for Equipment/Component Leaks**

| Configuration | Mitigated or Unmitigated |
|---|---|
| Asset has not implemented a DI&M program | Unmitigated |
| Asset has implemented a DI&M program, and: | |
| Components found to be leaking are repaired within 12 months of identification, unless repair within this time span is determined to not be cost-effective, e.g. in cases where repair requires a shutdown. Exhibits B and C | Mitigated |
| The repair of components found to be leaking is not in accordance with the principles described above. | Unmitigated |

For reporting purpose, Partners can use these approaches:

- To report unmitigated emissions from potential sources not covered by an acceptable leak monitoring program (e.g. DI&M Program[6]), Partners may use recognized population emission factors (EFs)[7]. To report unmitigated emissions from a leak detection program, but not evaluated for economic repair, actual leaks may be calculated from recognized leaker EFs,[8] or direct measurement of components that were found to be leaking assuming a leakage period of half the time since the last survey to the end of the reporting year, or a default leakage period of 12 months.
- To report emission reductions, Partners may use results from their own repair records for components covered by the acceptable leak monitoring program. Partners should calculate the number of months between the times of the last leak survey when a component was found not leaking and the month of repair, or all months within the reporting year *before* a leak was repaired if not surveyed earlier in the current year, and multiply that number by the leak rate in order to calculate the reduction.

[6] https://www.epa.gov/sites/production/files/2016-06/documents/ll_dimgasproc.pdf
[7] Population Emission Factors for Onshore Petroleum and Natural Gas Production Facilities and Onshore Petroleum and Natural Gas Gathering and Boosting Facilities. http://www.ecfr.gov/cgi-bin/text-idx?SID=97687ab553b499b28a3bdd9bd26942f9&mc=true&node=ap40.23.98_1238.1&rgn=div9
[8] Ibid.

**Quantification Methodology**

While the primary objective of this mitigation practice is finding and fixing leaks, it is recommended that one or more of the following methodologies be used to quantify annual fugitive emissions in unmitigated facilities and estimate reductions that result from repairing unintentional leaks from oil and gas operations. Mitigated facilities will not be required to quantify leak repairs. In principle, leak screening followed by direct measurement of identified leaks can be considered the most accurate method for quantifying methane emissions for determination of cost-effectiveness of repair. Where a Directed Inspection & Maintenance (DI&M) program is in place, measurement can contribute to greater certainty on emissions levels and economic costs and benefits (i.e., value of gas saved in areas which have a gas market). As such, measurement is highly encouraged whenever necessary to establish the cost-effectiveness of a leak repair where there is a market for gas. When direct measurement is not feasible, fugitive emissions can be estimated using "leaker emission factors"[9] for detected leaking components. Individual Partners may choose an alternative quantification methodology if judged to be more accurate by the Partner; in this case, the Partner should document and explain the alternative methodology in the Annual Report.

Partners can identify fugitive emissions through one or more leak screening techniques (listed below). Once leaks are identified, several emission measurement or estimation techniques exist to quantify methane emission rates. Partners should choose the most appropriate leak screening and measurement techniques according to the component or equipment being analyzed. Some techniques are more applicable to certain pieces of equipment/process components. For example, using soap solution is not feasible if the component being screened is too hot or too cold, has too large an opening (e.g., open-ended vent pipe), or is physically inaccessible, in which case an optical gas imaging camera or laser leak detector may be more appropriate. Measurements provide a flow rate for whole gas or methane depending on the device used. If applicable, Partners should then convert the flow rate to methane emissions using the methane content of the gas and then extrapolate it over the estimated duration of the leak. An annual volume of methane emissions is calculated by multiplying the estimated or measured methane emissions flow rate by half the operating hours of a piece of equipment between the last leak survey that found the component not leaking and the time when a leak is found and repaired. Operators can use a default factor of 12 months for estimating leak quantity.

- Leak Screening Techniques: Assets/facilities should be screened for leaks and vented emissions using one or more of the techniques listed below and described in Appendix A to the Technical Guidance Documents. Screening should include all components and equipment at the facility. Equipment surveyed should include, but not be limited to, facility piping, valves, connectors, flanges, compressor components, open-ended lines, as well as equipment such as pneumatic gas

[9] Default Whole Gas Leaker Emission Factors for Onshore Petroleum and Natural Gas Production Facilities and Onshore Petroleum and Natural Gas Gathering and Boosting Facilities. http://www.ecfr.gov/cgi-bin/text-idx?SID=97687ab553b499b28a3bdd9bd26942f9&mc=true&node=ap40.23.98_1238.5&rgn=div9

supply tubing to controllers and pneumatic pumps, compressor and pump seals, and tank thief hatches, keeping in mind any technical limitations associated with any given approach.

