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Cold Venting and Fugitive Emissions from Norwegian Offshore Oil and Gas Activities

Module 1
Surveying installations to identify potential emission sources

Prepared for Norwegian Environmental Agency

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Title

Cold venting and Fugitive Emissions from Norwegian Offshore Oil and Gas Activities
Module 1 – Surveying installations to identify potential emission sources

(Translation of Norwegian report M-510I2016)

Summary

Sources of direct emissions of methane and NMVOC were identified by a survey of the facilities on the Norwegian Shelf. For 15 of the installations the survey was conducted through full-day meetings with the operators key personell. The systems on the installations were reviewed and potential sources of emissions were identified and recorded. For the remaining devices the information was collected by means of a targeted questionnaire.

A total of 48 potential emission sources were detected and methods for quantifying emissions from individual sources were reviewed. The survey confirmed that the previously used quantification method is not sufficient.

Four Subject words

Offshore installations, direct emissions, mapping.

Front page photo

Heimdal. Source: Statoil, Photographer: Øyvind Hagen

Summary

Offshore oil and gas production on the Norwegian continental shelf leads to direct emissions of natural gas in the form of methane and NMVOC from several emission sources. Direct emissions through cold venting and fugitive emissions are a major contributor to such emissions.

Direct emissions of methane and NMVOC have been reported from the operators to the Norwegian Environment Agency since the mid-1990ôs according to a set of predefined methods and general emission factors. However, for several years it has been questioned whether there is an adequate overview of these emissions and if the current methodology for quantification is good enough.

The Norwegian Environment Agency has engaged add novatech to improve the knowledge of these emissions. The task is divided into 3 modules. This report covers module 1, which is an updated mapping of sources leading to such emissions.

The survey has been conducted in two main phases. Phase 1 was a detailed review of 15 facilities, while phase 2 was a simplified review of the remaining 53 fixed installations that produce and process oil and gas on the Norwegian shelf.

The survey showed that there are a number of processes that can lead to emissions of methane and NMVOC beyond those included in the current reporting format. This is processes/emission sources that to a certain extent have gone under the radar in the operating companies. This may explain why there was less relevant information available for the new sources. This has to some extent affected the result of the survey. A total of 48 processes/sub-processes that produce hydrocarbon-containing gases were identified during the survey.

The survey showed that amount of gas is not appropriate as an activity factor for the determination of emission from most sources. Emissions are primarily the result of other factors. This means that the actual emissions from some of the õoldò sources may differ significantly from those previously reported.

The potential emission quantities from the individual processes and sub-processes that generate hydrocarbon-containing waste gas varies enormously. While the dominant contributors have the potential to produce waste amounts in the range 100-1000 tons/year for some installations, there are some processes which have a waste gas production potential of a few kilograms per year or less on the same facilities. This suggests that it is important to focus on the processes and sources that dominate the emissions.

The way the waste gases are handled are, for many of the sub-processes, the main factor affecting the emissions. The survey has shown that for many sub-processes both recovery and flaring are possible options that are chosen for many installations. Reconstruction of existing facilities to recovery or flaring can be challenging.

The survey showed that some types of emissions cannot be eliminated, and some cannot be reduced much.

The opportunities to take samples and analyze the composition of the waste gases was only briefly mapped in the project. The following is recommended:

- That any sampling points must be considered specifically for each facility when better emission figures are available once Module 2 of the project is completed.

- That the sampling and analysis are assessed for and limited to emission points that contribute significantly to the emissions, and where satisfactory composition data are not obtainable otherwise in an easier way.

For many of the discharge points, equally good and more cost-effective methods to determine the distribution of methane and NMVOC than sampling and analysis of emissions, may be available.

The survey has shown clearly that it is possible to eliminate emissions from many of the larger waste-producing processes. This has also been done on several of the installations. The foundation for this is laid in the early design phase. Mistakes made in the design phase are difficult and expensive to correct later.

This shows that it is important that the operators have a clear philosophy and strategy regarding the elimination and minimisation of direct methane emissions and NMVOC, especially in connection with the planning of new facilities. Few operators could present that they followed such a strategy during the survey, but the findings of the survey clearly showed that this strategy had been in place for several of the reviewed facilities.

Content

1 Introduction

Reported emission data provide an essential basis for The Norwegian Environment Agencyõs monitoring of the facilities, including requirements and assessment of measures. Reported data forms the basis of the national emission inventory and monitoring of national goals and international commitments. The Norwegian Environment Agency therefore considers it important to provide more accurate emission figures than those that exist today.

The petroleum activities on the Norwegian continental shelf lead to emissions of methane and NMVOC from several sources. There are three main groups of sources/processes:

- Unburned natural gas from gas turbines, gas engines, boilers and flares.
- Gas emitted from shuttle tankers during loading of oil from offshore installations.
- Direct natural gas emissions comprising operational emissions (also called cold vents) and fugitive emissions and natural gas leaks. The direct emissions of natural gas contributed 71% of the methane emissions and 18% of NMVOC emissions from the Norwegian offshore oil and gas industry in 2013.

Annual inventories of direct methane and NMVOC emissions are reported by the operating oil companies to the Norwegian Environment Agency in their annual emission and discharge reports. The emission inventories are established using a generic methodology that has been in place since the mid 1990's. The methodology, which is based on a set of predefined emission sources and simple emission factors, is described in the emissions reporting guidelines prepared and issued by the Norwegian Oil and Gas Association (Ref.1). For several years, the relevance and accuracy of this methodology has been questioned including; if all relevant sources are covered, if the results are acceptable and if the reported emission inventories can be trusted.

Based on the above, the Norwegian Environment Agency engaged *add novatech as* to improve the understanding and background information behind the direct emissions of methane and NMVOC from the oil and gas installations on the Norwegian continental shelf. The study consists of 3 modules:

- Module 1 is a mapping of sources leading to direct emissions of methane and NMVOC.
- Module 2 cover a review and revision of the quantification methodology and emission factors for future reporting, and to establish a better emission inventory estimate.
- Module 3 shall highlight emission abatement possibilities including an assessment of what can be regarded as BAT for reducing direct emissions of methane and NMVOC from offshore petroleum activities. .

Module 1 and 2 were performed simultaneously in 2014, while module 3 was performed during 2015.

This report includes Module 1.

2 Emissions of HC gases

2.1 Why is there a focus on emissions of HC-gases?

Hydrocarbon gases, hereafter referred to as HC gas, are grouped into two discharge groups, methane (CH_4) and NMVOC (Non-Methane Volatile Organic Compounds).

Methane is a greenhouse gas, like CO_2, but has a substantially more powerful effect. The gas has a greenhouse effect (GWP) of 25 CO_2- equivalents in a 100-year perspective. This means that emissions of 1 tonne of methane has the same greenhouse effect as the emission of 25 tonnes of CO2. Methane over time will be oxidized to CO2 in the atmosphere. This means that the greenhouse effect of methane emissions decreases over time. On the other hand, and due to the same cause, the greenhouse effect of methane emissions will be higher in a shorter timeframe.

NMVOC is all hydrocarbon gases except methane. NMVOCs contribute to the formation of ground-level ozone, which provides a regional environmental impact. Norway has through the Gothenburg protocol committed to reduce its emissions of NMVOC by 40% from 2005 to 2020 (from 218 000 tonnes / year to 131,000 tons / year) [Ref: 6]. In addition to the regional environmental impacts which are managed through the Gothenburg Protocol, NMVOC is an ozone precursor. Ozone is also a short-lived climate driver.

According to the Norwegian Environment Agencyǿs preliminary report for the petroleum sector (background report to the proposed action plan for the short-lived climate drivers) is the greenhouse effect of the short-lived climate drivers / components shown in Table 1 [Ref: 5].

Table 1 Greenhouse effect in a 10-year perspective for short lived climate drivers [Ref: 5]

Component	Weighting Factor for $CO_{2e(GTP10,\ Norway)}$
CO_2	1
Methane, CH_4	86
Nitrogenoxides, NO_X	-28
Carbonmonoxide, CO	9
NMVOC	14
BC (Black Carbon)	2914

2.2 What is direct emissions of HC-gases?

Direct emissions of hydrocarbon gases can be divided into 2 emission categories:

a. **Fugitive emissions.** These are leaks of natural gas directly into the atmosphere through valves and seals, hoses and flexible piping, as well as evaporation from hydrocarbon liquids and from cuttings. Fugitive emissions can never be fully eliminated, but can be minimised by use of good / appropriate materials, equipment and design, as well as through good operating procedures. Fugitive emissions can occur anywhere on the facility where there is hydrocarbon gas.

b. **Venting /cold venting / cold flaring**. These emissions are hydrocarbon-containing gases, emanating from various processes or sub-processes at the facilities, and routed to the atmosphere as a result of planned and selected operational solutions. Emissions usually happens through dedicated pipe systems where the natural gas is discharged at a safe place1. Venting (direct emissions) as a solution may be selected for several reasons; safety issues, high levels of inert gases (mainly nitrogen) in the gas, pressure conditions of the facility or purely cost-related preferences (very expensive to eliminate/reduce emissions relative to the amount of emissions) or a combination of this. In many cases venting can be avoided by good design. The options may be recycling of gas or flaring. Environmentally, recycling is the best solution, but flaring may be preferable because the greenhouse effect of the products of combustion are significantly lower than for hydrocarbon gases. Some of the operational emissions of hydrocarbon gases are more or less impossible to eliminate because technical solutions are not available or because potential solutions are very costly.

[1] To avoid explosion hazard

3 Objective and scope of work

Module 1 of this project includes a survey with the aim of establishing an updated list of sources of cold venting and fugitive emissions at the facilities on the Norwegian shelf.

The survey should include the following:

- Sources of emissions and emission points (ventilation points).
- How emissions are quantified on the individual installation, including emission factors used and how activity data determined.
- Opportunities for sampling and analysis of gas composition at different emission sources / discharge points, including distribution of methane and NMVOC.
- Technology status / age of equipment with importance for emissions of methane and NMVOC (e.g. glycol plant, compressor seals, pumps, valves and flanges).
- Factors affecting the size of discharge, including production conditions, operating procedures and reservoir conditions.
- Implemented mitigation and achieved emission reductions.
- Any plans for further emission reduction measures on the facilities.
- Coldventing- and flaring strategy - why venting.
- Maintenance procedures for equipment of importance for the size of the emission.
- Procedures and methods for leakage control, including inspection rounds, detection systems (number of systems, location and detection/alarm level), use of handheld IR camera, sniffers, etc.

This report summarises the observations, findings and conclusions made in Module 1.

4 Method and Study Execution

There are 68 permanent facilities that manufacture, produce and process oil and gas on the Norwegian Continental shelf. Accommodation platforms and mobile offshore drilling units are not included in this number. Direct emissions of hydrocarbon gas occurs at all 68 facilities.

The following documents are used as a basis for the survey:

1. The Norwegian Oil and Gas Associationõs guidelines for emission and discharge reporting (Ref: 1). The guidelines contain an overview of a total of 13 predefined sources of emisson of hydrocarbongas and a description of how the emissions from these sources can be quantified and reported.
2. The report ñScreening study - Direct emissions of CH_4 and NMVOC ï Status and mitigation opportunitiesñ, add novatech for Norwegian Oil and Gas Association 2013 (Ref: 2).
3. The report ñUtslippsfaktorer for CH_4 and NMVOC fra glykol regenerering og produsert vannñ, add novatech for Norwegian Oil and Gas Association 2014 (Ref: 3).
4. The report ***ñ***Pilotstudie - Vurdering av direkte utslipp av metan og NMVOC fra 5 anlegg/innretningerñ, add novatech for Norwegian Oil and Gas Association 2014 (Ref: 4).

The survey was conducted in two phases:

Phase 1 was a comprehensive review of 15 offshore installations. These production units represented a balanced cross-section of the offshore facilities on the Norwegian continental shelf:

- Almost all operators with fields was included.
- A balanced mix of newer and older facilities.
- Both fixed and floating installations.
- Overall these facilities represented 50% of the reported direct methane- and NMVOC emissions from the Norwegian continental shelf.

The 15 facilities are listed in Appendix 1.

The reviews were conducted as full-day meetings. The operator's environmental coordinators and process and facility engineers with in-depth knowledge of the process plants attended. Specialists in certain areas were called upon as required. Hydrocarbon containing systems were thoroughly analysed using flowcharts and P&IDs in order to identify potential emission sources. Waste gas disposal solutions were evaluated and potential emission quantification methods discussed, including future methods as well as *ad hoc* methods that could be used in this study for establishing better emission estimates. An action list was prepared including tasks to be followed up by operators after the meetings.

The meetings were conducted in the period from October 21 to December 12, 2014.

Phase 2 was a simpler review of a total of 53 fixed installations on the Norwegian continental shelf (Appendix 1). This evaluation was conducted using a standardized questionnaire (Appendix 2). The questionaire was simplified based on the discoveries in phase 1. This was to ensure full attention to issues that may involve significant emissions. Potential emission sources that were found to be negligible in the first phase were left out. Also, potential sources that the primary review had provided satisfactory information about, were omitted in the secondary review.

The questionnaire was sent out January 9, 2015 with a deadline of January 30.

Four of the facilities were thoroghly reviewed in a project for Norwegian Oil and Gas Association in 2014 (see Ref: 4). These facilities received some additional questions to capture the gap compared to those who participated in the secondary review.

The secondary survey also included facilities that are in the construction / installation phase and are not yet in production. This is given in Appendix 1. For these facilities, the response was based on the design they have chosen. Also, two fields in the early planning stages (before detailed planning) were included (Johan Sverdrup and Johan Castberg) with a total of 4 facilities. For these facilities, only fundamental design choices were reflected in the questionnaire.

The reviews also highlighted factors included in Module 2 and 3 of this project. Separate reports will be made for these modules.

5 Current Methodology for Quantifying the Emissions

Quantification and reporting of direct methane and NMVOC emissions to the Norwegian Environment Association is based on a method given in Norwegian Oil and Gas Association guidelines for emissons reporting [Ref: 1].

The methodology for quantifying direct methane and NMVOC emissions was established in the mid-1990s by Aker Engineering [Ref: 7]. The methodology is based on 13 predefined potential emission sources. The methodology applies generic emission factors for methane and NMVOC emissions for each emission source. Emissions are calculated for the individual sources using a source emission factor and an activity factor, which for the majority of the sources is the amount of gas processed in the facility.

The following predefined sources were included:

- Glycol regeneration
- Waste gas from produced water system
- Dissolved gas in liquid from the scrubber
- Wet seal oil for compressors
- Leakage through dry compressor seals
- Equipment depressurization
- Purge and blanket gas
- Flushing of instrument bridles
- Extinguished flares
- Small leakages
- Annulus bleed from production strings
- Drilling
- Start-gas for turbines

Emissions from drilling are calculated using a fixed emission factor per well, while emissions from start-gas for gas turbines is calculated using a fixed emission factor per turine start (this only applies to turbines using combustible gas under pressure for start-up).

It has been known for a long time that this methodology is not very precise, and for some emission sources directly wrong. This is also documented in a report prepared by add novatech for Norwegian Oil and Gas Association in 2014 [Ref: 2]. The predefined sources are also somewhat imprecise and incomplete.

6 Sources and causes of direct methane and NMVOC emissions

6.1 What is an emission source?

Generally, the term emission source is used for sources that may involve direct emissions of methane and NMVOC. This concept may lead to misinterpretation.

There are a number of processes and sub-processes on an oil and gas facility which generate waste gases containing methane and NMVOC. These waste gases could potentially be released into the atmosphere as direct emissons, but this depends on how the waste gases are handled. All facilities that handle natural gas have some processes and sub-processes that can result in such emissions.

The waste gases from processes or sub-processes can be disposed of to result in, or not result in, direct emissions. This choice is made by the operator in the planning/design phase. Once the facility is built and in operation emission reduction measures are difficult and / or costly to implement. For some of the processes emissions are the only option.

Whether a potential process or sub-process leads to emissions is therefore a two-step assessment:

Step 1. Is the process or sub-process that can generate gases with methane and NMVOC present at the facility? If the answer is no, there is no emission from that source. If the answer is yes, this might be a potential source of emission from the installation and one can go to the next step.

Step 2. Is the waste gas sent to direct emission or disposed in another way?

There are three disposal opportunities for the waste gas: recycling, combustion in flare or incinerator, or direct emissons. Recycling and combustion are not viable alternatives for some of the processes / sub-processes because they are in conflict with the laws of physics[2], or because they are impractical.

In this report, it is therefore differentiated between processes / sub-processes, waste and emissions.

6.2 «Old» emisson sources and processes that produce waste gas that could be emissons

The survey showed that the emisson sources as defined in the current guidelines are incomplete. There are a number of processes at the facilities in addition to those covered in the guidelines that produce waste gases containing methane and NMVOC. The survey also showed that many of the «old» sources should be split into sub-sources to be able to quantify and report the emissions correctly and to be precise when implementing measures.

Listed in this sub-chaper are the identified processes and sub-processes. Most of the «old» sources are divided into potential sub sources. This is because an installation can have emissions from some of the sub-sources but not necessarily all of them. Table 2 provides an overview of the «old» emission sources with proposed process names, and how they can be split into sub-processes. Some of the sub-processes are believed not to have been included in the old emission sources. These are marked in red font.

[2] One example is an waste gas containing too low concentration of HC gases for it to burn or maintain a flame in the flare.

Table 3 provides an overview of new processes and sub-processes not included in Norwegian oil and gas association guideline for emissions reporting [Ref: 1].

Table 2 Identified sub-sources

«Old» predefined source/process	New sub processes
Triethylene glycol (TEG) regeneration	• TEG degassing tank (conventional TEG system). • TEG regenerator (conventional TEG system). • Stripping gas for water stripping in TEG regeneration. • (Sources in proprietary TEG systems (Drizo, coldfinger, etc.)).
Produced water treatment	• Produced water degassing tank. • Produced water flotation unit (flotation gas + off-gas from water). • Various tanks for collecting oil from produced water treatment • Discharge caisson
Low pressure scrubbers	• Low pressure scrubbers.
Compressor seal oil (wet seals)	• Degassing pots. • Seal oil holding- and storage tanks.
Dry compressor seals	• Primary seal gas (primary vent). • Secondary seal gas (secondary vent). • Leakage of primary seal gas to secondary seal vent.
Gas freeing of process systems	• Gas freeing of process systems.
Purge and blanket gas	• Purge gas for flare headers/tip and ventheaders[3]. • Purge and blanket gas for various tanks.
Depressurization / gas freeing of instruments/instrument bridles	• Depressurization/gas freeing of instruments/instrument bridles.
Flare gas that does not burn	• Extinguished flare. • Delayed flare ignition. • Non-combustible flare gas. • Open cold flare purged with nitrogen.
Gas leaks in process	• Large gas leaks (leaks requiring investigations). • Small gas leaks/fugitives.
Production riser annulus bleed	• Production riser annulus bleed.
Drilling	• Shale shaker. • Mud separator.
Start-gas for turbines	• Start-gas for turbiner. • Depressurization during shutdown.

The individual subprocesses are reviewed in more detail in the following chapters.

[3] A vent header is a piping system that captures waste gases from several devices and lead the gas to the discharge pipe where the gas is released unburned to the atmosphere.

Table 3 ñNewò processes and sub-processes producing HC waste gas

«New» processes and sub-processes	Sub-processes
MEG regeneration	MEG degassing tank. MEG regenerator.
Amine regeneration	Amine degassing tank. Amine regenerator.
Reciprocating compressors	Separator chamber. Crankshaft housing.
Screw compressors	Screw compressors.
Liquid-ring compressors	Liquid-ring compressors.
Stripping gas for injection water	Stripping gas for injection water.
Gas analysers and test/sample stations	Gas analysers and test/sample stations.
Turret on FPSOôs	Turret.
Pig launchers and receivers	Gas freeing of pig launchers and receivers.
Corrosion coupons	Corrosion coupons.
Flexible riser annulus bleed	Flexible riser annulus bleed.
Gas freeing crude oil storage tanks on FPSOs	Inspection of storage tanks. Abnormal operating conditions.
Storage tanks for crude oil on FSOs (floating oil storage)	Loading and unloading of the storage tanks.
Oil tanks (diesel, lubricating oil, etc.)	Oil tanks (diesel, lubricating oil, etc.).
ñDouble block and bleedò valves (DBB)	ñDouble block and bleedò valves (DBB).

The list may seem comprehensive, but it should be noted that most facilities only have a few of these waste-producing sub-processes, and that emissions from many of the sub-processes can be very small.

