APPENDIX A: CONDUCTING EMISSIONS SURVEYS, INCLUDING EMISSION DETECTION AND QUANTIFICATION EQUIPMENT

Emissions Surveys and quantification processes are necessary to provide a basis for understanding methane emissions sources and levels to evaluate future plans to mitigate emissions. These processes also provide data for OGMP Annual Reports. This appendix provides information on two different approaches to conducting Emissions Surveys and provides technical details on technologies that can be used to identify and quantify methane emission sources present in OGMP participating operations. The information provided in this appendix focuses on the nine methane emissions sources described in the Framework document.

Approaches to Emissions Surveys and Quantification

Emissions Surveys for each participating operation/asset consist of identifying the presence or absence of core emission sources, plus any additional sources chosen for evaluation, and quantifying the methane emissions from the unmitigated emission sources. There are two approaches to conducting an Emissions Survey: (1) Desktop studies involve gathering operational data elements remotely (e.g., through email and telephone communication) from site operators and quantifying unmitigated emissions using engineering calculations, software, and emission factors; and (2) Field surveys involve gathering operational data elements during a field site visit, identifying actual emissions from sources, and quantifying unmitigated emissions by either direct measurements or by engineering calculations that rely on field data.

Desktop Studies

Desktop studies are often conducted from regional or corporate headquarters or technical centers. Performing a desktop study is a first step to bring awareness regarding OGMP commitments and goals to personnel from all assets within a company’s scope of participation. A desktop study involves iterative collaboration between remote personnel who are coordinating the study and field personnel. It is recommended that field personnel from participating operations are provided with a description of the OGMP focal sources (nine core sources plus any additional sources) and an explanation of “mitigated” and “unmitigated” (provision of relevant OGMP Technical Guidance Documents can assist in this process). Field personnel can then count and categorize the sources and provide relevant data to the study coordinating personnel. After remote and field personnel have obtained an understanding of the types of sources present within participating operations, they collaborate on determining and collecting other operations data to serve as inputs for emissions estimation. Basic operating data necessary to remotely calculate potential emissions are typically readily accessible by field personnel. Examples of such operating data include: pressure in gas-liquid separator ahead of liquid storage tanks and produced oil flow rate to tank(s); glycol dehydrator configuration and type of pump; and number of gas pneumatic control loops.

Emissions estimation methods are chosen based on available field data. The most accurate methods for emissions that vary with process conditions are equilibrium models, such as E&P Tank[1] for liquid storage tank emissions and GlyCalc[2] for glycol dehydrator emissions. The next best alternative is use of general engineering calculation software, such as Aspen HYSYS[3] or first principles engineering calculations. The least preferred, but acceptable, emission estimation approach is use of emission factors, either company-developed from similar assets or emission factors from Technical Guidance Documents or other sources. Emission factors may be the only possible emissions estimation method for certain sources; one example is fugitive equipment and process leak emissions, because desktop study personnel do not have a way of knowing where leaks are occurring at any moment in time or the leak rates (such information can be better informed by field surveys than using default emission factors). Companies are encouraged over the course of OGMP participation to develop site-specific emission factors from data collected in field surveys.

Field Surveys

A field Emissions Survey collects needed operational data onsite and utilizes specialized equipment to identify methane emission sources and measure emissions levels of unmitigated sources, both fugitive sources (unintentional emissions from flanges, valves, fittings, etc.), and vents from normal operations, such as tank roof vents or wet seal compressor degassing drum vents. Annual emissions surveys should not be confused with the mitigation practice for fugitive leaks: Directed Inspection & Maintenance (DI&M). The Annual Operations/Asset Surveys reported each year are intended to be comprehensive in identifying the number of each of the nine core sources in the first year, the numbers mitigated and unmitigated, and quantify emissions from only unmitigated sources. Partners may choose to measure or quantify emissions from mitigated sources to assure that the mitigation is working properly with low emissions. Subsequent Annual Surveys focus on identifying changes in numbers of core sources and quantifying emissions from only unmitigated sources. The mitigation practice for fugitive emissions requires annual field leak surveys of all components in methane service and repair of those that are cost-effective to repair. Quantification is not required for fugitive components surveyed each year, although quantification may be useful in making a decision to repair a found leak.

Similar to a desktop Emissions Survey, participants should begin with an understanding of the OGMP focal sources (nine core sources plus any additional sources) and what counts as “mitigated” and “unmitigated.” The team can then count and categorize the sources and physically observe emissions levels, for example using a specialized infrared (IR) camera that visualizes hydrocarbon emissions. After remote and field personnel have obtained an understanding of the types of sources present within participating operations, they collaborate on taking actual emission measurements and, if needed, determining and collecting other operational data to serve as inputs for emissions quantification (e.g. if measurement on a particular source is not practicable).

To perform a field survey, persons trained in the use of specialized detection and quantification equipment must participate, and companies may enlist contractors or create internal survey teams to visit all participating assets. Specialized instruments (described in the below section) are used for detection and quantification of specific sources. The initial (baseline) survey sets the stage for subsequent surveys—in that once the first survey is completed, companies have an understanding of what sources are present and what

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[1] API Petroleum Measurement, Chapter 19.1 Evaporative Loss from Fixed-Roof Tanks. http://www.api.org/publications-standards-and-statistics/standards/standards-software/e-and-p-tanks

[2] http://gri-glycalc.software.informer.com/4.0/

[3] www.aspentech.com/hysys

equipment will be needed in future surveys, and subsequent surveys are more efficient based on data from previous surveys.

