METHANE MONITORING IS A 'MUST'

According the European Pollutant Release and Transfer Register (E-PRTR), refineries in Europe that reported data to the public domain emitted between circa 100 and 2000 Tonnes of the greenhouse gas methane per facility in 2017. Given that a typical house might consume 2kg of natural gas per day, the upper end of this range would supply about 2,700 homes for a year. The E-PRTR also reveals that methane emissions from gas pipelines, terminals, processing stations and offshore platforms are in the range of 100 to 1200 Tonnes per year per facility.

Gas production platform offshore

Natural gas leaks during extraction, storage, and transport are estimated to total in the order of 9 million tonnes per year in the United States alone. Natural gas is mostly methane, a greenhouse gas that traps 86 times more heat than carbon dioxide over a 20-year period. So, a natural gas leakage rate of 2 to 3% would have to the equivalent global warming potential as the reduced CO_2 emissions from natural gas combustion versus coal fired electricity generation. In addition to the greenhouse warming potential of these methane emissions and the lost opportunity to provide valuable energy to consumers, methane is a flammable gas and intensive leaks present a safety risk. So, for a host of good reasons, methane emissions monitoring is a 'must'.

Gas detection on offshore gas rig

Unravelling the array of methane monitoring techniques

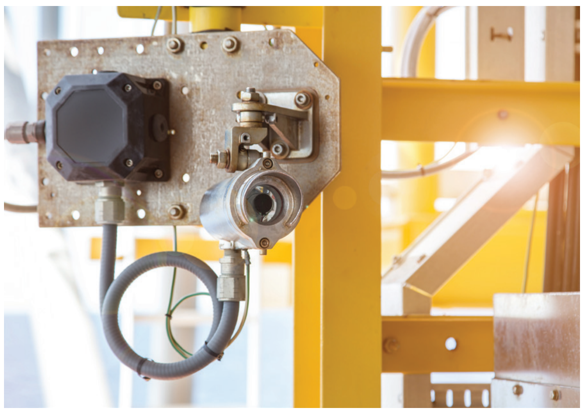
Optical gas imaging or portable FID/PID sniffers for methane leak detection and repair? Open path infrared optical gas detectors or portable PPE devices for process and personal safety? Methane monitoring in the refining and gas processing sectors is essential across several applications and the array of available measurement techniques is broad. The armoury is full but picking the most appropriate weapon is relatively easy with a few pragmatic considerations.

European Pollutant Release and Transfer Register, 2017

Site	Methane*
Equinor Mongstad Refinery, NO	2230
Equinor Refining, Kalundborg, DK	2090
Brae Bravo Platform, UK	1650
Beryl Bravo Platform, UK	1430
Repsol Cartagena Refinery, SP	1190
Beryl Alpha Platform, UK	1170
Brae Alpha Platform, UK	1100
Shell Bacton Gas Terminal, UK	855
Perenco Bacton Gas Terminal, UK	663
Hammerfest LNG, NO	650
Foinaven Floating Production & Storage, UK	566
Orlen Południe, PL	488
Captain Floating Production & Storage, UK	358
Perenco Dimlington Gas Terminal, UK	280
Sullom Voe Terminal, UK	267
Repsol Tarragona Refinery, SP	235
St Fergus North Sea Gas Terminal, UK	219
Ineos Chemicals Grangemouth, UK	203
Shell Nederland Refinery, NL	145
BP Refinery Rotterdam, NL	140
BP Forties Pipeline, UK	131
Esso Nederland Refinery, NL	114
Total Antwerp Refinery, BE	110

Oil refinery
Offshore oil and gas processing
Oil or gas terminal / pipeline

** 2017 Annual methane emissions in Tonnes*
E-PRTR https://prtr.eea.europa.eu/#/pollutantreleases
Table is an extract from the full data base for illustrative purposes



Line of sight gas detector on offshore rig

Refinery methane leak detection and repair

Methane emissions from refining and gas processing operations are regulated in the US by the EPA through the Climate Action Plan: Strategy to Reduce Methane emissions and the Clean Air Act. One of the goals is to reduce the methane emissions level in 2025 to 40 to 45% of 2012 levels. In Europe, the Industrial Emissions Directive (IED) and the associated best practice reference (BREF) notes for the refining of mineral oil and gas regulate methane emissions within the broad definition of volatile organic compounds (VOCs). The EU IED legislation specifies emission limit values for stack emissions of atmospheric pollutants such as oxides of nitrogen (NOx) and sulphur dioxide (SO_2), but it does not stipulate limit values for refinery methane emissions. On the other hand, BAT 6 of the refining BREF note does refer to 'sniffing' and optical gas imaging methods as being suitable for VOC detection as part of a leak detection and repair programme (LDAR). Under the latest revision of the US EPA regulations both of these methods are also acceptable for methane detection on refineries.