- Optical gas Imaging, such as an infrared (IR) leak imaging camera (designed to visually identify hydrocarbon emissions).
- Remote Methane Leak Detector (handheld device which uses tunable diode laser absorption spectroscopy for detection of methane).
- Soap bubble screening.
- Leak sensors such as a Flame Ionization Detector (FID), an Organic Vapor Analyzer (OVA) or a Toxic Vapor Analyzer (TVA) equipped with both Photo Ionization Detector (PID) and FID
- Acoustic Leak Detection.

For more details regarding each leak screening technique, including applicability and limitations, please reference Appendix A - Emission detection and quantification equipment.

- Direct Measurement Techniques, Exhibit D:[10] Following is a list of available measurement technologies that may be used to inform a decision on the economics of a repair. The appropriate measurement technique for a particular component/piece of equipment at a facility will depend on its operating conditions and any physical barriers to measurement access with certain instruments. More than one technique might be feasible for measuring emissions from any particular source. For more details regarding each leak measurement technique, including applicability and measurement methods, please reference Appendix A.

  - Calibrated vent bag.
  - High-volume sampler.
  - Vane anemometer.
  - Hotwire anemometer.
  - Turbine meter.
  - Acoustic leak detector and associated correlation equation.

When direct measurement is not feasible for safety, technical, or economic reasons, Partners can estimate fugitive emissions using relevant emission factors. Tables 2.3 to 2.8 at the end of this document provide standard emission factors for leaking/non-leaking equipment, and gas properties derived from internationally recognized data sets.

**Mitigation Option – Periodic directed inspection and maintenance surveys in which specialized equipment is used to detect and repair leaks.**

[10] Greenhouse Gas Reporting Program, Subpart W – Petroleum and Natural Gas Systems, Section 98.233 Calculating GHG Emissions, 40 CFR 98.233(q). http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=&SID=0205ead4170303569861d96d59fa596a&mc=true&n=pt40.23.98&r=PART&ty=HTML#se40.23.98_1233.

A Directed Inspection & Maintenance (DI&M) program[11] that mitigates fugitive emissions includes the following elements:

- **Baseline Fugitive Component and Equipment Leak Survey:** A Directed Inspection & Maintenance (DI&M) program typically begins with a baseline survey to identify leaks. Direct inspection involves a screening of equipment components to identify leaking components. Leaking components are identified with emissions detection equipment listed in Appendix A or equivalent. The inspection identifies individually those components that are found to be leaking methane-containing gas. Each leaking component that can be repaired ~~on the spot~~ should be repaired taking into account feasibility considerations such as volume of leak, safety implications, cost-effectiveness, and complexity of repair (e.g., ability to repair immediately with simple maintenance or need for shut down to repair). In order to claim mitigation for this source type, all components found to be leaking are repaired within 12 months of identification, unless repair within this time span is determined to not be cost-effective. If a partner chooses to report emission reductions from fugitive equipment and process leaks in the OGMP Annual Report, the date of repair, type of component and quantity (measured or estimated) of the methane emission reduction are documented. Fugitive emission reduction credits are taken in the year that the actual repair is done.

- **Annual Fugitive Component and Equipment Leak Survey**: For each year following the Baseline Fugitive Component and Equipment Leak Survey a modified, direct inspection is conducted. Leaking components are identified with emissions detection equipment listed in Appendix A or equivalent. This survey typically focuses on components and equipment in methane-containing gas service that were found to be leak-prone in the Baseline Fugitive Component and Equipment Leak Survey or subsequent leak surveys. This survey identifies individually leaking components within the boundary of the participating facility. Leak repairs are made on the spot when feasible, and within 12 months of the leak identification when economic. If the partner chooses to report fugitive emission reductions in their OGMP Annual Report, leak survey findings are recorded including the dates, component types and the quantity of methane emission reductions, measured or estimated.

