RECOMMENDED PRACTICE
DNV-RP-F302

SELECTION AND USE OF SUBSEA LEAK DETECTION SYSTEMS

APRIL 2010

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This document is valid until superseded by a new revision. Minor amendments and corrections will be published in a separate document normally updated twice per year (April and October).

For a complete listing of the changes, see the "Amendments and Corrections" document located at: http://webshop.dnv.com/global/.

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INTRODUCTION

— **Background**

Production systems for hydrocarbons are complex installations and it is known in the industry that smaller and larger unwanted leakages occur and cause discharge of hydrocarbons to the surroundings. Today, both operators and authority awareness towards the environmental impact of oil and gas production is constantly increasing.

In spite of the fact that methods for subsea leak detection have been available in the market for years, there are still gaps to fill concerning the design, engineering and operation of such methods to make them reliable for detection of discharge to the environment. Thus, there is a need for an industry reference in this technology field which can serve as a guideline today and a tool for coordinating the development of the field in the future.

This Recommended Practice (RP) summarizes current industry experiences and knowledge with relevance to selection and use of detectors for a subsea leak detection system. It covers relevant regulations, field experience and available technologies and also gives guidance on how to design and operate a system for subsea leak detection and recommendations for developments needed in this field of technology.

— **Acknowledgment**

This RP is developed within a Joint Industry Project. including: ConocoPhillips, ENI Norge, Shell and Statoil. In addition a broad selection of engineering companies and subsea leak detection technology suppliers have participated in workshops and hearing rounds.

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1. Introduction

1.1 Objective

The objective of this best practice is to summarize industry experiences and knowledge with relevance to selection and use of detectors for a subsea leak detection system. The intent is that this document can be used as a technical and practical guideline and reference for operators, suppliers, regulators and decision makers in the field of subsea leak detection. The referencing of this document will not substitute the development of a field specific leak detection strategy, but can rather be an element in one.

It is emphasized that the application of subsea leak detection systems shall not reduce the safety level for subsea systems in terms of design, manufacture, quality assurance etc.

It is also emphasized that the performance of a subsea leak detection system is not determined by the technical specification of the detector technology alone, but by an overall assessment of technical data, system layout and system operation.

1.2 Basis

OLF (The Norwegian Oil Industry Association) has through a JIP taken the initiative to improve practice in the industry regarding detection of subsea hydrocarbon leaks. The JIP partners have been Conoco Philips, ENI, Shell and Statoil. This best practice is a product of the JIP. The development of this document has been coordinated by DNV and the content is based on input from a broad selection of operators and suppliers in the industry.

Production systems for hydrocarbons are complex installations and it is known in the industry that smaller and larger unwanted leakages occur and cause discharge of hydrocarbons to the surroundings. Today, both operators and authority awareness towards the environmental impact of oil and gas production is constantly increasing.

Subsea leak detection is becoming more important in the petroleum industry. The regulations of PSA (Petroleum Safety Authority) Norway outline requirements for remote measurement of acute pollution. Regulatory bodies in UK, USA and also the European Union describe requirements for detection of acute pollution. This is further covered in Sec.1.3.

As well as detecting leakages, a leak detection system may be designed to provide condition monitoring data and may form part of a life extension strategy if for example the risks of leakage is considered too high to continue production without continuous monitoring.

1.3 Regulations

In this section relevant references to legislation are presented. A further description of the legislation referenced below is found in Appendix B.

Subsea leak detection is becoming important in the petroleum industry. A plan for remote measurement is by regulations required to be included in PDOs in Norway and Alaska. It has recently been stated by the Norwegian authorities in relation to future production in the Arctic region that there is a need for "*early warning system based on detecting leaks at the source*" /10/.

1.3.1 *Norway*

The Facilities Regulations Section 7 states that (ref. /24/)

"Facilities shall be equipped with necessary safety functions which at all times are able to:

a) *detect abnormal conditions*
b) *prevent abnormal conditions from developing into situations of hazard and accident*
c) *limit harm in the event of accidents.*

Requirements to performance shall be set in respect of safety functions. The status of safety functions shall be available in the central control room."

The Management Regulations Section 1 states (ref. /22/):

Risk reduction

In risk reduction as mentioned in the Framework Regulations Section 9 on principles relating to risk reduction,

"The party responsible shall choose technical, operational and organisational solutions which reduce the probability that failures and situations of hazard and accident will occur.

In addition barriers shall be established which

a) *reduce the probability that any such failures and situations of hazard and accident will develop further,*
b) *limit possible harm and nuisance.*

Where more than one barrier is required, there shall be sufficient independence between the barriers.

The solutions and the barriers that have the greatest risk reducing effect shall be chosen based on an individual as well as an overall evaluation. Collective protective measures shall be preferred over protective measures aimed at individuals."

The Management Regulations Section 2 states:

Barriers

"The operator or the one responsible for the operation of a facility, shall stipulate the strategies and principles on which the design, use and maintenance of barriers shall be based, so that the barrier function is ensured throughout the life time of the facility.

It shall be known what barriers have been established and which function they are intended to fulfil, ref. Section 1 on risk reduction, second paragraph, and what performance requirements have been defined in respect of the technical, operational or organisational elements which are necessary for the individual barrier to be effective.

It shall be known which barriers are not functioning or have been impaired.

The party responsible shall take necessary actions to correct or compensate for missing or impaired barriers."

The Authority say in their Activities Regulations /20/, section 50, that it is the responsibility of the operator to quickly discover and map pollution from the facility by remote measurements (see Appendix B). Further, the guideline to this section 50 says that:

"*a plan for remote measurement should be established, based on an environmentally oriented risk analysis. The system for remote measurement should comprise the following:*

a) *procedures and systems for visual observation and notification*
b) *procedures for interpretation of monitoring data*
c) *modelling tools to predict transport and spread of acute pollution,*
d) *procedures for quantifying the leak*
e) *other meteorological services that are necessary in order to support the remote measurement,*
f) *systems for detection of pollution in the recipients."*

Referring to the Norwegian legislation, addressing the issue of remote measurement of leak detection comprises having organizational procedures in place as well as applying monitoring technologies. The monitoring technology may be based on detection subsea, topside or both. The organizational and technical aspects should all be described in a plan for remote measurement.

1.3.2 *United Kingdom*

The Health and Safety Executive (HSE) in the United Kingdom have the Pipelines Safety Regulations (PSR) from 1996 /27/ as the key regulations concerning pipeline safety and integrity. There are at present no specific regulations concerning subsea production systems. However, regulation 6 of PSR states:

"*The operator shall ensure that no fluid is conveyed in a pipeline unless it has been provided with such safety systems as are necessary for securing that, so far as is reasonably practicable, persons are protected from risk to their health & safety*."

The associated PSR guidance states:

'*Safety systems also include leak detection systems where they are provided to secure the safe operation of the pipeline. The method chosen for leak detection should be appropriate for the fluid conveyed and operating conditions*."

1.3.3 *USA*

The Pipeline and Hazardous Materials Safety Administration in the USA say in § 195.452 of "Transportation of Hazardous Liquids by Pipeline" /26/ about "Pipeline integrity management in high consequence areas":

"*Leak detection: An operator must have a means to detect leaks on its pipeline system. An operator must evaluate the capability of its leak detection means and modify, as necessary, to protect the high consequence area. An operator's evaluation must, at least, consider, the following factors — length and size of the pipeline, type of product carried, the pipeline's proximity to the high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results.*"

The Alaska Department Of Environmental Conservation says in 18 AAC 75 "Oil and Other Hazardous Substances Pollution Control" /25/, paragraph 18 AAC 75.055 "Leak detection, monitoring, and operating requirements for crude oil transmission pipelines.":

"*A crude oil transmission pipeline must be equipped with a leak detection system capable of promptly detecting a leak, including (1) if technically feasible, the continuous capability to detect a daily discharge equal to not more than one percent of daily throughput; (2) flow verification through an accounting method, at least once every 24 hours; (3) for a remote pipeline not otherwise directly accessible, weekly aerial surveillance, unless precluded by safety or weather conditions.*"

1.3.4 *EU*

The EU have developed the IPPC (Integrated Pollution Prevention and Control) directive /28/, with the objective to prevent and limit industry pollution. The IPPC is based on 4 main principles. One of these is BAT – Best Available Techniques. The IPPC directive shall prevent and limit pollution from industry activities. Permissions for industrial installation shall be given following this directive and be based on the BAT principle. The definition of BAT can be found in Appendix B. For Norway, SINTEF have written a report on "Use of the BAT (Best Available Techniques) principle for environmental safety" /8/ which gives examples of practical implementation of BAT, including detection of subsea leaks.

1.4 Limitations

Statistical analysis /1/ shows that the majority of leaks observed in the North Sea are close to subsea installations, platforms and flow lines. At the current issue, this best practice is limited to subsea structures with access to the control system. The best practice focuses on continuous monitoring principles for leak detection.

For pipeline systems, the reader may refer to DNV-RP-F116 Guideline on integrity management of submarine pipeline systems.

Leakages are in this context limited to those originating from production of hydrocarbons in the form of natural gas, oil or multiphase, as these are considered to have the greatest environmental impact. Leak detection may also be of interest for CO2 injection systems and hydraulic control systems. Technologies for leak detection are, however, still immature and this document will focus on leakages from oil and natural gas production, as this is considered to have the greatest environmental impact. Some detection principles described in this guideline will in theory detect any liquid leaking at a certain pressure; others are depending on the chemical compound for detection.

The maturity of the technologies described is varying from concepts to commercially delivered products. However, the operational experience with subsea leak detection only goes back to the 1990's and is limited to a few of the described technologies. New developments and further developments of existing technologies are expected and the descriptions and recommendations given in this document should be developed accordingly.

This document has been developed based on input from suppliers, integrators and end users of leak detection technologies as well as PSA Norway. The information has been collected through questionnaires, seminars and hearings of this document. Also, important contributions to this document come from the results of previous work done under the OLF JIP on leak detection:

- Statistical analysis performed by ExproSoft in 2005 /1/
- Screening of available technologies done by SINTEF in 2006 /2/.
- Comparative laboratory test of a selection of technologies done by SINTEF in 2007 /3/.

The technical data on the different technologies found in Appendix D is based on information given from the suppliers. Collection of evidence to verify these data has not been performed during the development of this document.

2. Experience to date

2.1 Background

Subsea production systems have been developing since the first subsea completion as early as 1943 (Lake Erie, USA, 30 feet). The need for cost-effective solutions for offshore production has over time led to an extensive use of increasingly complex subsea solutions for the development of existing and new fields. In parallel to these developments has been the need to detect any leakages that may damage the environment.

Currently, most operating companies use a combination of technical and organizational measures to detect unwanted discharges of oil and gas, among others visual observation. Experience has shown that the current methods and equipment available are not as effective as desired (see item 2.3 and Appendix C).

OLF has coordinated a JIP focusing on leak detection. This document is a result of the 4th phase of the JIP and is based on the results from completed phases 1, 2 and 3 spanning from 2005 to 2007:

Phase 1 /1/ was a database review of available information on reported subsea leaks up to the year of 2005, mainly on the Norwegian and UK sectors in the North Sea. The main conclusions from Phase 1 were that most leak incidents occur at or close to subsea installations, most leaks are small and from smaller diameter pipes.

Phase 2 /2/ of the project was a review of available technologies for subsea leak detection. The main conclusion was that there are several different available technologies potentially suitable for continuous monitoring of subsea installations.

Phase 3 /3/ consisted of comparable experimental tests of different types of subsea leak detection principles. The main conclusions were that all the technologies tested in these experiments work well under laboratory conditions; both crude oil and gas leakages were detected. However, the technologies perform differently under varied conditions, due to their different strengths and limitations. Generally, gas leakages are easier to detect than crude oil leakages.

2.2 History

In the past decades, detection of gas pipeline ruptures near platforms has been in focus, to protect personnel and structures from explosion risk. Pipeline emergency shut down systems based on pressure monitoring have been installed by most operators. These systems generally work satisfactorily under normal production operations and when automatic warnings are included in the system. However, problems may arise during transients for example at start-up after shut down periods and when the systems rely on the operator reacting to the data instead of automatic warnings.

The forward trend in Norway seems to be adding permanently installed leak detection systems. The international trend points towards leak detection systems mounted on mobile units (ROVs) and deepwater applications. Inspection surveys are typically done once a year[1]. However, this may not prove sufficient for an increasing number of complex and large subsea structures.

1) The inspection interval will depend on the field specific inspection plan.

