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Cold venting and fugitive emissions from Norwegian offshore oil and gas activities

Summary report

Prepared for the Norwegian Environment Agency



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Title

Cold venting and fugitive emissions from Norwegian offshore oil and gas activities – summary report

Summary

The report presents a survey and mapping of direct methane and NMVOC emissions from Norwegian offshore installations, an updated estimate of emission inventories, proposals for improved future quantification of the emissions and an assessment of emission abatement opportunities. A total of 48 potential emission sources were identified. A small number of these sources contributed a dominant proportion of the emissions. Annual direct emissions were estimated to be about 12 500 tonnes of methane and 7 500 tonnes of NMVOC (2014), significantly lower than previously reported. However, the level of uncertainty is high, and particularly the contribution from fugitive emissions. New generic quantification methodologies are proposed for the major proportion of the emission sources. However, installation-specific quantification methods are recommended for some emission sources. It is proposed to compensate for emissions from sources making an insignificant contribution by adding a standard mark-up. Techniques and methods which enable total elimination of emissions from some of the major sources were identified. These techniques, which are already implemented on some of the installations currently in operation, can reduce the emissions significantly if implemented on future new installations. However, implementing emission abatement measures on existing installations can be costly.

4 Subject words

Offshore installations, emissions, methane, NMVOC

Front page photo

Heimdal. Source: Statoil, photographer: Øyvind Hagen

Summary

Offshore oil and gas production on the Norwegian continental shelf (NCS) leads to direct emissions of methane and non-methane volatile organic compounds (NMVOC). Emissions consist partly of fugitive emissions and gas leaks and partly of operational emissions (cold venting). The current methodology for quantifying these emissions has been in use for some 20 years, and its accuracy and ability to cover all emission sources is questionable.

The Norwegian Environment Agency (NEA) therefore engaged Add Novatech AS to conduct a study assessing emission status. The assignment had the following objectives.

1. Survey offshore installations and identify sources of direct methane and NMVOC emissions
2. Suggest new methods for quantifying emissions
3. Prepare new and better emission estimates
4. Assess best available techniques (BAT)
5. Assess methods and techniques for emission reduction

The study was carried out in several phases (modules) and separate sub-reports were prepared for each phase. The study was conducted in close collaboration with the industry and government agencies (the NEA, the Norwegian Petroleum Directorate and the Petroleum Safety Authority Norway).

All permanent offshore oil and gas facilities on the NCS were surveyed to identify potential emission sources. Fifteen of these were chosen for a thorough review, conducted as full-day meetings for each facility together with relevant specialists from the operator (primary survey). The remaining 53 facilities responded to a questionnaire (secondary survey) developed on the basis of results from the primary set.

These surveys demonstrated that the current (old) emission quantification methodology was incomplete where emission sources are concerned and also resulted in inaccurate calculation of emission inventories from some of the sources. The study identified a total of 48 potential sources of cold venting and fugitive emissions – ie, far more than the 13 which operators have previously reported from. This is partly because the former emission sources have been broken down into sub-sources and partly because new sources have been identified. The contribution from several of the "new" potential emission sources was found to be insignificant.

A new inventory estimate of annual emissions for 2014 was compiled. This was established partly by using the new quantification methodology proposed as part of this study and partly by using other available methods. The operators contributed actively to this work.

Table 1 Estimated emission inventories of methane and NMVOC for 2014 by main source [tonnes].

Main source:	Methane	NMVOC	VOC	% of total
Dry compressor seals	2 500	1 100	3 600	19%
Vent header (measured values)	1 950	1 350	3 300	17%
Produced water treatment	2 300	600	2 900	15%
HC purge and blanket gas	1 100	1 300	2 400	12%
Gas leaks/fugitives	1 250	950	2 200	11%
Flare gas not burnt	1 500	600	2 100	11%
Glycol regeneration	550	1 000	1 550	8%
Compressor wet seals	900	300	1 200	6%
Other sources	300	250	550	3%
Total	12 350	7 450	19 800	100%

The new estimates indicate that total emission inventories are significantly lower than those reported using the "old" quantification methodology. Reported emissions for 2014 were 24 922 tonnes of methane and 13 553 tonnes of NMVOC. However, significant uncertainties are also associated with

the new estimates in Table 1 above. The uncertainty is particularly high for gas leaks/fugitives. This reflects the huge inherent uncertainties in any methodology available for estimating emissions from these sources. Despite the uncertainties, the emission inventory presented in Table 1 is more accurate and far more consistent – and thereby better – than those calculated using the "old" methodology.

The sources included under "Other sources" in Table 1 contribute very low emissions. The contribution from some of them is far below 0.1 per cent of the total. No emissions were found for a few of the identified potential emission sources.

Based on the outcome of the survey, a new methodology for quantifying emissions has been proposed. Dedicated methods are recommended for the individual emission sources and sub-sources. Generic methods are recommended for the dominant proportion of the emission sources. These methods reflect the parameters which control the emissions. The use of generic methods will ensure consistency in the calculations over time and across facilities.

Installation-specific emission quantification methods are recommended for a few of the emission sources. These exist on only one or a few installations, and are so complex that a generic quantification method would not be adequate.

Where nine of the identified sources are concerned, the estimated emission inventories are very small (about 0.1 per cent in all of total direct methane and NMVOC emissions). The proposal is that operators do not need to quantify and report emissions from these sources individually, but instead cover all nine with a single percentage mark-up based on the sum of all other direct emissions from the facility – one per cent of the total, for example.

Many of the predominant emission sources produce waste hydrocarbon (HC) gases which can theoretically be recycled. The study has shown that recovery of such waste gases is a well-proven technique. The survey also found that the choice has been made on almost all installations on the NCS to emit methane and NMVOC from one or more of these sources, even though recovery could be an option. On the other hand, recovery is the chosen disposal solution for many of these emission sources on some installations. Technical or cost-related restrictions on the facilities without recovery may have made such action unfavourable. Where some of these facilities are concerned, direct methane emissions were not considered a climate challenge when the emission solution was chosen.

Where new installations are concerned, the recommendation is that waste gas recovery should be established as the BAT for emission sources/processes where recovery is feasible. Excluding small gas leaks and fugitive emissions, waste gas recovery could limit the direct release of methane and NMVOC from most of the new facilities to well below 10 tonnes per year per installation.

In the case of existing installations, recycling waste gas currently being emitted to the air will require technical modifications to processing plants. The associated costs may vary considerably from facility to facility. If the volumes of natural gas which can be recycled are small, the resulting income will be small and the abatement cost high. The recommendation is therefore that the industry applies a fictitious emission price in abatement cost calculations, based on the GWP₁₀₀ (global warming potential) of methane and NMVOC measured in CO₂ equivalents, combined with a CO₂ price consisting of CO₂ tax and the CO₂ emission allowance price. It is recommended that abatement cost calculations or assessments be done by the individual operators. Both abatement cost and an abatement assessment are included in requirements put by the NEA to the operators, with a deadline for response by 1 July 2016.

The emission reduction potential of existing facilities is regarded as limited, but an overall target of a 10 per cent reduction in direct methane and NMVOC emissions within a few years is assumed to be realistic. Reaching this target may be easier for some installations than for others.