In principle, direct measurement can be considered as the most accurate method for quantifying methane emissions.[4] Where a sound basis is in place, measurement can contribute to greater certainty on emissions levels and economic costs and benefits (i.e., value of gas saved). As such, measurement is highly encouraged whenever it is possible to establish this basis.

Emission Detection and Quantification Equipment

The following information includes equipment specifications and use procedures compiled from relevant service providers, vendors, and manufacturers.

The suggested methane emissions detection and measurement equipment contained in this document are intended to inform operators interested in identifying and reducing methane emissions at various international oil and natural gas companies. This information is not intended to be a comprehensive guide to the available methane emission measurement and detection equipment, but rather a compilation of experiences and methodologies.

Exhibit 1 gives an overall summary of the methane emission detection and quantification equipment presented in this section and how they apply to the nine methane emissions sources described earlier in the source-specific Technical Guidance Documents.

Exhibit 1: Summary of Methane Emissions Sources and Applicable Emissions Detection and Quantification Equipment

Emissions Source	Emissions Detection Equipment	Emissions Quantification Equipment
Natural gas driven pneumatic controllers and pumps	• Optical leak Imaging Exhibit A • Laser leak detector Exhibit B	• Calibrated Vent Bag Exhibit F • High volume sampler Exhibit G • Flow meter Exhibit H
Fugitive equipment and process leaks	• Optical leak Imaging Exhibit A • Laser leak detector Exhibit B • Soap Bubble Screening Exhibit C • Organic Vapor Analysers (OVAs) and Toxic Vapor Analysers (TVAs) Exhibit D • Acoustic Leak Detection Exhibit E	• Calibrated Vent Bag Exhibit F • High volume sampler Exhibit G • Vane anemometer Exhibit H • Hotwire anemometer Exhibit H • Turbine meter Exhibit I • Acoustic Detection Device (for through-valve leaks) Exhibit J

[4] Measurements should be conducted with appropriately calibrated instruments and per the manufacturer instructions for conducting measurements. Measurements should also be conducted in different operating conditions, to the extent that those can affect emissions levels. Guidance on instrument use can be found in this Appendix A to the Technical Guidance Documents. Where companies seek to generate Emission Factors for their operations, direct measurement should be based on a statistically sound number of measurements and gas analyses to understand the content of methane and other valuable hydrocarbons

Centrifugal compressors with wet seals	• Optical leak Imaging	• Vane Anemometer • Hotwire Anemometer • Turbine meter
Reciprocating compressor rod seal/packing vents	• Optical leak Imaging	• Vane Anemometer • Hotwire Anemometer • Turbine meter • Calibrated Vent Bag • High volume sampler • Acoustic Detection Device (for through-valve leaks) • Orifice meter (vent flow • measurement device)
Glycol dehydrators	• Optical leak Imaging	• Vane Anemometer • Hotwire Anemometer • Turbine meter
Hydrocarbon liquid storage tanks	• Optical leak Imaging	• Turbine Meter • Calibrated vent bag* • Vane anemometer* • Hotwire anemometer* • High volume sampler*
Well venting for liquids unloading	• Optical leak Imaging	• Vane Anemometer • Hotwire Anemometer • Turbine meter
Well venting/flaring during well completions for hydraulically fractured wells	• Optical leak Imaging	• Vane Anemometer • Hotwire Anemometer • Turbine meter
Casinghead gas venting	• Optical leak Imaging	• Turbine Meter • Hotwire anemometer • Vane anemometer

*Note: Calibrated vent bags, anemometers and High volume sampler are spot readings, less suitable for recording the emissions over a time period than a turbine meter with a totalizer.

Leak Detection

Optical Gas Imaging

Hydrocarbon emissions absorb infrared (IR) light at a certain wavelength and an IR camera uses this characteristic to detect the presence of hydrocarbon gas emissions from equipment at an oil and gas facility. The IR camera operator scans the leak area in real time (user selectable for cold/hot temperature environments). This scanned area is viewed as a live, black and white image such that the gas plumes are visible on the camera display due to their absorption of the IR light. IR cameras detect a wide variety of hydrocarbon compounds, not just methane, and so a knowledge of which streams and piping or vessel components contain a significant methane content is necessary to identify the leaks subject to this source category. Also, steam plumes diffract IR light, and appear the same as a hydrocarbon gas plume in the IR camera. The camera operator can easily distinguish between a steam plume (visible to the eye as a white plume) and a hydrocarbon gas (not visible to the eye).

The IR camera is simple to use with point-and-detect features similar to a normal motion picture camera. It can be switched between visible light mode and infrared (black and white) image, and many models come with a built in video recording capability. The two main functions available are zooming and image inversion. The zoom function allows the operator to close in on an emissions source. The image inversion feature allows the operator to view the image of a leak plume either as positive or negative (i.e., a black plume against a light background or white plume against a dark background) so that the emissions are clearly visible against the background. This camera is capable of screening hundreds of components per hour, depending on the facility layout. For the annual fugitive component and equipment leak surveys, the leak detection should be performed close enough to distinguish exactly where the leak is emanating to inform a repair: typically within 3 meters or 10 feet. Between annual DI&M leak surveys, fixed-monitor LEL detectors are valuable to alert operators that a significant, potentially explosive concentration of combustible hydrocarbon is present so that operators can search for the sources using leak detection equipment that identifies individual leaking components.