This list is not necessarily complete for all facilities producing oil and gas:

- There may be new facilities containing oil and gas with contaminants or components that require the use of new technologies which can be sources of direct emissions of methane and NMVOC[4].

- New technologies can be developed or put to use that introduce new emission sources. Examples include removal of H_2S and CO_2 from produced gas. The few facilities that have this problem today use technologies that are examined in the survey. But there are numerous other patented processes for the removal of such gases which may contain "new" sources, i.e. sources that have not been captured by this survey.

- On most facilities, there will be a number of "micro-sources" who have gone "under the radar" during the survey. This can be small tanks containing oily liquids that release gas to atmosphere, nitrogen purge gas that picks up small quantities of hydrocarbon gas as it sweeps over the oil holding tank, or drainage water tanks which may contain traces of oil, or it may be non-identified unit operations that can result in small emissions of HC gas. Overall, these sources represent emissions that hardly exceeds a few ă of the total direct emissions from the facilities.

6.3 Processes and sub processes producing HC-containing waste gases

This sub chapter contains a review of the individual processes and sub-processes that can generate HC-containing waste gas and describes to what extent these can lead to discharge.

All the processes and sub processes produce waste gas emissions. Whether these waste gases end up as emissions depends on how they are disposed. These are decisions made in the early design phase.

[4] Examples: 1) a new field can contain large amounts of sulphur and a patented process is selected for reducing the sulphur content. 2) a new field with a high wax content may require a dewaxing process that generates an HC-containing waste gas, which may represent a potential new source of emission.

6.3.1 TEG regeneration (glycol regeneration)

6.3.1.1 Introduction

Reduction of water content in the export gas is required to prevent hydrate formation during transport. This can be done using several technologies, but the use of triethylene glycol (TEG) as the absorption liquid counter-currently on the export gas in an absorption tower (often called contactor) is the dominant technology used at Norwegian facilities. Potential emissions occur when regenerating TEG (removal of absorbed water). Other absorption liquids and drying technologies can also be used. Such special methods should be handled in another way.

Some methane and NMVOC are dissolved in the TEG-solution in the absorption tower and are released again in the regeneration process. A typical regeneration process is shown in Figure 1.

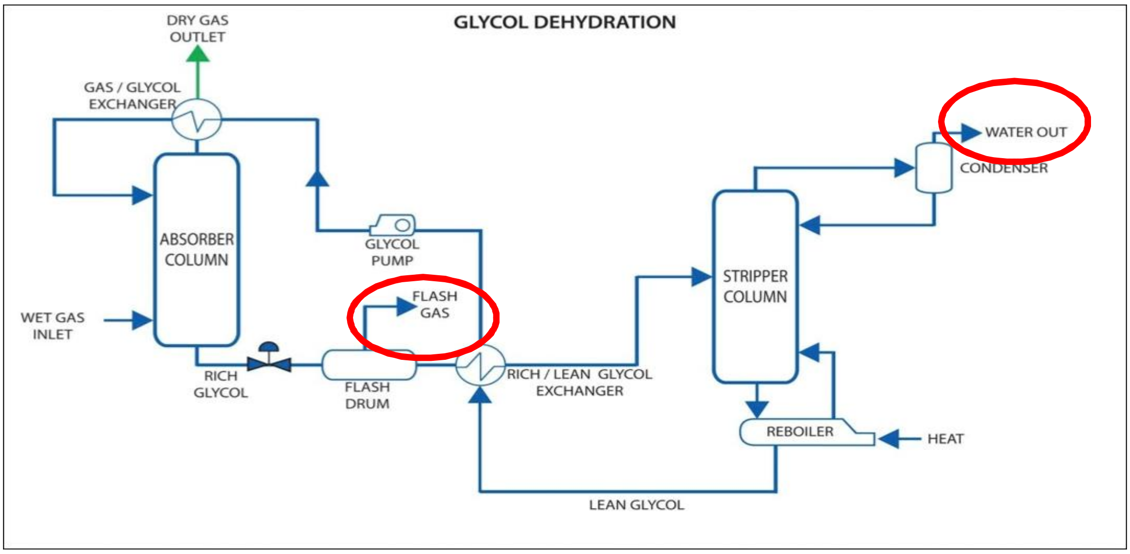


Figure 1 Typical TEG regeneration process (source: Wikipedia)

The figure shows that there are two discharge points for waste from the TEG solution:

a. From a degassing tank/«flash drum» (mainly absorbed natural gas)
b. From the regenerator, also called TEG reboiler (mainly water vapour)

In the degassing tank (operated at substantially lower pressure than the absorber) dissolved HC gas is released through depressurization (along with a little water vapour). In the boiler, operating at slightly above 200ºC, solved water is released by evaporation along with traces of methane and NMVOC.

On some facilities stripping gas is also added to, or used in connection with, the boiler. Fuel gas is most commonly used as stripping gas. Used stripping gas goes to waste along with decoction from the regenerator.

There are also some special processes for TEG regeneration. Two such processes are used on the Norwegian shelf:

- **Drizo-process**. Here, the waste from the boiler is routed through a cooler to condense water and heavy HC components in the waste gas. Gas, water and hydrocarbon liquid are separated in a separator downstrem the cooler (Water Liquid Separator). HC-liquid is used as stripping medium in the regeneration process instead of supplied HC-gas. The HC-gas from the separator is released as waste gas from the system.
- **Coldfinger-process**. This is a special version of the regeneration process to extract more water from the TEG solution. This process does not cause any changes that affects the waste gas flows.

There are 32 facilities on the Norwegian continental shelf with TEG regeneration.

The individual waste gas flows are described in the chapters below.

6.3.1.2 Waste gas from the degassing tank

The survey showed that no installations on the Norwegian continental shelf sends the gas phase from the degassing tank to direct emissions. All the facilities are routing the waste gas to recycling in the process or to flare.

Table 4 Waste gas from the degassing tank ï Key information

a. Potential waste gas quantity:	**Large**
b. Emission type	Continuously.
c. Cause/justification	Side effect of the dehydration of the export gas.
d. Disposal options	Recycling to the process, flaring or direct emissions to air.
e. Selected solutions	Mainly recycling and flaring.
f. Quantification until now	NOROGs guideline (does not separate between the sub-sources).
g. Quantification options	a) Measurement, simulation, analysis of HC-gases in TEG upstream and downstream the degasser tank. b) Calculation using a special application program (GRI-GLYCalc)
h. Influencing factors	Circulation rate of TEG (primarily), pressure and temperature in contactor and degassing tank as well as amount of gas in contactor assuming constant ratio between gas rate and circulation rate of glycol.
i. Possibilities for sampling	Possible, but depends on installation-specific conditions.
j. Technology status / age affecting the emissions	In practice,of no significance. Emissions are only governed by the operating conditions and disposal of waste gas.
k. Can direct emissions be eliminated	Yes, by recovery or flaring. This is done at the facilities on Norwegian shelf.

Subparagraph a. gives the potential emissions contribution from the sub-process indicated qualitatively. This is for the reader to get an instant insight into whether this is a significant or less significant contributor. The following terms are used:

Large: Magnitude >~100 t/year for some facilities, >~ 1000 t/year for Norwegian shelf
Medium: Magnitude ~ 1 ï 100 t/year for facilities, ~ 10 ï 1000 t/year for Norwegian shelf
Small: Magnitude < ~ 1 t/year for most facilities, < ~10 t/year for Norwegian shelf

6.3.1.3 Waste gas from the regenerator

Waste from regenerator emitted as direct emissions from 12 facilities at the Norwegian shelf. For the remaining 27 installations with TEG regeneration the waste gas goes to flare or recovery.

For stripping gas, see Chapter 6.3.1.4. The table below reflects facilities without added fuel gas as stripping gas.

Table 5 Waste gas from the TEG regenerator ï Key information

a. Potential waste gas quantity:	**Large.**
b. Emission type	Continuously.
c. Cause/justification	Side effect of the dehydration of the export gas.
d. Disposal options	Recycling to the process, flaring or direct emissions to air.
e. Selected solutions	Approximately equally divided between emissions, recycling and flaring.
f. Quantification until now	NOROGs guideline (does not separate between the sub-sources).
g. Quantification options	a) Measurement, simulation, analysis of HC-gases in TEG upstream and downstream the degasser tank. b) Calculation using a special applicationprogram (GRI-GLYCalc) c) Analysis of HC gases in TEG downstream degassing tank (assumes that the amount of TEG downstream the regenerator is negligible). It is not easy to measure the waste gas flow.
a. Influencing factors	Circulation Rate of TEG (primarily), pressure and temperature in the degassing tank (and regenerator, but the pressure here is usually so low that it has little practical meaning).
b. Possibilities for sampling	Sampling of the waste gas is not considered easy and is not appropriate since the waste is often mixed with other streams in the common vent. Sampling of the TEG solution downstream the degassing tank and analysis of the HC gas content are considered as the best solution. At most plants, samples are taken easily by filters downstream of the tank.
c. Technology status/age affecting the emissions	The Drizo-process also removes BTEX which is a health hazard and environmentally harmful component. The emissions are only controlled by operating conditions and disposal of waste gas.
d. Can direct emissions be eliminated	Yes, by recovery or flaring. This is done at many facilities.

There may be several reasons why direct emissions of waste gas is chosen at some of the facilities. It is believed the most important are that:

- The waste gas has virtually atmospheric pressure. This means that an additional compressor must be installed in order to recover the gas if the facility does not have a VAR-compressor[5].
- Pressure build-up in a flaring situation in the low pressure flare could result in a setback to the regenerator.
- A high content of evaporated water in the waste gas could increase the risk that the low pressure flare is extinguised (because of the low content of HC gas). The water content should in principle not preclude recovery for recirculation to the low pressure area in the process.

6.3.1.4 Waste gas from stripping gas

There are 27 facilities using fuel gas as stripping gas in the TEG regeneration. From 8 of these facilities the stripping gas is released to the atmosphere, together with waste gas from the TEG-boiler. All of the stripping gas follows the waste gas.

[5] A Low Pressure compressor that compresses gas at atmospheric pressure to the inlet pressure of the gas processing plant.

Table 6 Waste gas from stripping gas ï key information

a. Potential waste gas quantity:	**Large.** Facilities with a stripping rate of 30 Sm^3 fuelgas / hour, adds 200 ï 250 tonne / year HC-gas to the exhaust stream.
b. Emission type	Continuously.
c. Cause/justification	Effect of the need to use HC stripping gas to meet requirements for regeneration of the TEG solution.
d. Disposal options	Recycling to the process, flaring or direct emissions to air.
e. Selected solutions	Approximately equally divided between emissions, recycling and flaring.
f. Quantification until now	NOROGs guideline (does not separate between the sub-sources).
g. Quantification options	The amount of stripping gas can only be quantified through measurement upstream of the facility. If the waste gas is lead to a common vent that is measured, there is no need for a separate measurement of the stripping gas.
h. Influencing factors	Only the need to reduce the water content of the TEG solution. The operator should consider if the need for fuel gas stripping is present*.
i. Possibilities for sampling	The composition equals the fuel gas composition. The fuel gas composition is known.
j. Technology status/age affecting the emissions	No relevanse.
k. Can direct emissions be eliminated	Yes, by recycling the waste gas. Flaring eliminates the direct emissions of methane and NMVOC, but generates CO_2-emissions

* N_2 can also be used as stripping gas, but this requires N_2 of very high purity. Operators that have used a commercial N_2 with 99.5 % purity have registered operational problems when regenerating TEG (due to oxidation of TEG).

Since the stripping gas is mixed with the boiled off gas from the regenerator, the reasons for the choosen solution is the same as for waste gas from the regenerator (Chapter 6.3.1.3).

The survey shows that it is fully possible to eliminate direct emissions of methane and NMVOC from TEG regeneration at new field developments.

6.3.2 Waste gas from the produced water system

The water that follows the oil and gas from the reservoir and is separated in the facility's oil/water/gas separators are saturated with methane and NMVOC and contains traces of oil. In the cleaning process oil residues are separated from the water, and water pressure is reduced to atmospheric pressure, for the water that is discharged to sea.

On some facilities, all the water is discharged to the sea. On some facilities, some of the produced water is reinjected in an underground structure and on some facilities the entire amount is reinjected (ie the production stops if there are problems with the water injection system).

On facilities with treatment plants there are normally multiple waste streams. These are outlined schematically in Figure 2.

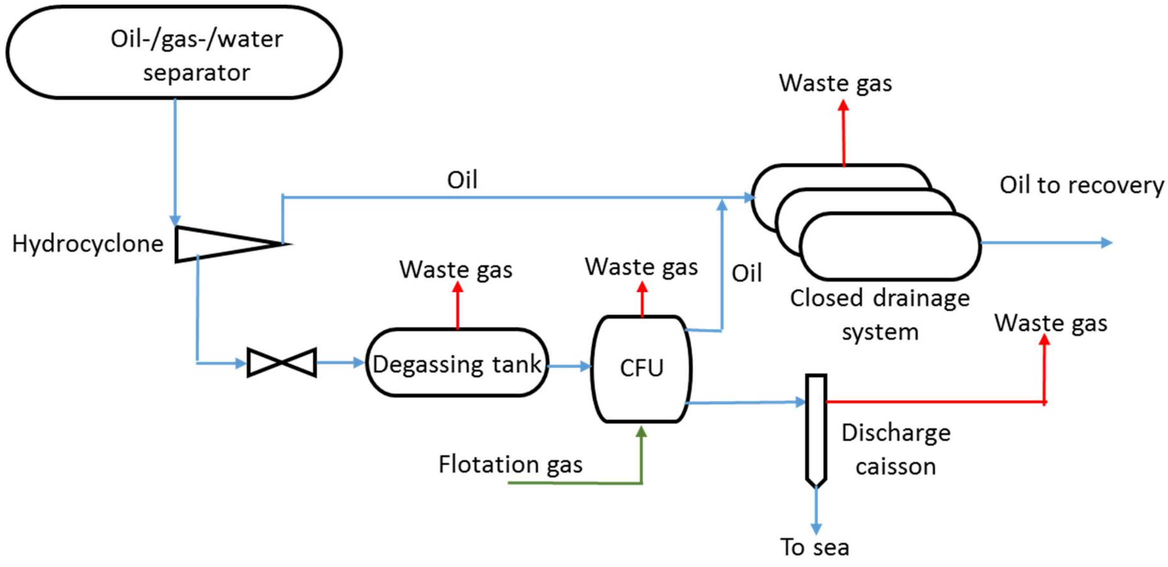


Figure 2 Principle sketch of treatment plant for produced water

There are a number of variations to the sketch shown above. Older installations often only have a degassing tank and flotation unit. A number of facilities do not have a CFU (compact flotation). Several plants use the CTOUR technology process in produced water treatment. This process normally does not affect the waste gases.

When the water leaves the separator, it is saturated with methane and NMVOC at separation pressure and temperature. All methane and NMVOC will emit waste gas when the water is discharged to sea (down to equilibrium state at atmospheric pressure). The waste gas is normally discharged through some or all of the following sources:

- **From degassing tank**. This normally has an operating pressure that varies between the facilities from below 1 barg up to 5 barg. The waste gas volume is controlled by the difference in solubility of methane and NMVOCs in the water at separation pressure and at the pressure in the degassing tank

  From flotation plant. Compact flotation plants (CFU) often have an operating pressure that is just below the pressure in the degassing tank. Conventional flotation plants often operate just above or at atmospheric pressure. Flotation processes have a supply of a flotation gas that is discharged along with gas released from the water in the flotation tank. Flotation gas is often nitrogen (N2), but may also be fuel gas. The flotation gas is added to the waste gas from the water, and in the case of fuel gas, will result in additional emissions.

- **From closed drainage systems.**. Oil residues from hydrocyclones and flotation are normally lead to the closed drainage system on the facility. Here, oil from the produced water system is mixed with oil residues from other sources. Residual water is separated from the oil in one or more tanks before it is sent back to the process for recycling. Purge gas is used in closed drainage system to prevent explosion. Normally, nitrogen is used as purge gas. Nitrogen captures gas vapors from the oil. The purge gas is normally released into the atmosphere through the facility's common atmospheric vent. The amount of oil is small, which means that the dissolved amounts of methane and NMVOCs are also small.

- **From emission caisson**. Produced water is discharged to sea through an emission caisson. The discharge point can vary. On some facilities the water is released from just above the water surface, while on other facilities it is discharged below the water surface. The water depth may vary and in some installations is as deep as 20 metres. The caisson is normally equipped with a vent at the top. This is to prevent the water in the caisson from causing a vacuum in pipes and equipment upstream of the discharge tube. At some facilities, the gas is led to a common atmospheric vent while other facilities only have a local vent. The content of methane and NMVOCs in this waste gas is controlled by the equilibrium solubility in water at the upstream vent (degassing tank, CFU or flotation) and equilibrium concentration at atmospheric pressure (discharge point).

6.3.2.1 Waste gas from degasser tank

The survey showed that a total of 43 facilities on the Norwegian shelf have produced water production with treatment plants. None of these release waste gas directly to discharge. From one facility the off-gas goes to a low pressure flare which does not burn due to the low content of HC gas in the flare gas. On another facility the waste gas is lead to an inert gas purged open torch (ignited). In both these cases, the waste gas goes to direct emissions. On the remaining facilities the off-gas is sent either to the recycling process or to flare were it is burned.

Table 7 Waste gas from degasser tank ï key information

a. Potetial waste gas quantity:	**Large**, depends on amount of produced water and pressure in the inlet separator.
b. Emission type	Continuously.
c. Cause/justification	Is caused by natural content of metan and NMVOC dissolved in the reservoir water that is produced along with oil and gas.
d. Disposal options	Recycling to the process, flaring or direct emissions to air.
e. Selected solutions	Recycling and flaring is used as standard solution on the Norwegian shelf.
f. Quantification until now	NOROGs guideline (does not separate between the sub-sources).
g. Quantification options	Measurement of waste gas volumes (not done), simulation and calculation based on equilibrium concentrations from literature data.
h. Influencing factors	Amount of produced water, pressure and temperature in the inlet separator and the degassing tank.
i. Possibilities for sampling	Not prepared for sampling. Since the emissions from this sourece are rare there is no need for this.
j. Technology status/age affecting the emissions	No relevance. The emissions are only controlled by the operating conditions and disposal of waste gas.
k. Can direct emissions be eliminated	Yes, by recovery or flaring. This is done at almost all facilities.

6.3.2.2 Waste gas from CFU/flotationtank

The survey showed that a total of 21 facilities have a CFU/flotation tank. The waste gas is discharged into the atmosphere from 4 of these facilities. For the remaining facilities the off-gas is recycled or burned in flares.

Table 8 Waste gas from CFU / Flotation tank ï key information

a. Potential waste gas quantity:	**Large** if the flotation gas is fuel gas. Small to medium if the flotation gas is N_2.
b. Emission type	Continuously.
c. Cause/justification	Caused primarily by amount of floation gas added (if this is fuel gas).
d. Disposal options	Recycling to the process, flaring or direct emissions to air.
e. Selected options	Recycling and flaring is used as standard solution on the Norwegian shelf.
f. Quantification until now	NOROGs guideline (does not separate between the sub-sources and does not take the amount of flotation gas into account).
g. Quantification options	Measurement of the amount of fuelgas used as flotation gas. Boil off due to pressure reduction as for degassing tank.
h. Influencing factors	Choice of flotationgas (fuel gas vs. N2).
i. Possibilities for sampling	The need for sampling is small. Fuel gas composition is known and the contribution from the released gas from the produced water is considered to be small. Since emission from this source is rare, there is no need for sampling.
j. Technology status/age affecting the emissions	No relevance. The emissions are only controlled by the operating conditions and disposal of waste gas.
k. Can direct emissions be eliminated	Yes, by recovery or flaring. This is done at almost all facilities. Using N_2 as flotation gas reduces the emissions significantly.

6.3.2.3 Waste gas from emission caisson for produced water

There will always be a residual amount of methane and NMVOCs in the produced water when it is discharged to sea. The amount is determined by the amount of HC gases dissolved in the produced water in the last degassing tank, and at atmospheric pressure. It is reasonable to assume that the gas will evaporate until it reaches equilibrium at atmospheric pressure. At some plants the produced water is discharged at greater depths (up to 20 metres) and gas bubbles are not seen in the water. Whether this means that the gas over time will not be released to the atmosphere is considered beyond the mandate of this study.