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Abbreviations

BAT	Best available techniques
BREF	Best available techniques reference document
CAPP	Canadian Association of Petroleum Producers
CH₄	Methane
CFU	Compact flotation unit
CO₂	Carbon dioxide
CONCAWE	Association of oil companies which aims in part to improve understanding of the health and environmental aspects of refinery operations
DBB	Double block and bleed
DIAL	Differential absorption lidar
EEMS	Environmental and emissions monitoring system
FPSO	Floating production, storage and offloading
Fugitives	Or fugitive emissions: minor gas leaks through gaskets, stuffing boxes, etc
GM	Generic methodology
GRI	Gas Research Institute (the company which developed GRI_GLYCalc)
GWP	Global warming potential
HC	Hydrocarbon
IR	Infrared
FSM	Facility specific methodology
LDAR	Leak detection and repair
MEG	Monoethylene glycol
NMVOC	Non-methane volatile organic compounds
NCS	Norwegian continental shelf
NEA	Norwegian Environment Agency
NO_x	Nitrogen oxides
NS-EN 15446	Norwegian standard for fugitive emission calculations
N₂	Nitrogen
OGI	Optical gas imaging
O₂	Oxygen
P&ID	Piping and instrumentation diagram
Survey	Thorough assessment of offshore facilities performed as a part of the study
TEG	Triethylene glycol
US EPA	United States Environmental Protection Agency
VOC	Volatile organic compounds (methane + NMVOC)
IPCC	UN Intergovernmental Panel on Climate Change

1 Introduction

1.1 Background

Methane (CH₄) is a powerful greenhouse gas. It has a greenhouse effect (GWP) of 25 times the CO₂ equivalent in a 100-year perspective. Combined with relatively large emissions, this makes methane the dominant greenhouse gas after CO₂, both globally and in Norway. Norwegian methane emissions came to 217 000 tonnes in 2013 (Ref: 15), corresponding to 5.4 million tonnes of CO₂ equivalents, which was about 10 per cent of the country's greenhouse gas emissions in that year.

NM VOC are volatile organic compounds other than methane, which have regional environmental impacts through the formation of ground-level ozone from their interaction with nitrogen oxide (NO_x) emissions. It also has an indirect greenhouse effect through conversion to CO₂ in the atmosphere.

Petroleum activities on the NCS lead to greenhouse gas emissions. These are split for reporting purposes into methane and NM VOC. They derive from three main groups of sources/processes:

- a. unburnt natural gas from gas turbines, gas engines, boilers and gas flares
- b. vapour emitted from shuttle tankers when loading oil from offshore installations
- c. direct emissions, which comprise operational emissions (also called cold venting) and fugitive emissions and natural gas leaks.

Direct emissions of HC gases (item c above) contributed 80 per cent of methane and 26 per cent of NM VOC emitted by the Norwegian offshore oil and gas industry in 2013.

Operational emissions are waste gases containing HC which are purposely routed to the atmosphere from processes and sub-processes on the facility. Emissions usually take place through dedicated piping systems (cold vents) from where the gas is released to the atmosphere at a safe location.

Motives for releasing these gases as emissions to the atmosphere include:

- safety
- high content of inert gases, making it difficult to recover and flare the waste gas
- pressure conditions, requiring added compression for recovery/flaring
- unacceptably high cost of implementing waste gas recycling or flaring
- a combination of these reasons.

Fugitive emissions are small gas leaks through valve seals, flanges, flexible hoses and so forth. They can and do occur everywhere in processing facilities where gas is handled under pressure. Such emissions are difficult to localise, quantify and mitigate.

Annual inventories of direct methane and NM VOC emissions are reported by the operating oil companies to the Norwegian Environment Agency (NEA) in their annual emission and discharge reports.

Emission inventories are established using a generic methodology which has been in place since the mid-1990s. Based on a set of predefined emission sources and simple emission factors, the methodology is described in the emission reporting guidelines published by the Norwegian Oil and Gas Association (Ref: 16). Questions have been raised over several years about the relevance and accuracy of this methodology, whether all relevant sources are covered, whether the results are acceptable and whether the reported emission inventories can be trusted.

Based on the above, the NEA engaged Add Novatech AS to improve understanding of direct methane and NM VOC emissions from oil and gas facilities on the NCS and to provide background information on this subject.

1.2 Objectives

The objectives of the study were as follows.

1. To conduct a thorough survey in order to identify all sources of direct methane and NMVOC emissions from oil and gas production facilities on the NCS.
2. To investigate and evaluate how these emissions can best be quantified and to suggest a quantification methodology which can be used by the industry as a basis for future reporting.
3. To prepare a new and better emission inventory estimate.
4. To evaluate methods and techniques for emission mitigation, what can be regarded as BAT, and the potential for reducing emissions.

1.3 Study organisation

The study originally consisted of three modules.

- Module 1 mapped sources of direct methane and NMVOC emissions.
- Module 2 covered a review and revision of the quantification methodology and emission factors for future reporting, and aimed to establish a better emission inventory estimate.
- Module 3 highlighted emission abatement opportunities, including an assessment of what can be regarded as BAT for reducing direct methane and NMVOC emissions from offshore petroleum activities.

A fourth module was added at a late stage in the study. This sought to check and verify (if possible) some available emission factors for quantifying fugitive emissions by using measured emission data from land-based oil and gas processing facilities.

The study started in October 2014 and was completed in March 2016.

A work group (study reference group) was established for this study with participants from the NEA, Norwegian Oil and Gas, the Norwegian Petroleum Directorate, the Petroleum Safety Authority Norway and operating oil companies in Norway. The members of the work group are presented in Appendix 1. This group held six meetings during the course of the study.

1.4 Reports

In addition to this summary report, which is available in both Norwegian and English, a total of five sub-reports have been produced which are available in Norwegian only:

Module 1 – Surveying installations to identify potential emission sources

Module 2 – Emission estimates and quantification methods

Module 3 – Best Available Technique (BAT) assessments

Module 3B – Potential for emission abatement and reduction

Module 4 – Verification of emission quantification methods for fugitive emissions and small gas leaks

2 Method and study execution

The study started with a thorough survey of all Norwegian offshore facilities handling oil and gas. The purpose of the survey was as follows.

- To identify "all"¹ sources of direct methane and NMVOC emissions. "Sources" in this context mean those which generate waste gas containing methane and NMVOC.
- To establish a background for and understanding of why and how the emission sources arise.
- To establish an understanding of how emissions from individual sources can be quantified. This can involve measurement, direct or indirect calculation, or other quantification methods.
- To establish an overview of how waste gases from emission sources are disposed of on offshore oil and gas facilities, and of the disposal options which may be available on these. "Disposal" in this context means emitting the waste gas directly to the atmosphere, flaring it – thereby releasing it to the atmosphere as combustion gases (mainly CO₂) – or recycling it back to the process for recovery.
- To establish an overview of what the industry has done and could do to reduce direct methane and NMVOC emissions at the individual facilities and to set a more general industry objective for the future.

Work was conducted in two phases.

Phase 1 involved comprehensive reviews of 15 offshore facilities. These were conducted as full-day meetings attended by the operator's environmental coordinators and their process and facility engineers with in-depth knowledge of the process plants concerned. Specialists in certain areas were called on as required. Hydrocarbon 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* solutions which could be used in this study to establish better emission estimates. An action list was prepared, including work to be followed up by the operators after the meetings.

Based on the findings of phase 1, a questionnaire was prepared for phase 2 and sent to the operators of the remaining 53 offshore oil and gas facilities on the NCS. In addition to installations in operation, facilities being developed were also included. All operators responded. Inaccuracies in the responses were followed up and clarified via phone and e-mail.

