Universitetet
i Stavanger

FACULTY OF SCIENCE AND TECHNOLOGY

MASTER'S THESIS

Study programme/specialisation: Mechanical and Structural Engineering and Materials Science/Offshore Structural Engineering	Spring / Autumn semester, 20.17.. Open/Confidential
Author: Kristian Ottestad Rød	………Kristian O. Rød……… (signature of author)
Programme coordinator: Supervisor(s): Faculty supervisor: Prof. Helge Hodne External supervisor: Per Jahre Nilsen, DNV GL	
Title of master's thesis: An Investigation of Sustained Casing Pressure Occurring on the NCS: A Related Risk Assessment	
Credits: 30	
Keywords: Sustained Casing Pressure Annular Pressure Norwegian Continental Shelf Plugging & Abandonment Accidents and Incidents Risk	Number of pages: .79……………… + supplemental material/other: ………… Stavanger,…15.12/2017………… date/year

ACKNOWLEDGEMENT

This thesis was written throughout the autumn of 2017 at the Faculty of Science and Technology, as a part of my master's degree program in Constructions and materials, at the University of Stavanger.

I would like to thank DNV GL and company supervisor Per Jahre-Nilsen for providing me with an interesting topic, access to a great work environment and superb guidance. I would also like to thank my supervisor at the University of Stavanger for his support and useful comments during my work.

By sharing we improve risk assessments, operational preparedness and thus increase our knowledge and the safety level. I would like to thank the operators and other companies who contributed with their valuable data and experience for this thesis.

Finally, yet importantly, I want to thank my family and friends for their support.

Kristian Ottestad Rød

ABSTRACT

Reports from the Gulf of Mexico (GoM) show that thousands of wells exhibit sustained casing pressure (SCP), however the extent of this phenomena and its driving factors have yet to be studied in detail on the Norwegian Continental Shelf (NCS). The central questions investigated and discussed are the occurrence of SCP, the specific factors that increase the likelihood of SCP and if SCP increases the likelihood of incidents or accidents during normal operations or permanent plugging and abandonment. The Petroleum Safety Authority does not require SCP to be reported on the NCS, but rather a general "Well Integrity Status". No previously identified research has investigated the full extent of SCP issues on the NCS. SCP is believed to be a significant issue on the NCS as indicated by findings from the GoM and through dialog with operators and review of the World Offshore Accident Database (WOAD) the author hopes to shed light on the topic. A survey and substantial document review has been performed to form the basis for analysis and further work, but the availability and willingness and time constrain by data owners to share well data and integrity information has been a limiting factor. It is apparent that SCP does occur on the NCS and is linked to overburden zones with flow potential and compaction induced well damage, however due to annulus inaccessibility there is significant uncertainty especially concerning subsea wells and the potential environmental risk.

TABLE OF CONTENTS

ACKNOWLEDGEMENT .... **III**

ABSTRACT .... **V**

TABLE OF CONTENTS .... **VII**

LIST OF ABBREVIATIONS .... **IX**

LIST OF FIGURES .... **XI**

LIST OF TABLES .... **XIII**

1. INTRODUCTION **1**

1.1 Case Histories of Problems Caused By SCP 3
1.2 Thesis Background 4
1.3 Scope and Objective 4
1.4 Research Methodology Overview 4

2. BASIC WELL DESIGN **7**

2.1 Well and Casing Design 7
2.2 Primary Cementing 8
2.3 Remedial Cementing 8
2.4 Cement/Barrier Quality Assurance 9
2.5 Wellhead Design 10
2.6 Shallow Gas 11
2.7 Compaction Induced Well Damage 11

3. WELL INTEGRITY AND RISK **17**

3.1 Risk Concept 17
3.2 Well Barrier and Well Barrier Elements 18
3.3 Well Integrity Categorization 19

4. ANNULAR PRESSURE BUILD-UP **21**

4.1 Annulus Monitoring Requirements 21
4.2 Monitoring Frequency Requirements 22
4.3 Government Notification Requirements 23
4.4 Thermal Pressure 24
4.5 Imposed Pressure 25
4.6 Sustained Casing Pressure 25
4.7 Sustained Casing Pressure Management 29

5. SCP ON THE NORWEGIAN CONTINENTAL SHELF **33**

5.1 Development Wells Sampled 33
5.2 Development Wells with SCP on the NCS 35
5.3 Data Significance and Bias 38
5.4 Reported Causes of SCP on the Norwegian Continental Shelf 40
5.5 Accidents and Incidents 41
5.6 Summary of Accidents/Incidents and Related Risk 45

6. WELL ABANDONMENT **47**

6.1 Prescriptive Practice of D-010 48
6.2 Suspension 48

6.3 Temporary Well Abandonment 48
6.4 Permanent Well Abandonment 49
6.5 Case Study – P&A With Gas Migration 50
6.6 Case Study – Haltenbanken P&A and Zonal Isolation 52

7. DISCUSSION 57

7.1 SCP on the Norwegian Continental Shelf 57
7.2 P&A With SCP 60

8. CONCLUSION 61

REFERENCES 63

APPENDICES 65

Appendix 1 – Survey Form 65
Appendix 2 – Risk Matrix 66

LIST OF ABBREVIATIONS

ALARP	As Low as Reasonably Practical
ANOVA	Analysis of Variance
AP	Annular Pressure
API	American Petroleum Institute
BOP	Blow Out Preventer
BSEE	Bureau of Safety and Environmental Enforcement
CFR	Code of Federal Regulations
DM	Drilling Manager
FIT	Formation Integrity Test
GoM	Gulf of Mexico
HC	Hydrocarbons
HPHT	High Pressure High Temperature
LOT	Leak-off Test
MAASP	Maximum Allowable Annular Surface Pressure
MAWOP	Maximum Allowable Wellhead Operating Pressure
MCP	Maximum Collapse Pressure
MIYP	Maximum Internal Yield pressure
MMS	Minerals Management Service
NCS	Norwegian Continental Shelf
OCS	Outer Continental Shelf (US)
P&A	Plugging and Abandonment
PP&A	Permanent Plugging and Abandonment
PSA	Petroleum Safety Authority Norway
RKB	Rotary Kelly Bushing
SCP	Sustained Casing pressure
TOC	Top of Cement
TVD	True Vertical Depth
UK	United Kingdom
US	United States of America
WBE	Well Barrier Element
WOAD	World Offshore Accident Database
XLOT	Extended Leak-off Test

LIST OF FIGURES

Fig. 1 - Hydrocarbon leaks greater than 0,1 kg/s, 2000-2016 (Petroleum Safety Authority 2016a)....... 1
Fig. 2 - Deepwater Horizon blowout. 2
Fig. 3 - An overview of research methodology used. 5
Fig. 4 - Typical well schematic (Dahle 2014). 7
Fig. 5 - SLB IC conventional wellhead system(Cameron 2017). 10
Fig. 6 - Subsea wellhead UWD-15 (FMC Technologies 2008). 11
Fig. 7 - Underreaming to Reduce Dogleg Rate and Casing Buckling Failure Modes (Dusseault, Bruno, and Barrera 2001) 12
Fig. 8 - Long Beach Subsidence (City of Long Beach Gas & Oil Department 2017) 14
Fig. 9 - WBS drilling with shearable drill string (NORSOK D-010 2013)... 17
Fig. 10 - WBS platform production well (NORSOK D-010 2013)... 18
Fig. 11 - Well integrity categorization (Recommended guidelines for Well Integrity no.:117 2008). . 20
Fig. 12 - Well integrity status on NCS (Petroleum Safety Authority 2016a). 20
Fig. 13 - Possible leak paths (Recommended guidelines for Well Integrity no.:117 2008). 24
Fig. 14 - Surface wellhead D annulus leak, Elgin G4 well (Total E&P UK Ltd 2013) 27
Fig. 15 - Annuli accessibility/monitoring (%)... 35
Fig. 16 - Status overview (all annuli). 35
Fig. 17 - Complete dataset of all annuli. 36
Fig. 18 - Annuli distribution (all annuli). 36
Fig. 19 - Overview (monitored annuli).. 37
Fig. 20 - Monitored annuli distribution. 37
Fig. 21 - Statistical sampling error. 39
Fig. 22 - Permanent abandonment of perforated well - From NORSOK D-010 (2013). 49
Fig. 23 - 34/7-22 P&A schematic (SAGA Petroleum 1994). 51
Fig. 24 - 34/7-22 Possible Barriers (SAGA Petroleum 1994) 52
Fig. 25 - Abandonment design (Conoco Norway inc. 1984)... 53
Fig. 26 - Dvalin P&A – Lysing/Lange formations(DEA Norge AS 2016). 54

LIST OF TABLES

Table 1 - Annulus monitoring requirements US Outer Continental Shelf (BSEE 2011). 22
Table 2 - Monitoring frequency requirements US Outer Continental Shelf (BSEE 2011). 23
Table 3 - Wellbore count NCS. 33
Table 4 - Fields included in dataset. 34
Table 5 - Incident/Accident categorization. 41
Table 6 - World Offshore Accident Database SCP events. 43
Table 7 - World Offshore Accident Database cementing job failures. 44
Table 8 - World Offshore Accident Database accidents/incidents related to SCP management and intervention. 45

1. INTRODUCTION

For a leak to occur in an oil and gas well, three elements must be in place: A leak source, a driving force and a leak pathway (Watson and Bachu 2009). In most oil and gas, development wells, two of these elements already exist and they are a prerequisite for hydrocarbon recovery. The porous and permeable reservoir with hydrocarbons or other pressurized overburden zones provide the source and the trapped formation pressure and hydrocarbon buoyancy provide the driving force. The last required element is leak pathways. When drilling a well a pathway is established to the reservoir, but a level of control and safety is required and barrier envelopes are established to safely produce through these pathways. The consequences of a major uncontrolled hydrocarbon release are significant and consequently the probability of such an accident must be reduced to acceptable levels. Unfortunately, there are many instances where uncontrolled leak paths are formed, in and around oil wells leading to hydrocarbon migration, small leaks and pressure build up. Fig. 1 shows all the reported hydrocarbon leaks on the Norwegian Continental Shelf (NCS) from 2000 to 2016 (Petroleum Safety Authority 2016a). A declining trend is apparent, but our knowledge of leaks from permanent abandoned wells is limited.

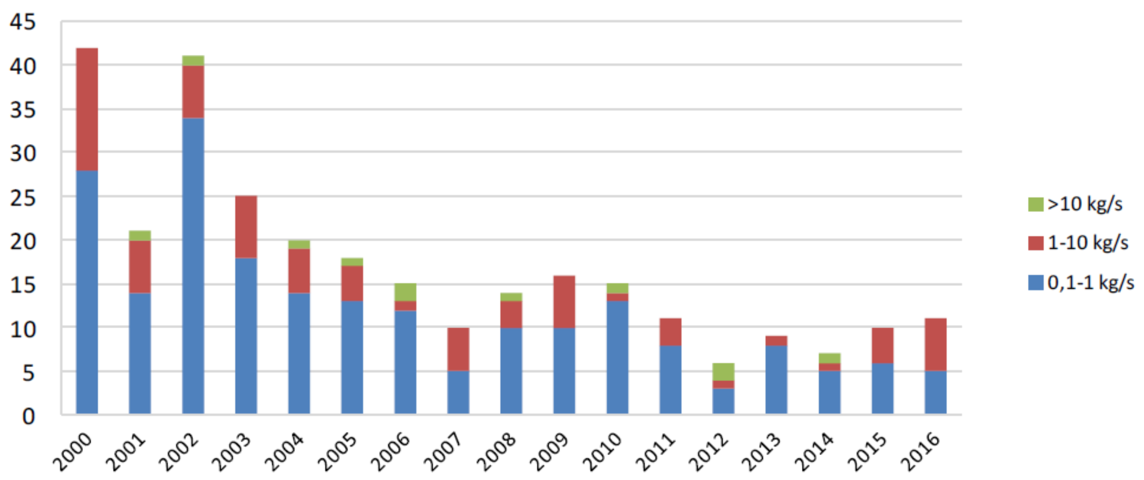

Fig. 1 - Hydrocarbon leaks greater than 0,1 kg/s, 2000-2016 (Petroleum Safety Authority 2016a).

Annular pressure build up in development wells is the major theme in this thesis, with the goal of increasing our understanding of the mechanisms and parameters causing annular pressure build up. This is closely linked to permanent abandonment of wells, but unfortunately there is no way of knowing the internal integrity status of a permanently plugged well and there is limited or no public statistics regarding leaking plugged wells. Hence, research and development related for permanent plugging of wells is challenging. The approach in this thesis is to study similar issues in active development wells i.e. annulus pressure or sustained casing pressure (SCP). The Norwegian Oil & Gas Association defines SCP as:

"Pressure in any well annulus that is measurable at the wellhead and rebuilds when bled down, not caused solely by temperature fluctuations or imposed by the operator."(Recommended guidelines for Well Integrity no.:117 2008)

SCP is generally linked to overburden issues, primary cement issues, and tubing leaks. As such, this is very relevant for permanent plugging and abandonment (P&A). SCP in a well is a clear indication reduced zonal isolation or barrier or well degradation. Annular pressure is also a known risk factor during many well operations, and the industry strives to reduce or limit these risks.

The remediation costs related to SCP could also be significant. In 2002, remediation costs could potentially be as high as one million US dollars per well including the cost of contracting a workover rig and fixing the leak (Abbas et al. 2002). Accounting for inflation this would approximately equal 1.36 million dollars in 2017, however rig-rate and oil price development is not considered. Another example of the high remediation costs reported by an operator involved spending 13 months and over 20 million dollars attempting to eliminate SCP in seven wells. SCP was still observed in some wells after the extensive efforts (Bourgoyne, Scott, and Manowski 2000).

The occurrence of sustained casing issues on the NCS has yet to be studied in detail and data has been collected from some operators that have been able to dedicate time and resources to share relevant data. On the NCS there are no specific requirements to report SCP, but regulations governing on the US Outer Continental Shelf requires diagnostics testing within 30 days if a pressure of 100psi is observed in the annulus. If your diagnostics test requires action, you shall within 14 days submit a notification of corrective action or a casing pressure request (BSEE 2011). Reports from the US Outer Continental Shelf have shown that several thousand wells suffer from SCP. This thesis will investigate the extent of SCP, document the causes and risk factors that in turn could contribute to better risk assessments before well operations and especially P&A.

A Minerals Management Service funded study, conducted by Louisiana State University Investigated the extent of SCP in wells on the US Outer Continental Shelf including the Gulf of Mexico (GoM). The study found that over 8000 wells and over 1100 wellbores have recorded undesirable SCP in one or more casing strings (Bourgoyne, Scott, and Manowski 2000). It could therefore be reasonable to assume that undesirable SCP will to some degree occur on the NCS. Although the regulatory systems and control systems may vary from country to country, many of the major operators will use the same procedures, equipment and technology.

Fig. 2 - Deepwater Horizon blowout.

In subsea completed wells annulus pressure monitoring of all annuli volumes is difficult or not possible at all. Because many wells are subsea completed the actual extent of SCP may not be known. If SCP goes undetected, it may increase the risk during well operations or in general increase the risk of well degradation over time. A typical example is during a P&A operation where casing is cut and pulled from the well. A trapped gas cap in the re exposed annulus could be released into the riser system and detection will normally not be fast enough to activate well control devices (i.e. Blowout Preventer). A general degradation of well cement, tubing leaks, underground blowouts cross flow and wellhead leaks may also occur and could go undetected over long periods.

Multiple well barrier failure can result in major accidents and presents a severe risk to personnel and the environment. If annular pressure build up and SCP is a common issue in a significant number of wells on the NCS and the associated risk of a major accident is significant, actions should be taken in order to increase understanding and reduce occurrence. This could result in better risk assessment, planning and design, and reduce non-productive time and cost related to well workover and P&A. The quality of the well barriers are vastly important, as they not only secure the well during production, but they should also secure the well after P&A with an eternal perspective.

The potential problems that can occur in wells with SCP are best understood through evaluation of incidents and accidents. Several accidents/incidents related to annular pressure build-up, annulus pressure bleed down and P&A have been reported and three examples are presented in the section below.

1.1 CASE HISTORIES OF PROBLEMS CAUSED BY SCP

1.1a Case 1

On the 23 August 2007, there was reported gas leaking at the mud line around a well in the GoM, but no pollution was visible. It was determined that the source of the gas was from the well and that the communication problem that had existed within the well previously had breached the production casing and reached the surface. Once the casing pressure breached the production casing, the magnitude of the casing pressure was more than sufficient to break down the shoe of the 16 inch surface casing at 2,220 feet measured depth. Numerous attempts were made to kill the well without success, and on September 22, the platform was found toppled/sunk after returning from storm evacuation.

A relief well was drilled and the well was killed with 525 bbl of mud and abandoned with 203 bbl of cement by November 10. The platform along with its three wells sank below the mudline as a result of the blowout. Before this incident, (January 29) a casing pressure diagnostic test had been performed on the 9 5/8 inch production casing indicating 1950 psig that would not bleed to less than 250 psig. The diagnostics test had not been reported to the Minerals Management Service (Minerals Management Service 2008b). If the diagnostics test had been reported, action would have been required and the loss of the platform and wells could have been avoided.

1.1b Case 2

During plugging and abandonment of an exploration well in the North Sea in 1993, trapped gas in the 13 3/8" – 18 5/8" annulus was released into the riser when pulling 13 3/8" casing and seal assembly. Gas entered the riser and evacuated mud onto the drill floor. It is believed that gas from a zone just below the 18 5/8" casing had migrated into the annulus and a small gas bubble had formed under the casing hanger (SAGA Petroleum 1994). Fig. 2 shows the catastrophic result of gas ignition on deck. The loss of drilling mud in the riser could have resulted in the loss of hydrostatic overbalance in the well and subsequently loss of well control. If well control equipment (i.e. annular preventer) had been active during removal of the seal assembly and casing hanger this incident could have been avoided. Currently this is standard practice on the NCS.

1.1c Case 3

In 2007 during exploration drilling in the GoM the cement sheath on the conductor casing failed, allowing shallow gas in a sand formation located below the drive pipe shoe to start flowing. This resulted in gas venting to the surface between the conductor and drive pipe. Seventy-eight crewmembers were evacuated from the rig and no personnel were injured. The main cause is thought to be failure of the primary cement job. Several contributing causes were hypothesised and they included(Minerals Management Service 2008a):

- Contamination of the cement slurry during primary cementing operation.
- Formation of a channel in the cement sheath caused by gas migration from the shallow gas sand below the drive pipe.
- Propagation of the channel caused by thermal expansion of the cement sheath due to the high temperature of the circulating drilling fluids.
- Propagation of the channel caused by mechanical vibration.

1.2 THESIS BACKGROUND

Plugging and abandonment of offshore wells has in recent years been a highly debated theme mostly due to the anticipated "wave" of mature wells to be plugged. P&A operations is a non-profit activity with large expenditures with a goal of sealing the well with an eternal perspective. These operations can in many cases be considered a risky operation with complex wells and reduced integrity.

The presence of annulus pressure or SCP should be considered during P&A design to ensure quality of the barriers. Annulus pressure or SCP can also increase risk during P&A operations if not managed. In this context, the author has been asked to investigate the extent of annular pressure build-up issues and SCP in offshore oil and gas wells on the NCS and the goal is to attain greater knowledge and understanding of these issues worldwide to further develop risk analysis methods in the future. These issues are critical for HSEQ in general, well control and especially P&A operations.

P&A regulations currently in use on the NCS is described in NORSOK D-010. NORSOK D-010 is regarded as the industry standard and is supposedly a performance-based standard with functional requirements. However when addressing P&A, D-010 is often utilized in a prescriptive manor. A relatively generic design is proposed even though two wells will never be the same. As a response to this development, DNV GL has developed a risk/performance based method (DNVGL-RP-E103 2016) for P&A which could increase efficiency and identify risk factors critical for the operations.

1.3 SCOPE AND OBJECTIVE

The primary objectives of this thesis work is to:

- Investigate the extent of annular pressure build-up issues i.e. SCP in offshore oil and gas development wells on the NCS.
- Determine if annular pressure and SCP can be correlated to certain well parameters and compile known causes, common factors and parameters causing gas migration, leaks, annular pressure build-up and SCP.
- Investigate if the presence of annular pressure build up and SCP in offshore oil and gas wells creates a significant risk of incidents, major accidents or major well integrity events e.g. blowouts during normal operation or P&A.

The thesis will mainly focus on the Norwegian offshore sector, but will also seek to attain an overview of these issues in other hydrocarbon producing areas such as the US GoM.

1.4 RESEARCH METHODOLOGY OVERVIEW

The thesis is carried out as a combination of survey and document/database reviews, and contains both qualitative and quantitative data analysis. Fig. 3 presents an overview of the methodology used in this thesis.

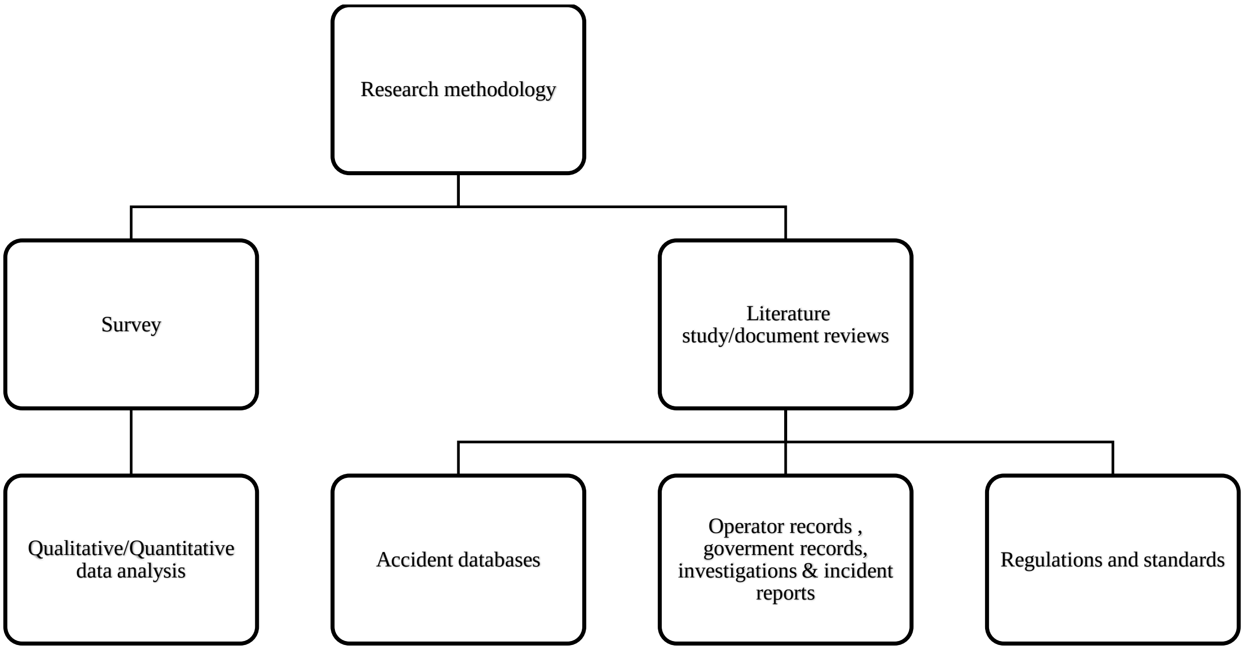

Fig. 3 - An overview of research methodology used.