*<u>Operational Considerations</u>*

As leaks are located during the baseline or subsequent surveys, Partners should estimate or measure leak rates for emissions reductions following repairs and when repair economics are uncertain. Direct measurement is done when safe and feasible, using any one of several measurement techniques described in this document or Appendix A. Detection and quantification (ideally by direct measurement equipment as outlined in the previous section and detailed in Appendix A - Emission detection and

[11] In some countries, for regulatory compliance, operators are required to implement a LDAR (Leak Detection and Repair) Program. DI&M and LDAR are significantly different while the objective is the same: reduction of fugitive emissions. The DI&M practice is based on cost-effective methane emission reduction, whereas LDAR defines leaks that must be repaired, even when not economical. LDAR regulations are very prescriptive and inflexible, with considerable records-keeping and retention, and potential penalties for non-compliance. DI&M is strictly voluntary best practice of methane fugitive emissions reduction.

quantification equipment) is fundamental in a DI&M program. For reference, experience shows that a majority of fugitive emissions from upstream facilities derive from valves, connectors, flanges and compressor seals.[12] Other emissions occur primarily from open-ended lines, crankcase vents, pressure relief devices that vent to the atmosphere, pump seals, and scrubber/vessel dump valves passing gas with liquid to separators or tanks. Experience indicates that the majority of emissions from leaking equipment and process components typically come from a relatively small percentage of leaking components.

As leaks are identified and quantified, Partners should record the baseline leak data so that future surveys can focus on the most significant leaking components. If the leak cannot be immediately repaired, Partners should tag leaks for tracking purposes and document the results of the DI&M survey. The information that Partners might choose to collect includes the following:

- An identifier for each leaking component.
- The component type (e.g., blowdown open-ended line).
- The measured or estimated leak rate.
- The survey date.
- The estimated annual gas loss.
- The estimated repair cost.

This information will help Partners direct subsequent emissions surveys, prioritize future repairs, and track the methane savings and cost-effectiveness of the DI&M program.

The final step in a DI&M plan is to develop a survey schedule using the results of the baseline survey to guide future inspection and maintenance protocol. Partners should develop a survey schedule that achieves maximum methane savings yet also suits the unique characteristics and operations of their facilities. For example, Partners can base DI&M surveys on the anticipated life of repairs during the previous survey or on the frequency of follow-up surveys on company maintenance cycles or the availability of resources. Given the flexibility of a DI&M program, if subsequent surveys show numerous large or recurring leaks, Partners can increase the frequency of DI&M follow-up surveys. These follow-up surveys can focus on previously repaired components or on the classes of operations/assets characterized as most likely to leak.

An effective DI&M plan should include the following elements:[13]

- A comprehensive plan to screen for leaking components.

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[12] EPA. Lessons Learned: *Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations*. https://www.epa.gov/sites/production/files/2016-06/documents/ll_dimgasproc.pdf.

[13] EPA. Lessons Learned: "*Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations.*" Costs updated to 2013 dollar equivalent using Nelson Farrar CE cost indices. https://www.epa.gov/sites/production/files/2016-06/documents/ll_dimgasproc.pdf.

- Leak screening and measurement tools and procedures for collecting, recording, and accessing DI&M data.
- A schedule for leak screening and measurement.
- Best practice guidelines for repair, including incorporation into planned maintenance and documentation/confirmation of repairs.
- Results and analyses of previous inspection and maintenance efforts that will direct the next DI&M survey.

Partners may choose to outsource leak detection and measurement or develop an internal team or teams to conduct the surveys. Although the latter may initially cost more up front (e.g., to acquire the necessary leak detection and measurement equipment), Partners can achieve greater efficiencies using the equipment over numerous facilities. In addition, internalizing the effort and communicating lessons learned from having the same team survey facilities of different types and regions also promotes efficiencies. Some operations might be found to have very few leaks, in which case internal technology transfer between assets/facilities can facilitate better leak performance in other operations.

*Methane Emission Reduction Estimate*

The potential methane emission reduction from implementing DI&M programs will vary depending on the size, age, equipment, and operating characteristics of the facility. Studies referenced below indicate that a DI&M program can profitably repair 78 to 92 percent of equipment leaks, with a 6 to 12 month payback.

For more information, see:

- Natural Gas STAR technical Document "Conduct Directed Inspection and Maintenance at Remote Sites" https://www.epa.gov/sites/production/files/2016-06/documents/ conductdimatremotefacilities.pdf.
- Natural Gas STAR technical Document "Test and Repair Safety Valves" https://www.epa.gov/sites/production/files/2016-06/documents/ testandrepairpressuresafety valves.pdf .
- Natural Gas STAR technical Document "Directed Inspection and Maintenance at Compressor Stations" https://www.epa.gov/sites/production/files/2016-06/documents/ll_dimcompstat.pdf.
- Natural Gas STAR technical Document "Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations" https://www.epa.gov/sites/production/files/2016-06/documents/ ll_dimgasproc.pdf.