The information obtained through these surveys provided the background for the emission source overview, the proposed new emission quantification methodology and the evaluation of emission reduction potentials presented in this report. That base was drawn on to develop a new emission quantification methodology for most of the emission sources, and a new emission inventory estimate was prepared. The emission inventory should be regarded as temporary, since it will be replaced by new data once the new emission quantification methodology has been adopted by the industry.

Where a few of the emission sources were concerned, information from the surveys was insufficient to develop new quantification methods and to prepare emission estimates. In these cases, the operators were requested to provide supplementary data. Taken together, this information has helped to establish better and more complete emission estimates, and provides the basis for developing a better emission quantification methodology for future reporting.

Only indirect and rather uncertain emission quantification methods were found to be available for small gas leaks. To verify these methods, an additional study was initiated. Four land-based petroleum processing plants in Norway were surveyed. Total methane and NMVOC emissions in dedicated areas at these plants were measured using the differential adsorption lidar (DIAL) method. Dedicated point sources (vents), combustion gases and fugitive emissions/small gas leaks were included. This supplementary work provided only limited constructive feedback to the study, owing to the short time available for the operators to establish emission estimates for the point sources (cold vents).

¹ "all" means sources which can yield significant emissions.

3 Direct HC gas emission sources

3.1 Current methodology for quantifying the emissions

A methodology for quantifying direct methane and NMVOC emissions was established in the mid-1990s by Aker Engineering (Ref: 6). This was based on 13 predefined potential emission sources. Several of these sources do not exist on most of the facilities. The methodology applies generic emission factors for methane and NMVOC emitted from each source. Emissions are calculated for each source using a source emission factor and an activity factor which, in the majority of cases, is the amount of gas processed in the facility. The following predefined sources were included

- glycol regeneration
- waste gas from the produced water system
- gas dissolved in liquid from the scrubber
- wet seal oil for compressors
- leakage through dry compressor seals
- equipment depressurisation
- purge and blanket gas
- flushing of instrument bridles
- extinguished flares
- small leakages
- annulus bleed from production strings
- drilling
- start gas for turbines.

The calculation methodology forms part of the emission reporting guidelines established by Norwegian Oil and Gas (Ref: 16).

As described in Section 1.1, this methodology is not very precise and directly inaccurate for some emission sources. That has also been documented in a report prepared by Add Novatech for Norwegian Oil and Gas in 2014 (Ref: 17). Apart from the inadequacy of the quantification methodology, the list of predefined sources is incomplete and to some extent imprecise. The need for a better quantification methodology has therefore been acknowledged, which will provide a more complete list of potential emission sources, more accurate quantification methods, and an overview of how direct methane and NMVOC emissions can be mitigated and reduced.

3.2 Updated sources for direct emission of methane and NMVOC

"All" potential sources were registered during the survey, regardless of the magnitude of their emissions, because it is as important to document that a source is small (or negligible) as it is to document that it is large. As a result, several "new" emission sources not covered in the current reporting regime were identified. Of equal importance was the discovery that many of the "old" sources consist in reality of several partly or fully independent sub-sources. The survey identified the importance of splitting some sources into such sub-sources – partly because the waste gas they emit was handled differently and partly because some of the sub-sources account for significant emission quantities.

The survey also established that some of the "new" sources/processes have historically been under the operator's radar. This may explain why information available from the operator for evaluating emissions from these sources was less relevant than for sources which had previously been in focus. A total of 48 processes/sub-processes producing HC waste gases which could potentially be emitted to the atmosphere were identified during the survey.

Table 2 Identified potential emission sources.

Main emission source/process	Sub-source/sub-processes
Triethylene glycol (TEG) regeneration	TEG degassing tank
	TEG regenerator
	Stripping gas for TEG regeneration
Produced water treatment	Produced water degassing tank
	Produced water flotation unit (off-gas from water)
	Flotation gas (where HC gas is used)
	Discharge caisson
Low pressure scrubbers	
Compressor seal oil (wet seals)	Degassing pots
	Seal oil holding tanks
	Seal oil 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	
Purge and blanket gas	
Depressurisation/gas freeing of instruments/instrument bridles	
Flare gas not burnt	Extinguished flare
	Delayed flare ignition
	Non-combustible flare gas
	Open cold flare purged with N ₂
Gas leaks in the process	Large gas leaks (requiring investigation)
	Small gas leaks/fugitives
Production riser annulus bleed	
Drilling	Shale shaker
	Mud separator
Direct emissions from gas turbines	Start gas for gas turbines
	Purging turbine at startup
	Depressurising turbines at shutdown
Monoethylene glycol (MEG) regeneration	MEG degassing tank
	MEG regenerator
	Stripping gas for MEG regeneration
Amin regeneration	Amin degassing tank
	Amin regenerator
Reciprocating compressors	Separator chamber
	Crankshaft housing
Screw compressors	
Liquid ring compressors	
Stripping gas for injection water	
Gas analysers and test/sample stations	
Pig launchers and receivers	
Corrosion coupons	
Flexible riser annulus bleed	
Gas freeing from oil storage tanks on FPSOs	Inspection of storage tanks
	Abnormal operating conditions
Consumption oil tanks (diesel, lubricating oil, etc)	
Double block and bleed (DBB) valves	

The sources shown in Table 2 represent an attempt at standardisation. Some of the processes generating HC waste gases may have facility-specific solutions which could differ from the distribution shown in the table.

As mentioned in Chapter 1.1, direct methane and NMVOC emissions may occur either as fugitive emissions/gas leaks or as operational emissions (cold venting). Fugitive emissions/gas leaks of methane and NMVOC occur on all facilities handling HC in gaseous form and can happen anywhere in the processing plants. Operational emissions of methane and NMVOC from the individual potential sources which have been identified occur from dedicated emission points (cold vents). None of the facilities on the NCS emit from all the sources listed in Table 2. This is because many facilities, for various reasons, do not possess the processes or sub-processes which generate waste gas containing methane and NMVOC. Furthermore, certain facilities with emission sources send the waste gas to recovery or flaring. Some registered sources are present on only a few facilities.

Potential amounts of waste gas from the individual processes vary enormously. While dominant emission sources may have the potential to produce waste gas quantities in excess of 100 tonnes per annum, some processes on the same facility generate no more than a few kilograms. This illustrates the importance of concentrating attention on the processes and sources which dominate the emissions.

4 Emission inventory estimates

4.1 Emission of methane and NMVOC by main source

The inventory of direct methane and NMVOC emission was recalculated/re-estimated. This was done partly using the emission quantification methodology recommended in this report (Chapter 5), and partly by Add Novatech and the industry jointly using the best available methodology for the relevant conditions. These have included supplier data, process simulations and measurements. Emissions were calculated for all installations handling HC gas and for all relevant sources. Where sources potentially producing very small emissions are concerned, calculations were carried out for a few installations or as examples to demonstrate that emissions will be small. These emissions were then scaled up to become representative for all facilities on the NCS. Emission estimates by main source are shown in Table 3 (2014).

Table 3 Emissions of methane and NMVOC for 2014 by main source [tonnes].