Portable VOC analysers appropriate for the methane sniffing method employ flame ionisation (FID) or photo ionisation (PID) detectors. Advanced units combine both techniques. When an FID is used, hydrogen will be required to generate the flame. Some instruments rely on a small refillable high-pressure hydrogen gas cylinder, others store hydrogen as a metal hydride which can be re-charged with hydrogen from an electrolysis unit or high-pressure hydrogen gas cylinder.

Gas turbine electrical power generation plant

The benefit of using a sniffer is that the methane concentration can be measured, and leaks can thereby be quantified. However, for rapid scanning of a refinery or gas processing facility a hand-held optical gas imaging (OGI) device can be ideal as part of a holistic LDAR programme. Some of these devices use a point and shoot type tunable diode laser spectroscope which has been selectively tuned to identify methane. Use of this technology enables long range gas detection and methane can also be detected through glass. Another option is to use a similar type of instrument which relies on infrared detection to identify methane and a broader range of VOCs. Most devices in this category display a visual map on their compact monitor to help locate leaks. These methane hot-spots can then be repaired or further investigated using sniffers to quantify the leak.

Catastrophic failures cost lives and money

Methane is also highly flammable. A natural gas pipeline explosion on the 9th of September 2010 in San Bruno, a suburb of San Francisco, resulted in a fireball that was reported to be 300 metres high and the fire that followed raged for hours as 200 firefighters tackled the blaze. Eight people lost their lives and 35 houses were destroyed. The crater left by the blast was the size of two tennis courts placed end to end. This hole in the ground was mirrored by a similar hole in the stock market valuation of the gas transmission company that owned and operated the pipeline. Their share price fell 8% in trading on the day after the explosion, leaving the company worth $1.5 billion less of the US stock exchange. If ever there is the need for a proof statement around the claim that an investment in safety pays dividends, here it is.

Gas pipeline through the wilderness

Gas pipeline valve

In a separate incident and a natural gas well in Greene County, Pennsylvania, an explosion on the 11th of February 2014 killed one worker and injured another. The fire burned for five days before it was extinguished. After an enquiry lasting several months, the gas well owner and operator was fined $940,000 by the Department of Environmental Protection (DEP). DEP investigators found the explosion was most probably caused when a contractor was preparing to put the three wells on the pad into production. A bolt and locknut assembly on one of the wellheads was not tightened sufficiently, allowing methane gas to escape and ignite. Beyond the DEP fine, $5 million dollars in compensation were paid to the family of the worker that was killed. To compound the tragic circumstances of the fatality, most of that money was used to establish a fund for the dead man's son, who was born soon after the explosion. Ultimately, the costs of safety incidents stretch far beyond any form of financial measurement.

Offshore drilling risk mitigation

Nowhere are the risks of methane leaks taken more seriously than offshore gas drilling and processing platforms. In those first seconds after a blast, there is only one emergency escape route from the rig; and that leap into the ocean can be like jumping 'out of the frying pan and into the fire'. With the risks in mind, portable gas detection systems are worn by operators as they move around the rig and fixed fuel-cell sensor systems are installed in locations with a high risk of gas leaks. And, as a third line of defence, open path gas detection systems are used to detect flammable gases in the line of sight where they are installed.

An established technology behind open path gas detectors is the use of infrared light to detect flammable gases that are infrared active, such as methane, ethane and propane, all of which are common in offshore oil and gas operations. Devices differentiate from each other in the way they compensate for the potential influence of fog and rain and their resistance to solar interference. Most units have a very rapid response time, reacting within a few seconds and when suitably specified, are generally able to scan across a path of up to 100 metres – so a network of several devices would be appropriate for most offshore rigs.

Moving methane safely through the wilderness

Gas pipelines cross seas and straddle vast regions of wilderness. Their construction and maintenance calls for engineers to be working in extreme locations. The Northern Lights gas pipeline, for example, transports gas from the Urengoy gas field, just south of the arctic circle to Minsk in Belarus. The average temperature in Urengoy, over the course of a year, reaches only -7.4°C and winter temperatures often fall to -30°C. This 2,500 km journey traverses tundra and weaves its way through dense forests.

In such remote locations, backup is often hours or days away, so maintenance and surveillance teams rely on the best and most modern methane leak gas detection equipment for their personal protection. Always by their side, sniffing for flammable gas, leaks they are an essential part of their PPE. Daily functional bump tests with specialty gas mixtures and periodic calibration are all part of the routine for ensuring that these life-savers are in tip-top condition when they are needed.

Gas drilling rig

Wearable methane gas detectors are also harnessing the power of cloud computing and big data to enable operators to monitor and store data on gas detection events from the devices worn by their employees. The dot-maps that are generated are a clear indication of where gas leak trouble spots are and where maintenance will soon be required.

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