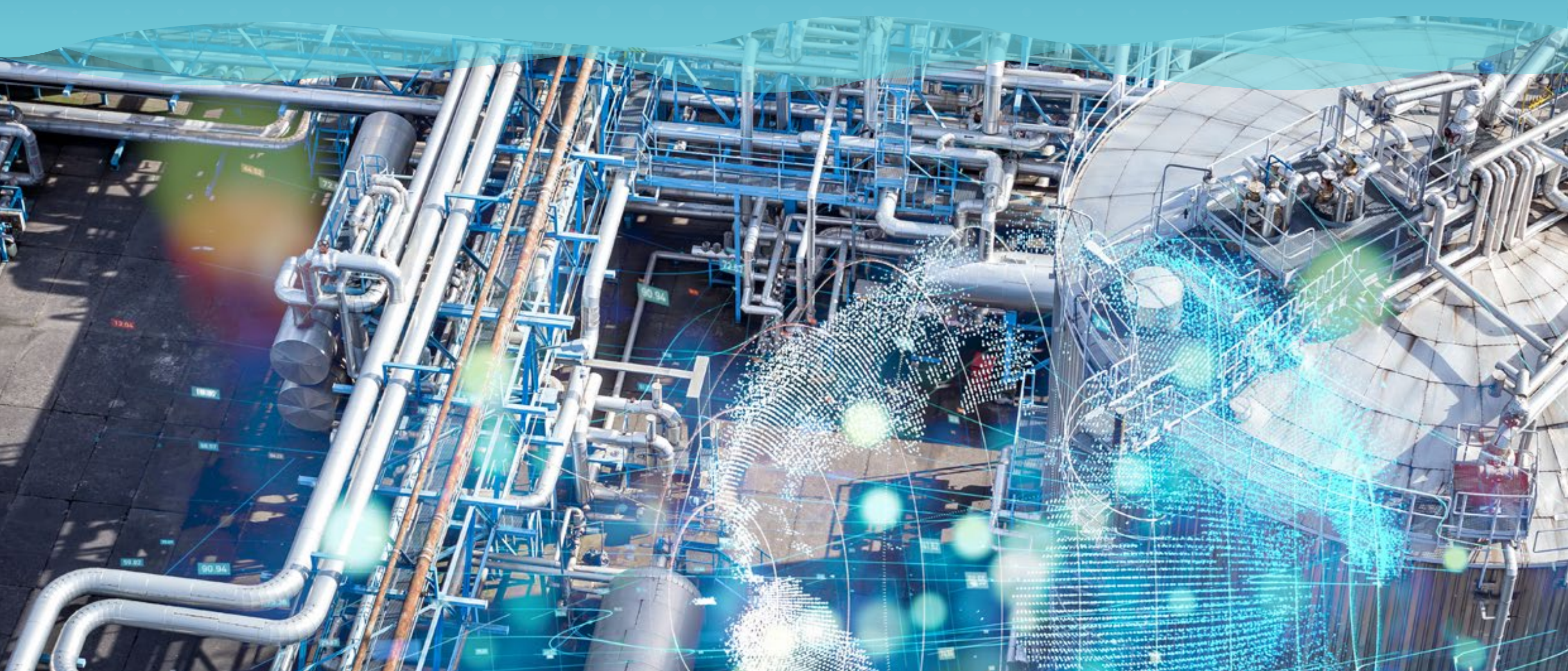
METHANE
GUIDING
PRINCIPLES

REDUCING METHANE EMISSIONS

Best Practice Guide: Identification, Detection, Measurement and Quantification

January 2024



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Disclaimer

Glossary

Asset
Physical equipment owned by a natural gas company, such as equipment that allows the company to produce, process, transport, store, and distribute gas.

Detection
Detecting emissions from potential sources of methane emissions by using methane-sensing equipment.

Downstream
The downstream sector/segment of the natural gas supply chain, which is the distribution network (supplying gas to customers through gas mains, service lines, and meters).

Emerging technology
Technology that is just becoming available, or has been made available but has not yet been widely adopted. As many technologies are continuously improved, some currently categorized as emerging may quickly become more widely adopted.

Identification
Listing and compiling all emission sources from a system based on known, designed emission sources, and surveying for unintended or undesired emissions. (This is also called 'detection' in some circumstances.)

Inventory
A record of all known sources of emissions and emission rates. An inventory provides a summary of emissions over a given period of time.

Method
A technology, or group of technologies, used for detection, measurement or quantification.

Measurement
Measuring methane emissions. Measurement can be of any variable (volume, concentration, mass, frequency and so on) that allows for detection or for an estimate of emission rate.

Midstream
The midstream sector/segment of the natural gas supply chain, which includes gas transmission and storage, and LNG terminals. In some circumstances, this segment of the supply chain may also include gas-processing plants.

Minimum detection limit (MDL)
The MDL is the lowest concentration or rate of emission that can be reliably detected.

Natural gas supply chain
The sequence of processes involved in the production and distribution of natural gas, from the producing well to the end use consumer.

Open path
A sensor that sends out a beam of light, detecting gas along the path of the beam by light absorption. The open path may be a few meters to a few hundred meters in length.

Passive/active
A description of sensors that use the electromagnetic spectrum to detect methane. Passive sensors measure existing natural radiation from objects, while active sensors have a radiation source.

Point sensor
A sensor that detects methane concentrations at a particular location. The sensor may be part of a portable device or a device fixed at a location.

Program
The set of methods chosen by a gas company for identifying, detecting, measuring and quantifying methane emissions. The program may include several screening and surveying technologies and techniques, as well as various quantification techniques to determine the rate of emissions from each detected source. The program summarizes and tracks emissions.

Quantification
Determining an emission rate. This can be done directly through measurement or indirectly through calculations and modelling.

Rate
A quantity of methane emitted in a set period of time.

Screening
Evaluations with the main purpose of identifying sources of emissions. In many contexts, screening can be the same as surveying. However, in some regulatory contexts, screening applies only to less rigorous or less sensitive detection approaches, such as AVO (Audio, Visual, and Olfactory).

Sector/Segment
A section of the natural gas supply chain. The sections include production, gathering, processing, transmission, storage, LNG liquefaction and regassification terminals, and distribution.

Spectrometry
Measurement of the wavelength and intensity of electromagnetic radiation.

Survey
Using detection equipment and measurements to examine a group of assets for signs of emissions.

TDLAS
Tunable diode laser absorption spectroscopy – a technique for measuring concentrations of certain molecules, for example, methane and water vapor, in a mixture of gases.

Upstream
The upstream sector/segment of the natural gas supply chain, which includes gas production and gathering. In some circumstances, this section of the supply chain may also include gas-processing plants.

Summary

A key step in reducing methane emissions is to identify and detect sources of emissions. Emissions are then measured, quantified and recorded in inventories, which are a starting point for prioritizing mitigation activities (activities to reduce emissions).

This guide briefly describes the methods used for identification, detection, measurement and quantification (IDM&Q) of methane emissions, and gives details of other documents that provide technical data for the methods and technologies. Best practice for identification, detection, measurement and quantification will depend on:

- the characteristics of a facility,
- the magnitude of the emissions;
- the cost-effectiveness of the methods used; and
- the purpose of the IDM&Q program.

The methods to use may also depend on regulatory requirements, and whether a regulatory approach can be replaced with an alternative method or only supplemented with additional voluntary methods. Case studies illustrate the types of IDM&Q technologies that organizations have used to meet the IDM&Q needs of several parts of the natural gas supply chain, the methods used in interpreting measurement data.

The process of identifying, detecting, measuring and quantifying emissions, as well as the information recorded in inventories, should be periodically updated and improved to incorporate new information and to track progress in mitigating (reducing) emissions.

The elements of IDM&Q programs are listed below.

Best practice for reducing methane emissions through identification, detection, measurement and quantification

Establish the goals of the IDM&Q program

Identify known sources and potential sources of emissions in an inventory.

Survey known and potential sources to detect actual emissions.

Quantify methane emissions directly by measuring emission rates, or indirectly using a combination of measurements, calculations and modelling.

Use information from quantification to create or update inventories.

Periodically update and improve IDM&Q programs.

Introduction

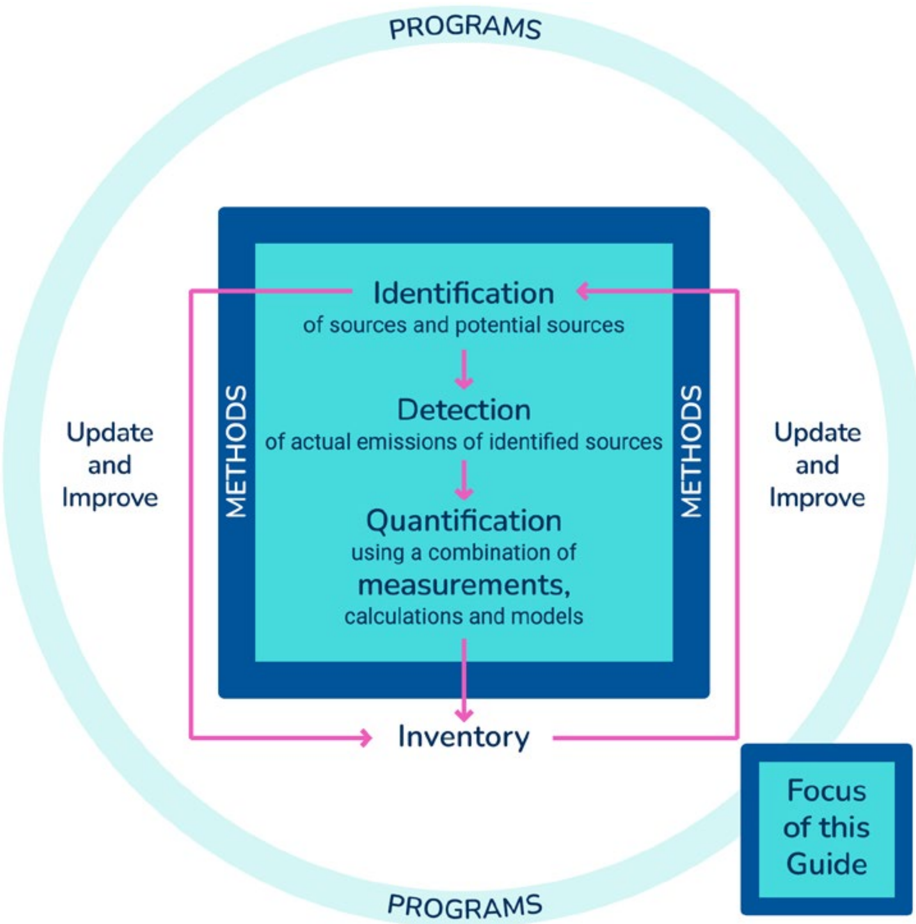
Sources of methane emissions in natural gas value chains include:

- venting (releasing gas into the atmosphere);
- fugitive leaks (leaks from equipment, generally from imperfections or ordinary wear in sealed joints such as flange gaskets, screwed connections, valve-stem packing, from poorly seated valves, or from permeation from polyethylene (distribution) pipelines);
- incomplete combustion (unburned methane in the exhaust gases of gas engines, gas turbines);
- flaring (flares combust methane that could otherwise be released directly into the atmosphere; incomplete combustion in flares leads to methane emissions).