Main source:	Methane	NMVOC	VOC	% of total
Dry compressor seals	2 500	1 100	3 600	19%
Vent header (measured values)	1 950	1 350	3 300	17%
Produced water treatment	2 300	600	2 900	15%
HC purge and blanket gas	1 100	1 300	2 400	12%
Gas leaks/fugitives	1 250	950	2 200	11%
Flare gas not burnt	1 500	600	2 100	11%
Glycol regeneration	550	1 000	1 550	8%
Compressor wet seals	900	300	1 200	6%
Other sources	300	250	550	3%
Total	12 350	7 450	19 800	100%

Table 3 shows that the eight main sources contribute 97 per cent of total direct methane and NMVOC emissions. This indicates which sources should be given attention. To obtain a full understanding of the table, the following comments on the individual main sources should be noted.

1. Dry compressor seals

Used HC seal gas is emitted to the air from some facilities, resulting in high emissions. Most installations utilising HC seal gas send it to recovery or flaring after use.

2. Vent header (measured flow rate)

Waste gas from many of the direct emission sources are collected in a vent header, routing the waste gas to the atmosphere at a emission point in a safe location (also called the “common vent”) on the majority of the facilities. The gas flow through the common vent is metered on some installations. In such circumstances, the metered gas volume is used to express the amounts of methane and NMVOC emitted rather than calculating this from the individual contributors (sources). Real emissions from some sources are therefore higher than the table indicates. Two installations in particular contribute to the high emission estimate for the vent header.

3. Produced water treatment

The discharge caisson (discharge pipe to the sea) is the principal source for methane and NMVOC emissions from the produced water handling system. These emissions derive from depressurisation of the produced water discharged.

4. Hydrocarbon purge and blanket gas

Fuel gas is used as purge and blanket gas on some facilities. The rather high level of emissions is attributable to a small number of installations.

5. Gas leaks/fugitives

The uncertainty in emission estimates from small gas leaks and fugitives is very great, depending on the calculation method and emission factors used. See Section 4.4.

6. Flare gas not burnt

Some flares operate partly or wholly as cold. The principal contributor to unburnt flare gas is cold flares purged with inert gas. Delayed flare ignition represents another emission sub-source. No data are currently available, making it impossible to estimate emissions from this sub-source.

7. Glycol regeneration

This includes both TEG and MEG regeneration.

8. Compressor wet seals

Compressor seal oil is an emission source because of the solubility of methane and NMVOC in the oil. Wet compressor seals were a common technology in compressors installed before 1995. Establishing good quantification methods for these emissions has been very difficult, and the operators are still working on this problem. The emission data in the table should therefore be regarded as preliminary.

9. Other sources

These comprise emissions from all other identified sources (see Section 4.2).

As shown in Table 3, total direct methane and NMVOC emissions represented a loss of 0.018 per cent from total Norwegian gas production in 2014.

4.2 Emissions from other sources

"Other sources" in Table 3 cover several minor sources, as presented in Table 4.

Table 4 Emissions of methane and NMVOC from other sources [tonnes].

Emission source	Methane	NMVOC	VOC	% of total
Amine regeneration	95	40	135	0.68%
Gas analysers and test/sample stations	71	54	125	0.63%
Drilling	57	57	114	0.57%
Gas freeing from oil storage tanks on FPSOs	71	55	126	0.64%
Gas freeing from process plants	18	16	33	0.17%
Double block and bleed (DBB) valves	1.2	1.1	2.3	0.01%
Low-pressure scrubbers	2.6	1.8	4.4	0.02%
Flexible risers	2.3	1.8	4.0	0.02%
Oil tanks (diesel, lubricating oil, etc)	-	3.5	3.5	0.02%
Pig launchers and receivers	3.6	2.3	6.0	0.03%
Direct emissions from gas turbines	0.5	0.5	1.1	0.01%
Depressurisation/gas freeing from instruments/instrument manifolds	0.05	0.04	0.09	< 0.01%
Corrosion coupons	0.01	0.00	0.02	< 0.01%
Annulus bleed in production riser	0.00	0.00	0.01	< 0.01%
Total	322	232	554	2.8%

Only one facility has emissions from amine regeneration. Each of the nine emission sources marked in orange contribute well under 0.1 per cent of total emissions.

Emissions from gas analysers and test/sample stations come from a few facilities taking gas samples for analysis from a slipstream bleeding off to the atmosphere on a continuous basis. Emissions from analysers and from samples sent to land are insignificant.

Emissions from drilling are calculated on the basis of 227 exploration and production wells completed in 2014 and the recommended emission factors provided in the Module 2 report (Ref: 2). Calculations can be somewhat conservative, since the emission factors assume that the wells penetrate HC-bearing formations, which is not the case for most exploration wells.

4.3 Impact of emissions on the climate

Methane is a powerful greenhouse gas with a GWP (global warming potential) of 25 times the CO₂ equivalent². This means the greenhouse contribution made by direct methane emissions from offshore installations amounts to some 300 000 tonnes of CO₂ equivalents, corresponding to 2.5 per cent of total greenhouse gas emissions from Norway's offshore oil and gas facilities.

Similarly, NMVOC emissions contribute indirectly to the greenhouse effect since these gases are oxidised to CO₂ in the atmosphere. NMVOC has a GWP of 4.5 times the CO₂ equivalent.

4.4 Uncertainty in the estimates

By their nature, direct methane and NMVOC emissions are difficult to quantify. Extensive use must be made of indirect quantification methods. This can be done by utilising emission factors combined with a specified activity factor or with other methods. Typical examples of using emission factors include:

- methane emissions from drilling can be calculated with a fixed emission factor per wellbore drilled:

$$\text{methane emission (tonnes)} = \text{number of wellbores} \times \text{emission factor for methane (tonnes/wellbore)}$$

- emission of NMVOC from the produced water discharge caisson can be calculated using an emission factor, the produced water discharge volume and pressure loss from the upstream degassing tank:

$$\text{NMVOC emission (tonnes)} = \text{produced water discharge volume (m}^3\text{)} \times \text{pressure loss (bar)} \times \text{emission factor for NMVOC (tonnes/bar/m}^3\text{)}$$

An example of emissions calculated using other methods might be:

- emissions from glycol regeneration can be estimated by using the GRI_GLYCalc emission calculation programme.

Accurate quantification methods are difficult to find for some sources. This indicates that uncertainties in the emission inventory can be large and difficult to quantify.

Among the larger emission sources, uncertainty is assumed to be greatest for small gas leaks/fugitive emissions. Fugitive emissions are gas leaks through flanges, valves and so forth which are (generally) smaller than 0.1 kg per second and not considered to constitute a safety threat at the facility. Fugitive emissions are often so small that they cannot be detected using stationary gas detectors or portable detectors during regular inspection of processing plants. Such emissions are very difficult to quantify, but a few methods do exist. One is "bagging", where the component is isolated in a plastic bag and emissions (if present) are measured over time. Another method is soap spraying and counting gas bubbles. This method is somewhat more uncertain. Were these methods alone to be applied for all components with leakage potential on a facility, the work and cost involved would exceed the level which is feasible in practical and economic terms.

² 100-year perspective

The Dial method, involving remote measurement of methane and NMVOC concentrations, is used at land-based gas plants but cannot be applied on offshore facilities.