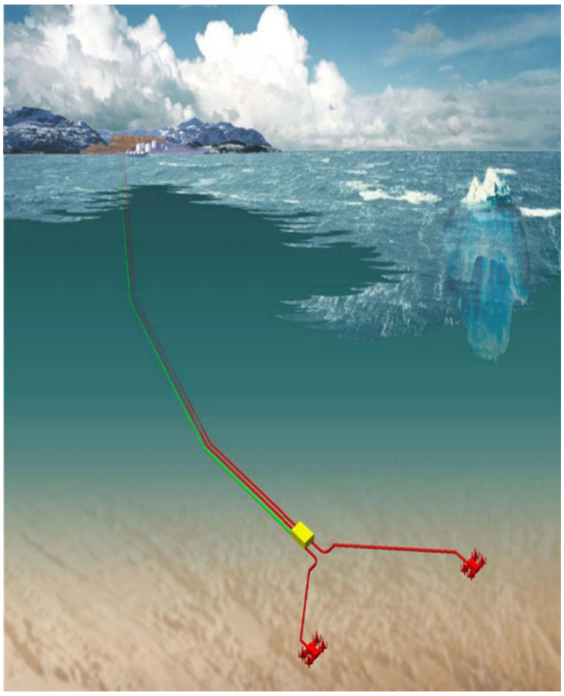

Figure 2-1
Subsea production to shore

2.3 Field experience

The field experience to date with leak detection systems is limited to the Norwegian sector and this field of technology is generally young. The existing experience includes problems with false alarms and consequently disabled sensors as well as fields where one has accomplished solutions that are described as promising. Subsea leak detection should be regarded as a monitoring system and is not at present mature enough to fulfil the requirements normally set for a safety system.

Below some field developments which include subsea leak detection systems are listed. The list is not complete, but is believed to be a representative selection of the experience to date. In Appendix C, a broader selection of installed leak detection systems is included.

- Snøhvit, Statoil – The Snøhvit Field is the first field development in the Barents Sea and has been developed by Statoil. It is a fully subsea field development concept and the best available technology at the time was used. The full development including future wells comprises twenty production wells and one CO_2 injection well. The leak detection system is based on capacitive detectors with a hydrocarbon collector at each wellhead. Snøhvit has experienced some challenges with its subsea leak detectors in the sense that they have at times given readings outside the 0 to 100 range, which is the defined range for these detectors. However, Snøhvit has also had one positive identification of a gas leakage at one well. At this instance, the detectors changed values from 0 to 100 and this indication of leak was verified by a corresponding pressure loss in the subsea system. This resulted in the well being shut down and further investigations were conducted. The conclusion was that there had been an intermittent leak from a stem in a valve. Snøhvit has also had a leak that was not detected by the capacitance detector, because the leak was outside the hydrocarbon collector roof, which is a requirement for this type of detectors.
- Tampen Link, Statoil – A 23 km long pipeline connecting the Statfjord field with the UK sector of the North Sea. The diameter of the pipe is 32”. Tampen link has five subsea leak monitors on the Norwegian sector in the North Sea. These detectors are ultrasonic non-intrusive acoustic leak monitors. The Leak Monitors are retrofitted on two 20” gas valves on the seabed to verify/disprove through-valve gas leakage. These valves are open and they will be shut to close off the bypass alternative. The Leak Monitors are self-contained and are deployed by ROV to operate continuously for periods up to one month. The monitors will be used during the closing of the two valves, and may later be operated on demand to verify their condition at a later stage.
- Tordis, Statoil – A passive acoustic leak detector was installed in 2007. The offshore commissioning included leakage testing but no positive warnings were triggered during liquid (water) discharge below 200 bar differential pressure. Warnings were triggered at 200 bar. Investigations revealed humidity in the hydrophones which was believed to explain lack of detection. The passive acoustic detector will be installed again in 2010 after a new hydrophone sealing technique is tested.
- One leak on Norwegian sector in 2003 released 750 m^3 of oil over 6 hours before it was detected. In spite of installed process surveillance of pressure, flow and temperature, the leak was detected as an oil slick and odour around the platform. The leak occurred when re-starting the subsea wells after a 2-week shutdown. Investigations succeeding the leak found that the process surveillance records showed the leak as manifold pressure dropping to seabed pressure. This pressure drop was, however, not recognised during the re-start. A learning point from this accident was the need for increased process surveillance and/or ROV observation when starting up subsea facilities.

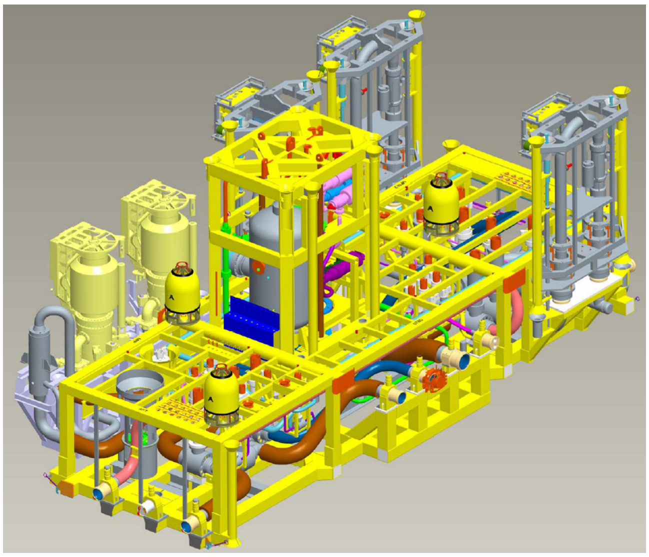

Figure 2-2
Three cone shaped acoustic leak detectors installed on Tordis

Table 2-1 Location and sizes for reported leaks on subsea installations in Norwegian sector

Location	Large leak	Medium leak	Small Leak	Very Small leak	Total
Mid line (>500 m from installation)	0	0	1	2	3
Subsea well/template/manifold (500 m radius)	1	2	1	3	7
Unknown	0	0	0	1	1
Total	1	2	2	6	11

2.4 Where and when leaks occur

This section presents available data on where leaks occur on subsea structures. This information may be used as an input when evaluating what components are of particular interest for monitoring.

The statistics are taken from /1/. This report covers pipelines and subsea equipment and was written in 2005.

The leak sizes are not listed in the PTIL/NPD file. Based on the information provided for each event, the leak sizes have been categorized in following four categories /1/ [2]).

1) Large
2) Medium
3) Small
4) Very small.

2) Categorization of leakages into specific size categories is not available in the current statistical data. Determining the size of a leak has been based on hole size, volume of leaked medium, reported actions taken, etc. which in turn is highly dependent on parameters as time, pressure, pipe dimension etc.

The large leak size type is used where a large crack, split, rupture or a substantial volume of fluids have leaked out. The medium leak size is used for incidents where the leak seems to have been significant, but not large. The small leak size category is used for incidents where the leak seems small, but corrective actions are initiated. The very small leak size category was used for incidents where no corrective actions were initiated. Typically the risk reduction measure was to observe the leak for further development.

Detection of very small leakages is interesting for monitoring (not repair) purposes.

The report from phase 1 /1/ concludes that only the PSA subsea release database has relevant data for subsea installations. 11 leaks were reported in total up to 2005. 6 of these are categorised as very small leaks. 1 of the 11 leaks was categorised as a large leak, meaning that a substantial volume of fluid leaked out. It should be noted that these 11 incidents may not represent the full picture, as some leakages may have not been detected and/or reported

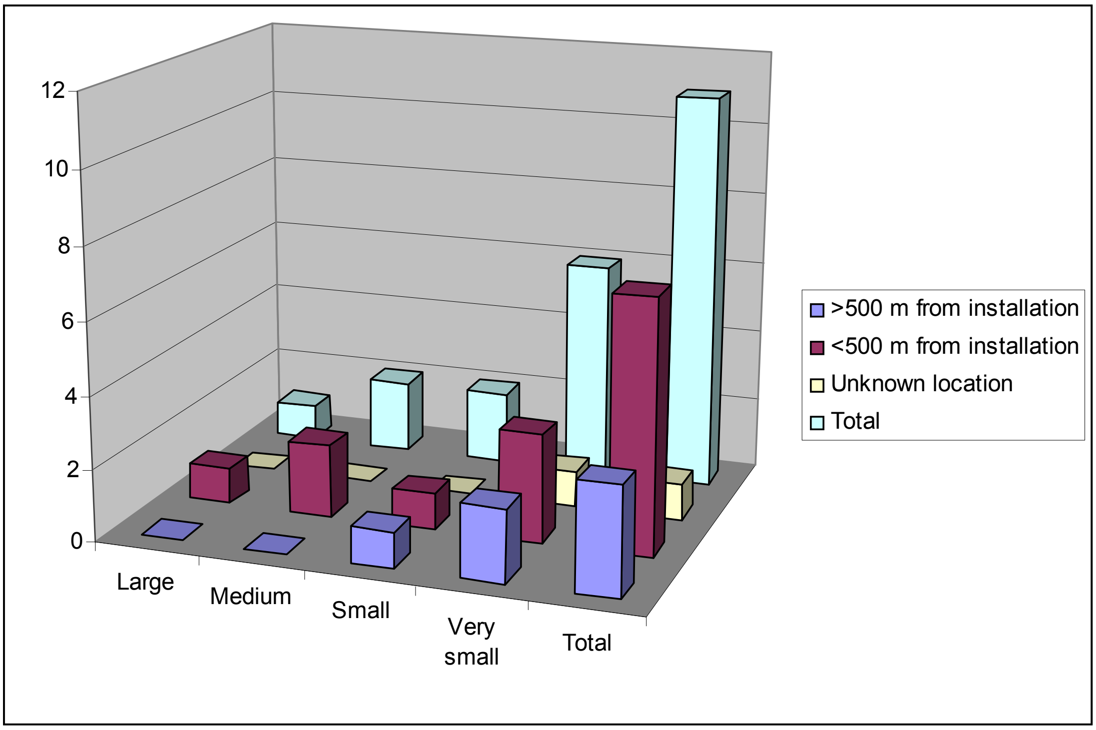

Figure 2-3
Number of reported subsea leaks in Norwegian sector up to 2005 /1/.
The graph shows the data in Table 2-1 displayed by location relative to the subsea installation and by leak size as defined in /1/.

The detection methods reported are mainly by ROV inspection and human observations. A few incidents are reported detected by pressure testing and automatic shut down/pressure loss of well.

It should be noted that the statistics show that the largest hydrocarbon leaks occur when the operation is unsteady (shut-in, start-up, maintenance etc). These are phases when mass balance cannot be used for leak monitoring due to unstable flow and pressure readings.

Structure components reported being subject to leaks are connections, connectors, flanges, seals, valves and welds. These can be considered critical points for monitoring of possible leaks.

Leaks caused by materials failure, due to corrosion, cracking, external impact, etc. can in theory occur in all structures and critical points for these failures may be harder to identify. However, it can be possible also for these failure modes to identify where a failure is most likely to occur (based on design and environmental parameters) and define these locations as critical points for monitoring.

A questionnaire for industry input /5/ distributed to oil companies, subsea system suppliers and subsea leak detector suppliers asked the recipients where leaks on subsea structures normally occur, to their experience. The replies were that leaks normally occur on flanges/connections and valves. Small bore piping was also mentioned.

The same questionnaires asked about failure modes causing leaks. Corrosion and bad installation were reported back as the most important ones, followed by impact, erosion, non-metallic seal degradation and failure of valve seats.

3. Leak detection technologies and their characteristics

3.1 Description of technologies

Principles and methods for leak detection are in the literature associated with many concepts, including surface detection, inspection and permanent subsea monitoring. An important target for detection of leakages subsea is to achieve early warning of small to medium sized leaks for monitoring and corrective actions.

The focus of this text is permanently installed subsea sensors that require access to the subsea control system for continuous monitoring subsea. Some of the principles are independent of the subsea control system.

Some of the principles described below provide area coverage, which means that they can place the leakage relative to the position of the sensor. The accuracy of the placement, the range covered and positioning parameters vary from principle to principle. Other technologies are point sensors that detect a leakage in their vicinity but can not determine the location of the leak. Point sensors may be an option for monitoring of high risk leak points.

The available technologies are divided into the following categories:

— active acoustic methods*
— bio sensor methods
— capacitance methods*
— fibre optic methods
— fluorescent methods
— methane sniffer methods*
— optical camera methods*
— passive acoustic methods*
— mass balance methods.