The most important sources of information used in this thesis is the replies to the survey received from the operators on the NCS and dialog with key company personnel. Various reports and previous studies performed by different research environments, consultant firms, authorities and industry organizations have also been vital as an indicator and reference to the NCS. To gain insight on the risk related to SCP, various accident databases have been evaluated and these include the World Offshore Accident Database (WOAD), SINTEF Blowout database and Exprosoft Welmaster RMS. Other relevant documentation received from the industry, public well data and incident investigation reports have proven to be useful.

1.4a Main Activities

The main activities performed during the thesis work is summarised below:

- Distribute and review of survey issued to selected operators and qualitative analysis to uncover cause of SCP and correlations to sub causes. If sufficient data is captured, there is a potential for qualitative statistical analysis.
- Document review of reports, government records, operator records, investigation reports and incident reports related to uncontrolled annular pressure build-up and SCP.
- Review of available accident/incident databases related to well integrity, pressure build up and SCP to determine if annular pressure build up and SCP in offshore oil and gas wells create a significant probability of well control incidents, accidents or major well integrity events i.e. blowout.
- Document review of regulations, standards and guidelines regarding annular pressure and SCP. Mainly concerning the NCS, but also other hydrocarbon producing areas such as GoM.
- Discussion of how the information in this thesis might impact future P&A design, including long term environmental considerations of leakage and impact from such.

1.4b Survey

The extent of SCP in offshore wells on the NCS is currently not documented in any complete database and only a few incidents caused by SCP can be found. Operators on the NCS are required to know the integrity status of all their wells and it is thus assumed that the same operators have knowledge of their wells with SCP. Although, this is not public information and the operators are not required to disclose such information. A survey (Appendix 1) was sent to the operators on the NCS. A response adaptive sampling method is utilized to account for the varying response and stratification could be required. A basic qualitative analysis of individual cases is performed to uncover causes and correlations.

1.4c Key Limitations and Sources of Error

Through dialog and evaluation, the relevance and credibility of data have been evaluated throughout the thesis work. Some key limitations have affected the outcome of this work and they include; limited access to well status information related to the scope; accurate and updated well status information; outdated studies and reports; undetected SCP (especially in subsea wells); unreported/undocumented SCP; and sampling error.

2. BASIC WELL DESIGN

To fully understand issues relating to sustained casing pressure (SCP), a basic understanding of the modern well design and relevant failure modes is important. Well construction elements like casing, tubing, cement and wellheads are briefly discussed. Cement quality assurance, shallow gas and compaction induced damage is also briefly discussed in relation to SCP and annular pressure.

2.1 WELL AND CASING DESIGN

Casing and liners are steel tubes that are cemented in place in the borehole and they form the main constructional components of a well. Casing, liners and drilling fluids are used to maintain borehole stability and integrity during drilling and throughout the lifetime of a well.

Due to varying pore pressure and fracture pressure the well must be drilled and isolated in sections to prevent fluid losses, fluid influx, well collapse and well fracturing during drilling. Therefore, casing strings are installed at predetermined intervals to isolate the different pressure regimes to ultimately reach the target depth. Once an open hole section is sealed off with casing cemented in place, the next section is drilled through the cased hole with a reduced diameter drill bit. A smaller diameter casing is inserted through the previous casing into the new open hole section and cemented once in place(Aadnøy 2010).

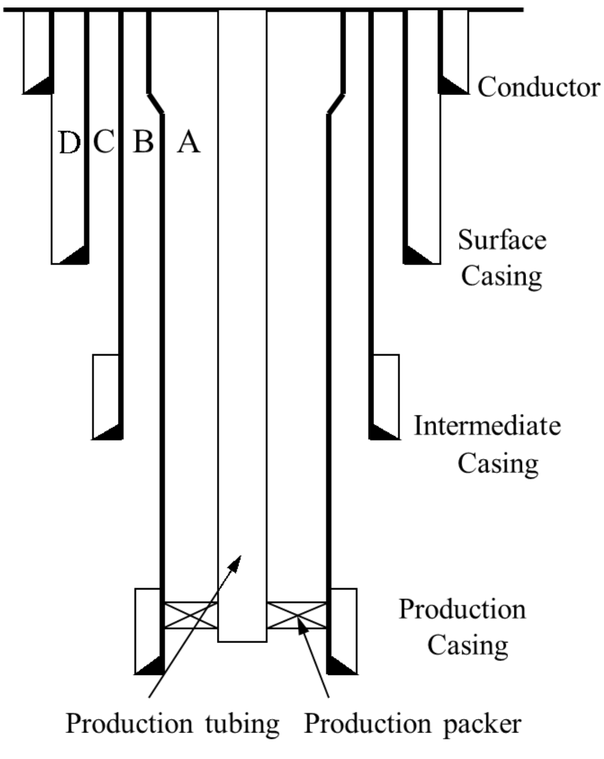

Fig. 4 - Typical well schematic (Dahle 2014).

A typical casing program on NCS could consist of a 30” conductor casing, 20” surface casing, 13 ¾” intermediate casing, 9 5/8” production casing and 7” production tubing.

The main characteristic of a casing versus a liner is that the casing is connected and hung off in the wellhead, where as a liner is typically hung off 30 - 150m above the previous casing shoe. Tieback strings can be used to connect liners to the wellhead if needed(Drilling Manager 2017).

When designing a well the strength of all casing and tubulars must be addressed. Casing is designed to avoid burst and collapse under the most severe load cases that might occur during drilling, cementing and production in combination with compressive and tensile loads. To ensure longevity of the well other properties such as corrosion resistance, chemical resistance and toughness must also be addressed in the casing design program. (Aadnøy 2010)

When constructing as described above, annular volumes are formed between each of the casing/tubing strings. These volumes are usually filled with drilling mud or spacer fluids (used during cementing) unless they are fully cemented to the surface (Surface casing). These annular volumes are generally not exposed to abnormal pressures as all pressured zones capable of flowing should be sealed off, but in some cases well barrier failures or undetected abnormally pressured zones cause pressure increases in the annular volumes.

2.2 PRIMARY CEMENTING

Primary cementing is the cementing operation described briefly in the previous section for installation of casing and is used to stabilize the borehole and to isolate formations with different pore pressure, strength and flow potential. The cement will also support the casing during loading and protect the casing from corrosion. A slurry of cement powder, water and various chemicals is mixed with the required properties and is pumped down the well and into the annulus around the casing. Various placement techniques of cement exist, but they will not be discussed in this thesis.

For a primary cementing operation to be successful the borehole must be properly conditioned before cementing. The casing should be centred in the hole for equal distribution of cement ensuring good bonding to pipe and formation. Displacement of cement in the annulus must be performed correctly and the minimum required volume of cement must be placed in the hole at the correct depth. The cement should bond well to casing and formation and the cement should have the required chemical and mechanical properties before and after hardening. Bottom hole pressure and formation temperature should be known in order to design a cement slurry with correct specific gravity (SG). Controlling the cement mixing and placement is very important in order to prevent fluid loss or influx from formation during cementing.

The process of cement hardening is a complicated process and outside the scope of this this thesis, but an important characteristic of cement hardening is the inability to maintain hydrostatic pressure during solidification. If significant strength is not achieved quickly, gas migration through the setting cement could cause channels. Cement will in general also shrink during setting which could cause debonding between cement and tubing or formation (Lavrov and Torsæter 2016).

2.3 REMEDIAL CEMENTING

Cement is used extensively in oil and gas wells and during construction or operation of a well and many issues associated with cement may occur. These potential flaws or issues will in many cases be the result of a poor primary cement job, cement degradation, pressure and temperature fluctuations or other external factors. The cementing operation used to repair damages to the cement sheath or fracture zones in the reservoir is categorized as “Remedial Cementing”. New techniques and technology have been developed to remediate a variety of wellbore and cement problems and most of these are squeeze cementing technologies or plug cementing (Lavrov and Torsæter 2016).

2.4 Cement/Barrier Quality Assurance

Primary cement quality is critical to ensure well integrity and special considerations when the primary cement is part of a barrier envelop. Verification of cement quality is difficult as the access is limited, but logging techniques have been developed to assess cement sheath quality (bonding to casing and no channels). These logs are not standalone verification tools and an overall assessment including cement operation records and other well data should be considered. For older wells where limited well data is available and the overall well integrity is unknown, verification of WBEs for abandonment purposes can be difficult. The most common logging and testing techniques are described in sections 2.4a and 2.4b.

2.4a Cement Bond Logs

Cement bond logs are tools used to evaluate the quality of the annulus cement bond to casing and formation. It is a commonly used important set of tools when evaluating zonal isolation and cement bond quality. The concept of a cement bond log is based on acoustic, resonance principles, the acoustic behaver of a “good bond” is different from a “bad bond” .The bond between casing and cement, or cement and formation is evaluated. To perform the logging operation, the tool containing both transmitters and receivers is centralized and run through the inside of the casing and the relevant interval is logged. The results are analysed by qualified personnel to determine the quality of the well section. Significant Channels and sections without cement will also generally be detectable. A more basic tool, temperature logging tool is commonly used to determine top of cement in the annulus when a cement bond log is not required.

2.4b Pressure Testing

Pressure testing is also a very important tool when evaluating the quality and strength of barriers. A “positive” pressure test is commonly performed by increasing the pressure in an enclosed volume to a specific predefined value for the test and then isolating the volume while monitoring the pressure. Thermal effects should be evaluated and minimized during testing to reduce sources of error. The pressure should hold within a set range for the duration of the test for approval.

A “negative” pressure test however is similar, but involves reducing the pressure in a volume (typically displacing fluid from the well) to achieve a similar overpressure from the surroundings or the formation. The most common methods used to test formation and cement strength under exploration and production are:

Pressure/Formation Integrity Test (PIT/FIT)

A pressure/formation integrity test is a test used to confirm that the formation or casing cement can withstand a predefined pressure without any loss of integrity. The predefined pressure is applied to the relevant formation/casing cement and test is accepted if pressure remains stable.

Leak-off Test (LOT)

The leak-off test objective is to determine the actual minimum strength of the formation/casing cement. The test pressure is increased until the fluids start to leak to the respective formation (deviation of linear pressure vs volume curve) and then stopped before formation fracture.

Extended Leak-off Test (XLOT)

The extended leak-off test objective is to determine the actual minimum in-situ formation stress. The XLOT is a continuation of the LOT and will provide considerable more formation data. The test pressure is increased until the fluids start to leak to the respective formation (deviation of linear pressure vs volume curve). The formation is fractured and a stable leak-of rate is observed. This is defined as the fracture propagation pressure. When the pressure is bled down the fracture closure pressure is observed. A second pressurizing cycle is performed to establish the fracture reopening pressure and confirm the fracture propagation and closure pressure (NORSOK D-010 2013, Torbergsen et al. 2012)

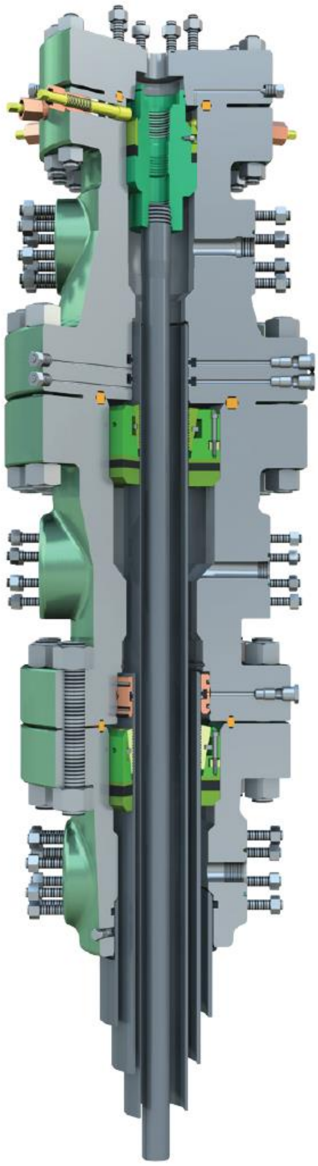

Fig. 5 - SLB IC conventional wellhead system(Cameron 2017).

2.5 WELLHEAD DESIGN

The wellhead is the structural interface between the well and the drilling/production equipment and provides pressure containment and a suspension point for all the casing strings in the well. Seal assemblies installed in the wellhead will also isolate the annular volumes. A key feature of the wellhead is the ability to allow fluid flow bypass before seal installation. This is critical for circulation and the displacement of cement in the annulus.

2.5a Subsea Wellhead Design

Different suppliers utilize different designs but in general the wellheads serve the same purpose. Casing design, well type, facility and reservoir properties will determine the wellhead selection. A key feature of subsea wellhead design is inaccessibility of the annuli volumes B, C and D (Fig. 6).

During primary cementing if the surface casing and wellhead, cement is displaced up the annulus to the wellhead and circulated out return ports in the wellhead housing on the conductor casing. The top of cement in the "D" annulus may be exposed to the environment through the conductor housing cement return port, unless valves are installed/closed by use of an ROV. In well templates with multiple wells typically used in modern field development, access around the wellhead is very restricted.

2.5b Surface Wellhead Design

A conventional surface wellhead is very different in design compared to a conventional subsea wellhead, but still their purpose is the same. The wellhead is assembled from several casing-housing elements and the individual casings are hung off with casing hangers and seals in the respective housings. A, B and C annuli access are generally available through valve assemblies fitted to the wellhead and some wellhead/casing designs allow for D annulus monitoring (Fig. 5). During primary cementing circulated fluid returns can flow through the annulus access vales for the respective casing strings. In other surface wellheads the D annulus can be open to the environment. Fig. 14 illustrates how a loss of multiple barriers resulted in gas venting from the D annulus in the G4 well on the Elgin field in 2012 (Total E&P UK Ltd 2013).

2.6 Shallow Gas

Shallow gas is known as areas of trapped biogenic gas (mostly methane) in the overburden (DNVGL-RP-E103 2016) or thermogenic gas that has migrated from deeper formations (Davis 1992). This gas build up is commonly encountered during drilling of the initial surface casing section. When drilling the initial sections (Conductor and Surface Casing sections) pressure control equipment (i.e. BOP) is not used as the wellhead has not been installed at this point in the operation. Cuttings and drilling fluid (water) are consequently released to the environment.

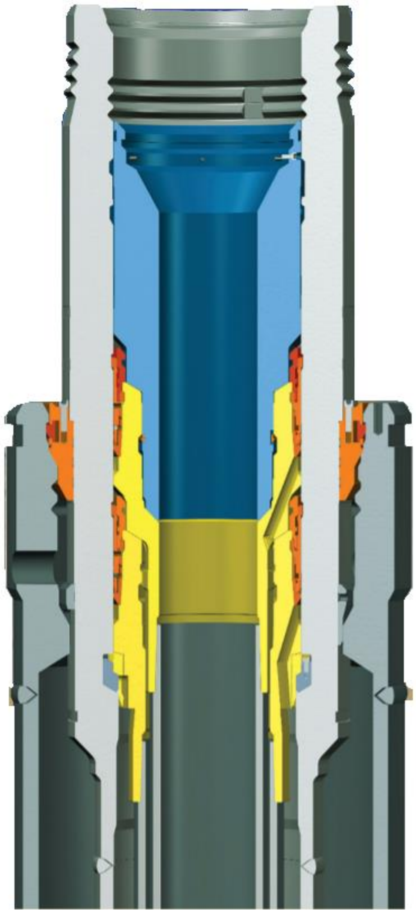

Fig. 6 - Subsea wellhead UWD-15 (FMC Technologies 2008).

If however shallow gas is encountered large amounts of gas can be released beneath and around the facility greatly increase the risk of fire/explosion. Well collapse is also common during shallow gas release. Typically the surface casing open hole section is a 26” hole, which increases the amount of released gas due to the large flow path and internal surface area of the well. In areas where shallow gas is expected, pilot holes (typically 12”) are predrilled to limit the release of gas and reduce risk.

In some cases shallow gas or high pressure zones can go undetected during drilling and running casing, but during cementing changes in the hydrostatic pressure in the well may result in inflow. This can in some cases cause channels in the cement sheath, contamination or a full-scale blowout through the cemented annulus. If the cement is contaminated or channels are formed, the integrity is greatly reduced and this may increase the risk of SCP later. In general shallow gas represents operational risk during drilling but, in deep water natural gas (methane) dissolves in the water column (Johansen, Rye, and Cooper 2003).

2.7 Compaction Induced Well Damage

Reservoir compaction and field subsidence are issues experienced in oil and gas fields around the world, and the consequences can be significant in terms of remediation cost and non-productive time. It is evident that large deformations of the wellbore in the longitudinal or lateral direction can affect well mechanics and integrity, but how this effects SCP occurrence or P&A is however not entirely clear. It is also important to note the positive effects of reservoir compaction in terms of production and reservoir pressure maintenance.

The fields on the NCS are very diverse concerning their reservoir characteristics and flow potential. Sandstone formations with varying age are common and a few chalk reservoirs are being produced. These reservoirs behave very differently when a field is depleted towards the end of field life, the effect on well integrity can change significantly.

2.7a Formation Stress

During depletion of a reservoir, the pore pressure is reduced because of production and hence the reservoir will ultimately be subjected to an increased effective stress as the formation will be subjected to more overburden weight. When the effective stress increases, soft formations will generally transfer more stress than harder formations to the wellbore cement and ultimately casing. If the effective radial stress in the cement-formation or steel-cement interface exceeds the tensile bond strength at the interface, de-bonding will occur and a micro annulus is formed. If the hoop stress in the cement sheath exceeds the tensile strength of the cement, radial cracks can form in the cement ultimately creating possible leak paths (Lavrov and Torsæter 2016).

2.7b Well Damage

The degree of compaction in a reservoir is a function of many variables, but key characteristics are the formation stress, formation strength, reservoir geometry and degree of pressure depletion. If the degree of compaction is significant, well damage can occur in the forms off casing shear, collapse and buckling.

A compacting reservoir with cemented casing will generally pull the casing, compressing it and above the reservoir the casing is stretched in the axial direction. In both situations the elongation or compression can cause failure in tension or buckling respectively (Doornhof et al. 2006).

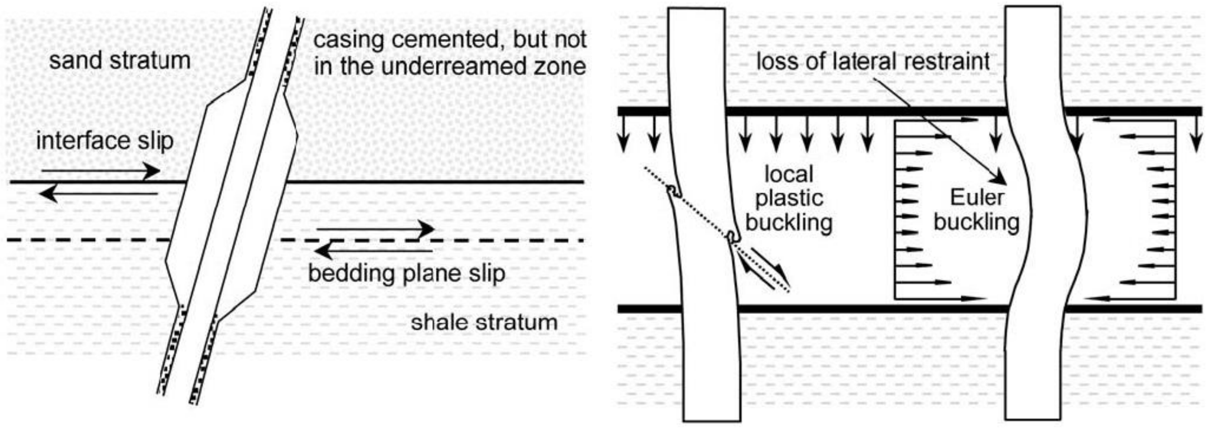

Fig. 7 - Underreaming to Reduce Dogleg Rate and Casing Buckling Failure Modes (Dusseault, Bruno, and Barrera 2001)

Shear failures and crushing are also very common during field subsidence. Initially stabile faults in the overburden will on some fields reactivate if the differential movement in the formation exceeds a limit. Slippage in the reactivated faults or bedding planes can ultimately shear or crush the wellbore. Reducing the shear failure rate is best achieved through avoidance of the critical areas, increasing wellbore compliance and adjusting production techniques to reduce overall plane slippage. Stronger casing is effective in very weak formations where plastic deformation (in formation) is easily achieved (Dusseault, Bruno, and Barrera 2001).

2.7c Norwegian Continental Shelf

The Ekofisk and Valhall fields on the Norwegian Continental Shelf (NCS) have undergone serious subsidence since production started in the 70s and 80s. Both fields produce from compressible chalk formations in the southern North Sea and Ekofisk has seen more than 10m of reservoir compaction and most wells that penetrate the reservoir formation have been damaged by shearing at least once. The casing shear zones are located in the shale cap-rock and well impairment is concentrated around the edges of the reservoir, with a large percentage occurring close to the Balder shale formation above the reservoir. The slip planes are typically sand/shale interfaces. In the Ekofisk field, underreaming has been used to mitigate share damage in the Balder formation (Fig. 7) (Dusseault, Bruno, and Barrera 2001).

The Valhall field has also seen significant challenges, but casing damage in the overburden and reservoir appears to be distributed across the entire field. Casing deformation on Valhall was first detected after only two years in production and after four years tubular deformation in the caprock was experienced. Casing deformation in the reservoir is in most cases a buckling deformation and compressive damage around the perforated sections (Fig. 7). To counteract the buckling issues on Valhall the operators has installed heavy wall casing in the reservoir sections(Dusseault, Bruno, and Barrera 2001).