Quantification methods using a gas sniffer in combination with statistics are recommended in a protocol from the US Environmental Protection Agency (EPA) (Ref: 9). This covers all types of industrial plants with a potential to produce fugitive HC gas emissions. The protocol forms the basis for much of the subsequent efforts to establish practical methods for quantifying fugitive emissions and small gas leaks. This includes work done by the Canadian Association of Petroleum Producers (CAPP) for 120 upstream land-based oil and gas installation in the provinces of Alberta and British Columbia. These facilities contain more than 270 000 valves, flanges and other components which are potential gas leak sources. Canada implements a standardised programme for inspection, identification and repair of leakage points (also called LDAR). This largely corresponds with the programme used on Norwegian offshore facilities. The CAPP has developed average emission factors per component type through surveys of the 120 facilities. These average factors, combined with an estimated number of components per component type for all Norwegian offshore installations, are used as the basis for estimating emission inventories from small gas leaks as presented in Table 3. The number of components was extrapolated from 11 Norwegian offshore installations which conducted component counts.

The protocol from the US EPA forms the basis of a European standard for quantifying gas leaks and fugitive emissions, which has also been adopted as a Norwegian standard (NS-EN 15446: 2008). According to this standard, all components which could leak HC gases must be sniffed but with "default" factors for use with inaccessible components. As a check, small gas leaks from Norwegian offshore facilities were also calculated using these default factors, as presented in Table 5.

Table 5 Methane and NMVOC emissions in 2014 by main source, with small gas leaks calculated on the basis of Norwegian standard NS-EN 15446 [tonnes].

Main source:	Methane	NMVOC	VOC	% of total
Dry compressor seals	2 500	1 100	3 600	12%
Vent header (measured values)	1 950	1 350	3 300	11%
Produced water treatment	2 300	600	2 900	10%
HC purge and blanket gas	1 100	1 300	2 400	8%
Gas leaks/fugitives	7 100	5 400	12 500	41%
Flare gas not burnt	1 500	600	2 100	7%
Glycol regeneration	550	1 000	1 550	5%
Compressor wet seals	900	300	1 200	4%
Other sources	300	250	550	2%
Total	18 200	11 900	30 100	100%

Table 5 shows that calculations using the default factors in the NS-EN 15446 yield emissions from small gas leaks which are almost six times higher than when calculated with the CAPP's average factors. One reason may be that the default factors in the Norwegian standard are deliberately conservative, since they are only to be used for components which are inaccessible for sniffing.

A review of four land-based petroleum installations (Kollsnes, Kårstø, Nyhamna and Melkøya) were also analysed. One objective was to compare the results of emission measurements using the Dial method, where emissions are calculated using component counts from these facilities together with the emission factors in the CAPP report and the Norwegian standard. To achieve this, emissions from all point sources (operational emissions) had to be established and then deducted from total measured emissions to find the contribution from small gas leaks/fugitives. Owing to the short time available, a complete overview of operational emissions (vents) could not be achieved. Despite these problems, it became clear that gas leak emissions measured with Dial at the land-based plants were significantly higher than those calculated using emission factors from both the CAPP report and the Norwegian standard for the same plants. The deviations were up to several hundred per cent.

Statoil has provided supplementary information to this study by making available the results of gas leak measurements on the two Draupner installations (Ref: 14). These measurements were made by scanning all valves and flanges with an infrared (IR) camera (the OGI method) to identify leaks. All those detected were then measured with soapy water and bubble count using a standardised method. This yielded emission results which were a 10th or less of the emission results obtained using the factor methods from the CAPP report and the Norwegian standard.

The comparisons above indicate that quantifying small gas leaks and fugitive emissions is associated with very considerable uncertainties. Simple factor-based methods will therefore fail to provide reliable emission inventory estimates for small gas leaks. This is taken into account in the recommended new emission quantification methodology (see Chapter 5).

This indicates that uncertainty in total emissions is linked largely to fugitive emissions and small gas leaks. The overall uncertainty of the total emissions shown in Table 3 is qualitatively estimated to be in the order of tens of percentage points. Unlike the previously reported emission inventories, however, the emission inventory estimates given in the table are established by using more consistent methods and should therefore provide more accurate results.

4.5 Comparison with previously reported emission data

Figure 1 shows the development of direct methane and NMVOC emissions reported in the annual emission reports to the NEA using the old calculation methodology (see Chapter 3.1).

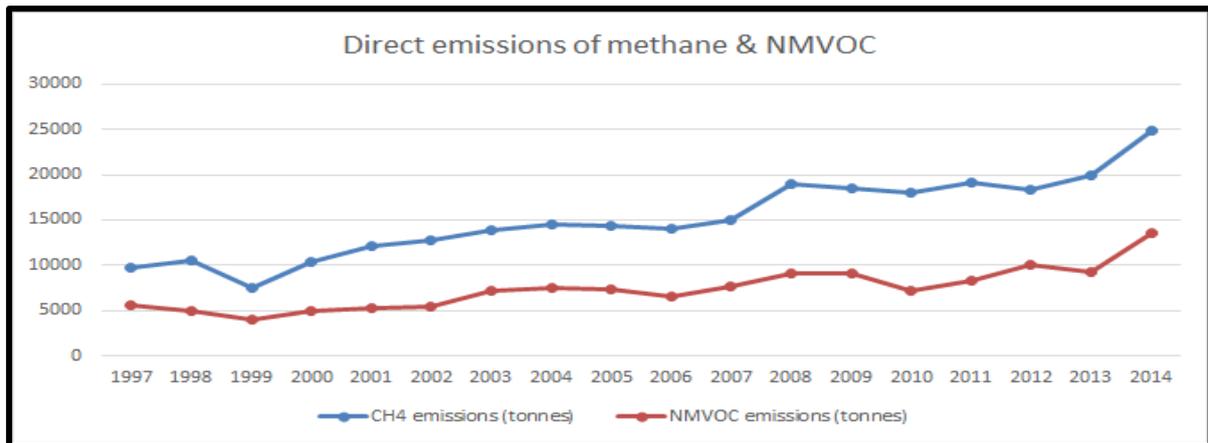


Figure 1 Reported methane and NMVOC emissions from 1997 to 2014.

Table 6 compares total direct emissions of methane and NMVOC inventories reported for 2014 with new emission estimates, where small gas leaks are calculated using average factors from NS-EN 15446 and the CAPP report respectively.

Table 6 Emissions in 2014. Reported emission inventories compared to new estimates.

Calculation method	Methane [tonnes]	NMVOC [tonnes]
Reported emissions (old method)	24 922	13 553
New estimate (NS-EN 15446)	16 700	10 800
New estimate (CAPP)	10 850	6 350

The table indicates that emissions were overestimated using the old quantification methods. However, it should also be borne in mind that the uncertainty of new estimates for small gas leaks is very high.

5 Proposed principles for a new emission quantification methodology

5.1 Main quantification principles

The survey demonstrated that using processed gas volumes as an activity factor (the approach taken by the current methodology) is inadequate for most emissions sources/processes. Emissions are controlled by other conditions and parameters, making the real emission inventories from some of the sources substantially different from those previously reported.

On the basis of the survey results and the potential emission-generating processes and sub-processes (emission sources) identified in Module 1 of this study, new principles for a future emission quantification methodology were developed and proposed.

None of the facilities which handle oil and gas have emissions from all of the identified sources, but all facilities have emissions from some of them. The proposed emission quantification methodology will therefore apply only to those installations which possess the relevant potential emission source and, in addition, route the waste gas from that source to the atmosphere.

Generic quantification methods are proposed for the majority of the emission sources. These are regarded as favourable because they ensure consistency between different operators, and make it possible to obtain consistent data trends year by year. Moreover, generic methods simplify the emission inventory calculation work for the operators.