Best practices for mitigating emissions from these sources have been described in other guides developed by the Methane Guiding Principles partnership[1] (available at **https://methaneguidingprinciples.org/best-practice-guides/**), and a vital element in these guides is to identify, detect, measure, quantify and track emissions.

Because of the wide range of emission sources in the natural gas value chains, methods for identifying, detecting, measuring and quantifying emissions vary, especially across sectors with different types of assets. The methods used will depend on whether the emissions information is needed for voluntary programs, for detailed corporate inventories, to prioritize emission mitigation efforts, or to meet regulations that require the use of specific methods.

Figure 1: Programs and methods that govern IDM&Q



As Figure 1 shows, identification, detection, measurement and quantification of emissions leads to comprehensive inventories which are regularly updated and improved. The topics that this guide focuses on are shaded turquoise shown in the center of Figure 1. The lighter shading shows topics that are partially covered.

This guide will focus on the methods used for identification, detection, measurement and quantification. Those terms are described below.

Identification and ***detection***: Some emissions sources are a known part of the design of natural gas systems. In these cases, analyses of system designs are used to identify sources. Other emissions are unintentional and detection surveys are required to identify unintended sources and to confirm known sources.

Measurement and ***quantification***: A wide variety of ***methods*** can be used to quantify emissions. Methods often involve methane concentration measurements in process streams or ambient air but could also include a wide variety of other measurements, ranging from measurement of process stream flow rates to wind speeds. Quantification of emission rate can be done through direct measurement of a source, or indirectly through a combination of measurements, calculations and models.

Programs to develop, update and improve ***inventories*** and direct ***mitigation*** efforts: Multiple methods are generally employed in comprehensive programs to identify, detect, measure and quantify emissions. This information is assembled into emission inventories, which are regularly updated and improved, and are used to prioritize emission mitigation efforts.

Scope of this guide

This guide briefly describes best-practice methods used to identify, detect, measure and quantify methane emissions and provides links to more detailed descriptions and case studies. It briefly summarizes advantages and disadvantages of the methods and gives details of reports that summarize the identification, detection, measurement and quantification of emissions in different sectors. Case studies show the types of programs that organizations in parts of the natural gas value chain have developed to fit their needs. Towards the end of this guide there is a checklist for developing and implementing IDM&Q programs.

Methods

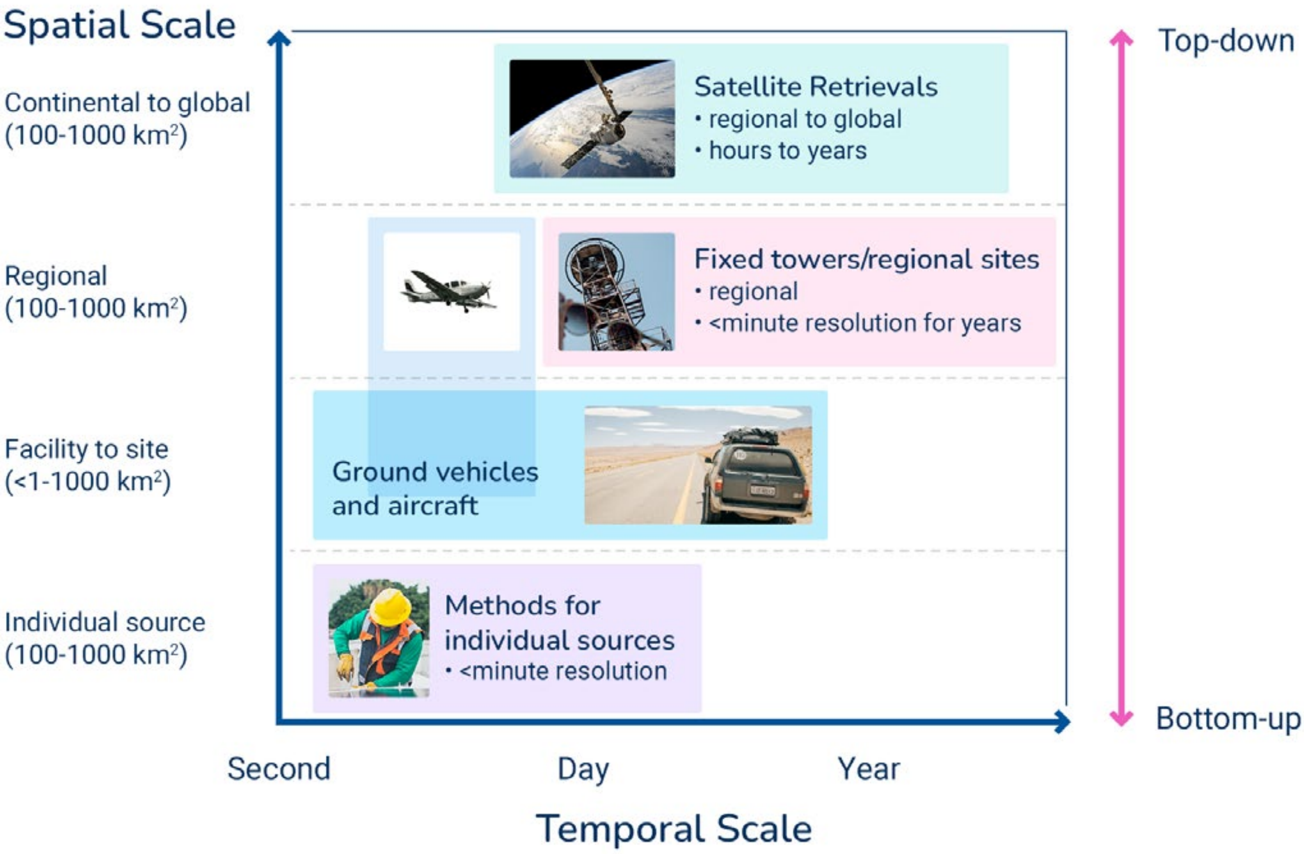
Methods for detection, measurement and quantification

Methods of detecting, measuring and quantifying emissions vary in scale, from programs used for individual sources to large-scale regional or global programs, as shown in Figure 2.

Methods applied at very large scales, typically where a single measurement includes many sources, are generally referred to as top-down assessments. Methods applied at the scale of individual sources, and then aggregated for a site or area, are generally referred to as bottom-up assessments. Both top-down and bottom-up assessments have advantages and disadvantages. Bottom-up assessments provide detailed information about individual sources and the types of equipment and operations that were emitting. This approach allows specific actions to reduce emissions, but may miss some unexpected, unintended or uncharacterized emissions sources. Top-down assessments generally lack detail about individual sources but can provide comprehensive information about emissions at a site or in a region. Depending on the scale of the program, top-down assessments may include contributions from sources that are not a part of the natural gas value chain, and this needs to be accounted for when interpreting top-down assessments, and when comparing top-down assessments to bottom-up estimates. Case studies of the coordinated use of both top-down and bottom-up assessments are provided in this guide. Coordinated assessments and reconciling top-down and bottom-up emission estimates require an understanding of the uncertainties of both approaches and case studies describe approaches to estimating these uncertainties.

Methods for detecting, measuring and quantifying emissions also vary in timescales. Some methods provide a single 'snapshot' of methane emissions; others are recurring or make measurements continuously. Snapshots can be useful when used to verify results of mitigation activities, such as activities to eliminate the source (for example, by replacing gas-powered pneumatic devices with devices powered by compressed air). Other emission sources can be intermittent and/or recurring, so increasing the frequency of detection and repair may lead to improved detection and larger reductions in emissions. The best practice for the frequency of detection, measurement and quantification will depend on the characteristics of the sources of emissions at a facility, the cost-effectiveness of the methods, and regulatory requirements. Generally, there is no single technology that will meet all measurement needs, and in some cases coordinated use of multiple measurement technologies may be the most effective approach. Case studies of coordinated use of multiple measurement technologies are provided in this guide.

Figure 2: Methods for emissions detection, measurement and quantification cover a wide range of spatial and temporal scales (adapted from reference 2)



Detection

Table 1 below summarizes methods used for detecting sources of emissions. The methods are carried out using handheld devices, fixed location detectors, by devices on vehicles, on drones or aircraft, or on a satellite. They may detect emissions using passive or active sensors at a fixed point or over an open path, or may involve imaging. The methods use a range of sensing technologies. Some methods apply to all sectors of the natural gas value chain. Others have more specialized uses. It is beyond the scope of this guide to provide detailed descriptions of each method and their advantages and disadvantages. However, the appendix provides links to more detailed descriptions and assessments of the methods. Those assessments have been carried out by professional or industry organizations such as the Interstate Technology Regulatory Council (ITRC),[3] MARCOGAZ (the technical association of the European natural gas industry),[4] and the National Association of Regulatory Utility Commissioners (NARUC).[5] In addition, links to information from method-testing centers,[6] and summaries of information from organizations such as the US National Academies of Science, Engineering and Medicine (NASEM)[2] are included.

Some detection technologies listed in Table 1 are emerging and may not be widely used yet.

Table 1: Methods for detecting methane emissions

Type of survey (and means of deployment)	Sensing method	Main use	Possibility of quantifying rates	Level of confidence in detection	Sectors where the method is used
Survey by a person on foot, used for individual sources	Open path sensor	Detecting leaks and emissions from venting	Possible	High	All sectors
	Point sensor		Possible	High	All sectors
	Plume imaging (Optical Gas Imaging) (passive)		Possible with additional processing	High	All sectors
	Soap screening		No	High if the approximate location of the leak is known	All sectors
	Ultrasound imaging		Possible	Medium	All sectors
detectors (on-site or perimeter)	Open path	Detecting unusual events (may also identify source)	Possible	High	Upstream and midstream sectors
	Point sensor			High	
	Plume Imaging			High	
Fixed-location detectors (area or region)	Open path	Detecting unusual events (may also identify source)	Possible	Medium	All sectors
	Point sensor				All sectors
Survey by wheeled vehicle	Open path	Detecting total emissions at a site	Yes	Medium	All sectors
	Point sensor	Detecting total emissions at a site	Possible	Medium to high	All sectors
	Plume imaging	Identifying sources of emissions	Possible with additional processing	High	All sectors

Type of survey (and means of deployment)	Sensing method	Main use	Possibility of quantifying rates	Level of confidence in detection	Sectors where the method is used
Survey by drone or UAV (unmanned aerial vehicle, a small aircraft piloted by remote control or onboard computers)	Open path	Substitute for on-foot survey	Possible	Medium	All sectors (This an emerging technology for midstream and upstream sectors)
	Point sensor	Substitute for on-foot survey	Yes	Medium to high	Upstream and midstream (This an emerging technology for midstream sectors)
	Plume imaging	Identifying sources of emissions	Possible with additional processing	High	All sectors (This an emerging technology for midstream and downstream sectors)
Survey by aircraft	Open path	Identifying sources of emission	Possible	High	Upstream
	Point sensor	Identifying sources of emissions and quantifying emissions	Possible, depending on technology	High (different technologies have different minimum detection limits)	All sectors (This an emerging technology for midstream and downstream sectors)
	Plume imaging	Identifying sources of emissions	Possible with additional processing	High	All sectors (This an emerging technology for midstream and downstream sectors)
Survey by satellite	Plume Imaging Detecting total emissions of a region		Possible with additional processing	To be determined. Large minimum detection threshold	All sectors (This an emerging technology for all sectors)

Measurement and quantification

Table 2 summarizes methods used for measuring and quantifying emission rates from emission sources. Some of these methods are linked to detection methods, where the quantification can be a result from the detection survey. Other quantification methods use completely independent technologies that are unrelated to a detection method or technology. An example of an independent quantification is the HiFlow™ Sampler device, which may be used to quantify emissions after a detection method has identified the source.