In recent years P&A has started on Valhall and Ekofisk, and re-entry in the well to establish qualified barriers at sufficient depths has proven to be very difficult (Njå 2012, Petroleum Safety Authority 2017).

2.7d Other Fields Experiencing Compaction Induced Damage

Other hydrocarbon producing areas have experience subsidence similar to what has been observed in the Ekofisk and Valhall field and in the Matagorda Island Block 623 field in the Gulf of Mexico (GoM), SCP has been directly linked to subsidence induce well damage. Although, the reservoir properties and subsidence mechanisms may be different.

Wilmington Oil field

Long Beach is a town on the Californian cost. It is situated above the Wilmington Oil field that is the third largest oil field in the US in terms of cumulative production. Oil, gas and water production caused a pressure drop in the sandstone reservoir and the weight of the overburden compressed the reservoir. In some locations, a surface subsidence of up to 8.8m has been recorded. The subsidence in and around Long Beach has been arrested, but continuous monitoring and control by the Long Beach Gas and Oil Department will continue. Stable land surfaces are crucial for continued regional economic growth and cannot be jeopardized by the effects of oil and gas production(City of Long Beach Gas & Oil Department 2017).

As a result of the subsidence, 500 wells underwent severe casing damage (Fig. 8). This included compression damage in the production interval and shear damage within the production interval and overburden. Hundreds of casings were sheared during subsequent earthquakes and the damaged areas were located at the field shoulders, to the sides of the subsidence bowl where the subsidence contour gradients were steepest (Dusseault, Bruno, and Barrera 2001).

Fig. 8 - Long Beach Subsidence (City of Long Beach Gas & Oil Department 2017)

The Matagorda Island Block 623 Field

The Matagorda Island Block 623 Field situated in the GoM also experienced field subsidence and subsequent well damage. The failures included SCP and sand production. Casing damage was detected both in the reservoir and the overburden and the casing damage included collapsed or parted casing sections, thigh spots and casing offset. In total, all 17 development wells on the field experienced well failure or damage during the 16 years of production.

In the years 1986 to 2000 maximum subsidence was equal to 0.3 m and the reservoir compaction was 1.62m. The field development was divided into three phases of drilling. The wells drilled in the first phase typically failed after 10 to 13 years in production, and the wells exhibited SCP after a significant increase in sand production. The phase one wells were completed using a variety of techniques, but no one were completed as frac packs. Well or casing failures were not attributed to fault movement.

In phase two however, failures occurred after one to five years. Phase two wells used a frack pack completion and production rates were higher than in phase one. Phase two wells did not see a significant increase in sand production before SCP detection in all wells. Well damage and failures in phase two had a high correlation with major fault locations and to the predicted onset of fault reactivation after sufficient depletion/compaction (Doornhof et al. 2006).

The Belridge Field

The Belridge Field in California is a shallow field producing from mainly two shallow reservoirs, Tulare sand formation and the Diatomite formation. The diatomite is very compressible and is subject to plastic deformation/collapse under pressure depletion. Since 1983, more than 900 wells have been damaged and damage is mainly concentrated around the top the Diatomite and a shale bed above the Diatomite formation. Water injection has reduced the subsidence rate significantly and ultimately reducing well damage occurrence, but approximately 3% of the active wells are impaired per year. It is not known whether the wells exhibited SCP as a result of compaction induced damage (Dusseault, Bruno, and Barrera 2001).

The Groningen Gas Field

The Groningen Gas Field in the Netherlands is the largest natural gas field in Europe and the tenth largest in the world. It has seen a subsidence of approximately 0.3m and large seismic activities due to subsidence. In difference to Chalk fields mentioned in the previous section the Groningen gas field is a competent sandstone reservoir which means it does not collapse similar to the Ekofisk and Valhall fields. Still, the producing formation is between 100 to 200m thick and elastic deformation causes significant deformation. Extensive structural damage on the surface due to seismic activity has been observed and one can only assume significant well damage has occurred, but no public reports have been found describing well damage in the Groningen Field (Doornhof et al. 2006).

3. WELL INTEGRITY AND RISK

Well integrity is the application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of the well. Some of these technical and operational solutions will include well barrier elements, which if used correctly will form qualified well barriers. To help operators manage and categorize their well integrity issues the Norwegian Oil & Gas Association has developed a categorization system to identify the level of risk presented by individual oil wells. The categorization will be explained in the following sections with emphasis on how sustained casing pressure (SCP) will effect well categorization and why many wells are to operate whilst exhibiting SCP.

3.1 RISK CONCEPT

Risk is in the industry commonly defined as the product of probability of an event occurring and the consequence this event might have. Risk analysis is a major part of planning and performing operations and is critical to maintain the risk level "as low as reasonably practical" (ALARP). A risk analysis is a structured use of available information to identify hazards and to describe risk (NORSOK Z-013 2010). A qualitative risk assessment should include the key steps:

1. Identify the system/operation and potentially hazardous events.
2. Assess how often the potentially hazardous events can occur (probability).
3. Evaluate the consequences of the identified hazardous events.
4. Estimate/Summarize the risk as a product of probability and consequence of the identified event.
5. Establish whether the risk is acceptable relative to established acceptance criteria or if mitigation measures are needed.

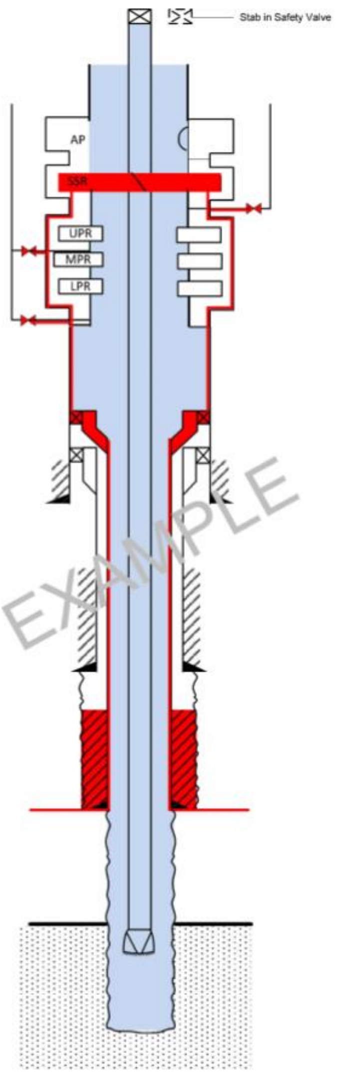

Fig. 9 - WBS drilling with shearable drill string (NORSOK D-010 2013)

The ALARP principle involves minimising all risks as far as practicable after having assessed foreseen failure modes, consequences and possible risk-reducing actions. ALARP shall be used both to minimise the probability for an undesired event and the consequences, should such an undesired event happen (DNVGL-RP-N101 2017)

3.1a Risk Matrixes

Risk matrixes is a simple tool using severity and consequence of accidents or hazardous events to assess the level of risk. Risk matrixes are typically used in early stages of a project to assess operations, procedures and scenarios (NORSOK Z-013 2010).

A generic risk matrix provided by DNV GL has been attached in Appendix 2 – Risk Matrix and will be used to semi-quantitatively evaluate the risk related to SCP, with the events uncovered from WOAD as basis. The consequence categories in a risk matrix are typically modified to suit a specific purpose or industry.

3.2 WELL BARRIER AND WELL BARRIER ELEMENTS

NORSOK D-010 (2013) has defined a well barrier as an envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation or to the external environment. A well barrier element (WBE) is a physical element, which does not necessarily prevent flow itself, but in combination with several well barrier elements could form a qualified well barrier.

The required level of redundancy is generally assessed with respect to the level of inherent risk in the operation, but two barriers are required when the source of inflow is a hydrocarbon bearing formation or an abnormally pressured formation with potential to flow to the surface. Using one well barrier is usually acceptable when operating in normally pressured formation with no hydrocarbons and no potential to flow to surface or in abnormally pressured hydrocarbon formations with no potential to flow to surface.

Although it is not always feasible, barriers should be sufficiently independent so that no single WBE failure will cause a loss of both well barriers. In situations where a WBE is shared by two barriers specific risk analysis should be performed and risk reducing measures applied to counteract the increased risk when using a common barrier (NORSOK D-010 2013).

If a barrier fails, the Norwegian Activities Regulations requires that no other activities shall be carried out in the well other than those intended to restore the barrier. However, SCP or annulus pressure can present without the loss of a barrier (green and yellow category section 3.3) and as a result, normal production/operation could formally proceed even when a well exhibits SCP. The well integrity categorisation presented in section 3.3 could be misleading as seemingly "healthy" wells could exhibit SCP. The term "Well barrier failure" is defined as the failure of a barrier or barrier element that has not resulted in a detectable leak to the environment.

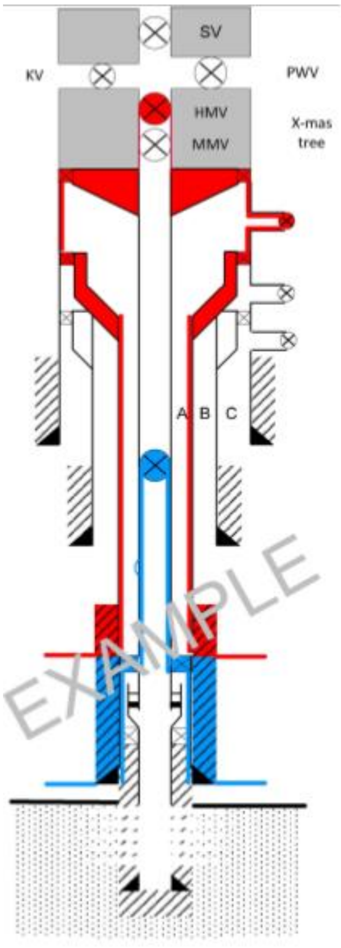

Fig. 10 - WBS platform production well (NORSOK D-010 2013).

3.2a Primary and Secondary Well Barriers

Drilling

The primary well barrier is the first set of barrier elements that prevent flow from a source. During drilling operations, this barrier is typically the fluid column providing hydrostatic overpressure in the wellbore. Management of the fluids specific gravity is very important to maintain the correct bottom hole pressure. The bottom hole pressure should be maintained above formation pore pressure, with sufficient safety margin during normal overbalanced drilling and below formation fracture pressure. Fig. 9 illustrates the primary barrier in blue and the secondary barrier in red.

The secondary well barrier during normal drilling operations is typically formed by several WBEs such as: In-situ formation, casing cement, casing, high pressure riser and drilling BOP.

Production

During normal production, a well is allowed to flow, but two well barriers must still be in place and ready in the event of required activation during production shutdown or in a well control situation. The primary barriers are typically: In-situ formation, casing cement, casing, production packer, completion string, down hole safety valve.

The secondary barriers in a platform production well is typically: In-situ formation, casing cement (above production packer), production casing hanger and seal, wellhead, tubing hanger and surface tree (Fig. 10). Well Integrity Categorization illustrates the primary barrier in blue and the secondary barrier in red.

Other equipment such as downhole sub-surface safety valves, gas lift valves, packers, annular safety valves etc. could potentially function as barriers.

3.3 Well Integrity Categorization

Norwegian Oil and Gas Association recommended guidelines for Well Integrity has a system to categorize wells with respect to their well integrity status and risk level. This system is widely used on the NCS and will be referred to when discussing wells and well status. The different categories are colour coded (Green, Yellow, Orange and Red) and an overview of the categories are presented in Fig. 11.

The categorization system is based on the two-barrier principle outlined in NORSOK D-010(2013) and should reflect the current well status and condition of the well. It is important to note that “Green” and “Yellow” wells can exhibit SCP.

The SCP issue is complex with regards to well integrity and can cause both high and low risk in a well. The Norwegian Oil and Gas Association recommended guidelines for Well Integrity No.:117 (2008) use the following criteria when categorising wells with SCP:

A well with SCP can fall within the Green category if:

- There are no leaks through both established primary and secondary barriers.
- No hydrocarbons in the annuli (unless intentionally placed there).
- Annuli pressures are less than defined pressure limits, and the leak rate into the annuli is within acceptance criteria.

A well with SCP can fall within the Yellow category if:

- There are no leaks through both established primary and secondary barriers.
- Annuli pressures are maintained below the defined pressure limits in a controlled manner, and the leak rate into the annuli are within acceptance criteria. Unintentional hydrocarbons can be present in the annuli.

A well with SCP can fall within the Orange category if:

- Annuli pressures are above defined pressure limits and the leak rate into the annuli is outside acceptance criteria.

A well with SCP can fall within the Red category if:

- Annuli pressures are above the defined pressure limits and the leak rate into annuli is outside acceptance criteria.

Category	Principle
Red	One barrier failure and the other is degraded/not verified, or leak to surface
Orange	One barrier failure and the other is intact, or a single failure may lead to leak to surface
Yellow	One barrier degraded, the other is intact
Green	Healthy well - no or minor issue

Fig. 11 - Well integrity categorization (Recommended guidelines for Well Integrity no.:117 2008).

3.3a Well Integrity Status – NCS 2016

The Petroleum Safety Authority annuli issues a report (RNNP) analysing the risk level in the Norwegian oil and gas industry. The 2016 report included an overview of the well integrity status on the NCS using the categorization described in the previous section. Included in the statistics are 1943 wells operated by 13 different operators in 2016.

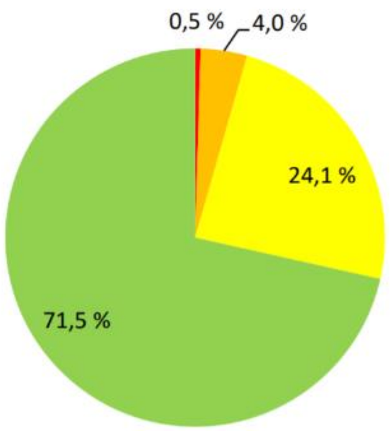

Fig. 12 - Well integrity status on NCS (Petroleum Safety Authority 2016a).

Fig. 12 shows that 28.5% of the wells included in the survey conducted by The Petroleum Safety Authority have degrees of integrity weaknesses. Wells in category red and orange have reduced well integrity according to the requirement of two barriers. There are registered nine wells (0.5%) in the red and 77 wells category (4%) in the orange category. There are injection and production wells that are included in red category, while the orange category also includes temporarily plugged wells under surveillance (Petroleum Safety Authority 2016a)

4. Annular Pressure Build-up

Annular pressure is commonly defined as fluid pressure in the annulus between tubing and casing or between two strings of casing. API RP 90(2016) categorizes these sources of annular pressure in three main groups; Operator imposed annulus pressure, thermally induced annulus pressure and sustained casing pressure (SCP). Imposed pressure is generally controlled by the operator (e.g. gas lift) and thermally induced pressure (expanding fluids during production startup/shutdown) will generally be addressed in the engineering phase. However, SCP is unpredictable and can develop over the lifespan of a well as a result of several factors such as tubing and casing leaks, poor primary cement (i.e., channel caused by flow after cementing) and damage to primary cement after setting (i.e., tensile crack due to temperature cycles, micro-annulus due to casing contraction). (Bourgoyne, Scott, and Manowski 2000).

Depending on the location, the regulatory requirements regarding annulus pressure vary considerably. Some countries have specific requirements for monitoring and reporting while others use functional requirements. For subsea wellheads, monitoring of B and C annuli has not previously been possible due to wellhead design, but in recent years, the industry has been driven to develop technology for B annulus monitoring in subsea wells.

4.1 Annulus Monitoring Requirements

In this section, the current annulus monitoring requirements governing on the Norwegian Continental Shelf (NCS) and US Outer Continental Shelf are presented.

4.1a Norwegian Offshore Continental Shelf

The Petroleum Safety Authority regulations relating to design and outfitting of facilities, section 54 state that:

> *"Christmas trees and wellheads shall be designed such that prudent well control can be performed through recovery, workover and well intervention.*
>
> *The christmas tree shall have at least two main valves, and at least one of them shall be automatic.*
>
> *In the case of hydrocarbon flow in the annulus, the closest outer annulus shall be pressure-monitored." (Petroleum Safety Authority 2015)*

The Guidelines regarding the facilities regulation section 54 in the facilities regulations state the following:

> *"To fulfil the requirements in the section, the standards NORSOK D-010 Chapters 7.7.2, 8 and 15, NORSOK U-001, ISO 10423 and ISO 13628 should be used, with the following additions:*
>
> *a) annulus should have pressure monitoring,…"(Petroleum Safety Authority 2015)*

The guideline is not legally binding, but should be used with the regulations for the best interpretations of the regulation. In essence, the majority off A annuli in oil and gas wells are monitored. For surface/platform wellheads annulus monitoring of all annuli is normal due to the easy access to most of the annular volumes. In contrast, direct access to B and C annuli in subsea wellheads is difficult. When utilizing gas lift, hydrocarbon flow is present in the annulus and monitoring is required. Since this requirement has become statutory new equipment for B annulus monitoring have been developed for subsea wells. NORSOK D-010 states that the pressure in all accessible annuli shall be monitored and maintained within minimum and maximum pressure range limits.

4.1b US Outer Continental Shelf

SCP has been a major issue in the Gulf of Mexico (GoM) with thousands of recorded wellbores with SCP and in recent years, the monitoring requirements and self-approval requirements have become reinforced. The US Code of Federal Regulations for Oil and Gas Wells – Completion activities have adopted the SCP management requirements in API RP 90 and this includes specific monitoring requirements. Code of Federal Regulations §250.518 requires that when the tree is installed, you must equip wells to monitor for casing pressure according to Table 1 (BSEE 2011).

IF YOU HAVE . . .	YOU MUST EQUIP . . .	SO YOU CAN MONITOR . . .
(1) FIXED PLATFORM WELLS,	THE WELLHEAD,	ALL ANNULI (A, B, C, D, ETC., ANNULI).
(2) SUBSEA WELLS,	THE TUBING HEAD,	THE PRODUCTION CASING ANNULUS (A ANNULUS).
(3) HYBRID * WELLS,	THE SURFACE WELLHEAD,	ALL ANNULI AT THE SURFACE (A AND B RISER ANNULI). IF THE PRODUCTION CASING BELOW THE MUDLINE AND THE PRODUCTION CASING RISER ABOVE THE MUDLINE ARE PRESSURE ISOLATED FROM EACH OTHER, PROVISIONS MUST BE MADE TO MONITOR THE PRODUCTION CASING BELOW THE MUDLINE FOR CASING PRESSURE.

Table 1 - Annulus monitoring requirements US Outer Continental Shelf (BSEE 2011).

4.2 MONITORING FREQUENCY REQUIREMENTS

To ensure sufficient response time and to capture variations and trends in annulus pressure a minimum monitoring frequency is necessary. In the GoM, the Code of Federal Regulations for Oil and Gas Wells state prescriptive requirements (Table 2) for monitoring frequency for different types of wells.

In comparison, the NCS has no requirements for the monitoring frequency. Nevertheless, continuous remote monitoring of all accessible annuli is considered best practice and recommended by Norwegian Oil and Gas Association Recommended Guidelines for Well Integrity no.: 117 (2008) and NORSOK D-010 (2013).

4.2a US Outer Continental Shelf

According to Code of Federal Regulations §250.520 you must monitor for casing pressure in your well according to Table 2 (BSEE 2011).

IF YOU HAVE . . .	YOU MUST MONITOR . . .	WITH A MINIMUM ONE PRESSURE DATA POINT RECORDED PER . . .
(A) FIXED PLATFORM WELLS,	MONTHLY,	MONTH FOR EACH CASING.
(B) SUBSEA WELLS,	CONTINUOUSLY,	DAY FOR THE PRODUCTION CASING.
© HYBRID WELLS,	CONTINUOUSLY,	DAY FOR EACH RISER AND/OR THE PRODUCTION CASING.
(D) WELLS OPERATING UNDER A CASING PRESSURE REQUEST ON A MANNED FIXED PLATFORM,	DAILY,	DAY FOR EACH CASING.
(E) WELLS OPERATING UNDER A CASING PRESSURE REQUEST ON AN UNMANNED FIXED PLATFORM,	WEEKLY,	WEEK FOR EACH CASING.

Table 2 - Monitoring frequency requirements US Outer Continental Shelf (BSEE 2011).

4.3 Government Notification Requirements

Two very different approaches with regards to reporting requirements of SCP are used on the NCS and US Outer Continental Shelf. On the US Outer Continental Shelf diagnostics and a notification is required upon detection of a "small" pressure increase. On the NCS, the operators will generally not notify the Petroleum Safety Authority when SCP is detected.

4.3a Norwegian Offshore Continental Shelf

The government regulations do not require SCP to be reported on the NCS. However, accidents and incidents shall be reported per the Petroleum Safety Authority Management regulations §29:

> *"Notification and reporting of hazard and accident situations to the supervisory authorities*
>
> *The operator shall ensure coordinated and immediate notification via telephone to the Petroleum Safety Authority Norway in the event of hazard and accident situations that have led to, or under slightly altered circumstances could have led to*
>
> *a) death,*
>
> *b) serious and acute injury,*
>
> *c) acute life-threatening illness,*
>
> *d) serious impairment or discontinuance of safety related functions or barriers, so that the integrity of the offshore or onshore facility is threatened,*
>
> *e) acute pollution.*
>
> *The notification shall be confirmed in writing.*
>
> *Acute pollution or the risk of acute pollution on or from onshore facilities shall also be reported in accordance with the Regulations of 9 July 1992 No. 1269 relating to notification of acute pollution, etc. (in Norwegian only).*

> *In the event of hazard and accident situations as mentioned in the first subsection, litera b through e, but of a less serious or less acute nature, the operator shall submit individual written notification to the Petroleum Safety Authority Norway on the first workday after the situation took place or was discovered."(Petroleum Safety Authority 2016c)*

SCP in general will in most cases not be placed in any of the categories above and hence SCP is seldom reported unless related to an incident or accident. Thus, the Petroleum Safety Authority does not have any records of the SCP occurrence on the NCS.

4.3b US Outer Continental Shelf

The regulations governing on the US Outer continental shelf requires diagnostics testing within 30 days if a pressure of 100psi is observed in the annulus.

The operator is required to act after a diagnostic test if per conditions specified in Code of Federal Regulations §25.525:

- If your casing pressure exceeds maximum allowable wellhead operating pressure (MAWOP).
- If your well has demonstrated internal communication.
- If SCP is bled down to prevent pressure exceeding MAWOP.
- If pressure is greater than 100 psig and cannot be bled to zero (platform wells).
- If your hybrid well riser or casing pressure exceeds 100 psig.
- If your subsea well casing pressure is 100psig above external hydrostatic pressure.