However, facility-specific quantification methods are recommended for some processes. That applies particularly to emission sources with such great variations and complexity that generic methods might easily yield inaccurate results, and to those found only on one or a few facilities. Facility-specific quantification methods should be established by the relevant operating oil company. It is recommended that the operator should demonstrate the accuracy/adequacy of the proposed method.

Using generic quantification methods where available is recommended. Should an operator prefer to apply a facility-specific method because it would give a better and more accurate emission inventory, however, this should be accepted providing documentation substantiating the proposal is provided.

New, not yet identified emission sources may be anticipated on future installations. In such cases, the recommendation is that the relevant operator establishes new facility-specific emission quantification methods for the source(s) in question.

For some processes/sub-processes, a combination of emission factors and activity factors is recommended. The activity factor which control emissions could, for example, be produced water volume and the number of wellbores. Otherwise, the methods may vary widely:

- measurement/sampling
- process simulations / use of special computer programmes
- utilising available registered measurement data
- logging of incidents (for batch emissions)
- supplier data.

Two alternative generic methods are proposed for some of the sub-processes. This is because one of the methods requires the use of specific commercial software.

Table 7 presents an overview of the recommended categories of quantification methods for the various sources. In the method category column, GM stands for generic method and FSM for facility-specific method.

Table 7 Overview of proposed emission quantification methods by potential emission source.

Main source	Sub-source	Method category	General definition
Triethylene glycol (TEG) regeneration	TEG degassing tank	FSM	Dedicated computer programme (GRI-GLYCalc, for example)
	TEG regenerator	GM	Analysis of TEG solution, alternatively the GRI-GLYCalc software
	Stripping gas	GM	Stripping gas flow rate
Produced water treatment	Produced water degassing tank	GM	Based on the pressure reduction and produced water volume
	Flotation tank / CFU	GM	Based on upstream pressure and produced water volume
	Flotation gas	GM	Hydrocarbon flotation gas flowrate
	Discharge caisson	GM	Based on the upstream pressure and produced water discharge volume
Compressor seal oil (wet seals)	Degassing pots	FSM	Established by each operator
	Seal oil holding tank	FSM	Established by each operator
	Seal oil storage tank	FSM	Established by each operator
Reciprocating compressors	Separator chamber	FSM	Simulations, vendor data, etc
	Crank house	FSM	Simulations, vendor data, etc
Dry compressor seals	Primary seal gas	GM	Seal gas metering/supplier data
	Secondary seal gas	GM	Seal gas metering/supplier data
	Leakage of primary sealing gas to secondary vent	GM	Seal gas metering/supplier data
Flare gas not burnt	Extinguished flare and delayed flare ignition	GM	Logging of time with unignited flaring/flare gas metering
	Non-combustible flare gas	FSM	Established by each operator
	Open cold flare purged with inert gas	GM	Flare gas metering
Leakages in the process	Large gas leaks	GM	Emission rate, duration, volume (current practice)
	Small gas leaks/fugitive emissions	GM	OGI "leak/no leak" method
Cold vent		GM	Waste gas metering/determining flow rate
Purge and blanket gas		GM	Purge/blanket gas metering/flow rate determination
Monoethylene glycol (MEG) regeneration	MEG degassing tank	GM	Recognised computer programmes (GRI-GLYCalc, MultiPro Scale, etc)
	MEG regenerator	GM	Recognised computer programmes (GRI-GLYCalc, MultiPro Scale, etc)
	Stripping gas	GM	Stripping gas flow rate
Amine regeneration	Amine degassing tank	FSM	Established by each operator
	Amine regenerator	FSM	Established by each operator
Gas analysers and test/sample stations		GM	Slipstream flowrate
Drilling		GM	Emission factor per completed wellbore
Gas freeing of FPSO oil storage tanks		GM	Storage tank volume
Gas freeing of process plants		GM	Volume of process plant

The proposed new methodology would ensure that future emission inventory reports are more consistent and correct than the estimates provided in Chapter 4 of this report. However, the nature of direct methane and NMVOC emissions indicates that substantial uncertainties should continue to be expected after the proposed new quantification methodology has been implemented.

Implementing the proposed quantification methodologies will ensure that the quality of emission inventory reports for direct methane and NMVOC emissions from offshore facilities will be significantly better than in previous reports, and at least as good as in comparable countries.

5.2 Emission sources with minor contribution

The survey showed that emissions from several identified emission sources are too small to have any significant impact on total emissions. As a result, no separate emission inventory calculations for these sources are proposed. Instead, a small mark-up should be added to the total estimated emissions to cover all these small sources. The emission sources shown in Table 8 contribute about 0.1 per cent of the total direct methane and NMVOC emissions presented in Table 3.

Table 8 Emission sources to be covered by a general percentage mark-up.

Emission source
Screw compressors
Double block and bleed (DBB) valves
LP scrubbers
Flexible risers
Oil tanks (diesel, lube oil, etc)
Pig launchers and receivers
Direct emissions from gas turbines
Flushing and depressurisation of instruments and instrument bridles
Corrosion coupons
Annulus bleed from production risers

5.3 Contribution from international work

Quantification methodologies used in other countries for direct methane and NMVOC emission inventory were investigated as a part of this study. The status in countries with a comparable industry to Norway, such as the UK, Denmark, the Netherlands, the USA, Canada and Australia, were studied. The investigation showed that methodologies used in these countries accord to some extent with the existing Norwegian approach in terms of relevance and accuracy. However, some exceptions do exist.

- Comprehensive work to map and develop quantification methods for methane and NMVOC emissions from glycol regeneration has been carried out in the USA.
- Much work has been done on better methods for quantifying fugitive emissions and emissions from small gas leaks, particularly in the USA and Canada. These efforts are also being followed up and utilised by other countries and parties. Part of the European Petroleum Refineries Association, Concawe works on such issues as environment-related problems in the refinery industry. Large oil companies in the European Economic Area (EEA) are members.

This study recommends that results and information from this work are utilised to the benefit of the Norwegian oil and gas industry. It is proposed that a software application developed by the American Gas Technology Institute to quantify waste gas rates (and emissions) from glycol regeneration be used on Norwegian installations. This programme (GRI-GLYCalc) has been tested on the basis of measurements taken from a series of American facilities, and is approved by the US EPA. It has also been tested by Statoil with good results. It is also proposed that small leakages / fugitive emissions be quantified according to the "OGI leak/no leak" method, developed in the USA based on substantial R&D work.

5.4 Quantification of emissions from small leakages / fugitive emissions

Selection of the quantification method for fugitive emissions/small gas leaks is important – because this source can be a dominant contributor to direct methane and NMVOC emissions and because this study has demonstrated very substantial uncertainties associated with their quantification. The US EPA published a protocol in 1995 (Ref: 9) which described a quantification method based on a

combination of leak detection by sniffer (using a specific procedure) and statistical distributions of emission rates for different components with a leak potential (control valves, other valves, flanges and so forth). Sniffing is a complicated, demanding and expensive operation.

New techniques are now emerging. Among these is the OGI "leak/no leak" method, which has received considerable attention. This is based on using an IR camera for leak detection in combination with a database containing all components with a potential for HC gas leaks. All components in the database are "scanned" for leakage by the IR camera. Component leak factors developed statistically are used to calculate emissions from all leaking components (high leak factor) and for all non-leaking components (low leak factor). Components with no documented leak also do leak.