Table 9 Waste gas from emission caisson for prodused water ï key information

a. Potential waste gas quantity:	**Large**, especially if the operating pressure in the degassing tank and CFU is relatively high (2 to 5 barg).
b. Emission type	Continuous on installations that do not have produced water re-injection. For facilities that have re-injection, there may be discharge during periods when the reinjection facility is inoperative.
c. Cause/justification	Because the produced water is saturated with methane and NMVOC when it leaves the degassing tank and flotation plant.
d. Disposal options	Recycling to the process, flaring or direct emissions to air.
e. Selected options	Direct emissions is standard solution on the Norwegian shelf. Either through a common atmospheric vent or through a local vent.
f. Quantification until now	NOROGs guideline (does not separate between the sub-sources).
g. Quantification options	Calculation using the equilibrium data at the last degassing point and at atmospheric pressure.
h. Influencing factors	Primarily produced water amounts to sea and pressure level at last upstream degassing point.
i. Possibilities for sampling	Can possibly take gas samples from the degassing vent in the emission caisson for produced water.
j. Technology status/age affecting the emissions	No relevance. The emissions are only controlled by the operating conditions and the produced water volumes discharged to sea.
k. Can direct emissions be eliminated	Since the pressure at the discharge point is so low, it is doubtful whether these emissions can be eliminated. Issues that must be overcome are: a) with any flaring of gas it must be ensured there is no backflow of flare gas in a flaring situation. b) the waste gas will be rich in inert gas (water vapour) and it should be ensured that this does not cause problems with ignition of the flare, and c) with recycling, a compressor must be installed to increase the pressure of the gas to a level which enables recirculation to the process (may be easier for facilities that have VOC/VRU compressor).

6.3.2.4 Gas from recycled oil

Recycled oil from the produced water treatment plant is sent to a closed drainage system where it is mixed with the oil contaminated water from other sources. Blanket gas from tanks in the drainage system is normally sent to a common atmospheric vent system.

The composition of the gas may vary considerably from source to source and from facility to facility. Oil volumes recovered from the treatment plant for produced water is small and only small fractions will evaporate and escape with inert gas (blanket gas).

Table 10 Waste from recycled oil ï key information

a. Potential waste gas quantity	Small.
b. Emission type	Normally continuously.
c. Cause/justification	Due to naturally occurring oil droplets in dispersed form in produced water.
d. Disposal options	Flare, reinjection and recycling to the process.
e. Selected options	Most often the atmospheric common vent.
f. Quantification until now	Not a separate emission source, it is contained in the source "Produced Water Treatment".
g. Quantification options	Difficult to quantify locally. The best way is probably by measuring and sampling in the common vent.
h. Influencing factors	Amount of oil collected by the hydrocyclones and the flotation plant.
i. Possibilities for sampling	Very difficult as hydrocarbons are trapped in the liquid fraction, blended with other sources and evaporates small amounts of gas continuously.
j. Technology status/age affecting the emissons	Equipment and age means little or nothing. The amount of waste is controlled by the amount of recovered oil and the content of HC gases in the oil.
k. Can direct emissions be eliminated	Only if the waste gas from the closed drainage can be entirely recycled to the process or burned in the low pressure flare.

6.3.3 Dissolved gas in the liquid from the scrubber

This was identified as a source of direct emissions of HC gas in Aker Engineering's 1993 study (Ref: 7) and has figured in the Norwegian Oil Industry Association's guidelines for emissions reporting since the mid-1990s. During the primary review, four cases where gas from scrubbers were sent to cold vent were identified:

1. At one facility a surge tank for condensate was equipped with a valve towards the atmospheric common vent. This opens only when needed. The emissions from the common vent are measured separately.
2. At one facility the liquid from the scrubbers upstream of the compressors are sent to closed drain. The gas from the closed drain is sent to the atmospheric common vent (measured). It has been decided to try another approach at the next planned shutdown so that the liquid is sent to the recovery tank for condensate and gas to fuel gas.
3. At one facility the liquid from the liquid scrubber upstream one of the compressors is sent to the atmospheric common vent (was originally routed to the low pressure flare, but had to reroute due. to frost problems). The operator has simulated emission quantities.
4. At the fourth facility the details were not mapped.

These are all special situations, where conditions will vary from facility to facility, depending on how the facilities are designed. In all cases, the gas is sent to atmospheric common vent where it is mixed with gas from a number of other sources. It is therefore inappropriate to operate with this as a standardized source in the future. Emissions have varying sizes. For the cases listed here the emissions varies from almost nothing (Example 1) to a few tonnes / year (Example 3) but may also be somewhat higher.

The emissions are a function of the chosen technical solutions at a detailed level. The examples shown above also illustrate that direct emissions from this source may, technically, be totally eliminated by a reasonable design.

6.3.4 Emissons from compressor seals

The survey showed that centrifugal compressors are the predominant compressor type used for natural gas compression at the facilities. In addition, some reciprocating and a few screw and water ring compressors are used. All compressor types must have a sealing system to prevent the compressed gas from escaping to the atmosphere through the gap that separates the static compressor casing and the rotating compressor shaft in the centrifugal and screw compressors and between cylinder housing and piston rod in the reciprocating compressors.

Older centrifugal compressors (installed before the end of the 1980s) have almost exclusively oil seals, while compressors on devices installed after 1990 predominantly uses dry seals with gas as sealing medium.

On some of the facilities reciprocating gas compressors are used. This is mainly at slightly older FPSOs. These compressors have oil seals.

For low pressure compression, mainly used for compression of flare gas from a closed flare and compression and recirculation of HC-blanket gas on crude oil tanks, both rotary screw compressors and water ring compressors are used.

In the following chapters oil seals and dry seals in centrifugal compressors are discussed in separate sub-chapters. There are separate subsections also for reciprocating and screw and water ring compressors.

6.3.4.1 Emissions from oil seals in centrifugal compressors

The emissions of HC-gas from oil seals is caused by the compressed gas, which comes into contact with seal oil, and to some extent dissolves therein. The seal oil is depressurized after use to be reused. Through depressurization dissolved gas is released and this waste gas must be disposed of. Depressurization normally occurs in two or in some cases, in three steps.

Whether the waste gas involves emissions of HC gas to air depends on how the waste gas is disposed of. This is a choice taken in the design phase.

Traditionally, seal oil was regarded as a significant source of emission of HC gas. This survey has indicated that this is not necessarily the case at the facilities on the Norwegian shelf. The survey has also shown that this is, potentially, one of the major sources which it has been difficult to obtain information about. This may be due to the fact that oil seals are primarily found at older facilities and that operators have been dependent on contacting their suppliers to get information.

The survey showed that there are 17 facilities on the Norwegian continental shelf with centrifugal compressors with oil seals. All facilities with seal oil that were mapped during the primary survey have several depressurization levels. First, the part of the seal oil that has been in contact with the gas is depressurized in degassing pots (also called sour gas pots). Normally there was a pot for each compression step and different pressure levels in the various pots. The gas from the pots were recycled or sent to flare at many facilities, but some of the facilities also sent the waste gas to atmospheric vent. For some of these, the waste gas from the high pressure compressor pot is sent to flare or recovery, while the gas from the low pressure compressor pot is sent to atmospheric vent.

The seal oil is then led to a holding tank. Some facilities had a holding tank before the oil was sent to a storage tank. Both tanks operate close to atmospheric pressure. The holding tank and the storage tank in most cases sent the waste gas to atmospheric vent, this was mainly a local vent. Discharges were generally not measured and some operators pointed out that measurement can be very difficult due to the location of the vent system (below deck on some facilities). Operators were requested to contact the supplier for emission data. The feedback has been limited so far.

Waste gas from the degassing pots:

Table 11 Gas from degassing pots ï key information

a. Potential waste gas quantity	Medium to **large.**
b. Emission type	Continuously.
c. Cause/justification	The gas in the compressor is in contact with and dissolved in seal oil.
d. Disposal options	Flare, reinjection, recycling to process and emissions through atm. vent.
e. Selected options	Recycling to the process in most cases and to a certain extent flaring. A few degassing pots at some installations have emissions to local atmospheric vent.
f. Quantification until now	NOROGs guideline (does not separate between the sub-sources).
g. Quantification options	Only relevant if it is discharged. Obtain data from the equipment supplier (if available) and analysis of oil samples upstream of the exhaust pots.
h. Influencing factors	Degree of contact with high pressure gas and pressure relief in degassing pots.
i. Possibilities for sampling	The operators report that measurement of waste gas quantity is difficult. Sampling and analysis of seal oil upstream of the exhaust pots is possibly easier. Measurement possibilities will depend on the facility specific circumstances and constraints.
j. Technology status/age affecting the emissions	The seals wear during use. It is unclear to what extent this will affect the amount of methane and NMVOCs dissolved in the seal oil.
k. Can direct emissions be eliminated	In principle, the emissions are eliminated by both the recovery of waste gas and by burning the waste gas in the flare. It may be costly to implement on existing plants where this is not already in place.

Waste gas from holding tank and storage tank:

Some facilities have both a holding tank and a storage tank for seal oil. Both tanks have venting of gases. Since the tanks are situated in series and both operate at about atmospheric pressure, these sources are treated together in the table below.

Table 12 Gas from holding tank and storage tank for seal oil ï key information

a. Potential waste gas quantity	Small to medium, but the discharge amount is inadequately known.
b. Emission type	Continuously.
c. Cause/justification	The seal oil downstream of the degassing pots still contains some dissolved methane and NMVOC. These gases are released into the holding and storage tanks.
d. Disposal options	Flare, reinjection, recycling to process and emissions through atm. vent.
e. Selected options	Most often a local atmospheric common vent.
f. Quantification until now	NOROGs guideline (does not separate between the sub-sources).
g. Quantification options	Measuring or collecting data from the equipment supplier (if available). Analyses of oil samples upstream of the holding/storage tank is also a possible method.
h. Influencing factors	Amount of gas dissolved in the seal oil and pressure and temperature conditions in the exhaust pots.
i. Possibilities for sampling	Measurement of emission rate and analysis of the waste gas is considered by the operators to be difficult to achieve. Analysis of the oil sample upstream of the holding/storage tank is found to be an easier method.
j. Technology status/age affecting the emissions	The size of the emissions is not dependent on the age of the equipment. The pressure levels selected in the design can have an impact on amount of dissolved gas in the oil.
k. Can direct emissions be eliminated	Although emissions through local vent is the dominant solution, it should be possible in most cases, to recover the gas by recycling to the process. In most cases this will require the installation of a low pressure compressor. Regarding flaring, it should be ensured that the backlash from flares during a flaring situation is avoided.

6.3.4.2 Emissions from dry seals in centrifugal compressors

Modern centrifugal compressors are equipped with dry seals. To meet regulatory requirements on Norwegian installations double barriers are required. The principle is shown in Figure 3. There are several types of double seals, depending on the supplier of the seal and mechanical design. The technique is being further developed.

Normally, process gas from the compressor is used as the primary sealing gas. It is very important that the gas is completely clean. The primary sealing gas has a slightly higher pressure than the gas in the compressor (0.3 to 0.7 bar overpressure). This means that the sealing gas leaks into the compressor, and prevents the compressor gas from leaking out. Up to 10% of the sealing gas goes the other way (called primary vent) in the figure. This gas can be recycled to the process, sent to flare or discharged to the atmosphere. All three solutions are found at the mapped facilities.

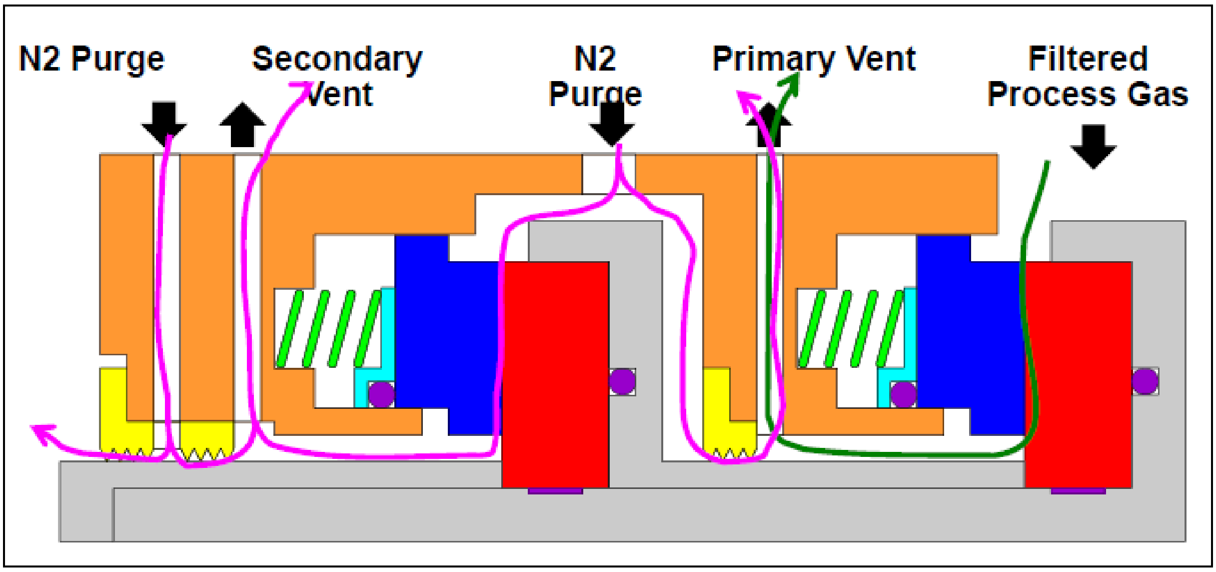


Figure 3 Dry seals. Double barrier using tandem seal and internal labyrinth (source: John Crane).

The secondary seal gas, called N_2 purge in the figure, represents the secondary barrier. On seals with internal labyrinth the secondary barrier has a higher pressure than the primary vent, thereby preventing the HC-gas from the primary seal from leaking. In the figure, N_2 is shown as the secondary sealing gas. This is normally released into the air. It was found in the survey that N_2 is used as a secondary seal gas on most compressors with dry seals, but there were also some which used process gas or fuel gas as secondary seal gas.

There are also dry seals without internal labyrinth. In these seals, some of the primary seal gas can leak out through the secondary seal and mix with the secondary seal gas.

The description above is schematically. There are several suppliers of dry seals on the Norwegian shelf. The seals have different structural details and the techniques are constantly being developed. There will therefore be different variations of the schematic image shown here.This means that generic emission calculations for this source may have inaccuracies and errors.

The degree of emission depends on the following factors:
Å**Primary seal gas: Seal with internal labyrinth:** All waste (used gas) is discharged through the primary vent. If this is sent to flare, or recovery, there are no emissions.

Å**Primary seal gas: Seal without internal labyrinth:** Some primary seal gas leaks to the secondary seal and is released into the air if the secondary seal gas is released into the air.

Å**N_2 as the secondary seal gas:** No emissions beyond leaks from the primary seal gas.

Å**HC gas as the secondary seal gas:** If the seal has an internal labyrinth, some of the secondary seal gas will leak into the primary vent. Emissions depend on how the primary gas is disposed. The remaining secondary seal gas goes to the "secondary vent." This is, in most cases, released to air. If the seal does not have an internal labyrinth, all the secondary seal gas goes to "secondary vent." Whether this leads to emissions depends on how the "secondary vent" is disposed of on the facility.

These conditions make it difficult to establish an overview of the emissions from dry seals in centrifugal compressors. The project has mapped the type of seal gas that is used for all centrifugal compressors with dry seals on the shelf, and how the used seal gas is disposed. It has not been possible during this survey to obtain an overview of how many compressors have seals with internal labyrinth.

However, it is be the choice of secondary seal gas and the choice of disposal solution for used seal gas (from primary and secondary vent) that predominantly affects the emissions of HC gas to atmosphere.

Providers often operate with the following leak rate (guaranteed number):
Å10% of primary seal gas goes to primary vent
Å10% of primary vent leaks into the secondary seal gas (for seals without internal labyrinth)

A few of the facilities in the survey had seal gas metres that showed both of the gas volumes. These indicated a much lower leakage number than the guarantee. The operator pointed out, however, that these measurements can be somewhat unreliable and therefore should only be used to detect trends in seal gas rate.

34 installations on the Norwegian continental shelf have centrifugal compressors that use dry seals (all or some of the compressors on the facility).

Primary seal gas:

Table 13 Used primary seal gas ï key information

a. Potential waste gas quantity	Medium.
b. Emission type	Continuously.
c. Cause/justification	It is difficult to get the seals completely tight.
d. Disposal options	Recycling to process and recovery of the gas, flare and emissions through atm. vent.
e. Selected options	On 4 facilities the gas is recovered. On 18 facilities the gas is sent to flare. On 12 facilities the gas goes to air through an atmospheric vent.
f. Quantification until now	NOROGs guideline (does not separate between the sub-sources).
g. Quantification options	The amount of gas into the seal is measured on most compressors. The vent gas rate is measured on some facilities. The amount of vent gas can be estimated as a percentage of the amount of seal gas into the compressor for compressors without measurements.
h. Influencing factors	Primarily: ÅDisposal of used seal gas. ÅType of dry seal (supplier, mechanical design).
i. Possibilities for sampling	Gas composition analysis (export gas and fuel gas).
j. Technology status/age affecting the emissions	Selection of seal design is important. Seal wear over time affects the leak rate. These conditions can be totally overridden by how the used seal gas is disposed of.
k. Can direct emissions be eliminated	Partly. This depends somewhat on the type of seal. If the seal has an internal labyrinth, uses N_2 as the secondary seal gas, and the primary seal gas is recovered, the emissions are eliminated. This can be expensive to implement on existing plants with other solutions.

Secondary seal gas:

Tablel 14 Used secondary seal gas ï key information

a. Potential waste gas quantity	Medium to large, by using HC-gas as a secondary seal gas.
b. Emission type	Continuously.
c. Cause/justification	Use of HC-gas as a secondary seal gas. Leakage of primary seal gas into the secondary barrier.
d. Disposal options	Recirculation to the process and recycling of the gas (if HC gas is used as secondary seal gas), flare (if HC gas used) or emissions through atmospheric vent.
e. Selected options	At all mapped facilities, the secondary seal gas is sent to atmospheric vent. The reason may be that the systems are designed to use N_2 as the secondary seal gas.
f. Quantification until now	NOROGs guideline (does not separate between the sub-sources).
g. Quantification options	Measuring secondary seal gas into the seal. If HC gas is used, all the used gas will give emissions of HC gas. If N_2 is used as seal gas, there will be no emissions of HC gas.
h. Influencing factors	ÅSelection of secondary seal gas. ÅDisposal of used seal gas.
i. Possibilities for sampling	Gas composition analysis (fuel gas).
j. Technology status/age affecting the emissions	Selection of seal design is important. Seal wear over time affects the leak rate[6]. These conditions can be totally overridden by how the used seal gas is disposed of.
k. Can direct emissions be eliminated	Yes, depends on the type of seal gas. If N_2 is used as the secondary seal gas the discharge contains no HC emissions (leakage of the primary seal gas across the seal is described in the section about primary seal gas).

6.3.4.3 Emissions from seals on reciprocating compressors

5 of the surveyed facilities had reciprocating compressors. A few facilities used reciprocating compressors in the entire gas compression train.

Gas seal on the reciprocating compressors are packing boxes on the piston rods. Gas leaking past the packing boxes are collected in one or more separator chambers in series. Information from the suppliers indicates that approximately 1% of the gas from the first chamber is led to the second chamber. Some gas may also leak further from the separator chambers to the crankshaft housing (should normally not occur). Gas leaking into the crankshaft housing is separated from the oil and led away.

During construction of the facilities, it is determined how the gas from each chamber will be disposed (recycling, flaring or direct emissions). The practice registered during the survey is that the gas from the first chamber is led to flare or recovery, while the much lower emission rates from the second chamber is led to atmospheric vent.

On one of the mapped facilities with reciprocating compressor the seal oil is depressurized according to the same principles as seal oil in centrifugal compressors.

[6] Impure seal gas can cause wearing of the seals.