If your diagnostics test requires action, you shall within 14 days submit a notification of corrective action or a casing pressure request. (BSEE 2011)

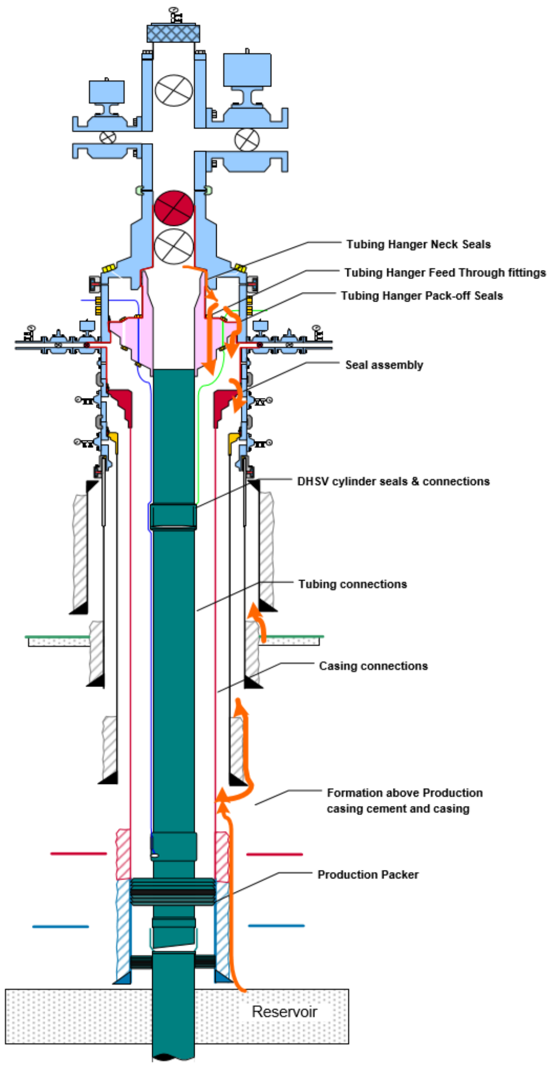

Fig. 13 - Possible leak paths (Recommended guidelines for Well Integrity no.:117 2008).

4.4 Thermal Pressure

Thermally induced annular pressure is caused by trapped fluid which is heated during production startup, changes in production volume, injection or well testing. If a casing string is conservatively cemented resulting in a trapped annular volume between two casing strings, the wellhead and cement a pressure increase could occur as the fluids may not be able to expand freely. After being bled down this pressure should not rebuild unless the temperature conditions in the well are changed. Thermal induced pressure build up should be addressed during well/casing design by ensuring pressure can be bled down at wellhead or that the pressure will bleed of to the exposed formation. Formation strength should be addressed in this situation to ensure fracture pressure is less than the maximum allowable annular surface pressure (MAASP). Rupture discs may also be used to prevent collapse or burst in critical components. (API RP 90-2 2016, Dahle 2014)

4.5 IMPOSED PRESSURE

Imposed annular pressure includes all forms of pressure in the respective annular volume that is applied by the operator through several operations to serve an intentional purpose such as gas lift, injection and other operations. Operator imposed pressure is not expected to rebuild after pressure has been bled off and the imposed pressure should be maintained between the maximum and minimum operating pressures (API RP 90-2 2016).

4.6 SUSTAINED CASING PRESSURE

The SCP cause can often be difficult to determine, but is mainly thought to be a result of flow from a formation with direct communication to an annulus, or where a barrier failure has opened a flow path to the annulus from a formation or other annular volume or production tubing. The typical causes are tubing, casing or mechanical equipment leaks, poor primary cement or damage to primary cement (Bourgoyne, Scott, and Manowski 2000).

The source of SCP can be any formation with pressure and the ability to flow. This includes hydrocarbons, water, shallow gas and shallow water bearing formations (API RP 90-2 2016). In Fig. 13 some possible leak paths are presented.

4.6a Relevant Indicative Studies

There have previously been performed at least two relevant studies involving a high number of wells experiencing SCP. They will serve as a reference point and indicator when evaluation SCP on the NCS and the main findings from both studies are presented in the following sections.

Study 1 - A Review of Sustained Casing Pressure Occurring on the Outer Continental Shelf

The study compiles information from Minerals Management Service and operators related to the occurrence of SCP on the US Outer Continental Shelf. The Minerals Management Service SCP database was made available to the Louisiana State University research team and SCP is seen in more than 11,000 casing strings in more than 8000 wells on the Outer Continental Shelf (Bourgoyne, Scott, and Manowski 2000).

Study 2 - Evaluation of the Potential for Gas and CO_2 Leakage along Wellbores

The study performed with The Alberta Energy Resources Conservation Board in Canada investigating the potential for gas and CO_2 leakage along wellbores in land wells. The study is an analysis of more than 315000 wells drilled up to the end of 2004 in the Alberta region. The study is performed on land-based wells and there are many similarities in land and offshore well design. Therefore, it is included and could be considered relevant for comparative purposes. Physical and chemical effects such as gas migration, cement degradation and corrosion are effects seen worldwide.

The relevant results from these studies are presented and could be considered indicative in relation to SCP challenges in other hydrocarbon producing areas such as the NCS. The findings from study 1 is most relevant in relation to the NCS, but technological and local regulative developments, operational advancements and remedial requirements may have reduced the occurrence rates of SCP in wells drilled after the study was performed.

4.6b Origins of Sustained Casing Pressure – Study 1

The study performed on the Outer Continental Shelf have shown that there are mainly three origins of sustained pressure. These are Tubing and casing leaks, poor primary cement and damage to primary cement (Bourgoyne, Scott, and Manowski 2000).

Tubing and casing leaks

Tubing and casing leaks is a common origin of SCPs in wells. Tubing and casing leaks can provide direct communication between a producing formation and the effected annulus and typical causes are corrosion, poor thread connections, thermal- stresses or mechanical rupture of the inner tubular. These leak flow paths are usually determined by changing the pressure in tubing or casing and observing the effects in the surrounding annuli. In production tubing, plugs and valves may be used to locate the depth of the leak. SCP between production casing and tubing is generally easier to diagnose and remediate than pressure on one of the outer casing strings as the production tubing can be accessed internally and potentially be removed. Paste experience has shown that tubing leaks have the greatest potential for causing significant problems. (Bourgoyne, Scott, and Manowski 2000). Fig. 14 shows gas venting from the Elgin G4 well (UK Continental Shelf), D annulus. It is suspected that multiple downhole leaks resulted in a high pressure gas zone above the packer venting through multiple casings to the surface(Total E&P UK Ltd 2013).

Poor primary cement

Poor primary cement can in many cases lead to annulus leaks or pressure build-up. As discussed in a previous section the inflow of gas and fluids during the cement hardening process can lead to channeling or contamination further reducing cement strength. During the solidification process, the cement is at some point no longer capable of maintaining hydrostatic pressure (as it is no longer at fluid slurry) and at the same time, the cement may not have achieved significant mechanical strength. This leaves the cement vulnerable to influx especially if the initial hydrostatic overpressure is low. Gas flow or water flow through setting cement is a major cause of SCP in the casing strings outside the production casing. Many factors during the primary cementing operation may affect the quality of the cement job, but in general, good cementing procedures should reduce cement contamination and reduce the leak risk. Poor annulus conditioning before cementing may also reduce the cement bonding ability, which could result in de bonding and formation of a micro annuli between the tubular and cement sheath or between the formation and cement sheath (Bourgoyne, Scott, and Manowski 2000) .

Damage to primary cement

Damage to primary cement may occur after the cement has set, during normal drilling operations or production. Even with a flawless primary cement job, damages can lead to leaks. Mechanical impacts to the casing during drilling, tripping and running casing can lead to de-bonding and due to the different elastic properties and thermal expansion properties of cement and steel, pressure and thermal effects typically seen during production or pressure testing may have the same effect. (Bourgoyne, Scott, and Manowski 2000)

4.6c Casing Strings Affected by SCP – Study 1

The same study investigating SCP on the Outer Continental Shelf (USA) concluded that approximately 50% of the wells (8122 wells) exhibited SCP in the production casing. Approximately 10% of the wells exhibited SCP in the intermediate casing strings, approximately 30% of the wells exhibited SCP in the surface casing string and approximately 10% of the well exhibited SCP in the conductor casing string (Bourgoyne, Scott, and Manowski 2000).

4.6d Magnitude of SCP by Casing String – Study 1

Approximately 80% of the production casings and intermediate casings on the Outer Continental Shelf that were included in the study exhibited a pressure less than 1000psi. For the other casing strings, approximately 90% exhibited less than 500 psi (Bourgoyne, Scott, and Manowski 2000).

4.6e Occurrence of SCP by Type of Well – Study 1

Most wells experiencing SCP on the US Outer Continental Shelf are shut in or temporarily abandoned wells. Approximately one third of the wells with recorded SCP are active and producing. Approximately equal numbers of oil and gas wells have casing strings with SCP (Bourgoyne, Scott, and Manowski 2000).

Fig. 14 - Surface wellhead D annulus leak, Elgin G4 well (Total E&P UK Ltd 2013)

4.6f Factors That May Increase Probability of Leakage – Study 2

The Study **Evaluation of the Potential for Gas and CO_2 Leakage along Wellbores** identified several factors that may increase the probability of gas leaks in wells. Bear in mind that these factors were identified in land wells and not all of them may have the same significance in offshore oil and gas wells (Watson and Bachu 2009).

Factors having major impact on occurrence of wellbore leaks (Watson and Bachu 2009):

- **Geographic area** had a major impact on occurrence of leaks, however it is not clear if the increased occurrence was a result of increased testing/reporting in the test area or an actual increase in occurrence. It is presumed that the ERCB increased the testing requirements in this area because of observed problems.

- **Wellbore deviation** was found to be a factor having a major impact on overall wellbore leakage This may be caused by mechanical aspects, such as casing centralization and cement slumping. Any well with a total depth greater than the true vertical depth was considered a deviated well. The impact of well deviation on the ratio of surface casing pressure to gas migration in the surrounding soil was minor.
- **Abandonment methods** predominantly used in Alberta in cased and completed wells are bridge plugs capped with cement. Based on the study and experience 10% of these bridge plugs will fail over a period of hundreds of years. Alternative methods, such as placing cement plugs across completed intervals using a balanced plug method, or setting a cement retainer and squeezing cement through perforations are expected to have lower failure rates.
- **Oil price, regulatory changes and testing** was plotted over time against the occurrence of leaks and gas migrations and positive correlations were found up until it diverges in the year 2000. Between 1973 and 1999 there was found a strong correlation between oil price and the occurrence of leaks and pressure build up and this could be linked to equipment availability and increased activity level.
- **Uncemented casing/hole Annulus** was found to be the most important indicator for well leakage. In addition, the low cement top or exposed casing has significant impact on external casing corrosion creating a potential for leaks through the casing wall. Detailed analysis of 142 wells indicated that; most significant corrosion occurs on the external casing wall; a significant portion of wellbore was uncemented; corrosion is most likely to occur in areas without or poor cement. It was determined that the top 200m of cemented annulus is generally of reduced quality and the clear majority of leaks originate from formations not isolated. In addition, the clear majority of casing failures occur in areas with reduced cement quality or no cement at all.

Factors having minor impact on occurrence of wellbore leaks (Watson and Bachu 2009):

- **Licensee** for the wells was expected to have some effect on leak development due to inequalities in the internal operating standards, but the effect of a company seemed to have a minor impact on the occurrence of wellbore leakage.
- **Surface casing depth** was not seen too have an overall impact on well leakage, but it was generally seen that when increasing the surface casing setting depth there was generally observed an increase in the occurrence of gas migration outside the casing and reduction in annular leakage. This can indicate that sources of leakage are found above the surface casing shoe and is dependent on surface casing cementing practice.
- **Total depth** would in generally result in a slight increase of leakage in the wells. This could be attributed to the fact that longer wells will generally have longer sections of uncemented wellbore.
- **Well density** was suspected to have a major impact on well leakage as well to well crossflow would result in several wells exhibiting leakage issues. Although, this was not the case for the wells in the test area. This was attributed to well age and better cementing or insufficient testing in the “dense” area.
- **Topography** was not found to have a strong correlation to well leakage, even though a reduced wellhead elevation could potentially represent a reduction in hydrostatic pressure and overburden formation.

Factors having no apparent Impact on occurrence of wellbore leaks (Watson and Bachu 2009):

- **Well age** was suspected to have a major impact on wellbore leakage. However, this was not the case. Many older wells may not have been reported, as they were plugged and abandoned before the mandatory leak testing requirements were statutory. It is unknown if age increases the likelihood of leaks due to lack of available data.

- **Well-operation mode** did not have an apparent impact on the occurrence of gas leaks after the wells were P&A. Yet small differences were noted in casing failures during operations, but these would have been repaired before P&A.
- **Completion Interval** or rather completion depth could not be correlated to the source of inflow depth. Good cement and zonal isolation was usually found deep in the wellbore.
- **H_2S and CO_2 presence** was investigated for a possible link to external or internal casing corrosion. No link was established, but this could be because of sour gas well requirements to protect the internal walls of the production casing with packers.

4.7 SUSTAINED CASING PRESSURE MANAGEMENT

If SCP is detected, the cause can be evaluated by reviewing well records, temperature and pressure trends and bleeding the pressure to monitor the subsequent build-up rate. SCP can be caused by a variety of parameters and is commonly regarded as a symptom of well integrity faults or well barrier failure. In time, SCP could lead to other well integrity issues. API-RP-90(2016) and Norwegian Oil and Gas Association Recommended Guidelines for Well Integrity No.:117 (2008) are significant resources for SCP management.

4.7a Annulus and Well Head Pressure Criteria

When evaluating SCP and annular pressure the strength of the relevant annulus must be considered. A major part of a well design is to establish the strength of the well considering pressure rating of all tubulars and elements in the well to ensure integrity is not lost during the drilling and production phase.

API RP 90 defines the Maximum Allowable Wellhead Operating Pressure (MAWOP) as a measure of how much pressure that can safely be applied to an annulus. This includes all three main forms of annulus pressure. MAWOP should be calculated for all annuli and should establish a safety margin when considering collapse of the inner tubular and burst of the outer tubular. When the Maximum Internal Yield pressure (MIYP) and Maximum Collapse Pressure (MCP) of all tubulars are established, safety factors represented as percent of MIYP and MCP are used to set the Maximum Allowable Wellhead operating pressure for each annulus (API RP 90-2 2016).

Norwegian Oil and Gas Recommended Guidelines for Well Integrity no. 117 (2008) however utilizes the term Maximum Allowable Annular Surface Pressure (MAASP) that is similar to MAWOP, but here the pressure where the risk of failure is as low as reasonably practical will determine the MASSP value. In difference from MAWOP, MAASP should also consider formation strength for exposed open hole section in the annulus.

A minimum annulus pressure and maximum operating pressure should also be defined to ensure a sufficient response time if pressure changes occur. Below the operating pressure limit, the operational risk should be within acceptable limits. The pressure limits should be based on the suspected pressure during normal operation and lowest limiting equipment pressure ratings.

4.7b Detection and Leak Source Evaluation

In section 4.1 the Annulus Monitoring Requirements were described. In addition, temperature and production rates should also be monitored to ensure a correct interpretation of the annulus pressure development over time. The annulus pressure should show clear dependency to the wellbore temperature mainly, but also adjacent annuli pressure and production flowrate during normal operation.

After production startup, a pressure increase is expected and if production is maintained the annulus pressure should stabilize at previously established levels unless bleed down or top ups have been performed. If thermal pressure and imposed pressure can be excluded one could suspect SCP if an assessment of pressure trends over a sufficiently long period has been performed. Operating well annuli with differential pressure may also facilitate detection of crossflow and annulus communication. In problematic areas where SCP is expected or regarded as a field, challenge increased testing and diagnostics could be appropriate. This could include; performing bleed downs and recording the subsequent pressure build up to establish trends and possibly leak rate; Fluids sampling to detect "foreign" fluids. The content may be used to determine the source formation; measurements of the liquid level and direct measurements of leak rate.

The evaluation of SCP should include an investigation of the leak nature, source, mechanism, location and the risk with respect to a loss of containment (Recommended guidelines for Well Integrity no.:117 2008).

4.7c Mitigation and Operation

Where SCP is a result of a barrier failure action is required, whether this means physical intervention or qualification of a "new" barrier envelope should be evaluated on a well-by-well basis per the ALARP principle. The Norwegian Activities regulations regarding drilling and well activities section 85 state:

"If a barrier fails, activities shall not be carried out in the well other than those intended to restore the barrier."(Petroleum Safety Authority 2016b)

Where a well barrier failure is not apparent, but a leak or pressure build up is detected outside the barrier envelopes other activates could potentially continue, but measures to reduce the probability and the consequence of failure should be initiated.

Technical solutions such as installation of additional valves related to SCP management and systems to facilitate early detection should be considered to reduce the risks related to SCP. Remote monitoring and automation creates opportunities such as automatic bleed down in the event of annulus pressures exceeding operational limits. Other risk reducing measures could include protection of the annuli from external damage or protection of equipment near the effected annuli to reduce the consequences in the event of a failure.

If SCP is suspected or confirmed, some operational aspects should be re-valuated. Formation strength in the effected annuli must be sufficient to limit crossflow and if annulus communication is confirmed, the lowest MAASP of the affected annuli must be applied. To maintain the annulus pressure within operating limits pressure bleed down may be required. Special considerations should be made to ensure the risk potential does not increase during or after such operations. Frequent testing and diagnostics is beneficial to monitor the development of the condition and in general, all plans for well operations should be revaluated with respect to the SCP.

Ideally, SCP should be eliminated after initially being detected, but the mechanism behind SCP could be complex and access is generally very limited. This makes it difficult to eliminate when first present and consequently the most effective way to reduce the risk of SCP is to address the issue during design and well construction. Especially when considering isolation of critical formations, environmental/operational loads and equipment service life. Increased oil recovery techniques and technology has in recent decades increased field life by many years. Equipment design life should be considered in relation to this trend increased service life.

Pumping operations are a common technique to mitigate or reduce SCP. In some wells the injectability is limited and initial bleeding is required to pumping of fluid, in other wells injection is acceptable.

Setting agents are commonly used to isolate the leak source, however considerations should be made as the leak is not necessarily stopped, but rather isolated from the wellhead. Heavy liquids are used to establish a hydrostatic overpressure in the effected annulus. If heavy liquids are used in the presence of permeable formations, fluid loss agents could aid in reducing fluid loss and extend the duration of the mitigating measure (Recommended guidelines for Well Integrity no.:117 2008).

4.7d Pressure Management in SUBSEA Wells

Subsea field development solutions have seen increased use in recent years through development of marginal and deep-water fields. As discussed previously in sections 2.5 and 4.1, annuli access is generally very limited in subsea wellheads. Nonetheless, the probability of developing SCP in a subsea well is comparative to that of a surface completed well, and measures to reduce the consequences must be consider as detection and bleed down is limited to the A annulus. It is not easily possible to remediate SCP pressures in subsea wells so measures to prevent overpressure are typically evaluated during design.

Several measures are in use and they include: Adjusting casing depth to allow leak off to the formation at the casing shoe; Installation of rupture discs in casing to reduce the probability of casing burst/collapse; Displacement of annular mud to brine or completion fluid to reduce the probability of barite plug formation and to maintain hydrostatic overbalance. During operations, continuous pressure and temperature monitoring is common practice and for early wellhead leak detection, the frequency of ROV inspections could be increased.

B annulus monitoring systems are required in gas lift wells, but could also be considered for “normal” wells. However, the threshold to initiate remediating measures in subsea wells exhibiting SCP in the outer annuli is significant and as such designing wells to avoid SCP occurrence is considered the best practice. (Dahle 2014, Recommended guidelines for Well Integrity no.:117 2008).

5. SCP ON THE NORWEGIAN CONTINENTAL SHELF

As of 2017 there has been drilled (drilling completed) 4478 development wells and 1646 exploration wells on the continental shelf. Of the development wells 3302 are production wells and the remaining are injection and observation wells. 1086 of the exploration wellbores are wildcats and the remaining 560 are appraisal wells.

These wells are primarily drilled in three areas with the majority in the North Sea and the remaining in the Norwegian Sea and Barents Sea. The full distribution of well types across the Norwegian Continental Shelf (NCS) is presented in Table 3 (Norwegian Petroleum Directorate 2017).

AREA		TYPE		PURPOSE	
NORTH SEA	5095	DEVELOPMENT	3913	INJECTION	586
				OBSERVATION	411
				PRODUCTION	2916
		EXPLORATION	1182	APPRAISAL	451
				WILDCAT	731
NORWEGIAN SEA	846	DEVELOPMENT	524	INJECTION	92
				OBSERVATION	72
				PRODUCTION	360
		EXPLORATION	322	APPRAISAL	81
				WILDCAT	241
BARENTS SEA	183	DEVELOPMENT	41	INJECTION	13
				OBSERVATION	2
				PRODUCTION	26
		EXPLORATION	142	APPRAISAL	28
				WILDCAT	114
Total					6124

Table 3 - Wellbore count NCS.

Currently there has been drilled approximately 1500 - 1600 subsea completed developments wells and approximately 3000 platform development wells. According to the Norwegian Petroleum Directorate, there are registered 1849 subsea and platform development wells that are online/operational as off 27.09.2017 (Norwegian Petroleum Directorate 2017).

5.1 DEVELOPMENT WELLS SAMPLED

The survey presented in Appendix 1 was issued to seventeen operators on the NCS. Five were willing to share their data, two could or would not share their data and the remaining did not respond. The response included 267 wells distributed over the North Sea and Norwegian Sea and the fields included are presented in Table 4.

The Petroleum Safety Authority has stated that they do not withhold any records or reports of sustained casing pressure (SCP) occurrence. However, some incidents/accidents related to SCP have been found in the World Offshore Accident Database (WOAD) and will be discussed.

Operators own licenses to explore and produce hydrocarbons for specific areas (blocks) of the NCS and not all the areas are represented in the reported data. The operators that have responded to the survey and operate several fields did not specify the distribution of operational wells on the individual fields, or in which wells/fields SCP is detected. Nonetheless, the reported causes and general field history can indicate where SCP is occurring.