Concawe has completed a comprehensive project which concluded that the OGI method provides comparable results to the sniffing approach. It was also checked against controlled leak measurements using the bagging technique, and found to provide comparable or more conservative results. The OGI method has several advantages over sniffing. Leaks from components inaccessible to sniffing can be detected, for example. The method is faster, less resource-intensive, far cheaper, and likely to replace sniffing eventually. The OGI method is therefore recommended for quantifying fugitive emissions and small gas leaks from Norwegian offshore facilities.

5.5 Flow rate metering

Where some of the sources are concerned, a proposed method for quantifying emissions is the gas flow rate. This applies to processes where HC gas is added to the process and subsequently emitted (by gas stripping, for example). The method could also apply to emissions through common cold vents which contain waste gases from various sources. Where smaller gas volumes are concerned, the flow rate could be determined by simple calculations. Metering is recommended for more substantial emissions. Some facilities have already installed flow meters on their common vents to the atmosphere, but retrofitting a flow meter on a facility in operation can be costly.

Ultrasonic flow meters were found to represent the most attractive metering principle. The use of ultrasonic flow meters may also enable the gas phase to be split into methane and NMVOC. Ultrasonic meters can be installed on HC gas piping by hot tapping. These units can also be installed externally as a clamp-on meter. That applies primarily to feed streams under pressure, such as stripping gas, purge gas and so forth. Clamp-on meters are not recommended today for low-pressure emission streams.

In most cases, waste gases emitted through common cold vents contain varying quantities of other gases, such as CO₂, water vapour and N₂. These will be included in the metered results. In cases where flow meters are used for quantification, non-HC gases should be quantified, documented and subtracted from the total.

5.6 Split between methane and NMVOC

The composition of emission gases varies from source to source, and from facility to facility. Since direct emissions must be reported as methane and NMVOC, the gas composition needs to be known. The exact composition of many waste gases is unknown. However, the survey indicated that waste gas composition from many sources does not differ much from fuel, flare or sales gas composition. Since the composition of these gases is determined by regular sampling and analyses, it is recommended that fuel, flare or sales gas composition be used in many cases. Each operator should therefore assess which of these gas analyses is most representative, and use this as the basis for establishing the distribution of methane and NMVOC from individual sources.

However, gas emitted from some sources may differ radically in composition from fuel, flare or sales gas. In such cases, composition could be determined by specific calculations or simulations. Typical examples are waste gases from produced water treatment and from MEG or TEG regeneration.

Where some other sources are concerned, such opportunities do not exist and separate gas sampling and analyses may be required. However, this can be complicated and expensive. The recommendation in such cases is therefore that sampling and analyses be limited to waste gases making a significant contribution to total emissions, and only if satisfactory data on composition cannot be obtained by other and simpler methods.

6 Emissions abatement opportunities

Direct methane and NMVOC emissions to air from some sources/processes also occur because they cannot be eliminated or significantly reduced. This applies to fugitive emissions and to some operational emissions. However, many of the latter can theoretically be eliminated with the use of simple techniques:

- off-gas can be recycled back to the process and recovered
- N₂ can be used as stripping and flotation gas instead of HC gas
- N₂ can be used as secondary seal gas in compressors instead of HC gas
- N₂ can be used as purge and blanket gas instead of HC gas.

These solutions are already selected and in use on many existing Norwegian facilities. Such sources account for a significant share of direct methane and NMVOC emissions from offshore installations.

6.1 Emission sources which can theoretically be eliminated by gas recovery

The table below gives an overview of sources producing waste gas which can in theory be recovered.

Table 9 Emission sources which can theoretically be eliminated with recirculation and recovery.

Main source	Sub-source
Glycol regeneration	All sub-sources
Produced water treatment	Produced water degassing tank
	Flotation tank
	Flotation gas
Compressor seal oil	All sub-sources
Dry compressor seals	Vent from primary barrier
	Vent from secondary barrier (when HC gas is used)
Gas analyses and sampling	Slipstreams continuously emitted

These are significant emission sources. In addition come many small sources (see Table 4).

Recovery of waste gas from these sources and sub-sources has been implemented on many facilities on the NCS. On some of these, the waste gas is flared. This eliminates direct methane and NMVOC emissions, but emits more CO₂ and other combustion products, including NO_x and particles.

A number of reasons may exist for routing waste gases to direct emission, including a lack of attention to reducing methane and NMVOC emissions in the conceptual design phase. Facility-specific conditions which show that recovery is more complicated and expensive than emitting waste gases may also have been decisive.

Based on the information collected in this study, no clear tendency can be seen towards recovering off-gases on new installations which came on stream after 2000 compared with older installations.

6.2 Use of nitrogen (N₂) instead of HC gas

Using HC gas as flotation, stripping, purge and blanket and secondary seal gas in compressors creates no emission problems if the waste or used gas is recovered. Problems only arise if it is released to the air. The study revealed that many facilities use HC gas as stripping gas in glycol regeneration systems and route the waste gas to the air. Some installations had initially used N₂ for stripping, but replaced this with HC gas after a period. The reason was that small amounts of O₂ in the N₂ gas caused oxidation and degeneration of the glycol solution. One solution to this problem could be purer (and more expensive) N₂.

Some facilities use HC gas instead of N₂ as a secondary barrier gas in the dry compressor seal system. Some operators reported that HC gas was selected because N₂ caused corrosion in the seals owing to trace amounts of oxygen. Again, purer N₂ could be a solution.

6.3 New technology

Where most emission sources are concerned, existing well-proven technology is capable of eliminating or reducing emissions. But new or improved technology is required for some sources.

Direct emission of HC gas from the flare prior to ignition (delayed flare ignition) occurs mainly because of inefficient ignition technology. Some information collected through the survey indicates that the ballistic ignition system, which involves shooting a pellet along a guide tube to a spark plate at the flare tip, leads to faster and more secure ignition than ignition using a signal gun. The industry is therefore recommended to check this out more closely.

6.4 Emission sources which are difficult to eliminate

Unlike the emission sources mentioned above, several cannot be eliminated in practice. The most important of these are listed in Table 10.

Table 10 Emission sources which are difficult to eliminate.

Main source	Sub-source	Methane + NMVOC emissions (tonnes)
Small gas leaks		2 200
Produced water treatment	Discharge caisson	2 150
Flare gas not burnt	Open cold flare purged with N ₂	1 750
Amin regeneration		135
Depressurising oil storage tanks on FPSOs		126
Drilling		114
Depressurisation/gas freeing from instruments/instrument bridles		33
Flaring	Extinguished flare and late ignition	Unclarified
Double block and bleed (DBB) valves		2
Flare gas not burnt	Delayed flare ignition	4
Depressurisation/gas freeing from instrument bridles		< 1
Gas analysers and sampling		< 1
Flare	Non-combustible flare gas	See note

Note: only one facility has flare gas which is not combustible. The corresponding emissions are reported under amine regeneration.

Three emission sources predominate in Table 10.

- Small gas leaks cannot be eliminated, but can be reduced through continuous and effective monitoring, control and repair. Internationally, this is covered by the term LDAR. Operators on the NCS monitor gas leaks continuously with procedures which are in line with LDAR.
- Emissions from produced water discharge caissons occur mainly on facilities where substantial produced-water discharges are combined with a large pressure drop from the closest upstream degassing tank to the discharge point. Emissions can be reduced by lowering pressure in the degassing tank, and by reinjecting some or all of the produced water.
- Emissions from an open cold flare purged with inert gas occur on very few facilities. Where this flare concept has been selected, emissions cannot be eliminated but only reduced. Switching to

another flare concept can be very expensive or impossible on practical grounds for some of these facilities.