Waste gas from separator chamber:

Table 15 Waste gas from the separator chamber in the reciprocating compressors

a. Potential waste gas quantity	Medium to **large**.
b. Emission type	Continuously.
c. Cause/justification	Waste gas is being discharged.
d. Disposal options	Recirculation to the process and recycling of the gas, flaring or emissions through atmospheric vent.
e. Selected options	To flare from the first chamber. To atmospheric vent from second chamber.
f. Quantification until now	NOROGs standard factors for seal oil is partly used.
g. Quantification options	Primarily supplier data (if available). Other methods are not considered.
h. Influencing factors	Number of compressors, capacity and supply pressure. Wearing of the piston rings and pack boxes. Allocation of emissions.
i. Possibilities for sampling	Not studied.
j. Technology status/age affecting the emissions	Wearing of the piston rings and pack boxes can affect the leak rate over time.
k. Can direct emissions be eliminated	Yes, by recycling and recovery. Controlled by the disposal of the waste. Can be expensive to implement on existing installations.

Waste gas from crankshaft house:

Table 16 Waste gas from crankshaft house ï key information

a. Potential waste gas quantity	Small.
b. Emission type	Continuous or discontinuous, depending on the operating situation.
c. Cause/justification	It is difficult to get the seals completely tight.
d. Disposal options	Recirculation to the process and recycling of the gas, flaring or emissions through atmospheric vent.
e. Selected options	To atmospheric vent.
f. Quantification until now	NOROGs standard factors for seal oil is partly used.
g. Quantification options	Primarily supplier data (if available). Other methods are not considered.
h. Influencing factors	Number of compressors, capacity and supply pressure Wearing of the piston rings and pack boxes. Allocation of emissions.
i. Possibilities for sampling	Not studied.
j. Technology status/age affecting the emissions	Wearing of the piston rings and pack boxes can affect the leak rate over time.
k. Can direct emissions be eliminated	Yes. Controlled by the disposal of the waste. Can be expensive to implement on existing installations.

6.3.4.4 Waste gas from screw compressors

The survey showed that there are screw compressors on 3 of the installations on the Norwegian shelf. These are used for compression of HC gas from low pressure sources (closed flare and blanket gas from crude oil tankers (VRU-compressors)). There are several types of screw compressors. On one of the facilities, an oil-filled screw compressor is used. The oil droplets following the gas is separated out in a separator. The compressor seals are flushed with N_2. Used oil goes into a drain pot with venting to air in a safe area.

There are two seals on the compressor shaft, an inner wet seal and an outer dry seal. At the inner wet seal the lubricating oil will leak to the drainage pot with a low rate (ml/h) together with the nitrogen used to flush the compressor seals. The nitrogen purge acts as a buffer to prevent the lubricating oil from affecting the dry seal.

Leakage and potential emissions from screw compressors, for the kind of service and capacity as such compressors are used for on the Norwegian shelf, is very small (approximately kg/year).

Table 17 Waste gas from screw compressors ï key information

a. Potential waste gas quantity	Small.
b. Emission type	Continuously.
c. Cause/justification	It is difficult to get the seals completely tight.
d. Disposal options	Recirculation to the process and recycling of the gas, flaring or emissions through atmospheric vent.
e. Selected options	Emissions through atmospheric vent because of small quantities of emissions.
f. Quantification until now	NOROGs standard factors for seal oil is partly used.
g. Quantification options	Primarily supplier data (if available). Other methods are not considered.
h. Influencing factors	Number of compressors, capacity and supply pressure. Seal type and design. Allocation of emissions.
i. Possibilities for sampling	Not studied. Data from supplier is available for the operators.
j. Technology status/age affecting the emissions	Wearing of the seals. Technological developments and a trend towards dry seals.
k. Can direct emissions be eliminated	Yes. Controlled by the disposal of the waste. Can be expensive to implement on existing installations and the potential emissions are small.

6.3.4.5 *Waste gas from water ring compressors*

The principle of a water ring compressor is shown in Figure 4.

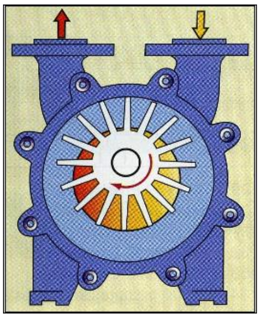


Figure 4 Schematic diagram of water ring compressor (source: Internet)

This is a compressor type utilising a liquid ring (shown in blue in the figure) as the compression medium. HC gas (shown in yellow to red in the figure) enters the compressor through the suction nozzle. Centrifugal forces separate liquid and gas. The gas moves between the liquid and the vanes of the rotor and is compressed because the available space is reduced due to the rotor eccentric location. Water Ring Compressors are mostly used as vacuum pumps and for low pressure compression in general.

There are water ring compressors at 3 facilities on the Norwegian shelf. The compressors are used for compression of the purge gas, used for recycling from cold flare, and HC purge gas at crude oil tankers.

Some of the gas is dissolved in the water in the compressor. The water goes to the facility's drainage system. The dissolved gas that evaporates there is emitted from the ventilation of the drainage system to the low pressure flare or atmospheric vent. The waste amount from the water ring compressors is extremely small. This is caused by low flow rates and low pressure for the compressed gas. Almost no data was available regarding emission quantities.

Table 18 Waste gas from screw compressors – key information

a. Potential waste gas quantity	Small.
b. Emission type	Continuously.
c. Cause/justification	Gas is dissolved in the water phase and evaporates when the water is sent to the drainage system.
d. Disposal options	Flaring or emissions through atmospheric vent, together with gas from other sources that go to drainage. Larger amounts of N_2 and other inert gases in the gas phase of the drainage system can make flaring impossible.
e. Selected options	Emissions through LP flare and possibly also to atmospheric vent.
f. Quantification until now	Unclear, but probably not taken into account.
g. Quantification options	Primarily supplier data. Other methods are not considered.
h. Influencing factors	Number of compressors, capacity and supply pressure. Allocation of emissions.
i. Possibilities for sampling	Not evaluated since the source is only present on a few facilities and because the emissions are small.
j. Technology status/age affecting the emissions	Wearing of the seals. Technological developments and the trend towards dry seals.
k. Can direct emissions be eliminated	Yes. Controlled by the disposal of the waste. Can be expensive to implement on existing installations and the potential emissions are small.

6.3.5 Pressure relief of process equipment

This is one of the sources included in the current method for quantifying direct methane and NMVOC emissions. The emissions are calculated by standard values as a function of the processed amount of gas.

In this project depressurization of processing plants, in all of the 15 facilities that contributed to the primary survey, has been mapped.

The survey showed that individual components / processing equipment, containing hydrocarbons as liquid or gas, is depressurized and purged by inspection or replacement of equipment. Such operations occur preferably in connection with planned shutdowns, but may also occur at other times. The entire hydrocarbon-containing process plant, or parts of it, is normally depressurized and purged during shutdown. Planned auditing shutdowns usually last for 3 to 4 weeks. The rate varies somewhat, every three years is common, but it can also be four years between each shutdown and in rarer cases, two years.

Gasfreeing of individual components in the process is done using the the following procedure for all 15 facilities in the primary survey:

- The component / equipment is isolated from the rest of the plant which is operated as usual
- The component / equipment is depressurized against the burning flare down to atmospheric pressure
- Components / equipment containing oil is washed internally with water
- The component is purged with nitrogen or other inert gas. This can be done either by purging or more commonly by increasing the pressure in the component with inert gas to 3-5 barg and then depressurizing against a burning flare. Because the total volume of the component is small (up to a few m3, it will normally be rotating equipment or valves that this procedure is used for), the inert gas content will not affect the combustibility of the flare. This operation may take place several times to ensure that the component is free of HC-gases.

HC-gases are thereby not released to atmosphere by depressurization and purging of gas of individual components during normal operation.

During shutdown, the production is stopped and the processing plant is closed-off and isolated from the wells. All or large parts of the hydrocarbon containing processing plant is then depressurized and freed for gas. The procedure is the same as for individual components with one essential difference. If flushing with inert gas, depressurization after the plant is filled with the inert gas will result in the flare being extinguished for a period, due to the reduced content of combustible hydrocarbon gases. This means that the residual content of methane and NMVOCs in the facility will be released unburned into the atmosphere through the flare. It is unclear how long the flare will burn after gas freeing has started. Ignition concentration of methane is 4.4% and lower for components of NMVOCs. The flare is expected to extinguish before coming down to these concentrations because of combustion conditions: flare gas is diluted before it reaches the combustion zone, the weather will have a negative impact on the combustion, etc.

Based on this, it is reasonable to assume that all hydrocarbon gas remaining in the facility before gas freeing started will end up in the atmosphere as unburned methane and NMVOC. As the pressure will be approximately atmospheric pressure when gas freeing starts, the gas volume measured as Sm^3 approximates the volume of gas free plant in m^3. The processing plant at production facilities on the Norwegian shelf range in size from under 100 m3 to a few 1000 m3. With a density of the gas of just under 0.001 tonnes per. Sm^3, the total methane and NMVOC emissions is in the order of around 1 tonne per facility per. shutdown.

There is currently no technology available that can eliminate these emissions.

Emissions during shutdowns:

Table 19 Emissions during shutdowns ï key information

a. Potential waste gas quantity	Small to medium.
b. Emission type	Discontinuously.
c. Cause/justification	Need for inspection and maintenance of the facilities.
d. Disposal options	Only emissions through unignited flare (after the flare extinguish due to low concentration of hydrocarbon gases).
e. Selected options	Only emissions through unignited flare.
f. Quantification until now	NOROGs guideline.
g. Quantification options	Based on the volume of the process plant and the method described above.
h. Influencing factors	Volume of processing plant and the frequency of depressurization and gas freeing.
i. Possibilities for sampling	There are sampling points at several locations in the process which will technically make it possible to take samples for analysis of the gas in the plant before gasfreeing starts. There is some uncertainty as to how representative these tests are (may be necessary to take samples at several locations in the facility to get a representative composition of the gas). Small quantities of emissions indicate that the cost/benefit effect of getting accurate composition of emissions should be discussed. The small quantities of emissions suggest that using the fuel gas composition should be satisfactory.
j. Technology status/age affecting the emissions	As long as technology status and age do not affect the frequency of shutdowns, this has no effect on the emissions.
k. Can direct emissions be eliminated	No.

6.3.6 Emissions from/of purge and blanket gas

Purge and blanket gas is used to prevent air (oxygen) from penetrating into the tanks and pipes containing hydrocarbon gases. This avoids the occurrence of an explosive gas mixture.

The hydrocarbon gas (mostly fuel gas) and inert gas (mainly nitrogen, N_2) is used as purge and blanket gas.

N_2 is used primarily as follows:

a. As purge gas in the flare booms on facilities with enclosed flare (used downstream of quick opening valve). This application area does not emit HC emissions.
b. As purge gas in low pressure flare header and flare. May reduce the combustion capability of the flare gas during normal flaring conditions causing the flare to stop burning more easily.

c. As purge gas in common atmospheric vent. Is mixed with HC gas from other sources.
d. Purge and blanket gas in the drainage system pipes and tanks. Will "collect" some HC gas evaporating from the oil in these systems. Normally released into the atmospheric vent, but also to low pressure flare in some cases.
e. As blanket gas on atmospheric storage tanks containing hydrocarbon liquids. Will also here "collect" some HC gas.

N_2 blanket gas is therefore not a source of HC emissions in itself, but may be mixed with the HC-gas from other sources. The sources of point d. and e. above are mostly pipe systems and tanks in drainage systems, as well as various storage tanks and containers that emit HC gases to overhead blanket gas by evaporation. The sources of HC gas vary from facility to facility and emissions are small to negligible. Emissions will in many cases be difficult to calculate.

Inert gas (waste gas from dedicated facilities that burn oil stoichiometric):

- Blanket gas in storage tanks for crude oil on dedicated storage vessel that is placed permanently on the field (FSO). This will mix with the NMVOC and methane evaporating from the oil. The waste gas may contain a large amount of NMVOC and methane. Emissions are quantified using the same methods as for shuttle tankers. The same type of measures for mitigation is applied. See Section 6.3.21.3.
- Blanket gas on some oil tanks at the FPSOs. The inert gas will "collect" some HC gas evaporating from the storage tanks. These are not addressed in this project.

The fuel gas is primarily used as follows:

- As purge gas in the flare header on facilities that have closed flare. The gas is recovered by recycling to the process (often using a low pressure compressor). Emissions to the atmosphere is equal to 0 under normal operating conditions.
- As purge gas in open flare systems. The gas is burned in the flare when this is ignited. Direct emissions equal 0 during normal operating conditions.
- As blanket and purge gas for special hydrocarbon containing tanks at the process plant. This is an application that is only used on a few facilities. If the waste gas is led to the atmospheric vent, it means that all the supplied fuel gas to this source is emitted to air. Evaporation from the tank or tanks supplied blanket gas could add to the emissions. This additional amount is usually small compared to the amount of blanket gas. The survey showed that the amount of supplied blanket gas is not normally measured. It is supplied through a valve with a set aperture. From this, the amount is estimated with a relatively large uncertainty.
- As blanket gas in storage tanks for crude oil on the FPSO. The gas is recovered by recycling to the process during normal operation.

This means that:

- Direct emissions of methane and NMVOC from N_2 and inert blanket gas is gas that has evaporated from the hydrocarbon liquid in pipes and tanks and mixed with blanket/purge gas. It may also be HC-gas from other sources that are mixed into the blanket/purge gas and discharged together with this.
- Direct emissions of HC blanket and purge gas will only occur if the gas is released directly into the atmosphere. This will include both the blanket/purge gas amount, and the hydrocarbon gases that evaporate from liquids in pipes and tanks, and the HC gas that is supplied to the purge gas.

Therefore, only hydrocarbon blanket and purge gas represents a significant source of direct emission of methane and NMVOCs.

HC blanket gas for processing plants and containers

Table 20 HC blanket gas to processing plants and containers ï key information

a. Potential waste gas quantity	Medium.
b. Emission type	Normally continuously.
c. Cause/justification	Use of HC-gas as blanket gas.
d. Disposal options	Recycling to the oil- and gas process, flaring, emissions through atmospheric vent.
e. Selected options	Recycling to the oil- and gas process, flaring, emissions through atmospheric vent.
f. Quantification until now	Included as blanket gas in NOROGs guideline.
g. Quantification options	Measurement or calculation of the feed rate of fuel gas.
h. Influencing factors	Choice of blanket gas (Fuel gas or N_2).
i. Possibilities for sampling	Not necessary. Sampling and analysis of fuel gas takes place routinely.
j. Technology status/age affecting the emissions	Little or no importance.
k. Can direct emissions be eliminated	By recycling the blanket gas or burning it in the flare. Replacement of the fuel gas with N_2 is also an option. On one of the facilities that were surveyed during the primary review, N_2 was replaced with fuel gas because the N_2 gas was not clean and caused corrosion. This shows that a seemingly simple solution may not necessarily work in practice.

HC blanket gas for crude oil storage tanks

The survey showed that all 10 FPSOs (floating production vessels with crude inventory), and one SPAR platform, use/will use fuel gas as blanket gas. On all these facilities, the gas is returned to the gas processing plant and reused.

Table 21 HC blanket gas for crude oil storage tanks ï key information

a. Potential waste gas quantity	**Large.**
b. Emission type	No discharge during normal operation. Emissions may occur if the reinjection compressors (also called VOC compressors and VRU-compressors) are out of service for longer periods.
c. Cause/justification	NA.
d. Disposal options	Recycling to the oil- and gas process.
e. Selected options	Recycling to the oil- and gas process.
f. Quantification until now	NA.
g. Quantification options	NA.
h. Influencing factors	NA.
i. Possibilities for sampling	NA.
j. Technology status/age affecting the emissions	NA.
k. Can direct emissions be eliminated	Yes.

6.3.7 Flushing and maintenance of instruments and instrument manifolds

Instruments and instrument manifolds in process plants must be occasionally flushed to remove water retention. This normally takes place without causing emissions, but there may be cases where this is not possible. Instruments must also be maintained and sometimes changed between auditing shutdowns. Operators illuminated during the survey that the normal procedure is to isolate the instrument, and then depressurize it and gas free it with N_2 against flare. In some cases, however, connection to flare is not possible. In such cases, the instrument is depressurized and purged through a hose connection leading the emissions to a safe place. The operators stated that this was not a frequently occurring situation. One of the operators assumed they had a maximum of 100 such operations annually, of which a minority led to emissions to air.

Such emissions are not measured. To get an overview of the amount of emission, a calculation is made based on the following conservative assumptions:

ÅThe number of operations per. year involving emissions to air:	100
ÅVolume per. instrument:	1 litre (very conservative)
ÅEstimated average pressure:	30 barg
ÅEstimated weight of gas:	1 g/standard litre

This results in annual emissions of 3 Sm^3/year, equivalent to approximately 3 kg/year, in other words negligible amounts compared to many of the other sources.

Table 22 Flushing and maintenance of instruments and instrument manifolds - key information

a. Potential waste gas quantity	Small.
b. Emission type	Discontinuous.
c. Cause/justification	Some instruments are not connected to flare.
d. Disposal options	Flare or direct discharge to atmosphere.
e. Selected options	Flare or direct discharge to atmosphere.
f. Quantification until now	According to NOROGӳ guidelines.
g. Quantification options	Estimate of the number of operations per year that leads to direct emissions and the average volume and pressure per operation.
h. Influencing factors	Installation of connection points to the flare.
i. Possibilities for sampling	Not relevant.
j. Technology status/age affecting the emissions	It could be assumed that newer facilities have fewer instruments that is not connected to the flare or which can be connected to flare. This was not examined in the study due to the small size of the emissions.
k. Can direct emissions be eliminated	They can not be completely eliminated, but can be reduced through good design.

6.3.8 Flare that is not burning

Most facilities have two flares:
ÅHigh Pressure Flare
ÅLow pressure Flare

On some facilities, they also have an atmospheric flare. This may be in addition to, or as a substitute for, the low pressure flare

The high pressure flare is connected to equipment operating under high pressure, while the low pressure flare is connected to the equipment operated under low pressure. The reason there are two separate systems is to prevent depressurization of equipment under high pressure leading to setbacks for low pressure equipment. It is therefore, primarily, the pressure relief manifolds (also called flare headers) that are separated. In some cases, tanks and vessels operating at atmospheric pressure can not be connected to the low pressure flare header. This is because the pressure level in the low pressure flare header is not compatible with parts of the process that operate at atmospheric pressure, such as drainage systems. This is one of the reasons why waste gas from some low pressure sources can not be led to the flare, but must be discharged as direct emissions (cold vent).

In Norwegian Oil and Gas Association's guidelines for emissions, extinguished flare is one of the 13 potential emission sources. The survey in this project has shown that the reality is more complex, and the following combinations of sources and causes are found:

Å**Extinguished flare**. This applies to cases where the flare stops burning due to wind and weather conditions, often as a side effect when the flaring rate is low.

Å**Delayed ignition of flare**. Igniting the flare can be complicated. When the flare is being ignited, it takes some time from start-up of flare gas flow from the flare tip, until it is ignited. In some cases it may take a relatively long time, depending on the weather conditions and ignition system. The review showed that this is primarily a problem for facilities with closed flare. This is because the flare must be ignited more often on such facilities, and normally in connection with high flare rate.

Å**Not flammable flare gas**. When the flare gas has such a low concentration of hydrocarbon gases that it does not burn. In such cases, emissions of hydrocarbons in the flare gas is sent directly to the air through the flare.

Å**Inertgas flushed open flare**. Normally unignited flare that uses nitrogen as purge gas.

6.3.8.1 Extinguished flare

Emissions were quantified using a given emission factor for methane and NMVOC, based on the total amount of gas produced on the facility. The survey has shown that this method did not reflect the actual situation.

The survey also showed that extinguished flare rarely occurs at most installations. Some say they have never experienced an extinguished flare, others that it has not happened in years. At some facilities, it was stated that it occurs more often. Extinguished flare may happen as a result of unfavourable weather conditions, as a result of the low mass flow, or as a combination of both.

Most facilities have installed a camera that is directed constantly at the flare / flares. This is shown on a screen in the control room. In certain periods, it may be light conditions that make it difficult to see on the screen if the flare is burning. It was also stated, for some facilities, that it may be difficult to see if the low pressure flare burns because the flames are shielded by flames from the high pressure flare. In addition to that, the staff in the control room do not look at the screen all the time.

Automatic flame detectors that give feedback if the flare stops burning are not common. The survey showed that such events are not recorded. It is therefore not possible to calculate these emissions.