FIELD	PRODUCTION START-UP YEAR	MAIN AREA	DEVELOPMENT TYPE	RESERVOIR	CONTENT
VALE	2002	NORTH SEA - CENTRAL	SUBSEA	SANDSTONE	GAS/CONDENSATE
GJØA	2010	NORTH SEA - NORTH	SUBSEA	SANDSTONE	GAS/OIL
OSELVAR	2012	NORTH SEA - SOUTH	SUBSEA	SANDSTONE	OIL/GAS
TRYM	2011	NORTH SEA - SOUTH	SUBSEA	SANDSTONE	GAS/CONDENSATE
VALHALL	1982	NORTH SEA - SOUTH	PLATFORM	CHALK	OIL
HOD	1990	NORTH SEA - SOUTH	PLATFORM	CHALK	OIL/GAS
KNARR	2015	NORTH SEA - NORTH	SUBSEA	SANDSTONE	OIL
GAUPE	2012	NORTH SEA - CENTRAL	SUBSEA	SANDSTONE	GAS/OIL
BØYLA	2015	NORTH SEA - CENTRAL	SUBSEA	SANDSTONE	OIL/GAS
VILJE	2008	NORTH SEA - CENTRAL	SUBSEA	SANDSTONE	OIL
VOLUND	2009	NORTH SEA - CENTRAL	SUBSEA	SANDSTONE	OIL
TAMBAR/ TAMBAR ØST	2001/2007	NORTH SEA - SOUTH	PLATFORM	SANDSTONE	OIL
IVAR AASEN	2016	NORTH SEA - NORTH	PLATFORM	SANDSTONE	OIL/GAS
ULA	1986	NORTH SEA - SOUTH	PLATFORM	SANDSTONE	OIL
SKARV	1998	NORWEGIAN SEA	SUBSEA	SANDSTONE	GAS/CONDENSATE
DRAUGEN	1993	NORWEGIAN SEA	PLATFORM	SANDSTONE	OIL
ORMEN LANGE	2007	NORWEGIAN SEA	SUBSEA	SANDSTONE	GAS

Table 4 - Fields included in dataset.

Subsea and platform development wells are included and the majority are active wells in operation today. It is also generally assumed that all wells have a minimum of four annuli (A, B, C and D). However not all annuli are accessible or monitored and many D annuli could be open to the environment. In that case, pressure build-up is not possible, but leaks and gas migration, could still occur.

5.1a Annuli Monitoring – Sampled Wells

For most of the included subsea wells only annulus pressure in the A annulus is known, but in four included subsea wells, A and B annulus is monitored. For the platform wells A, B and C annuli are mostly monitored. The D annulus can in many instances be open to the environment, or the surface wellhead design does not allow monitoring. In Subsea wells the D annulus between the conductor casing and surface casing will in most cases be either inaccessible or open to the environment. Fig. 15 shows the percentage of how many of the annuli are monitored relative to the total number of annuli per type.

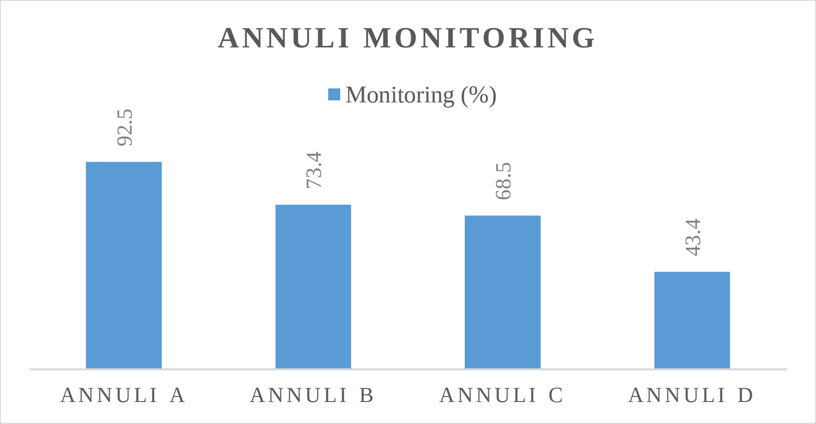

Fig. 15 - Annuli accessibility/monitoring (%)

Of the 267 wells in the dataset, 92.5% of the A annuli are accounted for hence monitored. Why 7.2% of the A annuli are not monitored or included is not specified by the operators. Approximately 70% of all B and C annuli are monitored. This could largely be because subsea wells are included in the sample. Less than half (43.4%) of the D annuli are monitored. This is mainly related to three factors: annulus is inaccessible, annulus is not monitored or annulus is open to environment.

5.2 Development Wells with SCP on the NCS

Of the 1068 annuli in the dataset, 11% exhibited SCP, 58% of the annuli were reported to be healthy and the status was not specified in 31% of the annuli (Fig. 16). The large numbers of annuli with unknown status is mainly due to wellhead/field development design and monitoring accessibility in subsea completed wells.

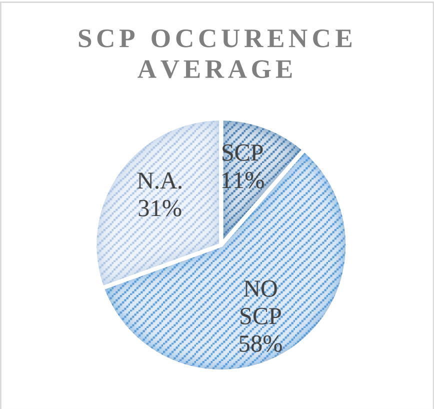

Fig. 16 - Status overview (all annuli).

5.2a SCP Occurrence

The number of annuli exhibiting SCP for each respective annulus is presented in Fig. 17. Annuli without SCP and unmonitored annuli are also included. In total 121 annuli have SCP and it is not known whether some wells exhibited SCP in more than one annulus. One hundred and twenty-one different wells could potentially exhibit SCP or several wells could exhibit SCP in one or more annuli.

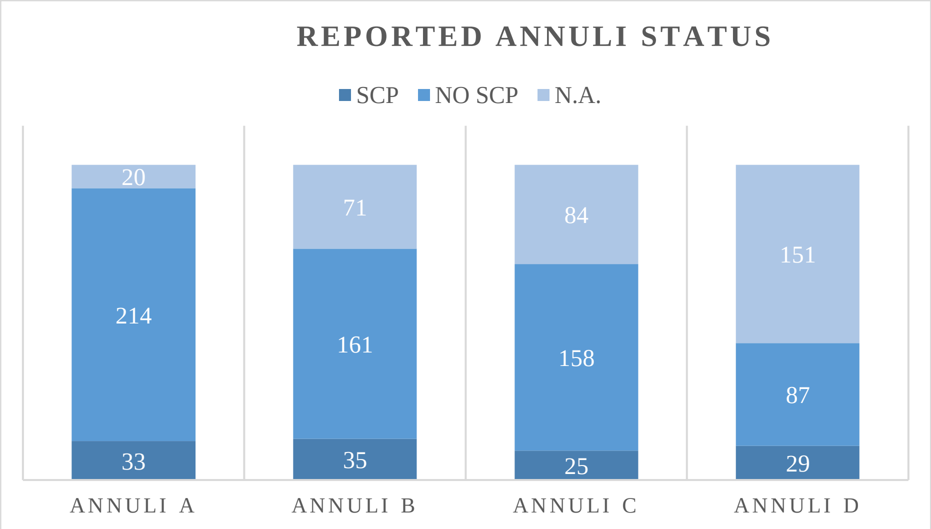

Fig. 17 - Complete dataset of all annuli.

Fig. 18 shows the percentage distribution of SCP, no SCP and Un-Specified for all annuli. The percentage of annuli with SCP is relative to the total number of respective annuli included in the data. This includes the undefined or non-monitored annuli which in practise presents a skewed view as the unspecified annuli either does or does not have SCP and hence the actual occurrence percentage in the wells with monitoring is greater.The A annuli have the best coverage with regards to monitoring and 12.4% of all the A annuli exhibit SCP (including unmonitored). Of all B and C annuli included, a similar 13.1% and 9.4% with SCP is observed. The D annulus has the lowest coverage with regards to monitoring. Less than 50% of the annuli are accounted for. Of all D annuli included 10.9% have SCP.

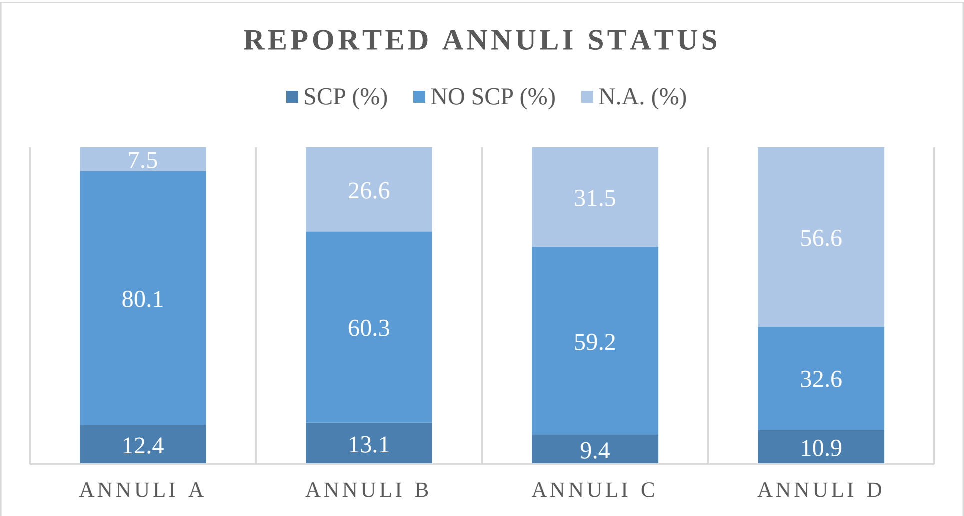

Fig. 18 - Annuli distribution (all annuli).

5.2b SCP Occurrence – Monitored Annuli

The number of annuli with SCP relative to the total number of monitored annuli could better represent the actual occurrence percentage for each respective annulus. Although, the sample size and geographical distribution of the samples should be considered if the wells are to be considered representable for the NCS. The average occurrence of SCP for all monitored annuli is 17% as seen in Fig. 19.

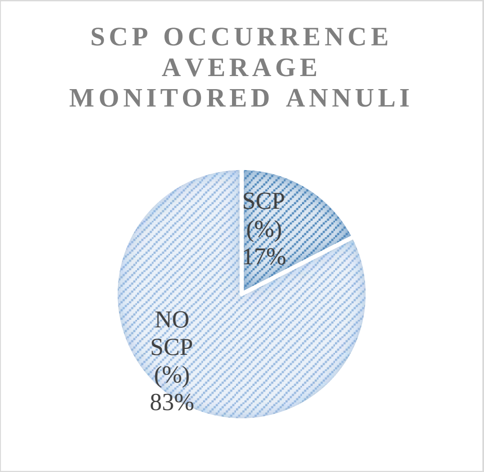

Fig. 19 - Overview (monitored annuli).

Fig. 20 shows the percentage distribution of annuli with SCP and without SCP relative to the number of monitored annuli, in the respective group (A, B, C and D). Thus, only the annuli with known annuli status are included in the statistics.

In general ther is observed an increased proportion percentage of SCP when the un monitored annuli are removed from the dataset. The A and C annuli show similar percentages of occurrence of SCP at approximately 13%. The monitored B annuli exhibited SCP in approximately 18% of the annuli. The monitored D annuli exhibited SCP in 25% of the annuli.

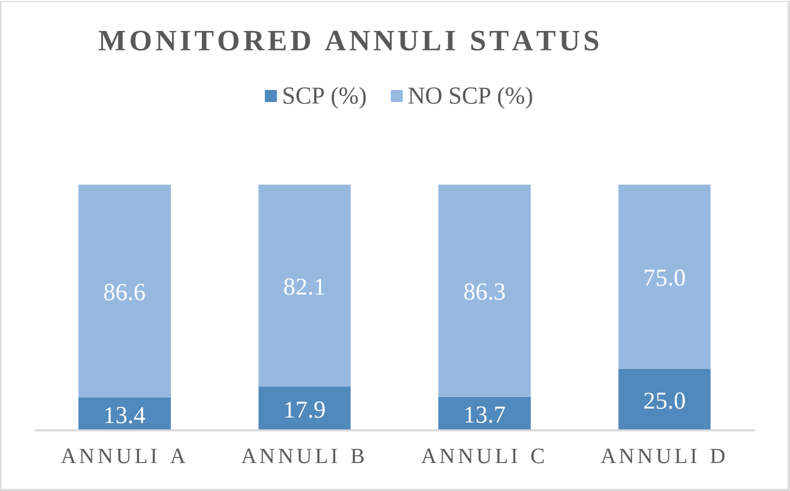

Fig. 20 - Monitored annuli distribution.

5.3 DATA SIGNIFICANCE AND BIAS

This study has sampled data from a fraction of the total number of active/operational wells on the NCS and it is important to evaluate if the data set is representable for the entire population. Significant biases may have been introduced, which could result in systematic errors that must be considered when determining whether the sample is a good representation of the entire population. The dataset is considered a non-random sample from the population of 1849 active/operational wells on the NCS.

In section 5.3 the systematic error, statistical sampling error and some analysis alternatives that could not be performed are discussed.

5.3a Systematic Error

The operators that have been contacted could control whether they wanted to respond to the survey and the result is a non-response bias. The traits that effect the study (occurrence of SCP) may also effect the operator's decision to participate in the study. This is considered a systematic error and could affect how representable the dataset is for the NCS.

The non-response bias in this context will greatly effect geographical distribution of the samples. This is important as different areas and fields of the NCS are extensively differentiated by field and reservoir properties, development age, production strategies and completion design. These properties can affect the occurrence of SCP.

Operators own licences to produce hydrocarbons from specific fields or geographical areas known as blocks, and because not all the fields are represented the sample proportion does not accurately represent the NCS. The systematic error can influence in both the positive and negative direction. It is not entirely clear if the dataset has a larger occurrence of SCP than the population.

5.3b Analysis of Variance

An Analysis of Variance (ANOVA) has been recommended to determine which parameters and well attributes that significantly affect the occurrence of SCP on the NCS. However, the data that is provided by the operators do not contain nearly enough well specific data to perform such an analysis in combination with public well data.

ANOVA can be used to systematically investigate the factors that influence SCP occurrence, thereby providing the engineers with information that can be used to improve well reliability. Assuming that many operators contributed with specific well information, the relative contribution of certain parameters and well attributes to SCP occurrence could be evaluated. The design of the experiment should be developed with the operators to ensure the appropriate factors are tested and sufficient data is available.

One approach is to evaluated time until failure (SCP detected in the well) in relation to the individual factors. Possible interaction between factors related to SCP can be found if the ANOVA experiment design is good. Stratification of the analysis could also be beneficial to identify local variations. Some factors may not be relevant in certain areas.

Some factors that could be relevant to evaluate include well age, HPHT reservoir, corrosive fluid content, reservoir properties (type, strength, reservoir depth and overburden formations), completion design, well deviation, shallow gas, overburden reservoirs and field subsidence.

5.3c Stratified Analysis

The fields on NCS experience varying degree of wellbore issues are due to large variations in the local geology. It is assumed that the occurrence of SCP is different in groups of the "population" (wells on the NCS). It could be beneficial to stratify the analysis to provide meaningful statistics. The mature fields in the Southern North Sea could potentially represent such a group due to the similar reservoir properties, water depth and development age. However, sufficient data to perform a "local" analysis is not available at this point.

5.3d Statistical Sampling Error

To investigate if a sample proportion of annuli with SCP is representative for a population of 1849 online/operational development wells on the NCS (Norwegian Petroleum Directorate 2017), the confidence intervals for the respective annuli have been determined with a 95% confidence level. This evaluation will quantify the pure statistical error introduced when sampling from a population.

A prerequisite for this statistical analysis is that the sample is a "simple random sample" and hence there must be an equal probability that any part of the population could be sampled. In essence, the calculation represents the margin of error in a random sample and not necessarily the dataset presented in section 5.2.

The confidence interval is an estimation of the error introduced during sampling from a population. A finite population correction factor has been included as the population size is "small" compared to the sample size. Eq. 1 estimates the confidence interval for the proportion using the finite population correction factor (Løvås 2010).

$$C.I. = p_s \pm Z\sqrt{\frac{p_s(1-p_s)}{n}}\sqrt{\frac{N-n}{N-1}} \quad (1)$$

Due to the lack of monitoring of D annuli (small sample size) there is observed a significant margin of error when sampling from the finite population. Approximately $\pm 8\%$ (Fig. 21).

For B and C annuli, the margin of error is approximately $\pm$ 5%. In addition, for A annuli the margin of error is $\pm$ 4% calculated with 95% confidence.

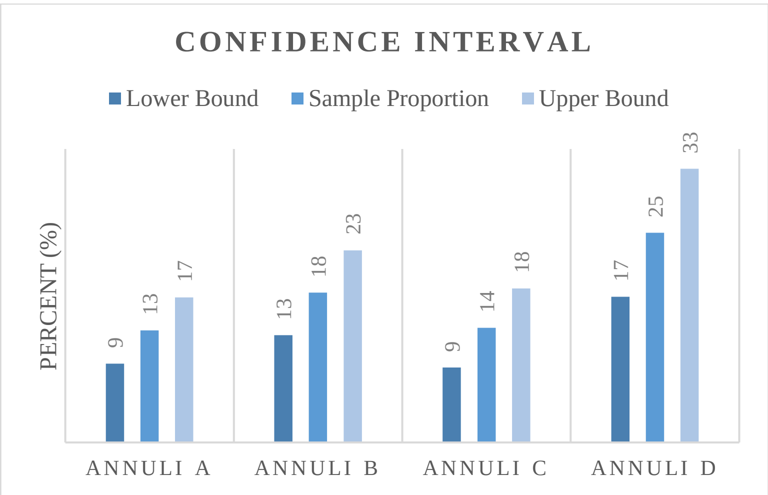

Fig. 21 - Statistical sampling error.

The error introduced when sampling from a population could potentially mean that as much as 603 "D" annuli (32.6%) or as few as 331 "D" annuli (17.4%) exhibit SCP. This error is calculated with 95% confidence assuming a simple random sample had a similar sample proportion as the dataset. This error does not include other systematic errors introduced during sampling and analysis.

5.4 Reported Causes of SCP on the Norwegian Continental Shelf

In general, leak cause detection in development wells is difficult. There are several hundred joints in the casing strings, downhole equipment and large uncertainties with regards to annular cement quality. Complex wells with reduced well integrity can further complicate source detection.

5.4a Overburden Issues

In the reported instances on the NCS, “overburden issues” was determined as the main cause of SCP. This is considered a combination of hydrocarbon zones and reduced zonal isolation or casing shoe cement (Operator 1 2017a). The hydrocarbon zones referred to have been, or should have been isolated, but through the lifespan of the wells the casing primary cement or casing shoe cement quality has been reduced and consequently the annuli is unintentionally exposed to pressure or formation fluids. Hydro carbon zones with flow potential can also significantly impair the quality of the primary cement job during cementing (Bourgoyne, Scott, and Manowski 2000). Several of the wells in the included dataset have several hydrocarbon bearing zones. SCP has been linked to subsidence induced well collapse and poor primary cement jobs (Operator 1 2017b).

Leaks in other well barrier elements such as the production packer/seal assembly have also been observed, but they are not the main cause in the reported wells (Operator 1 2017b).

5.4b Underlying Causes

Several factors could contribute to the degradation of annulus cement quality, reduced zonal isolation and well collapse. The factors described above are considered the main factors contributing to SCP development in the reported wells. SCP has been directly linked to compaction induced well damage as described in section 2.7d. (Dusseault, Bruno, and Barrera 2001) and the southern part of the North Sea, reservoir compaction and field subsidence is a significant issue for the operators on the Ekofisk and Valhall fields. Therefore, the cause of SCP in the southern North Sea is linked to compaction induced well damage. This compaction is due to the properties of the soft reservoirs, pressure depletion and water weakening effects in the chalk reservoir (Doornhof et al. 2006). Other mechanisms resulting in casing damage, reduced zonal isolation and reduced casing shoe cement could be present in fields with different characteristics. Shallow gas and overburden reservoirs can also directly influence the quality of the primary cement quality and since some of the reported wells are in areas with multiple hydro carbon zones with flow potential, it is reasonable to believe that this has effected the quality of the primary cement (Bourgoyne, Scott, and Manowski 2000).

5.5 ACCIDENTS AND INCIDENTS

In the offshore oil and gas industry, accidents and incidents are unfortunately unavoidable due to the inherent nature of risk. To learn and reduce risk in future operations an evaluation of previous accidents/incidents has proven useful. An accident is defined as an event that causes injury, illness and/or damage/loss to assets, environment or third parties and an incident is defined as event or chain of events, which could have caused injury, illness and/or damage/loss to assets, the environment or third parties.

Through the history of the offshore oil and gas industry, many of these events have been reported and recorded in databases. WOAD and the SINTEF Blowout Database are such databases and they provide valuable statistics and experience data when evaluating operations and risk. Failure rates of specific equipment in use are also recorded and one of these is the Exprosoft - Wellmaster RMS database.

Access has been granted WOAD and all events related to annulus pressure build up and SCP have been evaluated and categorized appropriately in this context. With regards to specific equipment failure and degradation, the Exprosoft - Wellmaster RMS database compiles reliability and failure statistics for downhole and subsea equipment, and it should provide important insight when evaluating leak paths and annulus communication in wells. However, there is insufficient data to correlate specific well equipment failure rates to SCP. The Sintef Blow Out Database is currently offline due to technical issues and no evaluation has been made possible.

All the relevant events were categorized according to Table 5. Main category two involves accidents or incidents related to, but not caused solely by annular pressure or SCP. These events typically occur during SCP management activities, well intervention, primary cementing or during P&A. Main category one involves annular pressure/SCP accident and incidents. With events that can be placed in several categories the initial failure/event will apply. Incidents where flow and migration through the annulus is not contained below the well head (e.g. surface casing to conductor casing annulus) are also included, as this incident would in many cases be regarded as SCP if enclosed by the wellhead.