Some IR cameras have not been certified intrinsically safe. Therefore, the operator should initially search for hydrocarbon presence from the perimeter of facility before entering it. If hydrocarbon presence in the ambient air is significant then it might be unsafe to take the camera into a facility or close to equipment. Alternatively, Lower Explosive Level (LEL) detectors can be used to detect potentially explosive concentration of combustible hydrocarbon near operations before the camera is used. The only unsafe part of the camera is opening it to replace the battery, so ensuring that the battery is replaced in a secure location away from equipment or operations will reduce any safety risks. A company's safety practices will need to determine whether a hot-work permit is required.

The effectiveness[5] of IR camera emission surveys is dependent on the skill and training of the camera

[5] Ravikumar, A.P., Wang, J. and Brandt, A.R., 2017. Are Optical Gas Imaging Technologies Effective For Methane Leak Detection? *Environmental Science & Technology*. http://pubs.acs.org/doi/abs/10.1021/acs.est.6b03906.

operator. Personnel conducting surveys should receive internal or external training of use of the camera for leak detection. It is beneficial for new camera operators to conduct some observations under the guidance of an experienced camera operator.

The IR camera requires no calibration. The only change required might be replacement of lenses for detecting emissions from longer distances. However, this is a simple process and can be done in the field while the study is being conducted. The recommended operating temperature for the camera ranges from -20 to 50°C (-4 to 122 °F).[6] The cost to purchase an IR camera can range from $85,000 to 115,000.[7]

Laser Leak Detector

Laser detection is another useful method for locating potential methane emissions sources. As with optical gas imaging, this technology allows operators to safely scan a facility and equipment from a distance. It also prevents operators from walking the entire length of a pipeline or service line, allowing them to stay in place and scan for leaks along the sight line. A popular laser leak detector used in the oil and gas industry is the Remote Methane Leak Detector (RMLD). This device uses tuneable diode-infrared laser tuned at a frequency absorbed by methane, allowing it to detect any methane present in a gas plume from a maximum distance of 30 meters (100 feet).[8] When the laser beam from the RMLD passes through a gas plume and is reflected back to the camera, it will detect if any methane present in the beam path by comparing the strength of the outgoing and reflected beam. The RMLD will not give a false positive for other hydrocarbons. This device only detects methane gas.

The RMLD uses two lasers: an invisible IR laser and a visible, green spotter laser. The IR laser detects the presence of methane and is continuously on while the RMLD is running. The IR laser beam is conical in shape with a 56-centimeter (22-inch) diameter at 30 meters (100 feet).[9] The green spotter laser is visible and helps operators confirm exactly what the device is pointed directly at. It is turned on and off by depressing and pressing the RMLD's trigger button.

For the RMLD to work properly, it is necessary that there be a background surface within 34 meters (110 feet) from the device for the infrared beam to bounce back to the instrument receiver. The reflected light is collected by the RMLD and subsequently converted to an electrical signal. This signal is then processed into a methane concentration in parts per million per meter (ppm-m) of beam path length. This is a non-quantitative, relative measure of the amount of methane in the beam path. It cannot be converted to the quantity of gas leakage.

[6] FLIR GF320 technical specifications: http://www.flir.co.uk/ogi/content/?id=66693

[7] Cost estimate from FLIR Systems, Inc.

[8] Heath Consultants. Remote Methane Leak Detector brochure. http://www.http://heathus.com/wp-content/uploads/rmld_poster.pdf

[9] Ibid.

The RMLD is intrinsically safe, which makes it desirable for use in oil and gas facilities and near related operations/equipment. Its 34-meter (110-feet) range makes this device particularly useful for detecting methane leaks originating from hard-to-reach sources and/or throughout difficult terrain. Because of its range, the RMLD can quickly and accurately screen hundreds of components per hour.

The RMLD has a measurement range of 0 to 99,999 ppm-m and has a sensitivity of 5 ppm-m at distances from 0 to 15 meters (0 to 50 feet) and 10 ppm-m and higher at distances from 15 to 30 meters (50 to 100 feet).[10] It can operate in a temperature range from -17 to 50 °C (0 to 122 °F) and a relative humidity range of 5 to 95 percent.[11] This device weighs 4.5 kilograms (10 pounds) and uses a rechargeable internal lithium-ion battery pack that can run for up to eight hours.[12]

Soap Bubble Screening

Soap bubble screening ("soaping") is a quick and low-cost leak detection technique. This method involves squirting a soap solution on small and accessible components such as flanges, valves, fittings, threaded connections, etc. If there is a leak, soap bubbles will develop from the solution. Soaping is effective for locating loose fittings and connections. It is not effective on large openings such as open ended pipes or vents. Leaks can typically be eliminated on the spot by tightening the necessary components and subsequently evaluating the repair's effectiveness. Most methane emission sources that are cost-effectively repaired are typically larger than the small leaks most likely to be found by soaping. However, since soaping is quick and minimal in cost, this practice can easily be integrated into existing maintenance programs. Operators can screen about 100 components per hour by soaping. Being a water based solution, it cannot be used on equipment above the boiling point of water (100 °C/212 °F) or below the freezing temperature of water (0 °C/32 °F).

Using a soap solution to detect methane containing gas leaks typically costs less than $100 for equipment (spray bottles and soap solution).[13] When performed as part of operators' routine rounds, the labor cost is minimal.