*Economic Considerations*

The cost of performing DI&M screening/measurement depends on several factors, including the team performing the survey (internal or hired contractor), size/type of facility being screened, and equipment used. For an internal team, an estimated capital cost for leak screening and measurement equipment is approximately $105,000, based on an estimated cost of $85,000 for FLIR Model GF320 infrared camera[14] and $17,500 plus $1,200 for a calibration kit for a high-volume sampler.[15] Studies have shown that a small gas processing facility can contain approximately 14,200 components while a large processing facility might contain approximately 56,400 components.[16]A model onshore wellsite had 468 components. Labor costs for DI&M screening/quantification will vary according to the number of components to be screened within a given facility. As an example, at a labor rate of $30.46/hour,[17] assuming two days of a two-man team for a small gas processing plant, four days for a large gas processing plant, using an IR camera and a high-volume sampler,[18] the estimated cost range for facility screening and measurement labor is $1,200 (small processing plant) to $2,400 (large processing plant). These costs may apply to an offshore platform, where there is an equivalent concentration of many fugitive components. For wellsites, the leak survey and repair would have to be incorporated into normal operational rounds to make this practice cost-effective. Note that the referenced EPA Natural Gas STAR Program documents have a method to update costs to current costs.

As previously mentioned, the initial investment costs for leak detection and measurement equipment might be greater than outsourcing the work. Considering that the purchased equipment and training can be applied to future surveys, however, this initial investment can pay for itself through gas savings from found and fixed leaks. In addition, developing a plan for sharing the equipment and training across several facilities will help Partners further amortize the initial investment cost. The economics for an initial investment in detection and measurement equipment depend on how many facilities are going to be inspected each year.

Should a Partner decide to rent leak detection and measurement equipment, an example payback scenario could assume a daily rental cost of $1,000 for an optical leak imaging camera and $400 for a high-volume sampler. In this case, with labor costs of $1,200 to $2,400 (per the example above) and a pipeline gas value of $3/MMBtu, natural gas savings of 900 to 1,700 thousand standard cubic feet (Mscf) (25,000 to 50,000 standard cubic meters (scm)) would pay back the small and large plant gas processing plant survey costs, assuming costs to fix the leak are treated as normal maintenance costs. These gas savings

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[14] 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.*

[15] For more information concerning detection and measurement equipment, please reference Appendix A: Leak Detection and Quantification Equipment.

[16] EPA. Lessons Learned: *Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations.* https://www.epa.gov/sites/production/files/2016-06/documents/ll_dimgasproc.pdf.

[17] 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.* Section 8.4.3. Page 8-31. https://nepis.epa.gov/Exe/tiff2png.cgi/P100CHY5.PNG?-r+75+-g+7+D%3A%5CZYFILES%5CINDEX%20DATA%5C11THRU15%5CTIFF%5C00000001%5CP100CHY5.TIFMaximumDocuments=1&FuzzyDegree=0&ImageQuality=r75g8/r75g8/x150y150g16/i425&Display=hpfr&DefSeekPage=x&SearchBack=ZyActionL&Back=ZyActionS&BackDesc=Results%20page&MaximumPages=1&ZyEntry=174&slide.

[18] EPA. Lessons Learned: *Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations.* https://www.epa.gov/sites/production/files/2016-06/documents/ll_dimgasproc.pdf.

are equivalent to a year's operation assuming 100 to 200 standard cubic feet per hour (scf/hour) (3 to 6 scm/hour) of leak reductions.

Alternatively, Partners can hire outside consultants to conduct a baseline screening and measurement survey. Using a general costing rule of thumb of $1/component,[19] the cost range for a baseline survey would be $14,000 (small facility) to $55,000 (large facility). Experience has shown that follow-up surveys in an ongoing DI&M program cost 25 to 40 percent less than the initial survey because subsequent surveys focus on the components found most likely to leak. For some equipment components, leak screening and measurement can be performed most efficiently during a regularly scheduled DI&M survey program. For other components, Partners can incorporate simple and rapid leak screening into ongoing operation and maintenance procedures.

## Emission Factors

Table 2.3 provides methane emissions "leaker" factors[20] for equipment found to be leaking in the natural gas production, gathering and boosting, and processing sectors. Note that leaker emission factors help estimate emissions from sources that have been identified to be leaking and therefore are applied only to those components that have been found to be emitting gas.