MAIN CATEGORY 1	**ACCIDENT/INCIDENTS DIRECTLY RELATED TO ANNULAR PRESSURE/SCP**
SUB CATEGORY 1.1	TUBING/EQUIPMENT FAILURE RESULTING IN ANNULAR PRESSURE/SCP
SUB CATEGORY 1.2	PRIMARY CEMENTING FAILURE RESULTING IN ANNULAR PRESSURE/SCP

MAIN CATEGORY 2	**OTHER RELATED ACCIDENTS/INCIDENTS**
SUB CATEGORY 2.1	BLEED DOWN ACCIDENT/FIRE/INCIDENT
SUB CATEGORY 2.2	OTHER EQUIPMENT FAILURE OR LOSS OF WELL CONTROL
SUB CATEGORY 2.3	P&A
SUB CATEGORY 2.4	PRIMARY CEMENT JOB FAILURE RESULTING IN ANNULAR PRESSURE OR BLOWOUT
SUB CATEGORY 2.5	SHALLOW GAS RESULTING IN AP/BLOWOUT/ANNULAR FLOW

Table 5 - Incident/Accident categorization.

5.5a World Offshore Accident Database

WOAD is a comprehensive database with information from more than 6000 offshore incidents and accident. The database dates back to 1970 and has since 1975 been curated by DNV GL. The database provides accident description, causes, location, social and economic impacts, etc. that are valuable for their risk management initiatives. The database is updated continuously and is the most extensive of its kind. The database contains several incidents and accident caused by or directly related to annular pressure and SCP and several incidents/accidents related to primary cementing job and equipment failures. As these events are accidents/incidents, several equipment failures could have occurred in a series of events. All the relevant events in WOAD (DNV GL 1970) have been describes in sections 5.5b, 5.5c and 5.5d.

5.5b Accident/Incidents directly related to annular pressure and SCP

From Table 6 it is observed that the majority of events involving SCP and annulus pressure that resulted in an accident or incident were initially caused by tubing leaks or initial failures causing pressure build-up in the production casing. In events were the known initial failure is the primary cement, the failure occurs predominantly in the intermediate or outer casing strings (conductor casing and surface casing). It is important to note the severity of the accidents and incidents. All the reported incidents/accidents on the NCS caused minor damage and no injuries or fatalities.

EVENT	CAT.	INITIAL FAILURE	SECONDARY FAILURES	TERTIARY FAILURES	CONSEQUENCE	DAMAGE	LOCATION
1	1.1	PRODUCTION TUBING LEAK	PRODUCTION CASING 9 5/8”	SURFACE CASING SHOE 16”	BLOWOUT (HC)	SEVERE	GoM
2	1.1	(NOT SPECIFIED)	PRODUCTION CASING	INTERMEDIATE CASING	UNDERGROUND BLOWOUT (HC)	SEVERE	GoM
3	1.2	PRIMARY CEMENT LEAK 30-20” ANNULUS	WELLHEAD LEAK		ANNULUS PRESSURE. SMALL GAS LEAK	INSIGNIFICANT	NCS
4	1.2	PRIMARY CEMENT LEAK 13 3/8” CASING			ANNULUS PRESSURE	INSIGNIFICANT	NCS
5	1.1	PRODUCTION TUBING LEAK 5 ½”			ANNULUS PRESSURE	INSIGNIFICANT	NCS
6	1.1	PRODUCTION TUBING LEAK			ANNULUS PRESSURE	INSIGNIFICANT	NCS
7	1.1	PRODUCTION CASING LEAK 9 5/8”			ANNULUS PRESSURE	INSIGNIFICANT	NCS
8	1.1	PRODUCTION TUBING LEAK			ANNULUS PRESSURE	INSIGNIFICANT	NSC
9	1.1	PRODUCTION TUBING LEAK			ANNULUS PRESSURE	INSIGNIFICANT	NCS

10	1.1	PRODUCTION TUBING LEAK (NON-CHROME CONNECTION CORROSION)	CORROSION AND LEAK PRODUCTION CASING 9 5/8”	CORROSION AND LEAK PRODUCTION CASING 13 3/8”	BLOWOUT (HC) 13 3/8”-20” ANNULUS (OPEN)	MINOR	NED
11	1.2	PRIMARY CEMENT LEAK (CONDUCTOR CASING)			BLOWOUT: GAS VENTING TO SURFACE BETWEEN THE CONDUCTOR AND DRIVE PIPE.	INSIGNIFICANT	GoM
12	1.2	LEAK IN PRODUCTION CASING PLUG	LEAK IN 7” PRODUCTION CASING. HOLE IN 10 ¾” CASING	10 ¾”- 16” ANNULUS LEAK	BLOWOUT (MUD, CEMENT AND GAS)	MINOR	GoM

Table 6 - World Offshore Accident Database SCP events.

Elgin G4 Well Accident

Since the accidents on the NCS are not very severe, a serious accident from the British North Sea is briefly described to illustrate the risk potential. The Elgin Field operated by Total is a HPHT gas and condensate field between Norway and England. In 2012, a blowout occurred during a kill operation and the well released over 6000 tons of gas and condensate to the environment over the next 52 days (Fig. 14). No personnel were injured, but there was a serious risk of fire /explosion that could have caused many fatalities had the circumstances been different.

The G4 well initially developed SCP in 2004 and A annulus pressure was managed by bleeding down the pressure regularly. It was suspected that a failure in the production casing (and primary cement) caused the SCP. The source was the high-pressure Hod formation. At some point, the pressure build-up rate increased significantly resulting in an increased frequency of bleed down operations. Total were concerned that the increased bleed down frequency could cause further issues and hence bleeding was stopped in order to allow the pressure to build and stabilise in the annulus.

On the 25th of February 2012 the production casing and intermediate casing failed resulting in SCP in the A, B and C annuli. At this point, the surface casing was the single remaining barrier and operations to repair the well were initiated, but not in time. On the 25th of March the surface casing failed resulting in the blowout through the D annulus and surface wellhead. (Bradley 2017, Total E&P UK Ltd 2013).

5.5c Primary Cement Failures – During/after Cementing

Seven incidents related to failure of primary cement during or immediately after cementing operations, were uncovered from the WOAD archive. All the incidents resulted in a blowout and five events resulted in hydrocarbon release. No personnel injuries were reported and the incidents primarily occurred in the US Gulf of Mexico (GoM). Event 18 resulted in significant damage to the drilling barge the crew was evacuated. During event 19 the surface casing burst below the wellhead. The pressure recorded was below the burst rating of the surface casing, but the investigation showed extensive wear inside the surface casing causing the casing to fail below the burst rating. The incidents are primarily caused by bad cement jobs and/or shallow reservoirs.

In relation to SCP, these events are a clear indication that the quality of the primary cement jobs in the surface and intermediate casing can be significantly compromised in the presence of shallow reservoirs. Significant contamination of the primary cement could occur without any surface indication. This inherent weakness of the cement could potentially be and origin of SCP as discussed in section 4.6b. Gas flow or water flow through setting cement is a major cause of SCP in the casing strings outside the production casing (Bourgoyne, Scott, and Manowski 2000).

EVENT	CAT.	OPERATION	INITIAL FAILURE	CAUSE	CONSEQUENCE	DAMAGE	LOCATION
13	2,4	DEVELOPMENT DRILLING	PRIMARY CEMENT JOB	GAS MIGRATION THROUGH CEMENT. WAITING FOR CEMENT TO SET.	BLOWOUT DUE TO LEAKING WEARPLUG	INSIGNIFICANT	GOM
14	2.4/2.5	DEVELOPMENT DRILLING	PRIMARY CEMENT JOB (SURFACE CASING)	FAILURE OF SURFACE CASING CEMENT JOB (2HOURS AFTER SET CASING)	BLOWOUT/ UNDERGROUND BLOWOUT	INSIGNIFICANT	GOM
15	2,4	DEVELOPMENT DRILLING	PRIMARY CEMENT JOB (SURFACE CASING 13 3/8”)	FAILURE OF SURFACE CASING CEMENT JOB (SHORTLY AFTER CEMENTING)	BLOWOUT	INSIGNIFICANT	GOM
16	2,4	DEVELOPMENT DRILLING/SLOT RECOVERY	PRIMARY CEMENT JOB (SURFACE CASING)	FAILURE OF SURFACE CASING CEMENT JOB (3.5 HOURS AFTER SET CASING)	BLOWOUT	INSIGNIFICANT	GOM
17	2,4	DRILLING	PRIMARY CEMENT JOB (13 3/8 INTERMEDIATE CASING)	FAILURE OF CASING CEMENT JOB 13 3/8”	WELL PROBLEM, NO BLOWOUT	INSIGNIFICANT	NCS
18	2,4	EXPLORATION DRILLING	PRIMARY CEMENT JOB (13 3/8 INTERMEDIATE CASING)	FAILURE OF CASING CEMENT JOB 13 3/8”	BLOWOUT	SIGNIFICANT	GOM
19	2.4 (2.2)	DEVELOPMENT DRILLING	BURST SURFACE CASING AFTER CEMENTING INTERMEDIATE CASING	PRESSURE MIGRATION FROM SHALLOW RESERVOIR	UNDERGROUND BLOWOUT	INSIGNIFICANT	GOM

Table 7 - World Offshore Accident Database cementing job failures.

5.5d Accident/Incidents Related to SCP Management and Intervention

Incidents and accidents that occur during SCP management activities and well intervention/workover could present increased risk to personnel involved as indicated from Table 8. However, the number of incidents are not sufficient to determine a significant probability, but it gives an indication that the presence of SCP presents an operational risk. Four of the events occurred during casing pressure bleed down and the remaining two events during well workover/intervention with SCP.

EVENT	CAT.	OPERATION	INITIAL FAILURE	CONSEQUENCE	INJURIES/ FATALITY’S	DAMAGE	LOCATION
20	2.2	WELL INTERVENTION	FAILED MASTER VALVE. DOWNHOLE LEAK.	BLOWOUT AND FIRE		SEVERE	GOM
21	2.2 (1.1)	WELL WORKOVER	TUBING DAMAGE AND SCP.	BLOWOUT/ LOSS OF WELL CONTROL	2 INJURIES AND 1 FATALITY.	SIGNIFICANT	GOM

22	2.1	CASING PRESSURE DIAGNOSTIC TEST/BLEEDING DOWN CASING FLUID	STATIC ELECTRICITY IGNITED CONDENSATE IN BLEED DRUM.	FIRE		INSIGNIFICANT	GOM
23	2.1	CASING PRESSURE BLOW DOWN	TUBING EXTENSION ON THE BLOWDOWN VALVE ASSEMBLY ROTATED RAPIDLY	FATALE EQUIPMENT MALFUNCTION.	1 FATALITY	INSIGNIFICANT	GOM
24	2.1	WELL WORKOVER/BLEEDING ANNULUS PRESSURE	FLAMMABLE LIQUIDS TRAPPED IN BLEED LINE WAS FORCED OUT TO SEA CAUSING A SMALL FIRE.	SMALL FIRE ON WATER		INSIGNIFICANT	NCS
25	2.2 (2.3)	BLEED DOWN (PAnA)	FAILURE OF A GREASE FITTING ON PRODUCTION CASING VALVE DUE TO CORROSION.	.HC LEAK		INSIGNIFICANT	GOM

Table 8 - World Offshore Accident Database accidents/incidents related to SCP management and intervention.

5.6 Summary of Accidents/Incidents and Related Risk

The number of reported accidents/incidents related to SCP Management or Intervention (Table 8) or primary cement job failures (Table 7) on the NCS is considered low and there was only reported insignificant damage and no injurie or fatalities. When comparing these incidents to the GoM events there is in general reported more accidents/incidents related to SCP Management and Intervention and primary cement job failures than there is in the US GoM. This could be attributed to the larger number of drilled wells in the GoM or/and an actual increased frequency. The number of reported events directly related to SCP (Section 5.5b) on the NCS is greater than the GoM, but again the severities of these events are not as significant compared to the GoM. In the GoM there are established regulatory requirements to report wells with SCP and it would be unlikely that SCP would be reported as an incident/accident alone, unless linked to other severe events.

5.6a Category 1.1 and 1.2

Twelve incident/accident events involving SCP were caused by either downhole tubing/equipment leaks, failure of primary cement or a combination (Cat 1.1 and 1.2). Three of which resulted in surface blowouts and one which resulted in surface and underground blowout. Zero fatalities or injuries were recorded. Six events had recorded hydrocarbon release. Depending on where the leak occurs in the well these events are typical barrier failures.

5.6b Category 2.1 and 2.2

Six incident/accidents related to SCP management and intervention were found (Cat 2.1 and 2.2). These were events occurring during well intervention, workover and annulus bleed/blow down operations with annuls pressure present. This resulted in one blowout, two firers and one combined blowout/fire. Two fatalities and two injuries were recorded. Five events had recorded hydrocarbon release.

5.6c Category 2.4 and 2.5

Seven Incidents/accidents related to failure of primary cement during or immediately after cementing operations were recorded (Cat. 2.4 and 2.5). Four events caused blowouts and two events caused combined blowout and underground blowouts. Five events had recorded hydrocarbon release.

5.6d Risk Evaluation

Using the events from WOAD a superficial evaluation of the risk related to SCP can be performed using the risk matrix attached in Appendix A. The consequence categories "people", "environment" and "Delay/Downtime" will be considered.

There have been recorded seven events in category 1.1 and 1.2, and one event in category 2.1 on the NCS. It is conservatively assumed that not all events are reported and hence the likelihood is equivalent to a moderate level ("Has been experienced by most Operators") for all the consequence categories.

There have not been recorded any injuries to personnel ("No or superficial injuries") or hydrocarbon release ("slight effect on environment < 1bbl") and hence the severity is low for both categories. The product of likelihood and severity is equal to a medium risk level. If we consider "Delay/Downtime", the severity might be higher as fixing downhole leaks could be a substantial job. Still a medium risk level is observed

However this generic evaluation is no substitute for a thorough case by case risk evaluation should your well exhibit SCP. If there are significant numbers of incidents/accidents related to SCP that are not reported or recorded it is assumed their severity is low. This would result in the same level of risk as if they had been reported/recorded. The reported events from the GoM are on the other hand significantly more sever involving fatalities, injuries and well release.

6. WELL ABANDONMENT

There are mainly three abandonment categories: Suspension, temporary abandonment and permanent abandonment. To ensure well integrity stringent requirements have been developed to prevent well release or blowouts after abandonment with an eternal design perspective. Permanent well abandonment will be the main focus area of this chapter. The full regulations regarding suspension or temporary abandonment will not be cited. The Petroleum Safety Authority Facilities Regulation regarding barriers section 48 state the following:

> *"Well barriers shall be designed such that well integrity is ensured and the barrier functions are safeguarded during the well's lifetime.*
>
> *...*
>
> *The well barriers shall be designed such that their performance can be verified."(Petroleum Safety Authority 2015)*

This includes wells that are in the permanent abandonment phase. The Activities regulation for Drilling and Well Activities section 88 state:

> *"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."(Petroleum Safety Authority 2016b)*

In essence, the Petroleum Safety Authority utilizes functional requirements, but it provides reference to and recommends NORSOK D-010 in order fulfil the requirements. NORSOK D-010 (2013) requires that all sources of inflow shall be identified and documented. The primary barrier shall isolate the inflow source. The secondary barrier should also isolate the source of inflow (back up) and cross flow barriers should prevent flow between reservoirs where this is considered unacceptable. This is typically reservoir zones in different pressure regimes. Overburden formation including shallow sources of inflow shall be assessed with regards to abandonment requirements.

Overburden formations are typically a source of inflow resulting in sustained casing pressure (SCP) and if they go undetected during well construction, production and P&A operation, pressure build up may occur after the well has been abandoned. Previous versions of NORSOK D-010 have not focused strongly on overburden zones and hence there could be many plugged and abandoned wells being unknowingly pressurized. For permanently abandoned wells, the internal pressure below the surface plug is unknown. As such, the integrity failure will only be detected when leaks are large enough to be detected at the surface.

During well abandonment, the presence of trapped gas or hydrocarbons associated with SCP may increase the risk during key operations performed during P&A operation. On surface wellheads, this pressure is typically bled down before the operation, but with subsea wellheads this is not possible for B and C annuli and most operators will typically perforate the casing close to the wellhead to relieve the pressure. The gas bubble that is trapped may still be released through the riser even though the overpressure is relieved. To reduce the risk of uncontrolled flow from the annuli in into the well/riser during cutting, perforating and pulling casing activated pressure control equipment shall be in place. This typically involves closing the annular preventer in the BOP stack and relieving any released annular gas through the choke line and manifold.

Recent experience during the Ekofisk 2/4 A P&A campaign is a testament to the fact that adhering to NORSOK D-010 is not always possible or reasonably practical in old and degraded wells. Significant well damage from fault slipping (shear) and compaction has reduced the ability to place qualified barriers at the required depth and the result is an alternative solution. However, a proper risk assessment must be made before alternative solutions are used (Petroleum Safety Authority 2017).

6.1 PRESCRIPTIVE PRACTICE OF D-010

NORSOK D-010 is considered to be a performance based standard with functional requirements:

"This NORSOK standard focuses on well integrity by defining the minimum functional and performance requirements and guidelines for well design, planning and execution of well activities and operations." (NORSOK D-010 2013)

Nevertheless, operators and engineers generally use the current version in a prescriptive manner during P&A design. The minimum specified cement plug height; position and external barrier height is used without well specific analysis, which is arguably contradictory to their initial defined scope.

The use of "one" design solution for all wells is potentially very inefficient. It is only logical that a HTHP well would present a greater risk compared to a well in a depleted reservoir or hydrocarbon formations with a limited flow potential. Consequently, the design should be tailored to meet the individual requirement based on actual risk for the respective well. This would be closer to a performance based methodology and could potentially be more cost effective.

Due to the high numbers of wells that require plugging and the high associated cost, the Petroleum Safety Authority and industry is working to develop efficient and safer P&A technology, but our knowledge of risk should also be developed to optimize the load cases used in the performance based, specific well design. In the subsequent sections the different abandonment categories are presented and two case studies are reviewed to highlight differences in older P&A designs in relation to SCP and zonal isolation.

6.2 SUSPENSION

Suspension of a well is regarded as a well status that applies to wells under construction or intervention. When a well is suspended, further operation in the well is "suspended" and well control equipment is left in place on the wellhead until the operation is resumed.

6.3 TEMPORARY WELL ABANDONMENT

Temporary well abandonment is where a well is plugged and abandoned with the intent of re-entering the well later. On the NCS Requirements for isolation of formations, fluids and pressures for temporary and permanent abandonment are the same. However, the choice of WBEs may vary with respect to abandonment duration and well access. Casing and surface equipment are not cut and removed from the well as re-entry is required to permanently plug the well.

If the abandoned well is monitored (primary and secondary well barriers) and routinely tested, there is no maximum abandonment period. Wells that are not monitored and routinely tested may be abandoned for three years. Wells that are temporary abandoned without monitoring should be visually inspected regularly, at least once a year. (NORSOK D-010 2013)

6.4 Permanent Well Abandonment

If a well or wellbore is to be permanently plugged and abandoned, it will be plugged and abandoned with the intention of never being used or re-entered again. In Fig. 22 the barriers in a permanently abandoned well is presented as an example. The well is perforated and production tubing is removed before P&A.

The primary barrier (Blue) is composed of a cement plug set in the reservoir (extending above), casing/liner, cement and in-situ formation.

The Secondary well barrier (Red) is composed of cement plug, casing, casing cement and in-situ formation.

The Surface Barrier (Green) is composed of cement plug, casing and casing cement.

The **external well barriers** (e.g. casing cement) shall be verified to ensure vertical and horizontal integrity and the minimum cement height shall be minimum 50m with sufficient formation integrity at the base of the interval. A reduced external barrier height (30m) can be qualified if sufficient bonding is verified by logging.

If sustained pressure is observed in the well, the sealing properties of the casing cement shall be re-verified.

The **internal well barriers** (e.g. cement plug) shall be positioned over the interval of verified external well barrier and if set on a foundation (mechanical/cement plug) shall be minimum 50m long otherwise 100m. For open hole sections the cement plug shall be 100m, with 50m above any source of inflow. If plug transitions from open hole to cased hole, plug should extends 50m above casing shoe. The **surface plug** shall be 50m if set on a foundation (mechanical plug) otherwise 100m is required when set in surface casing below the surface (NORSOK D-010 2013).

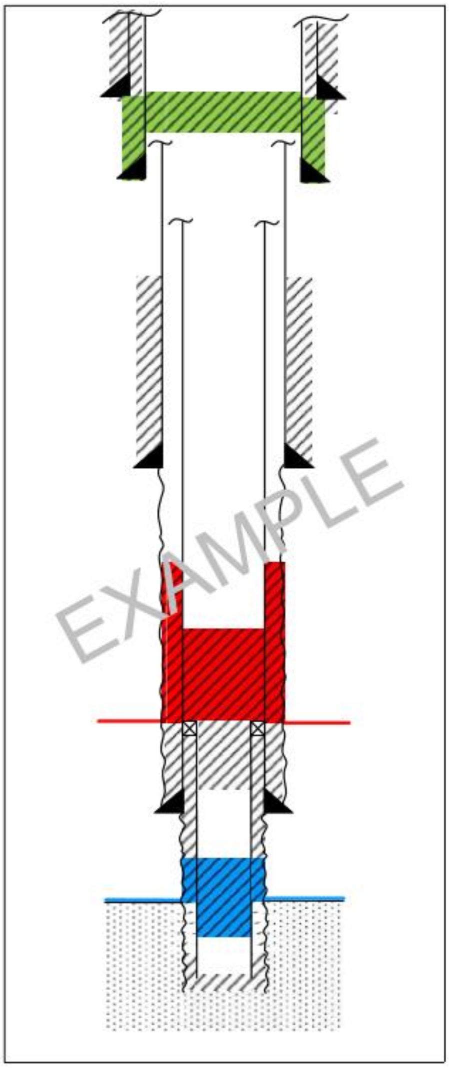

Fig. 22 - Permanent abandonment of perforated well - From NORSOK D-010 (2013).

After the surface plug is set, the wellhead and surface equipment is removed. This is usually done with abrasive cutting equipment, but explosives may be used in some cases. The lifting and removal usually requires a drilling rig with heavy hoisting equipment.

6.4a P&A Operation Overview

P&A operations are complex and contain many sub operations such as tubing retrieval, plug cementing, squeeze cementing, cutting and milling. Well design and integrity will determine the P&A scope. Old wells that have been shut inn for long periods of time with reduced barrier integrity could further complicate the operations. A brief overview of the main operations for performing P&A in a subsea production well is presented below:

1. Mobilization of vessel and subsea equipment needed.
2. Kill and secure the well.
3. Removal of production tree and installation of BOP stack.

4. Retrieval of production tubing.
5. Plug cementing (Primary and secondary barrier).
6. Cutting and retrieval of production and intermediate casing top section.
7. Plug cementing (Surface barrier)
8. Cutting and retrieval of surface casing and conductor casing top section and wellhead.