One product representing each of the technologies marked by "*" were tested in the SINTEF laboratory test, item 3.2.

At the time of writing, mainly qualitative functional descriptions for operation of the different technologies are available.

The descriptions given below are based on information from suppliers and the industry collected directly and via questionnaires and from technology screening and comparative laboratory tests done by SINTEF /2/, /3/, /4/, /5/.

Available supplier technical data for the different technologies are given in Appendix D. Technical requirements for installation of each of these technologies are covered in item 6.6.

It should be noted that, although it is the intention, the overview presented here may not include all available technologies.

3.1.1 *Active acoustic methods*

Active acoustic sensors are sonar detectors. The detector emits pulses of sound that are reflected by boundaries between different media (boundaries of impedance change[3]). Fluids of different density will have different acoustic impedance. This means that as the sound pulse travels through water and hits a bubble of gas or droplet of oil, sound will be reflected back. This technology does not depend on the leaking medium being of a specific composition; however, the acoustic impedance must be different to that of water.

3) The impedance is a material characteristic and depends on sound velocity, density, salinity and temperature of the medium.

Active acoustic methods give area coverage and leak positioning is possible. This technology has high sensitivity for gas, due to the high impedance contrast to water. Larger droplets or plumes of a leaking medium will give a stronger backscattered acoustic signal and are easier to detect.

A limitation to the active acoustic method is that it can be sensitive to shadowing of the acoustic signal by the subsea structures. This may, however, be solved by using more than one detector. Also, some active acoustic detectors currently generate a lot of data. Suppliers are currently working on new solutions that will make subsea interfacing easier and allow more efficient data transfer. Experience has shown that the performance will depend on water depth, as gas bubble size will change with water depth.

Active acoustic sensors have been commercially delivered for use on ROV and have been used to find leaks in the North Sea. Solutions for permanent monitoring are under development.

3.1.2 *Bio sensor methods*

Bio sensors utilize the response of organisms to pollution in the surroundings. Suitable organisms are placed on the structure to be monitored. One example of an organism used as sensors are mussels. Sensors register the heart rhythm and the degree and frequency of opening and closing of the clam.

This is a point sensing method. Positioning the leakage relative to the sensor will not be possible, but area coverage may be achieved by using several sensors. The sensitivity compared to size of leak will be dependent on distance to the leak and drift of the leaking medium.

Direct contact with the leaking medium is required. Seawater currents may lead the leaking medium away from the sensor.

This technology concept is currently under testing in shallow water and with access to topside facilities. The concepts that include bio sensors combine them with other sensors (e.g. semi-conductor (item 3.1.7), temperature meters, salinity meters and hydrophones). Different organisms may be used when entering into deeper waters.

3.1.3 *Capacitance methods*

Capacitive sensors measure change in the dielectric constant of the medium surrounding the sensor. The capacitor is formed by two concentric, insulated capacitor plates in the same plane, the one being a disc and the other being a surrounding annulus. The sensors capacitance is directly proportional to the dielectric constant of the medium between the capacitor plates. The dielectric constants of seawater and hydrocarbons are very different. If the sensor gets in direct contact with hydrocarbons, this will show as a change in the measured capacitance.

The capacitance method is a point sensing method. Positioning the leakage relative to the sensor will not be possible. The sensitivity compared to size of leak will be dependent on distance to the leak and drift of the leaking medium. When leaking medium comes in contact with the sensor, the sensitivity is high.

A limitation to this product is that direct contact with the leaking medium is required. Seawater currents or buoyancy effects may lead the leaking medium away from the sensor. This can be solved by installing a collector for hydrocarbons over the monitored structure. Where template protective covers are used as protection to fishery, these covers can be modified to serve as a hydrocarbon collector. Laboratory tests have shown challenges with collecting oil, since the oil flow does not stop in the collector. This effect may be less significant in a realistic subsea environment, due to the much larger size of a template roof collector compared to the experimental collector. Additionally, live crude oil always contains some natural gas which may be easier to collect by the template roof.

The product maturity of capacitance sensors is high. These sensors have been on the market since the 1990s. Operators have experienced some false alarms from these sensors (ref. Appendix C). However, by number of installed sensors, this type is the most common.

3.1.4 *Fibre optic methods*

Fibre optic methods are used for locating and measuring mechanical disturbances at acoustic frequencies along a continuous optical fibber. Disturbances can be caused by e.g. vibrations, seismic waves or acoustic signals from for example leaking gas or liquids. Simultaneous disturbances may be detected and positioned to approximately one meter accuracy along the fibre.

By performing comparison with a data library the likely cause of the disturbance can be proposed.

There is a trade-off between spatial resolution along the sensing fibre and detection sensitivity. For example, if it is not necessary to isolate the detection of vibrations between every adjacent meter of fibre, but ten meters would be acceptable, then the detection sensitivity can be increased by roughly a factor of ten.

A benefit with fibre optic methods is that no power or electronics is required along the length of the cable and it is immune to electrical interference.

For monitoring of subsea structures, this technology has not yet been taken beyond the conceptual stage. The concept has been tested for pipelines onshore.

This technology will not be covered further in this version of this document. Some technical parameters are found in Appendix D.

3.1.5 *Fluorescent methods*

Fluorescent detectors use a light source of a certain wavelength for exciting molecules in the target material to a higher energy level. The molecules then relax to a lower state and light is emitted at a different wavelength which can be picked up by a detector.

To use fluorescent methods, the medium to be detected must naturally fluoresce or a fluorescent marker must be added into the fluid. This is the reason why this technology has traditionally been adopted for subsea inspection and pressure testing. However, many hydraulic fluids have fluorescent markers added as standard. For hydrocarbon leak detection, crude oil has significant natural fluorescence.

Fluorescent technology has been proven for use with ROVs and is currently under development for permanent installation on subsea structures. However at the time of writing there is no information about prototype installations available.

Fluorescence based detectors can potentially differentiate between hydraulic fluid and oil leaks due to the different fluorescence spectrum of these fluids and also provide an indication of the leak size from the relative signal intensity. These detectors can be point sensors or can provide coverage over 3-5 meters line of sight.

As with optical cameras marine growth over optics could potentially be an issue but may be solved with maintenance and optimal choice of surface coatings.

This technology will not be covered further in this version of this document. Some technical parameters are found in Appendix D.

3.1.6 *Methane sniffer methods*

Two measurement principles exist on the market for measuring methane dissolved in water. Both sensor types are based on dissolved methane diffusing over a membrane and into a sensor chamber. Methane sniffers are point sensors. Positioning the leakage relative to the sensor will not be possible.

The sensitivity of these sensor types compared to the size of a leak will be dependent on the distance to the leak and the drift of the leaking medium. Both sensor types can detect very small concentrations of dissolved gas in water.

Limitations to these technologies are that quantification of leaks is difficult. Also, identifying a leak is dependent on diffusion towards the sensor and seawater currents may lead the leaking medium away from the sensor.

3.1.7 *Semi-conductor methods*

For the semi-conductor methods, the dissolved methane changes the resistance of an internal component in the sensor chamber. This generates an electrical signal from the detector.

Ongoing developments are aiming at achieving long term stability of 5-10 years for this type of sensors.

3.1.8 *Optical NDIR methods*

For the optical non-dispersive infrared spectrometry (NDIR) method, the methane concentration is measured as degree of absorption of infrared light at a certain wavelength. The infrared light is directed through the sensor chamber towards a detector. The intensity of infrared light at the detector will thus be a measure of the methane concentration, which is measured electronically.

Sensors with a said long term stability of 3+ years are available today. Ongoing developments are aiming at achieving long term stability of 5 years or more for this type of sensors.

3.1.9 *Optical camera methods*

Optical camera methods are based on a video camera for surveillance of the subsea system. This technology provides spatial coverage and determining the direction from the camera to the leak can be possible. The capabilities of such methods is typically to record and send 3 -30 min of video and 1 -10 still pictures per hour.

Optical cameras for subsea leak detection are sensitive to water turbidity. Another limitation is the need for contrast background to detect oil (the camera must be directed towards the yellow structure). It has been shown in laboratory testing /3/ that cameras need additional light for detection beyond 1 m. The limitation with extra light is 3-4 meters. Marine growth may also be a problem; however this can be solved by maintenance.

The optical camera technology is in use with ROVs and pilots have been installed subsea.

Table 3-1 Findings from laboratory testing, by SINTEF /4/

Principle	*Sensitivity*	*Detection of crude oil*	*Detection of gas*	*Area coverage*	*Detection time*	*Leak positioning*	*Limitations*
Capacitance	High to moderate. Small leaks not detected due to hole in collector	Good; coalescence problems due to turbulent flow	Very good	Point sensor. Area coverage determined by size of collector	Gas: 15 sec to 9 min. Crude oil: approx 10 min	No	Sensitive to biological growth. Dependent upon size and shape of collector. Less suited for oil than gas due to coalescence problems.
Semi conductor	Very high	N/A	Very good	Point sensor. Indirect area coverage possible due to diffusion of hydrocarbons in water and by using several sensors.	Immediate detection to no detection	No	Quantification of leak difficult. Long term stability not proven.
Optical camera	Moderate. Depends upon colour of surroundings	Very good; dependent upon background colour	Very good	Yes. Range limited to 3-4 m	No response time reported	Yes	Sensitive to water turbidity and biological growth.
Passive acoustic	High	Good	Very good	Yes. Range dependent upon pressure difference of leakage.	No response time reported	Yes	Sensitive to background noise
Active acoustic	High, especially for gas	Limited	Very good	Yes. Range dependent upon plume size.	No response time reported	Yes	Generates significant amounts of data. Sensitive to shadowing objects.

3.1.10 *Passive acoustic methods*

These sensors contain hydrophones (under water microphones) picking up the pressure wave, or sound, generated by a rupture or leak and transmitted through a structure or water. As long as there is a sufficiently strong pressure wave, passive acoustic sensors are not dependent on the chemical compound of the leaking medium.

Passive acoustic detectors come in variants designed for spatial coverage as well as variants for monitoring of specific critical components.

Positioning is possible by using more than two sensors for spatial coverage. Arrival time of a sound at each sensor can be used to locate the origin of the sound.

These sensors are little affected by seawater currents and turbidity. Passive acoustic sensors are available on the market and have been commercially delivered.

A limitation to this technology is that the sound from small leaks might not reach the hydrophones. Background noise may disturb the measurements and shadowing of the acoustic waves may be a problem. A sufficient pressure drop over the leak path is a requirement for detection.

Passive acoustic sensors may also be used for monitoring of valve opening and closure, choke opening or adjustments and function of rotating machinery.

3.1.11 *Mass balance methods*

Mass balance methods are based on monitoring the pressure drop between two or more pressure sensors installed in the subsea production system. According to a SINTEF report /2/ a leak will have to be above a certain threshold (5% of total flow) to be detected by mass balance. However, the actual threshold for detecting a leak will depend on the complexity of the mass balance system, type of process (gas, liquid or mixed), the accuracy and quantity of the instrumentation available and the pressure drop over other system components for each application. For example, including pressure and temperature sensors at the riser base in addition to the Xmas tree and manifold will improve the system performance. Normally, a feasibility study is done for each application to calculate the actual achievable accuracy which may be far better that 5% of the total flow. For high flow rates, the error band of the pressure sensors will be relatively small compared to the pressure drop which gives an improved accuracy for high flow rates.

The economical threshold for applying mass balance methods is considered low, when assuming that most subsea systems already apply pressure- and flow sensors. What is needed in addition is procedures and software for rising and handling warnings.

Mass balance technology is mature and can act as a complementary principle to the younger technologies described above. Mass balance can also cover the pipeline system.

3.2 SINTEF laboratory test

The SINTEF laboratory tests /3/ exposed 5 technologies to the same, controlled environment and compared their performance for detecting releases of gas and oil.

There are limitations to a laboratory test when it comes to fully representing a subsea environment. This must be considered when reading the results from the laboratory test summarized in Table 3-1. Due to the size of the basin, there are constraints to the distance between the leakage and detector and reflections of acoustic signals from the basin walls. A basin test does not fully cover the effects of sea water currents and there are limitations on allowable flow rate of the generated leaks. Also, the ambient hydrostatic pressure is lower than for real applications. Life time and effects of marine growth is not tested realistically. The pressure difference between process and ambient will be different than in a real application.

At real subsea conditions there will be some natural leakage or seeping of hydrocarbons from the ground. The effect of this is not covered in the lab test. natural leakage is most likely to affect the principles based on the chemical compound of the medium, like capacitive sensors, semi-conductor sensors and bio-sensors.