Upstream oil and gas facilities that have already implemented a formal DI&M program can also use emission factors provided in Table 2.4:[21]

**Table 2.3: Onshore Operations Methane Emission Factors**

| Service | Component | Leaker Emission Factor (scf/hour/component) | Leaker Emission Factor (scm/hour/component) |
|---|---|---|---|
| **All Components – Gas Service** | Valve | 4.9 | 0.14 |
| | Flange | 4.1 | 0.12 |
| | Connector(other) | 1.3 | 0.037 |
| | Open-Ended Line | 2.8 | 0.079 |

[19] Cost estimate for processing plant using infrared camera and high-volume sampler as primary tools. EPA Methane to Markets Partnership Expo. Rules of Thumb and Best Practices for Conducting Directed Inspection and Maintenance. 2010. https://www.globalmethane.org/expo-docs/india10/postexpo/oil_robinson_2.pdf

[20] EPA. *Greenhouse Gas Reporting Rule*. Title 40, Part 98 Subpart W-Petroleum and Natural Gas Systems. February 6, 2017. Tables W-1E and W-2. http://www.ecfr.gov/cgi-bin/text-idx?SID=777564a9f8d1264edbfc1c55a7a989ba&mc=true&node=sp40.23.98.w&rgn=div6.

[21] Extract from Table 10 in "Update of Fugitive Equipment Leak Emission Factors" document (CAPP, 2014). http://www.capp.ca/publications-and-statistics/publications/238773.

| | | | |
|---|---|---|---|
| | Pressure Relief Valve | 4.5 | 0.13 |
| | Pump Seal | 3.7 | 0.10 |
| | Other | 4.5 | 0.13 |
| **All Components – Light Crude Service** | Valve | 3.2 | 0.091 |
| | Flange | 2.7 | 0.076 |
| | Connector(other) | 1.0 | 0.028 |
| | Open-Ended Line | 1.6 | 0.045 |
| | Pump | 3.7 | 0.10 |
| | Agitator Seal | 3.7 | 0.10 |
| | Other | 3.1 | 0.088 |
| All Components – Heavy Crude Service | Valve | 3.2 | 0.091 |
| | Flange | 2.7 | 0.076 |
| | Connector(other) | 1.0 | 0.028 |
| | Open-Ended Line | 1.6 | 0.045 |
| | Pump | 3.7 | 0.105 |
| | Agitator Seal | 3.7 | 0.105 |
| | Other | 3.1 | 0.088 |
| Onshoure Natural Gas Processing Plants Compressor Components, Gas Service | Valve | 14.84 | 0.420 |
| | Connector | 5.59 | 0.158 |
| | Open-Ended Line | 17.27 | 0.489 |
| | Pressure Relief Valve | 39.66 | 1.13 |
| | Meter | 19.33 | 0.55 |
| Onshore Natural Gas Processing Plants Non-Compressor Components, Gas Service | Valve | 6.42 | 0.18 |
| | Connector | 5.71 | 0.16 |
| | Open-Ended Line | 11.27 | 0.32 |
| | Pressure Relief Valve | 2.01 | 0.057 |
| | Meter | 2.93 | 0.083 |

**Table 2.4: Emission Factors for Fugitive Emissions After the Implementation of a Formal DI&M Program**

| Sector | Component Type | Service[a] | EF (scf THC/h/source)[b] | EF (scm THC/h/source)[b] |
|---|---|---|---|---|
| Gas | Compressor Seals | GV | 41.97 | 41.97 |
| Gas | Connector | GV | 0.03 | 0.001 |
| Gas | Connector | LL | 0.01 | 0.000 |

| Sector | Component Type | Service[a] | EF (scf THC/h/source)[b] | EF (scm THC/h/source)[b] |
|---|---|---|---|---|
| Gas | Control Valve | GV | 1.57 | 0.044 |
| Gas | Open-Ended Line | All | 1.83 | 0.052 |
| Gas | Pressure Relief Valve | All | 0.01 | 0.000 |
| Gas | Pump Seal | All | 0.11 | 0.003 |
| Gas | Regulator | All | 1.51 | 0.043 |
| Gas | Valve | GV | 0.02 | 0.001 |
| Gas | Valve | LL | 0.03 | 0.001 |
| Oil | Compressor Seals | GV | 0.58 | 0.016 |
| Oil | Connector | GV | 0.02 | 0.001 |
| Oil | Connector | LL | 0.01 | 0.000 |
| Oil | Control Valve | GV | 3.55 | 0.101 |
| Oil | Open-Ended Line | All | 6.15 | 0.174 |
| Oil | Pressure Relief Valve | All | 0.01 | 0.000 |
| Oil | Pump Seal | All | 0.09 | 0.003 |
| Oil | Regulator | All | 20.72 | 0.587 |
| Oil | Valve | GV | 0.05 | 0.001 |
| Oil | Valve | LL | 0.02 | 0.001 |