Organic Vapor Analysers (OVAs) and Toxic Vapor Analysers (TVAs)

Organic Vapor Analysers (OVAs) and Toxic Vapor Analysers (TVAs) are portable hydrocarbon detectors that can be utilized to identify methane leaks. An OVA consists of a flame ionization detector (FID), which is capable of measuring the organic vapor concentration ranging from 9 to 10,000 parts per million (ppm).[14] For higher concentration leaks, a TVA combines an FID, which is particularly sensitive

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[10] Ibid.

[11] Ibid.

[12] Ibid.

[13] EPA. Lessons Learned: Directed Inspection and Maintenance at Compressor Stations. June 2016. https://www.epa.gov/sites/production/files/2016-06/documents/ll_dimcompstat.pdf

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

to methane, with a photoionization detector (PID), which is sensitive to other hydrocarbons but insensitive to methane, to measure total organic vapor concentrations over 10,000 ppm.[15] In combination, OVAs and TVAs can measure the methane concentration in the area surrounding a leak over a large range.

Screening with these devices is performed by placing the suction probe in close proximity, no more than one centimetre, of a seal or an opening where methane leakage can occur. The OVA or TVA sucks in air and measures concentration of combustible hydrocarbon as the probe is slowly moved along the seal interface or opening. Once a maximum concentration reading is determined, it is then recorded as the leak screening value. Using OVAs and TVAs for leak screening is somewhat slow; each device can survey approximately 40 components per hour.[16] Additionally, these instruments require frequent calibration. The approximate capital cost for an OVA or TVA is under $10,000 (depending on instrument sensitivity/size).[17]

The measured combustible hydrocarbon concentrations from these devices are not direct measurements of the quantity of emissions. However, the concentrations can be converted to an approximate mass emissions rates using SOCMI correlation equations.[18] This can be a cost-effective method for estimating methane emissions (especially if an OVA or TVA is already available at a facility) and is discussed in further detail in the "Leak Quantification" section of this appendix.

<u>Acoustic Leak Detection (for through valve leakage)</u>

For through valve leaks (which are internal), companies can use portable screening devices that detect the resulting acoustic signal when gas under pressure escapes through a valve plug or gate that is not tightly closed or tightly sealing. Using a handheld sensor, operators can view and record the intensity readings to gain a relative idea of the leak's size. For example, a leak with a higher emissions rate will give a higher or "louder" reading. Acoustic leak detectors can detect either high or low frequency signals and are useful for detecting leaking valves when the vent is inaccessible (e.g., blowdown valves and pressure relief valves connected to elevated vent stacks).

In noisy environments (e.g., compressor rooms), high frequency acoustic detection is best and can be used to screen for leaks using a handheld sensor. To detect a signal, the acoustic sensor is placed directly on the equipment. For airborne ultrasonic signals (frequency range: 20 to 100 kHz), ultrasonic leak detection is used. Ultrasonic leak detectors are equipped with a handheld probe or scanner that is pointed at a possible leak source from distances up to 30 meters (100 feet).[19] By listening for an increase in the sound intensity through headphones, operators can target the location of a leak. Although ultrasonic leak detectors can be sensitive to background noise (e.g., in a noisy environment), most detectors typically

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[15] Ibid

[16] Ibid.

[17] EPA. Lessons Learned: Directed Inspection and Maintenance at Compressor Stations. June 2016. https://www.epa.gov/sites/production/files/2016-06/documents/ll_dimcompstat.pdf

[18] EPA. Protocol for Equipment Leak Emission Estimates. November 1995. http://www.epa.gov/ttnchie1/efdocs/equiplks.pdf. Page 2-12

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

have frequency tuning capabilities which allow the probe to be tuned to a specific leak.

Acoustic leak detectors can detect methane leaks from all components but are particularly useful for inaccessible components, larger leaks, and pressurized gas. Devices can cost operators $1,000 to $20,000 depending on instrument sensitivity, size, and any associated equipment/parts.[20]

Leak Quantification

Turbine Meter

A 2-inch mini turbine meter is used on hydrocarbon emissions with flows exceeding or 0.283 standard m^3/minute or 10 standard ft^3 (scf)/minute. A magnetic pick-up records each turbine rotation which is sent to a recording device and converted by calibration to a cumulative flow volume. The magnetic mechanism in turbine meters allows continuous and automated measurement with a recording device. For this application, the meter is typically mounted on piping, the length and diameter of which can be sized as needed. The requirements call for the meter to be installed with ten pipe diameters upstream of the meter and five pipe diameters downstream of straight pipe without valves or connectors.

The accuracy of the turbine meter is ±1 percent if within the stated range (i.e., flows exceeding 0.283 standard m^3/minute).[21] If operating outside of the range, the turbine meter's accuracy is ±25 percent.[22] This device is also available in sizes from 10 to 30 centimeters (4 to 12 inches) and fully electronic. Its operational temperature range is -18 to 104 °C (0 to 219 °F).[23] The turbine meter requires no field calibration. The unit needs to be inspected for debris lodged in the rotor blades. This is a simple inspection and can be done in the field prior to use.