The main results from the SINTEF research are presented in Table 3-1.

4. Design of subsea leak detection systems

The design of the leak detection system should be integrated in the overall subsea system design. According to industry input /5/, the structures where leak detectors have been installed to date are mainly Xmas trees, templates and manifolds. The feedback from subsea system integrators /12/ is that integrating the sensors to subsea structures mechanically, and to the control system, in most cases is solvable, but that it is important that this requirement is identified early in the design process. The leak detection system should therefore be included as a primary design requirement and not considered as an add-on late in the design process.

4.1 General requirements

The leak detection system should as a minimum comply with the requirements found in ISO 13628-6.

The specific contents of the qualification activities must be tailored for each technology. DNV-RP-A203 *Qualification Procedures for New Technology* /15/ may be used as a guideline for the qualification process.

4.2 System performance requirements and technology selection

For designing an appropriate leak detection system to be applied for a specific field, performance requirements for the system should be developed. The requirements should be based on:

— authority requirements
— environmental and safety risk analysis for the specific field
— corporate requirements
— field specific conditions that will affect the performance
— interface to the control system
— integration into the overall operational management philosophy of the subsea equipment.

A leak detection system comprises selected leak detection technologies as well as tools for data management, operational procedures (ref. item 5.1) and layout/placement of sensors. The total system layout should fulfil the developed field specific performance requirements. This is also discussed in the OLF guideline *"Recommended procedure for evaluating remote measuring initiatives"* /7/.

The selection of sensors must be optimized for each application. A risk assessment may be valuable to identify the locations on subsea production system where it is most likely that leakages will occur and hence where to place the detectors. It is also necessary to take into account process medium, process pressure and external conditions at the site. To enable operators to select the right sensor types for their system, all commercial available leak detection technologies should have a specification sheet specifying parameters like:

— mechanical, electrical and communication interfaces
— bandwidth requirements
— power requirements
— requirements to location and environment (current etc.)
— sensitivity to noise and other effects from other components
— design pressure, design temperature
— test conditions, e.g. water depth, pressure and temperature, for qualification testing and FAT testing
— sensitivity and drift
— ability to determine location of leak.

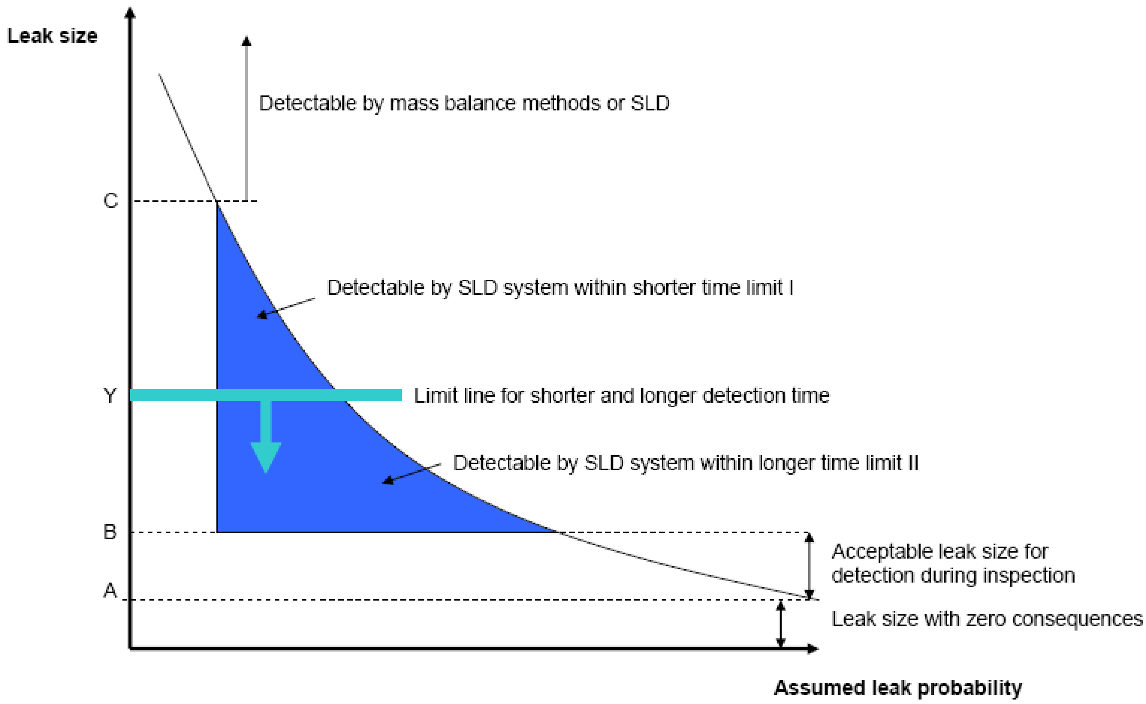

Figure 4-1
The figure gives an illustration of the process for determining the performance requirements for a subsea leak detection system. In this figure it is assumed that the subsea production system is designed in such a way that the probability of large leaks is lower than the probability of smaller leaks, as indicated by the graph. This assumption is supported by the statistics described in item 2.4 and /1/.

A suggested principal for designing a subsea leak detection system is illustrated by Figure 4-1. The engineering of a subsea leak detection system for a field will involve determining the thresholds A, B and C (Figure 4-1) and required detection times, based on the environmental and safety risk analysis for the field. Subsequently, the subsea leak detection system is tailored based on the specifications of available technologies, the field specific conditions, connectivity to the control system and operational management philosophy of the subsea equipment. There may be gaps between the desired and achievable performance of the leak detection system. These gaps may be addressed by adjustments to the mass balance system or the inspection methods / intervals.

As indicated in Figure 4-1, leaks over a certain size C will be detectable by mass balance and SLD.

The smallest leaks, below a threshold A, may not be detectable by any methods.

The conditions specific to the field (environment, production process, field layout, fluid composition, etc.) will together with the performance specifications of the technologies determine the threshold B between what will be detectable by the leak detection system and what must be detected during inspection. The inspection interval must be determined from how long a leak of size B can be allowed to endure, considering the HSE risk.

The target leak regime for the subsea leak detection system will be the shaded area in the graph, namely leaks of medium probability and between size thresholds B and C. The detection time may (depending on technology types) be dependent on the size of the leak, as indicated by the limit line at leak size threshold Y. The general principal is that detection time should be lower for larger leaks in order to reduce the consequences of the leak.

Suggested functional requirements for subsea leak detection systems are found in Appendix A.

4.3 Combining technologies

Combining two or more types of sensors may provide more confidence in the overall leakage detection system. Complementary sensor technologies should be selected to compensate for the respective weaknesses and enable indication of a leak event from one sensor type to be confirmed by positive indications from the other sensor type.

One of the selected technologies should be able to perform detection over an area (not be limited to point sensing). Point sensors may be installed over critical leak points.

The downside of combining more sensors can be the additional complexity relating to the subsea control system. In addition there is the commercial impact of having more detectors to purchase, service and integrate. Further, the scenario of one sensor type triggering a warning and the other not needs to be considered.

The selection of one sensor type versus two or more should be based on system integration and performance requirements (ref item 4.2). E.g. in an especially sensitive area where a leakage of hydrocarbons will have huge safety or environmental impact, the additional cost and complexity may be acceptable and even required. In an area where the consequences are less, and it is less likely that leakage will occur, a more simple sensor solution may be acceptable.

5. Operating Philosophy

The objective of this section is to advise on the operation of subsea leak detection systems.

5.1 Operating procedures

The operation should be in line with the principle Detect – Confirm – Act:

— Detect: The subsea detector sends a warning to the topside control room
— Confirm: The operator checks if the warning is real or false according to established procedures
— Act: If the warning is false, the warning is cancelled and an investigation of why the false warning occurred is initiated. If the warning is real, the operator acts according to an emergency preparedness plan on what to do with the operation of the subsea production system and what to do about further warning of facility personnel, preparedness personnel and authorities

A general approach to how to operate a measuring system is found in ISO 10012 "*Measurement Management Systems – Requirements for Measurement Processes and measuring equipment*" /18/.

5.1.1 *Warning display and action*

Most permanent subsea leak detection principles rely on the subsea control system to convey the detection of hydrocarbons to a topside or onshore facility. The signal will trigger a form of warning.

It is assumed that a warning signal will either be transformed to an audio or visual warning (e.g. signal lamp), and subsequently this signal will be observed by a human operator who will decide on the actions to follow.

The maturity of subsea leak detection technologies is today too low to have an independent safety function. Setting firm limits for what detector response represents a positive finding of a leak is challenging. Further investigation of a leakage warning is needed for confirmation and quantification of the leak. The further investigation may include:

— check of parallel systems (e.g. mass balance)
— downloading of raw data from the detector giving the warning for further analysis
— inspection on surface visually, by satellite, radar, plane etc.
— inspection subsea e.g. by ROV.

The operator response upon a warning from the leak detection system must be captured in operational procedures for the leak detection system.

5.2 Sensitivity and response time

Field experiences referenced in Appendix C show that unwanted warnings are frequently experienced with subsea leak detectors. One reason behind this is natural seepage of gas from the seabed. Technically, sensitivity and unwanted warnings are not independent factors when designing detectors. A sensor designed for high sensitivity to hydrocarbons will more easily trigger a warning due to natural seepage.

The response time and efficiency of a subsea leak detector will depend on the sensors technical performance but also on how it is integrated into a system and operated.

5.2.1 *Requirements from operators*

A requirement from the operators of subsea leak detection systems is that the number of false warnings is minimized. At the same time, response time should be as short as possible for major leaks.

To avoid false warnings and maintain operator confidence in leak detection system, a longer response time should be accepted for small leaks.

Specific requirements on response time, allowable leak rates and released volume (i.e. defining large, medium, small and very small leaks) should be developed for each field. These requirements should be based on a field specific environmental and safety risk analysis and the emergency preparedness for the field (see also item 4.2).

The system should be manned by a trained operator who knows what the detectors measure and the system limitations. The data display should be of such a quality that it is easy to interpret for a trained operator.

5.2.2 *Findings from laboratory tests*

The SINTEF report /3/ describes the response time for some technologies during the tests. Please see Table 3-1 for the recorded test results. It should be noted, however, that these response times are found under laboratory conditions and should not be directly applied for subsea applications.

5.3 Trouble shooting, data download and self diagnosis

The leak detectors have limited field history, and will require close follow up in operation. A high data rate transparent communication interface will enable the operator to evaluate data from the detector, perform fault tracing, download updated software or even reprocess raw data on topside computers (see also item 6.3).

Detector self diagnosis should be developed for known failure modes. Redundancy and automatic disabling of components should be implemented to avoid the effect of these failure modes.

6. Installation and interfaces

6.1 General

The various sensor types will have different requirements for parameters like mechanical interface, required space, power needs, communication link bandwidth, etc. Likewise, each subsea system will have different capacities available for such parameters for the leak detection sensors. Procedures for correct installation and positioning of the leak detectors should be available for all commercially available technologies.

Below, some general guidelines are given for interfacing to the subsea control system and for testing of a subsea leak detection system, followed by technology specific requirements.

6.2 Communication bandwidth

Bandwidth capacity for subsea leak detectors is in general a lesser challenge for new fields than for retrofit to existing fields. However, bandwidth limitations can be imposed on the subsea leak detection system depending on the field specific spare bandwidth capacity.

6.3 Communication interface

The SIIS (Subsea Instrumentation Interface Standardization) /9/ JIP is an initiative from the industry. The aim is to standardize the interface between subsea sensors and the subsea control system. SIIS has developed levels for defining subsea instrumentation interfaces.

Referring to the SIIS definition /9/, advanced detectors should typically have a SIIS level 3 interface (Ethernet TCP/IP), while simpler or more proven detectors could use a SIIS level 2 (CANOPEN fault tolerant, ISO 11898-3) interface. In the future, sensors complying with the SIIS standards are what oil companies most likely will request and what will be the easiest to interface to their system designs.

Please also see item 5.3.

6.4 Power requirements

ISO 13628-6 /14/ may serve as a reference for the power requirements for subsea leak detectors.

Subsea control systems are optimized for power. Thus, keeping the power requirements for the subsea leak detection system to a minimum will always be a benefit.

6.5 Test methods

The leak detection system should be tested to verify that it meets the specified functional requirements (ref item 4.2).

FAT is described in ISO 13628-6 /14/.

System level tests are described in ISO 13628-1 and 13628-6 /14/.

Descriptions of sensor specific test methods should be provided by the vendor for all commercially available leak detection systems.