The assessments of the quantification methods listed in table 2 have been carried out by professional or industry organizations such as the Interstate Technology Regulatory Council (ITRC), and MARCOGAZ. In addition, links to information from method-testing centers,[6] and summaries of information from organizations such as IPIECA and the Oil and Gas Climate Initiative (OGCI),[7] and the US National Academies of Science, Engineering and Medicine (NASEM)[2] are included. Other sources of information are listed in the appendix.

Table 2 refers to the same types of survey, ranging from foot surveys to satellites, as in table 1. However, some of the detection methods in table 1 cannot be used to produce a rate of emission, so are not included. Some general advantages and disadvantages of each measurement and quantification method are listed in the table. However, an organization should evaluate the suitability of a selected technique for each specific application.

The measurement and quantification methods use a range of sensor technologies, which are described by the studies and reports listed in a table in the appendix. Most of the extensive reports listed in the appendix do not select a single best practice nor even a set of recommended practices. Tools for initial recommendations are beginning to emerge,[7] although recommendations should be viewed with caution. Precise details of the various sensor technologies is beyond the scope of this guide.

Table 2: Measurement and quantification of an emission source

Type of survey (and means of deployment)	Technology	Measurement/ quantification method	Accuracy of quantification	Advantages and Disadvantages	Sectors where the method is used
Survey by a person on foot, used for individual sources	Sniffer sampler, such as a flame-ionization detector (FID) or high-sensitivity semiconductors, that sample the concentration of methane in the air	Indirect. Through use of a correlation equation that relates concentration to rate, or through use of leak/no-leak emission factors	Medium to high	Advantage: Well documented methods exist, such as models/ correlation factor of EN15446, which is an indirect quantification methodology Disadvantage: post-survey calculations and correlations must be used	All sectors for above-ground facilities
	Flow sampling (a device pulls in enough air to capture the entire emission)	Direct	High	Advantage: Real-time emission rate Disadvantage: original HiFlow™ Sampler (HFS) device has been discontinued, but alternatives are now available; original device had known technical issues; time consuming	All sectors, but not sensitive enough for many small distribution-system leaks
	Optical-gas imaging combined with real-time image processing (OGI+QOGI) (This is an emerging technology for quantification.)	Indirect	Low to medium	Advantage: real-time emission rate estimate Disadvantage: low confidence level; highly dependent on environmental conditions; poor for extremely large leaks; requires specific training	All sectors, but often not sensitive enough for small distribution-system leaks
	Mass-flow meter, pitot tube, or other flow device inserted into a flowing emission source such as a vent stack	Direct	High	Advantage: Direct flow measurement Disadvantage: Safe access to emission source line is often an issue	All sectors with vent stacks
	Calibrated bags	Direct	High	Advantage: Inexpensive materials, accurate Disadvantage: Time consuming and labor intensive	All sectors if leak size is appropriate

Type of survey (and means of deployment)	Technology	Measurement/ quantification method	Accuracy of quantification	Advantages and Disadvantages	Sectors where the method is used
	Mass flux chamber (an enclosure built around a surface expression of a pipeline leak, allowing air pulled out to be measured for concentration)	Direct	Medium	Advantage: Does not rely on atmospheric modelling Disadvantage: Quantifies emission rates only from covered areas; labor intensive; assumes full leak capture and measures after loss in soil	Transmission and distribution, for buried pipeline leaks
	Ultrasound imaging (This an emerging technology for all sectors)	Indirect	Not yet known, likely medium	Advantage: Real-time, fast Disadvantage: New and still being assessed; requires certain pressure drop; software for methane still at the development stage	All sectors
Fixed-location detectors (perimeter or fence-line)	Open Path light absorption	Indirect only. Possible with additional modelling and meteorological information	Medium	Advantage: Available technology Disadvantage: Expensive	Upstream and midstream with significant population density of above-ground facilities
	Point sensors on site (This an emerging technology for all sectors.)		Medium	Being developed	
Fixed-location detectors (area or region)	Point sensors in a network (This an emerging technology for all sectors)	Indirect. Possible with additional modelling and meteorological information	Medium to low	Being developed	Upstream and midstream with significant population density of above-ground facilities
Survey by wheeled vehicle	Vehicle with methane detection plus analysis using meteorological information and inverse dispersion modelling	Indirect	Medium to low	For many approaches, quantification is done desk-top, after the survey is finished	All sectors (above-ground facilities with nearby vehicle access, or buried pipelines with vehicle access)
	Detection vehicle and tracer release	Direct. Only ratios are needed to determine rate	Medium to high	Advantage: Well understood and highly vetted Disadvantage: Labor intensive; accuracy dependent on tracer/ emission source co-location	All sectors, but mostly used upstream and midstream

Type of survey (and means of deployment)	Technology	Measurement/ quantification method	Accuracy of quantification	Advantages and Disadvantages	Sectors where the method is used
Survey by drone or UAV (unmanned aerial vehicle, an aircraft piloted by remote control or onboard computers) **(There are many UAV detection technologies, but few of them produce a rate quantification, so are not included in this table.)**	Mass-balance model (upwind and downwind measurements using a flight path that encloses the source)	Direct	Low	Advantage: Inexpensive compared with larger-scale top-down methods Disadvantage: few providers; requires favorable atmospheric conditions	Upstream and midstream
Survey by aircraft	Mass-balance by flight path upwind and downwind	Direct	Medium (can be high if a single plant is enclosed by the flight path)	Advantage: peer-reviewed approach Disadvantage: Expensive; requires favorable atmospheric conditions; few providers	All sectors, though less in distribution
	Passive light absorption	Indirect. Plume pixel modelling is used	Low	Advantage: Several providers Disadvantage: Poor minimum detection limit; high uncertainty	All sectors
	Active light absorption	Indirect. Plume pixel modelling is used	Medium	Advantage: Demonstrated technology Disadvantage: Few providers	All sectors

Type of survey (and means of deployment)	Technology	Measurement/ quantification method	Accuracy of quantification	Advantages and Disadvantages	Sectors where the method is used
Survey by satellite (Other satellites that can detect methane are planned for launch.)	Spectrometry TROPOMI (The TROPOspheric Monitoring Instrument)	Indirect. Extensive processing is required	Medium	Disadvantage: Requires significant processing of satellite information to estimate emissions	All sectors
	Spectrometry Methane Sat to be launched in 2024 (This an emerging technology for all sectors)	Indirect. Extensive processing is required	Unknown	Advantage: Free, frequent and public facing (for Methane Sat) Disadvantage: Not yet launched; requires significant processing of satellite information to estimate emissions. Expected delay for rate data	All sectors
	Spectrometry (WAF-P (Wide-Angle Fabry-Perot) GHG Sat (This an emerging technology for all sectors) (Other satellites that can detect methane are planned for launch such as other GHG Sat series, as well as GOSAT-3, GeoCarb, MERLIN, EarthCARE, CarbonSat, GEO-CAPE and the Metero series)	Indirect. May be added after analysis	Unknown	Advantage: Available Disadvantage: Service for hire; limited microsatellites currently in orbit; high MDL	All sectors

Characterizing Uncertainties

The types of uncertainties associated with measurements of emission rates depend on whether the emission rate is measured directly at the source or indirectly by making an atmospheric measurement at a location remote from the source. For both direct and indirect measurements, there are uncertainties in the measurements made by the device. For indirect measurements, there are also uncertainties associated with converting an atmospheric measurement, made remote from the source, into an estimate of an emission rate. Different types of uncertainties are characterized using different methods and are reduced using different approaches.

Device uncertainties in direct and indirect measurements of emission rates
Uncertainties in emission rate measurements made at the source (direct measurements) and atmospheric concentration measurements (used in indirect measurements) are generally characterized using laboratory and field calibrations and are reduced by improving sensor system performance; these uncertainties are among the smallest contributors to overall uncertainty.

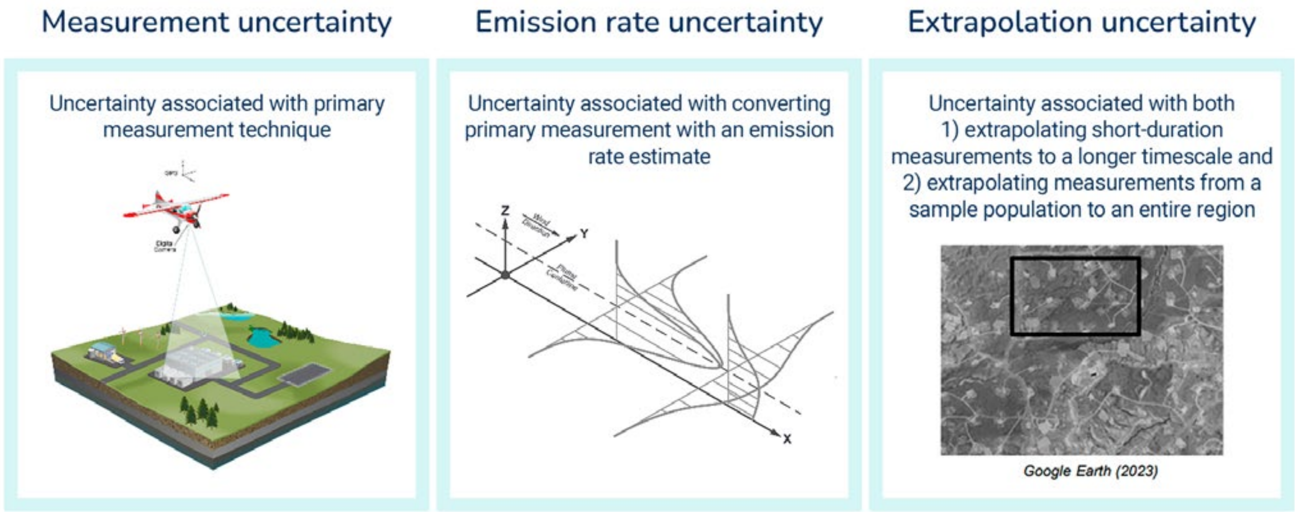
Uncertainties in converting atmospheric measurements remote from a source into emission rates
Indirect measurements convert atmospheric concentrations into estimated emission rates using dispersion models and other atmospheric modeling tools. These uncertainties have been assessed using controlled releases at simulated facilities and controlled releases at operating facilities. The uncertainties are reduced through more accurate characterization of the atmospheric dispersion and transport of methane.