One model for example, the Daniel MRT-97 flow rate indicator/totalizer, is battery-operated and will accept magnetic pick up pulses from the turbine meter and displays them as a discrete unit of volume. The MRT-97 will display the flow rate in scf per sec/min/hr. The totalizer will display units of gallons (GAL), barrels (BBL), thousand cubic feet (MCF), or cubic meters (M^3).[24] The MRT flow rate indicator / totalizer enclosure is explosion proof: Class I, Division I, Groups B, C, & D Class II, Division I, Groups E, F, & G. The approximate cost of the turbine meter and flow rate indicator/totalizer is $4,000.[25]

Because this device measures the flow in actual volume over time, the volume would have to be converted to standard volume using the temperature and pressure of the gas that is being measured. In addition to the operating conditions and accuracy range for which the device is applicable, turbine meters require a good seal between the venting line and the meter itself. The diameters of open ended lines, such as tank pressure relief valves or compressor rod packing vents will vary significantly. To ensure best results, it is important to know

[20] Ibid
[21] Turbine manufacturers include Emerson Process Management http://www2.emersonprocess.com/siteadmincenter/PM%20Daniel%20Documents/08018A-Mini-Gas-TurbineM-1-3In-Sizes-guide.pdf
[22] Ibid.
[23] Ibid.
[24] http://www2.emersonprocess.com/siteadmincenter/PM%20Daniel%20Documents/Mini-Gas-Turbine-Meter-DS.pdf
[25] Cost estimate from vendor.

the diameter of vent lines ahead of time so that suitable adapters can be put in place.

Calibrated Vent Bag[26]

Calibrated vent bags are non-elastic bags of calibrated volume when fully inflated (e.g., 0.085 m^3 or 3 ft^3), made from antistatic plastic with a neck shaped for easy sealing around a vent pipes. Measurement is made by timing the bag expansion to full capacity. The temperature of the gas is measured to allow correction of volume to standard conditions. Additionally, gas composition should be analysed to determine the methane content of the vented gas because in some cases air may also be entrained in the vent, resulting in a mixture of gas and air. A key advantage of the bag expansion technique over rotating meters (e.g., turbine meter) is that it does not exert a significant back pressure on the vented component. This eliminates any potential interference with the vented operation and allows for low-pressure drop measurements. Bags are various sizes and known volume are available as calibrated during manufacture.

These bags are useful for quantifying leaks greater than 17 m^3/hour (600 ft^3/hour) and can measure leaks as large as 408 m^3/hour (14,400 ft^3/hour). Calibrated vent bags measurements have an accuracy of ±10 percent and require no additional power source. The measurement variability occurs in timing bag inflation with a stop-watch or sweep-second-hand watch, so repeat measurements are taken for each component measured. The only additional equipment required is a temperature measuring device such as a thermometer to measure the gas temperature before and during inflation. Calibrated vent bags can measure gases ranging from 0 to 49 °C (32 to 120 °F).[27]

It is recommended to use calibrated vent bags where the emissions are at near-atmospheric pressures to ensure it is safe to handle, below the maximum temperature specified by the vent bag manufacturer, and the entire emissions source can be quickly encompassed and tightly sealed in the neck of the bag during measurement.

Calibrated vent bags require two individuals to perform measurement. One individual quickly places the vent bag neck over the emissions source in a manner that captures all gas emissions and ensures the bag unfurls properly during inflation to avoid rips or creases in the bag. A second individual times bag inflation and takes start/stop commands from the first individual. Gas composition and temperature are recorded to adjust to standard conditions. Several measurements are taken for each source to arrive at an average value.

Calibrated vent bags require physical access to the emissions source by the measurement technician. The technician must be able to have safe use of both hands during measurement which is a safety issue if ladders are used to access components. Measurements will be attempted for sources with manageable fall hazards. These bags cost approximately $50 each and can be re-used approximately 100 times if handled with care.[28]

[26] http://heathus.com/products/anti-static-measurement-bag/
[27] Retrieved from vendor.
[28] Cost estimate from vendor.

Vane Anemometer[29] [30]

A vane anemometer consists of a vane wheel flow velocity sensor and handheld unit that displays the measured velocity of gas that passes through the device's vane wheel. Vane anemometers are best for measuring open ended lines and end-of-pipe vents of known cross-sectional area. They do not require complete capture of emissions. Placing the vane anemometer at the center of the vent pipe opening or inserting it through a port in the vent pipe measures the maximum velocity of emissions. The number of fan blade revolutions are detected with a magnetic pick-up and correlated to a flow velocity. Using the pipe's diameter, the cross-sectional area of the pipe can be calculated.[31] The cross-sectional area is then multiplied by the measured flow velocity, to estimate the volumetric flow rate of emissions through the vent. The emissions estimate is less accurate if the flow direction of the vent pipe changes near the vane anemometer measurement, which distorts the velocity profile. A typical measuring range of actual gas flow velocity is 0.4 to 80 meters/second. A vane anemometer has a measurement uncertainty of 0.9 to 1.5 percent of the measured gas velocity value.

The working temperature range of this vane wheel sensor is typically -15 to 260 °C (5 to 500 °F) while the handheld unit has a smaller working range of 0 to 50 °C (32 to 122 °F). The handheld unit is powered by a 9 Volt battery (or appropriate plug-in supply) and has a battery operating time of approximately 30 hours. Additionally, some models of the handheld unit have electronic data storage capacity of 1,000 measured data records.