6.6 Technology specific requirements

6.6.1 *Active acoustic methods*

Due to the active function and high processing demands, some active acoustic detectors require more bandwidth and power than passive acoustic detectors.

For size, weight and further technical parameters, please refer to Appendix D.

6.6.2 *Bio sensor methods*

In the concepts being developed today, the bio sensors are mounted in a sensor rack together with other sensor technologies.

These racks will be installed on or near the subsea structure to be monitored. The prototype racks have dimensions of 2 m × 0.4 m × 0.4 m.

The sensor rack will be connected to the subsea control system via cable.

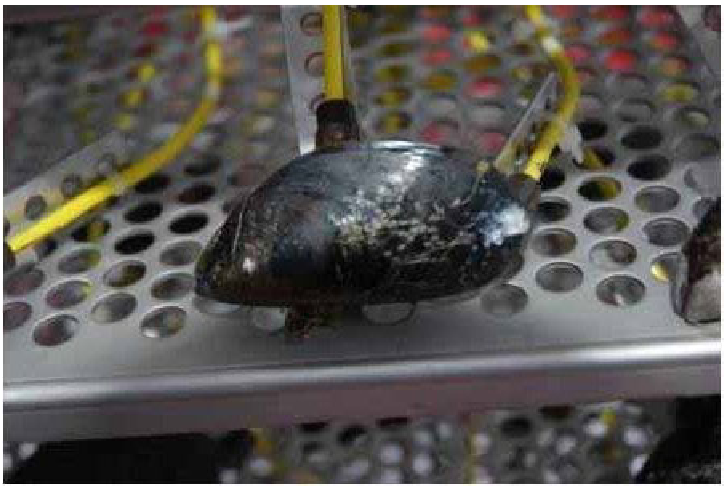

Figure 6-1
Illustration of bio sensors

6.6.3 *Capacitance methods*

Capacitive sensors are point sensors dependant on a hydrocarbon collector.

Typical location of this type of sensor will be bolted on to a collector, typically in the shape of a protection structure, above an expected leak point. The protection structure is produced out of either steel or composite material or a combination of these. In order to collect hydrocarbons, the protection structure needs to be leak tight. A vent hole to release natural seepage may be required. Protection covers with several holes or in the shape of grids will not provide the required hydrocarbon collection.

Retrofit of capacitance sensors may be a challenge since many template covers today are gratings and not solid covers that can be used for hydrocarbon collection. Solid covers are in general found on the NCS and in some British fields.

The electrical interface will be via cable.

For size, weight and further technical parameters, please refer to Appendix D.

6.6.4 *Methane sniffer methods*

6.6.4.1 Semi-conductor methods

These sensors are developed for underwater monitoring of methane down to a depth of 2000 m. This type of sensors can also be used for monitoring purposes at platforms in oceans, rivers and lakes as well as deep-sea and coastal areas. Semi-conductor sensors can be deployed in shallow water areas from a small boat, allowing vertical or horizontal profiles. The adaptation of these sensors to probe systems or loggers is possible because it is equipped with standard analogue outputs.

Figure 6-2
Example of semi-conductor sensor

The electrical interface will be via cable.

For size, weight and further technical parameters, please refer to Appendix D.

6.6.4.2 Optical NDIR methods

These sensors are recommended to be installed underneath the roof hatch of templates and manifolds. The sensors are equipped with a ROV handle for recovery and maintenance. The connection to the control system will be via cable with a wet mateable connector.

For further technical parameters, please refer to Appendix D.

6.6.5 *Optical Cameras*

Optical cameras are generally ROV mountable. Some optical cameras can be installed with a mounting device. This device can be adapted to the structure in question.

The required number and location of the cameras needs to be evaluated considering acceptable coverage. Due to a "dense" construction as a manifold will be, it is assumed that more than one camera will be required

For size, weight and further technical parameters, please refer to Appendix D.

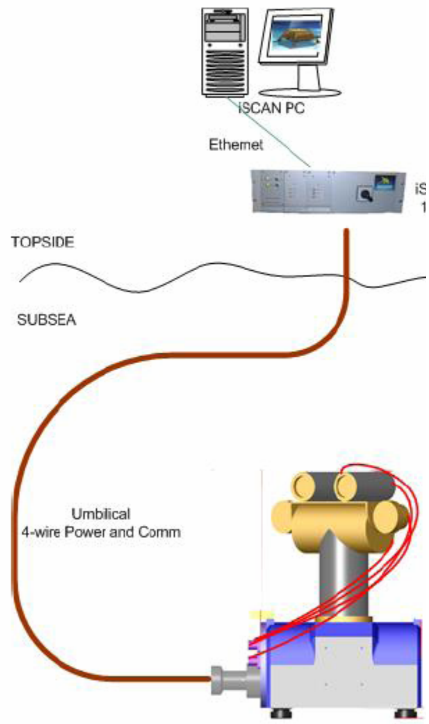

Figure 6-3
Example of optical camera

6.6.6 *Passive acoustic methods*

Passive acoustic detectors are available as compact sensors based on a single hydrophone as well as lager sensors with more hydrophones and functions (i.e. positioning of leak).

For the larger versions, providing area coverage, considerable space on the subsea structure can be required. Other versions of passive acoustic detectors are designed to be installed at critical points such as valves, flanges, joints, etc.

Versions of passive acoustic detectors exist that can be mounted by ROV and the smaller types may be retro-fitted.

The data is communicated to the surface by either a dedicated fibre-optic cable or via cable to the subsea control system (SCS).

For size, weight and further technical parameters, please refer to Appendix D.

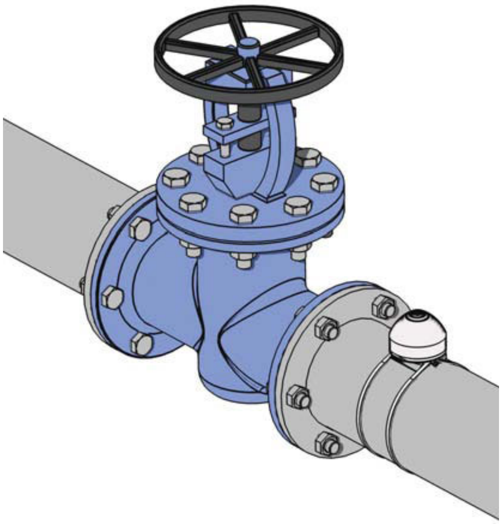

Figure 6-4
Example of large passive acoustic detector prepared for installation (left) and compact passive acoustic detector installed on a topside valve (right).

7. Calibration, inspection and intervention

A practical procedure for calibration should be available for industrialized sensors and systems. The accuracy and the stability of the sensor readings should be quantified. For detectors that can experience some kind of saturation, re-calibration from topside when installed subsea should be described.

Lifetime for subsea equipment should be long enough to keep the intervention frequency and cost at an acceptable level. A typical lifetime for non retrievable equipment is 25 years. The lifetime and requirements regarding maintenance and whether the units are retrievable must be described. Procedures for this must also be available.

Available supplier information on calibration, inspection and intervention is found in Appendix D.

Table 7-1 Typical supplier specification for calibration, inspection and intervention

Technology	*Calibration*	*Inspection and intervention*
Active acoustic	Automatic calibration at installation or calibration during Sea Acceptance Test	3-8 years interval depending on product and water depth Depending on product, major parts may be field replaceable units due to modular construction.
Bio sensors	Calibration after installation	Replacement of biosensor module
Capacitance	No on site calibration required	Inspection and/or cleaning of marine growth. Using a hydro-jet for cleaning should be OK
Fibre optic	No calibration	2 Years
Fluorescent	No recalibration required	Possible lens cleaning every 3-5 years
Mass balance systems	The pressure and flow sensors that give readings into the mass balance system will have to be calibrated and maintained according to normal procedures. The software for giving warnings must be calibrated with threshold pressure drop values as a minimum and more extensive process input for advanced flow assurance systems.	Inspection and intervention as required, product specific for the pressure and flow sensors.

Table 7-1 Typical supplier specification for calibration, inspection and intervention (Continued)

Technology	*Calibration*	*Inspection and intervention*
Methane sniffer; optical NDIR method	No recalibration required	Subsea interchange of complete sensor for membrane service required every 36 months Membrane service every 36 months
Methane sniffer; semi conductor	2 years	2 years
Optical camera	No calibration	Check moving parts and lens cleaning every 2 years. Intervention every 5 years
Passive acoustic	No recalibration needed.	No requirements for intervention or maintenance

8. Challenges for further research and development

The following topics are mentioned by the industry as directions one would like to see the leak detection technologies to take in the future:

8.1 Technology

Detection

The message from the industry today is that there is a need for improvement of the performance of leak detection technologies. A leak detector should ideally be able to perform identification, localization, quantification and classification (medium, harmful/harmless) of a leakage. Today, no technology alone can perform all of these operations and it may even be hard to accomplish by combining sensors.

One aspect that is mentioned in particular for sensor performance is unwanted warnings, often generated due to natural seepage of hydrocarbons from the seabed. Handling of natural seepage without giving unwanted warnings is a challenge for further development of subsea leak detection.

To improve performance on detection of leakages it may be beneficial to develop a better understanding of leakages and their characteristics through e.g. modelling work.

Robustness

Any technology that is deployed subsea should work reliably over a defined design life and be robust to impacts and loads that are present in a subsea environment. The need for maintenance and calibration should be well defined so that this can be taken care of through planned operations. Potential failure modes for the technology should be thoroughly identified so that mitigations can be designed into the technology or be planned. One such mitigation is built-in self diagnosis and redundant functionality of a detector for known technical failure modes and automatic compensation for these failure modes.

Interfaces

Basing the detector design on standardized interfaces, mechanically and for communication and power, is enabling for easy integration into the subsea production system. Technologies that can offer this fulfil one important criterion for being preferred in the design phase.

For leak detection technologies with relatively high power consumption, integration into the subsea control system power supply can be a challenge. Finding solutions for lower power consumption for technologies where this may be an issue will be an important task for the future.

Qualification and Testing

Proper qualification is important for technologies being deployed subsea. Qualifying a product should be done through defining its functions and limits; assessing what functions are not proven, identifying failure modes and carrying out activities that through objective evidence minimize failure modes and prove functionality. General requirements are found in ISO 13628 (/14/, /16/); however, the specific contents of the qualification activities must be tailored for each technology. As an example, deriving the qualification process may be done according to DNV-RP-A203 Qualification procedures for new technology /15/.

It is important for the operator to be able to verify the function of the leak detectors after deployment. Methods for testing of the detectors after installation subsea (> 200 m) should be developed.

8.2 Operation of leak detection systems

The experience with practical application of leak detectors from field testing and operation is limited today and restricted to a few detection principles, ref. Appendix C. More systematic testing by the industry is needed to get a better understanding of the effect, advantages and limitations of the different technologies. More experience will also confirm and further identify gaps in technologies and in the operation of leak detection systems.

Pilot projects can be a means for providing the interfaces required for gathering real data. This would potentially allow for improvements of the integration to power and communication, detector algorithms and to find better solutions to the mechanical integration of leak detection technologies into subsea systems. Pilot projects can also give a possibility for trying combinations of different technologies into systems and give input to procedures for management and operation of such systems and requirements for a surface user interface.

8.3 Requirements

The requirements for leak detection will be based on field specific conditions and will hence vary from field to field, see item 4.2. The operating companies should for each field define clear and quantified requirements for a subsea leak detection system. For each field the magnitude of the minimum detectable leak should be defined. Further, the leaking medium to be detected should also be defined.

8.4 Collection of statistical data

For future development of leak detection it is recommended to conduct statistical analysis on leaks detected or not detected and to compare the procedures used for reporting and collecting leak data. Further analysis of other regional data and Norwegian subsea leakages in the period since 2005, should also be addressed.

To establish more experience data on subsea leak detectors, it is recommended that this information is reported through OREDA (Offshore Reliability Data) /19/, preferably per technology type as described in this document.

Learning from history by collection and analysis of successes and failures in operation of subsea leak detection system is recommended. Such an activity may reveal what parameters that drive the successes and failures and enable better management of these parameters in the future to increase the number of successes within subsea leak detection.

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APPENDIX A SUGGESTED FUNCTIONAL REQUIREMENTS FOR SUBSEA LEAK DETECTION SYSTEMS

The list below covers parameters that may be relevant for the performance of a leak detection system for a particular subsea installation. This list may be used when identifying the performance requirements of such a system.