Both direct and indirect measurements are frequently conducted for relatively short periods of time and may be applied at only a subset of an organization's facilities. If these measurements are to be used in creating measurement-informed annual emission inventories, the measurements must be extrapolated to longer times and additional facilities. This extrapolation also introduces uncertainty.

Uncertainties in extrapolating short duration measurements to annual emission estimates
Most emission rate estimates are based on short duration measurements at a limited number of facilities. To develop comprehensive annual emission inventories, short duration measurements made at a subset of facilities for limited time must be extrapolated to all sites and all times. The uncertainties in extrapolation to facilities where measurements are not available are reduced by sampling more facilities or by careful selection of the sampled facilities. Uncertainties in extrapolating short duration measurements to annual emission estimates are reduced through characterizing the frequency and duration of emission events.

Uncertainties of all types depend on local conditions, however, generalized methods are emerging for quantitatively estimating uncertainties. Case studies of uncertainty estimation are provided in this guide.

Figure 3: **Emission measurement practices have three types of uncertainties: measurement uncertainty, emission rate uncertainty and extrapolation uncertainty. Methods for estimating these types of uncertainties are provided in case studies in this guide.** (Source: Reference 8)



Continual improvement

Methane emissions that have been identified, detected, measured and quantified are recorded in inventories for facilities, companies and regions. These inventories can be used to guide mitigation efforts and should be regularly updated to reflect changes in equipment and operations, and any other new information.

New information that can be used to update and improve bottom-up assessments may come to light. This may include new detection methods, new studies that update average emission rates from equipment (emission factors), new models for estimating emissions, or other innovations. As improved information becomes available, inventories should be updated.

Information from top-down assessments can also be used to periodically update and improve inventories. A large number of measurement studies have shown that a small fraction of sites, or a small fraction of certain categories of equipment in the natural gas supply chain, account for a large proportion of total emissions. Based on experience in the US, 5% of sources were generally responsible for over 50% of total emissions[2,9]. These sources, known as high-emitting sources, may not be accounted for in emission inventories and multiple programs have been established to quickly identify sources with large emission rates. These programs include the large emission event (super-emitting event) identification and reporting program, established in 2023 by the U.S. Environmental Protection Agency for sources with emission rates >100 kg/h,[10] and the emerging Methane Alert and Response System (MARS) of the UN's International Methane Emission Observatory (IMEO).[11] As satellite methods and other top-down assessments expand large emission event identification systems globally, it will become possible to regularly compare bottom-up emission inventories to independent top-down quantifications. These comparisons can be challenging but can guide continual improvement of inventories of methane emissions.

Case studies

The case studies in this guide come from different sectors in the natural gas value chain. They represent current practices and illustrate a variety of identification, detection, measurement and quantification methods. Some case studies combine more than one technology. Some case studies address information about measurement uncertainties. Table 3 below summarizes the sectors and survey types that the case studies apply to. Case studies were selected such that every sector was represented, and different survey types were represented. Case studies are categorized based on whether a single measurement method was used (S), whether multiple measurement methods were used (M), whether top-down and bottom up measurements are reconciled (R), or whether measurement uncertainty is quantitatively evaluated (U).

Table 3: Case studies for sectors and types of survey

Type of survey	Industry sector			
	Upstream	Transmission and storage	Distribution	LNG terminals
Foot	Case study 1 (M)	Case study 4 (S) Case study 5 (M)	Case study 6 (M)	Case study 7(M)
Fixed location	Case study 2 (M) Case study 9 (U) Case Study 10 (U) Case Study 14 (U) Case Study 15 (M)	Case Study 16 (M,U)		
Wheeled vehicle	Case study 2 (M)		Case study 6 (M)	
Drone or UAV	Case study 2 (M)	Case Study 16 (M,U)		
Aircraft	Case study 3 (S) Case study 8 (R) Case study 11 (U) Case study 13 (U)	Case study 8 (R)	Case study 8(R)	
Satellite	Case study 8 (R) Case study 12 (U)	Case study 8 (R)	Case study 8 (R)	

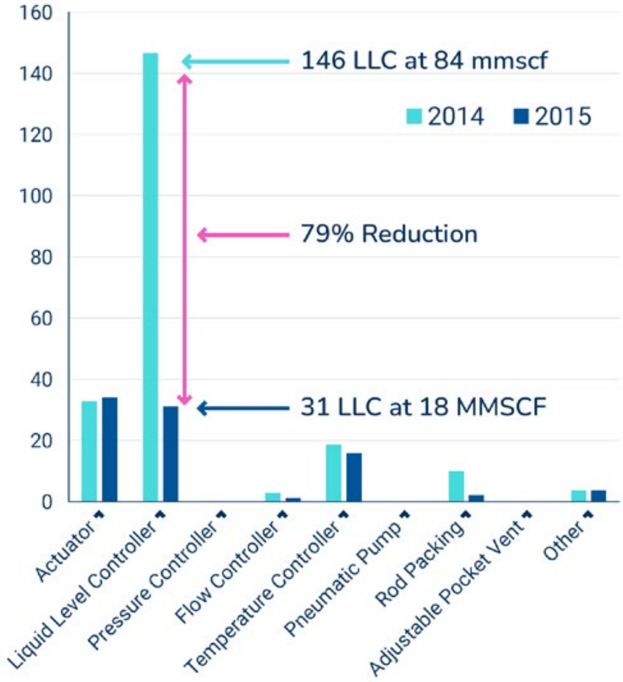
Case study 1:
Upstream (production and gathering)

Case study: Southwestern Energy (SWN) 'Smart LDAR' – an enhancement above regulatory requirements

Description of program: Beginning in 2014, SWN began optical gas imaging (OGI) surveys of new and modified well sites and gathering compressor stations, as required by US federal regulation (NSPS OOOOa). SWN added the following elements, which went above regulatory requirements.

- They included all existing sites, which were not part of the regulation.
- They added the following to the required OGI leak scan.
  - A duplicate survey by an extra open-path laser instrument
  - HiFlow™ Sampler rate quantification of identified leaks
  - Pneumatic controllers were included as a target

Result: SWN was able to identify malfunctioning pneumatic liquid-level controllers (LLC) and reduce emissions from these devices by 79% in one year, saving 115 million scf/yr (standard cubic feet per year) of emissions from this category. By using the HiFlow™ Sampler, they were able to quantify their reductions. They also achieved reductions in fugitive leaks from other equipment, but those savings were considerably smaller.



Costs: SWN spent approximately US$500,000 a year on the elements that went beyond the regulatory requirements. The value of the gas saved was approximately US$250,000 a year, so the program had a negative rate of return.

Learnings: SWN staff were placed in two teams – one focused on well sites, and one focused on midstream gathering stations. Each site was visited every year. SWN believe the investment produced many other non-monetary returns. They also believe that using the open-path laser as a second detection method greatly increased the number of leaks found, the verification of leaks, and the speed of their teams.

Source: Presentations by SWN to the US EPA, shown at https://www.epa.gov/sites/production/files/2017-11/documents/15.jordan_2017aiw.pdf

Case study 2:
Upstream (production and gathering)

Case study: Field trial of methane-detection technologies (XTO/ExxonMobil)

Description of program: As leak detection and repair (LDAR) programs expand, new ways of improving site coverage, data tracking and response-time efficiencies, and overall cost-effectiveness, have gained increased attention. Developers of emerging technologies have responded by developing several detection, measurement and quantification systems for methane emissions. ExxonMobil undertook a voluntary LDAR program that went beyond regulatory requirements. They trialed three distinct detection technologies (vehicle, drone and fixed-location systems) while performing conventional emissions surveys and downwind measurements.

Result: Emissions were assessed using a drone-mounted sensor, a fixed-location downwind sensor, a vehicle-mounted sensor, and a mobile downwind monitor. The emission detection and quantification were compared against emissions detected using optical gas imaging at several operating well sites in a dry gas-production region of east Texas. Results for all methods were gathered at as close to the same time as possible. Emissions were quantified using a HiFlow™ instrument at a selection of sites to verify the methods. The methane emission detection, localization (source attribution) and quantification technologies were compared against each other.

Costs: Not reported.

Learnings: Similar distributions of emissions were recorded across the drone, downwind and conventional methods used for detection and quantification. Emerging medium- to high-frequency monitoring technologies currently offer faster detection and insights into trends, often outperforming optical gas imaging in terms of identifying sources of emissions. Downwind sampling identifies emissions at sites, and drone-mounted technologies can pinpoint emissions from specific equipment and quantify those emissions. However, optical gas imaging still plays an important role in identifying components that leak.

Sources: 'Insights from a field trial of methane detection technologies', American Geophysical Union Annual Meeting, San Francisco – EE Tullos, S Aminfard, FJ Cardoso-Saldaña, D Allen, I Mogstad, L DeWitt, B Flowers, SC Herndon, A Scott, S Elms, and B Smith December 2019: Tullos, E.E., Stokes, S., Cardoso-Saldaña, F.J., Herndon, S.C., Smith, B., Allen, D.T., Use of short duration measurements to estimate methane emissions at oil and gas production sites, Environmental Science & Technology Letters, 8, 463–467 (2021).

Case study 3:
Upstream (production and gathering)

Case study: Field trial of aerial methane-detection technologies (XTO/ExxonMobil)

Description of program: During 2019, ExxonMobil carried out an aerial survey of Permian Basin assets (west Texas and southeast New Mexico) using aircraft-based Gas Mapping LiDAR™ (active open path) technology. The purpose of this project was to understand both the frequency and quantity of methane emissions in the targeted areas.

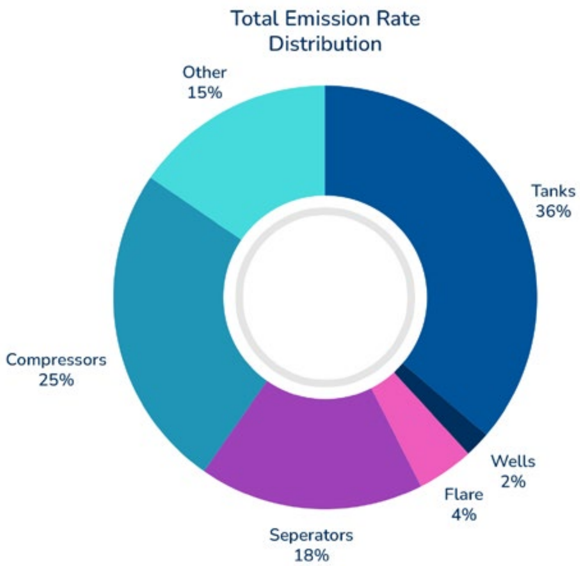
Result: The emissions that were found were overlaid on aerial photography taken using the built-in camera of the sensor to locate and identify equipment on 505 pads in the survey area. By analyzing the types of equipment visible in the aerial photos, emissions could be associated with certain equipment types, such as tanks, wells, flares, separators, compressors and other (unclassified) equipment. The results provided an emission estimate for each emission that was discovered, and a breakdown by equipment.