To ensure the most accurate measurements when using this device, the velocity should be measured at the center of the pipe, close to the open end of the vent, and the temperature of the gas stream measured. An appropriately-sized meter can be used to prevent the gas flow from exceeding the full measurement range of the meter and conversely to have sufficient momentum for the meter to register continuously in the course of measurement. Operators are advised to avoid situations where using this device exerts a backpressure on the measured vent. To calibrate a vane anemometer, it is recommended for operators to develop calibration curves by following the manufacturer's instruction.
Purchase costs for each device can range from $1,400 to $5,500.[32]

Hotwire Anemometer[33]

A hotwire anemometer is similar to a vane anemometer. It is inserted in the gas flow from an open ended pipe or through a port in a gas flow pipeline. It consists of an exposed hot wire either heated up by a constant electric current or maintained at a constant temperature when inserted into a flowing gas stream. It operates on the principle of heat transfer. This device measures gas velocity calibrated with the electrical current through the wire as heat is conducted away by the gas flow. The heat lost to emissions by convection is proportional to the gas flow velocity. Hotwire anemometers are best for measuring vents, open ended lines, and flow in closed pipes of known cross-sectional area (e.g., flare

[29] http://www.hoentzsch.com/en/products/categories/product-list/m/fluegelrad-fa/c/1-eintauchfuehler/
[30] http://www.hoentzsch.com/en/products/categories/m/fluegelrad-fa/
[31] Cross-sectional area = π * (pipe diameter / 2)^2
[32] Cost estimate from vendor
[33] http://www.hoentzsch.com/en/products/categories/product-list/m/thermisch-ta/c/27-eintauchfuehler/

lines) and do not require complete capture of emissions. The flow estimation is most accurate when the hot wire element is positioned at the center of the vent, close to the open end, and the stream temperature is measured. The measureable range of gas flow velocity is 0.2 to 200 meters per second (m/s), which can then be translates into a volumetric flow rate by multiplying times the cross-sectional area of the flow in square meters.

For gas flow velocities less than or equal to 40 m/s, the thermal flow sensor measurement uncertainty is 2 percent. For velocities greater than 40 m/s, the uncertainty is 2.5 percent. The thermal flow sensor has a maximum working pressure of 1.6 MPa (16 bar) above atmospheric pressure and gas temperature range from -10 to 140 °C (14 to 284 °F). The handheld unit is powered by a rechargeable lithium-ion battery with a run time of approximately 20 hours. Additionally, the handheld unit has storage for 1,000 measured data records.

Hot wire anemometers have lower levels of accuracy in clean gas streams compared to other insertion devices but may be the only option in dirty gas streams (i.e., gas streams with liquid droplets, sticky entrained particulates). Liquid droplets or sticky particulates could interfere with measurement and/or permanently damage a vane anemometer inserted into the flow stream.

To ensure accurate measurements it is recommended that calibration curves be developed by following the manufacturer's instruction. Purchase costs for each device can range from $1,400 to $5,500.[34]

<u>High Volume Sampler</u>[35]

The High volume sampler is an air suction pump with a combustible hydrocarbon concentration measurement. The calibrated air flow and hydrocarbon concentration is converted to a volumetric flow rate of the gas sucked into the device. It is designed to capture the total amount of the emissions from a leaking component or vent line. Specially-designed attachments are provided for use as needed to ensure total emissions capture or to prevent interference from other nearby sources. A dual-element hydrocarbon detector (i.e., catalytic-oxidation/ thermal-conductivity) measures combustible hydrocarbon concentrations in the captured air stream ranging from 0.01 to 100 percent. A background sample-collection line and hydrocarbon detector allows the sample readings to be corrected for ambient gas concentrations. A thermal anemometer, also inserted directly into the main sample line, monitors the mass flow rate of the sampled air-hydrocarbon gas mixture.

This device has a measureable leak rate of 0.02 to 18 m^3/hour (1 to 630 ft^3/hour). Its operating temperature is from 0 to 50 °C (32 to 122 °F) and weighs about 9 kilograms (20 pounds). The High volume sampler's reported accuracy is ±10 percent of the calculated leak rate (which corrects for background gas) when calibrated for the gas being measured. This device uses an intrinsically safe NiMH rechargeable battery pack with a runtime of approximately 4.5 hours. The High volume sampler is intrinsically safe and is equipped with a grounding wire to dissipate any static charge that may accumulate as air passes through the sample collection line and instrument.

[34] Cost estimate from vendor.
[35] http://heathus.com/wp-content/uploads/hiflow_sampler_rev7.pdf

The High volume sampler uses battery-operated, adjustable flow rate fan to draw in the air and hydrocarbon emission at a maximum leak rate measurement capacity of 14 m^3 per hour (480 ft^3 per hour). Increasing the sampling rate generally improves the leak capture efficiency; however, care should be taken to ensure against increased dilution of the emissions with ambient air. Excessive dilution may cause the pollutant concentration to fall below the detection range of the sample detector resulting in a zero reading. Consequently, the sampling rate should be adjusted manually to ensure that the hydrocarbon concentration is within the sensing range of the hydrocarbon detector.

Calibration is recommended every 30 days and a log created each time the equipment is calibrated. The calibration procedure is provided in Chapter 4 of the equipment instruction manual (see footnote) and for measuring methane-rich emissions, recommends calibration gas concentrations of 2.5 percent methane in air and 100 percent methane samples. Verification checks should be performed daily to confirm that the instrument remains properly calibrated.

The sample and background hydrocarbon detectors in the High volume sampler do not distinguish between methane and heavier hydrocarbons (e.g. ethane, propane, etc), and therefore read any hydrocarbon leak in terms of equivalent amount of methane when calibrated on 100 percent methane and 2.5 percent methane-in-air. For hydrocarbon emissions that deviate widely from pipeline quality natural gas, it is best to calibrate the High Flow Sampler on the gas composition being measured, adjusted for the methane content. The calibrations should be done prior to use of the High volume sampler at each site, and then periodically thereafter to ensure that no significant drift has occurred.