Table 23 Extinguished flare ï key information

a. Potential waste gas quantity	Unknown, but is assumed to be small.
b. Emission type	Individual occurances.
c. Cause/justification	Too low mass flow, at special weather conditions or a combination of these.
d. Disposal options	If the flare stops burning, the amount of gas flared will automatically flow into the atmosphere as methane and NMVOC. There will be no alternative disposal options.
e. Selected options	The gas is emitted unignited.
f. Quantification until now	According to NOROGös guidelines.
g. Quantification options	Registration of the time when the flare is not burning. Mass flow is measured continuously in a flare metre. This will require the introduction of a log where the time when the flare extinguishs, and when it ignites again, is logged manually.
h. Influencing factors	Flaring rate, method for rapid detection when the flare is extinguished and a safe method for fast ignition.
i. Possibilities for sampling	Not possible. The allocation method used for composition of the flare gas should be acceptable (CMR method).
j. Technology status/age affecting the emissions	There were no conditions found during the survey which indicated that technology status or age have an impact on emissions.
k. Can direct emissions be eliminated	No, only reduced.

6.3.8.2 Discharge in connection with delayed ignition of the flare

The survey showed that in many cases it takes some time to ignite the flare / flares after shutdown, for example, after a shutdown or when a flaring situation occurs on a flare that is normally closed (closed flare).

Different methods are used for flare ignition. This can be done by using a so-called "flame front generator", electronic ignition of a high voltage spark plug, ignition by using an ignition ball ("pellet) to be launched to the flare through a conductor or by using a" flare gun "(see how this is done at Statfjord C: https://www.youtube.com/watch?v=-nLVXRaiSds). All these systems have their weaknesses, and it may take time before the flare is ignited. This is especially the case for the ñflare-gunò, if the weather is poor. Today there are no historical records for how much gas is released due to delayed ignition, but from what emerged during the survey, the discharge volumes due to delayed ignition will probably be considerably larger than the extinguished flare.

Closed flares should reduce the emissions of greenhouse gases. However, for facilities with closed flare and many ignition instances, the benefit is reduced.

Table 24 Delayed ignition of the flare ï key information

a. Potential waste gas quantity	Unknown.
b. Emission type	Individual occurances.
c. Cause/justification	Need for ignition of the flare, for example in flaring situations in closed flare, during shutdowns and other flaring breaks.
d. Disposal options	If the flare does not ignite, there is no other disposal option for the gas than emissions.
e. Selected options	Emission (no other choice).
f. Quantification until now	Not covered by current method.
g. Quantification options	Registration of the elapsed time from when the flare opens to when it ignites. Mass flow is measured continuously in a flare metre. This will require the introduction of a log where flare opening and ignition time are logged manually.
h. Influencing factors	Flaring rate, rapid ignition and a reliable method for ignition.
i. Possibilities for sampling	Not possible. The allocation method used for composition of the flare gas should be acceptable (CMR method).
j. Technology status/age affecting the emissions	There were no conditions found during the survey which indicated that technology status or age have an impact on emissions.
k. Can direct emissions be eliminated	No, only reduced.

6.3.8.3 Non-flammable flare gas

One of the installations on the Norwegian continental shelf has a low pressure flare that works as a cold vent. This means that the flare was not lit under normal operating conditions. The reason for this is that the flare gas contains large amounts of non-combustible gas. The concentration of hydrocarbon gas is therefore too low to keep the flame lit under normal flaring conditions.

The facility had a closed high pressure flare with the flare tip located next to the low pressure flare. This means that the hydrocarbon components of the gas flowing out of the flare tip at low pressure flare ignite when the high pressure flare is ignited. This relationship causes major challenges in quantifying the emissions of methane and NMVOC and, at the present time, there are substantial uncertainties associated with emission quantities.

This emission source is unique and is not covered by NOROGs guidelines. A standard method has been established as the basis for tradeable carbon emissions. This survey gave indications that this method may have resulted in excessively high emissions of methane and NMVOCs, because the content of inert gases appears to have been under estimated.

This emission situation is only relevant for this one facility, and the development of a reliable method of calculating the emissions of methane and NMVOCs will be facility specific. The same will apply for methods and measures to reduce or eliminate emissions from this source.

Table 25 Non-combustible flare gas ï key information

a. Potential waste gas quantity	**Large.**
b. Emission type	Continuous in periods when the high pressure flare is not ignited.
c. Cause/justification	The concentration of hydrocarbon gases is too low to maintain the flame in the flare.
d. Disposal options	No alternative disposal options for the gas is found.
e. Selected options	Direct emissions by closed high pressure flare.
f. Quantification until now	Conservative method applied.
g. Quantification options	A thorough review of the contributing sources to the low pressure flare may form the basis for a more precise quantification.
h. Influencing factors	How long the high pressure flare is ignited. A more thorough review may show that the contribution from some of the sources that goes to the low pressure flare can be reduced. Supply of fuel gas to the low pressure flare will improve combustion characteristics, but will in return lead to higher CO_2 emissions.
i. Possibilities for sampling	There are two dominant sources that goes to the low pressure flare. The composition of these sources can be simulated, which can help reduce the need for sampling.
j. Technology status/age affecting the emissions	The age of the equipment has no effect on the emissions.
k. Can direct emissions be eliminated	Possibly, but a solution for this will require considerable effort from the operator.

6.3.8.4 Emissions from inert gas purged open flare

It is normal practice for open flares to flush the flare header and the flare with combustible gas. In addition to keeping the flare system free of air (explosive), the fuel gas purging ensures that the flare is always burning. This also means that there will be a continuous flame in the flare in a real flaring situation.

During the survey, it was registered that 4 facilities operate with an open flare with a nitrogen purge gas flare system. There are also several facilities in the development phase that are planned to have such a flare solution.

At one of the facilities in operation (which is a riser platform) depressurization situations occur occasionally, which leads to gas emissions through the flare for short periods. By depressurization of tubular elements and components at the facility, the gas is released directly without burning, i.e. all methane and NMVOCs are released directly into the atmosphere. The amount of gas is measured in the flare metre and reported to the authorities as methane and NMVOC emissions in the operator's annual emissions report. In flaring situations involving larger quantities of emissions (like depressurization of the transportation pipeline systems) the flare is ignited and HC gases are combusted and reported as CO_2 emissions. These discharges occur very rarely (many years between each time). During normal operation, there is no flaring or venting of gas.

In an emergency flaring situation safety valves, that protect equipment and pipe sections, open and gas flows out through the flare header. The principle is illustrated in Figure 5.

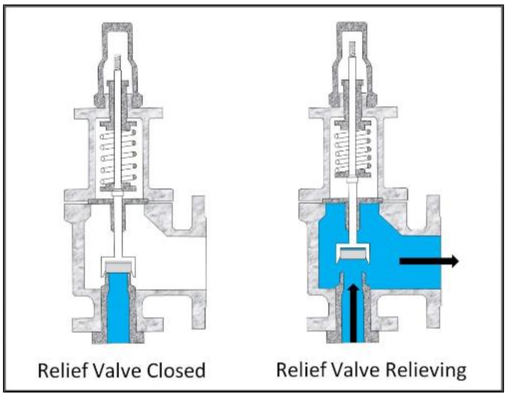


Figure 5 Safety valve, schematic diagram (source: myChemE ï Your Chemical Engineering Portal)

It may occur that such valves leak gas out to the flare header while the valve is in the closed position. In flare systems purged with fuel gas this is not a problem, because the gas is mixed with the purge gas and burned in flares or (for closed flares) recycled to the process. This also means that there is no strict control of such leaks, as it is with leaks that go directly to the atmosphere. Such leaks, in inert gas purged open flares, may be a source of direct emissions of methane and NMVOC. Because the gas quantities are small (if they are present) and because there runs a continuous stream of nitrogen through the pipes, they will normally not be registered by the flare gas metre. For small installations with few safety valves, this is not expected to be a big concern, but for facilities with large comprehensive processing plants and hundreds of safety valves, the situation may be different. The main problem is that very little is known about the extent and magnitude of such leaks, or how they can be detected.

Table 26 Emissions from inert gas purged open flare ï key information

a. Potential waste gas quantity	Small.
b. Emission type	Continuous if emissions occurs.
c. Cause/justification	Leakage through safety valves.
d. Disposal options	No alternative disposal options for the gas is found. Due nitrogen purge, burning in the flare will be no alternative.
e. Selected options	Direct emissions through flaring.
f. Quantification until now	Not covered by current method.
g. Quantification options	Flare gas meter.
h. Influencing factors	First and foremost, the quality of the safety valves.
i. Possibilities for sampling	It may be possible to take samples of the gas adjacent to the scrubber at the base of the flare boom.
j. Technology status/age affecting the emissions	The age of the equipment can definitely affect the leak rate and discharge rate due to wearing.
k. Can direct emissions be eliminated	Direct emissions in connection with depressurization of piping and components of the facility can be eliminated if the flare is ignited during such situations. If the quantity of gas to be depressurized is small, the time it takes to ignite the flare make this difficult. It is not possible to fully eliminate discharge in connection with leakage through the safety valves.

6.3.9 Leaks in process plants

Leaks of hydrocarbon gas from processing plants should not occur, but experience shows that it is very difficult to make a processing plant 100% leakproof.

Leaks of HC-gases represent a significant security risk on an offshore production facility. Leaks have a strong focus in both the authorities and operating companies because of the significant consequences arising if they lead to fire or explosions at the facility. As a result, all facilities have permanent gas detectors which initiate an alarm and shutdown of production if gas is detected. Norwegian Standard S001, referred to in the facilities Regulations manual, provides detailed requirements for location and alarm limits. Normally, so-called LLA (Low Level Alarm) at 20% LEL (lower explosion limit is 4.4% for methane) and HLA (High Level Alarm) at 30% LEL. There are some deviations from this, depending on location. The standard also provides requirements for the interruption of production as a result of alarms.

In addition to the fixed gas detectors, the operators make regular inspection tours at the facilities, with some operators doing this daily. During these inspections they also look for leaks. If a leak is identified, this is checked with a sniffer. All detected leaks are put on a "sweat list" and will be subject to evaluation on the basis of safety concerns. Depending on the evaluation, a leak may lead to shutdown of parts or the entire process. If the leakage measurement is above 0.1 kg/second 10 cm downstream (wind direction) from the leakage point, this will be characterized as a large leak.

Minor leaks are not quantified.

It is therefore natural to divide the gas leaks into two groups:
a. Larger leaks
b. Minor leaks and fugitive emissions

6.3.9.1 Larger leaks

These are leaks where the emission rate is measured to be at least 0.1 kg/sec using handheld or stationary detectors. These leaks will normally result in immediate shutdown of the process plant, or parts thereof, and are subject to investigation. As part of the investigation work, the discharge amount is calculated (often from volumes and duration of the shutdown). The emissions are reported in the annual emissions report to the Environment Directorate as "Unintentional emissions", according to the reports in section 8.

During the last couple of years there has been 6 to 12 discharge events (greater than 0.1 kg/sec) annually from production facilities on the Norwegian shelf. There has been a tendency in recent years towards slightly declining emissions. The amount of emissions varies from year to year, but in recent years it has been between 2 and 100 tons/year HC gas in total for the Norwegian shelf.

From surveys and interviews with the project leader for hydrocarbon leaks in the Norwegian Oil and Gas Association, it became clear that human error was the cause of many of the larger leaks (Ref: 8).

Table 27 Larger leaks ï key information

a. Potential waste gas quantity	Medium.
b. Emission type	Random.
c. Cause/justification	Partly human error, partly technical reasons.
d. Disposal options	Only direct emissions.
e. Selected options	No alternative disposal option.
f. Quantification until now	Quantified as a part of the investigation.
g. Quantification options	Like today.
h. Influencing factors	Operator training, maybe also improved maintenance.
i. Possibilities for sampling	Not practically possible.
j. Technology status/age affecting the emissions	Perhaps to a smaller degree.
k. Can direct emissions be eliminated	No, it can only be reduced.

6.3.9.2 Minor leaks

These consist of detected leaks that are put on the operators ñsweat listsò plus minor leaks that are not detected and which are not on this list. During the survey it emerged that the individual facilities had from a few up, to 10-15, leaks on their ñsweat listò annually.

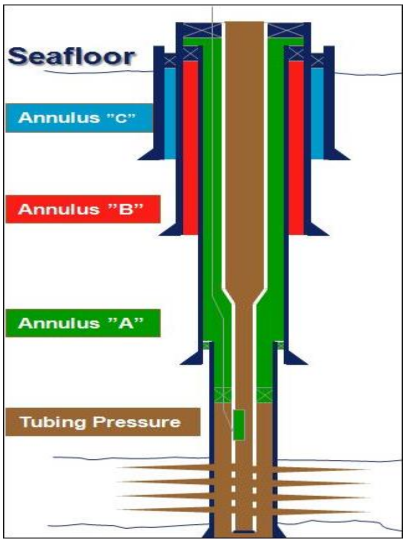
It is also known that smaller molecules like methane can diffuse through elastomer, such as packings, packing boxes, hoses, etc. The contribution from such fugitive emissions is not known.

It was apparent from the survey that control valves and screwed connections (grease nipples, etc.) were components that were often the cause of leaks that ended up on "sweat list."

Table 28 Minor leaks ï key information

a. Potential waste gas quantity	Unknown.
b. Emission type	Random.
c. Cause/justification	Technical reasons, human errors.
d. Disposal options	Only direct emissions..
e. Selected options	No alternative disposal option.
f. Quantification until now	According to NOROGõs guidelines. Emission factor as a function of the processed amount of gas.
g. Quantification options	Looking at other possibilities. No clear candidate.
h. Influencing factors	More thorough inspections using modern detectors may lead to additional leaks to be detected early so that the duration of the leaks can be reduced.
i. Possibilities for sampling	Not practically possible.
j. Technology status/age affecting the emissions	Perhaps in less degree.
k. Can direct emissions be eliminated	No, it can only be reduced.

6.3.10 Pressure relief of annulus in production risers



Gas can leak into the annulus (the space) between production riser and casing in exploration and production wells. In order to prevent pressure build-up, the well-head is provided with a pressure relief valve. The mapping showed that the released gas is recycled, sent to the flare for burning or released directly to the air. It emerged from the survey that the released gas quantity is not measured. According to the operators. pressure build up happens slowly over time, and emission quantities are small. Expressions like "pressure must be released once in a while" was used by several. No information was found during the survey indicating that this is a significant source of emissions. It is reasonable to assume, therefore, that these leaks are small, but documentation for this has not been available.

Figure 6 Annulus in production risers (source: Emerson Process management)

Sources of such gas leakage can be leakage through cementing or from the well, leaks in the casing due to corrosion, etc. Leakage quantities into the annulus may therefore differ from facility to facility and from well to well.

Table 29 Pressure relief of annulus in production risers ï key information

a. Potential waste gas quantity	Small.
b. Emission type	Random and non-continuous.
c. Cause/justification	Uncontrolled minor leakage into the annulus.
d. Disposal options	Direct emissions to atmosphere or flaring.
e. Selected options	Both direct emissions and flaring.
f. Quantification until now	According to NOROGõs guidelines. Emission factor as a function of the processed amount of gas.
g. Quantification options	Can be roughly calculated from the flowrate and valve opening.
h. Influencing factors	Better quality in the completion process.
i. Possibilities for sampling	Sampling downstream of the bleed valve if possible.
j. Technology status/age affecting the emissions	Maybe in a small degree, for example leaks caused by corrosion of the casing.
k. Can direct emissions be eliminated	Yes, by arranging bleed to flare.

6.3.11 Discharges from drilling

Emissions of methane and NMVOC from drilling can come from two sources:
ÅEvaporation of oil-based mud
ÅGas from the hydrocarbon-containing formation being drilled through.

Oil based drilling fluids are often used in the drilling of the lower sections of the well. This is oil with low content of methane and other volatile compounds. Accordingly, there is little gas that can be evaporated off.

Used drilling fluid and cuttings are returned to the platform from the well, the drilling fluid is recovered and the cuttings are separated from the drilling fluid in the cuttings sieves. Some gas evaporates in the cuttings sieves. This gas is not normally collected, but is released directly into the air. The drilling fluid then goes to the mud degassing tank (mud separator). The gas content is measured (trended) during drilling as part of the security control. If the amount of gas increases, it is an indication that the drilling fluid is underbalanced and gas is entering the well from the formation being drilled. This is compensated for by increasing the density of the drilling fluid. Normally, the gas content will be stable. The gas from the flash tank is sent to flare on some facilities, while on other facilities it is sent directly to the atmosphere via a vent pipe, which often has its emission point at the top of the drill rig.

As there are two waste sources, and only one is measured, it is difficult to get a good overview of the waste gas flow. To get an idea of the magnitude, a theoretical estimate calculation was conducted, based on some assumptions (conservative):

- No inflow of gas to the well (due to overpressure in the drilling fluid). This limits the amount of gas to the volume of the borehole in hydrocarbon bearing formations.
- Diameter of the well 8½ "(0.216 m)
- Washout factor: 30%
- Reservoir pressure: 300 barg (about 3000 metres)
- Pore volume: 30% (gas fills the pore volume)

This gives a total volume of gas (methane plus NMVOC) of about 4.3 kg/metre well through the hydrocarbon bearing formations. If a well is drilled 500 metres through a hydrocarbon-bearing formation (assuming a horizontal well), emissions will be approximately 3.2 tons. Compared to other sources, this is a small contributor.

Emissions from cuttings sieves

Table 30 Emissions from cuttings sieves ï key information

a. Potential waste gas quantity	Small.
b. Emission type	Only during drilling and primarily by penetration of hydrocarbon bearing layers.
c. Cause/justification	Gas absorbed in the drilling fluid downhole.
d. Disposal options	Direct emissions to atmosphere.
e. Selected options	Only direct emissions.
f. Quantification until now	Included in NOROGõs guidelines (included in total factor for drilling).
g. Quantification options	Difficult. Emissions per well will be less than theoretical total emissions.
h. Influencing factors	Length of well in HC-bearing layers, porosity, downhole pressure and washout factor.
i. Possibilities for sampling	No possibilities found.
j. Technology status/age affecting the emissions	Age has no effect.
k. Can direct emissions be eliminated	No.

Emissions from the degassing tank for drilling fluid (mud separator)

Table 31 Emissions from the degassing tank for drilling fluid ï key information

a. Potential waste gas quantity	Small.
b. Emission type	Only during drilling and primarily by penetration of hydrocarbon bearing layers.
c. Cause/justification	Gas absorbed in the drilling fluid downhole.
d. Disposal options	Direct emissions to atmosphere. Burning in flare and recovery is technically possible on facilities that have production. On mobile drilling rigs these opportunities are not available.
e. Selected options	Both direct emissions (and burning in flare at some production facilities).
f. Quantification until now	Included in NOROGõs guidelines (included in total factor for drilling).
g. Quantification options	Difficult. Emissions per well will be less than theoretical total emissions.
h. Influencing factors	Length of well in HC-bearing layers, porosity, down hole pressure and washout factor.
i. Possibilities for sampling	It should be possible to take samples of the waste gas from the degassing tank.
j. Technology status/age affecting the emissions	Age has no effect.
k. Can direct emissions be eliminated	Only possible on units with a production plant. On drilling rigs it is not possible to eliminate the emissions.

6.3.12 Starting gas for gas turbines

Starting gas for gas turbines is one of the 13 emission sources on NOROGs check list of sources contributing to the direct methane and NMVOC emissions. During the survey, no gas turbines were found to use high pressure HC gas to rotate the turbines during start-up. Other methods were used at the mapped facilities. This alternates between pneumatic, hydraulic and electric start.

In connection with the shutdown of the gas turbines, a closed pressurized gas flow (between two block valves) must bleed off. This happens for many turbines against the flare, while there are some that bleed off the pressure from atmospheric vent. The volume is a few litres or tens of standard litres per occurance. This corresponds to about the same number of grams in mass units. Accordingly, this is a negligible source that is not followed up further in the project.

6.3.13 Emissions from MEG regenerering

MEG (Mono Ethylene Glycol) is an absorption liquid which is partly used for drying gas in the same way as TEG (see Sec. 6.3.1). This takes place on a small number of facilities on the Norwegian shelf. The regeneration process here is similar to the regeneration of TEG.

MEG is used mainly to prevent hydrate formation in multiphase pipelines. MEG is fully miscible with water and prevents the formation of hydrates which can plug the pipeline. Typical applications include in the flow pipe for the well stream from the satellites to the treatment facility. In some instances it is sufficient to add MEG only if the transport is shut down with the multiphase mixture left in the tube. At other facilities, a continuous supply of MEG during operation is required.

On some facilities water-rich MEG is sent to land for regeneration, while other facilities regenerate the MEG on the facility. The process may vary slightly, but generally it follows these principles:
a. The water/MEG mixture is separated from the oil/gas in a one or two-stage oil/gas/water separator.