Equipment	Count of Equipment overflown	% of Equipment Type that was Emitting
Tanks	512	7.4
Wells	313	1
Flares	65	6.2
Separators	310	6.1
Compressors	39	64.1
Other*	33	100

* 'Other' is inclusive only of unclassified pieces of equipment that were found to be emitting. It does not mean all other pieces of equipment on the sites surveyed.

Costs: Not reported

Learnings: This screening and survey approach provided a fast identification method, producing initial findings within 24 hours, with an emission estimate one week later. Some emission sources, such as compressors, were expected. Others, such as flares, were unexpected. Further work will have to be carried out to classify tank emissions, as there should be no emissions from tanks with working vapor-control systems, while emissions from permitted, uncontrolled tanks are expected. Results also showed that tank systems for non-Exxon sites in the area surveyed were a much larger fraction of the total emissions than from ExxonMobil sites (78% non-ExxonMobil vs 36% for ExxonMobil).



Source: Stokes, S., Tullos, E., Morris, L., Cardoso-Saldaña, F.J., Smith, M., Conley, S., Smith, B., Allen, D.T., Reconciling multiple methane detection and quantification systems at oil and gas tank battery sites, Environmental Science & Technology, 56, 6055–16061, doi: 10.1021/acs.est.2c02854 (2022).

Case study 4:
Midstream (transmission, underground storage, and LNG terminals)

Case study: Snam 'Best practice for Identification & Quantification'

Description of program: Snam has used a method developed internationally with the Gas Research Institute and the US Environmental Protection Agency, integrated with a series of field measurements carried out with the US company Radian, on assets and representative sections of their network. From 2018, and especially during 2019/2020, Snam carried out an on-site measurement campaign. The activity was carried out using flame-ionization detector (FID) sniffer equipment and, in some cases, a HiFlow™ Sampler (HFS), to quantify emission rates. Correlation factors were used to estimate and report fugitive leaks. Bagging and a combination of blower flow rates and FID measurements were also used.

Result: Snam was able to improve the emission accounting system based on field measurements. In two years of activity, more than 150,000 components were measured. Based on this information, emission factors were updated. A new field campaign is in progress.

Costs: Snam spent approximately €200,000 a year to perform these activities.

Learnings: Snam was able to better understand the major sources of emissions in its assets and to introduce mitigation programs to replace specific components. Snam is also introducing LDAR programs to identify methane leaks and plan maintenance work. The following results were achieved:

- Reduction of network emissions from leaks (-0.8 Mcm in 2019), due to the continuation of the initiative to install / replace a ball valve in the network pressure reduction stations. This reduced gas escaping from the filter blowdown systems of the station, due to a lack of internal tightness of the blowdown valve. This program will lead in a four-year period 2017-2020 to the modification of 351 stations, and an ultimate saving of 2.5 Mcm of gas;
- Reduction of emissions resulting from depressurizing systems, especially in some storage facilities;
- New plans to carry out the LDAR technique with staff in 2020.

Source: 'Snam in the Task Force on Climate-related Financial Disclosure', a report on climate change published each year from 2019. See the Snam website at **https://www.snam.it/en/Sustainability/strategy_and_commitments/task_force_CFD.html**

Case study 5:
Midstream (transmission, underground storage and LNG regasification terminals)

Case study: Enagás are the natural gas infrastructure company in Spain and have 12,000 km of gas pipelines, 19 compressor stations, 493 regulation and metering stations, three underground storage facilities and four LNG regasification plants. Enagás have voluntarily calculated and verified their annual carbon footprint, including methane emissions, since 2013.

Description of program: Before 2013, the reduction of methane emissions by Enagás was linked mainly to safety requirements. As fugitive leaks are an important part of the carbon footprint, Enagás decided to carry out their first LDAR campaign in 2013/2015. This campaign covered fugitive leaks in all LNG terminals, all underground gas storage and a sample of the transmission-gas infrastructure. Campaigns were carried out with external support.

Fugitive leaks were initially measured using two different technologies – HFS (HiFlow™ Sampler) and portable detectors which use high-sensitivity semiconductor sensors. In subsequent campaigns, Enagás decided to measure emissions using a portable detector, as the HFS was time consuming. So leak detection and measurement is currently carried out using a portable detector and an OGI (optical gas imaging) camera. Quantification is achieved using correlation factors from the portable device readings to estimate the emission rates of every detected leak, according to the standard EN 15446.

Result: Based on the experience gained during the first LDAR campaign, Enagás have carried out several additional campaigns in the past few years. In 2019 repairs allowed Enagas to avoid 140 tons of emissions. Since 2013, fugitive leaks have been reduced by 47%.

Enagás now carry out LDAR campaigns internally as part of their maintenance program, to increase the frequency of the campaign (annually in all the infrastructure operated in Spain) and ensure continuous improvement.

Costs: The cost of conducting LDAR campaigns is approximately of €200,000 per year.

Learnings: The main lessons learned from the LDAR campaigns are as follows.

- There is still great uncertainty associated with measurement technologies, emission factors and correlation factors, and there is no standard methodology.
- On-site measurement is currently the most effective and reliable technique for detecting leaks, quantifying emissions and introducing mitigation measures.
- The frequency of the campaigns is also a determining factor for reducing fugitive leaks, especially in installations where equipment operates under large variations of temperature.

Source: Enagás's 2019 Annual Report at **https://www.enagas.es/stfls/ENAGAS/Documentos/Annual%20Report_2019.pdf**

Case study 6:
Downstream (distribution)

Case study: NEDGIA (a gas-distribution company in Spain) co-ordinated with SEDIGAS (the Spanish Gas Association) and established a way of quantifying natural gas flowrates for underground leaks detected by routine surveys.

Description of program: Leak-detection surveys are routinely carried out by vehicles or by people on foot, or both. Leak detection is carried out in stages. First, leaks are located by someone walking as close as possible over the buried pipes, taking air samples at the surface of the ground. Approximate leak locations are confirmed by surface drillings that start at the edge of the area where gas is detected, progressing towards the opposite edge of detection. The drillings must be deep enough to go through any pavement and concrete base. The gas detector probe is introduced into the drilled hole. The portable gas detector used has high-quality (0 to 9,900 ppm) thermal conductivity sensors for 0 to 100% methane, and a response time of 20 seconds. Probes must have a cone or other suitable closure system to avoid outside air being taken in through the suction point once it is introduced into the drilled hole.

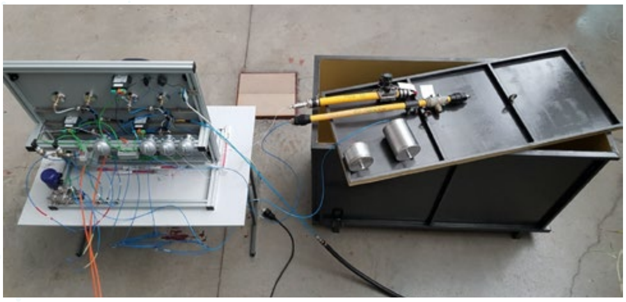
Identified leaks are quantified through a research program that was designed to get specific emission factors for different parts of the gas-supply network. The program quantifies the flowrate of natural gas in the hole that causes the leak, without taking into account how that gas reaches the surface. Using samples from dug-up sections of pipe , a lab uses the 'pressure drop' method in a sealed sample, starting at field operating pressure and temperature, in order to determine the net leak rate. The physical samples collected are a subset of all leaks, but the samples are carefully selected to represent the various network construction and operational conditions for all leaks, such as the operating pressure, equipment material, equipment size, and leaking part (for example, pipe, valve, coupling, welding).

Costs: SEDIGAS plans to spend approximately €150,000 on this project.

Result: A database was created that links a list of leaking elements and their specific features to an average leak flowrate for each type of leaking element and operating condition. As a result of this, once a leak is detected, a flowrate can be assigned from that database.

Learnings: Better quantification should now be possible along the whole grid, providing distribution operators with suitable factors for quantification. The results also showed that further care relating to some elements of the grid (for example, connections and joints) needs to be taken.

Source: Presentations by NEDGIA and SEDIGAS about 'Evaluation of fugitive emissions in gas distribution networks'.



Case study 7:
LNG systems

Case study: Enagás LNG terminal operator – methane emissions management and reduction

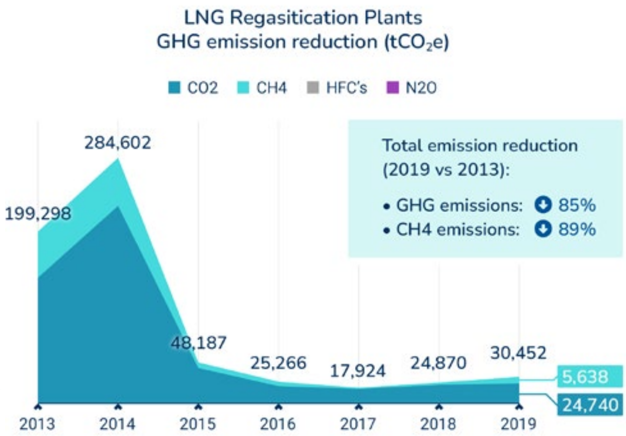
Description of the program: Managing and reducing methane emissions are part of the culture of Enagás, at all levels of the company. Enagás operates and maintains three LNG regasification plants.

Enagás classify methane emissions in three categories – fugitives, vented and incomplete combustion. Enagas uses a Sensit portable detector (a point sensor) in the daily operation of LNG terminals (such as at the end of the ship loading and unloading activities), and during start-ups and maintenance activities.

Depending on the emission type and associated equipment, specific quantification methods and mitigation measures are applied in the LNG terminals.

- Identifying fugitive leaks: Detection and measurement of leaks is carried out using a portable detector and an OGI camera. Since 2020, LDAR campaigns that meet European standard EN 15446 are carried out every year at all the LNG terminals that Enagás operate in Spain (Barcelona, Cartagena, Huelva). Fugitive leaks are repaired in parallel during LDAR campaigns. Leaks that cannot be fixed at the moment of detection are included in the maintenance plan and are repaired before the end of the year, unless a repair requires major works.
- Quantifying venting: methane emissions from technical devices (e.g. gas analyzers) are calculated considering the gas composition, total number of technical devices and the total volume of gas vented. In the case of operational and maintenance vents, methane emissions are measured with ultrasonic flow meters at the vent stack.
- Site-level measurement technologies: Enagás have some collaborative projects related to site-level measurements (wheeled vehicles, drones, satellites) in order to compare the on-site measurements with available information on different sources of emissions.