Additionally, before and after each measurement campaign, the High volume sampler should be calibrated by measuring known flow rates of methane in the sampler inlet and comparing the leak rate measured by the High volume sampler to the actual gas release rate as determined using a separate gas flow meter.

The High volume sampler costs approximately $17,500, depending on the auxiliary components purchased[37]. The calibration kit is bought separately and costs approximately $1,200. This instrument can be shared by several facilities, distributing the costs and the benefits of gas leak quantification. The cost of conducting a measurement survey using a high volume sampler is dependent on the labor rates and number of components at the facility. Alternatively, contractors provide leak measurement services at a rate that ranges from $1.00 to more than $2.50 per component measured.

[37] Heath Consultants. Personal contact.

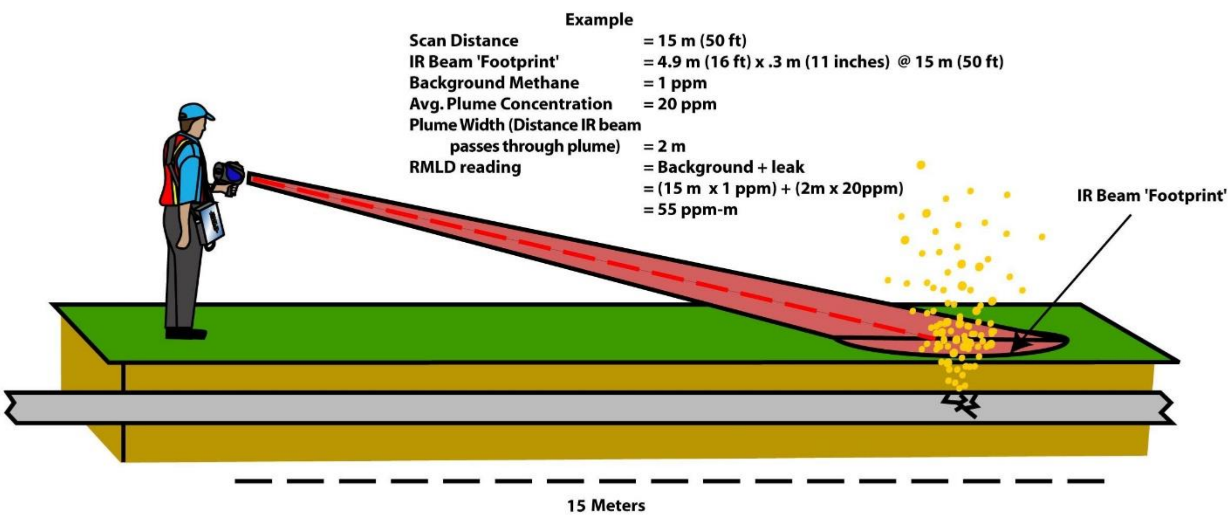
Exhibit A – Optical Gas Imaging Camera[36,37,38]

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

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

[38] Methane to Markets, Production Technology Experience in the U.S.: Priorities, Moscow, Russia, October 4, 2010: “Seminar with Russian Independent Oil and Gas Producers on Methane Mitigation Technologies and Strategies,” presented by EPA

Exhibit B – Laser Leak Detector[39,40]



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

[40] 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 C – Soap Bubble Leak Detection[41]

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

Exhibit D – Organic Vapor Analyzer (OVA) and Toxic Vapor Analyzer (TVA)[42]

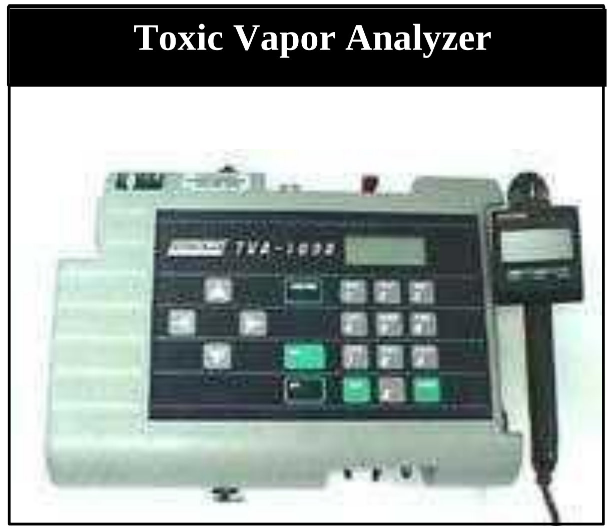
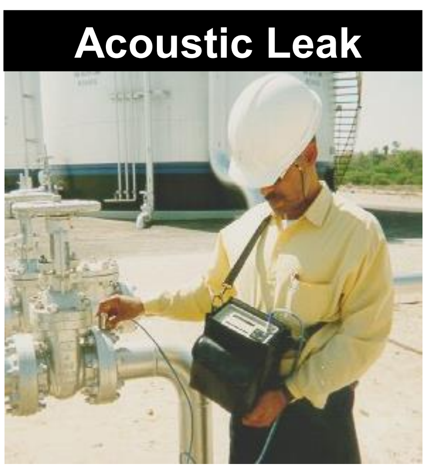
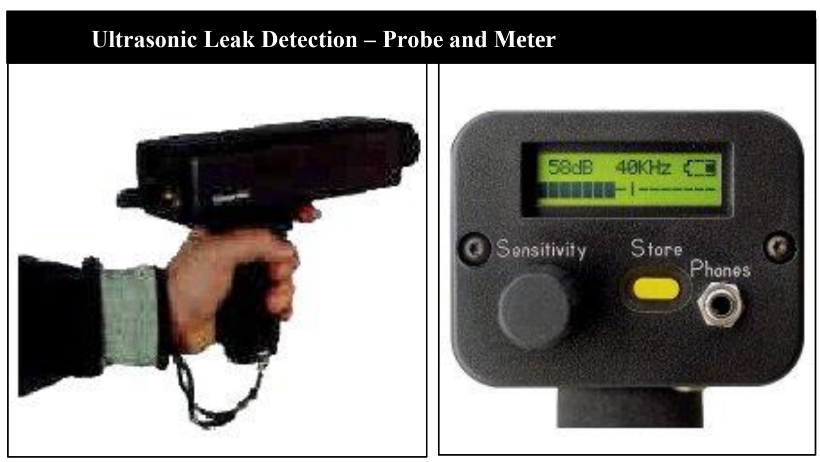


