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MASTER'S THESIS

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Author: Unni Marina Berge	…………………………………………… (signature of author)
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Abstract

More challenging wells in sensitive areas require appropriate integrity monitoring to address the safety and environmental concerns.

The purpose of this thesis was to gain an overview of the current status of well integrity monitoring on the Norwegian Continental Shelf, and available sensors for producing and plugged wells.

Published material, meetings with suppliers, manufacturers and a technical specialist from the Petroleum Safety Authority (PSA) Norway, and the 2017 Leak Detection Seminar held by the PSA have been used as a basis for this thesis.

Driving forces for implementing monitoring and developing sensor technology are identified, and several important challenges and solutions are presented.

Despite challenging situations, there are many suitable continuous well integrity monitoring sensors available. New technologies are also being developed using state of the art technology. These can be used to avoid serious integrity failures leading to leaks to the environment, or to detect occurred leaks. Monitoring solutions must be considered during the early stages of well or field development and need to include abandoned wells.

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Abbreviations

3D	Three Dimentional
4C	4 Component
4D	4 Dimentional
AALD	Active Acoustic Leak Detection
AILD	Autonomous Intelligent Leak Detector
AMS	Annulus Management System
APB	Annular Pressure Buildup
API	American Petroleum Institute
AUV	Autonomous Underwater Vehicle
BAT	Best Available Technique
C	Capacitance
CAA	Civil Aviation Authority
CM	Corrosion Monitoring
CO_2	Carbon Dioxide
CPA	Climate and Pollution control Agency
D	Distance
DAS	Distributed Acoustic Sensing
DC	Direct Current
DHNC	Downhole Network Controller Card
DHSV	Down Hole Safety Valve
DMF	Drilling Managers Forum
DNV	Det Norske Veritas

DNVGL	Det Norske Veritas Germanicher Lloyd
DTS	Distributed Temperature Sensing
EEA	European Economic Area
EO	Electro Optical
Eq	Equation
ER	Electrigal Resistance
EU	European Union
H_2S	Hydrogen Sulphide
HC	HydroCarbon
HLD	Hydrocarbon Leak Detector
HPHT	High Pressure, High Temperature
HSE	Health, Safety and Environment
IDNS	Integrated Downhole Network System
IEC	International Electrotechnical Commission
IR	Infra Red
IRIS	International Research Institute of Stavanger
ISO	International Standards Organization
IT	Information Technology
L	Length
LED	Light Emitting Diode
NCS	Norwegian Continental Shelf
NMD	Norwegian Maritime Directorate
NORSOK	NORsk SOkkels Konkurranseposisjon

	(Norwegian shelf's competitive position)
NPT	Norwegian Post and Telecommunication
O_2	Oxygen
^oC	Degree Celcius
P	Pressure
P & T, PT	Pressure and Temperature
PAF	Plugging and Abandonment Forum
PSA	Petroleum Safety Authority
PSI	Pounds per Square Inch
R	Resistance
R & D	Research and Development
ReM	Reservoir Monitoring
RNNP	RisikoNivå i Norsk Petroleumsvirksomhet (Risk level in the Norwegian petroleum industry)
ROV	Remotely Operated Vehicle
S	Shear
SCP	Sustained Casing Pressure
SE	Sand Erosion
SINTEF	Selskapet for INdustriell og TEknisk Forskning (Industrial and technical research company)
SPE	Society of Petroleum Engineers
T	Temperature
USA	United States of America

WIF	Well Integrity Forum
WL	WireLine
ε	Dielectric constant

1 Introduction

The first oil and gas wells were constructed with no regard to well integrity or future environmental challenges. They were simply drilled and produced with the available and most practical materials. When the wells no longer produced oil or gas, they were simply abandoned. They were not, and some are still not, plugged[1]. By the time the Norwegian oil and gas industry was started, some guidelines had already been established as a response to previous incidents and experience.

In 1969 as a response to the Santa Barbara incident, President Richard Nixon said: *"The deterioration of the environment is in large measure the result of our inability to keep pace with progress. We have become victims of our own technological genius"* [2].

With increased complexity follows an increased risk of failure, and therefore an increased need for monitoring.

Environmental requirements have become stricter, tolerating fewer mistakes and oil and gas leaks. New technology needs to constantly be developed to reach these requirements. A leaking well is not only a potential environmental disaster but can also be an economic disaster for an operating company, and avoiding it is therefore of great importance for any company.

This thesis covers relevant laws and regulations, which form the basis for standards and guidelines including well integrity monitoring on the Norwegian continental shelf (NCS). Well integrity and the use of technical barriers for producing and plugged wells are described. Understanding well integrity is necessary to understand the causes and consequences of integrity failure, and how these can be detected. This thesis focuses on integrity monitoring and detection of integrity failure. Various challenges are presented and possible technical solutions are described. Focus is on the use of continuous monitoring sensors that can be used on the NCS.

2 Laws, Regulations and Guidelines

Requirements and guidelines for well integrity monitoring on the NCS are defined and described in laws, regulations and guidelines. **Fig. 2.1** illustrates the relationship between these.

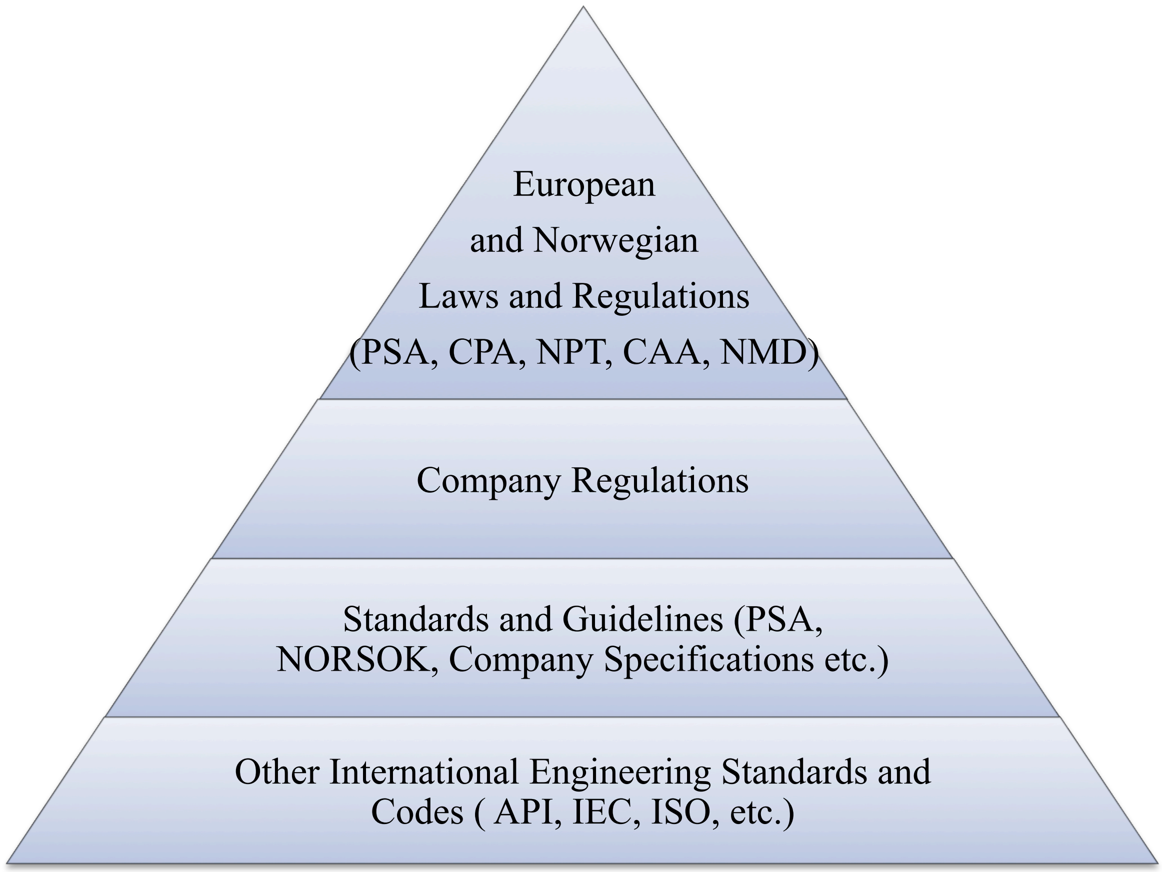

Figure 2.1: Hierarchy of Regulating Bodies on the NCS. PSA: Petroleum Safety Agency, CPA: Climate and Pollution Control Agency, NPT: Norwegian Post and Telecommunication Authority, CAA: Civil Aviation Authority, NMD: Norwegian Maritime Directorate.

The European and Norwegian laws and regulations are the highest deciding body for petroleum activities on the NCS. Next are the companies' own regulations, then standards and guidelines, and, finally, other international engineering standards and codes.

As a member of the EEA Norway has to comply to certain EU directives (laws)[3]. In Norway petroleum activities are subject to the Petroleum act and acts relating to Health, Safety and Environment (HSE), such as pollution control acts and ship safety acts, etc.. Requirements are described in different regulations. Oil companies must follow these regulations, but also often have their own.

Company Regulations are based on previous experience and may also often incorporate legislation from their country of origin.

Regulations refer to standards and guidelines. These can be national and international standards or internal company standards.

Engineering standards and codes cover design, construction and working methodology, and can be very specific. For example the American Petroleum Institute (API) standards cover equipment and components used in the petroleum industry. The International Electrotechnical Commission (IEC) is the European standard for instrumented safety systems and the International Standards Organizarion (ISO) standards cover many aspects of the petroleum industry, including well integrity.

2.1 Laws and Regulations

Laws applicable on the NCS are described in numerous acts. Some acts relevant to well integrity monitoring are highlighted in this section.

The European Parliament Directive on safety of offshore oil and gas operations states: *"The objective of this Directive is to reduce as far as possible the occurrence of major accidents relating to offshore oil and gas operations and to limit their consequences"* and *"An offshore regime needs to apply both to operations carried out on fixed installations and to those on mobile installations, and to the lifecycle of exploration and production activities from design to decommissioning and permanent abandonment"* [4].

In addition to specifying avoidance of accidents for all development and operating phases, this directive also focuses on the importance of use of best available techniques (BAT) and the sharing of experience.

The Norwegian Petroleum Act is in line with this EU directive. Some relevant paragraphs from the Norwegian Petroleum Act are given here:

§ 9-1 Safety: *"The petroleum activities shall be conducted in such manner as to enable a high level of safety to be maintained and further developed in accordance with the technological development"* [5].

§ 10-1 Requirements to prudent petroleum activities: *"Petroleum activities according to this Act shall be conducted in a prudent manner and in accordance with applicable legislation for* *such petroleum activities. The petroleum activities shall take due account of the safety of personnel, the environment and of the financial values which the facilities and vessels represent, including also operational availability"* [5].

The Norwegian laws are detailed in regulations describing specific requirements.

2.2 Regulations used on the NCS

Regulations describe the functional requirements, and refer to recognized standards, such as NORSOK and other guidelines, for examples of how to meet the requirements. This way, the regulations describe what should be monitored, not how, and it is up to the operating companies to work out how to meet the requirements.

The Petroleum Safety Authority Norway (PSA) is responsible for enforcing the Norwegian Government's legislation of the petroleum activities on the NCS.

These legislations are divided into:

- Framework; Regulations relating to health, safety and the environment in the petroleum activities and at certain onshore facilities
- Management; Regulations relating to management and the duty to provide information in the petroleum activities and at certain onshore facilities
- Facilities; Design and outfitting of facilities, etc. in the petroleum activities
- Activities; Regulations relating to conducting petroleum activities
- Technical and Operational Regulations; Regulations relating to technical and operational matters at onshore facilities in the petroleum activities etc.
- Working Environment Regulations
- Other Regulations

Several of the categories have relevant regulations related to well integrity, monitoring and leak detection. These are highlighted in the following sections.

2.2.1 Framework Regulations

Framework section 48: Duty to monitor the external environment states, *"To ensure that the decision basis and knowledge about the marine environment is sufficient to maintain an acceptable environment condition, the operator shall monitor the external environment.*

Sufficient information shall be obtained to ensure that pollution caused by own activities is detected, mapped and assessed, and that necessary measures are implemented as soon as possible"[6].

A failure of well integrity will lead to pollution, and the operator is required to have necessary monitoring in place.

2.2.2 Management Regulations

Management section 5: Barriers states, *"Barriers shall be established that at all times can*

a) identify conditions that can lead to failures, hazard and accident situations,

b) reduce the possibility of failures, hazard and accident situations occurring and developing,

c) limit possible harm and inconveniences…"[7]

The integrity of a well must be ensured by the use of barriers. This will be further explained in Chapter 3: Well Integrity.

2.2.3 Facilities Regulations

Facilities section 8: Safety functions states, *"Facilities shall be equipped with necessary safety functions that can at all times*

a) detect abnormal conditions,

b) prevent abnormal conditions from developing into hazard and accident situations,

c) limit the damage caused by accidents…" [8]

To meet this regulation, integrity monitoring methods must be put in place to assist prevention and early detection of failure.

Facilities section 48: Well barriers states, *"…The well barriers shall be designed such that their performance can be verified"* [8].

Monitoring methods to verify barrier performance need to be included in the design.

2.2.4 Activities Regulations

Activities section 57: Detection and mapping of acute pollution (remote sensing system) states, *"Operators shall establish remote sensing systems to detect and map the position,* *area, quantity, and properties of acute pollution…”,“… With the aim of detecting acute pollution, the area around the facility shall be regularly monitored. The need for continuous monitoring shall be evaluated...” and “…Operators shall contribute with further developing the remote sensing systems”* [9].

Monitoring of the area is required to detect leaks from the well to the environment. The use of continuous monitoring systems and participation in development of new sensors is also highlighted.

Section 88: Securing wells states, *“All wells shall be secured before they are abandoned so that well integrity is safeguarded during the time they are abandoned, cf. Section 48 of the Facilities Regulations. For subsea-completed wells, well integrity shall be monitored if the plan is to abandon the wells for more than twelve months...” and “…hydrocarbon-bearing zones shall be plugged and abandoned permanently within three years if the well is not continuously monitored…”* [9].

Temporary abandoned wells must be monitored if abandoned for more than 12 months. In the case of a permanently plugged well monitoring is not specified, but the company is liable for environmental damage, etc. in the event of well integrity failure of the plugged well. This gives an incentive to install integrity monitoring and/or leak detection systems.

2.3 Standards and Guidelines used on the NCS

Well integrity is described in several different standards and guidelines used by the oil industry on the NCS. These also include some guidelines related to integrity monitoring.

Applicable national standards relating to well integrity monitoring covered in this thesis include:

- NORSOK D-010: Well integrity in drilling and well operation.
- DNVGL-RP-F302: Offshore leak detection.
- Norwegian Oil and Gas Guideline No.100: Recommended guidelines for accessing remote measurements solutions.
- Norwegian Oil and Gas Guideline No.117: Recommended guidelines for well integrity.

These guidelines and recommended practices are prepared by work groups with representatives from a broad background within the petroleum industry. Members from Plugging and Abandonment Forum (PAF), Well Integrity Forum (WIF) and Drilling Managers Forum (DMF) and various oil companies incorporate their experience and regularly update these documents. In addition to these national standards, each company has their own set of standards and a list of qualified suppliers.

Specific guidelines of particular relevance to this thesis are given in relevant sections.

3 Well Integrity

The regulations and standards referred to in chapter 2: Laws, Regulations and Guidelines aim to ensure a high level of well integrity on the NCS and to detect abnormal situations or uncontrolled hydrocarbon (HC) release in order to limit damage to the environment in the event of well integrity failure.

NORSOK D-010 defines well integrity as the *"application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids and well fluids throughout the life cycle of a well"*[10].