Comments for the other sources.

- Emissions from drilling cannot be eliminated, merely reduced to some degree. A large part of drilling activity takes place on mobile rigs, which do not have flares or processing facilities which enable gas recovery.
- Emissions related to gas freeing from process systems and crude oil storage tanks on FPSOs cannot be reduced nor eliminated in a practical way. The tanks and process systems are purged with N₂ as a part of the gas-freeing process, thereby gradually increasing the N₂ concentration in the waste gas emitted. Separating HC gas from N₂ will be very expensive, especially given the small gas volumes involved.
- Emissions from delayed flare ignition can be reduced to some extent – but not eliminated – by using better ignitions techniques.
- Emissions from gas analyses and sampling are small, but can be reduced significantly by modifying slipstreams which continuously emit gas to the atmosphere. Remaining emissions will then be negligible.

6.5 Best available techniques (BAT)

No "best available techniques reference (BREF) documents" are available which specifically cover BAT related to direct HC gas emissions from the oil and gas industry. However, the EU has initiated a process to establish such a document for petroleum production. With reference to the identified emission sources, this report proposes that techniques and solutions which eliminate methane and NMVOC emissions and are already implemented on Norwegian facilities should be regarded as BAT.

The study documented that recovering waste gases by recycling back to the process is a well-proven technique which can be used for most of the potential emission sources (processes and sub-processes) producing waste gases with methane and NMVOC. Where processes enabling waste gas recovery are concerned, that solution has been chosen for several Norwegian facilities. The survey also found that almost all existing Norwegian installations send waste gases with methane and NMVOC to the atmosphere as emissions from one or more sources, even if recovery is an option. On some installations, the emission option is selected for several of the processes generating potentially recoverable HC waste gases. However, technical or cost-related restrictions on these installations could favour the emission option. It should also be borne in mind that the environmental aspects of methane and NMVOC were not well known and not given much attention when some of these installations were designed and built.

Where the construction of new offshore production facilities is concerned, recovery of HC waste gas from the majority of sources with a potential for substantial emissions should be regarded as BAT. Table 11 presents an overview of proposed BAT for the major direct sources of methane and NMVOC emissions.

Table 11 Proposed BAT for new installations.

Main source	Sub-source	Proposed BAT, new installations
Purge and blanket gas		Use N ₂ if recovery is impossible in practical terms
Glycol regeneration	All sub-sources	Waste gas recovery Use N ₂ as stripping gas
Produced water treatment	Produced water degassing tank	Waste gas recovery
	Flotation tank	Waste gas recovery
	Flotation gas	N ₂ as flotation gas Waste gas recovery (when HC is used as flotation gas)
	Discharge caisson	Re-inject all produced water Low pressure in the upstream degassing tank
Compressor seal oil (wet seals)	Degassing pots, oil tanks, separator chambers	Waste gas recovery
Dry compressor seals	Vent from primary barrier	Waste gas recovery
	Vent from secondary barrier	Use N ₂ as seal gas Waste gas recovery (when HC is used as seal gas)
	HC gas leakage to secondary vent	Use leak-proof seal gas system (internal labyrinth)
Gas turbines	Start gas	Do not use HC start gas (not used today)
	Purge of turbines at startup	Waste gas recovery
	Depressurising residual gas at turbine tripping	Waste gas recovery
Gas analysers and test/sample stations		Recovery of slipstream gas
Low pressure scrubbers		Waste gas recovery
Pig launchers and receivers		Waste gas recovery
Annulus bleed in production riser		Waste gas recovery
Annulus bleed in flexible riser		Waste gas recovery

However, recovery is not possible for some emission sources with currently available techniques. Gas leaks are the most important of these. The BREF document for oil and gas refineries refers to LDAR as a systematic method for reducing fugitive gas leaks. It states:

"Fugitive VOC emissions can be reduced by the detection and subsequent repair or replacement of leaking components. This is achieved by adopting a structured approach, commonly known as a leak detection and repair (LDAR) programme. A LDAR programme includes two fundamental steps:

- *identification of the leaking components;*
- *repair of these leaks in order to minimise losses."*

The survey of the Norwegian installations showed that the operators use the LDAR method to monitor and inspect gas leaks, even if this is not covered by industry guidelines. Considering LDAR as a BAT for inspecting and controlling gas leaks is recommended.

Since cost also forms part of the BAT concept, techniques regarded as BAT for new installations are not necessarily BAT for existing facilities. In some cases, technical modifications to implement BAT solutions can become very expensive. Piping systems may have to be converted, LP compressors could need to be installed, and safety and technical challenges must be solved. Since each facility is designed and constructed differently, the cost of modifications to solve supposedly the same problem

may vary significantly from one facility to another. This means that a measure which has a low abatement cost for one facility may cost much more on another.

Since such modifications could involve hot work in process areas, conversion and modification work may have to be carried out when production is shut down. If the work cannot be done during normal turnarounds, production may have to be suspended specifically for such work.

Giving priority to the measures with the lowest abatement costs is recommended if existing installations are to be upgraded to meet the recommended BAT solution. In most cases, this would involve curbing the sources with the greatest emissions.

6.6 New versus existing facilities

Using the recommended emission-free techniques on new installations can significantly reduce direct methane and NMVOC emissions compared with facilities on stream today. The additional cost of implementing such measures on new installations is considered to be small or non-existent, but facility-specific exceptions may occur. Disregarding small gas leaks, annual emissions could be limited to less than 10 tonnes of HC gas (methane plus NMVOC) per facility for installations without crude-oil storage. Installations with such storage (eg, FPSOs) will have somewhat higher emissions because of the need to gas-free the tanks for inspection.

The position is completely different for existing rather than new facilities. Implementing emission-free techniques on existing installations is also technically feasible, but the considerable conversion work which might be required would yield high abatement costs. Since the scope of such conversion might vary significantly from one facility to another because of different designs and conditions, costs cannot be calculated on a general basis for each abatement measure. No good basis therefore exists for calculating a realistic potential for emission reductions. Based on a qualitative assessment per emission source, however, it should be possible to reduce emissions from existing installations by at least 10 per cent over a few years. That would very much depend on the industry's future operating conditions. The uncertainty is considered to be substantial.

Abatement costs are difficult to calculate because modification costs are unknown and methane and NMVOC emissions do not have a defined price. This study recommends that the industry uses a fictitious price for waste gases in its abatement cost calculations. This should be based on the GWP₁₀₀ of methane and NMVOC measured in CO₂ equivalents, combined with a CO₂ price consisting of CO₂ tax and CO₂ emission allowance price. It is recommended that the abatement cost for each facility be calculated or assessed by the operating companies, with attention directed at the dominant emission sources.

7 References

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Appendix 1 The study work group

The project had a work group with the following members.

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Bjørn A Christensen, NEA
Tor Fadnes, Norwegian Petroleum Directorate (first half of the study)
Halvard Hedland, Norwegian Petroleum Directorate (second half of the study)
Espen Landro, Petroleum Safety Authority Norway
Hildegunn T Blindheim, Norwegian Oil and Gas Association
Odd-Arne Follum, Statoil
Bjørnar Lassen, ExxonMobil
Erik Husby, Norske Shell
Eirik Høvring, Engie
Ole Bakkevold, Repsol
Øyvind Hille, Det Norske
Anne Kristine Norland, ConocoPhillips (second half of the study)