Exhibit E – Acoustic Leak Detectors[43]





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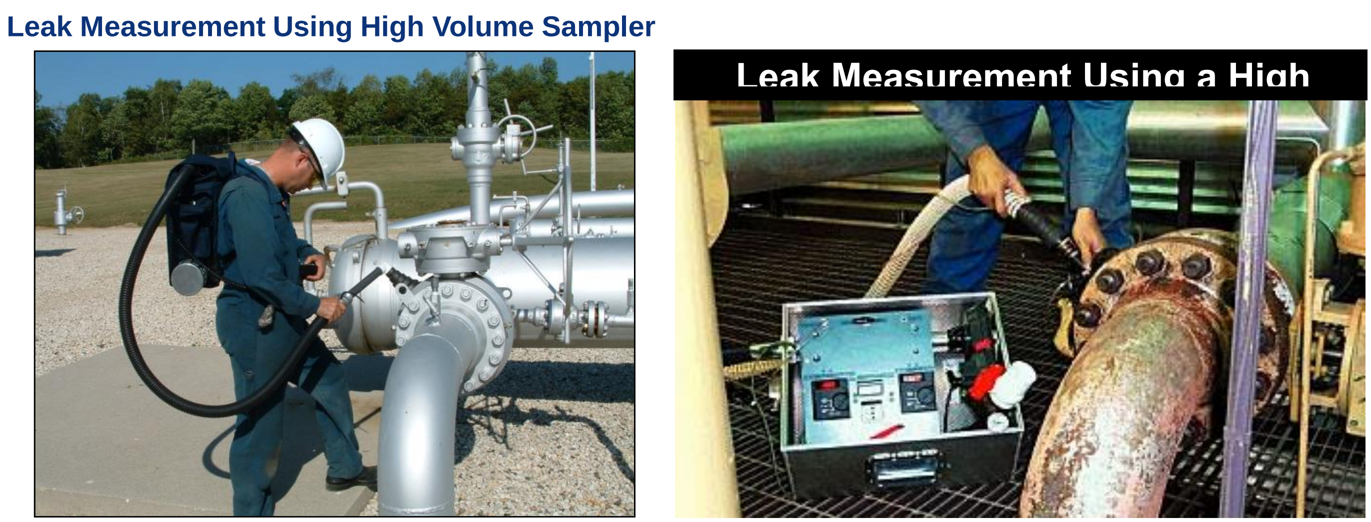
[42] CCAC Oil and Gas Methane Partnership - webinar April 7, 2015: "Fugitive Equipment and Process Leaks," presentation by UNEP

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

Exhibit F – Calibrated Vent Bag[44]

Exhibit G – High Volume Sampler[45]



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

[45] 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

Exhibit H –Hot Wire and Vane Anemometer[46,47,48]

Vane Anemometer

[46] 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

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

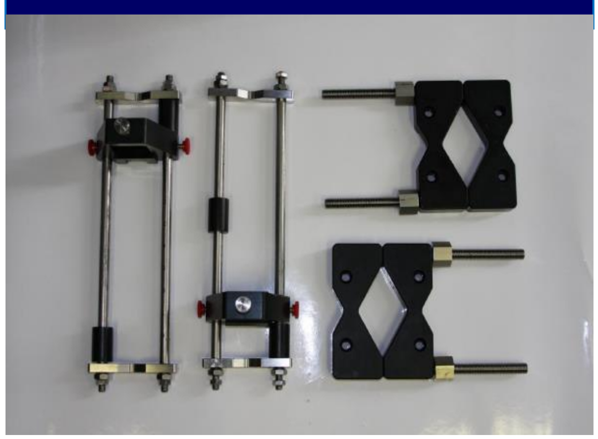
[48] Global Methane Initiative, Natural Gas STAR International, Bucaramanga, Colombia, May, 2012: “Ecopetrol Eco-Efficiency, Methane Emission Reduction Opportunities,” presented by EPA

Exhibit I – Turbine Meter[49]

Turbine Meter

Exhibit J – Acoustic Detection for Through Valve Leak[50]

Ultrasonic Meter



[49] Global Methane Initiative, Natural Gas STAR International, Bucaramanga, Colombia, May, 2012: "Ecopetrol Eco-Efficiency, Methane Emission Reduction Opportunities," presented by EPA

[50] Global Methane Initiative, Natural Gas STAR International, Bucaramanga, Colombia, May, 2012: "Ecopetrol Eco-Efficiency, Methane Emission Reduction Opportunities," presented by EPA