Following from the performance requirements, a leak detection system is designed after evaluating what technologies must be chosen and integrated and how the total system must be operated to meet these requirements.

Note that it is not anticipated that a single technology / principle would be able to detect all of the possible leaks in all possible environments.

Functional requirements for subsea leak detection systems may include but not be restricted to:

1) Media to be detected:

- multiphase flow (oil/gas/water)
- natural Gas
- other media that it could be of value to detect:
  - produced water
  - injection water
  - CO_2.
- production chemicals including:
  - methanol / MEG
  - hydraulic fluid – oil based
  - hydraulic fluid - water based
  - lube oil
  - fluorescent dye injected for leak detection.

2) Process operating conditions of the media:

- process pressure
- process temperature.

3) Facilities to be monitored to include:

- subsea manifolds
- subsea PLEMs, PLETs and riser bases
- subsea Xmas trees
- subsea processing plants.

4) Environment

- water depth
- sea temperature
- all year or seasonal ice coverage on water surface.
- for dispersion of leaks:
  - salinity
  - sea current.

5) Leak quantification / identification

- detection level / concentration
- sensing with some degree of spatial coverage and leakage localization
- independent principles or technologies for confirmation / verification of leakages.

6) Monitoring frequency

- continuous
- permanent/temporary installation.

7) Data availability

- real time communication to host
- intermittent download.

8) Design

- high focus on system reliability and remote fault diagnosis capability in design
- inspection and maintenance requirements to be minimized by careful material selection and redundancy in design
- critical components to be designed as modules and be easily retrievable to surface by remote (diver less) systems.

APPENDIX B LEGISLATION

B.1 NORWAY

The Guidelines for the Management Regulations /22/ Section 1 and 2 states:

"Re Section 1

Risk reduction

When choosing technical, operational and organisational solutions as mentioned in the first paragraph, the responsible party should apply principles that provide good inherent health, safety and environment properties as the basis for such selections. See also item 5.4.1 and Appendix A of the ISO 17776 standard.

Situations of hazard and accident as mentioned in the first paragraph, constitute a collective term that includes both near-misses and accidents that have occurred, as well as other unwanted conditions that may cause harm, ref. the Framework Regulations Section 9 on principles relating to risk reduction.

Barriers as mentioned in the second paragraph, may be physical or non-physical, or a combination thereof.

The requirement to independence as mentioned in the third paragraph, implies that several important barriers shall not be impaired or cease to function simultaneously, inter alia as a consequence of a single failure or a single incident.

Re Section 2

Barriers

The strategies and principles as mentioned in the first paragraph, should, inter alia, be formulated such that they contribute to giving all involved parties a common understanding of the basis for the requirements for the individual barriers, including what connection there is between risk and hazard assessments and the requirements on and to barriers.

In order to fulfil the requirement for stipulation of strategies and principles, the IEC 61508 standard and OLF guidelines No. 70 revision 2 should be used for safety systems.

Performance as mentioned in the second paragraph, may, inter alia, refer to capacity, reliability, availability, efficiency, ability to withstand loads, integrity and robustness."

The Authority says in the Activities Regulations, section 50: Remote measurement of acute pollution /20/:

'The operator shall establish a remote measurement system that provides sufficient information to ensure that acute pollution from the facility is quickly discovered and mapped.'

The guideline to section 50 reads:
"*Remote measurement of acute pollution*

Remote measurement means a system that, independent of visibility, light and weather conditions, can discover and map positions and extent of pollution on the surface of the sea. Such a system may consist of satellite-based and/or aircraft-based active sensors in combination with passive sensors in aeroplanes, helicopters, on the facility or vessel during periods when visibility and light conditions make this possible.

The purpose of the remote measurement is to ensure that the information concerning the pollution is sufficient, so that the correct actions are taken in order to stop, limit and map the pollution.

The system for discovering acute pollution should consist of

a) *procedures and systems for visual observation and notification from facilities, vessels and aircraft,*
b) *procedures for interpretation of monitoring data from the various available sensors,*
c) *modelling tools to predict transport and spread of acute pollution,*
d) *procedures for quantifying oil and chemicals with the aid of area measurement and colour thickness maps for the relevant types of oil and chemicals,*
e) *other meteorological services that are necessary in order to support the remote measurement,*
f) *systems for detection of pollution in the recipients.*

In order that the remote measurement system shall discover significant pollution as mentioned in literas a through f, the area surrounding the facility should be subjected to remote measurement on a regular basis. There should be a plan for remote measurement based on an environmentally oriented risk analysis, cf. the Management Regulations Section 16 on environmentally oriented risk and emergency preparedness analyses."

A selection of further relevant requirements in the context of leak detection from the Petroleum Safety Authority Norway is found below. The list includes examples only and shall not be regarded as complete list of requirements.

Framework HSE regulation /21/	
Section 4	Definitions
Section 9	Principles relating to risk reduction
Section 27	Duty to monitor the external environment
Management regulation /22/	
Section 5	Internal requirements
Section 6	Acceptance criteria for major accident risk and environmental risk
Section 13	General requirements to analyses
Section 15	Quantitative risk analyses and emergency preparedness analyses
Section 16	Environmentally oriented risk and emergency preparedness analyses
Information duty regulation /23/	
Section 5	Requirement on consent to certain petroleum activities
Section 6	Contents of application for consent
Section 11	Alert and notification to the supervisory authorities of situations of hazard and accident
Facilities regulation /24/	
Section 4	Design of facilities
Section 7	Safety functions
Activities regulation /20/	
Section 50	Remote measurement of acute pollution
Section 52	Environmental monitoring
Section 43	Classification

Further information can be found at www.ptil.no

B.2 THE EUROPEAN COMMISSION

The IPPC (Integrated Pollution Prevention and Control) /28/ directive of the European Commission is based on 4 main principles. One of these is BAT – Best Available Techniques. The IPPC directive shall prevent and limit pollution from industry activities. Permissions for industrial installation shall be given following this directive and be based on the BAT principle.

BAT is defined as follows:

From COUNCIL DIRECTIVE 96/61/EC of 24 September 1996:

"*Best Available Techniques shall mean the most effective and* *advanced stage in the development of activities and their methods of operation which indicate the practical suitability of particular techniques for providing in principle the basis for emission limit values designed to prevent and, where that is not practicable, generally to reduce emissions and the impact on the environment as a whole:*

- "techniques" shall include both the technology used and the way in which the installation is designed, built, maintained, operated and decommissioned,

- "available" techniques shall mean those developed on a scale which allows implementation in the relevant industrial sector, under economically and technically viable conditions, taking into consideration the costs and advantages, whether or not the techniques are used or produced inside the Member State in question, as long as they are reasonably accessible to the operator,

- "best" shall mean most effective in achieving a high general level of protection of the environment as a whole."

The BAT principle is also referenced in PSA Norway's Framework regulation /21/, section 9, paragraph 2:

"*In effectuating risk reduction the party responsible shall choose the technical, operational or organisational solutions which according to an individual as well as an overall evaluation of the potential harm and present and future use offer the best results, provided the associated costs are not significantly disproportionate to the risk reduction achieved.*"

From the guideline to section 9:

"*The second paragraph expresses the principle of best available technology (the BAT principle). This entails that the party responsible for the petroleum activities must base its planning and operation on the technology and methods that, based on an overall assessment, produce the best and most effective results."*

More information can be found at

http://eippcb.jrc.es/

http://ec.europa.eu/environment/air/pollutants/stationary/ippc/index.htm

B.3 THE UNITED KINGDOM

The Health and Safety Executive (HSE) in the United Kingdom have the Pipelines Safety Regulations [PSR] (SI 1996/825) /27/ as the key regulations concerning pipeline safety and integrity. There are at present no specific regulations concerning subsea production systems. The regulations came into force in 1996, replacing earlier prescriptive legislation on the management of pipeline safety with a more integrated, goal-setting, risk based approach encompassing both onshore and offshore pipelines. PSR does not cover the environmental aspects of accidents arising from pipelines but compliance with the regulations will help to ensure that a pipeline is designed, constructed and operated safely, provide a means of securing pipeline integrity and thereby will contribute by reducing risks to the environment.

More specifically in relation to pipeline leak detection systems which are covered (but not explicitly) by Reg. 6 of PSR - Safety systems. The regulation states:

"*The operator shall ensure that no fluid is conveyed in a pipeline unless it has been provided with such safety systems as are necessary for securing that, so far as is reasonably practicable, persons are protected from risk to their health & safety."*

However, the associated PSR guidance L82 booklet (ISBN 0 7176 1182 5) states:

"*36 Safety systems also include leak detection systems where they are provided to secure the safe operation of the pipeline. The method chosen for leak detection should be appropriate for the fluid conveyed and operating conditions."*

HSE Information relating to Pipeline safety and integrity can be found on the HSE web http://www.hse.gov.uk

B.4 THE UNITED STATES

Pipeline and Hazardous Materials Safety Administration, DOT

Part 195 - Transportation Of Hazardous Liquids By Pipeline /26/

§ 195.134 CPM leak detection.

"This section applies to each hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid). On such systems, each new computational pipeline monitoring (CPM) leak detection system and each replaced component of an existing CPM system must comply with section 4.2 of API 1130 in its design and with any other design criteria addressed in API 1130 for components of the CPM leak detection system."

§ 195.452 Pipeline integrity management in high consequence areas.

"Leak detection. An operator must have a means to detect leaks on its pipeline system. An operator must evaluate the capability of its leak detection means and modify, as necessary, to protect the high consequence area. An operator's evaluation must, at least, consider, the following factors — length and size of the pipeline, type of product carried, the pipeline's proximity to the high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results."

Alaska Department Of Environmental Conservation. 18 AAC 75

"Oil and Other Hazardous Substances Pollution Control", Revised as of October 9, 2008 /25/:

18 AAC 75.055 Leak detection, monitoring, and operating requirements for crude oil transmission pipelines.

"*(a) A crude oil transmission pipeline must be equipped with a leak detection system capable of promptly detecting a leak, including*

(1) if technically feasible, the continuous capability to detect a daily discharge

equal to not more than one percent of daily throughput;

(2) flow verification through an accounting method, at least once every 24 hours;

and Register 188, January 2009 ENVIRONMENTAL CONSERVATION 12

(3) for a remote pipeline not otherwise directly accessible, weekly aerial surveillance, unless precluded by safety or weather conditions.

(b) The owner or operator of a crude oil transmission pipeline shall ensure that the incoming flow of oil can be completely stopped within one hour after detection of a discharge.

(c) If aboveground oil storage tanks are present at the crude oil transmission pipeline facility, the owner or operator shall meet the applicable requirements of 18 AAC 75.065, 18 AAC 75.066 and 18 AAC 75.075.

(d) For facility oil piping connected to or associated with the main crude oil transmission

pipeline, the owner or operator shall meet the requirements of 18 AAC 75.080. (Eff. 5/14/92,

Register 122; am 12/30/2006, Register 180)

18 AAC 75.425. Oil discharge prevention and contingency plan contents.

(a) An oil discharge prevention and contingency plan submitted for approval under 18 AAC 75.400 - 18 AAC 75.495 must be in a form that is usable as a working plan for oil discharge prevention, control, containment, cleanup, and disposal. A

plan must contain enough information, analyses, supporting data, and documentation to demonstrate the plan holder's ability to meet the requirements of AS 46.04.030 and 18 AAC 75.400 - 18 AAC 75.495.

(b) The plan for a facility comprised of multiple operations as described at 18 AAC 75.442, must describe, for each category of operation at the facility, the appropriate response measures to meet the applicable portion of the response planning standard.

(c) The submitted plan must be accompanied by a cover page (…)

(d) The plan must (…)

(e) The information in the plan must include

(1) Part 1 - Response Action Plan: (…)

(2) Part 2 - Prevention Plan: The prevention plan must include a detailed description of all oil discharge prevention measures and policies employed at the facility, vessel, or operation, with reference to the specific oil discharge risks involved. The prevention plan

must describe how the applicant meets all the applicable requirements of 18 AAC 75.005-

18 AAC 75.085. The prevention plan may be submitted as a separate volume, and must include, Register 188, January 2009 ENVIRONMENTAL CONSERVATION 119 at a minimum, the following information:

(A) discharge prevention programs - a description and schedule of regular oil discharge prevention, inspection, and maintenance programs in place at the facility or operation, including

(i) oil discharge prevention training programs required by 18 AAC 75.020(a);

(ii) substance abuse and medical monitoring programs required by 18 AAC 75.007(e);

(iii) security and surveillance programs required by 18 AAC 75.007(f).