These solutions are commonly referred to as barriers. A barrier prevents potentially hazardous situations from happening or can prevent a hazardous situation from escalating

A Technical barrier refers to the design, selection and construction of equipment and systems that form the physical barriers that prevent release from a well. These include tubing/annulus integrity, tree/wellhead integrity, casing, cement, valves and safety systems, and are known as well barriers.

Organisational barriers are part of the company's accountability and responsibility and require that companies have personnel with defined roles who are specifically trained to safely operate wells. They also include emergency preparedness in the event of a failure.

Operational barrier elements include the procedures that describe the actions or activities personnel must perform to ensure well integrity such as operation within limits and constraints, leak testing, testing of safety systems, etc., as well as how to react to abnormal situations.

A failure in any of these barriers such as badly designed well systems, inadequate testing, insufficient maintenance, poor procedures, "misoperation" due to not following procedures, human error or lack of training, will compromise the well integrity. In the worst case, this can lead to a blowout.

This chapter looks at technical barriers and how petroleum fluids can leak from the well to the environment. It is the status of these barriers that need to be monitored.

3.1 Technical Well Barriers for Producing and Plugged Wells

Wells are designed with multiple barriers to ensure well integrity.

NORSOK D-010 Specifies that *"There shall be two well barriers available during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled outflow from the borehole/well to the external environment"* [10].

This is to prevent leakages and reduce risks associated with drilling, production and intervention activities.

Two qualified well barrier envelopes are required in a well, whether it is a production well or a plugged well. These envelopes are the primary well barrier and the secondary well barrier. The primary well barrier is closest to the pressure source and is put in place to seal off the reservoir. The secondary well barrier is put in place so that outflow from the well is prevented should the primary barrier fail.

Well barriers are made up of several well barrier elements forming barrier envelopes. A failure of a well barrier element will usually result in a well with reduced integrity. Integrity failure occurs when both barriers fail.

3.1.1 Producing Wells

An example of a production well with primary and secondary well barrier envelopes is shown in **Fig 3.1**.

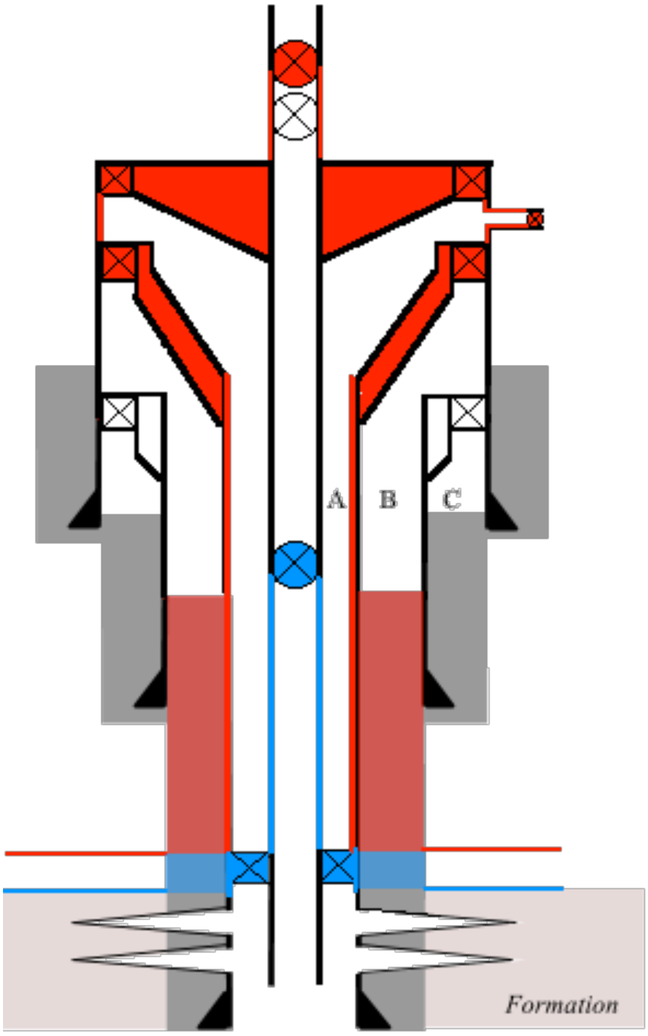

Figure 3.1: Primary and Secondary Well Barriers of a Production Well. The blue elements are primary barriers and the red elements are secondary barriers.

Primary well barrier elements in a producing well include:

- Formation rock above reservoir
- Production casing cement
- Production casing
- Production packer
- Completion tubing string
- Down Hole Safety Valve (DHSV)

Secondary well barrier elements in a producing well include:

- Formation above the production packer
- Casing cement

- Casing with steel assembly
- Wellhead
- Tubing hanger with seals
- Annulus access line and valve
- Production tree (X-mas tree)

Completed wells usually have at least two annuli, the A annulus and the B annulus, illustrated in **Fig. 3.2**. The A annulus is the space between the production tubing and the production casing, and the B annulus is the space between the production casing and the intermediate casing. **Fig. 3.2** also includes the C annulus.

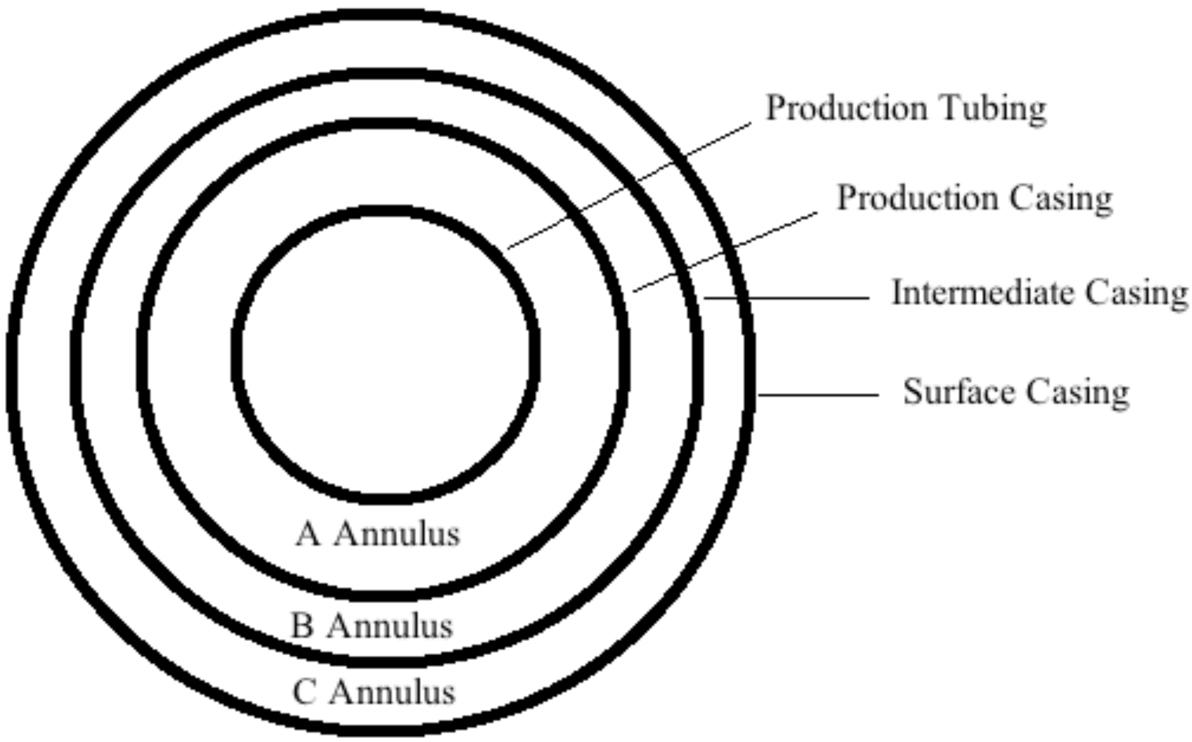

Figure 3.2: A Annulus, B Annulus and C Annulus in a Production Well.

During production there are four main ways in which hydrocarbons can migrate from the well to the environment (wellhead and X-mas tree assembly is not included):

- Through the wall of the downhole completion tubing and casing string
- Through the production packer
- Through the cement between the annuli
- Between casing and cement or cement and formation

Fig. 3.3 illustrates these migration paths.

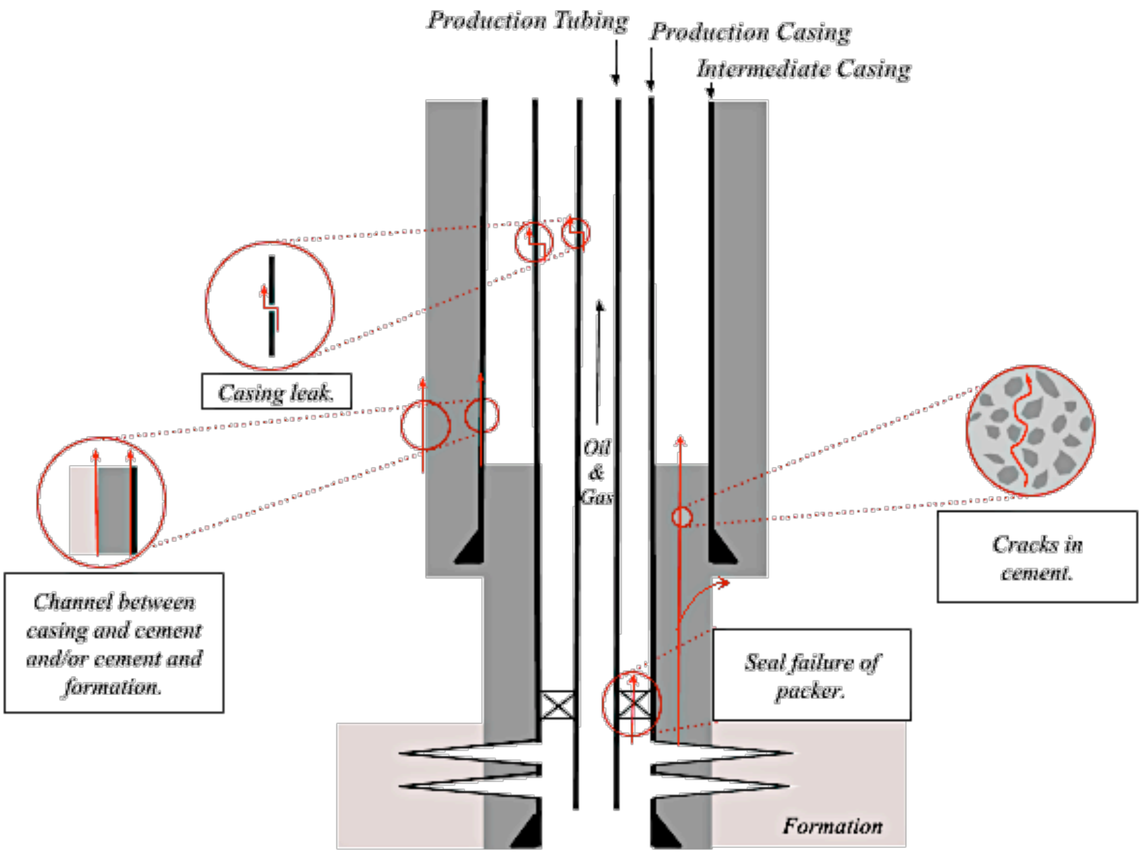

Figure 3.3: Hydrocarbon Migration Paths of a Producing Well.

3.1.2 Plugged Wells

Temporary and permanently plugged wells have additional barrier requirements.

Temporary well barrier elements need to be designed to last the expected duration of the abandonment period and so that safe re-entry is possible after the abandonment phase. Qualified mechanical barriers can be used as barrier elements for temporary abandonment. Temporary abandonment can be divided into two categories:

- Temporary abandonment with monitoring
- Temporary abandonment without monitoring

If a well is temporarily abandoned with monitoring, both the primary and secondary well barriers are continuously monitored and routinely tested. Such wells have no maximum period of abandonment. A well that is temporarily abandoned without monitoring can be abandoned for a maximum of three years.

Fig 3.4 shows an example of a temporary abandoned well with primary and secondary well barrier envelopes.

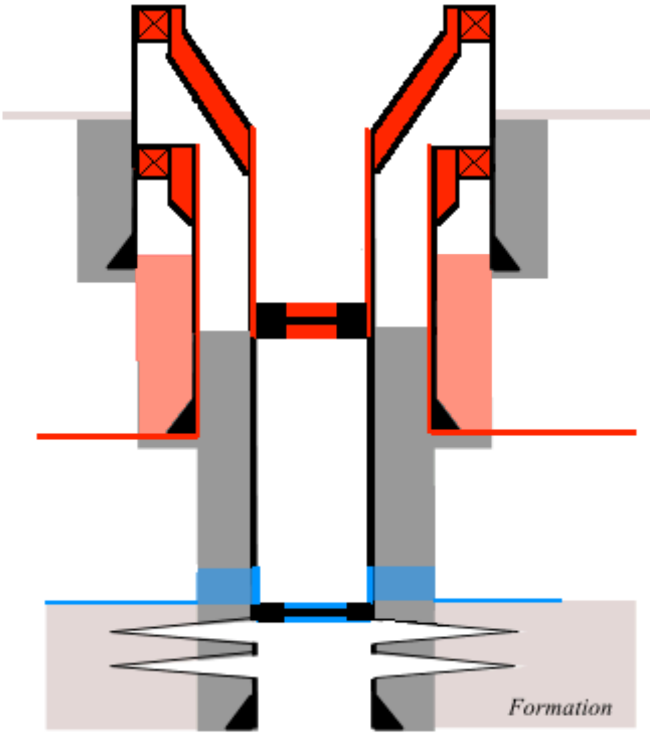

Figure 3.4: Primary and Secondary Barriers of a Temporary Abandoned Well. The blue elements are primary barriers and the red elements are secondary barriers.

Primary well barrier elements in a temporary plugged well include:

- Formation rock above reservoir
- Production casing
- Production casing cement
- Production packer
- Deep set plug

Secondary well barriers in a temporary plugged well include:

- Formation above the production packer or at shoe
- Casing cement
- Casing
- Cement plug or mechanical plug
- Casing hanger with seals
- Tubing hanger with seals

Permanently abandoned wells must be plugged with an eternal perspective. Mechanical barrier elements can degrade over time, and are not accepted as well barrier elements alone in permanently plugged wells. The plug must cover the whole cross-section of the well and seal both vertically and horizontally.

Fig 3.5 shows an example of a permanently abandoned well with primary, secondary and open hole to surface well barrier envelopes.

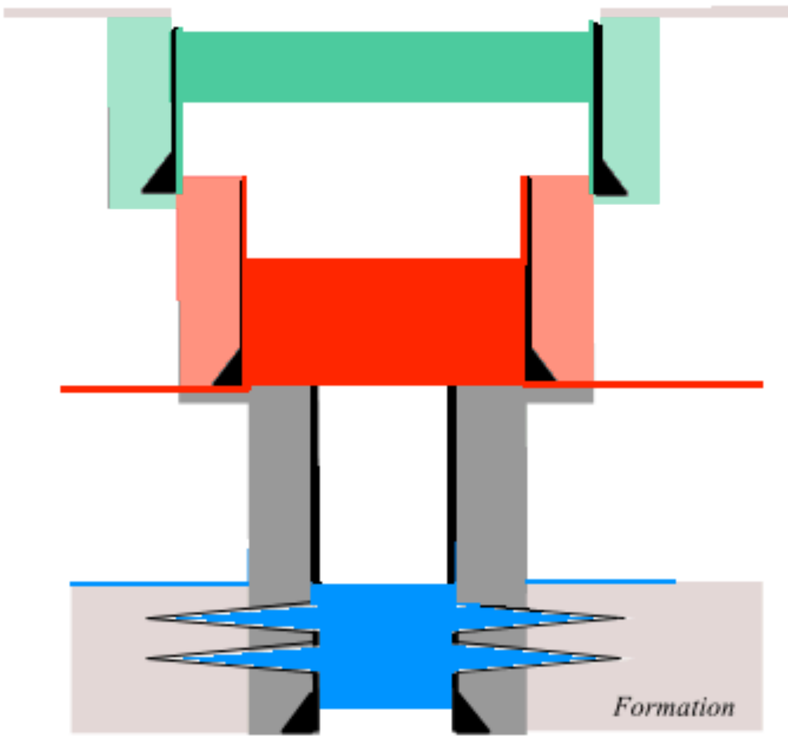

Figure 3.5: Primary, Secondary and Open Hole to Surface Barriers of a Permanently Abandoned Well. The blue elements are primary barriers, the red elements are secondary barriers and the green elements are open hole to surface barriers.