Result: Since 2013, fugitive leaks at LNG terminals have been reduced by 55% and vents by 98%, and the total of all methane emissions has been reduced by 89%. A web application was specially developed to monitor and register the information obtained in the LDAR campaigns. The application estimates annual emission rates and annual emission savings, as well as prioritizing leaks based on their magnitude.



Learnings: A comprehensive identification, detection, measurement and quantification approach has produced considerable results for Enagás.

Source: Enagás

Case study 8:
Reconciling top-down and bottom-up assessments

Case study: Methods for reconciling bottom-up emission inventories with top-down measurements are wide ranging and vary in scale. In upstream production, reconciliations may be performed at a single facility or at a regional or basin level. At midstream surface facilities, such as compressor stations, gas-processing plants and large metering and regulating stations, the comparison is generally at facility level. In distribution systems, the comparison is often regional, and in this analysis it is difficult to separate emissions from the natural gas value chain from other sources, and to separate emission sources inside the distribution system from emissions that arise after the gas has been metered and transferred to customers.

Description of program: The need for reconciliation may range from continuous improvement of inventories to voluntary commitments for individual companies.

Results: Several case studies document reconciliations between bottom-up and top-down assessments. However, most of this analysis has been done in North America. The summary below focuses on analyses that have appeared in peer-reviewed scientific journals. A summary appears in a report from the US National Academy of Sciences, Engineering and Medicine.[2] Additional information on reconciliation can be found in guidance from the Oil and Gas Methane Partnership (OGMP 2.0)[i].

- **Upstream production sites and gathering compressor stations:** top-down estimates have generally been larger than bottom-up estimates. The comparisons have been made at different scales, including the following.
  - Top-down, site level measurements taken for hundreds of production and gathering sites[ii-v]
  - Top-down measurements taken basin-wide using aircraft .[vi-vii] Although some of these analyses have indicated that top-down measurements are larger than bottom-up estimates[vi], others have reconciled the observations using very careful accounting of inventoried episodic emissions (particularly liquid unloadings of wells).[vi]
  - Satellite measurements are now becoming available, providing average emission estimates each year for areas as small as 50 km^2.[viii, ix] Satellites planned for 2023 onwards are anticipated to improve spatial and temporal resolution.
- Measurements made downwind of surface transmission and storage facilities indicate that some bottom-up estimates of emission are higher than suggested by top-down measurements, but others are lower. High-emitting sites contributed the majority of emissions.[x,xi]
- Distribution
  - Networks showed a wide variety of emission characteristics – urban areas with corrosion-prone distribution lines had emissions approximately 25 times higher than areas with more modern pipeline materials[xii].
  - For a single extremely large leak from a single well containment failure at an underground storage field, studies employed various top-down measurement techniques[xiii].

Learnings:

- Top-down verifications can point out emissions that are uncharacterized or inadequately estimated in bottom-up assessments
- Top-down estimates should be compared with bottom-up assessments that have the same spatial and temporal scales as the observations.
- High-emitting sub-populations of equipment can account for a substantial proportion of total methane emissions from natural gas supply chains. If high-emitting sources are due to malfunctions or abnormal operations, they may not be predicted by bottom-up estimates.
- Most top-down measurements are currently brief snapshots of emissions, are limited in their spatial scale, and are expensive to perform. However, this is changing as emission estimates based on measurements made by satellites, aerial surveys and ground-based monitoring systems begin to emerge.

Sources:

i. Oil and Gas Methane Partnership (OGMP 2.0), United Nations Environment Program, https://ogmpartnership.com/

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x R Subramanian, LL Williams, TL Vaughn, D Zimmerle, JR Roscioli, SC Herndon, TI Yacovitch, C Floerchinger, DS Tkacik, AL Mitchell, MR Sullivan, TR Dallmann and AL Robinson, 'Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol', Environmental Science & Technology 49(5):3252-3261. DOI: 10.1021/e35060258, 2015

xi. DJ Zimmerle, LL Williams, TL Vaughn, C Quinn, R Subramanian, GP Duggan, B Willson, JD Opsomer, AJ Marchese, DM Martinez, and AL Robinson, 'Methane Emissions from the Natural Gas Transmission and Storage System in the United States', Environ Sci Technol 49(15): 9374–9383 doi: 10.1021/acs.est.5b01669, 2015

xii JC von Fischer, D Cooley, S Chamberlain, A Gaylord, C J Griebenow, SP Hamburg, J Salo, R Schumacher, D Theobald and J Ham, 'Rapid, Vehicle-Based Identification of Location and Magnitude of Urban Natural Gas Pipeline Leaks', Environmental Science & Technology 51(7):4091-4099. DOI: 10.1021/acs.est.6b06095, 2017

xiii S Conley, G Franco, I Faloona, D.R Blake, J Peischl, and TB Ryerson, 'Methane emissions from the 2015 Aliso Canyon blowout in Los Angeles, CA', Science, 351, 1317-1320, doi: 10.1126/science.aaf2348, 2016

Case study 9:
Controlled testing of continuous monitoring systems: Detection

(photo courtesy of D.T. Allen)

Case study: Testing has been conducted of multiple continuous methane monitoring systems to determine the ability of sensing systems to detect enhanced methane concentrations.

Description of tests: The ability of continuous monitoring systems to detect enhanced methane concentrations was tested under field conditions in the Permian Basin in west Texas. Seven sensing systems were evaluated on a production site, over a 9-month period. The accuracy of methane concentrations recorded by the sensing systems were compared to certified gas standards and to the measurements of a state of the art methane sensing system deployed within a few meters of each individual sensor.

Results: The testing in the Permian Basin confirmed the ability of multiple sensing systems to accurately detect enhancements in atmospheric methane concentrations. Systems based on infrared and metal oxide semiconductor sensors were able to operate continuously for months with over 80% data capture rates, under their own power and communicating data to cloud systems. The infrared systems, while more expensive, had higher accuracy for detecting emission events based on absolute methane concentrations. Metal oxide systems needed reliable background correction algorithms to successfully identify emission events.

Based on this testing, three of the sensing systems were deployed in larger numbers in a network of approximately 50 sites in the Permian Basin, over a multi-year period. Metal oxide semiconductor based sensing systems continued to need baseline corrections and some of the infrared systems had degraded performance when ambient temperatures exceeded 110°F. Data capture for these sensing systems initially averaged >80%, however, maintaining that level of data capture over more than one year required routine maintenance for some sensors.

Learnings: The tests indicate that continuous monitoring systems can be effective in emission detection if concentration enhancements of methane are in the range of several ppm.

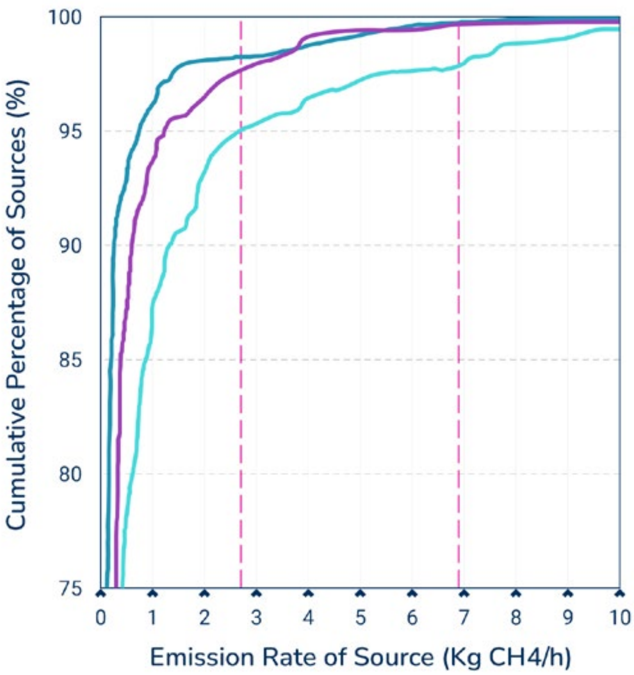
Sources: Torres, V.M., Sullivan, D.W., He'Bert, E., Spinhirne, J., Modi, M., Allen, D.T., Field inter-comparison of low-cost sensors for monitoring methane emissions from oil and gas production operations, Preprint amt-2022-24 (2022).

Case study 10:
Controlled testing of continuous monitoring systems: Quantification

Case study: Controlled release testing characterized the emission quantification capabilities of continuous monitoring systems at the Methane Emission Technology Evaluation Center (METEC),

Description of tests: Limits of emission detection, probabilities of detection and uncertainties in emission quantification were evaluated for eleven anonymized continuous methane monitoring systems in single blind testing at the METEC facility at Colorado State University. Emission rates ranging from 0.4 to 6400 g/hr were evaluated under conditions that simulated typical configurations of production sites in the United States, but lacked some of the complexities of actual operating sites. The eleven systems tested included point source sensors and scanning/imaging systems.

Results: Results can be grouped into assessments of minimum detection limits, probabilities of detection (POD) as a function of emission rate, and uncertainties in emission quantification.



(chart adapted from Bell, et al.)

Minimum detection limits were generally in the range of a few kg/hr. These minimum detection limits were compared to the distribution of emission rates for sources in the US natural gas supply chain. Shown to the left as colored lines are the emission distributions reported in three studies that measured emissions in the US natural gas supply chain. Dashed lines indicate detection limits for two of the eleven continuous monitoring systems that were evaluated. More than 95% of emission rates observed in US natural gas supply chain systems were below the detection limits of typical continuous monitoring systems, indicating that to estimate total site emissions, some correction would need to be made for emissions below detection limits.

Probabilities of detection were defined as the fraction of controlled release emission events that were detected (true positives). More broadly, sensing system performance can be characterized by the fraction of detections that were true positives, the fraction of sensor detections that were not controlled releases (false positives), and the fraction of controlled releases that were not detected (false negatives). The emission rate at which the probability of detection (true positives) reached 90% ranged from 3 to 30 kg/hr, depending on the technology. False positive rates ranged from 0 to 79%.

Quantification uncertainties were high. For a controlled release rate of 0.1–1 kg/h, the solutions' mean relative errors (95% confidence limits) ranged from −44% to +586% with single estimates between −97% and +2077%. Upper uncertainty exceeded +900% for four of the eleven technologies. Above 1 kg/h, mean relative error was −40% to +93%, with two solutions within ±20%, and single-estimate relative errors were from −82% to +448%.

Learnings: Current continuous monitoring systems are able to detect emissions above a few kg/hr, but quantification with better than a factor of 2 uncertainty remains challenging.

Source: Bell, C., Ilonze, C., Duggan,A., and Zimmerle, D., Performance of Continuous Emission Monitoring Solutions under a Single-Blind Controlled Testing Protocol, Environ. Sci. Technol. 2023, 57, 5794–5805.