(B) discharge history -a history of all known oil discharges greater than 55 gallons that have occurred at the facility (…)

(C) potential discharge analysis - an analysis of potential oil discharges, including size, frequency, cause, duration, and location, and a description of actions taken to prevent a potential discharge;

(D) specific conditions - a description of

(i) any conditions specific to the facility or operation that might increase the risk of a discharge, including physical or navigation hazards, traffic patterns, and other site-specific factors; and

(ii) any measures that have been taken to reduce the risk of a discharge attributable to these conditions, including a summary of operating procedures designed to mitigate the risk of a discharge;

(E) discharge detection - a description of the existing and proposed means of discharge detection, including surveillance schedules, leak detection, observation wells, monitoring systems, and spill-detection instrumentation; if electronic or mechanical instrumentation is employed, detailed specifications, including threshold Register 188, January 2009 ENVIRONMENTAL CONSERVATION 120 detection, sensitivities, and limitations of equipment must be provided;

(F) waivers - (…)

(3) Part 3 - Supplemental Information: (…)

(4) Part 4 -- Best Available Technology Review: Unless application of a state requirement would be pre-empted by federal law, the plan must provide for the use of best available technology consistent with the applicable criteria in 18 AAC 75.445(k). In addition, the plan must

(A) identify technologies applicable to the applicant's operation that are not subject to response planning or performance standards specified in 18 AAC 75.445(k)(1) and (2); these technologies include, at a minimum,

(i) for all contingency plans, communications described under (1)(D) of this subsection; source control procedures to stop the discharge at its source and prevent its further spread described under (1)(F)(i) of this subsection; trajectory analyses and forecasts described under (1)(F)(iv) of this subsection; and wildlife capture, treatment, and release procedures and methods described under (1)(F)(xi) of this subsection;

(ii) for a terminal, a crude oil transmission pipeline, or an exploration and production contingency plan: cathodic protection or another approved corrosion control system if required by 18 AAC 75.065(h)(2), (i)(3), or (j)(3); a leak detection system for each tank if required by 18 AAC 75.065(i)(4) or (j)(4);

any other prevention or control system approved by the department under 18 AAC 75.065(h)(1)(D); a means of immediately determining the liquid level of bulk storage tanks as specified in 18 AAC 75.065(k)(3) and (4) or in 18 AAC 75.066(g)(1)(C) and (D); maintenance practices for buried metallic piping containing oil as required by 18 AAC 75.080(b); protective coating and cathodic protection if required by 18 AAC 75.080(d) (k)(1),(l) or (m); and corrosion surveys required by 18 AAC 75.080(k)(2); Register 188, January 2009 ENVIRONMENTAL CONSERVATION125

(iii) for a tank vessel contingency plan: (…)

(iv) for a crude oil transmission pipeline contingency plan: leak detection, monitoring, and operating requirements for crude oil pipelines that include prompt leak detection as required by 18 AAC 75.055(a);

(v) for a barge contingency plan: (…)

(vi) for a railroad tank car contingency plan (…)

(B) for each applicable technology under (A) of this paragraph, identify all available technologies and include a written analysis of each technology, using the applicable criteria in 18 AAC 75.445(k)(3); and

(C) include a written justification that the technology proposed to be used is the best available for the applicant's operation."

APPENDIX C
SUBSEA LEAK DETECTION INSTALLED BASE

Table C-1 Subsea Leak Detectors - Installed Base
(The data below is collected from the field operators. The data is provided as information only, no quality check of the data has been performed)

Field	Operator	Leak detection technology	# sensors delivered	Installed year	Installed on structure	How is the data from the technology managed / integrated in your operation?	Detectors still in use?	Leaks identified by the technology? Please describe	Have you had leaks that the technology did not detect? Please describe	False alarms? Other failure modes? Please describe	Particular challenges?	Comments, experiences
Alve	Statoil	Capacitance	1	2009	XMT	Control system	yes	No	No	yes	subsea testing	
Draugen	Shell	Capacitance	3	1993	XMT		yes			yes	testing	*vent holes on protection structure *during commissioning they didn't give positive signal during testing (hydraulic fluid being injected in the vicinity) *they were then pulled and tested in a hyperbaric chamber, where they worked *no firm conclusion,
Gullfaks	Statoil	Capacitance	13									
Gullfaks	Statoil	Passive acoustic (small)										
Heidrun NF	Statoil	Capacitance	All 12 wells	2001	FCM	as alarm i SAS	All in use but two of them gives alarms continously due to shallow gas.	No	No	Many false alarms due to shallow gas in area		
Heidrun Satelite	Statoil	Optical camera		2009	Bracket on Guidepost	video on web browser	Presently out of order	No	No			Presently out of order due to eart fault. Camera is retrieved, but will be installed after refurbishment.

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Heidrun Satelite	Statoil	Capacitance	1 well	2007	FCM	as alarm i SAS	Yes	No	No	Many false alarms due to shallow gas in area		
Kristin	Statoil	Optical camera										
Kristin	Statoil	Capacitance	12	2005	XT roof	via SAS system to control room	yes(12)	no	Yes, there was leakage which was detected by ROV	no	no	
Loke	Statoil	Capacitance	1	1993	XT	alarm inHKR	1		No			
Mikkel	Statoil	Capacitance	62	1998-2009	HXT	alarm at CCR	all	1 to 2	several, the sensor was not located where leak occured	Lots of "false" alarm. Difficulr to establish correct treshold level for alarm. Shallow gas migth set off alarm intentionally.	Sensor must not at any time give false alarm. Only few false alarms will make operator hesitant to repond to it. Reliability/ fidelity/ robustnes is kea words.	The data are given for Mikkel, Yttergryta and Åsgard together. By no measn try to implement technology which is unqualified and not tested under realistic condition. No one will ever install leak detector technology which in stead of increasing the safety
Morvin	Statoil	Capacitance	3-4	Planned installed	XMT	NA*	Production start 08-2010	NA*	NA*	NA*	NA*	NA*
Norne	Statoil	Capacitance	20	1997-2000	HXT roof	Control system	yes, mostely all	No	No	False alarms	Only HXT covered	Has started a projcet to try to test the detectors by pumping gas/air on each. Not completetd yet.
Norne K		Capacitance	3	2006	FCM (HXT roof)	Control system	yes	No	No			

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Ormen Lange	Shell	Passive acoustic	3		At each template							2 out of 3 units returned to shore for replacament of hydrophones due to contruction error. The third unit is collecting data but will also need to get the hydrophones replaced.
Rimfaks, Skinfaks	Statoil	Capacitance	12									
Urd	Statoil	Capacitance	8	2005-2006	XMT	Control system	yes	No	No	yes	subsea testing	
UMC North Cormorant	Shell	Capacitance										
Sigyn	Statoil	Capacitance	3	2002	XT	alarm inHKR	3		No			
Skarv	BP Norge	Capacitance			XMT and manifold							
Sleipner Vest SVAN	Statoil	Capacitance	4	2004	XT	alarm inHKR	4		No			
Sleipner Øst SLØ	Statoil	Capacitance	2	1993	XT	alarm inHKR	2		No			
Snorre UPA	Statoil	Capacitance	4	First installation 1992. Last istallation after repair 2008	Yes, 2 detectors above each other in each end of the protection roof	Alarm on operation screen. Signal through the subsea controle system	4	The detectors are place up under the collection roof and we have detected collection of non-water	No, but hard to say for sure	It has been very difficult to make these detector work properly. So we don't know if it is a instrument failure or not	The challange has been to make this detectors work properly. There is no possibility to see if there is oil or gas collected under the roof by ROV.	The Snorre SPS is covered by a roof that can collect as much as 40m3 of spilled hydraulicoil, gas and/or hydrocarb. It is possible to emty the roof to the Snorre Plattform by use of the 3" servise lines. It is not possible to confirm that the roof is empt

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Snøhvit	Statoil	Capacitance	10	2005	XT	Alarm and value in control room (PCDA)	8 still in use. 2 out of function due to lost readings, ref M2 40876817 and M2 40705054.	1 temporary leak detected. Cause of leak not concluded, but from the production valve block, probably stem leak in valve. Ref M2 40913922.	1 gas leak from XT/CBM multibore hub not detected by HC detector. Ref Synergi 1001496. Leak estimated to 0.3 kg/s for 5 to 51 days, ie a total of 16-1277 tonnes of gas.	No false alarms besides the 2 sensors out of function.		Not very reliable and no redundancy (20% out of function after 4 years). Not able to detect leakages from choke bridge module or manifold.
SRI	Statoil	Capacitance	6									
Statfjord Nord	Statoil	Capacitance	8	1995	XMT	Alarm	Yes	No	No	Yes		
Statfjord Øst	Statoil	Capacitance	8	1995	XMT	Alarm	Yes	No	No	Yes		
Sygna	Statoil	Capacitance	3	2000	XMT (FCM)	Alarm	Yes	No	No	Yes		
Tampen Link	Statoil	Passive acoustic	5									
TOGI Troll Oseberg Gas Injection	Statoil	Active acoustic	5	1989/90	XT	Integrated in the control system. SD when leak.	0. The Transponders were installed on a 5 meter high pole. The poles were broken over the years caused by trawling.	No. There have been no leaks on Togi. But the system was tested yearly by releasing gas to the water.	No	There have been false alarms caused by big shoal of fish. One or two times.	No	It has been a reliable and good detection system. (SIMRAD). Togi has not produced since 2002. So no effort has been made to fix the poles. The technology installed on Togi is now out of date.

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Tordis	Statoil	Capacitance		1994						Tordis field was installed with hydrocarbon detectors, but these were abandoned due to many false alarms.		
Tordis IOR	Statoil	Passive acoustic	3	2007	SSBI (subsea separator)	Still not working, modules onshore for testing verification	No, will be re-installed when ready.	No	No	No	Defining the different leak sectors.	New installations at T&V fields with acoustic sensors seem to show some progress, but still in their infancy. Most likely the way forward.
Troll Pilot	Statoil	Passive acoustic			not permanent installation							
Tyrihans	Statoil	Capacitance	4	2008 - 2009	XT-Roof	Data from the sensor are sent to control room. Warnings shown in control room	4	2 leaks during start-up of wells due to shallow gas.	None	Shallow gas	None	Only 4 of 12 wells in produktion
Vega	Statoil	Passive acoustic	0	Planned installed	NA*	NA*	NA*	NA*	NA*	NA*	NA*	NA*
Vigdis	Statoil	Passive acoustic	1	2008	manifold	Sector alarms back to CR if noises experienced	yes	No	No	Yes. During vessel operations at other locations at the field. Tuning of the system when installed important for building confidence in the system. False alarms lower the confidence for the system.	Defining the different leak sectors.	
Yme	Statoil	Capacitance	2									

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Yttergryta	Statoil	Capacitance	See Mikkel	See Mikkel	See Mikkel	See Mikkel	See Mikkel	See Mikkel	See Mikkel	See Mikkel	See Mikkel	See Mikkel
Åsgard	Statoil	Capacitance	See Mikkel	See Mikkel	See Mikkel	See Mikkel	See Mikkel	See Mikkel	See Mikkel	See Mikkel	See Mikkel	See Mikkel
Åsgard	Statoil	Optical camera			valve							

* NA = Not Applicable

Table C-2 Subsea Leak Detectors - Fields with no leak detection installed

Field	Operator
Fram Vest/Øst	Statoil
Heidrun VIKS	Statoil
Njord	Statoil
Oseberg Delta	Statoil
Oseberg Vestflanken	Statoil
Oseberg Sør K	Statoil
Oseberg Sør J	Statoil
Skirne/Byggve	Statoil on beholf of Total
Snorre B	Statoil
Troll B and C.	Statoil
Tune	Statoil
Vale	Statoil
Vilje	Statoil