Primary well barrier elements in a permanently plugged well include:

- Formation rock above reservoir
- Cement plug

Secondary well barriers in a permanently plugged well include:

- Formation at casing shoe
- Casing cement
- Casing
- Cement plug

Open hole to surface well barrier elements in a permanently plugged well include:

- Casing cement
- Casing
- Cement plug

The main ways in which hydrocarbons can migrate from a plugged well to the environment are:

- Through the cement plug
- Through the casing cement
- Through the casing
- Between casing and cement or cement and formation

These migration paths are illustrated in **Fig. 3.6**.

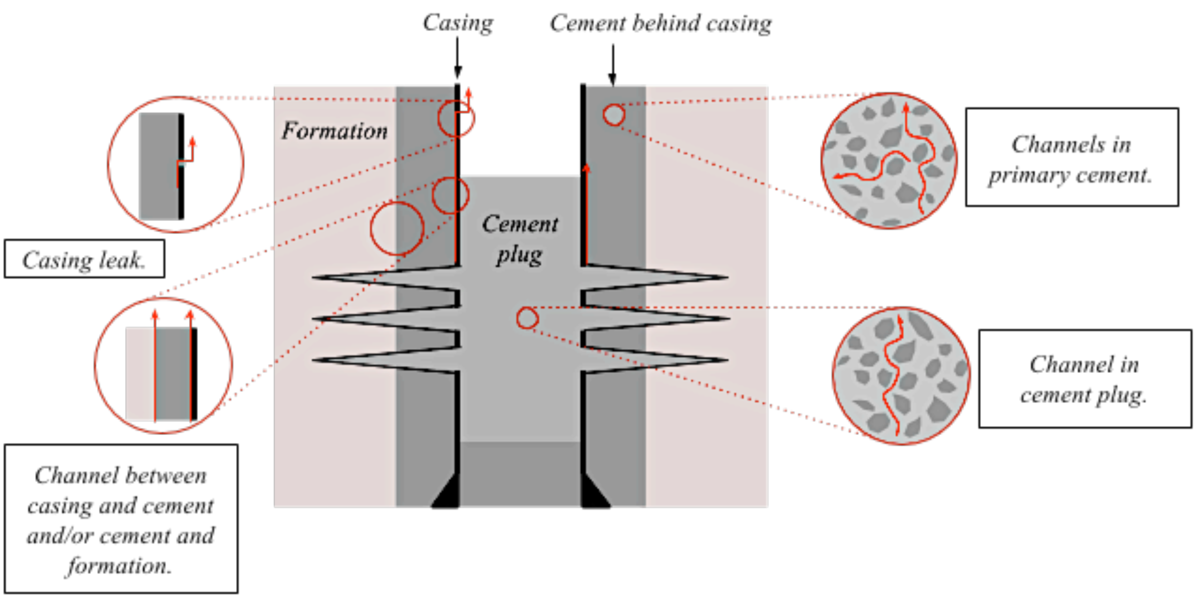

Figure 3.6: Hydrocarbon Migration Paths of a Permanently Plugged Well.

3.2 Causes of Reduced Integrity and Failure

Many different factors can lead to reduced well integrity. Some general factors that contribute to reduced well integrity are inadequate maintenance, barrier failure, failure of safety systems, unverified barrier elements and human error. Operating outside the safe operating window and frequent changes to operation can increase the risk to integrity.

Corrosion and erosion can cause degradation of the well casings and tubing. Chemical deterioration of cement, casings or tubing can be caused by formation fluid or the production fluid, pressure build up in the annuli can harm the casings and tubing and potentially lead to collapsed or burst casings or tubing, etc..

Changes in the reservoir structure can occur. This can be due to seismic events such as earthquakes or due to movement in the geological structure. These changes can lead to reduced integrity of the cap rock and other formation, and leak paths may be formed through faults or cracks in the formation.

Many of the currently producing and plugged wells are old. They were constructed with older technology and different requirements than today and therefore can not be expected to have the same integrity as newer wells[11].

If all well barriers fail the well could leak petroleum fluids to the environment. This is defined as an integrity failure.

3.3 Consequences of Integrity Failure

Well integrity issues can occur at all stages of a wells lifecycle and poor integrity can have great economical and environmental impacts as well as being a safety risk. In the event of leak to the environment, consequences are harm to marine life and harm to animal life due to pollution and oil leakages, and release of greenhouse gases that can negatively impact the climate. Releases to the environment are punished with fines for the operating company.

Gas leaks can migrate to a topside installation with the risk of explosion and subsequent personnel injury, damage to equipment and loss of production.

Severe cases of integrity loss a blowout, and resulting fire or explosion could lead to loss or shut down of wells and premature abandonment. The economic impact on the operating company is also considerable due to penalties and need for costly and risky repairs, and not least loss of reputation.

A gas leak is mainly a safety threat, while oil leaks are usually associated with environmental consequences.

Not only major leaks have consequences. Small leaks over time can also have consequences and can evolve into larger leaks.

3.4 Examples of Well Integrity Failure

A well integrity survey was performed in 2006 by the Petroleum Safety Authority (PSA) to assess the extent of well integrity issues on the NCS. 18% of the 406 wells in the survey suffered some degree of well integrity failures, issues or uncertainties, and 7% of the wells had been shut in as a result of integrity problems. The survey also revealed that the production tubing is the most common sufferer of well integrity problems[12]. This is likely due to the exposure to erosive and corrosive production flow, and because of the high number of connections which are potential leak points.

Since 2008 a categorisation of the integrity of wells in operation has been implemented in the Norwegian petroleum industry[13]. The categorisation system is based on traffic light principles with the colours red, orange, yellow and green to indicate the status of each well. **Table 3.1** gives a definition of the colour categories.

Table 3.1: Categorisation of Well Integrity[13].

Category	Principle
Red	One barrier failure and the secondary barrier is degraded/not verified, or leak to surface.
Orange	One barrier failure and the secondary barrier is intact, or single failures that may lead to leak to surface.
Yellow	One barrier degraded, the secondary is intact.
Green	Healthy well – no or minor issue.

In the activities regulations it is stated, *"If a barrier fails, activities shall not be carried out in the well other than those intended to restore the barrier"* [9]. This regulation applies to all wells in orange and red category.

The diagram in **Fig. 3.7** shows he percentage of wells in each colour category on the NCS in the years 2008-2016.

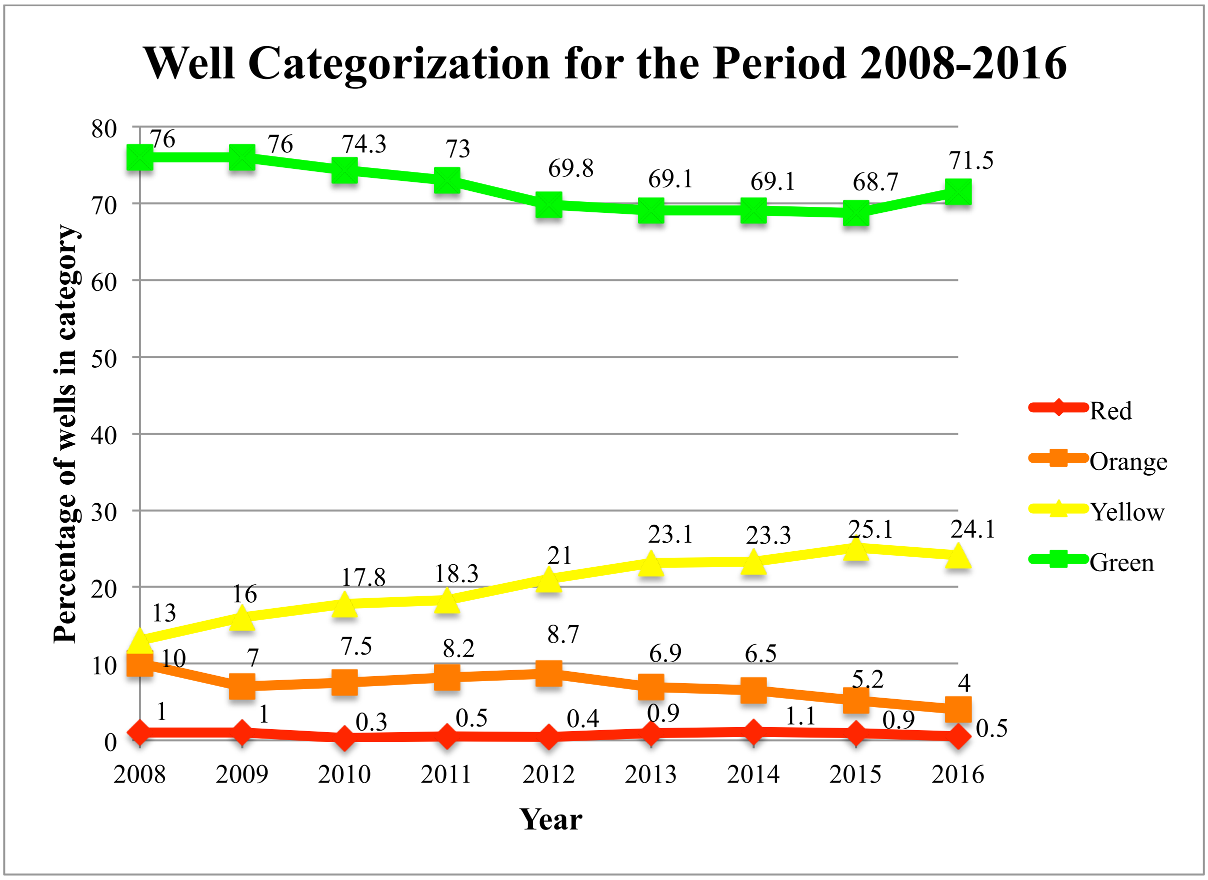

Figure 3.7: Well Categorization for the Period 2008-2016 on the NCS. (data from RNNP[13])

The number of healthy wells is dominating, but there are some wells suffering barrier degradation. These wells do not meet the criteria of having two barriers. The number of wells in the red category is low. However, it is alarming that there are wells that have suffered such significant integrity degradations.

Not only in Norway has there been done studies on well integrity statuses. An example is USA, where there are oil and gas wells that are currently leaking into the environment. Integrity issues in oil and gas wells can lead to methane leak to the atmosphere and into underground sources of drinking water[14]. This is not only an explosion risk but also a significant contribution to the release of greenhouse gases.

A study done on abandoned wells in Pennsylvania without records of their origin and condition revealed a number of insufficiently sealed wells. The lack of documentation on these wells makes it hard to localize them, and they could be located in forests or even in back yards. There is also no documentation of their age or of attempts to plug these wells. Some wells appear as an open pipe coming up from the ground[15]. These wells are both an environmental and a safety hazard.

Modern offshore wells can also have integrity issues that can lead to disasters. One example is the Elgin platform owned by Total, that in March 2012 suffered a blowout. The blowout occurred during an attempt to kill one of the 11 high pressure, high temperature (HPHT) wells on the site located off the coast of Aberdeen, Scotland.

Due to failures in the casing cement and the production casing the well was suffering from pressure influx from the Hod chalk formation located above the production reservoir. The pressure increase in the annuli was controlled by bleeding-off to stay within the defined safe operating windows. Due to an increased frequency in bleeding-off pressure a decision was made to stop all bleeding and allow the pressure in annulus A to rise to and balance against the influx pressure. In February 2012 the production casing and the intermediate casing failed. The surface casing was now the only barrier preventing gas from escaping the well. Well intervention was started to kill the well in March 2012.

Failure in casing was caused by corrosion[16]. The leak paths are illustrated in **Fig. 3.8**.

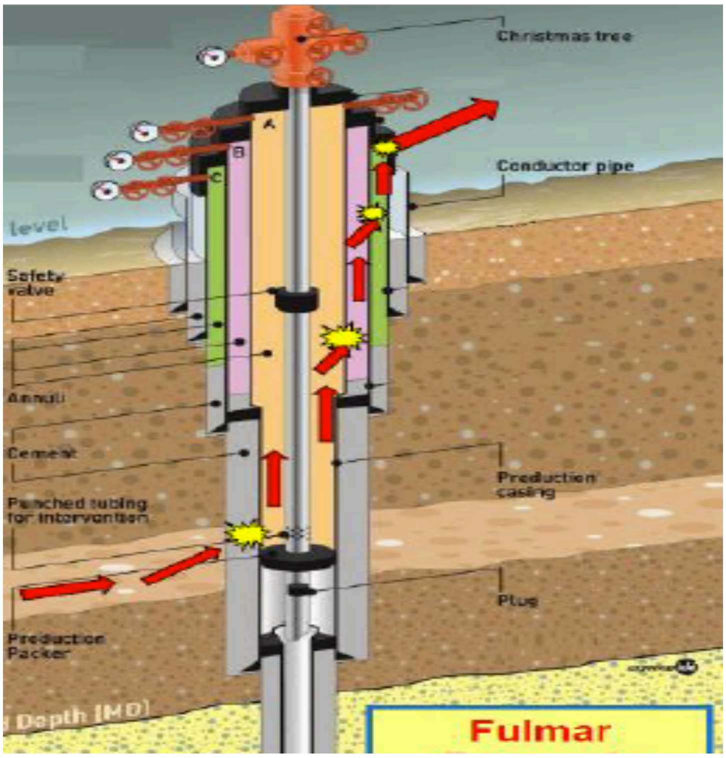

Figure 3.8: The Elgin Well Integrity Failure. The red arrows illustrate the hydrocarbon migration path from the HOD reservoir to the environment [17].

The well kill did not go according to plan. Control of the well was lost and pressure increased until the surface casing failed. Gas and condensate started leaking from the wellhead.

The potentially explosive gas release resulted in the shut down of the Elgin facility and neighbouring platforms, and the evacuation of all personnel. A two-mile shipping and aircraft exclusion zone had to be implemented around the Elgin zone. The leak lasted for 51 days and a total of 6172 tonnes of gas and condensate was released to the environment as a result of the blowout[18].

From the annulus measurements Total was aware that there was a problem with one of the well barriers. They were controlling this by the Annulus Management System (AMS). The failure of the well integrity was also indicated by annulus pressure measurement.

This case illustrates not only the importance of well integrity monitoring but also the importance of appropriate response.

4 Well Integrity Monitoring

Despite careful design and selection of materials, correct procedures, testing and inspection, and verification of installed barriers, unforeseen circumstances can result in reduced well integrity or failure. Measures can be taken to detect compromised or failed barriers. These are described in this chapter.

In NORSOK D-010 it is written *"All parameters relevant for preventing uncontrolled flow from the well shall be monitored"* [10]. Relevant parameters include annuli pressure, annuli temperature, production flow parameters, barrier performance, corrosion and erosion rates, sand production, and leak detection. Monitoring of these parameters is important to make sure that operation stays within the safe operating window to avoid reduced integrity, and to detect leak in the event of an integrity failure. It is important to detect potential failure at an early stage to be able to avoid failure or at least to keep the impact at a minimum, and also to be able to pinpoint the source of leak as accurately as possible.

Methods used to detect reduced integrity include field monitoring and downhole monitoring. Downhole monitoring can be done via wireline (WL), but requires production stop, which is costly. Installing continuous monitoring can require costly investment but provides continuous information and can reduce the need for production stops.