Case study 11: Controlled testing of aircraft-based detection and quantification of large emission events

Case study: The emission quantification capabilities of aircraft-based methane emission measurement systems were evaluated using controlled release testing.

Description of tests: Limits of emission detection, probabilities of detection and uncertainties in emission quantification were evaluated for three aircraft-based methane detection and quantification systems. The technologies evaluated were Bridger Photonics Inc.'s Gas Mapping LiDAR (GML)™, Kairos LeakSurveyor™ and NASA/JPL AVIRIS-NG. Testing was done in a combination of single blind, semi-blinded and unblinded modes. In these modes, the technology operators may or may not have known whether and where an emission was occurring and the magnitude of the emission rate.

Results: Results can be grouped into assessments of minimum detection limits, probabilities of detection (POD) as a function of emission rate, and uncertainties in emission quantification.

Minimum detection limits and probabilities of detection depend on factors such as wind speed and flight altitude and sensing system; general equations were developed to predict probability of detection as a function of these parameters for each technology type. If a minimum detection limit is defined as an emission source with a 10% probability of detection, the Bridger Photonics Inc.'s Gas Mapping LiDAR (GML)™ had a emission source detection limit of approximately 0.5-2 kg methane/hr at wind speeds ranging from 2 to 8 m/s (lower detection limits at lower wind speeds). The Kairos LeakSurveyor™ and NASA/JPL AVIRIS-NG detection limits ranged from 10-30 and 5-10 kg/hr, respectively. These values are representative and can change with flight altitude, whether the emitted gases have high or low methane concentrations, and other parameters. Probabilities of detection increased to 90% at source emission rates of 1.5-7, 30-90 and 10-25 kg/hr for Bridger, Kairos and NASA/JPL AVRIS-NG, respectively. Again, while representative, these values can change with flight altitude and other parameters, but at these detection limits, these technologies will detect only the very largest emission sources at oil and natural gas facilities.

Quantification uncertainties had 95% confidence intervals that were generally within a factor of 0.5 to 2 of the controlled release rate.

Learnings: Aircraft based systems can detect emission rates as low as a few kg/hr with a 90% probability, but detection varies with wind speed and other conditions and detection limits can vary by an order or magnitude, depending on the technology. Emission rate quantification within a factor of 2 was a typical performance.

Source: Conrad, B.M., Tyner, D.R., Johnson, M.R., Robust probabilities of detection and quantification uncertainty for aerial methane detection: Examples for three airborne technologies, Remote Sensing of Environment 288 (2023) 113499.

Case study 12: Controlled testing of satellite detection and quantification of large emission events

Case study: Satellites are increasingly being used as tools for detecting large methane emission events. Controlled releases were used to assess the ability of multiple types of satellite systems to detect and quantify emissions.

Description of tests: Emissions ranging from 200 kg/hr to 7200 kg/hr were released at an isolated desert location in North America, with no other nearby sources. Data from five different satellite systems were evaluated by five different science teams using a single blind protocol, in which the study team knew the emission rate but the detection and quantification teams did not.

Results: The detection and quantification teams correctly identified 71% of all releases. Wide-area satellites detected emissions as low as 1400 kg/hr. Targeted systems detected the lowest release rates of 200 kg/hr. Quantification was more challenging. While three-quarters (75%) of quantified estimates fell within ± 50% of the metered value, when the five independent teams were provided primary data from the same satellite, the range of estimates provided by the five groups ranged from -80% to +300% of the true controlled release emission rate.

Learnings: While both tests indicate that satellite-based systems can be effective in emission detection the performance of the emission quantification systems of the technologies needs to be better understood before relying on results for emissions mitigation programs or regulatory reporting.

Source: Sherwin, E.D., Rutherford, J.S., Chen, Y., Aminfard, S., Kort, E.A., Jackson, R.B., Brandt, A.R., Single-blind validation of space-based point-source detection and quantification of onshore methane emissions, Sci Rep, 13, 3836 (2023).
https://doi.org/10.1038/s41598-023-30761-2

Case study 13:

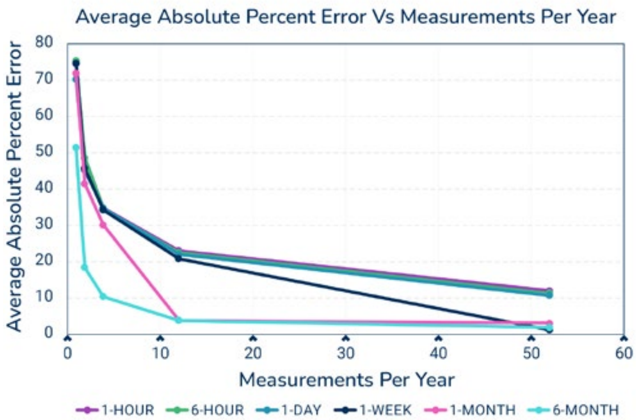
Frequency of sampling in regions with emission events

Case study: The impact of the frequency of periodic sampling on uncertainty in estimating total annual emissions was evaluated for a collection of sites with emission events. Monthly, quarterly, semi-annual and annual sampling frequencies were evaluated

Description of tests: Short duration remote sensing measurements of methane emissions from oil and gas operations are being deployed at a large scale, but interpretation of these snapshot measurements is complex due to the spatial and temporal variability of methane emissions. Sampling uncertainties associated with short duration measurements of varying frequencies from a group of simulated production sites representing the Barnett Shale region were examined.

Results: The accuracy and precision of annual emission estimates extrapolated from short duration measurements depend on the measurement frequency and duration of emission events. Routine, frequent emissions are accurately captured with minimal bias through semiannual sampling; however, infrequent high-emission rate events increase the error associated with annual emission estimates, even under the assumption of no measurement uncertainty. For a case study designed to simulate production sites in the Barnett Shale production region in the United States, if emission events had a duration of ≤1 week, monthly sampling had an estimated sampling error of >15%. For quarterly sampling with emission events that persist for ≤1 month, the sampling error is >30%. There is also negative bias associated with quarterly, semiannual, and annual sampling, which suggests infrequent campaigns may be systemically underestimating emissions. The sampling error increases as the duration of the high-emission events become shorter, making the temporal persistence of emission events an important factor in designing measurement protocols.

Uncertainty in annual emission estimates decreases as measurements per year increase from 1 (annual sampling) to 52 (weekly sampling). Uncertainty also decreases as the large emission event duration increases from 1 hour to 6 months, as illustrated by different colored curves. Results assume that periodic measurements have zero measurement uncertainty and are representative of production sites in the Barnett Shale (Source: Schissel and Allen, 2022)



(chart adapted from Schissel et al.)

Learnings: Uncertainties associated with extrapolating periodic sampling to estimate annual emission events can be significant if emission events account for a high percentage of emissions; methods for estimating the uncertainty were developed and a key variable is the ratio of average event duration to the time between measurements.

Source: Schissel, C. and Allen, D.T., The impact of high-emission event duration and sampling frequency on uncertainty of emission estimates, Environmental Science & Technology Letters, 9, 1063–1067, doi: 10.1021/acs.estlett.2c00731 (2022).

Case study 14:
Dependence of uncertainty on the number of sites sampled

Case study: Measurement campaigns typically measure a subpopulation of facilities, and these measurements are extrapolated to a larger region or basin. Methane emissions from oil and gas systems are inherently variable and intermittent, which makes it difficult to determine whether a sample population is sufficiently large to be representative of a larger region.

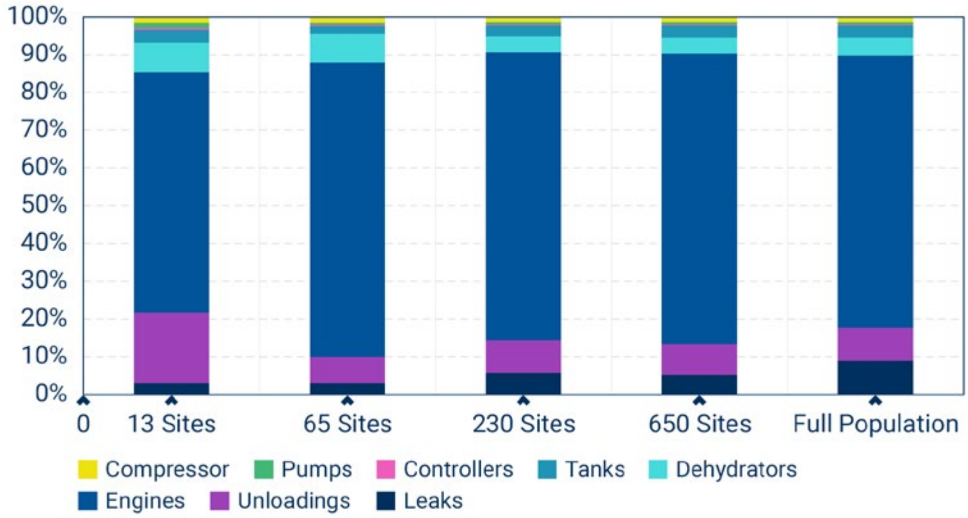
Description of tests: Sampling uncertainties associated with sampling between 5% and 100% of production sites in a simulated population of ~1400 sites representing a production region in the Upper Green River Basin in the United States were examined.

Results: When a subset of sites are sampled, as opposed to the full population, the fraction of emissions contributed by different sources change; this means that extrapolating from a subpopulation to the emissions of the entire population should account for these differences. Methods are suggested for extrapolation.

Uncertainties in the estimates emissions from all sources from all sites can be estimated based on the uncertainties in individual source categories.

Learnings: Uncertainties associated with extrapolating measurements from a sub-population of sites to estimate annual emission events from an entire population of sites can be significant if differences in source types between sub-populations and the full population are not accounted for. Uncertainties also depend on the variability in emissions in different source categories.

Source: Schissel, C., Allen, D. and Dieter, H., Methods for spatial extrapolation of methane measurements in constructing regional estimates from sample populations, ChemRxiv, doi: 10.26434/chemrxiv-2023-zcqnq-v2 (2023).



(chart adapted from Schissel et al.)

Case study 15:
Improving detection and quantification using multi-scale measurements

Case study: Snapshot measurements with aircraft-based and drone-based sensing are coupled with continuous monitoring systems, operator information and optical gas imaging measurements to improve emission quantification.