[a] Service types: GV=gas/vapor, LL=light liquid, All=all service types,

[b] THC = total hydrocarbons

If leakages are detected by using EPA Method 21[22], it is possible for Partners to estimate the total organic carbon (TOC) emissions using the correlation equations and the emission factors provided in Table 2.5. TOC emissions must be converted to methane emissions using the percentage of methane in the stream composition (if unknown, Partners can refer the GRI\EPA average methane composition reported in Table 2.6).

**Table 2.5: Correlation Equations and Pegged[a] Emission Factors for TOC**

| Source | Service | Equation | Pegged Value 10,000 ppm[b] | Pegged Value 100,000 ppm | Default Zero Emission Rates scf/hr/source | Default Zero Emission Rates scm/hr/source |
|---|---|---|---|---|---|---|
| Valves | All | $2.29E-06 \times (SV)^{0.746}$ | 0.064 | 0.140 | 3.06E-04 | 8.67E-06 |
| Pump Seals | All | $5.03E-05 \times (SV)^{0.610}$ | 0.074 | 0.160 | 9.41E-04 | 2.67E-05 |

[22] https://www.epa.gov/emc/method-21-volatile-organic-compound-leaks

| Source | Service | Equation | Pegged Value 10,000 ppm[b] | Pegged Value 100,000 ppm | Default Zero Emission Rates scf/hr/source | Default Zero Emission Rates scm/hr/source |
|---|---|---|---|---|---|---|
| Connectors | All | 1.53E-06 x $(SV)^{0.735}$ | 0.028 | 0.030 | 2.94E-04 | 8.33E-06 |
| Flanges | All | 4.61E-06 x $(SV)^{0.703}$ | 0.085 | 0.084 | 1.22E-05 | 3.44E-07 |
| Open-End Lines | All | 2.20E-06 x $(SV)^{0.704}$ | 0.030 | 0.079 | 7.84E-05 | 2.22E-06 |
| Others | All | 1.36E-05 x $(SV)^{0.589}$ | 0.073 | 0.110 | 1.57E-04 | 4.44E-06 |

[a] pegged means instrument registers full scale [b] ppm = parts per million parts

Partners must use the equation for all the equipment with a screening value (SV) between zero and the instrumental over range. Pegged values are used for the "over range" equipment (according to the maximum detectable value, 10,000 or 100,000 ppm). Partners must use default zero emission rates for no leakers.

**Table 2.6: Default GRI\EPA Methane Composition[23]**

| Industry Segment | Average $CH_4$ Composition | Uncertainty |
|---|---|---|
| Production | 78.8% | 5.53% |
| Gas Processing | 86.8% | 6.54% |
| Transmission | 93.4% | 1.80% |
| Distribution | 93.4% | 1.80% |

If leakers are detected using the Optical Gas Imaging technology, Partners can refer to the emission factors derived in collaboration with API and provided in Table 2.7.[24]

**Table 2.7: Alternative Leak/No-Leak Emission Factors for OGI technologies**

| Component Type | Emission Factor Type | Emission Factor (g/h/component) for Specified Leak Definition (g/h)[a] | | | |
|---|---|---|---|---|---|
| | | 3 | 6 | 30 | 60 |
| Valves | No-leak | 0.019 | 0.043 | 0.17 | 0.27 |
| | leak | 55 | 73 | 140 | 200 |

[23] American Petroleum Institute. *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry*. August 2009. Table E-4 page E-6.
[24] Epperson D., Siegell J., Ritter K. *Derivation of new emission factors for quantification of mass emissions when using optical gas imaging for detecting leaks*. Lev-On M1. J Air Waste Manag Assoc. 2007 Sep. 57(9):1061-70. http://www.tandfonline.com/doi/pdf/10.3155/1047-3289.57.9.1061.

| Component Type | Emission Factor Type | Emission Factor (g/h/component) for Specified Leak Definition (g/h)[a] | | | |
|---|---|---|---|---|---|
| | | 3 | 6 | 30 | 60 |
| Pumps, Compressors | No-leak | 0.096 | 0.13 | 0.59 | 0.75 |
| | leak | 140 | 160 | 310 | 350 |
| Flanges | No-leak | 0.0026 | 0.0041 | 0.01 | 0.014 |
| | leak | 29 | 45 | 88 | 120 |
| Other components | No-leak | 0.007 | 0.014 | 0.051 | 0.081 |
| | leak | 56 | 75 | 150 | 210 |

[a] g/h = grams per hour based on the U.S. EPA definition of a "leak" being greater than 10,000 ppm by OVA. No-leak factors are averages of measured leaks less than 10,000 ppm. If a leak can be seen with a gas imaging camera, it should be quantified with "leak" factors.