Advancements in WL tools and methods play an important role in well integrity, but this thesis focuses on monitoring methods that do not require production stop.

Typical monitoring performed for producing wells:

- Check of primary and secondary barrier status:
    - Intermittent pressure testing to detect failures of valves, joints and connections, and inspection of accessible surfaces
    - Valve closure and safety instrumentation system testing
    - Continuous monitoring of tubing and accessible annuli parameters to detect compromised barrier integrity (corrosion, etc.). sometimes followed by WL for verification
- Monitoring to ensure operation stays within safe operating window and to detect factors that could negatively affect integrity, e.g. corrosion and erosion.
    - P and T in tubing and annulus

  - Production flow and composition, and sand production
  - Composition of annulus fluids
- Monitoring for leaks to the environment
- Monitoring of changes in reservoir and formation

Monitoring of plugged and abandoned wells is very limited and relies on good well construction. However, it is possible to:

- Monitor for leaks to the environment
- Monitor for changes in reservoir and formation

New IT solutions improve availability of data and allows input from multiple sensors to be combined into an integrated system and sent to centralised control facilities.

4.1 Continuous Monitoring of Well Integrity Status

Research and development (R&D) in the petroleum industry lead to the development of continuous monitoring methods to give a real-time overview of how the well is performing without having to stop production. Also, with the introduction of computer systems many manual measurements, e.g. P & T at the wellhead, have been supplemented by continuous measurements.

The advantage of continuous monitoring is that possible abnormal situations can be detected immediately. Much like a smoke detector, continuous monitors can give an alarm as soon as a leak occurs. Continuous monitoring systems can also be used to study trends over time, which can be used to indicate anomalies.

Many sensors are available for continuous measurement, e.g. Pressure, temperature and acoustic sensors can be installed to monitor conditions downhole instead of using WL techniques. In the event of integrity failure, leaks to the environment can be detected by systematic surveillance rather than relying on leak or gas bubbles being spotted by an operator on deck, by helicopter or by a standby boat. Now optical sensors, chemical sensors, biological sensors, etc. supplement intermittent subsea surveillance, e.g. using ROVs.

4.1.1 Migration of Oil and Gas Leaks

When designing/selecting the overall monitoring system, which may consist of several different sensors, it is important to consider how a leak spreads.

Gas leaks which travel up to a platform can be detected at the wellhead area (for a dry well) by fire and gas detection systems connected to safeguarding instrumentation systems, which will generate alarms and trigger shutdown of the wells and process topside.

Subsea oil and gas spills which travel to the surface can be detected by monitoring of the sea surface, but not all leaks will migrate to the surface and the surface is actually quite far from the origin of the leak. In some cases heavy oil will stay below the sea surface or migrate to the seabed. Oil and gas can also be carried far from the source by sea currents, as illustrated in **Fig. 4.1**, or disperse in the water. Dissolved gas spreads out faster than oil and further away than bubbles. Placement of sensors needs to take these leak characteristics into consideration.

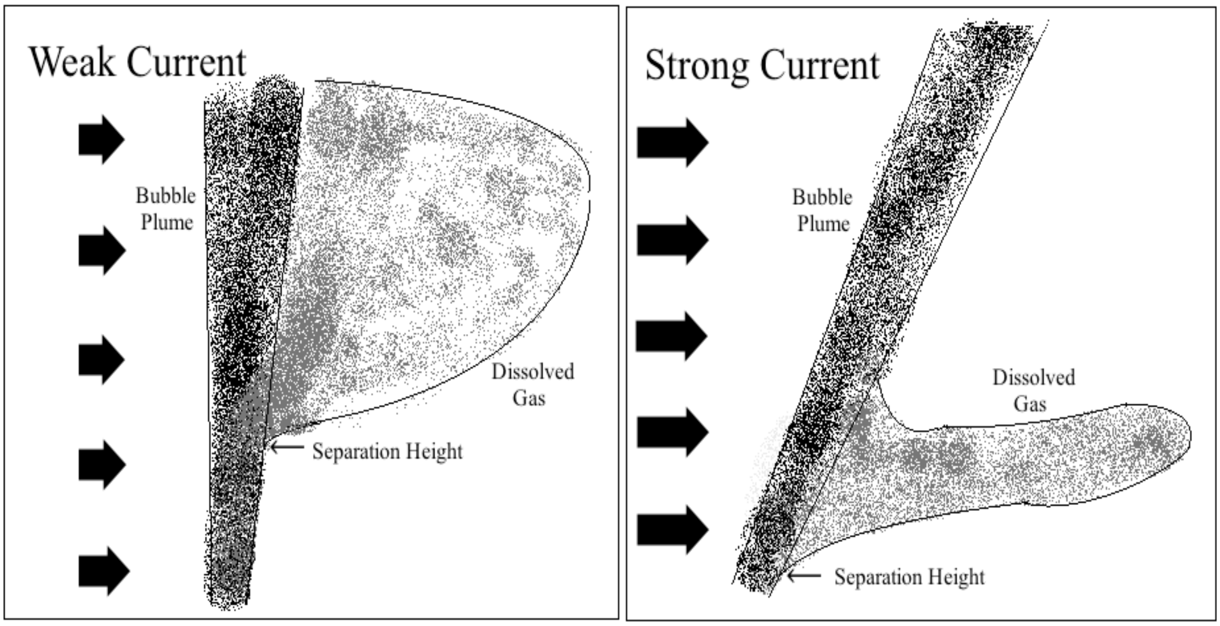

Figure 4.1: Characteristics of Seabed Gas Leaks for Weak and Strong Currents.

4.2 Integrity Monitoring Sensors

Sensors can be point sensors and/or area sensors. A point sensor can detect anomalies only at the installed position, while an area sensor provides area coverage and can place the leakage relative to the sensor's position. Some point sensors may achieve area coverage and can be used to localize a leakage by using multiple sensors[19].

Some parts of the well structure are referred to as critical points for monitoring as they are subject to leaks. These include connections, connectors, flanges, seals, valves and welds. Monitoring sensors, especially point sensors, should be placed with regards to the position of these critical points.

Monitoring sensors can be divided into three main categories;

- Physical sensors
- Chemical sensors
- Biological sensors

4.2.1 Physical Sensors

Included in physical sensors are temperature and pressure sensors, acoustic sensors, corrosion and erosion sensors, sand production sensors, capacitance sensors and cameras.

4.2.1.1 Pressure and Temperature Sensors

P&T sensors monitor whether the operation is within the safe operating window by monitoring production flowrate, downhole P & T and P & T in the annulus. These parameters are also used to detect well barrier failure before the problem escalates.

In addition to the tubing conditions, permanent downhole pressure and temperature gauges are used to measure annulus A,B and C where wellheads are on the platform.

NORSOK D-010 says *"The pressure in all accessible annuli shall be monitored and recorded"* and *"All wells shall have continuous monitoring of the B-annulus with alarms. For subsea wells the B annulus shall be designed to withstand the effect of thermal induced pressure (APB)"* [10].

High annulus pressures do not necessarily indicate a leak. The interpretation of pressure changes can be quite complex since pressure variations during production are normal.

When production is started or re-started after even a short shut down the hot production fluid flowing up the tubing will naturally cause fluid in the annuli to expand and hence create an increased pressure. Wells are designed to withstand this increased pressure caused by thermal expansion, or controlled with design limits by bleeding off pressure in a safe way. Annular pressure is bled off from the annuli and into the topside process. When an unexplained increased pressure, ie. one not caused by thermal expansion is observed in the annuli this is defined as sustained casing pressure (SCP). SCP will rebuild after a bleed-down and is caused by gas flowing into the annuli from a high-pressure formation due to a leaking barrier element, eg. cement, casing or tubing or through the production packer. The composition of bled off fluid can in some cases help identify the source of leak.

Sudden changes in temperature can also indicate a leak.

4.2.1.2 Corrosion and Erosion Sensors

Corrosion and erosion sensors are used to predict potential failure of tubing integrity.

Metal loss in pipelines due to corrosion can have many different reasons. CO_2 corrosion, O_2 corrosion, H_2S corrosion, microbiological influenced corrosion, corrosion due to organic acids, corrosion due to sand erosion, etc. are some of the many degradation mechanisms that can occur[21].

Erosion most commonly occurs at chokes or bends in the well tubing due to sand and water in the production fluid.

Material degradation in pipelines can be challenging to predict. Erosion and sand monitoring sensors can be installed downstream of the wellhead and can be used to estimate what is happening in the well itself. New sensors are also able to monitor corrosion and erosion conditions inside a well by direct measurement.

4.2.1.3 Acoustic Sensors

Acoustic monitoring systems using optical fibres can be installed in the A-annulus and can monitor for well barrier failure, e.g. hole in tubing. Passive and active acoustic sensors can monitor for leaks to the environment over a wide area in the subsea field. Seismic sensors can be used to monitor changes in the formation, which can affect integrity.

4.2.1.4 Optical Sensors

Oil and gas that has migrated to the sea surface can be detected by systematically and regularly monitoring large areas by use of drones, radar satellites, airplanes or ships. Drones and ships can be equipped with laser, infrared (IR) and electro optical (EO) sensors, airplanes can be equipped with laser, IR/EO and radar, and satellites use radar sensors for monitoring. The purpose of the different sensors are to detect (Radar), classify (IR,EO) and identify (laser) oil spills[20].

Special cameras can be used subsea, e.g. to detect the natural fluorescence of crude oil, to detect leaks.

4.2.2 Chemical Sensors

Chemical sensors include mass spectrometry and sniffers. These are used to detect hydrocarbons in the seawater to notify of leaks that have occurred. Depending on installation these can be either point or area sensors.

4.2.3 Biological Sensors

Biological sensors use natural living organisms, such as algae, microbes, mussels and dna to detect hydrocarbon leaks. These are point sensors as the organisms must be directly subjected to a change in environment to react. Living organisms are very sensitive and can be used as an early leak detection method and do not rely on a large spill.

4.3 Challenges and Concerns

Increasingly challenging fields are being developed. The reservoirs are deeper, the water depth is greater, and temperatures and pressures are higher.

Harsher and more sensitive environments are being developed, such as the arctic environments of the far north. These areas are more remote with little or no existing infrastructure.

New challenges and new degradation mechanisms, e.g. microbiological influenced corrosion and CO_2 corrosion, can be encountered[21].

Extending the life of wells also presents challenges. The content of H_2S can increase as a result of well souring and lead to corrosion of tubing and casings. Increased water cut in the production may increase the temperature and cause pressure increase due to thermal expansion. It also increases the risk of scaling. Increased probability of sand production at late field life means increased risk of sand erosion in the production tubing. Damaged sand screens will add to this risk.

Design and qualification of today's components have in general been based on a design life of 20-25 years. This must be taken into consideration when extending the life of a well[21]. Lifetime of integrity monitoring sensors need to match the lifetime of the well.

It has become common for new operators to take over the tail end production of old fields. This can introduce additional risks due to lack of experience and resources, and a lower commitment to well integrity.

Subsea wells are becoming more common. An increasing number of wellheads and other equipment are being installed subsea.

Annuli on platform wells can be designed to allow annuli pressure measurement, however, the annular space is one of the most inaccessible areas of a subsea production well[22].

Monitoring of the B annulus in subsea wells has been a challenge of two main reasons. Firstly, the casing string must not be perforated as this can lead to integrity failure, specifications for subsea wells require that primary well barriers shall not be breached[23]. Data and power cables can not be run through the casing string. Secondly, batteries can not be used as an alternate power supply as this would significantly reduce the lifetime of the monitoring system because batteries can not be changed in equipment located in the B annulus[24].

Plugged wells are even more inaccessible.

Development and implementation of new technology is being held back by costly qualification processes. Small specialist companies involved in development of new sensors rely on strong operating companies to support R&D and take risks in developing and testing new equipment rather than using proven technology.

Sensor performance can be a problem. Some sensors may not be suitable for certain environments or could experience reduced performance. This can be because of water clarity, marine growth, background noise, currents and weather. False alarms and lack of availability can occur.

Area coverage is a challenge for monitoring sensors. It is not possible for one single technique to cover everything. Multiple integrated sensor systems may be necessary. Significant effort and cost is required to develop a reliable and robust system, which is fit for purpose. Maintenance costs can also be considerable due to less accessible sensors.

Sensors must be sensitive enough to be able to detect leaks early without generating false alarms, which require verification.

More complex continuous monitoring systems require higher data and power transmission rates.

4.4 Innovations in Monitoring Methods

There are several relevant, developing technologies that can contribute to well integrity monitoring:

Wireless power transmission and communication improves access and benefits to defeating challenges with power supply and wiring.

Improvements to battery lifetime will improve the viability for sensors that can not be connected to a permanent power supply and are reliant on batteries.

Development of sensors based on nanotechnology is expected to result in sensors that are much more sensitive and also require much less power.

The use of fibre optics aimed specifically at oil and gas applications is on the increase. Due to electronics, conventional P & T sensors are unreliable at high temperatures. Fibre optic sensors do not have these limitations and can be used to measure conditions through the whole length of the fibre (multiplexing). This includes data transfer from sensors and systems, the supply of power to sensors and systems, and also a recent range of sensors. Pressure, distibruted temperature sensors (DTS), and distributed acoustic sensors (DAS) for leak detection can be installed along the entire length of casing or tubing.

5 Description of Selected Continuous Monitoring Methods

5.1 Physical Sensors

5.1.1 Pressure and Temperature Monitoring

Monitoring the pressure and temperature in the tubing and in the annuli of a production well can give information about how the well is performing. Results are analysed to determine whether pressure changes are caused by thermal expansion or a well integrity issue.

5.1.1.1 Background

Traditionally pressure forces acting on the well barriers in a subsea structure are modelled based on worst-case scenarios to ensure that the strength will be sufficient. Wells are often designed with over dimensioned casings in case the modelling and calculations are inaccurate. Over dimensioning to avoid burst or collapsed casings is expensive, but due to uncertainties and the lack of regular pressure monitoring, this has become normal procedure. By monitoring pressure regularly, well integrity can be confirmed and kept under control by regulating well flow or bleeding off high annulus pressure.

Continuous P & T monitoring of the well and the annuli reduces the need to excessively over dimension the wells and can also avoid unnecessary shut in of wells.

New wellhead platforms have continuous P & T monitoring of tubing and all accessible annuli. Subsea wells commonly have P & T monitoring of tubing and A annulus.

The special case of monitoring the pressure in the B annulus of subsea wells has required a new approach to measurement and described in this chapter.

5.1.1.2 How Does It Work

The sensors for monitoring P & T in annulus are run down hole with the completion string. Signals from these sensors are transferred up to the platform or to shore for long-term analysis and expert interpretation of anomalies.

Various manufacturers have their own solutions for monitoring of P&T in annuli. Some manufacturers are Emerson, Halliburton and Techni. In this thesis Emerson’s solution for subsea annulus monitoring will be presented.

5.1.1.3 P & T Sensor Example: Emerson Roxar Downhole Wireless PT Sensor System Annulus B

Emerson has developed the Roxar Downhole Wireless PT Sensor System Annulus B, shown in **Fig. 5.1**, for online and real-time continuous monitoring of the pressure behind the production casing in subsea production wells. This system overcomes the two main challenges of monitoring annulus B described in *Chapter 4.2: Challenges and Concerns*, as it does not require batteries and no wires penetrate the casing, ergo integrity of the casing barrier is not affected.

The system consists of two main parts, a casing part that is run into the well as a joint of the production casing and a completion string part that is run as part of the well completion with the production tubing. The casing part consists of an antenna, an electronic section and a sensor section. The antenna sends signals from the sensor to the completion string section of the tool. The completion string part is equipped with a corresponding antenna, a receiver section and an interface to the Intelligent Downhole Network System (IDNS). Both signals and power are transmitted wirelessly between the two parts. Signals are transmitted via the antennas and power is transmitted wirelessly from the completion string part to the electronic section in the casing by induction. Non-magnetic materials are used to allow penetration f power and wireless signals. The sensor includes no moving parts and no batteries, and can be used to monitor the pressure and temperature in both A- and B-annulus.