In some wells, the external barriers are not qualified and further intervention is required. This typically includes milling operations or perforation, washing and cementing techniques to establish qualified internal and external barriers. Older wells are commonly plugged with different designs compared to wells plugged in recent years.

6.5 Case Study – P&A With Gas Migration

This incident was briefly described in the introduction of this thesis and will be discussed further. The key point in this case study is the fact that the well was plugged per plan even when gas migration into the annulus was observed.

The case study superficially reviews how the P&A design in well 34/7-22 compares to current design standards and it is discussed whether the well to has a significant risk of leakage. The first edition of NORSOK D-010 was implemented five years later after the well was plugged.

6.5a Incident

During plugging and abandonment of the exploration well 34/7-22 in the North Sea in 1993, trapped gas in the 13 3/8” – 18 5/8” annulus was released into the riser when pulling 13 3/8” casing and seal assembly. Gas entered the riser an evacuated some mud onto the drill floor. (SAGA Petroleum 1994).

6.5b Source

It is believed that gas from a zone just below the 18 5/8” casing had migrated into the annulus and a small gas bubble had formed under the casing hanger (Fig. 23). Noe sign of abnormal pressure was detected during drilling of the 13 3/8” section but some shallow gas was detectable in the mud (SAGA Petroleum 1994).

6.5c Consequence

The incident did not escalate to an accident, but the risk of hydrocarbon ignition and further well issues would have been present.

6.5d Current Operating Procedure

Today active pressure control equipment, typically an annular preventer would be activated to prevent uncontrolled flow from annuli between casings and into the well or riser during cutting or perforating the casing or during retrieval of seal assemblies.

Key operational personnel employed in Saga Petroleum at the time of the incident have commented that if this incident had occurred during the operation today the zone would most likely have been isolated (i.e. cemented) before completing the P&A operation. Or the event would never have occurred as the formation potential would have been detected during drilling and isolated through primary cementing (Drilling Manager DEA 2017) .

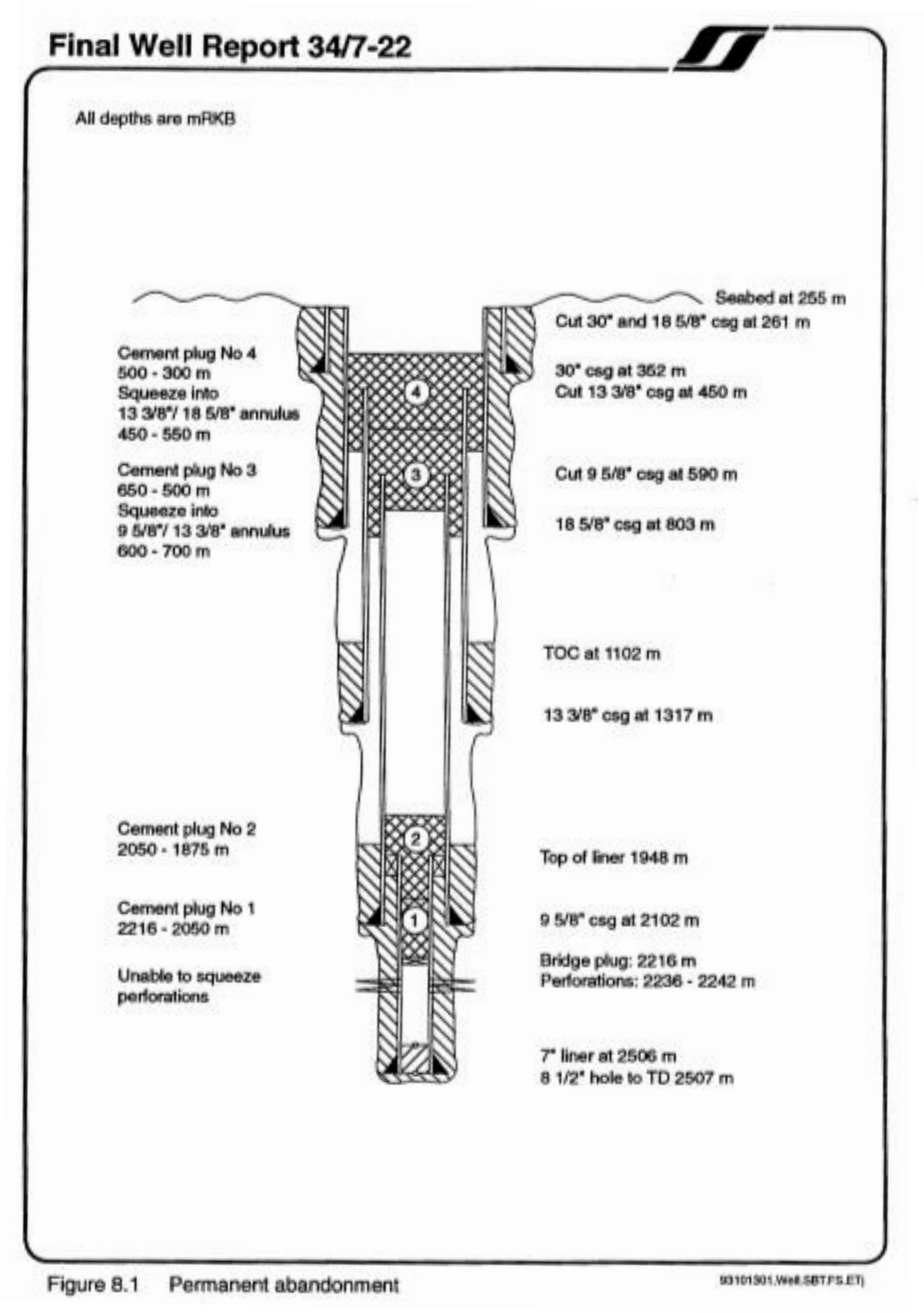

Fig. 23 - 34/7-22 P&A schematic (SAGA Petroleum 1994).

6.5e Qualified Well Barriers

They key question remains whether this 24-year-old design presents a leakage risk after plugging and abandonment compared to current standards for establishing primary and secondary barriers.

An examination of the cement heights of Plug four (Fig. 24), shows that there is 250 m of vertical cement (100m annulus cement and 150m plug cement) between the potential hydrocarbon formation and the surface. By today's standards, the top section of Plug four could potentially be considered a qualified primary and secondary barrier (50m+50m on foundation) towards the detected source of gas migration. To be fully qualified as an external well barrier the surface casing primary cement presence and quality must be confirmed.

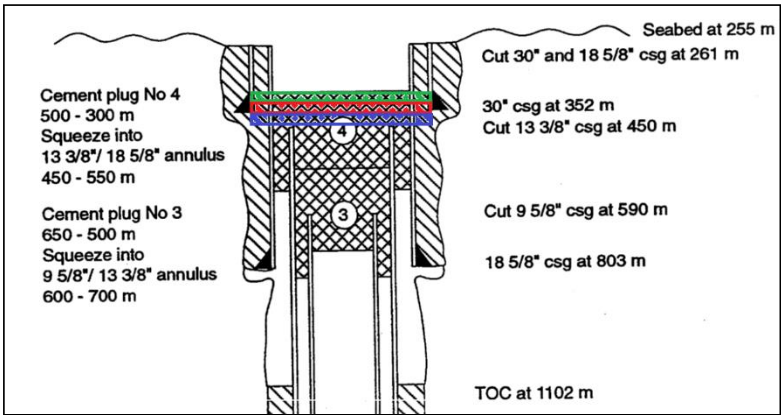

Fig. 24 - 34/7-22 Possible Barriers (SAGA Petroleum 1994)

The remaining 50m of cement could also be considered qualified as a surface plug. The pore pressure where the suspected gas migration originated is also less than the formation integrity strength at the surface casing shoe and plug four. In addition there is 100m of squeeze cement in the annulus below the proposed barriers.

6.5f Evaluation

The probability of leakage from 34/7-22 could potentially be comparable with a recently plugged well. The potential of gas migration and build-up is present because the zone was not isolated from the annulus.

An important note is the effective hours used specifically on P&A activities. For this well 89 hours was used on P&A (SAGA Petroleum 1994). As this is a "simple" exploration well, the P&A duration may not be comparable to a complicated production well, but the time spent performing P&A is very important in relation to the cost of the project. The time spent on P&A for one well was 20-60 days in 2013 (Straume 2013), but since then a reduction of approximately 30% in average time spent on P&A has been reported.

6.6 Case Study – Haltenbanken P&A and Zonal Isolation

The object of this case study is to show some key difference in well design regarding zonal isolation and shed light on why many older production wells could be exhibiting SCP due to overburden issues.

The two formations in question are the Lysing and Lange Formation in the Cromer Knoll Group. These formations have been identified as "challenges" concerning annulus pressure in the upcoming Dvalin field development and if these zones are not isolated the risk of SCP is identified as significant(Dahle 2014). The formations require full isolation to fully adhere to NORSOK D-010 (2013) P&A requirements.

Well 6507/7-1 was selected because it is located close to the Dvalin field and penetrates the same overburden formations regarded as "challenging" by today's standards. The Dvalin field has not been developed, but the planned P&A design is presented below (DEA Norge AS 2016, Conoco Norway inc. 1984).

6.6a Well 6507/7-1

The exploration well (Fig. 25) was completed and plugged in 1984 drilling a major fault block with the hope of testing oil bearing middle Jurassic Sandstone at approximately 3898m. The Lysing formation was encountered and at 2926m TVD and Lange Formation at 3000 TVD.

The abandonment profile indicates that top of cement (TOC) in the production casing annulus (9 5/8" casing) is at 3048m, just below the lysing formation and top Lange formation. Hence, these formations are exposed or partly exposed in the open hole casing annulus. The formation testing indicated the presence of Methane and Ethan at 2716-2904m from rotary kelly bushing (RKB). From 2904-3000m Propane was also detected. From 3000-3352m Propane content increased.

During the P&A operation the 9 5/8" casing was perforated and squeeze cemented at the 13 3/8" casing shoe with 100 sacks of cement and later cut/pulled (Conoco Norway inc. 1984). This would approximately equal to 110m of cement in the annulus between 13 3/8" and 9 5/8" casing.

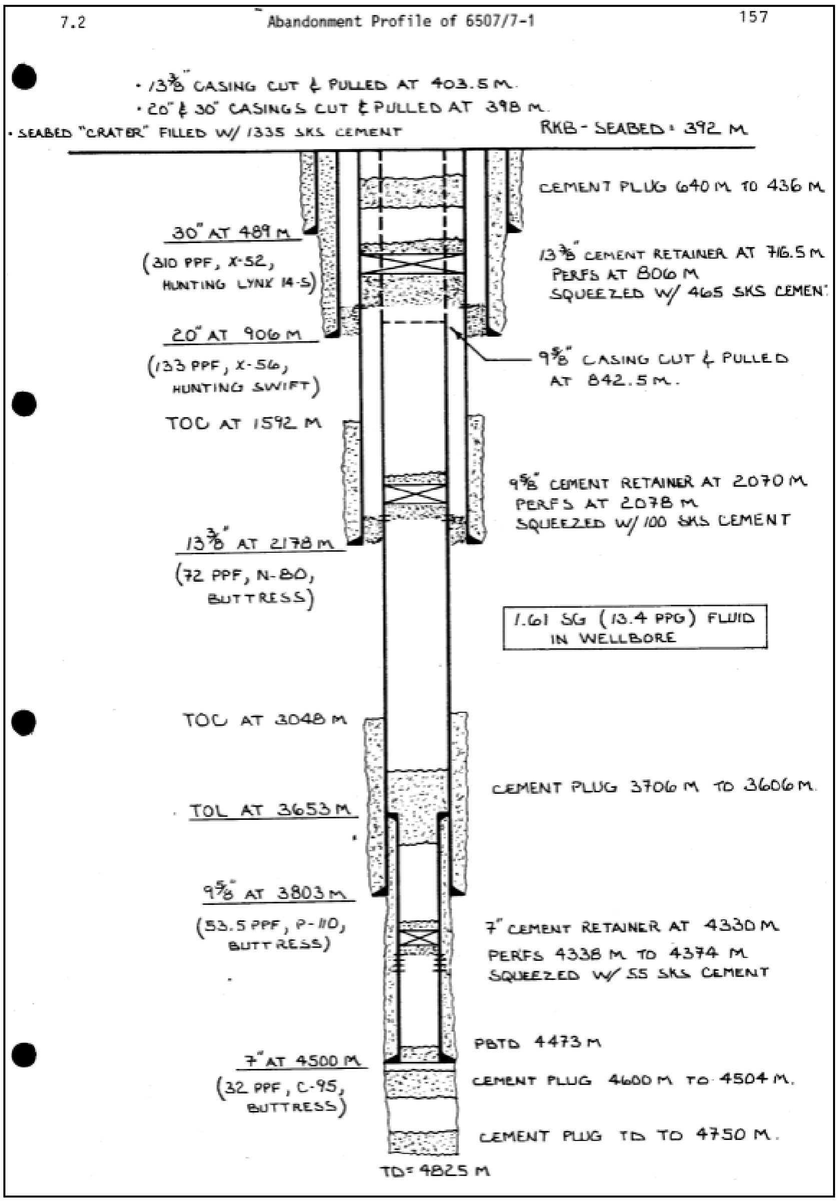

Fig. 25 - Abandonment design (Conoco Norway inc. 1984).

6.6b Dvalin Field Development

The Dvalin Field is a gas field in the Norwegian Sea on the Haltenbank. The field is due for development soon with a subsea production system tied back to a nearby field. The operator responsible for the development has identified two formations that requires isolation in addition to the main reservoir.

The casing design and primary cement isolates both Lysing and Lange formations initially during well construction and is designed with P&A in mind (Fig. 26). The two well barrier schematics show the primary and secondary barriers isolating both the critical overburden formations according to NORSOK D-010 (2013). Annular cement is of sufficient height and will be qualified as external barriers with CBL. The internal barriers are qualified through pressure testing and tagging. (DEA Norge AS 2016)

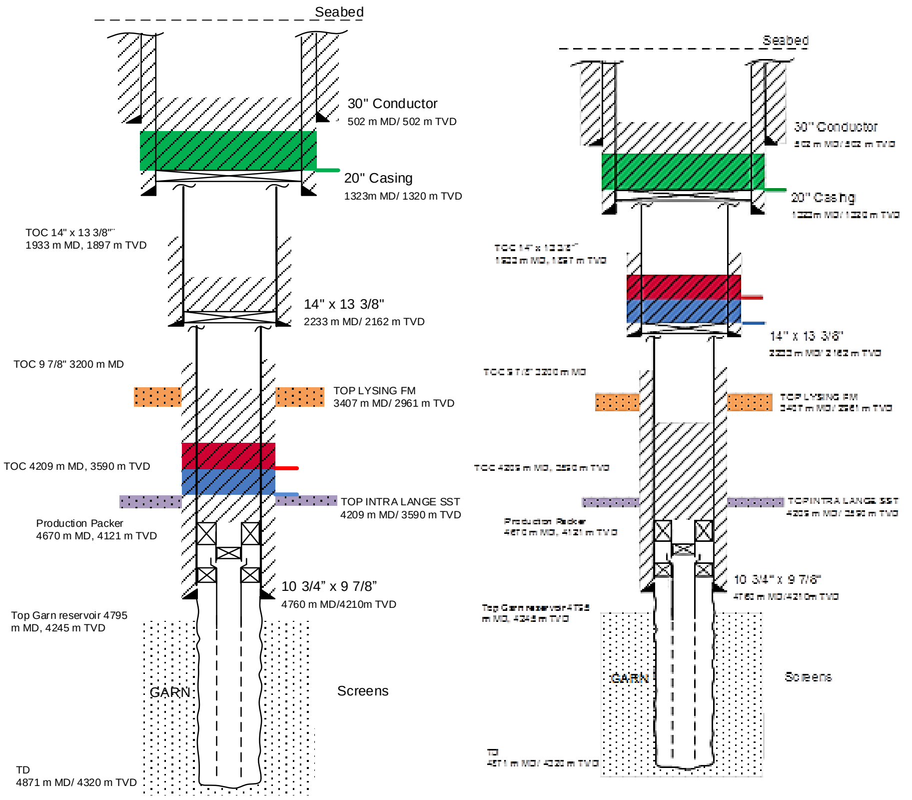

Fig. 26 - Dvalin P&A – Lysing/Lange formations(DEA Norge AS 2016).

6.6c Evaluation

Some key difference in P&A design can be observed. In the Dvalin design, annular top of cement in the production casing will be placed 200m above the top of the Lysing formation (if present), and gas tight cement will be used.(DEA Norge AS 2016) This cement isolates the formations from each other, prevents inflow and protects the external casing surface from corrosion. 6507/7-01 does not have complete annular cement across the critical formations increasing the probability of inflow.

In the Dvalin P&A design, primary and secondary barrier cement plugs are set close to the source of inflow with qualified external well barrier elements. The Dvalin surface plugs (≥50m) are set in surface casing with sufficient external well barrier length. 6507/7-01 has a 200m long surface plug placed in the intermediated casing without external annular cement(DEA Norge AS 2016).

The 6507/7-01 well intermediate casing is perforated and squeeze cemented above the surface casing shoe below the internal plug. In principle, 6507/7-01 has dual barriers between the Lysing/Lange formations and the surface, but not to other formations or between the two. Cement bonding, displacement and quality of these barriers are unknown and they do not comply with cross-sectional sealing requirements of NORSOK D-010(2013).

Whether 6507/7-01 presents increased leakage risk is very dependent on the quality of cement plugs, squeeze cement place during P&A and casing corrosion. Assume that the squeeze cement in well

6507/7-1 is of poor quality, there could be gas migrate through the squeezed annuls cement to the cement plug in the 13 3/8" casing if sufficient flow potential is present.

The 13 3/8" casing is also penetrated and squeeze cemented and as such, there is further potential for leakage through the perforations to the annulus between 20" casing and 13 3/8" casing. Crossflow would also be possible if the formations over Lysing and Lange are permeable and hold lower pore pressure. The question whether 6507/7-01 leaks internally or to the environment will most likely never be answered.

6.6d Zonal Isolation

Well integrity in older abandoned wells presents great uncertainty and there are in total 1182 wells P&A before NORSOK Rev 3 was implemented (Samad 2017). Many wells are also recorded in the Norwegian Petroleum Director Factpages as "plugged" and this involves a total of 1243 wells plugged before NOSOK Rev 3 (Samad 2017). NORSOK D-010 was initially implemented in 1997 and revision 3 that specified stricter requirements for zonal isolation was issued in 2004. Consequently there is a possibility that 2425 wells do not fully isolate critical zones similar to the case studies in section 6.5 and 6.6.

An argument supporting the integrity of older plugged wells is the practice in which they we abandoned. The first regulation regarding drilling and exploration on the NCS (Royal decree of 25th August 1967) is purely performance based, requiring that:

"*the operation shall be performed with a good oilfield practice, with top cement plugs in such a number, of such length and such spacing between the individual plugs. In addition, the compartment between the cement plugs shall be filled with drilling fluid that has the density that can withstand the pressure that may develop in the well*" (Samad 2017).

Ultimately a well plugged in 1970, could have been conservatively plugged when compared to the requirements described in section 6.4 even though critical zones were not isolated.

NORSOK D-010 (2013) requires zonal isolation and barriers as described in section 6.4 and the probability of gas migration or leaks is supposedly reduced to a risk level considered ALARP if the barriers are correctly constructed. Many older plugged wells may not fulfil the current zonal isolation requirements. Nevertheless, the field case study in section 7.5 indicated a P&A design before NORSOK implementation could potentially represent a similar level of leakage risk just considering cement plug heights, but this is very individual and might vary greatly as indicated by the field case study in section 6.6. At the time of P&A, the respective formation or zone may not have been considered a risk or their flow potential or hydrocarbon content were never detected. It is important to note that reduced zonal isolations is in many wells linked to SCP.

7. DISCUSSION

7.1 SCP ON THE NORWEGIAN CONTINENTAL SHELF

7.1a SCP Cause, Occurrence and Annulus Distribution

As stated in section 5.4, Overburden issues has been reported as the main cause of sustained casing pressure (SCP) in the wells on the Norwegian Continental Shelf (NCS) represented in the dataset. The described problems encountered correspond well with observations from the Gulf of Mexico (GoM) and it is confirmed through evaluation of World Offshore Accident Database (WOAD) incidents and accidents. Bourgoyne, Scott, and Manowski (2000) stated that the primary causes are tubing/casing leaks, poor primary cement and damage to primary cement.

Poor primary cement jobs is a cause that has been linked to SCP in the reported wells. As described in section 2.2 there are several aspects of primary cement jobs that can jeopardize the cement quality. A factor that can influence the quality significantly is the inflow of gas or fluids that form channels in the cement (Bourgoyne, Scott, and Manowski 2000). In extreme cases this could lead to blowouts or loss of well control as seen from the WOAD incidents in section 5.5c. The fundamental issue here is that if channels are formed they are a permanent flaw in the cement sheets that is difficult to detect and remediate. An interesting observation from the dataset is the fact that 25% of the monitored D annuli exhibited SCP. The D annulus is typically between the conductor and surface casing which is normally cemented to the mudline. This is contradictory to the high rate in which D annuli exhibit SCP as it is logical that a fully cemented annulus provides a good seal. The Surface casing penetrates the overburden formations which can contain shallow hydrocarbon zones and an example of this is the Valhall field where up to nine distinguishable permeable zones including the main reservoir have been identified (Njå 2012). Shallow gas could be considered a factor that increases the probability of SCP occurrence.

If areas with shallow gas or shallow hydrocarbon formations were mapped against wells with SCP in the outer annuli this possible correlation could be quantitatively investigated. Locally an analysis of the fluid content to determine the source could further strengthen the argument and applying logging techniques to the surface casing cement could identify areas of reduced quality that could result in SCP. Using this knowledge and developing cementing techniques to avoid it is no easy task, but the knowledge that there is an increased risk of SCP in certain areas could promote better planning, procedures, well design and risk assessment.

Damage to primary cement has also been observed on the NCS, but in difference to observations from the GoM (Bourgoyne, Scott, and Manowski 2000) compaction and shearing is a significant problem encountered in several fields on the NCS and a number of wells in the dataset represent this group. Reservoir compaction and shearing has caused severe damage to multiple wells and has significantly increased the challenges related to P&A (Petroleum Safety Authority 2017, Njå 2012). SCP has been attributed to compaction induced well damage in the sampled wells and other hydrocarbon producing fields with similar compaction have also seen a direct link between SCP and compaction induced damage (Doornhof et al. 2006).