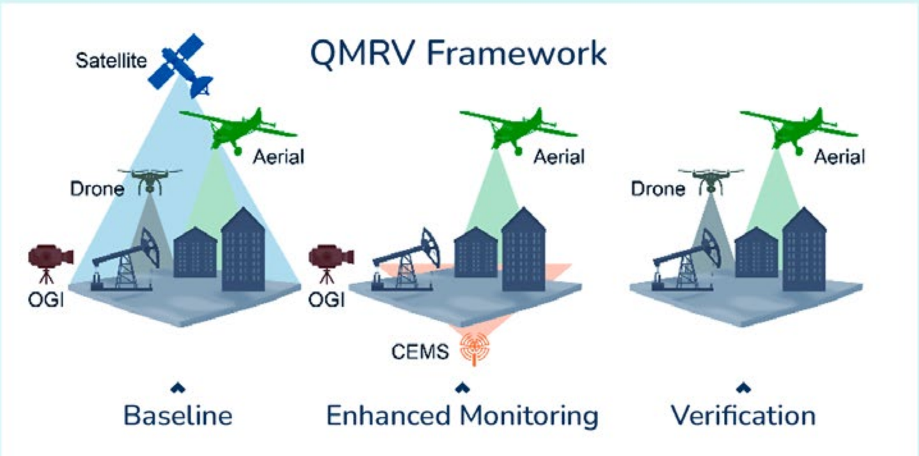
Description of tests: On-site continuous measurements were used to characterize the frequency and duration of intermittent emission events; periodic aircraft-based and drone-based measurements were paired with simultaneous measurements from continuous emission monitors to improve emission quantification.

Results: Key results included documentation of emission event duration, methods for coupling information at using multiple techniques.

Learnings: Four guidelines for measurement protocols to accurately estimate methane emissions

1. Snapshot measurements with high accuracy, coupled with information about the operational status of the site at the time of the measurements are needed to help reconcile measurements with inventory estimates.
2. Measurements to develop distributions of the frequency and duration of intermittent emissions events are key to annualize any snapshot measurement. Because events can last less than 24 hours, high sampling rate technologies like continuous monitors will likely be needed to develop these distributions.
3. Detailed record keeping of emission events, maintenance activities, and upset conditions help reconcile measurements with emission inventories.
4. Independent verification of measurements and quantified emissions provides additional confidence in results.

Source: Wang, J.L., Daniels, W.S., Hammerling, D.M., Harrison, M., Burmaster, K., George, F.C., Ravikumar, A.P., Multiscale Methane Measurements at Oil and Gas Facilities Reveal Necessary Frameworks for Improved Emissions Accounting Environ. Sci. Technol. 2022, 56, 20, 14743–14752.



A quantification, monitoring, reporting, and verification (QMRV) protocol, using multiple measurement technologies applied in a coordinated manner was demonstrated

(chart adapted from Wang, et al.)

Case study 16: Controlled testing of methane emission detection and quantification at a midstream site

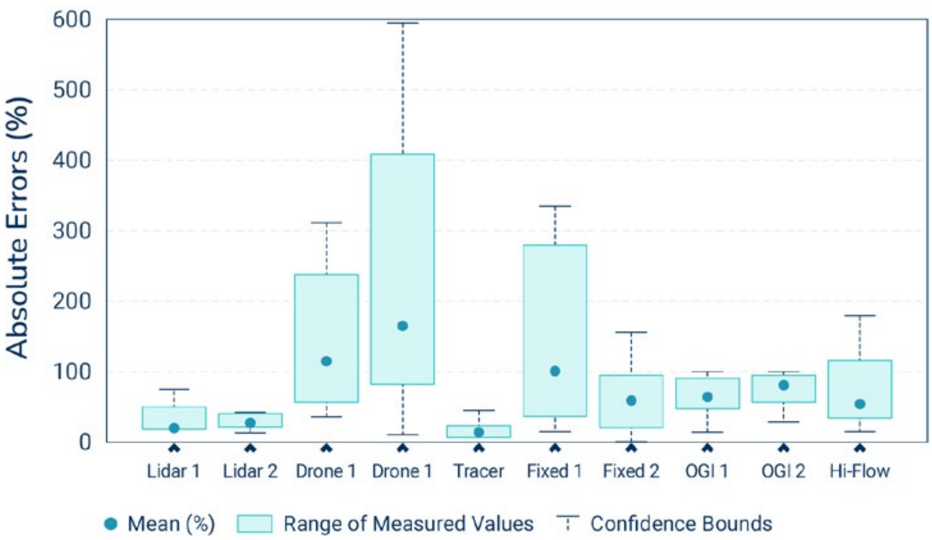
Case study: A variety of emission detection and quantification technologies were evaluated at an inerted midstream compressor station.

Description of tests: Detection and quantification capabilities for methane measurement systems were evaluated at a compressor station. Measurement platforms included aircraft, drones, trucks, van, and ground-based stations, as well as handheld systems. The tests consisted of a total of 17 blind, 2-hour releases, with emission rates ranging from 0.01 kg h^{-1} to 50 kg h^{-1} from single or multiple simultaneous exhaust points. The

Results: Most systems were able to quantify the emission rates releases within a factor of 2-3, on average, as shown in the Figure below, although individual errors could approach an order of magnitude for some technologies. The level of errors from the different systems was not significantly influenced by release rates larger than 0.1 kg/h.

Learnings: Handheld OGI cameras tended to underestimate emissions while 'site-level' systems tended to overestimate the emission rates. Multiple simultaneous releases degraded performance. The tracer system exhibited the strongest overall performance because, in using a tracer to characterize atmospheric dispersion, it minimizes errors that can dominate in other systems.

Source: Liu, et al., Assessment of current methane emissions quantification techniques for natural gas midstream applications, Atmospheric Measurement Techniques preprint, doi: 10.5194/amt-2023-97 (2023).



(chart adapted from Liu, et al.)

Errors in emission rates for technologies deployed at a midstream compressor station; emission rates in kg/hr are indicated by different shapes of points on the diagram

Checklist

The following checklist assesses progress in reducing methane emissions through identification and quantification.

Activity	Completed	Percentage of all equipment or processes in this program
✓ Identify known sources of emissions and survey for unintended or undesired emissions		
✓ Quantify known and found sources directly by measuring emission rates, or indirectly using a combination of measurements, calculations and models		
✓ Use this information to create or update emissions inventories		
✓ Periodically update and improve emission identification and quantification plans • Compare quantification of sources to large-scale measurements, accounting for uncertainties • Consider testing emerging technologies that have the potential to improve efficiency of identification or quantification, or at better cost • Use technologies that have the potential to reduce time between emissions arising and initial detection		

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Appendix:

Studies and reports that evaluated detection, measurement and quantification technologies

Name of study or report	Year	Relevant Sectors	Major conclusions
Improving Characterization of Anthropogenic Methane Emissions in the United States[2]	2018	All	• Chapter 3 (Methane Emission Measurement and Monitoring Methods) describes different scales of quantification methods. • Chapter 6 (Meeting the Challenges of Characterizing Methane Emissions) outlines recommendations for top-down and bottom-up reconciliations.
Evaluation of Innovative Methane Detection Technologies[3]	2018	All	• Chapter 4 (Applications) discusses practical applications for the technologies. • Chapter 5 (Evaluation Guidelines and Principles) discusses the importance of system objectives being specified before a particular method can be evaluated. • There is a summary of evaluations of many methane-sensing technologies and a large evaluation table comparing 18 individual sensor technologies.
Assessment of methane emissions for Gas Transmission and Distribution system Operators[4]	2019	Transmission and distribution only	• Recommends data-collection campaigns for leaks, operational emissions and incidents. • Chapter 7 provides a comparison table of 18 methods of measuring and quantifying methane leakages. • Also provides methods for engineering estimates.
Potential ways the gas industry can contribute to the reduction of methane emissions: Report for the Madrid Forum (5 to 6 June 2019)[10]	2019	All	• A broad document, covering identification and quantification protocols. • Offers only an overview of detection categories and no specific technologies (see section 4.2.1) • Covers concepts of quantification, top-down assessments, bottom-up assessments and super emitters.
Sampling of Methane Emissions Detection Technologies and Practices for Natural Gas Distribution Infrastructure[5]	2019	Distribution only	• Identifies existing and emerging technologies and practices suitable for detecting leaks. • Produces a table (appendix A) comparing 27 technologies, though the table is not prescriptive or exhaustive. • This is 'An Educational Handbook for State Energy Regulators'

Name of study or report	Year	Relevant Sectors	Major conclusions
Single-blind inter-comparison of methane detection technologies–results from the Stanford/EDF Mobile Monitoring Challenge[11]	2019	All, but focus was production	• Compared, through a field test, 10 methods that used a ground or aerial vehicle platform to perform detection. • Results using single-blind controlled release tests showed that the technologies are generally effective at detecting leaks, with six of the 10 technologies correctly detecting over 90% of leaks. However, they could only identify the specific piece of equipment in 50% of scenarios. • Emissions quantification needs improvement as most technologies could generally only provide estimates for very high emissions.
A methane emissions reduction equivalence framework for alternative leak detection and repair programs[15]	2019	All, but focus on production	• This paper proposes a five-stage framework for demonstrating similarities across new leak-detection technologies. The approach combines controlled testing, simulation modeling and field trials.
A review of close-range and screening technologies for mitigating fugitive methane emissions in upstream oil and gas[12]	2019	Upstream	• Compares six technology classes for use in LDAR – handheld instruments, fixed sensors, mobile ground labs (MGLs), unmanned aerial vehicles (UAVs), aircraft, and satellites. • Minimum detection limits for technology classes range from <1 g h^{-1} for method 21 instruments to 7.1×10^6 g h^{-1} for the GOSAT satellite. • Introduces a hybrid screening-confirmation approach, called a comprehensive monitoring program, to LDAR. Currently, fixed sensors, MGLs, UAVs and aircraft could be used as screening technologies, but their performances must be evaluated under a range of environmental and operational conditions to improve detection effectiveness.
Technical Guidance Document Number 2: Fugitive Component and Equipment Leaks[13]	2017	All	• Lists five leak screening techniques. • Lists six direct measurement techniques.

Name of study or report	Year	Relevant Sectors	Major conclusions
Best Practice Guidance for Methane Management in the Oil and Gas Sector[14]	2019	All	• Discussed techniques on a broader level, such as top-down versus bottom-up, and scale of measurement. • Makes recommendations on methods, plans and mitigation measures, but not on specific detection, measurement or quantification technologies.
Recommended practices for methane emissions detection and quantification technologies – upstream[7]	2023	Upstream	• Provides initial recommendations for methane detection and quantification technology selection at upstream oil and gas facilities
Methane Abatement for Oil and Gas, Handbook for Policymakers[16]	2023	Upstream	• Section 8 describes inventories in broad terms suitable for policymakers • Section 9 describes measurements in broad terms suitable for policymakers
Onshore oil and gas: quantifying whole-site methane emissions and associated uncertainties[17]	2023	All	• Detailed analysis of whole site emission quantification methods: (i) Plume-based flux recovery (US EPA Other Test Method 33a (OTM33a) Geospatial Measurement of Air Pollution (GMAP)) (ii) component-level measurements (iii) mass balance • (iv) fenceline monitoring (v) tracer method

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This series of 10 Best Practice Guides have been designed to improve performance in methane emissions management across the natural gas supply chain. Each Guide provides a summary of current known mitigations, costs and available technologies as of the date of publication. The Guides are available, upon request, in English, French, Arabic, Mandarin, Russian and Spanish.