A Downhole Network Controller Card (DHNC) is placed in the subsea structure and connected to multiple sensors throughout the completion string and to an electrical cable coupled to a welded tubing hanger penetrator. The reason for using an electrical cable rather than batteries is based on lifetime expectancy. Battery-operated solutions are expected to last less than two years, while this equipment is designed and qualified to last up to 20 years at temperatures up to 150 ^{o}C and pressures up to 10.000 PSI.

The pressure and temperature sensors can be combined with others, such as water cut and velocity sensors, density sensors and valve position indicators in an IDNS. This provides a wide range of measurements with the use of a single tubing hanger penetration.

The system does not affect the reliability of the well barriers and can be installed without making changes to the existing control systems.

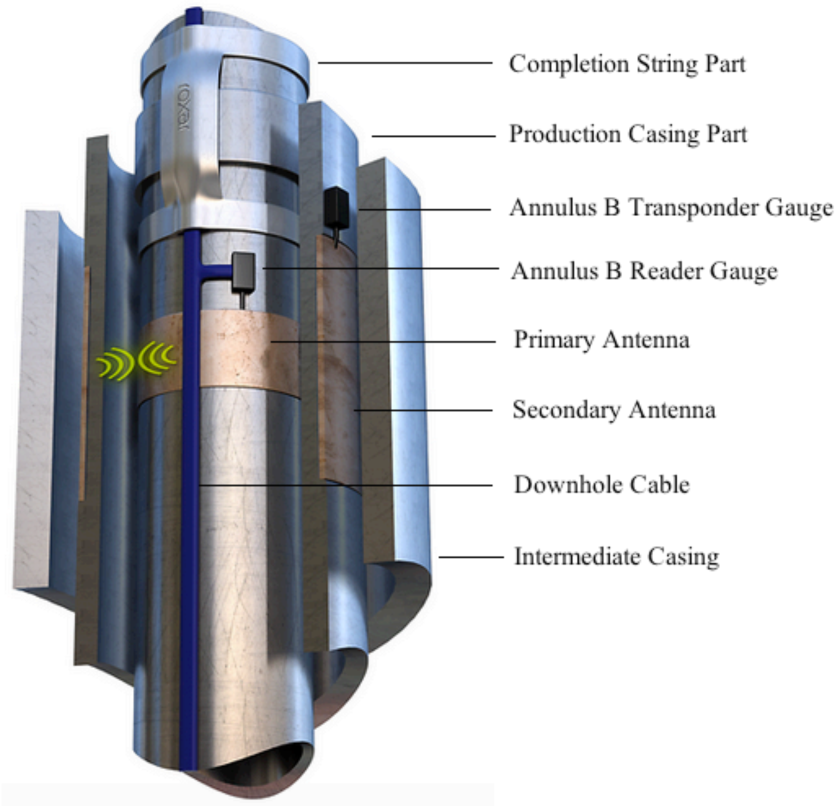

Figure 5.1: Emerson Roxar Downhole Wireless PT Sensor System Annulus B[25].

A new transmission concept was developed where power and signal could go through the casing wall. The transponder antenna is placed outside the production casing and the reader antenna is fully welded and factory mounted to the tool. The transponder antenna is designed as small as possible to allow flow past it and the opportunity of cementation[24].

5.1.1.4 Actual Applications

Emerson Roxar Downhole Wireless PT Sensor System is available for use on NCS. It has been installed in several wells, e.g. at Skuld, Draugen, Gullfaks and Tyrihans.

5.1.1.5 Advantages and Disadvantages

Advantages of the Downhole Wireless PT Sensor System Annulus B include:

- Can be incorporated with valves
- Allows for better communication
- Recent technology makes it more robust
- Saving space and weight, as well as cost, on platforms by using wireless systems.

- No need for wiring and associated infrastructure[22]
- Is operational at high temperatures, up to 205^{o}C

Some disadvantages of the PT sensor include:

- Only measures conditions at point of location
- Requires planning. Must be installed together with production casing

5.1.2 Corrosion and Erosion Monitoring

Sand and corrosion are constant integrity challenges in producing wells[26].

Since 70% of the world's oil and gas reserves are in sandstone reservoirs[22] sand production is almost inevitable. According to NORSOK D-010 sand production and erosion should be monitored in these wells: *"It shall be assumed that wells in sandstone reservoirs may produce sand. Sand production from each well should be monitored continuously or at frequent intervals (downhole, subsea or at surface). Threshold values for maximum allowable sand production should be established. Erosion loss in the flow conduit from the reservoir and to the entry of the first stage separator should be estimated or measured, and compared with maximum allowable wear loss. When sand production occurs, efforts should be taken to reduce the effect of sand erosion"* [10].

Erosion of the production tubing is caused by sand particles in the production fluid. Sand production monitoring is an important part of well integrity management as sand can lead to erosion of the steel tubing and removal of protective coatings that could lead to corrosion of the steel tubing. In addition to integrity failure due to erosion and corrosion, sand production can lead to clogged production equipment and pipelines, reduced wellbore access and difficulties in operating downhole equipment.

Corrosion can cause holes in tubing and cases, as illustrated in **Fig. 5.2**. Corrosion monitoring gives a warning of a future integrity issue and is used to avoid significant corrosion to steel casings and tubing.

Figure 5.2: Corroded Tubing.[27]

5.1.2.1 Background

Many current solutions are WL based. Another solution is to monitor sand and corrosion or erosion in the process lines downstream the wellhead and use this information to predict downhole status.

New methods aim to measure the problem more directly inside the well.

5.1.2.2 How Does It Work

5.1.2.3 Corrosion Monitoring

Pipe corrosion can be measured rapidly and accurately with the use of corrosion sensors. Electrical Resistance (ER) is used to measure the rate of corrosion as an increase in electrical resistance. **Eq. 5.1** gives the proportionate relation between the electrical resistance of a metal or alloy element and the size of the element.

Eq. 5.1:

$$ER = r \times \frac{L}{A}$$

ER: Electrical resistance, r: specific resistance, L: element length, A: cross sectional area.

Based on this information the corrosion rates can be calculated.

The technique is applicable in all corrosive environments and will work in oil, water and gas.

5.1.2.4 Erosion Monitoring

Erosion due to sand production can be monitored with intrusive or non-intrusive sensors. Intrusive sensors measure erosion directly as metal loss due to impact of sand particles in the production fluid. Like the corrosion sensor, the erosion sensor measures metal loss by recording the ER of each of the measuring elements on a regular basis.

Non-intrusive sensors are acoustic based and use microphones to monitor sand production by recording the sound caused from sand particles hitting the pipe wall. The sensors will give immediate response on sand production[28].

By combining intrusive and non-intrusive sensors to compliment each other the operator can gain information about the short- and long-term effects of erosion, and sand production in the well.

5.1.2.5 Corrosion and Erosion Sensor Example: Emerson Roxar

The Roxar Subsea SenCorr CM Sensor, shown in **Fig. 5.3**, is a tool for monitoring corrosion in the production tubing of a well based on ER. It consists of an instrument connected to a probe that is directly exposed to the corrosive fluid and a reference element sealed within the probe body. The tip of the probe is made from a section of the pipeline so that the steel is the same as the inside of the pipe wall. The tool is designed for a water depth of up to 3000 m and has a design lifetime of 25 years[29].

Figure 5.3: Roxar Subsea SenCorr CM Sensor for Monitoring of Corrosion[29].

The Roxar Subsea SenCorr SE Sensor, shown in **Fig. 5.4**, is a sand erosion sensor that detects actual damage caused to metal elements in the probe when they are impacted by sand particles. It works by measuring the increase in ER of four independent sensing elements as they are exposed to sand erosion in the production tubing. The sensor covers the entire diameter of the pipe and is placed downstream of a bend where sand is uniformly distributed in the flow. The sensor is designed for a water depth of 3000m and a design lifetime of 25 years[30].

Figure 5.4: Roxar Subsea SenCorr SE Sensor for Monitoring of Sand Erosion[28].

The Roxar SandLog wireless sand erosion monitoring sensor, shown in **Fig. 5.5**, is a non-intrusive acoustic based sensor. The sensor is attached to the outside of a pipe by clamp-on and placed downstream a 90^{o} bend where the sand particles will hit the pipe wall. The sound that occurs when the particles hit the walls of the production tubing is monitored to calculate sand production rates and give immediate response to changes in sand production[31]. It can be installed downstream the wellhead, and the results are used to estimate conditions in the well tubing.

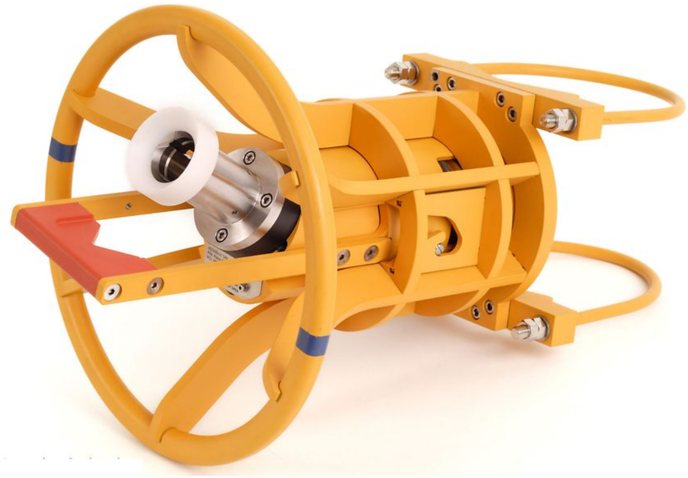

Figure 5.5: The Roxar SandLog Clamp-on Unit for Acoustic Monitoring of Sand Production[28].

Emerson's Roxar solutions can be directly integrated to Emerson's smart wireless network together with the Roxar wireless PT system described in *Chapter 5.1.1: Pressure and Temperature Monitoring*.

5.1.2.6 Actual Applications

Emerson's Roxar corrosion, erosion and sand production sensors are available for applications on the NCS.

5.1.2.7 Advantages and Disadvantages

Some advantages of corrosion, erosion and sand production monitoring sensors include:

- Improved flexibility
- Cost reduction
- Improved access to areas of the reservoir
- Predicting potential integrity problems
- Highly sensitive and accurate

Some disadvantages of Emerson's corrosion, erosion and sand production monitoring sensors include:

- Do not detect occurred leaks
- Only measures conditions at point of location

5.1.3 Active Acoustic Leak Detection

Active acoustic leak detection uses sound waves to detect leaks already occurring from the well to the subsea environment. By using active acoustic point sensors in the subsea field, oil and gas droplets in the water can be detected.

5.1.3.1 Background

The use of acoustic monitoring is well known to the marine industry. Active acoustics was originally developed for tracking submarines in 1915 but has since been used for example to find fish, for depth measurements and for mapping the ocean floor.

5.1.3.2 How Does It Work

Sensor technologies using active acoustics can provide continuous data that can effectively be used for surveillance to detect subsea leaks. The active acoustic sensors make use of the density difference between petroleum fluids and seawater to detect gas and oil droplets.

Acoustic pulses are actively emitted and received by the sensors. The sound waves propagate through the water until they meet an object or a medium of different density to the seawater, e.g. oil or gas. The signals are then backscattered to the receiver and the distance to the object or medium can be calculated based on the travel time[32].

5.1.3.3 Active Acoustics Leak Detector Example: Metas AS Active Acoustic Leak Detection Sensor System (AALD)

Metas AS has developed a compact active acoustic sensor system for subsea oil and gas leak detection and monitoring, the AALD shown in **Fig. 5.6**. This is an autonomous system that can be used to detect and localise leaks as well as estimating the leakage trend, quantity and duration, within a 1000 meters radius at up to 1500 meters depth. Horizontal scanning is selectable from 0-360 degrees, and vertical from 0-90 degrees. This means that entire subsea fields can be monitored with one single sensor. A software system analyses results and localises leakages based on the acoustic data and can present the data in 3D. The alarm settings of the system can be customised[33].

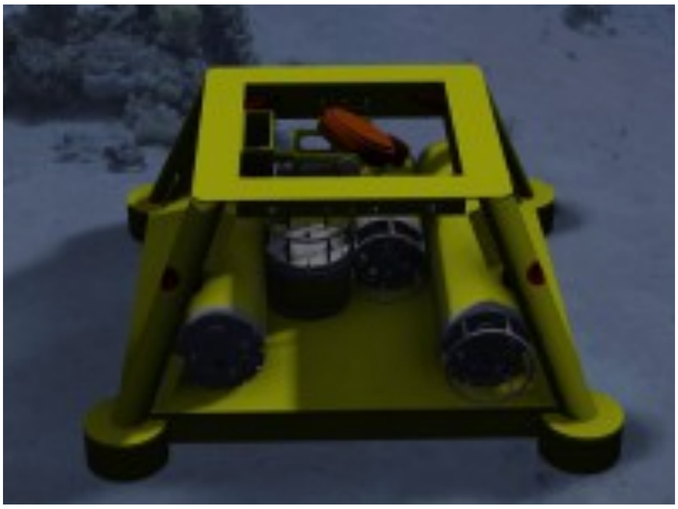

Figure 5.6: The Metas Active Acoustic Leak Detector for Subsea Application[33].

5.1.3.4 Applications

This sensor has been tested on the Kristin field.

5.1.3.5 Advantages and disadvantages

Some advantages of the active acoustic leak detector include:

- High sensitivity
- Few or no false alarms from foreign objects or noises
- Can stay at the seabed for a long time
- Can localize point of leak

Disadvantages of the active acoustic leak detector include:

- Leak to the environment must have occurred in order to be detected

5.1.4 Passive Acoustic Leak Detection

Passive acoustic leak detectors monitor sound as signs of leakages and is used to detect and locate oil and gas leaks to the environment.

5.1.4.1 How does it work

Passive acoustics use hydrophones placed on the seabed to detect sound waves subsea. A hydrophone is a type of microphone specifically designed to measure sound underwater. A point of leak will be a source of noise that can be detected by the hydrophones since sound from leaks propagates very well in water. The hydrophones are connected to topside and an alarm is triggered in the event of leak detection.

The passive acoustic sensor transforms noise to an electric signal that can be processed and analysed. Vibration is also a source of sound and can therefore be detected by the hydrophones. This gives this type of sensor a dual use as it can be used for condition monitoring of subsea equipment based on vibration. Known sounds from regular production or nearby ROVs can be filtered out to reduce the number of false alarms.

By connecting three or more hydrophones as shown in **Fig. 5.7,** triangulation can be used to localize the source of the leak.

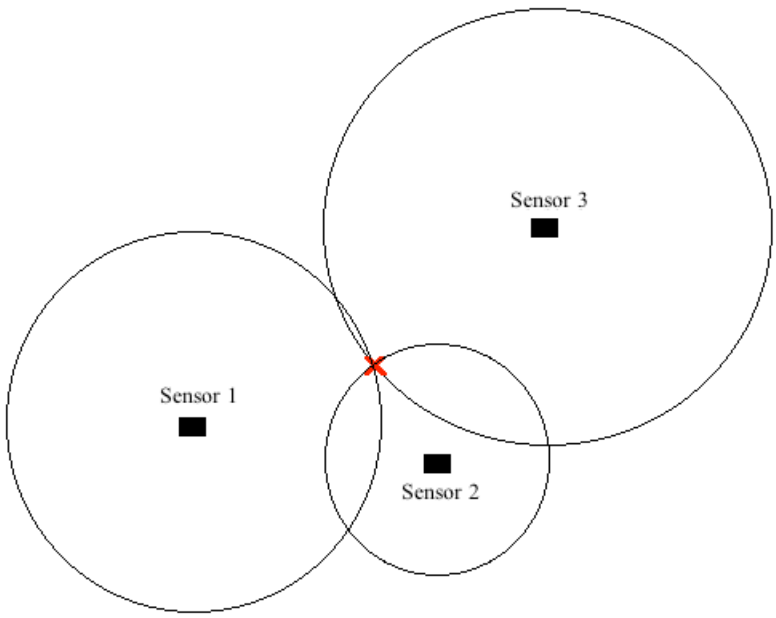

Figure 5.7: Triangulation. The distance from each sensor to the source of the leak, illustrated as a red cross, can be calculated to find the exact location.