- The water/MEG mixture, which may be about 50/50 of each, plus dissolved gas is sent to a flash tank, where the dissolved gas is separated out.
- Separated gas is recycled, sent to the flare or to discharge through atmospheric vent.
- Water and MEG goes to storage tanks for wet (rich) MEG and further on to the regenerator.

b. In the regenerator, which operates under vacuum and high temperature, all the liquid is boiled off.

- Solid particles, which do not boil off, are separated.
- The waste gas, consisting of MEG + H_2O + residual gas, goes to a distillation column where the gas is cooled by liquid flowing countercurrently, and the MEG solution and water are separated. The MEG phase goes to storage tanks for dry MEG, while the water is measured and discharged to sea.
- The gas that is withdrawn from the top of the distillation column via vacuum pumps, is sent to the atmospheric vent, flare or recovery. The amounts of HC-gas can be simulated, but the results are uncertain.

Few facilities on the Norwegian shelf have regeneration of MEG.

From MEG degassing tank

Table 32 Gas from MEG degassings tank ï key information

a. Potential waste gas quantity	Medium.
b. Emission type	Continuously.
c. Cause/justification	Some HC gas is dissolved in the water/MEG phase under the prevailing pressure and temperature conditions.
d. Disposal options	Direct emissions to the atmosphere, flaring or recycling.
e. Selected options	Both recycling and flaring.
f. Quantification until now	Not included in NOROGs guidelines.
g. Quantification options	Can be simulated, but not very relevant if the gas is not emitted. Alternatively, measurement, simulation, analysis of HC gases in MEG upstream and downstream of the degassing tank.
h. Influencing factors	Amount of water in the pipe and quantity of MEG used.
i. Possibilities for sampling	It should be possible to take samples of flue gas from the degassing tank.
j. Technology status/age affecting the emissions	Age has no effect.
k. Can direct emissions be eliminated	Yes, by routing gas to flare or recovery.

From MEG regenerator

Table 33 Waste gas from MEG regenerator ï key information

a. Potential waste gas quantity	Medium.
b. Emission type	Continuously.
c. Cause/justification	Some HC gas is dissolved in the water/MEG phase under the prevailing pressure and temperature conditions.
d. Disposal options	Direct emissions to the atmosphere, flaring or recycling.
e. Selected options	Emissions to atmosphere.
f. Quantification until now	Not included in NOROGs guidelines.
g. Quantification options	Measurement, simulation, analysis of HC gases in MEG downstream of the degassing tank (assuming negligible amount of HC gas in MEG after regeneration). Can also be simulated, but the quality of the simulation is uncertain.
h. Influencing factors	Amount of water in the pipe and quantity of MEG used.
i. Possibilities for sampling	If a sampling point is not already installed, the installation of such a sample point could depend on the access on the individual installation.
j. Technology status/age affecting the emissions	Age is believed to have little impact.
k. Can direct emissions be eliminated	Yes, by routing gas to flare or recovery.

6.3.14 Regeneration of Amine

On two of the installations on the Norwegian continental shelf the produced gas contains such a large amount of CO_2 and H_2S that the contents of these components must be reduced to meet the buyers required specifications of the gas and to avoid corrosion damage to processing equipment. Both facilities on the Norwegian shelf that have this problem utilise an alkyl amine solution to extract CO_2 and H_2S from the natural gas. There are several other processes that may be used for the same task. Here only amine is described.

- The natural gas is passed through a contactor countercurrently to the amine solution, which absorbs H_2S and CO_2. In addition to H_2S and CO_2, some methane and NMVOCs from the gas are absorbed into the amine solution. Purified gas is sent to the gas export system, while the rich amine solution is regenerated.
- Rich amine is sent to one (or more) amine degassing tanks operating at a few bars overpressure. Here, most of the methane and NMVOC content flash off, as a result of pressure reduction. Flash gas is sent to the flare, recycled to the process or discharged into the atmosphere during normal operation.
- The amine solution is sent further to an amine regenerator. Here H_2S and CO_2 and residual HC gas is boiled off. This gas can be sent to vent or reinjected (deposited) in an appropriate secure underground landfill. Both solutions are used on the Norwegian shelf.
- The waste gas from the regenerator will not be recycled because it will lead to an accumulation of CO_2 and/or H_2S in the process. It is usually unsuitable as a flare gas because the content of CO_2 can be so high that the gas is not flammable.

From amine degassing tank

Table 34 Gas from amine degassing tank ï key information

a. Potential waste gas quantity	Unresolved, but apparently large.
b. Emission type	Continuously.
c. Cause/justification	Some HC-gas is dissolved in the amine solution together with CO_2 and H_2S.
d. Disposal options	Direct emissions to the atmosphere, flaring or recycling.
e. Selected options	Recycling to the process.
f. Quantification until now	Not included in NOROGs guidelines.
g. Quantification options	Can be simulated, but not relevant since the gas is not emitted.
h. Influencing factors	Amount of CO_2 and H_2S in the gas and recycle rate of amine.
i. Possibilities for sampling	Not relevant on Norwegian facilities since there is no emissions.
j. Technology status/age affecting the emissions	Age has no effect.
k. Can direct emissions be eliminated	Yes, by routing gas to flare or recovery.

From amine regenerator

Table 35 Waste gas from amine regenerator ï key information

a. Potential waste gas quantity	**Large.**
b. Emission type	Continuously.
c. Cause/justification	Some HC-gas is dissolved in the amine solution together with CO_2 and H_2S.
d. Disposal options	Direct emissions to atmosphere or underground disposal. Flaring or recycling is no solution to this challenge.
e. Selected options	Emissions to the atmosphere and underground disposal.
f. Quantification until now	Not included in NOROGs guidelines.
g. Quantification options	Can be simulated, but the quality of such a simulation is uncertain.
h. Influencing factors	Amount of CO_2 and H_2S in the gas and recycle rate for amine. Carry-under of gas with amine from contactor can also affect the amount of waste gas.
i. Possibilities for sampling	If a sampling point is not already installed, the installation of such a sample point could depend on the access on the individual installation.
j. Technology status/age affecting the emissions	Age is believed to have little impact.
k. Can direct emissions be eliminated	Difficult task since content of CO_2 (and H_2S) excludes flaring (burning) of the entire waste gas. Separation of HC-gas from the waste gas will require very large, extensive and costly construction. Underground reinjection is being done at one facility.

6.3.15 Stripping gas for injection water

Injecting sea water for reservoir pressure maintenance requires that the water is oxygen-free to prevent corrosion in pipes and equipment in the injection well. Several methods are used to achieve this, both the use of chemicals, and stripping of oxygen using a stripping gas. Both nitrogen and natural gas are possible stripping gases.

As a part of the survey, it was investigated whether hydrocarbon stripping gas is used on some of the offshore facilities. None of the facilities that were covered by the primary survey used HC gas as stripping gas. This was not followed up in the secondary survey.

6.3.16 Emissions from gas analysers and test stations

All facilities have some fixed gas analysers. Gas passing through the analysers for analysis is in most cases released to air. The analysis is not continuous but over short time intervals. The gas volumes that go to analysis are small, and for most analysers these are measured in ml/min. At some installations, the gas to be analysed is taken from a small side stream, which in some cases is also released to air. In some instances there is a continuous side stream. The amount of gas in the side stream is far higher than the one being analysed (up to 1000 times higher than the amount being analysed). In these cases, emissions can amount to a few tons/year.

Some gas samples are also taken and analysed, either in the facility's laboratory or in a laboratory on land. In both cases the waste gas is led to the air. This would amount to only a few litres of pressurized gas per sample bottle. The frequency of sampling may vary, but in many cases it will be approximately two parallel samples a month plus, some extraordinary specimens. The emission volumes will be small regardless.

For all installations that were included in the primary survey, with the exception of 3, a detailed overview of analysis and samples and associated emissions were obtained from the operating companies. For 8 of these, the annual emissions were calculated to be between 1 and 20 kg. For 4 of the facilities, the emissions were calculated to be significantly higher (up to 1000 times as high). This was on facilities where the analysis was taken from the side stream and discharged continuously into the atmosphere.

Following the outcome of the primary survey, no further questions were asked regarding emissions from sampling and analysis in the secondary survey.

6.3.17 Emissions from turret on FPSOôs

All production ships are moored to the seabed via a "turret". This is a rotary disc which is located midships in the vessel. The rotary disc is stationary relative to the seabed, while the ship may rotate around the rotation disc. This is shown schematically in Figure 7.

For this to work, all piping between the seabed and the vessel must be connected to the ship above the rotary disc. This can be done in two ways, either by means of hose connections or using swivels.

Figure 7 Alvheim FPSO. Sketch of the turret configuration (Source: Oljefakta.no)

In the beginning of the study, the turret on FPSO's was considered to be a potential source of direct emissions of HC gases. A total of 10 FPSOs were included in the study, of which 3 are in the planning/construction phase. For one of the FPSOs currently in operation, and which is provided with swivels, the gas leak was collected and sent to flare. For the other FPSOs, the turret was inspected for leakage as part of the inspection for the processing plants. There were localized gas leaks here. Gas leaks in the turret are therefore treated in the same way as gas leaks otherwise at the facilities.

6.3.18 Emissions from pig launchers

Pig launchers were considered to be a potential source of HC emissions. A pig receiver is a transmission chamber or a receiving chamber for pigs. Pigs are tools/instruments sent through pipelines for curettage of deposits on the pipe wall, for pressing out water retention, to identify weakening of the wall thickness, etc. An example is outlined in Figure 8.

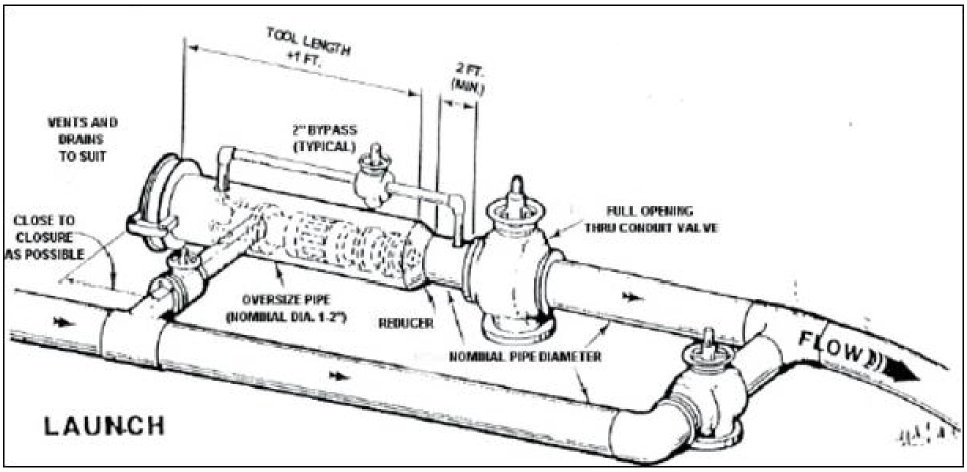


Figure 8 Sketch of a pig launcher (Source: Sweco Fab. Inc.)

When a pig is inserted into, or taken out of, the launcher, the launcher must be depressurized and free of HC gas. For most facilities that participated in the primary survey and which used pig launchers, the following procedures were used:

- The launcher is flashed against flare. For facilities with enclosed flare, this meant that the gas was recycled to the process.
- The launcher was then freed for gas using N_2 towards open, ignited flare.

This procedure means that there are no methane and NMVOC emissions during operation of the pig launchers. Two of the facilities in the primary survey were freed for gas with emissions to the atmosphere. Emissions from these were estimated to be 10.8 kg (methane + NMVOC) per year, based on the volume of the pig launcher.

It is believed that similar procedures also apply to other facilities that use pig launchers on the Norwegian shelf. Because emissions are very small, this was not enquired about in the secondary survey.

6.3.19 Emissions by drawing corrosion coupons

A corrosion coupon is a simple and effective tool that monitors corrosion rates in pipes and equipment. They also show the type of corrosion occurring. Corrosion coupons consists of metal pieces of varying shape, size and materials. They are installed inside the equipment and exposed to the same corrosion as the equipment to be monitored.

Direct emissions of HC gas may occur when corrosion coupons are drawn for inspection. The primary survey showed that drawing of corrosion coupons takes place to a very small degree, on some facilities less than a few operations per year. Depending on the method and tools used the emissions vary per operation from zero to maybe a few litres of gas under pressure. At many of the facilities, modern tools make it possible to draw coupons, while the equipment or piping system is operating, and without causing emissions to air.

The observations from the survey indicated that emissions of HC gas to air for all the installations on the Norwegian shelf hardly exceeds a few kilograms per. year. Based on this a further mapping of this source was not performed in the secondary survey.

6.3.20 Emissions from flexible risers

In connection with floating production facilities and subsea completed wells, a variety of flexible risers are installed on the Norwegian continental shelf since the 1990s. Flexible risers consist of alternating layers of steel and elastomers, as shown in Figure 9.

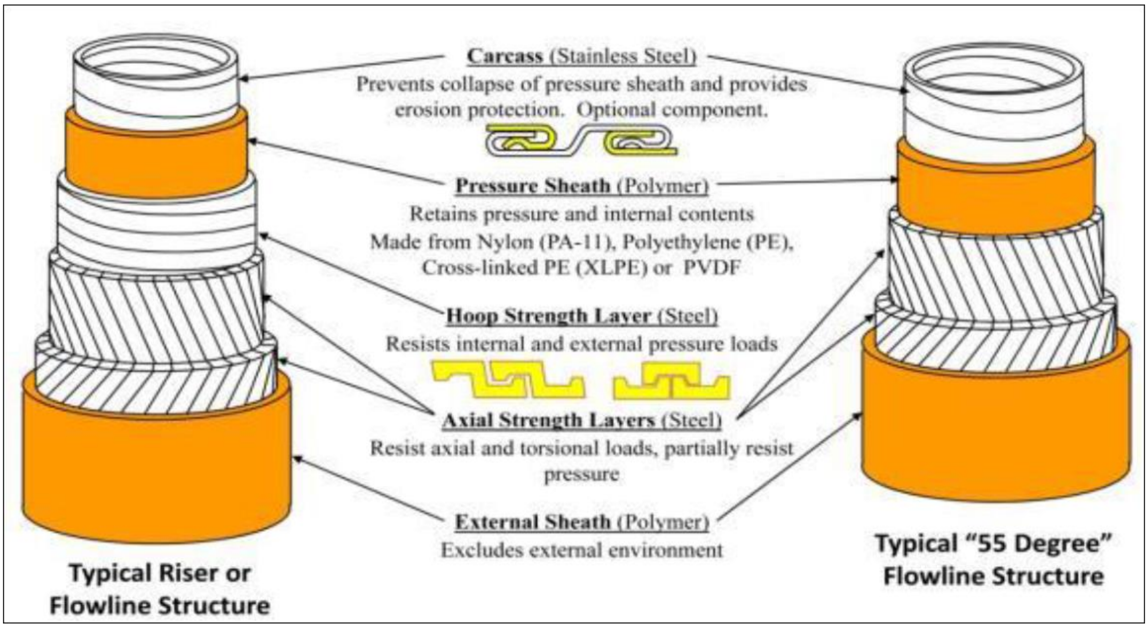


Figure 9 Example of the structure of flexible risers - principle drawing (Source: 4Subsea AS (from the internet)).

Steel layers provide strength and are not gas tight. Polymer layers shall ensure that the gas and oil is not leaking into the sea.

A certain degree of gas leakage occurs anyway, through the polymer layers, by diffusion. Static pressure on the outside of the riser (water pressure) prevents the gas from leaking to sea. Diffused gas is collected in the steel layer, which acts as an annular space and directs the gas to a valve station on the facility, where the gas pressure is released. The annulus pressure is normally monitored and the pressure is released at a given set point for the pressure.

The technology for flexible risers is continually evolving. On the most modern systems leaking gas is collected, measured and sent to the flare or recovery. There are no measurments on the oldest systems on the shelf. At some installations, the gas is also emitted in the atmospheric vent.

Elastomers degrade over time. This also applies to polymer layers in the flexible risers, and causes the diffusion rate to increase as the pipes age. Along with other factors, this means that the pipes need to be replaced after a certain number of years in operation. On newer risers, the measurement of diffusion rates over time provide trend data used in monitoring the condition of the risers.

Diffusion data for methane and NMVOCs was collected from installations, where such data was available, during the primary survey. This contributed to an insight into the size of emissions of methane and NMVOC from flexible risers.

Table 36 Emissions from flexible risers – key information

a. Potential waste gas quantity	Small.
b. Emission type	Continuous and discontinuous.
c. Cause/justification	Diffusion through the elastomer layer in the riser.
d. Disposal options	Flare, recycling and emissions.
e. Selected options	Both flare, recycling and emissions.
f. Quantification until now	Not included in the current guidelines.
g. Quantification options	Measured on newer risers. Supplier data can be retrieved for older equipment, but these data are uncertain due to aging and degradation of the elastomeric layer.
h. Influencing factors	Diffusion resistance in the elastomer component in risers and disposal option for waste gas.
i. Possibilities for sampling	Possible to do in the depressurization station at the facility.
j. Technology status/age affecting the emissions	Elastomeric layers degrade over time. This means that the diffusion rate increases and the old pipes need to be replaced after some years of use.
k. Can direct emissions be eliminated	Yes, by flaring and/or recycling.

6.3.21 Emissions from storage tanks for crude oil

All FPSO's have storage tanks for crude oil (and floating production facilities of the Spar type). Because these also have production facilities for oil and gas, and because the regulations allow it, fuel gas is used as blanket gas. The blanket gas is recovered by recycling to the process, which means that this does not lead to discharge during normal operation. This is discussed in Chapter 6.3.6.

Crude oil tanks on floating production facilities will give emissions to atmosphere during inspection of the tanks, and this can also occur under abnormal operating situations.

There are also 4 stationary storage vessels for crude oil connected to production installations using subsea-installed piping. These do not have access to fuel gas, or other natural gas to be used as blanket gas, or reception possibilities for blanket gas after use. Therefore, so-called neutral gas, which is waste gas from stoichiometric combustion of oil, is used as blanket gas.

6.3.21.1 Tank inspection of crude oil tanks on FPSOs

Storage tanks for oil at floating production facilities should be inspected every five years in accordance with the regulations. This is normally done by inspecting 1/5 of the tanks annually.

During tank inspection, the tanks are emptied for oil and purged with gas. Gasfreeing is carried out by flushing the tank with an inert gas or N_2. The mixture of inert gas/N_2 and fuel gas cannot be returned to the process because the inert gas will contaminate the gas to be exported, and therefore it is discharged through a ventilation outlet attached to the tanks.

Since the storage tanks operate at atmospheric pressure, and all the fuel gas in the empty tank is to be removed, the amount of HC gas discharged (measured as Sm^3) approximates the volume of the tanks purged. The density and composition of the gas is approximately equal to the corresponding parameters for the fuel gas. With a total storage capacity for crude oil of 600 000-700 000 m^3 (estimate) and an assumed density of about 0.7 kg/Sm^3, the annual emissions from all FPSOs on the Norwegian continental shelf will be in the range of 100-150 tonnes of methane and NMVOC in total.

Table 37 Emissions from tank inspection of crude oil tanks on FPSOs - key information

a. Potential waste gas quantity	Medium.
b. Emission type	Only a short time-period during annual tank inspection.
c. Cause/justification	Regulatory requirements for inspection and mixture of inert gas in the blanket gas.
d. Disposal options	Only emissions to atmosphere.
e. Selected options	Emissions to atmosphere.
f. Quantification until now	Not included in NOROGs guidelines. Not reported.
g. Quantification options	Can be calculated conservatively using the tank volume.
h. Influencing factors	If the waste gas is directed to the flare, some of it will be burned.
i. Possibilities for sampling	Technically yes, but the composition will vary over time. A composition based on the fuel gas composition could be representative.
j. Technology status/age affecting the emissions	Age has no effect.
k. Can direct emissions be eliminated	Emissions can be reduced if the waste gas is routed to the low pressure flare. A condensation facility at all FPSOs will be able to reduce the emissions.

6.3.21.2 Abnormal operating situation on FPSOs

If the VRU compressor is inoperative[7], the blanket gas cannot be recycled. The supply of blanket gas must then be reduced or terminated, and depending on how long such an operating situation lasts, the maximum pressure could be reached and the gas must then be discharged. In practice this means emissions to atmosphere.

This will be a special situation. Emissions quantities will depend on how long the situation lasts.