Emission factors are provided for both leak and no-leak equipment and for several leak definitions of the instrument used (if no information are available, Partners should use the higher leak definition – 60 g/h). Partners must convert TOC emissions to methane by using the percentage of methane in the stream composition or by referring to default value reported in Table 2.6.

Partners must convert methane emissions calculated in mass to a volume (scm or scf) applying the density of the gas (if known) or using a default standard conversion factors (see Table 2.8).

**Table 2.8: Default Density Values for Crude Oil and Natural Gas**

| Fuel | Typical Density |
|---|---|
| Crude Oil | 873.46 kg/scm |
| Natural Gas | 0.6728 kg/scm |

**Exhibit A – Sources of Equipment/Component Leaks[25]**

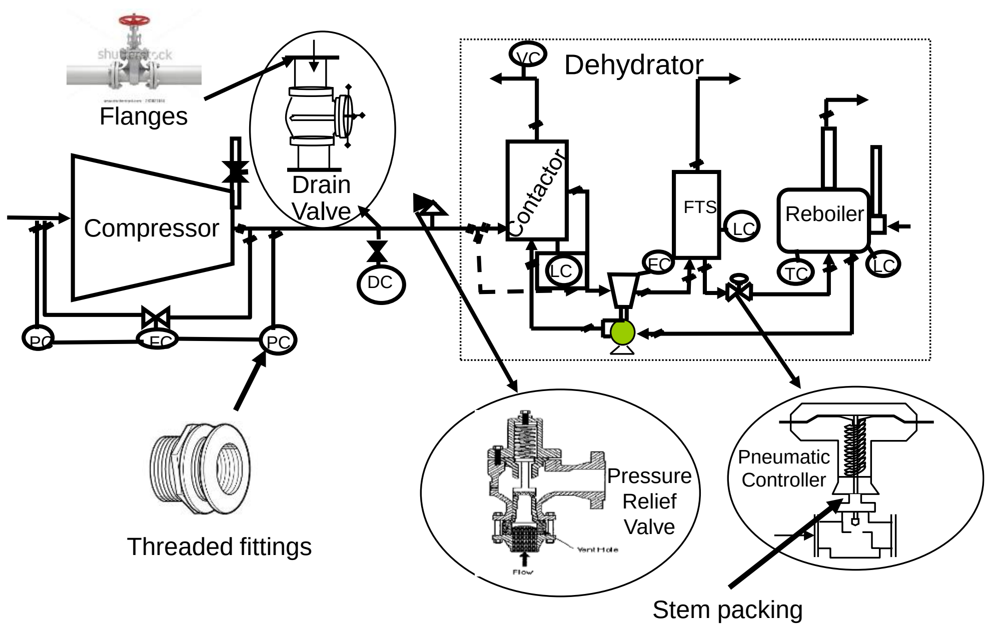



**Exhibit B – Leak Detection Using Hand-Held Instruments[26,27]**


[25] CCAC Oil and Gas Methane Partnership: webinar April 7, 2015: "Fugitive Equipment and Process Leaks," presentation by UNEP

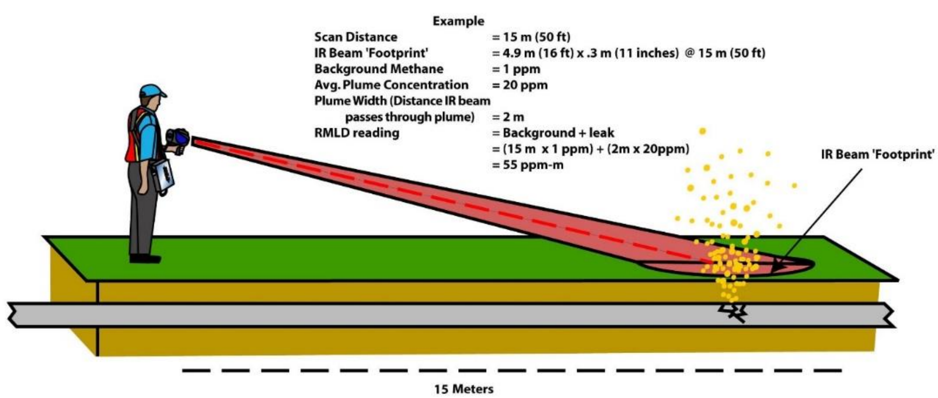
[26] CCAC Oil and Gas Methane Partnership - webinar April 7, 2015: "Fugitive Equipment and Process Leaks," presentation by UNEP