5.1.4.2 Active Acoustic Leak Detector Example: Naxys A10

Naxys has produced a subsea leak detector based on passive acoustics, the Naxys A10 shown in **Fig. 5.8**. The Naxys A10 sensor can cover the entire subsea field with its wide area coverage of 500m. Highly sensitive leak detector sensors and a subsea power unit are fixed in a titanium frame and are connected to a subsea control module. The leak source is pinpointed using 10 acoustic sensors.

Figure 5.8: The Naxys A10 Passive Acoustic Leak Detector[34].

The titanium frame is non-intrusive, meaning that it has no impact on the well, and has an ROV lifting interface This makes it easy to install. The manufacturer claims that no maintenance is required on the Naxys A10, which has a design life of 30 years at 3000m depths[35].

5.1.4.3 Applications

A passive acoustic leak detector was installed at Statoil's Tordis field in 2007. The sensors experienced some problems with humidity in the hydrophones that reduced the performance of the leak detector[19].

5.1.4.4 Advantages and Disadvantages

Advantages of passive acoustic sensors include:

- Early detection of leaks
- High sensitivity. Small leaks can be detected
- Fast response, usually 2 minutes
- Ability to locate leak source
- Can detect behind structures and around corners, ”line of sight” is not required since, the sound will arrive

- Wide area coverage in all directions, 100m from sensor

Some disadvantages of active acoustic sensors include:

- "Silent leaks" are not detectable with this method, as it requires a minimum of differential pressure. Need a pressure difference of at least 5 bar for fluids, less for gas
- Background noise (e.g. from nearby ROVs) can cause false alarm, new technology/software is developed to handle this problem by detecting the presence of ROVs, or alarm limits can be adjusted

5.1.5 Microseismic Monitoring

Microseismic monitoring measures sound generated by microseismic events and uses this information to monitor the integrity of formation barriers.

5.1.5.1 Background

Seismics have been used in the oil industry for a long time to map subsurface structures. 4D seismic surveys have traditionally been done to monitor reservoir behaviour by running 3D seismic surveys at several time intervals from towing vessels. The more recently developed method of obtaining 4D seismic information is by using four component (4C) seabed cables or 4C autonomous node surveys. These new methods can be used to obtain more frequent surveys and improved data quality[36] and can display the reservoir condition as a "movie" to give better understanding of the reservoir's dynamic behaviour.

5.1.5.2 How Does It Work

Microseismic monitoring can be used to monitor the integrity of the reservoir formation barrier known as the cap rock, and to detect formation fractures before they reach the surface. This monitoring method offers real time monitoring of stress changes, microseismic events and geomechanical deformation within the reservoir[37].

Microseismic monitoring works by combining permanent downhole arrays with near-surface networks on the seabed to accurately capture a broad spectrum of signals and can be deployed as a permanent reservoir monitoring system. This can provide information of changes in real time, from small seismic events to larger magnitude induced seismicity. The receiver sensors measure both pressure waves (P-waves) and shear waves (S-waves). Unlike P-waves that can travel through liquids and gases, S-waves only travel through solid material and will not propagate through gas or liquids. This means that the sensors must either be physically attached to the seabed or trenched into the seabed to avoid seawater between the sensor and the seabed. The latter case will also protect the sensor against damage from fishing activities.

Seismic surveying on the seabed can be used in active mode or passive mode.

Active seismic surveying is done by emitting a signal into the subsurface from an acoustic source, for example by having a vessel deploying an airgun source. Signals run through the formation and are reflected to the receiver sensors spread out on the seabed when they meet a change in formation density. This can be done at chosen intervals.

Passive seismic surveying is done without emitting signals into the subsurface by listening to small seismic events that generate sound. Activity in the formation that emits acoustic signals is monitored by the receiver sensors on the seabed in real time and can provide very early warnings of unwanted fracturing. The system can operate continuously in passive mode 24/7.

5.1.5.3 Microseismic Monitoring Example: Octio's ReM System

The Reservoir Monitoring (ReM) system developed by Octio and Siemens is a seabed seismic system. The ReM system consists of two parts, the topside system consists of a power supply, data storage media, sensor array interface and a recording computer, and the subsea system consists of a centralized hub and sensor modules. The system is illustrated in **Fig. 5.9**.

The main ReM sensor is a 3-component sensor with shear wave detection. The hub powers all the sensor lines, gathers information from the sensors and delivers to topside through an ethernet cable or through existing infrastructure.

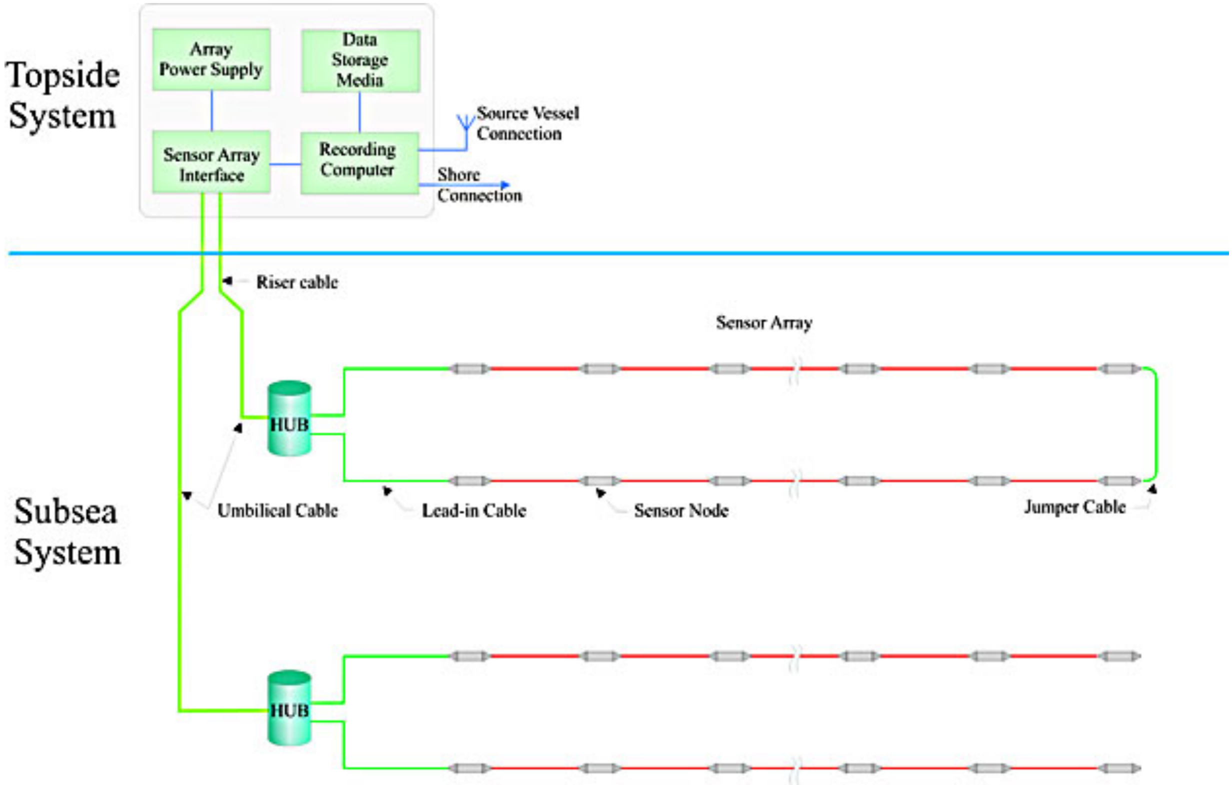

Figure 5.9: The configuration of the ReM system by Octio[38].

Octia claims that the network can be expanded to an unlimited size and that 3rd party sensors and systems can be incorporated. This way the permanent reservoir monitoring system can be used for a holistic understanding of the well with monitoring of the reservoir, the cap rock, the overburden, the underburden, the seabed, marine life, and chemical and biological contents of the water column.

The manufacturer claims that the system has a lifetime of 25 years at a water depth of up to 2000m.

5.1.5.4 Applications

A couple of permanently installed 4C cable systems have been in operation for some years. Statoil has installed a permanent reservoir monitoring seismic system on the Grane field on the NCS[39].

5.1.5.5 Advantages and Disadvantages

Some advantages of microseismic monitoring include:

- Can be used to pinpoint and determine location of fracture[40]
- Flow paths can be mapped
- Wide area coverage

Some disadvantages of microseismic monitoring include;

- Shear pressure waves can not travel through fluids, so the sensors require direct contact with the seabed
- Requires verification. Does not necessarily indicate leak

5.1.6 Visual Camera Surveillance

Video surveillance of subsea fields can be used to reveal eventual leaks at an early stage by using a combination of advanced camera technology and sensor technology.

5.1.6.1 Background

The conventional use of satellites and radars to visually monitor for leaks can cover large areas and provide continuous oil spill monitoring of entire fields, but have limitations. Satellites need some wind in order to work. 2-15m/s. This could be problematic, typically in January as it can be too windy. Satellites and radars will only monitor oil that has leaked to the surface, and the oil spill must be of a certain size in order to be detected by these systems. Subsea leaks sources can not be located with the use of radar and surface techniques. Visual monitoring needs daylight, IR needs clear, dry weather as it will not work through clouds, but will work in both daylight and in the dark[20].

New additional surveillance methods have been developed to support the conventional use of visual surveillance.

274 temporary abandoned wells in the Norwegian sector are in need of surveillance for leak detection[41]. Visual surveillance has been developed in order to meet the requirements for surveillance of these wells. The previously existing technology did not analyse images and did not automatically report leaks. Cameras with these functions that would work at 3000m water depths were requested.

5.1.6.2 How Does It Work

By using an autonomous underwater camera, temporary abandoned wells can be continuously monitored. The system combines sensors for detection and camera surveillance for verification. Rather than continuously sending images to the surface, the camera only starts when a leak is detected by the sensors, leaving the screens onshore black until an eventual leak is detected. In the event of a leak an alarm including images is sent to the topside or onshore facilities.

Information from the system can be received via copper or glass fibre cable, or it can be sent from a buoy via satellite if such infrastructure does not exist in the area. Multiple cameras can be connected to a single cable from the seabed to the platform or buoy.

5.1.6.3 Camera Surveillance Example: Proserv Seahawk™

Trollhetta AS, Proserv and Weatherford cooperated in the development of a leak detection system that uses video analysis to detect potential leaks from subsea structures[42].

The Proserv SeaHawk™ subsea camera surveillance system is an intelligent leak detector that autonomously interprets images from the seabed. The system is operated using a power line and wireless communication and allows the cameras to be steered in the desired direction.

The system works down to depths of 3000 m.

Fig. 5.10 shows the SeaHawk™, a subsea high-quality video camera with advanced Light-Emitting-Diode (LED) lighting.

Figure 5.10: The SeaHawk^{TM} Advanced Subsea Camera with LED Lighting[43].

5.1.6.4 Applications

The SeaHawk project is operational, but the Autonomous Intelligent Leak Detector (AILD) is still under development.

A SeaHawk camera is installed in the Troll C field for subsea surveillance of a defective methanol line[44].

5.1.6.5 Advantages and Disadvantages

Some advantages of subsea Camera surveillance systems include:

- Less expensive than using ROVs
- Fewer false alarms (avoid shutting down wells due to false alarms)
- Needs less power as it only sends images when leak is detected
- Can easily verify, e.g. easy to differentiate between a passing fish and an oil/gas leak
- Location of leak can be found by steering the camera

Some disadvantages of subsea camera surveillance systems include:

- Marine growth can cover the lenses and hinder surveillance performance
- Visibility can be reduced by unclear water
- Cameras must be pointed against the yellow subsea installations to see leaks for verification

- Difficult to know if the system has failed as images are not sent unless leak is detected

5.1.7 Capacitance

Capacitance sensors are used to detect hydrocarbon leaks in seawater at subsea installations.

5.1.7.1 Background

Capacitance sensors have been on the market since the 1990s and are commonly used in the petroleum industry[19]. The sensor electronics were improved in 2014 [20].

5.1.7.2 How Does It Work

The capacitance sensor consists of two electrodes and one oscillator. When something other than water passes between the two electrodes, through the sensing field, it will cause a change in the frequency and indicate a leak. The principle of the system is illustrated in **Fig. 5.11**. A collector is used to steer fluid through the electrodes as the sensor's performance depends on direct contact with the leakage.

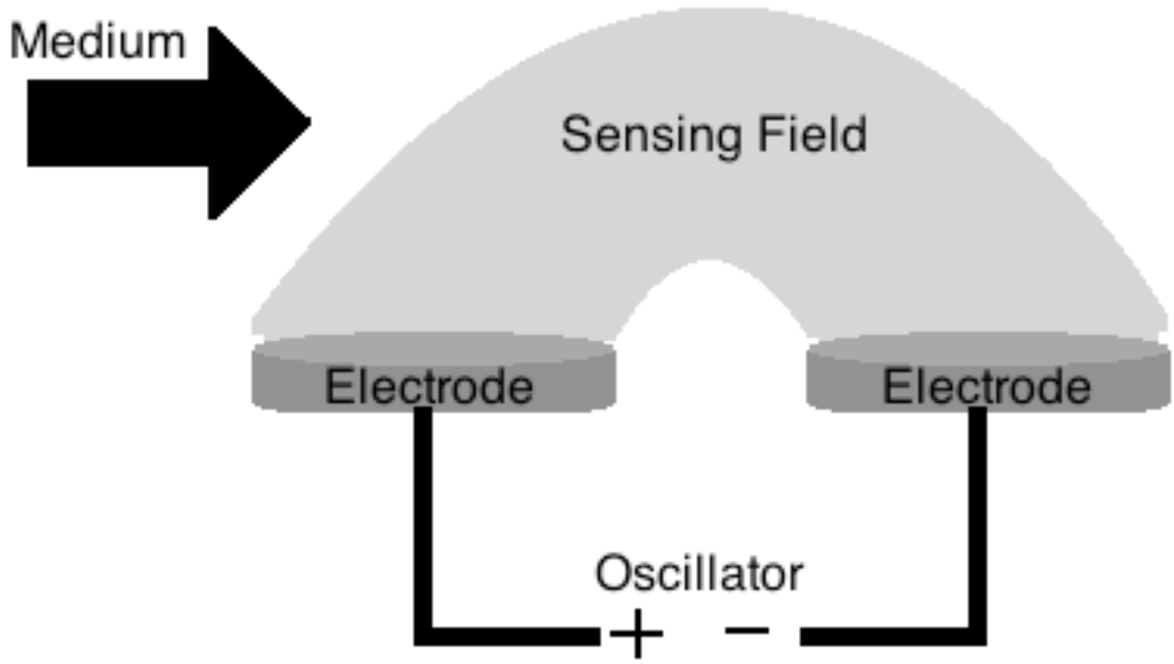

Figure 5.11:The Principle of Capacitance Sensing.

The Capacitance sensor measures the dielectric constant, which is directly proportionate with capacitance, of the passing medium to identify leakages. The relation between capacitance and dielectric constant is given in **Eq. 5.2**.

Eq. 5.2:

$$C = \varepsilon \times \frac{A}{d}$$

C: Capacitance, ε: Dielectric constant of the medium, A: Area of the electrodes, d: Distance between the two electrodes.

The significant difference in dielectric constants of petroleum fluids and water, shown in **table 5.1**, makes leakages easy to detect.

Table 5.1: Dielectric Constants of Selected Fluids[20].