Table 38 Emissions in abnormal operating conditions on FPSOs - key information

a. Potential waste gas quantity	Small to medium.
b. Emission type	Isolated cases.
c. Cause/justification	Equipment failure.
d. Disposal options	Direct emission to atmosphere, maybe flare if this is facilitated, but low tank pressure makes this difficult.
e. Selected options	Emissions to the atmosphere.
f. Quantification until now	Not taken into account in the current guidelines for emissions reporting.
g. Quantification options	Must be clarified depending on the situation. Difficult to use general methods here.
h. Influencing factors	Equipment reliability.
i. Possibilities for sampling	Technically yes, but the composition will not differ much from the fuel gas composition.
j. Technology status/age affecting the emissions	The VRU-compressors reliability is essential.
k. Can direct emissions be eliminated	Maybe. Two parallel VRU-compressors will significantly reduce the likelihood that such an event occurs.

[7] The VRU compressor (also called VOC-compressor) recompress the blanket gas after use and recycle it to the process for recovery.

6.3.21.3 Stationary storage vessels for crude oil

There are currently 4 crude oil storage vessel (FSO) on the Norwegian shelf.

Table 39 Emissions from stationary storage vessels for crude oil - key information

a. Potential waste gas quantity	**Large,** especially NMVOC. Methane emissions can be large even if a recycling plant is installed.
b. Emission type	Continuous.
c. Cause/justification	Evaporation of the gas from the crude oil. Storage vessels use inert gas as blanket gas.
d. Disposal options	Recycling plants reduce emissions of NMVOC.
e. Selected options	Three of the four FSOs have an absorption plant with 90% «design efficiencyȯ
f. Quantification until now	According to the VOC-cooperations methods* for shuttle tankers.
g. Quantification options	Here it may be possible to come up with better estimation methods, but this is a complicated field, which is illustrated by the extensive research work Marintek did ahead of the measures implemented for the shuttle tankers.
h. Influencing factors	Installation of a recycling facility.
i. Possibilities for sampling	NA.
j. Technology status/age affecting the emissions	Not studied.
k. Can direct emissions be eliminated	No, only reduced.

* VOC Industrial Cooperation (VOCIS) is a collaboration between operators responsible for loading oil from the field to shuttle tankers.

The technical situation for storage vessel is analog to shuttle tankers. Neutral gas must be used as blanket gas, because there is no access to sufficient HC-gas to be used as blanket gas or disposal opportunities for used HC gas, and the same assumptions and the lack of conditions for recovery and reduction of emissions applies. The emission quantities are calculated using the same methods as for emissions from shuttle tankers that are loading on the field, and the same technologies for recovering the evaporated HC gas is used.

6.3.22 Tanks for diesel and other petroleum products

Diesel tanks, and some other storage tanks for oil products, in most cases do not use blanket gas and are equipped with local vents that "breathe" against air. This is also an accepted practice on landbased storage tanks of this type.

Emissions of HC-gases from such tanks are difficult to estimate. The content of methane in the fuel oil is, in practice, almost zero. There is also very little of other volatile HC emissions. Therefore, during normal operation the emissions are considered to be less important. But when the tanks are filled, the contents of the gas above the liquid surface are displaced and discharged. A certain proportion of this is HC gas, and virtually everything is NMVOC, due to the absence of methane in such oil. It is difficult to estimate how much of this that is HC gas.

Diesel consumption varies considerably from facility to facility. The size of the emissions are partly dependent on oil consumption. The survey showed that a number of major installations use (and refill) 10 000 to 100 000 m^3 diesel per year. The replenishment volume of other oil products such as hydraulic and lubricating oil is significantly lower.

6.3.23 DBB valves

The survey showed that "Double block and bleed" valves are a potential source of direct emissions of methane and NMVOC. In connection with maintenance, repair, etc. equipments are isolated from the the process by means of two shut-off valves (double block). The gas between the shut-off valves is bled-off by means of a small vent valve. The waste gas can either be sent to recycovery or to the low pressure flare, or it can be released to air locally or through atmospheric common vent. If gas leak occurs through the first pressurized block valve, then the gas will also bleed-off through the bleed valve.

Most operators in the primary survey did not have information available that made it possible to calculate or estimate emissions. However, information which could form the basis for emission calculations was provided by three installations. They showed emissions between 0.01 and 0.15 tonnes/year of methane plus NMVOC emissions, based on gas volumes emitted per closing of DDB and the number of such operations annually. This is very small compared to the many other emission sources (~1ă). There is reason to assume that this is representative for most installations. Emissions from DBB valves were not enquired about in the secondary survey given that, relatively speaking, there is much work needed to provide the necessary background information required.

6.4 Emission points

The emission source survey showed that direct emissions of methane and NMVOC are released to the atmosphere from different emission points;

- From flare (which does not burn)
- From dedicated atmospheric common vents
- From local dedicated vents in the installation
- Directly from equipment and components in the installations in the form of fugitive emissions

The survey showed that the solutions chosen are largely facility-specific, but there are also a few typically common patterns.

6.4.1 Flares that do not burn

Direct emissions from flare comes from the following sources:

a) Extinguished flare
b) Emissions from ignition of flare
c) Non-combustible flare gas
d) Open flare purged with inert gas

Emissions from extinguished flare, and emissions from flare ignition, take place in all installations with flare.

Emissions from non-combustible flare gas is a special case and is only limited to one facility in the Norwegian shelf. The reason is the low concentration of HC-gas in the flare gas.

Emissions from open flare purged with inert gas is also limited to a few facilities (only four facilities were identified during the survey).

All flare systems are equiped with fiscal flare gas metres. However, problems related to source d) can arise, since the gas volumes in periods may be so low that they can be hardly captured by the metre and even if it does it will be with very low accuracy.

6.4.2 Emissions from atmospheric common vent

The survey showed that almost all installations had one, or in some cases two, common vents for direct emissions of HC gases. In some facilities, only a few sources are linked to the common vent. Some installations have metres monitoring the flow rate at any time.

In most installations N_2 is used as purge gas in the atmospheric common vent. In addition, often inert gases from other sources are led to the common vent. It is primarily nitrogen, but also water vapour (H_2O) and CO_2 can be found. The survey showed that some installations can have significant variations in the emission flow rate and composition from the atmospheric common vent over time. This makes it difficult to quantify the amount of HC gas that flows out, and the distribution of methane and NMVOC gases at all times, even on installations with a flow metre.

These conditions vary greatly from facility to facility and set the requirement to apply facility-specific factors and conditions if a measurement plan is to be implemented. In some installations metres are used as a basis to establish emission figures that are subject to quotas. Because of the factors mentioned, emissions subject to quotas are determined by using a flate-rate. The survey has shown that HC gas emissions determined with the the flat-rate method can differ significantly from the actual emissions of these gases, where the flat-rate method gives conservative (highest) figures. The survey showed that deviations may be so high that they may form more than 10% of the total reported direct emissions of methane and NMVOC from the Norwegian continental shelf. This indicates that the flat-rate method may be inconvenient as a basis for determining the actual offshore methane and NMVOC emissions.

On most installations, common vents have their relase point (to the atmosphere) approximately halfway up the flare boom. Metres and sampling points on atmospheric common vents should be established close to the bottom of the flare boom. This is considered technically possible, but the difficulty of access and cost will vary significantly from facility to facility.

6.4.3 Emissions from local vents

A typical characteristic of a local vent (release point) is that it is only linked to one emission source.

The survey showed that local vents for the release of waste gases to the atmosphere exist in all facilities. Vents can release all kinds of waste gases and mixtures, from pure nitrogen to pure HC gas. Vents are not normally equipped with metres. While some facilities have only local vents, the majority have a combination of common vents (one or two) and local vents. There may be several factors that have lead to this distribution and no common patterns for this has been found.

Installing flow metres and sampling points would be possible for most local vents, but there has not been time and resources to assess this. It should be noted that the cost of such installations can be significant. Many of the local vents are fed from sources where emissions can be quantified more easily and with enough accuracy in other ways, other than measurement and analysis of samples, for example by calculations.

Some of the local vents are goosenecks located on diesel tanks and other types of oil tanks. Here the tanks are vented directly to the atmosphere. This means that when the tanks are filled, the gas phase is pressed out through the local vent. When the oil in the tanks is used, the gas volume automatically increases due to air flow through the gooseneck into the tank.

6.4.4 Emissions directly from equipment and components in the installation

Some HC gas emissions are directly released from the equipment components to the atmosphere. This is what is called fugitive emissions. Leaks and spills from depressurization of local instruments during maintenance operations can be categorised under this group. These are emissions which are not measured. In practice, measurement and sample taking is not possible for this emission group.

7 Summary of the survey

The survey showed that the direct emissions of methane and NMVOC is far more complex, complicated and extensive than earlier understood. Several new processes and sub-processes that produce waste gases with methane and NMVOC were found. The survey has shown that many of the 13 sources that were previously reported consist of several sub-processes. These must be quantified separately to provide reliable data on emissions, and they must be addressed individually when mitigation measures are considered. In total 68 permanent facilities for the production/transport of oil and gas on the Norwegian continental shelf has been reviewed. As a result of this review, 48 emission producing processes and sub-processes are identified and addressed in this report.

This chapter gives a summary and an assessment of the discoveries made during this survey.

7.1 Scope and limitations

With 68 facilities and 48 identified processes/sub-processes that produce waste gases, the scope has been very extensive. During the survey, some processes with waste gas production could not be assessed further due to the insufficient information that was available. This was largely processes that generate little or very little waste gas, for example emissions from flare ignition, emissions from drilling. For many of such emission sources work to be done both by add novatech and the operater to gather background information for estimating emissions was condiered to very much considering the small contrubition of these emission sources to total emissions. Such conditions have lead to that processes with small emission potential are handled less thoroughly than the dominant contributors.

The survey showed that there are several other processes that produce HC-containing waste gases than those in todays reporting regime. These processes/emission sources to some extent have not been recognised by the operater companies, consequently the operators had less relevant information available for the evaluation of these sources than for the "existing" sources. This has to some extent affected the result of this survey. Emissions from flare ignition is an example to this.

7.2 Comparing the findings of the survey with the current quantification method

As shown in Chapter 5 todays emission quantification method for 11 of the predefined "emission sources" is based on a given emission factor given as a function of the amount of gas processed. The survey showed that processed amount of gas is irrelevant as an activity factor for the determination of emissions from these sources. Emissions primarily emerge due to other factors. This will be further explained in the Module 2 report.

These circumstances indicate that the actual emissions from some of the "old" sources may differ significantly from those reported up to now. The survey so far however gives no indication that the total direct emission of methane and NMVOC will be of a different magnitude than those reported so far.

Quantification methods and emission quantities are included in the second module of this project and will be presented in the Module 2 report.

7.3 Contribution of process and sub-processes

The survey showed that the potential quantities of emissions from the individual processes and sub-processes that generate waste gases varies enormously. While the dominant contributors have the potential to produce waste gas amounts in the range of 100 -1000 tonnes/year, some processes have a waste gas production potential of several kilograms per year or less.

With a total of 48 identified processes and sub-processes, it is important to focus on those that dominate emissions, both to get as accurate emission figures as possible, and also to implement abatement measures where it matters most.

The contribution of the individual processes and sub-processes will be assessed in Module 2 of this project, but it is already clear from the survey that approximately a dozen of the processes and sub-processes account for more than the half of the total emissions, while a large number of the processes and sub-processes contribute less than 1%.

7.4 Why are the main processes divided into sub-processes?

The survey has shown that it is both useful and necessary to split some of the main processes to sub-processes. This is illustrated schematically for a TEG (glycol) regeneration process which consists of three sub-processes:

Degassing tank:	Waste gas can be routed either to air as emissions, to flare where the waste gas is burned, or recycled back to the process (recovery). On most intallations, the waste gas from the degassing tank goes to flare or recovery.
Regenerator:	The waste gas can in principle be handled in the same way as the waste gas from the degassing tank, but there are factors that can make this more complicated, such as low pressure and high water content in the waste gas. On most installations, the waste gas from here is sent to air as emissions.
Stripping gas:	Fuel gas is used as stripping gas in some of the installations that has TEG regeneration. Stripping gas is discharged together with the waste gas from the boiler.

Emissions from TEG is thus totally dependent on how the waste gas from the last two sources are handled and whether HC is used as stripping gas.

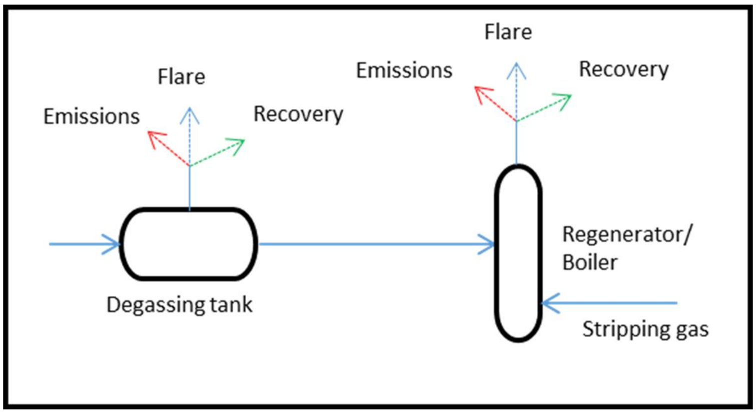


Figure 10 Sub-processes in TEG regeneration

The same situation arises in the produced water treatment system, seal oil systems for compressors and dry compressor seals to name a few of the "old" emission sources.

There are many operations that must be split to sub-processes to get a correct overview of the emission situation and to put the action in the the right place. Many of these sub-processes are potentially significant contributors to total emissions.

7.5 Factors that affect the emissions

Most of the direct emission sources have a factor that affects or "controls" emissions. The key controlling factor for many sub-processes is how the waste gases are handled. For several of the sub-processes with a potential for high emissions, several disposal options are available (emissions, flaring or recovery). The survey has shown that for all sub-processes where recovery or flaring is possible, these options are selected in one or more facilities. There are also some facilities that have consistently chosen these disposal options for all sub-processes where it was possible.

The survey has also shown that some facilities had selected the emission solution (i.e. venting) for a dominant part of sub-processes when they had that option. No clear correlation between the choice of the disposal solution and the age of the facility is found. On some of the older installations (from the 1970/1980's) mostly emission-friendly disposal options (recovery and flaring) are chosen, while on some relatively new installations the emission option is chosen for many of the sub-processes.

Another significant factor that affects the level of emissions is the pressure level in degassing tanks. Waste gas from these tanks are mostly routed to recovery or flaring, while the remaining methane and NMVOC separated downstream of the process is often released to air as emissions. Typical processes with such set-ups are glycol (TEG) regeneration and produced water treatment. The lower the pressure in the degassing tank is, the less waste gas will remain in the TEG solution and in the produced water, and thus less methane and NMVOC will go to emission points.

For one of the main processes; compressor seals, the choice of technology is important. Choosing dry seals over oil seals can practically eliminate emissions from this process. The same can be achieved by using alternative technology that replaces HC-gas as stripping gas or by using a stripping gas that does not contain HC-gas, such as N_2. Similar solutions are used in flotation plants for produced water treatment. Fuel gas is a commonly used flotation gas, but in many installations today, nitrogen is used. It should be noted here that nitrogen gas should have a high degree of purity, as small oxygen impurities can cause corrosion problems.

For the following sub-processes alternate or new technologies can help to reduce/eliminate waste gas quantities and thus potential emissions (sources with small emissions are not included).

Table 40 Possibilities for emission reduction by using new or alternative technology

Sub-process	Abatement measure	Comments
TEG regenerator	Reduce the pressure in the degassing tank.	Reduces the amount of waste gas.
HC-stripping gas to TEG regenerator	Avoid the use of stripping gas or use pure N_2.	It is important that nitrogen is pure. 99.5% N_2 contains so much O_2 that TEG is oxidised.
Produced water discharge pipe	Reduce the pressure in the degassing tank.	Reduces the amount of waste gas from the discharge pipe.
Produced water flotatation	Replace fuel gas with N_2.	Common solution.
Compressor seal oil holding and storage tanks	Reduce the pressure in the degassing pots.	Reduces the amount of waste gas.
Emissions from compressor seal oil	Replace oil seals with dry seals.	Best practice. Commonly used on installations built after 1995.
Ignition of flare	Develop more effective ignition systems.	Delayed ignition can be a significant emission source.

The survey also showed that there are few sub-processes where wearing affects emissions, and good preventive maintenance is a mitigation factor, but there is two registered:

Table 41 Processes where wearing can lead to increased emissions

Sub-processes	Cause
Dry compressor seals	Seals are wearing, particularly if the sealing is not clean. Major maintenance items are: clean the sealing and replace seal when it is seriously worn.
Compressor seal oil	By use of seal oil, the increased wearing on the seals will lead to more contact between the oil and gas, resulting in higher emissions.

In most processes and sub-processes technology choices do not affect emissions. In many of the processes, emissions are a direct result of how much methane and NMVOC are dissolved in water, oil or absorbents. This is governed by the laws of physics and cannot be solved by technology.

7.6 Emissions that can be completely eliminated

For the following sub-processes emissions can be eliminated completely by recovering the waste gas or burning it in flare:

Table 42 Process where emissions can be eliminated by alternative disposal of waste gas

Sub-process	Abatement measure	Comments
TEG degassing tank	Waste gas to recovery or flare	Used almost in all facilities.
TEG regenerator	Waste gas to recovery or flare	The gas contains a lot of H_2O which can cause problems. Low pressure in the regenerator can be a challenge.
TEG stripping gas	Waste gas to recovery or flare	Like above
Produced water degassing tank	Waste gas to recovery or flare	Used almost in all facilities.
Produced water CFU/flotation tank	Waste gas to recovery or flare	Used in some facilities.
Compressor seal oil degassing tanks	Waste gas to recovery or flare	Used in most facilities with oil seals.
Compressor seal oil holding- and storage tanks	Waste gas to recovery or flare	Low pressure in the tank can be a challenge.
Compressor primary seal gas	Waste gas to recovery or flare	Used on most facilities with dry seals.
Compressor secondary seal gas	Waste gas to recovery or flare	Possible if fuel gas is used as seal gas. When N_2 is used as seal gas emissions can be eliminated if the seal system has an internal labyrinth.
Reciprocating compressors separator chamber	Waste gas to recovery or flare	Used in one or more facilities.
MEG degassing tank	Waste gas to recovery or flare	Same principle as for TEG.
Amine degassing tank	Waste gas to recovery or flare	Same principle as for TEG.
Flexible riser	Waste gas to recovery or flare	Used in some facilities.

7.7 Sub-processes that exist on all installations

Many of the sub-processes exist only on some offshore facilities. But there are some processes and sub-processes that can, or will cause, emissions and exist in all installations that handle oil and natural gas.

Table 43 Sub-processes that exist and give emissions on all production facilities

Sub-process	Cause
Gas freeing during depressurization in connection with planned shutdowns	All process installations must regularly go through planned shutdowns (every 2.-4. year).
Purging and maintance of instruments	All process installations have instruments that require maintenance and to some extent replacement during the facilityʹs lifetime.
Extinguished flare	All process installations have flaring. Although extinguished flare has shown to be a rare event, it could happen in all flare systems.
Delayed ignition of flare	All flare must be ignitied periodically. The survey has shown that it "always" takes some time before the gas from the flare tip is ignited.
Leaks in process	This happens in all process facilities.
Gas analysers and sampling stations	This exists in all process facilities. Although emissions are small, they do occur.

7.8 Emissions that cannot be eliminated

The survey showed that there are some emissions that cannot be eliminated, and some that cannot be especially reduced. The table below gives an overview.

Table 44 Emissions that cannot be eliminated

Sub-process	Cause
Depressurization/gas freeing of process	Gas freeing during shutdowns will result in direct emissions of methane and NMVOC from the time the flare extinguishes due to low concentration of methane and NMVOC in the waste gas. These emissions cannot be eliminated. Emissions are relatively small.
Inspection of crude oil tanks on FPSOs	While gas freeing crude oil tanks, a mixture of inert gas and HC gas is relased to the atmosphere. Some methane and some more NMVOC can be recovered in the recondensation process, but not eliminated. A recondensation system is expensive.
Extinguished flare	If the flare is extinguished, the flare gas stream goes to atmosphere. Historically small emissions. Emissions can be reduced through measures that reduces the risk of extinguished flare, but cannot be eliminated.
Open cold flare purged with inert gas	Emissions due to leaks through closed safety valves cannot be eliminated 100%. This sub-process exists only in a few installations and contribution to the total direct emissions of methane and NMVOC are extremely low. Emissions can be reduced by proper maintenance of the safety valves.
Leaks in process	Leaks can be reduced, but not eliminated.