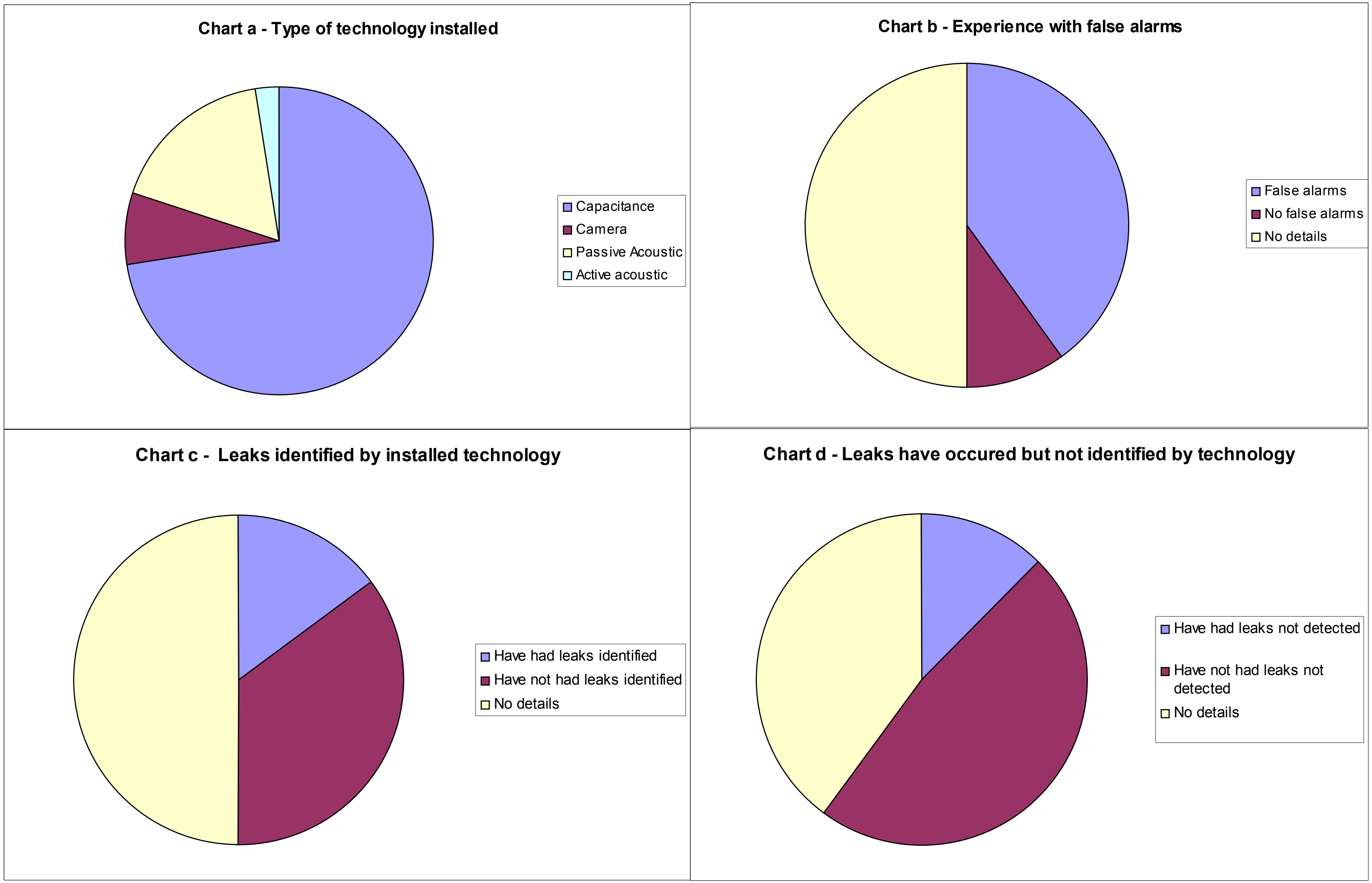

Figure C-1
The pie-charts above show the data gathered from the 40 fields (out of a total of 53 investigated fields) that have some technology installed for leak detection.

Chart a shows what technology is installed at each field
Chart b shows whether the field has had false alarms
Chart c shows how many of the fields have had leaks identified by the installed leak detection (it is not known how many leaks there have actually been for the various fields)
Chart d shows how many of the filelds that know they have had leaks that the installed leak detection did not detect.

APPENDIX D
SUBSEA LEAK DETECTORS SUPPLIER TECHNICAL DATA

Table D-1 Detectors - Supplier Technical Data

Technology	Calibration/ Re-calibration	Maintenance	Mechanical interface	Weight [kg]	Dimensions	Connection to power and communication	Power need	Bandwidth need	Maturity [1]	Detectable release limit or other accuracy information	Detectable media	Detection range	Reliability data [2]	Design life [years]	Water depth [m]	Temperature [°C]
Active acoustic	Calibration during Sea Acceptance Test	3-5 years interval	Mounted on ROV skid or directly to template structure. Will be designed to be ROV retievable.	Receive array 9.6 (dry), subsea bottle 24.8 (dry), transmit array 4.5 (dry),	Receiver: 102 x 496 x 131mm Transmitter: 240 x 86 x 99mm Subsea Bottle: 530.9 x 174mm	48V, Ethernet	40W - 100W	High, development goal is 1-10Mbit ethernet interface	Baseline offshore product: Commercially delivered. Subsea version: Concept	Small gas leakages (0.35 mm nozzle, 2 bar pressure difference) detected at about 30 meters. Fluid leak from 5mm nozzle with 15bar pressure difference detected at 50m	Not dependent on chemical compound as long as acoustic impedance is different to that of seawater.	depends on leak size and media. Small gas leaks seen up to 125m range. Fluid seen up to 50m range (maximum test range to date	NA*	NA*	400 and 6000 versions available	-5 to 40 (operation) -30 to 55 (storage)
	Calibrates automatically at installation. No recalibration needed.	Deepening on water depht from 4-8 years interval	ROV mountable on Xmas tree, no pre installation required	<11kg complete unit (dry)	226 x 62 x 154 mm	15-36V 100Mb/s Ethernet 16 Mb/s RS-485	Typ: 15 W <30 W - dependent on required updating rate	Dependent om requierment and infromation, can be low 9600 Baud - system spesific	Prototypes	Angular resolution < 0.75° Range resolution < 10 mm	Not dependent on chemical compound as long as acoustic impedance is different to that of seawater.	Angle horizontal 90° or 120° Angle vertical 20° Range 1 to < 100 m	NA*	25	300 or 3000	-20-60
Bio sensors	Calibration after installation	Replacement of biosensor module	Installed in a sensor rack integrated or in proximity of the monitored structure	Bio sensor module: 2-3 (in air)	Prototype racks are 2 m x 0.4 m x 0.4 m (physical, chemical and biological sensor array)	Connected to subsea control system via cable. RS-485 or Ethernet	approx .10W	Low	Pilots installed for shallow water. Concept for deep water	< 0.06 ppm on hydrocarbons (raw oil)	Not dependent on chemical compound, specification will depend on selected biosensor.	Depending on leak size, media and sea current (upstream/ downstream approach)	NA*	NA*	100 (500 from 2012)	Ocean temperature range.

Table D-1 Detectors - Supplier Technical Data (Continued)

Technology	Calibration/ Re-calibration	Maintenance	Mechanical interface	Weight [kg]	Dimensions	Connection to power and communication	Power need	Bandwidth need	Maturity [1]	Detectable release limit or other accuracy information	Detectable media	Detection range	Reliability data [2]	Design life [years]	Water depth [m]	Temperature [°C]
Capacitance	No recalibration required	Cleaning. Using a hydro-jet should be OK	Bolted on to cover above leak point.	<5	<1000 ccm = 1 l	4-20 mA and CANBus	24 V, 0.5 W	Low	Commercially delivered and qualified	Even small leaks are detected.	All hydrocarbons	Depending on overall system design.	Approx. 300 units delivered, no returns and no reports of failure after installation.	25	4000, deeper if required.	All sea temperatures OK.
Fiber optic	No calibration	2 Years	System Specif	20kg - surface equipment	56x45x15cms	Ethernet at surface	240/ 110v 300w at surace	System spefic	Concept tested (topside for pipelines)	Gas bubble at 1Hz detected. Low pressure threshold approx 2bar. No upper limit	Not dependent on chemical compound, detects vibrations caused by a leak	Dependent on energy, but typically 5 m	NA*	20	4000	+5 to +50 (operation)
Fluorescent	No recalibration required	Possible lens cleaning every 3-5 years	Bolted on to XT and SPS	10 -15 in air	Ø200x200mm, 100x200x200mm	4 wire Tronic/ Canbus/ 4-20mA	24V, <10W	Low	In use with ROV. Concept version for subsea	Wide dynamic range. <100ppm @4m	Crude oil. Production fluids with fluorescent markers	3-5m	NA*	NA*	NA*	NA*
Methane sniffer; optical NDIR method	No recalibration required	Membrane service every 36 months	ROV mountable/ interchangeable by wet-mateable plugs and ROV handle	5,2 in air 2,7 in water	Diameter 90mm, length 700mm	wet-mateable plug	3 W	low	commercially delivered	very small leaks	Methane	NA*	Stability 3 years. New version 5 years	10	6000	-4 up to 50
Methane sniffer; semi conductor	2 years	2 years	adaptable to fit application	0.5kg in water	Ø 49 mm x 200 mm	wet-mateable plug	1W	Low	Baseline product commercially delivered. Concept version for subsea	very small leaks	Methane	lower range limit 1nM (oceanic background)	lifetime 5 years	5	4000	0-30

Table D-1 Detectors - Supplier Technical Data (Continued)

Technology	Calibration/ Re-calibration	Maintenance	Mechanical interface	Weight [kg]	Dimensions	Connection to power and communication	Power need	Bandwidth need	Maturity [1]	Detectable release limit or other accuracy information	Detectable media	Detection range	Reliability data [2]	Design life [years]	Water depth [m]	Temperature [°C]
Optical camera	No	Check moving parts and lens cleaning every 2 years. Intervention every 5 years	ROV mountable on Xmas tree, no pre installation required	camera 3.2 in air. Light 4.1 in air.	ø100x200mm. 880*550*450	4 wire tronic. Communication via power line.	96 W	Medium. Communication on separate line or via subsea control system	First prototype with pattern recognition ready in 2006	Not defined	All hydrocarbons and injected chemicals	10 meters	NA*	25	1000 made in aluminium 3000 made in titanium	
Passive acoustic	Adapts to background noise at installation site. No recalibration required	Non	ROV mounting, for larger type of systems a special cone is required	Smaller type 2-3, larger type 250 in air	Smaller type ø64 x 357mm, larger type ø1 x 1.8 m	NA*	Larger type: 25 W	Dependent om processing subsea or topside. Processing topside requires more bandwidth	Commercially delivered, both larger and smaller type	Smaller type: 5 liter/ min @ 25Bar diff pressure at 2m distance. Detection range 50m with increased leakage rate. Larger type: 5 liter/ min @ 5Bar diff pressure at 5m distance. Detection range 1000m with increased leakage rate.	Not important, all leaks as described under 'Detectable release limit'	See detectable release limit	25.8year calculated MTBF based on dataheets, EPRD-97 and MIL-HDBK-217F.	5 for small type and 25 for large type.	2500	operational in sea water: -5 - +30. Onshore test temperature -20 - +70. Storage -40 - +70
	Calibrates automatically at installation. No recalibration needed.	Non	ROV mountable on Xmas tree, no pre installation required	<7kg sensor unit (dry) < 15kg funnel (dry)	324x ø90mm	Connected to subsea control system via RS485, CanBus, Profibus, Modbus or Ethernet	0,8W, 12-38 VDC	minimum 1200 baud, upto 115 Kbaud	Commercially delivered	Minimum for liquid: dP>3 bar, min. leakage rate 0.1 l/min Minimum for gas: dP>1 bar, min. leakage rate 0.1 l/min instrument to be close to leak source - mechanical on to structure or valves	Short area coverage	within radius of 3 meters - leaks need to be larger to be detected beyond this area	Delivered in several versions - more than 1000 systems installed subsea MTBF calculations > 140 Years	+30	4500	-20-215

Table D-1 Detectors - Supplier Technical Data (Continued)

Technology	Calibration/ Re-calibration	Maintenance	Mechanical interface	Weight [kg]	Dimensions	Connection to power and communication	Power need	Bandwidth need	Maturity [1]	Detectable release limit or other accuracy information	Detectable media	Detection range	Reliability data [2]	Design life [years]	Water depth [m]	Temperature [°C]
Note 1: The data below are collected from various suppliers of leak detectors. For some of the technologies, more than one supplier is available and have been giving input to the data below. When considering a specific product for a given application, objective evidence should be collected from the supplier to verify the performance specifications for that specific product.																
Note 2: Other suppliers than those that have given input to this table may exist																
1 Maturity classes are for this table defined as follows: Concept, Concept Tested, Prototypes or Pilots tested, Commercially delivered, Commercially delivered and qualified																
2 Reliability data may be calculated from field experience data or may be calculated by applying a reliability model. In both cases, the reliability data should be specific and given in hard numbers																
* NA = Not Applicable																