FLUID	DIELECTRIC CONSTANT
Air	1,0
Carbon dioxide	1,0
Methane	1,7
Petroleum	2,0 – 2,2
Heavy oil	3,0
Water	80,0

5.1.7.3 Capacitance Sensor Example: Phaze Hydrocarbon Leak Detector

Benestad Solutions AS has developed a sensor that uses capacitance to detect hydrocarbon leaks during production, the Phaze Hydrocarbon Leak Detector (HLD). This sensor, shown in **Fig. 5.12**, is used with a collector to detect small leaks[45].

Figure 5.12: Benestad Solution AS's Phaze HLD Capacitance Sensor[45].

Fig. 5.13 illustrates the principles of the Phaze HLD capacitance sensor. Size and spacing between the electrodes is kept as constant as possible to avoid affecting the measurements and results.

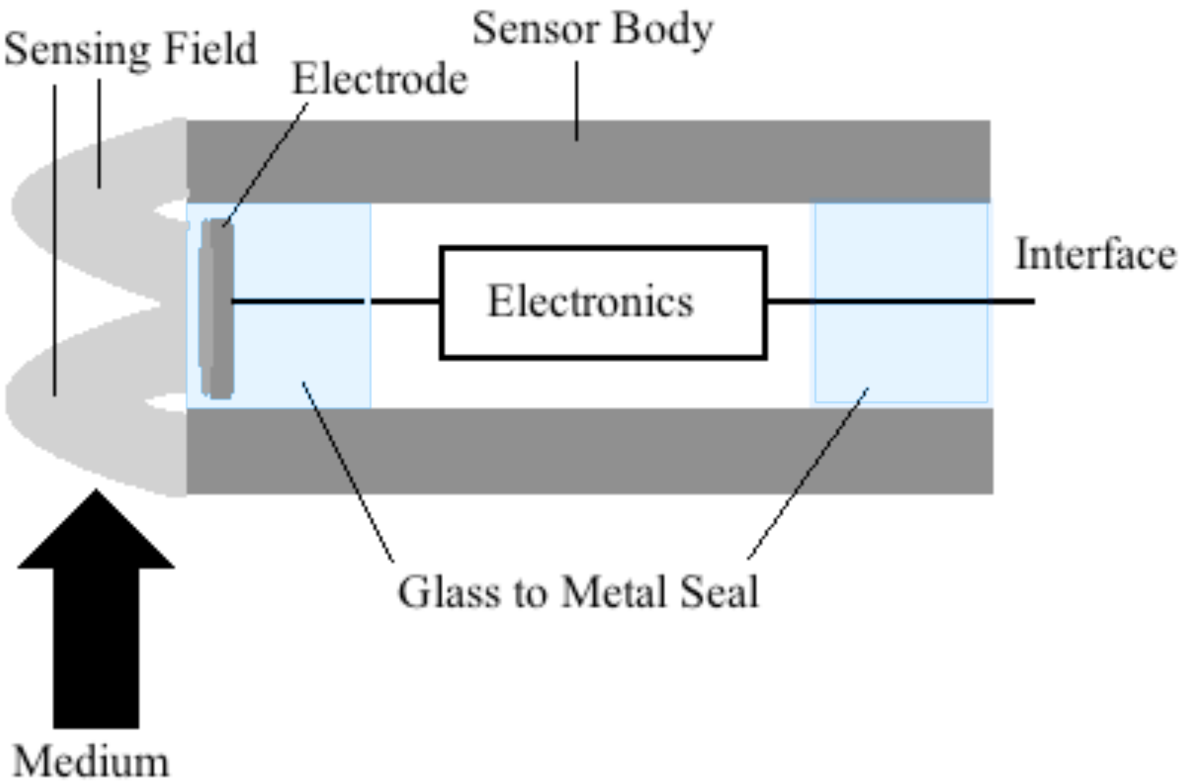

Figure 5.13: The principle of Benestad Solutions AS's Phaze HLD Capacitance Sensor.

5.1.7.4 Applications

This capacitance sensor is a point sensor for leak detection. It detects oil and gas leakages in the subsea environment. However, it is better for detection of gas than oil[32].

Statoil's Snøhvit field in the Barents Sea is one of the many fields that have been developed with a capacitive leak detection system. The Subsea field has equipped all wellheads with hydrocarbon collectors and capacitance leak detection sensors. The leak detection system has succeeded to identify one gas leak in one of the wells, but failed to detect another leak because the leak was not captured in the hydrocarbon detector roof[19].

5.1.7.5 Advantages and Disadvantages

Capacitance is a robust detection technique, with advantages that include:

- No need for calibration
- Few false alarms due to the significant difference between the dielectric constant of water and of petroleum fluids
- Unaffected by water clarity, background noise, age

Some disadvantages of the capacitance sensor include:

- The electrodes will fail to detect hydrocarbons if they are covered in marine growth
- Thick slime or silt covering the sensors will also reduce the sensitivity of the instrument
- Point detector, leak must be captured in the collector in order to be detected
- Does not pinpoint the leak
- Sensitivity depends on the distance to the leak and the drift of the leaking medium. Currents or buoyancy effects may lead the leaking medium away from the sensor. The collector is installed to avoid this

5.2 Chemical

5.2.1 Subsea Mass Spectrometry

Subsea mass spectrometry is used to locate and identify hydrocarbon leaks in the subsea field by quantitatively identifying hydrocarbons at trace concentrations dissolved in the seawater.

5.2.1.1 Background

Mass spectrometry is a well understood and much used technique for analytical purposes dating back to 1942. The technique has a wide range of applications on land, and in the recent years mass spectrometers have been developed to work in underwater applications.

5.2.1.2 How Does It Work

Mass spectrometry quantitatively identifies dissolved chemicals at low concentrations by separating a sample into separate ions and sorting the ions based on their mass within the sample. The result is a plot that tells what ions are present and in what concentration. **Fig. 5.14** shows a typical plot from a mass spectrometer. The placement of the curve on the x-axis shows what component is present and the height of the curve on the y-axis shows the concentration of the component in the sample.

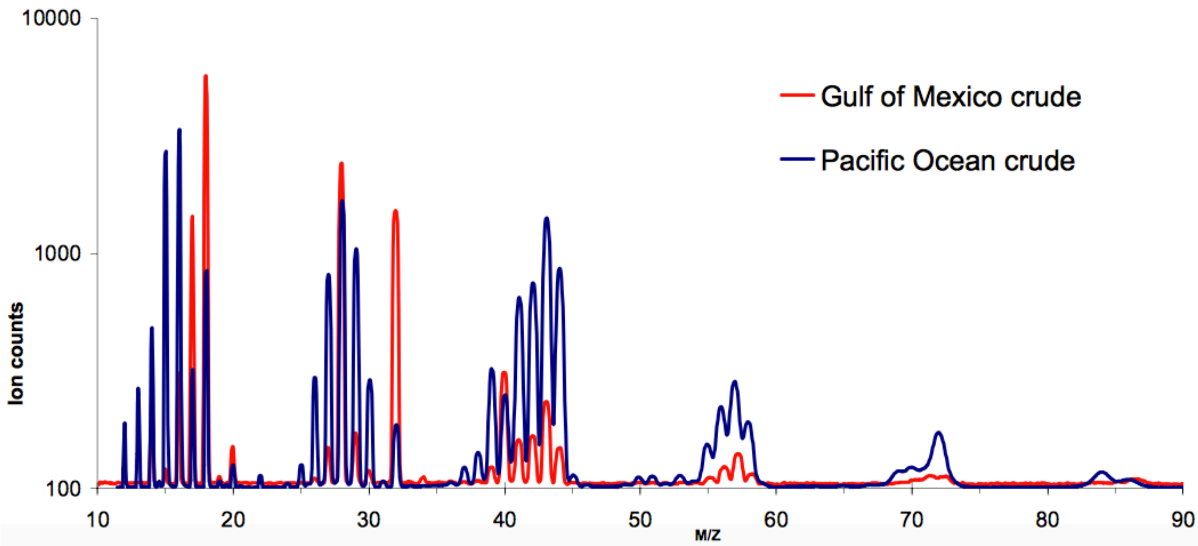

Figure 5.14: A Typical Mass Spectrometry Plot of Two Different Crude Oils[46].

Fig. 5.14 shows the mass spectrometry plot of two different crude oils, a Gulf of Mexico crude and a Pacific Ocean crude. The use of mass spectrometry allows "fingerprinting" of petroleum by comparing the composition of the detected petroleum to reference measurements of known crude oils. This means that based on the hydrocarbon composition and the isotopic distribution of the petroleum, the source can be determined by correlation with samples from different sources.

5.2.1.3 Subsea Mass Spectrometer Example: TETHYS In-Situ Mass Spectrometer

The TETHered Yearlong Spectrometer (TEHTYS), shown in **Fig. 5.15,** is a small, compact, self-contained mass spectrometer developed for subsea leak monitoring at depths of up to 5000 meters. This is a point sensor that provides accuracy and reliability as well as sensitivity[46].

When using this mass spectrometer with AUVs, towed platforms, ROVs or human occupied submersibles, it becomes mobile and can provide data from larger fields even though it is a point sensor.

Communication with the system is done via Ethernet and batteries provide power.

Figure 5.15: The TETHYS Mass Spectrometer[46]. The compact sensor is almost as small as a shoe.

5.2.1.4 Applications

The TETHYS mass spectrometer has been used for offshore oil platform and pipeline leak detection and clean-up operations.

5.2.1.5 Advantages and Disadvantages

Some advantages of this subsea mass spectrometer include:

- Low power requirement
- Can cover large areas when combined with subsea vehicles
- Abundant sensitivity and accuracy

- Reliable
- Small
- Can be used to identify the source of leaked oil and gas by “fingerprinting”

Some disadvantages of this subsea mass spectrometer include:

- Limitation in battery life time
- Must be in contact with the leaking media to detect it

5.2.2 Sniffers

Hydrocarbon sniffers can be used to measure the concentration of dissolved hydrocarbons, like methane, in seawater to detect hydrocarbon leaks in subsea fields.

5.2.2.1 Background

In some cases methane leaks will not show as bubbles, not even at the crack. Sniffers can therefore be of better use than visual subsea surveillance of fields to detect leaks that might not be visible.

5.2.2.2 How Does It Work

Dissolved methane in the seawater diffuses over a membrane, that functions as illustrated in **Fig 5.16**, and into a sensor chamber in the sniffer, leaving the water outside the sniffer. The methane molecules are then absorbed at a semi-conductor, which generates an electric signal directly proportionate to the methane concentration.

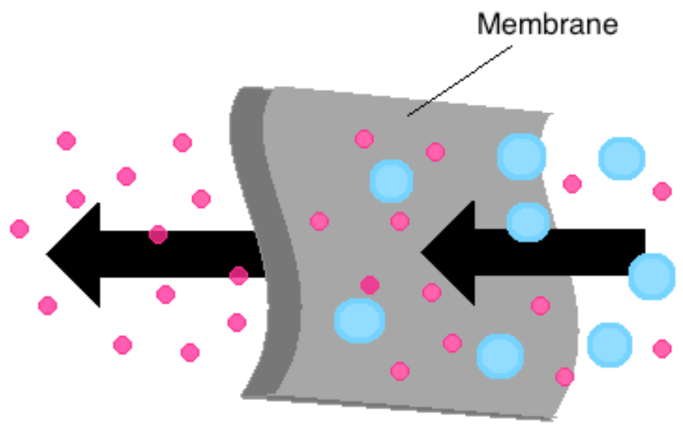

Figure 5.16: The Function of a Membrane. The blue bubbles are water and the pink bubbles are methane.

Methane is dissolved fast into water and can be transported far away from the source by currents. Since gas plumes spread out faster than oil, and because heavy oil may creep to the ground and not be visible, methane detection can be an early indicator of leak.

Sniffers can be used to accurately monitor for leaks in real time and by using triangulation the location of a leak can be determined.

Other sniffers use IR or laser absorption spectroscopy to detect hydrocarbons.

5.2.2.3 Sniffer Example: Franatech Mets Methane Sensor

Franatech has developed the Mets methane sensor, shown in **Fig. 5.17**, for leak detection at subsea fields. This sniffer is a point sensor that can be connected to AUVs, ROVs, etc. or used on weak points of the subsea structure in terms of integrity, e.g. valves. As well as being used for gas detection, the sniffer can be used to detect crude oils, since they usually contain some dissolved gas, at depths of up to 4000 meters[47].

Figure 5.17: Mets Methane Sensor by Franatech[47].

5.2.2.4 Applications

Sniffers have been used in the petroleum industry for detecting oil and gas leaks. Eleven Mets methane sensors are already installed in a network on the NCS for long term monitoring[48].

5.2.2.5 Advantages and Disadvantages

Some advantages of the methane sniffer sensor include:

- Sensitivity well below the ppb-region
- Low power requirement
- Requires no fixed installations
- Low failure risk and power drain due to no internal moving parts or pumps[49]
- Fast response time, reaction within few seconds

- Highly selective, giving no false positive alarms
- Can be used for other hydrocarbons than methane
- Area coverage
- Measures freely in water with no shadows
- Lightweight

Some disadvantages of the methane sniffer sensor include:

- No identification between shallow gas and reservoir gas
- Not able to determine the source of the detected leak
- Current in the water is required to detect the methane[32]

5.3 Biological Monitoring

Biological monitoring is done by placing suitable organisms, such as mussels or algae, at a subsea installation and monitoring their behaviour.

This chapter is focussed on the use of mussels for subsea leak detection.

5.3.1 Bio Sensors - Mussels

Integrity monitoring systems can also combine biosensor technology with chemical and physical sensors to monitor the marine environment and to detect leaks in real-time.

5.3.1.1 Background

Studies on marine life have been done previously to monitor harm done to the environment and marine species. Large leaks can do major harm to the environment, and organisms in the sea will react to such changes. Rather than monitoring harm that is done to the environment, biological organisms can be exploited to monitor smaller changes to the environment close to subsea installations, before large leaks have developed.

5.3.1.2 How Does It Work

The sensing system measures the mussels' heart rate and frequency of opening and closing to monitor their response to the environment.

Mussels are used because they easily stabilize and adapt to new environments, they are biologically appropriate and because they are the most studied animals in the sea. They are hardy and robust while being sensitive to pollution. The shells are a thousand times more sensitive to hydrocarbons than chemical and physical sensors[50].

Different types of mussels can be used to adapt the system to different environments. The species are chosen depending on the environment to be measured and based on what type of species are most relevant for the area. For example: For depths up to 100m the common blue mussels (Mytilus edulis) are used, while for depths up to 500m the ocean quahog (Arctica islandica) is better suited. In Brazil the brown mussel (Perna perna) is most relevant, and therefore this is the mussel used for biological subsea monitoring in this area. **Fig. 5.18** shows some of the different types of mussels that are used for biological monitoring.

Figure 5.18: 3 Different Types of Mussels for Biological Monitoring. From the left: blue mussels, ocean quahog and brown mussels [51, 52, 53].

5.3.1.3 Bio Sensor Example: Biota Guard

Biota Guard developed a real time subsea leak and environmental monitoring system that uses mussels to detect changes in the subsea environment.

Infrared sensors are attached to mussels to measure heart rate, like shown in **Fig. 5.19**. Opening-closing frequency is also monitored and logged. When the mussels react to pollution these parameters will reflect a change in environment and set off an alarm[55].