7.9 Common vent that burns

This is a special situation that was found during the survey. On one of the installations the disposal point of the cold vent is located next to the flare, which means that emissions from the cold vent are periodically ignited (depending on the wind conditions, the concentration of HC gas in the cold vent, etc.), but with the construction as it is today it is not possible to control when cold vent is ignited. The consequence is that all waste gas through the cold vent is reported as emissions. During the second survey it was not investigated whether other installations are in a similar situation.

7.10 Difficult emissions

There are a few emission categories that are particularly difficult, or impossible, to do anything about. They are problematic because the amount of methane and MNVOC emitted can be significant. These are emission streams that contain very large amounts of inert gases or non-combustible gases. Such emissions come from a few sub-processes and are identified only in a few facilities in the Norwegian shelf. The challenges are as follows:

- Waste gas cannot be recovered. This is because the high concentration of inert gases (N_2, CO_2, H_2S) can contaminate the export gas (the aim is to reduce CO_2 in the the gas prior to export, then it cannot be injected back again)
- The low content of HC-gases in the waste gas mean the flare does not burn.
- Total amount of waste gases can be so big that methane and NMVOC emissions are significant despite the low concentrations.

Such issues emerge primarily in installations that have high CO_2- (and H_2S) concentrations in the natural gas.

Contributors here are waste gases from amine regeneration, which can contain alot of CO_2. Common vents that are fed with alot of nitrogen can also be categorised in this group. If the cold vent is purged with nitrogen, and in addition fed with secondary seal gas from the compressor seals (which can contain predominant amounts of nitrogen), it will be difficult to recover or burn the waste gas in the flare.

7.11 Gas flow measurement and gas sampling

A major challenge with direct emissions of methane and NMVOC is that emissions in many cases are not measured. Flowmetres are installed on all flare towers. The measurements are used as a basis for taxes. This means that there are strict requirements for measurement accuracy. Some atmospheric common vents are also equipped with accurate flow metres, while there are several smaller emission pipes that do not have flowmetres. Since the amount of emissions varies considerably, it is the largest emissions that it is important to quantify with accuracy.

In principle, it is technically possible to install flowmetres for most emission streams, but field-specific conditions indicate that the complexity and cost may vary considerably.

Direct emissions of hydrocarbon gases are reported as two components, methane and NMVOC, in accordance with the Norwegian regulations and international agreements. Allocation of emissions between methane and NMVOC can sometimes be problematic. There are several ways to do this, but no matter how, it is important to handle this question by considering where the gas comes from and the magnitude of emissions.

Part of the waste gases from the processes and sub-processes consists of pure, or almost pure, fuel gas or export gas. This is the case for some of the larger "waste-gas producers". Samples of both the fuel gas and export gas are taken regularly to analyse their composition.

Some waste gases are released in small amounts relative to the major contributors in the same installation. A more flat-rate distribution of methane and NMVOC for smaller emissions should be acceptable, since this distribution will have little impact on the facility's overall distribution percentage of methane and NMVOC emissions.

A challenge with emissions, especially emissions through common atmospheric vent, is that at some facilities, composition may vary over time. This may require that tests and analyses must be taken at a certain frequency to ensure representativeness.

From most atmospheric common vents, other gases than methane and NMVOC are released, mainly nitrogen (N_2). N_2 is used as purge gas in the ventilation pipes and can represent a significant amount of the waste gas. In addition, there may be significant amounts of of water vapour and CO_2. This must be considered when amount of methane and NMVOC are to be determined. The survey showed that this represents a major problem for quantifying emissions of methane and NMVOC in some facilities.

The survey showed that there is need for better emission quantification methods, and better methods for splitting them into components, than those available today. This particularly concerns common vents that have significant emissions. Sampling and analysis of the waste gases is a method that can be used to determine the distribution between methane and NMVOC emissions. There are, however, other methods:

- Process calculations and process simulations. Although such methods may involve high uncertainty for some of the processes in question here, there may be processes where the distribution of methane and NMVOC can be calculated within an acceptable accuracy.
- Taking samples of liquid that contain dissolved gas. This especially concerns absorbents such as TEG, MEG and amine where the residual amounts of methane and NMVOC is largely released in the final step of the regeneration process. If all the present methane and C2 to C5/C6 (that represents NMVOC) in the sample ends up in the waste gas, this is probably a good and a completaly acceptable assumption. Such samples may be taken downstream of the degassing tank. The filter downstream of the degassing tank in TEG systems will normally have a sampling point. Similarly, samples can be taken from the compressor seal oil systems, downstream of the degassing pots.

Based on this, it is recommended that installations are assessed individually for the eventual points / locations for taking samples, once better emission figures are available, after completion of Module 2 of this project.
It is also further recommended that sample taking and analysis is considered, and limited to, emission points that contribute with significant amounts of emissions, where acceptable/good composition data cannot be obtained in other ways.

7.12 Existing facilities versus new facilities

The survey has shown that some installations, in practice, have eliminated emissions from processes and sub-processes when possible. This is done during the design phase of the project, and is largely based on implementing premises and practical solutions so that waste gases can be routed to recovery or flare when possible. There is little to suggest that the selection of these mitigation solutions has been cost driven.

There may be conditions on individual installations that make it difficult to select the recovery or the flaring solution. Installations that have alot of CO_2 in waste gases encounter the problems as outlined in this report. In order to select the recovery or flaring solution, it is essential that the operator is aiming to eliminate direct emissions of all waste gases from the start of the field development, where possible.

For facilities that are in operation, it may be both difficult and costly to build a zero-emission solution (i.e., leading waste gases to recovery or flaring when possible). There are two barriers here:

1. Reorganise piping systems, i.e. connect the waste gas streams to low pressure flare. This can look relatively easy, but the work and the cost may be substantial and may vary substantially from one installation to another.

2. Rerouting of waste gases from atmospheric vent to low pressure flare may conflict with the rationale behind the faciltiy's system design. For example, the pressure levels in the process may be a hinder for such rebuildings, the pressure level in the low pressure flare can be so high that it might expose the HC waste gas sources for back-flow from flare. Therefore, in some facilities it might be easier to recover waste gases by recirculating it to the process. Facilities that have VRU-compressors (common on FPSO), will have better conditions for this than other facilities. Another challenge is waste gases that contain large amounts of impurities of N_2 and CO_2. Such gases are undesirable in the process and could impede both recovery and burning in the flare.

These conditions indicate that generic solutions, to seemingly similar waste gas problems, do not necessarily work. This means that the problems for each installation must be solved separately.

7.13 Unfortunate or bad design

As mentioned above, everything is decided in the design phase. The survey has shown that the poor solutions which the operators struggle with in the operation phase were selected in the design phase. A few examples illustrate this:

- Burning waste gases in an incinerator and in flare with such a low content of HC-gas that the waste is not combustible.
- Routing used HC seal gas from compressors to atmospheric vent instead of recovery or flare.

This underlines how important it is to have a clear policy in place before the design starts.

7.14 New sources

The survey indicates that new sub-processes, for which there is no overview today and which will generate waste gases of methane and NMVOC can, and will, begin to be used. This survey shows that it has happened several times over the last 20 years, and can happen again. It is therefore important that the reporting procedures and guidelines can be adapted to include new sub-processes/emission sources and emissions.

7.15 Implemented abatement measures and abatement measures under planning

The survey showed that in many new installations solutions that minimise emissions of methane and NMVOC were clearly designed. On the other hand, the participants from the operator companies in the primary survey, to a big extent, had limited familiarity with the original plans.

During the survey, it was observed that few measures to reduce emissions of methane and NMVOC were implemented after the installations started to operate. One abatement measure that nonetheless was implemented on many facilities, was rebuilding the storage tanks at the FPSOs, to use fuel gas as blanket gas instead of waste gas (inert gas). This measure resulted in the installation of VRU compressors on the facilities, and made it possible to completely recover the blanket gas and eliminate emissions of HC-gas from the operation.

A corresponding small number of measures were mentioned in the survey. This may be an indication that operator companies have given little focus to the reduction of direct methane and NMVOC emissions.

7.16 Cold venting strategy

Operator companiesôstrategies to prevent direct emissions of hydrocarbon gases were requested during the survey. A few of the larger operators did submit business strategies which stated that their systems should be designed and operated so that direct emissions of hydrocarbon gases are prevented. These strategies paricularly address the larger potential emission sources mentioned in this report. However, during the primary survey it was found that the general strategies in this area were little known by the facilitysôoperators. This shows that companies have only managed to communicate their strategies in this area, to their operational units, to a limited extent.

On the other hand, the observations showed that the elimination/reduction of direct emissions had focus during the planning and design of many installations. For installations that are currently under planning phase and construction, the survey showed that the elimination and reduction of direct emissions are taken seriously. It is also clear that when alternatives to direct emissions are available, reuse by recycling to the process is often preferred.

8 Conclusions and summary

The survey showed that there are many processes that produce hydrocarbon containing waste gases that can lead to emissions of methane and NMVOC, besides those covered in the current reporting regime. These processes/emission sources were not given much attention by the operator companies, which may explain why the operators had less relevant information available that enabled the assessment of these emission sources, than for those they previously they had focus on. This has, to some extent, affected the results and the findings of the survey. A total of 48 processes/sub-processes that produce hydrocarbon-containing gases were identified during the survey.

The survey showed that the amount of processed gas is irrelevant as an activity factor for the determination of emissions from most sources/processes. Emissions are primarily results of other factors. These factors indicate that the actual emissions from some of the "old" sources can substantially deviate from those reported earlier.

The emission potential of the individual processes and sub-processes that generate hydrocarbon-containing waste gases varies enormously. While the dominant contributors have the potential to produce waste gases in the range of 100-1000 tonnes/year, there are some processes which have a waste gas production potential of several kilograms per year or less on the same installation. This suggests that it is important to focus on the processes and sources that dominate emissions.

The survey has shown that the main factor that affects emissions is how the waste gases from the individual sub-processes are handled or disposed of. For many of the sub-processes, both recovery and flaring of waste gases are possible. These are solutions that are selected on many installations. At these facilities, the selection is made in the early design phase. The survey showed that reconstructing facilities in operation for recovery or for flaring of waste gases took place only to a small degree. This is because such modifications are expensive.

The survey has shown clearly that it is possible to eliminate emissions from many of the emission producing processes, and also from processes that are big contributors to direct emissions of methane and NMVOC on the Norwegian continental shelf. This has been done on many installations. The basis for this is decided in the early design phase. If the emission option is selected in the design phase, it is difficult and expensive to fix this later.

The survey also showed that some types of emissions cannot be eliminated, nor can some be reduced by a considerable amount.

Possibilities to take samples and to analyse the composition of waste gases was only roughly reviewed in the project. It is recommended:

- That eventual points/locations for taking samples are assessed individually for all installations when better emission figures are available after Module 2 of the project is completed.
- That taking samples and analyses are assessed and limited to emission points that contribute to significant amounts of emissions, where good/acceptable composition data is not obtainable with easier ways.

For many emission points equally good and more cost-effective methods may exist, to determine the distribution between methane and NMVOC, than taking samples and analysing emissions, for example calculations based on other available parameters.

This shows how important it is that operators have a clear philosophy and strategy regarding the elimination and minimisation of direct emissions of methane and NMVOC, especially when upgrading existing facilities and designing new facilities and new sub-processes. A few operators were able to present such a strategy during the survey, but the survey clearly showed that this had been in place in many of the facilitites that were reviewed.

References

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Ref: 5 *Foreløpig Sektorrapport - Underlagsrapport til Forslag til handlingsplan for norske utslipp av kortlevde klimadrivere, 2013 (Norwegian only).*

Ref: 6 *Environment.no (pr.12.02.2015).*

Ref: 7 *Aker Engineering: ñDirect Hydrocarbon Emissionsò, 1993.*

Ref: 8 *Conversation, 21.01.2015, with Jan Erik Vinnem, hired project manager for leakage project in Norwegian Oil and Gas Association.*

Appendices

Appendix 1 - Facilities that were included in the survey

The list of installations on the next two pages include all that was covered in the survey.

Facilities that are highlighted in bold were covered in the primary survey. In the report, it is stated 15 installations, while the list includes 16. The reason for this is that Sleipner West was reviewed. It comprises of the wellhead platform Sleipner B and the gas processing platform Sleipner T.

The floating storage vessels for crude oil (FSOs) that are at the bottom of the list did not participate in the survey by completing the questionnaire. The information about them are taken from the Annual VOC Industry Collaboration report.

Facilities included in the study	Comments
Aasta Hansteen	
Alvheim FPSO	
Balder FPU	
Brage	
Draugen	
Draupner E og S	Includes Draupner S and Draupner E
Edvard Grieg	
Ekofisk B	
Ekofisk C	
Ekofisk J	
Ekofisk K	
Ekofisk M	
Ekofisk X	
Ekofisk Z	
Eldfisk A	
Eldfisk B	
Eldfisk E	
Eldfisk S	
Embla	
Gina Krog	
Gjøa	
Goliat	
Grane	
Gudrun	
Gullfaks A	
Gullfaks B	
Gullfaks C	
Gyda	
Heidrun	
Heimdal	
Ivar Aasen	
Johan Castberg	
Johan Sverdrup_P1	
Johan Sverdrup_RP_DP	Johan Sverdrup RP and Johan Sverdrup DP
Jotun A	Includes Jotun A and Jotun B
Knarr	
Kristin	
Kvitebjørn	
Martin Linge	
Njord A	
Norne	
Oseberg C	

Facilities included in the study	**Comments**
Oseberg F	Includes Oseberg A, Oseberg B and Oseberg D
Oseberg SØR	
Oseberg Øst	
Ringhorne	
Skarv	
Sleipner A	
Sleipner B	
Sleipner T	
Snorre A	
Snorre B	
Statfjord A	
Statfjord B	
Statfjord C	
Tor	
Troll A	
Troll B	
Troll C	
Ula	Includes Ula DP and Ula PP
Valemon	
Valhall	Includes Valhall PH, Valhall IP, Valhall WP and Valhall DP
Varg	
Veslefrikk	Includes Veslefrikk A and Veslefrikk B
Visund	
Volve	
Åsgard A	
Åsgard B	
Heidrun FSO	FSO- Information is taken from the Annual VOC Industry Collaboration Report
Navion Saga (Volve) SFO	FSO- Information is taken from the Annual VOC Industry Collaboration Report
Njord B SFO	FSO- Information is taken from the Annual VOC Industry Collaboration Report
Åsgard C SFO	FSO- Information is taken from the Annual VOC Industry Collaboration Report

Appendix 2 - Questionnaire, second survey

INFORMATION ABOUT THE FACILITY AND CONTACT PERSON
Operator company
Field
Facility
Name of the contact person
e-mail address of the contact person
Phone number of the contact person

Questions:

1. FLARE AND VENT SYSTEMS
1.1. HP- flare
a. Is flare closed or open?
b. What purge gas is used?
c. List possible continuous contributors/sources of HC gas to HP flare
1.2. LP- flare
a. Is flare closed or open?
b. What purge gas is used?
c. List possible continuous contributors/sources of HC gas to LP flare
d. Is flare open and extinguished over long periods? Comment
1.3. Atmospheric vent
a. Does the facility have an atmospheric common vent?
b. What purge gas is used?
c. List the most important contributors/sources to atmospheric common vent.
d. Is the amount of emissions and gas composition measured?
e. If not, can measurements be implemented? Comment
1.4. Other emission points of HC-gas
a. Give all emission points of direct emissions of methane and NMVOC
2. PURGE AND BLANKET GAS
a. Which gas is used? Fuel gas or inert gas?
b. Where is the used gas routed?

3. TEG REGENERATION
a. Is the conventional TEG system, Coldfinger or Drizo (or another concept) used?
3.1. Degassing tank
a. Where is the waste gas from the degassing tank routed?
b. What is the pressure in the degassing tank? [barg]
c. Is it possible to take samples of TEG, downstream the degassing tank to analyse the composition of methane and NMVOC? Comment
d. If emissions, give amount of CH_4 and nmVOC emissions [tonnes/year] and the emission quantification method used
3.2. TEG regenerator/boiler
a. Is fuel gas used as stripping gas in the regeneration process?
b. What is the rate of the stripping gas? [Sm^3/h]
c. Where is the used stripping gas and the waste gas from the TEG regenarator routed?
d. Is the amount of waste gas measured? If yes: What is the rate [Sm3/h]?
e. Is it possible to measure the amount of waste gas?
f. Is the composition of the waste gas from the regenartor known? If yes: Give the composition
g. Is it possible to calculate the emissions with simulations? If yes: Which simulation program?
h. If emissions, give the amount of CH_4 and nmVOC emissions [tonnes/year] and the emission quantification method used
4. MEG REGENERATION (only if MEG is regenarted at the facility)
a. Describe/scetch the facility with waste gas/emisson points.
b. Which waste gas/emission points exist? Describe
c. Where is the waste gases routed?
d. Is it possible to measure and analyse the amount of waste gas or to determine the amount via simulations? (When direct emissions)
e. If emissions, give the amount of CH_4 and nmVOC emissions [tonnes/year] and the emission quantification method used
5. PRODUCED WATER TREATMENT
a. Describe/scetch the facility with waste gas/emisson points.
b. Where is the waste gas from the degassing tank routed?
c. Where is the waste gas from the possible flotation unit routed?
d. Where is the waste gas from the discharge caisson for produced water routed?
e. Where is the waste gas from other emission sources routed?
f. What is the operating pressure in the degassing tank and in the possible flotation unit? [barg]
g. Is natural gas used as flotation gas and how much is used?
h. Is the amount of flotation gas measured? If yes: What is the rate [Sm^3/h]?

6. COMPRESSOR FOR NATURAL GAS
a. Give all the compressors at the facility and state their duty
b. Give pressure levels and type of each compressor
c. Give the selected sealing system for each compressor
7. COMPRESSORS THAT USE OIL SEALS
a. Give a short description of the seal oil system with degassing pots and tanks where the used seal oil is degassed
b. What is the pressure in those pots and oil tanks? [barg]
c. Where is the waste gas from the individual tanks routed?
d. Where is the waste gas from the individual degassing pots routed?
e. If cold venting (**common vent** or local vent): Is it possible to measure the emissions? Is it possible to measure the composition?
f. How can the emissions be quantified if the emissions are not measured? Operators should give an estimate on emissions [tonnes/year] and describe the emission quantification method used.
8. COMPRESSORS THAT USE DRY COMPRESSOR SEALS
a. Which gases are used as barrier gas by different barriers? (HC, Nitrogen?)
b. Where is the used primary barrier gas routed?
c. Where is the used secondary barrier gas routed?
d. If cold venting: Is the waste gas emissions routed to common vent and is it possible to measure or calculate the emission rates and composition? How are they calculated?
e. Give seal gas rate into the compressor for all compressors that use HC-gas as primary barrier gas.
9. RECIPROCATING COMPRESSORS/OTHER TYPE OF COMPRESSORS
a. Is reciprocating compressors or other type of compressors than centrifugal compressors used at the facility? Give compressor types
b. If yes, how are the leaks through seals handled and where is the leak gas routed?
c. Is it possible to measure or calculate emissions?
d. If emissions can be calculated: Describe the emision quantification method and give emission estimates

10. STRIPPING GAS FROM SEAWATER AS INJECTION WATER
a. Is HC-gas used for removing (stripping) oxygen from seawater that will be used as injection water?
b. If yes: Where is the gas routed?
c. If yes: How is the flow rate controlled?
d. If yes: What is the flow rate? [Sm^3/h]
11. ANNULUS IN PRODUCTION RISER
a. Is the annulus depressurized continously or batch?
b. Where is the bled/depressurized gas routed?
c. Is the amount measured or can it be quantified in other ways? Explain
12. ANNULUS IN FLEXIBLE RISER (only for installations that has such)
a. Is the annulus depressurized continously or batch?
b. Where is the bled/depressurized gas routed?
c. Is the amount measured or can it be quantified in other ways? Explain
13. DRILLING OPERATIONS
a. Does drilling take place from the facility?
b. Is drilling planned from the facility for the next few years?
c. What is the average emissions of CH_4 and nmVOC [tonnes/well]?
14. TURRET ON FPSOs
a. Is the gas depressurized contionusly or batch?
b. Where is the bled/depressurized gas routed
c. Is the amount measured or can it be quantified in other ways? Explain