[27] Natural Gas STAR Technology Transfer Workshop, Houston, Texas, September 22, 2004: "Methane Emissions Management at TransCanada Pipe Lines," presented by TransCanada

**Exhibit C – Leak Detection Using Remote Leak Detection Instruments[28,29]**

IR gas imaging cameras


Laser Remote Methane Leak Detector[30]

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[28] Natural Gas STAR Producers Technology Transfer Workshop, Vernal, Utah, March 23, 2010: photo during field leak detection demonstration

[29] CCAC Oil and Gas Methane Partnership: webinar April 7, 2015: "Fugitive Equipment and Process Leaks," presentation by UNEP

[30] Turkmenistan Symposium on Gas Systems Management - Methane Mitigation, Ashgabat, Turkmenistan, April 26, 2010: "Methane Leak Detection and Measurement Technologies," presented by Heath Consultants Inc.

**Exhibit D – Leak Quantification Instruments[31,32]**

## Leak Measurement Using High Volume Sampler

Hot Wire (left) and Vane (middle, right) Anemometers[33,34]


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[31] Natural Gas STAR Processors Technology Transfer Workshop, Dallas, Texas, September 23, 2004: "Directed Inspection and Maintenance (DI&M) at Gas Processing Plants," presented by EPA

[32] Natural Gas STAR Producers Technology Transfer Workshop, College Station, Texas, May 17, 2007: "Directed Inspection and Maintenance and Infrared Leak Detection," presented by EPA

[33] Hot Wire Anemometer: Lechtenbohmer, S. et al, Wuppertal Institute for Climate, Environment, Energy, Germany, International Journal of Greenhouse Gas Control (2007) pp. 387 – 395 "Tapping the leakages: Methane losses, mitigation options and policy issues for Russian long distance gas transmission pipelines," Fig. 4, August 22, 2007

[34] Global Methane Initiative All-Partnership Meeting, Oil and Gas Subcommittee – Technical and Policy Sessions, Krakow, Poland, October 14, 2011: "Routing Centrifugal Compressor Seal Oil De-gassing Emissions to Fuel Gas as an Alternative to Installing Dry Seals," presented by BP

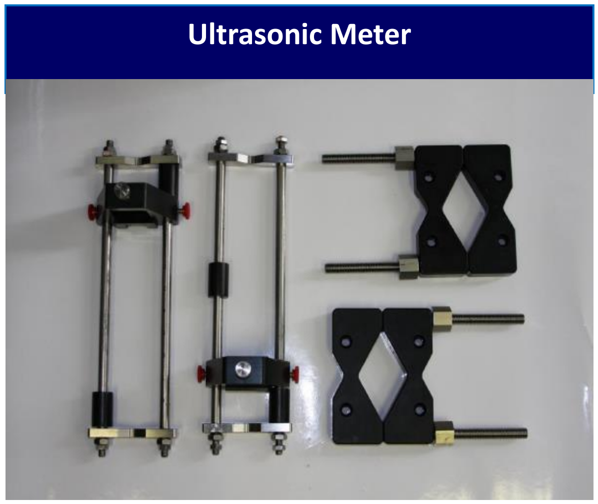
Calibrated Vent Bag[35]

Turbine Meter with Totalizer[36]


[35] Turkmenistan Symposium on Gas Systems Management - Methane Mitigation, Ashgabat, Turkmenistan, April 26, 2010: "Methane Leak Detection and Measurement Technologies," presented by Heath Consultants Inc.

[36] CCAC Oil and Gas Methane Partnership: webinar March 12, 2015: "Hydrocarbon Liquid Storage Tanks and Casinghead Gas Venting," presentation by UNEP

Acoustic Detection Device with Calibration Algorithm for Through Valve Leaks[37]




[37] Natural Gas STAR Annual Implementation Workshop, San Antonio, Texas, November, 2008: "Chevron's experience with Directed Inspection & Maintenance (DI&M) to minimize Methane Releases from Offshore Platforms," presented by Chevron GOM