In the GoM 50% of the wells (8122 wells evaluated) exhibited SCP in the production casing. Approximately 10% of the wells exhibited SCP in the intermediate casing strings, approximately 30% of the wells exhibited SCP in the surface casing string and approximately 10% of the well exhibited SCP in the conductor casing string (Bourgoyne, Scott, and Manowski 2000). In difference to the study, the operators on the NCS have not specified which casing string that is effected, but rather the annulus volume affected. This can make it difficult to compare directly as the wellhead and well designs are different. The D annulus may not necessarily represent the annular volume between the surface casing and conductor casing. However, if it is assumed a “typical” casing design program in the North Sea is used in the majority of the wells reported, it might be appropriate to compare. In the wells included 33 A annuli exhibited SCP (13% of monitored A annuli), 35 B annuli exhibited SCP (18% of monitored B annuli), 25 C annuli exhibited SCP (14% of monitored C annuli) and 29 D annuli exhibited SCP (25% of monitored D annuli). The distribution is not very similar to the observations from the GoM, but the sample size is very small which may increase uncertainty. On the other hand, the local mechanisms resulting in SCP could be different resulting in a different distribution.

The survey response uncovered that a large percentage of the monitored D annuli in platform completed wells exhibited SCP. Assuming the occurrence percentage in the sample is representable for the entire NCS many subsea wells will exhibit SCP. As a consequence, these wells could be leaking from the D annulus. Since SCP typically is slow pressure build up the equivalent leak rate could be difficult to detect when survey/visual inspection is performed infrequently. If this does occur, the cumulative environmental effect from multiple wells should be considered.

On the other hand, the occurrence percentage of D annuli may not be as high in the population. If these issues are expected when designing a well it would be logical to monitor the annuli. In effect, the probability that D annuli with SCP are monitored is greater than for non-monitored annuli. The systematic errors introduced during the survey could potentially also explain the significant percentage of SCP.

7.1b Data Significance

As described in section 5.3 it is apparent that the dataset could be significantly biased and does not necessarily provide a good representation of the NCS. The dataset does not contain wells from all fields on the NCS, as the operators could choose whether or not to respond to the survey. The parameter that is being investigated (SCP occurrence) can also effect the individual operators choice to respond to the survey. These systematic errors are hard to counteract when relying on goodwill from the respondents.

It is not entirely clear if the dataset has a larger occurrence of SCP than the population. The Valhall field that is included in the dataset is known to have significant well issues and represent a larger portion of the wells. This could potentially lead to an overestimation and the sample may represent a greater occurrence than the population. However, Ekofisk is not included in the dataset, but the field has also experienced significant well issues and could potentially represent similar occurrence rates. This would account for another significant portion of the NCS wells.

7.1c Costs Related to SCP

Costs related to SCP has not been a focus point of this thesis, but there is little doubt that the cumulative costs of management and remediation of SCP could be significant in problematic areas. The individual operator’s motivation to reduce or eliminate the occurrence of SCP is naturally linked to occurrence rate in the wells they operate. This might be limited to a small number of operators and could ultimately limit the incentive in the industry. On the other hand, the license to produce from a field is typically owned by a partner group and as a result, a larger number of parties are effected.

In general, reduced operating expenses will ultimately lead to increased oil recovery as profitable production can be sustained longer. And a key question is whether costs related to SCP management and mitigation are large enough to motivate the operators to find solutions to reduce the occurrence of SCP. An initial step would be to document SCP related expenses and evaluate SCP occurrence on the NCS as a whole and locally. It is believed that the operators together hold the required well data to perform a quantitative evaluation of SCP related factors and hence research cost can be limited to analysis and evaluation. However, this involves sharing sensitive data, which the operators could be hesitant to do, as commercial interests are strong.

If the economical expenditures related to SCP are significant, there could be grounds to initiate a Joint Industry Project (JIP) to quantitatively evaluate causes and factors that promote and lead to SCP. This could result in positive side effects as increased understanding of how local effects influence well integrity and casing/cement design.

7.1d Willingness to Share

The survey issued to the operators on the continental shelf (operators of one or more production wells) received a variable response. The small operators could quickly provide an overview of their SCP status, but for the larger operators this would require considerably more work and due to large current workloads, many could not prioritize this voluntary data collection. On the other hand, the larger operators commonly use established well integrity management systems and could easily accesses the relevant data.

One intent of this thesis was to provide original statistics and observations from the NCS that could hold value to the operators. This factor was thought to motivate the operators to contribute and share specific data on the subject. Seven operators have been very helpful and five of these currently operate development wells on the NCS. Several operators that were contacted did not respond or did not have the capacity to contribute and this is unfortunate as it significantly increases the uncertainty when evaluating the population of wells.

Efficiency and HSE are two elements that are continually developed in the oil and gas industry, but it is possible that the industry is not efficient in promoting and facilitating research and development. Sharing information is a key issue and throughout the thesis work it has become apparent that large gains are possible if sharing is properly facilitated. In the case of SCP, experience data from the NCS could initially result in better well planning and a risk reduction when drilling in high-risk areas resulting reduced operating risk during drilling and reduced SCP management costs during production. This could be said for all technological and environmental challenges (e.g P&A), and the initial step would be to evaluate the type of data that should be shared and how it should be compiled in order to promote high quality research and development.

7.1e Accidents and Risk

An evaluation of accidents and incidents is a good tool to quantify the risks related to certain situations or conditions. There are firm requirements for reporting hazardous events on the NCS and hence it is logical that if there were a significant number of events related to SCP they would be reported and captured. On the other hand the severity of these events might not justify notification unless they represent severe risk. The evaluation of events found in WOAD has uncovered several events related to SCP, but there is limited damage and no fatalities or injuries recorded on the NCS. Based on the events on the NCS there is seemingly a moderate risk to “people”, “environment” and “delay/downtime”. In comparison, the accidents and events from the GoM are significantly more severe.

It is important to note that WOAD does not capture all reported events and many events reported to the Petroleum Safety Authority would be unavailable to the public. Hence there is uncertainty regarding the number and severity of events related to SCP.

However, the risks related to SCP should not be taken lightly and major accidents still occur. The Elgin Franklin G4 well accident (2012) in the North Sea (UK) is evidence that the SCP can have major consequences even when it is managed within acceptable limits. The Loss of containment due to SCP resulted in over 6000 tons of gas and condensate being released from the D annulus in the surface wellhead. The well was brought under control after 51 days, but the blowout had the potential to result in a major fire or explosion risking the lives of the operating personnel (ref).

The findings in this thesis also indicate that subsea wells can exhibit undetected SCP in multiple annuli. In an operational perspective, this is important for well workover and P&A and should be part of the risk assessment.

7.2 P&A WITH SCP

There are few publicly recorded incidents of P&A wells leaking on the NCS. This could be due to the lack of monitoring, insufficient monitoring techniques, lack of reporting or the fact that they do not leak. Whether older plugged wells present greater leakage risk is arguable.

If however a well has previously exhibited SCP there could be an increased risk of well leakage or barrier degradation. The materials and methods used for P&A are similar to the materials and methods used in initial well construction or remedial efforts. The findings in this thesis show that these methods, materials and technology fail from time to time or do not always function as intended and therefor the probability that similar problems occur in plugged and abandoned wells is larger.

There is a strong motivation to reduce P&A costs in the oil and gas industry. This has increased use of requalified casing cement as well barriers in P&A design and there is a tendency towards leaving more tubing and equipment in the well. This approach and development is only logical and efficient, but if the well initially exhibited SCP, there was obviously a leak path or an area of reduced zonal isolation that might jeopardise the quality of the permanent abandonment barriers.

SCP is generally known to increase the operational risk during P&A, and it is common practice to apply risk-reducing measures such as active well control equipment during critical operations even when SCP is not expected or detected in the respective well. It can be argued that it does not matter whether SCP is present in the well before P&A as the barriers will be re-evaluated before the well is abandoned. Consequently, new regulations for notifications could be unnecessary. However, SCP does give a strong indication of reduced barrier quality, well leakage or previously undetected formations with flow potential. This is vital information that could affect the overall quality of the abandonment design. As previously described, in subsea wells SCP in the C, D and most B annuli could go undetected through the entire life so monitoring of subsea well annuli should be considered.

An understanding of the mechanisms resulting in SCP in the respective well should be a prerequisite when plugging and abandoning the well. This substantiates the need for research and development and the need for better solutions to externally and internally monitor plugged and abandoned wells. In the event that a plugged wells systematically begin leaking in the future, technology to re-enter permanently plugged and abandoned wells to re-establish well barriers could potentially also be needed.

8. CONCLUSION

During this thesis work, it became apparent that very little public information regarding sustained casing pressure (SCP) on the NCS is available and since there are no specific reporting requirements the Petroleum Safety Authority does not hold specific statistics on the subject. Some events might be captured if they result in significant hazard or serious accident, but in practice only the operators hold the majority of this information. The survey response has been variable, but, some operators have been very helpful and can confirm that SCP does occur on the NCS. In addition, there is limited information related to leakage and pressure build-up in permanently plugged and abandoned wells, hence it is not known whether the SCP effects the integrity in plugged and abandoned wells.

Overburden issues (hydrocarbon bearing zones, reduced zonal isolation and casing shoe cement) have been reported as the main cause of SCP in the sampled wells from the NCS. Furthermore, an evaluation of the incidents/accidents related to SCP in the World Offshore Accident Database (WOAD) indicates that tubing/casing leaks and primary cement leaks have caused SCP on the NCS. These findings correspond with past research conducted on wells in the Gulf of Mexico (GoM) that claims that SCP is caused by poor primary cementing, damage to primary cement and tubing leaks (Bourgoyne, Scott, and Manowski 2000). Hydrocarbon bearing zones can directly affect the quality of the primary cement job and provide a potential source of SCP. Reduced zonal isolation and casing/tubing damage have been linked to compaction induced well damage.

Through evaluation of the incidents and accidents in the WOAD there is little evidence that suggests the presence of annular pressure build up or SCP represents a significant risk of major accidents during normal operation or P&A on the NCS. The operators control the risks sufficiently related to SCP and introducing new stringent reporting requirements may not be justified. However, severe accidents related to SCP do occur and avoiding SCP altogether is best. To develop techniques and procedures to mitigate and ultimately avoid SCP, cooperation and sharing is recommended. To justify an increased effort to reduce occurrence of SCP a detailed evaluation of the costs and risk related to SCP management and remediation would be a good starting point.

In conclusion, it is evident that SCP does occur in a number of development wells on the NCS. However, SCP occurrence could be very field specific and due to the incomplete coverage of the dataset, further research is required to reveal the full extent and distribution of SCP. If the driving mechanisms causing SCP is determined, the industry could develop techniques to mitigate and potentially avoid it. Because annulus monitoring in subsea wells is primarily limited to the A annulus, insight is limited. However well design in subsea and surface completed wells are very similar, consequently it can be reasonably to assume that SCP occurs in unmonitored annuli in both surface and subsea wells.

To fully understand the complex mechanisms that result in SCP, experience sharing and cooperation between the relevant parties in the industry is recommended. This includes the service companies, the operators and the R&D organisations in cooperation with the Petroleum Safety Authority. The author recommends a systematic and continues data collection from the NCS gathered in one database. The initial step toward this solution could be a joint industry project to determine what information should be shared. The key elements would be to protect commercial interests of the individual operators and promote high quality research and development. Assuming the operators already hold all the relevant well data, the required research costs would be low for the licence owners. An increased understanding of the mechanisms behind SCP could ultimately reduce the occurrence and related remediation costs.

REFERENCES

Aadnøy, Bernt Sigve. 2010. *Modern well design*. 2nd ed. ed. Boca Raton: CRC Press/Balkema.

Abbas, Raafat, Erick Cunningham, Trevor Munk, Bente Bjelland, Vincent Chukwueke, Alain Ferri, Greg Garrison, Doug Hollies, Chris Labat, and Omar Moussa. 2002. "Solutions for Long-Term Zonal Isolation,." *Oilfield Review*.

Adams, Eric, and Scott A Socolofsky. 2017. Deep Oil Spill Modeling Activity Supported by the Deepspill JIP and Offshore Operators Committee.

API RP 90-2. 2016. Recommended Practice 90-2, Annular Casing Pressure Management for Offshore Wells, First Edition. American Petroleum Institute.

Bourgoyne, A, S Scott, and Wojciech Manowski. 2000. A Review of Sustained Casing Pressure Occurring on the OCS.

Bradley, Paul. 2017. How the HSE regulates the oil and gas industry offshore Health and Safety Executive

BSEE. 2011. Title 30 - Mineral Resources, CFR Part 250 - Oil and Gas and Sulphar Operations in the Outher Continental Shelf, Subpart E Oil and Gas Well-completion operations. edited by Department of the Interior Bureau of Safety and Environmental Enforcement. https://www.ecfr.gov/cgi-bin/ECFR?page=browse: Bureau of Safety and Environmental Enforcement, Department of the Interior

Cameron. 2017. Surface Systems Technology. http://www.slb.com/services/drilling/wellhead-systems/conventional-wellhead-system.as: Schlumberger.

City of Long Beach Gas & Oil Department. 2017. "Subsidence." City of Long Beach Gas & Oil Department

accessed 21.11.2017. http://www.longbeach.gov/lbgo/about-us/oil/subsidence/.

Conoco Norway inc. 1984. Final Well Report: Well 6507/7-1; License PL095. NPD Factpages: NPD.

Dahle, Bjørn Olav. 2014. Zidane Annulus Management (PPP).

Davis, A. M. 1992. "Shallow gas: an overview." *Continental Shelf Research* 12 (10):1077-1079. doi: https://doi.org/10.1016/0278-4343(92)90069-V.

DEA Norge AS. 2016. PL435 Zidane PDO Drilling and Completion Support Document.

DNV GL. 1970. World Offshore Accident Database. DNV GL AS.

DNVGL-RP-E103. 2016. Recomended Practise Risk-based abandonment of offshore wells. DNVGL AS.

DNVGL-RP-N101. 2017. Recommended Practice, Risk Management in Marine and Subsea Operations. DNV GL AS.

Doornhof, Dirk, Tron G. Kristiansen, Nagel Neal B., Philip D. Pattillo, and Colin Sayers. 2006. "Compaction and Subsidence." *Oilfield Review*.

Drilling Manager. 2017. Interview. edited by Kristian Rød.

Drilling Manager DEA. 2017. Interview. edited by Kristian Rød.

Dusseault, Maurice B., Michael S. Bruno, and John Barrera. 2001. "Casing Shear: Causes, Cases, Cures." doi: 10.2118/72060-PA.

FMC Technologies. 2008. Subsea Drilling System. FMC Technologies.

Johansen, Øistein, Henrik Rye, and Cortis Cooper. 2003. "DeepSpill—Field Study of a Simulated Oil and Gas Blowout in Deep Water." *Spill Science & Technology Bulletin* 8 (5):433-443. doi: https://doi.org/10.1016/S1353-2561(02)00123-8.

Lavrov, Alexandra , and Malin Torsæter. 2016. *Physics and Mechanics of Primary Well Cementing, Petroleum Geoscience & Engineering*: Springer.

Løvås, Gunnar G. 2010. *Statistikk, For Universiteter og Høgskoler*: Universitetsforlaget.

Minerals Management Service, Gulf of Mexico OCS Regional Office. 2008a. Accident Invstigation Report, Rowan Juneau, 07.09.2007. United states department of the interior, minerals management service, gulf of mexico region.

Minerals Management Service, Gulf of Mexico OCS Regional Office 2008b. Investigation of Blowout: Main Pass Block 91 Platform A: OCS-G 14576: August 23, 2007 New Orleans: U.S. Department of the Interior.

Njå, Nils Oskar Berg. 2012. "P&A of Valhall DP wells." MS MS Thesis, Petroleum Engineering, University of Stavanger, Norway.
NORSOK D-010. 2013. D-010 Well integrity in drilling and well operations (Rev. 4, Juni 2013). Lysaker: Standard Norge.
NORSOK Z-013. 2010. Z-013 Risk and emergency prepparedness assessment(rev. 3, Oct 2010). Lysaker: Standard Norge.
Norwegian Petroleum Directorate. 2017. "Factpages, Norwegian Petroleum Directorate." Norwegian Petroleum Directorate, accessed 29.07.2017. http://factpages.npd.no/factpages/Default.aspx?culture=nb-no.
Operator 1. 2017a. "Email 1." 30.11.201.
Operator 1. 2017b. "Email 2." 08.11.2017.
Petroleum Safety Authority. 2015. Regulations relating to design and outfitting of facilities, etc. In the petroleum activities. edited by Petroleum Safety Authority. http://www.ptil.no/facilities/category400.html.
Petroleum Safety Authority. 2016a. Hovedrapport, utviklingstrekk 2016, norsk sokkel. In *Risikonivå i etroleumsvirksomheten norsk sokkel* Stavanger.
Petroleum Safety Authority. 2016b. Regulations relating to conducting petroleum activities. edited by Petroleum Safety Authority Norway. http://www.ptil.no/activities/category399.html.
Petroleum Safety Authority. 2016c. Regulations relating to management and the duty to provide information in the petroleum activities and at certain onshore facilities (the management regulations). edited by Petroleum Safety Authority. http://www.ptil.no/management/category401.html.
Petroleum Safety Authority. 2017. Rapport etter tilsyn med permanent plugging og forlating av brønner på Ekofisk 2/4 Alpha - oppgave 009018134 Petroleum Safety Authority.
Recommended guidelines for Well Integrity no.:117. 2008. Norwegian Oil and Gas Association Recommended guidelines for Well Integrity no.:117. In *117*: Norwegian Oil and Gas Association,.
SAGA Petroleum. 1994. Final Well Report: 34/7-22. Oslo.
Samad, Nina Nishta. 2017. "A historical development of P&A requirements on the NCS and its effects on permanently plugged and abandoned wells." MS, Petroleum Engineering, University of Stavanger, Norway.
Straume, Martin. 2013. "Plugging and Abandonment Seminar." Plugging and Abandonment Seminar, Sola, 13.06.2013.
Torbergsen, Hans-Emil Bensnes, Hilde Brandanger Haga, Sigbjørn Sangesland, Bernt Sigve Aadnøy, Jan Sæby, Ståle Johnsen, Marvin Rausand, and Mary Ann Lundeteigen. 2012. An Introduction to Well Integrity.
Total E&P UK Ltd. 2013. "Elgin Platform." Last Modified 11.03.2013, accessed 12.12. http://www.elgin.total.com/elgin/home.aspx.
Watson, Theresa L., and Stefan Bachu. 2009. "Evaluation of the Potential for Gas and CO2 Leakage Along Wellbores." doi: 10.2118/106817-PA.

APPENDICES

APPENDIX 1 – SURVEY FORM

SUSTAINED CASING PRESSURE ON THE NCS

Reports from the Gulf of Mexico have shown that several thousand wells suffer from sustained casing pressure (SCP), but the extent of this issue on the Norwegian Continental Shelf has yet to be studied in detail.

I am a student at the University of Stavanger who is currently writing a master thesis in cooperation with DNV GL. I am exploring the extent of sustained casing pressure on the NCS, but I am also mapping causes and risk factors that in turn could contribute to better risk assessments prior to well operations and especially P&A. The Petroleum Safety Authority encourages you to support this study, which will improve risk assessments, operational preparedness and thus increase our knowledge and the safety level.

Should your company contribute, you will receive a summary report of my findings and a presentation of the results if they are found interesting to you. Your contribution will increase the accuracy of my report and will be greatly appreciated. All data you contribute will be anonymized to protect sensitive and confidential information.

"Sustained casing pressure (SCP) is defined as pressure in any well annulus that is measurable at the wellhead and rebuilds when bled down, not caused solely by temperature fluctuations or imposed by the operator" Norwegian Oil & Gas guideline no 117

In the initial phase of this project, your company's contribution in answering the following questions within 3-4 weeks is appreciated:

PRODUCTION WELLS (ACTIVE OR TEMPORARY SUSPENDED/ABANDONED)

1. How many of your wells have documented SCP?
2. How many of your wells are suspected to have SCP? (Typically subsea completed)
3. What are the most common causes of SCP in your wells?
4. What are the most common annuli (A, B & C) to experience SCP?

EXPLORATORY & APPRAISAL WELLS

5. How many of your exploration/appraisal wells have experienced well integrity issues during well operations and P&A due to SCP? (Typically, when pulling seal assembly and casing/tubing).
6. What are the most common causes of SCP in the exploration/appraisal wells?
7. Which are the most common annuli (A, B & C) to experience SCP in the exploration/appraisal wells?

Best regards,
Kristian Rød
+47 99565411
Kristian.Ottestad.Rod@dnvgl.com

APPENDIX 2 – RISK MATRIX

Risk Matrix

Severity	Consequence Categories					Increasing Likelihood					
	People	Environ-ment	Delay / Downtime	Reputation	Quantitative Scale	1 Failure is not expected $< 10^{-5}$	2 Never heard of in Industry 10^{-4} - 10^{-5}	3 An incident has occurred in Industry 10^{-3} - 10^{-4}	4 Has been experienced by most Operators 10^{-2} - 10^{-3}	5 Occurs several times per year per Operator 10^{-1} - 10^{-2}	6 Occurs several times per year per facility $>10^{-1}$
1	No or superficial injuries	Slight effect on environment, < 1 BBL	< 2 hours	Slight impact; local public awareness but no public concern	≤ 1 x Risk Limit	L	L	L	M	M	M
2	Slight injury, a few lost work days	Minor effect Non-compliance. < 5 BBL	< 1 day	Limited impact; local public concern – may include media	≤ 10 x Risk Limit	L	L	M	M	M	H
3	Major injury, long term absence	Localized effect Spill response required. < 50 BBL	1 - 10 days	Considerable impact; regional public/slight national media attention	≤ 100 x Risk Limit	L	M	M	M	H	H
4	Single fatility or permanent disability	Major Effect Significant spill response, <100 BBL	10 - 60 days	National impact and public concern; mobilization of action groups	≤ 1000 x Risk Limit	M	M	M	H	H	H
5	Multiple fatalities	Massive effect Damage over large area, >100 BBL	> 60 days	Extensive negative attention in international media	> 1000 x Risk Limit	M	M	H	H	H	H

Risk Definition:

High	Actions must be taken to reduce risk to at least the medium level
Medium	Risk reduction measures must be taken if their respective costs are not disproportionately high as compared to their attained benefits (ALARP principal); actions need to be taken to manage and measure risk.
Low	Monitoring actions required to identify whether the risk rises to medium level