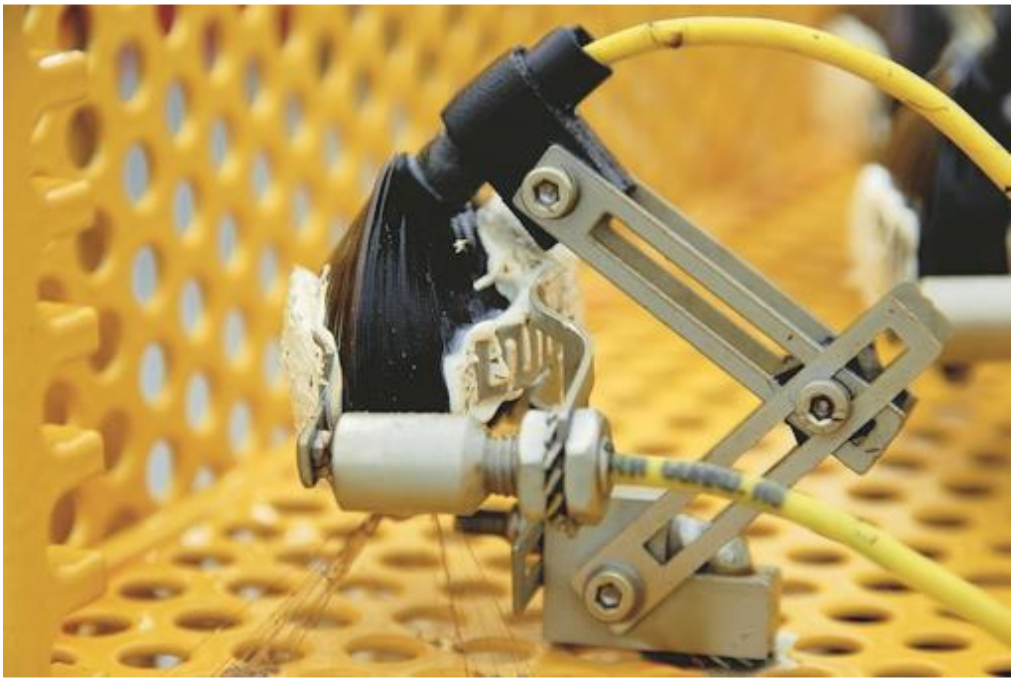

Figure 5.19: A Mussel Equipped With Biota Guard's Sensors[54].

By monitoring the heart rate and frequency of opening-closing, the mussels' natural behaviour in the environment can be logged and abnormal behaviour can be noticed as a sign of change in the environment, for example in the case of a leak or pollution. The results of measurements are statistically analysed to determine normal and abnormal behaviour.

The biosensors are placed in clusters and can be combined with other sensors in a sensor system to gain complete overview of the subsea field. Usually the biosensors are combined with acoustic and optical sensors to monitor environmental effect. These three types of sensors compliment and complete each other. The sensor system uses a battery powered sensor station to gather information from the different sensors and send to topside or shore facility at desired intervals. The chosen intervals will impact the battery lifetime of the sensor station. Using long intervals will save battery as the system can be put in standby in between signal sending, while short intervals will require more power but give more information. If an offshore facility is not present at the site, a floating buoy connected to the sensor system as shown in **Fig. 5.20** can be used to send signals to shore[55].

Figure 5.20: The Biota Guard System With Buoy for Sending Signals[56].

5.3.1.4 Applications

The system was deployed at Ekofisk for some months for testing, but at this time there are no wells using mussels as a leak detection method[5]. The technology is mature and ready to be used, but is not popular because regulations do not specify monitoring of pollution to the area around wells. The lack of demand for this product caused Biota Guard to go bankrupt in 2015[57]. IMARI has since taken over the technology and offers it to customers that might be interested.

There are other application areas for the system than subsea wells. Biota Guard successfully monitored process water discharge from Mongstad Oil Refinery continuously for almost 6 months[58].

5.3.1.5 Advantages and Disadvantages

Some advantages of this biological sensor include:

- Measures direct impact on environment
- Highly sensitive
- Can be combined with other sensors in an integrated network system

Some disadvantages of this biological sensor include:

- Batteries limit lifetime of the system. The expected lifetime of a mussel is 25 years, so the limiting factor is lifetime of batteries for monitoring data system subsea
- The fishing industry is not pleased with floating buoys for transmitting data
- The organisms must be directly subjected to a change in environment to give response, and are point sensors for leak detection

6 Discussion

The number of wells in the red well integrity category presented in **Fig. 3.7** in *chapter 3.4: Examples of Well Integrity Failure* is alarming because it proves that there are still wells on the NCS that have suffered significant integrity failures that have lead to a leak to the environment. It is important to address this before a catastrophic incident occurs. Monitoring systems must be implemented to prevent this and help maintain integrity in the entire well. A common cause of failure is degradation of the production tubing.

Regulations are laid down by the authorities and are important driving forces for implementation of monitoring systems. The NCS is already quite well regulated and the PSA currently do not have any plans of putting in place more regulations regarding integrity monitoring and leak detection, for either producing or plugged wells[59]. Environmental organisations would of course like to see more regulations, particularly as increasingly sensitive areas are planned for production, and as new, less experienced companies are taking over tail-end operations and responsibility for well abandonment. A difficult economic climate can negatively affect willingness to invest in development or implementation of monitoring systems, but regulations still need to be met. On the other hand, regulations must not hinder the use of new technology, e.g. with overly stringent qualification requirements.

Monitoring sensors that can not only be used for integrity monitoring, but can also be used for production and reservoir optimization can give operating companies an economic incentive to use these sensors. Development of such systems and sensors could increase the use of integrity monitoring sensors in production facilities.

Operating companies need to perform a risk analysis for each planned well to identify likely scenarios and well integrity issues to assess the consequences of a potential integrity failure. Based on this they can decide which monitoring systems should be used for the entire life cycle including abandonment of the well. The risk assessment will include identifying possible leaks to the environment, hydrocarbon migration paths and spreading. Solutions must suit the field conditions: depth, visibility, availability of infrastructure, distance from land, background noise, and natural oil and gas leaks from the formation. The aim is to ensure fast, accurate detection to minimize consequences to safety and the environment.

Multiple technical barriers are included in the design of wells to ensure well integrity for all phases of the well life cycle. At least two barriers are required according to regulations, and these need to be monitored when possible.

By combining sensors that measure different aspects of well integrity, a better overall coverage and control of well integrity status can be achieved.

Some sensors are proactive and give an early warning of potential integrity failure, for example:

- Sensors to monitor that the operation of the well is within design limits, e.g. tubing and annuli P & T
- Sensors to detect a potential situation that can compromise the well barrier integrity, e.g. corrosion, erosion, formation changes and sustained casing pressure (SCP)
- Sensors that detect the failure of an individual well barrier, e.g. annulus P & T, microseismics and downhole acoustic sensors

Other sensors are reactive and aim to detect integrity failures that already have occurred, e.g. sensors that detect leak to the environment.

Using different detectors also enables verification of observed anomalies.

Decisions of which methods to use must be based on the specific challenges and requirements for each well or field. When choosing what sensors to use, some aspects that should be considered are:

- **Sensitivity**: How sensitive must the sensors be? What leak sizes are necessary for the different sensors to detect a leak, and what leak sizes do we want to detect? Even small leaks can cause serious problems in the long term, and can be harder to detect. Some sensors only require small changes to the seawater, e.g. dissolved gas or dispersed oil, to detect a leak while some might require larger spill volumes in order to react. Oversensitive systems can generate false alarms.
- **Area coverage**: How large is the area we want to monitor and where will leaking fluids travel? Will they travel up to the sea surface, down to the seabed or will they be carried away subsea by currents? Choosing between point sensors and area sensors, or perhaps a combination, should be done with regards to this aspect. Point sensors need to be correctly placed to come in contact with a leak and may require HC collectors to

be incorporated in template design. Where the point sensors should be placed should be determined based on the expected travel paths and spread of the fluids, or based on weak points in the well.

- **Monitoring frequency**: Is intermittent monitoring enough or should continuous monitoring be implemented? How long intervals are acceptable between data transmissions? Continuous monitoring has advantage over intermittent measurements, such as WL measurements, because it provides far more data and the data is in real-time. Continuous, rather than intermittent, measurements could be of economical advantage as fewer production stops are required. It is possible to select transmission rate to meet the purpose of each individual case. For some sensors a choice can also be made whether transmission of data should be continuous or only in the event of anomalies. The latter is less reliable as sensor failures will not be easily discovered, and the system could fail to inform the operator of an integrity failure, unless self-testing is incorporated in the design.
- **Lifetime and maintenance:** What is the estimated well lifetime and for what parts of the well life cycle shall there be monitoring? If well life is going to be extended, the lifetime of the sensors should match the extended lifetime. What is the sensor's lifetime and how much maintenance will it require? Most sensor systems have a lifetime of about 25 years, but developers are working on increasing this. The access and possibility to repair or replace the sensors should be assessed, and also the cost of these operations. The robustness of sensors will also be an important consideration since this will affect their availability and maintenance requirements.
- **Type of well:** What are the well conditions? Is the wellhead on the seabed or on a platform? Which annuli are accessible? What is the sea depth? What about water visibility and marine growth? Conventional sensors may not be suitable for HPHT wells. Subsea wells are physically more complicated to access, and annulus monitoring is limited since penetration of casing is not permitted. New technology can resolve these challenges, e.g. optic fibres and wireless transfer of data and power. Other sensors and monitoring system may have visibility or depth limitations.

Different sensor types have different advantages and limitations. **Table 6.1** summarises some of the applications of the different sensor types presented in *Chapter 5: Description of Selected Monitoring Methods.*

Table 6.1: Overview of Continuous Sensor Types and Applications.

Sensor Type	**Predict Potential Integrity Failure**	**Detect Integrity Failure**	**Point Sensor**	**Area Sensor**	**Determine Leak Location**	**Could be Used or Adapted for Plugged Wells**
P & T (tubing and annuli)	X	X	X[1]		X[1]	
Corrosion & Erosion	X		X			
Active Acoustics	X[2]	X	X[1]	X[3]	X	X
Passive Acoustics		X		X	X	X
Microseismics	X	X	X	X	X	X
Visual Surveillance		X		X	X	X
Capacitance		X	X			X
Mass Spectrometry		X	X		"Fingerprint"	X
Sniffers		X	X	X	X	X
Bio Sensors		X	X		X	X

Ideally, integrity issues should be detected before a leak to the environment occurs. However, most sensors detect leaks rather than predicting integrity failure. Methods used to monitor for potential leaks, microseismics and well barrier status monitoring combined with leak detection give a good picture of the overall integrity status. The importance of this is illustrated by the Elgin incident presented in *Chapter 3.4: Examples of Well Integrity Failure.* The seriousness of this incident might have been anticipated earlier if the significance of the available monitoring information about the well status and formation had been recognised and understood earlier, and preventative action taken.

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[1] Multiplex measurement possible
[2] Fibre optic only
[3] METS active active acoustic sensor

Point sensors can be installed at a critical leak point, while area sensors cover a wider area. Both can be used to pinpoint the location of the leak. Some sensors, which can be used to predict integrity failure, are not suitable for HPHT wells since the electronics are not designed for these conditions. It is a positive advancement that sensors have been developed to measure pressure and temperature in B annulus for subsea wells. This not only improves safety but also avoids unnecessary interruption of production caused by well shut down.

Permanently plugged wells currently have no requirements for monitoring. If the increase in complexity of wells continues in the future, this might become a subject. Installing monitoring systems for plugged wells can be of advantage, even though it is not required, due to the cost and consequences of an eventual integrity failure (leaking petroleum fluids from plugged wells have occurred).

Predicting integrity failures in plugged wells is challenging, as there is no downhole access. Monitoring of plugged wells is mainly a matter of leak detection, although microseismics can be used for monitoring formation conditions.

Some of the sensors that have been developed for integrity monitoring and leak detection for producing wells can be adapted for use for plugged wells (e.g. by adding collection hoods and keeping power and data infrastructure). Development of inexpensive sensors with long lifetime would be advantageous for this part of the well life cycle.

Installation of monitoring sensors for downhole use in a well has to be decided in the design phase of the well. Also leak detection systems around the well and necessary infrastructure should be planned during the field design phase. Modifications to subsea assembly and infrastructure (power and data requirements) can be expensive or infeasible at a later stage. ROVs can be used to modify a construction, but have limited capability, although they can be used for maintenance and repair of sensors. Some monitoring systems on and above the seabed can be added at a later stage, provided that there is adequate infrastructure for power and data. Generally on the NCS companies are willing to share infrastructure.

New wells are designed and constructed to meet higher integrity than older wells. Older abandoned wells can have a poor well integrity. These need to be monitored even more closely, but may not be close to required infrastructure.

All sensors require a power supply. During production, the power source may be on the offshore installation, but where will power supply come from when the field is abandoned? A permanent infrastructure must be provided unless a local battery source can be used. Similarly, data communication also needs to be connected to an existing infrastructure. This can include cables to surface or to shore. Wireless solution could be used, but these would entail using buoys. This could impede fishing activities and shipping.

It is not enough just to install a collection of sensors. With modern technology multiple sensors can be integrated into a single system. This system has to be correctly designed with a good human machine interface (HMI) so that information is presented in a clear and usable way. The operator must also ensure adequate resources for maintenance and operation of the sensors, procedures and training. The user needs to not only know how to use the sensors but also how to respond to different situations.

Cooperation between authorities, companies, industrial forums, e.g. WIF, DMF and PAF, and international contacts is important to develop best practices, standards and monitoring solutions. Companies with diverse technical backgrounds (from IT solutions to oil and gas sensors) work together with operating companies, and also involve research institutions such as SINTEF and IRIS to develop new sensors. Together, new solutions can be found as new challenges appear.

Focus must be kept on developing new and improved monitoring sensors suited for new and increased challenges in the petroleum industry now and in the future. Future innovative sensor technologies can allow for new possibilities, e.g. by using nanotechnology and fibre optics, the development of batteries with longer lifetime, and wireless power and data transmission.

7 Conclusion

There is an increasing requirement for well integrity monitoring as more challenging wells in sensitive areas are being developed, causing additional safety and environmental concerns.

Regulations on the NCS have been an important driving force that has resulted in the development of extensive monitoring sensors and systems. A good cooperation between different bodies has promoted the development of good guidelines, e.g. NORSOK, which are referred to internationally. Continued development and improvement of standards are anticipated. There are currently no plans to introduce new regulations.

To prevent well integrity issues it is important that the design and construction of the well is fit for purpose, also for the plugging and abandonment of wells. This can be an issue for older wells. The installation and verification of barriers must be adequate to last the well's entire life cycle to ensure that integrity stays intact. Monitoring and associated infrastructure have to be planned in the well design phase together with the field development. Infrastructure may have to be maintained long after production has been stopped in order for monitoring systems to be operational for abandoned fields.

Well integrity monitoring solutions must meet the specific field and well requirements. Key qualities for continuous monitoring systems are reliability, robustness, long lifetime and no or few false alarms. The aim is to have a good overall coverage, provide early detection and have a reliable and functional system that can be maintained for as long as monitoring is required. No single sensor can cover all aspects of the well integrity. A comprehensive monitoring system will include both proactive and reactive sensors, integrated in a single system, which can be monitored centrally.

The monitoring of plugged wells has long been of concern to environmentalists. For plugged wells in sensitive areas, application of integrity monitoring sensors must be considered. Although this can be very expensive, the cost is insignificant compared with the cost to the operator if a catastrophic well integrity incident happens.

Operators are responsible for maintaining integrity, also after production has ended. Long-term surveillance of abandoned wells has to be done to ensure that the environment is protected for future generations. However, there is a problem to ensure monitoring indefinitely due to limited lifetime of sensors and power solutions. This requires even more innovative monitoring solutions.

Many well integrity monitoring sensors are available. Recent developments have helped meet challenges with integrity monitoring of subsea wells, and many more solutions are being developed and improved. New developing technologies are being developed by cooperation between different companies with different technical backgrounds, and can open up for improved integrity monitoring. In order to ensure that this development continues, it is important that companies are willing to cooperate by sharing experience and constructing shared infrastructure, and that operating companies are willing to use new technology. The authorities can promote the use of more and new sensors and systems by enforcing more stringent regulations and imposing more severe penalties. Relying on the operators' moral sense of obligation is not enough.

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