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Maintaining well integrity during slot recovery operations

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Preface

This thesis presents my work in the subject TPG4910 at the Norwegian University of Science and Technology (NTNU). The Master's thesis was written in the spring semester of 2012.

First of all a thank to my supervisor Sigbjørn Sangesland for support while writing this thesis.

Second, I would like to thank my family, and especially my mother and father for proof-reading and corrections in addition to continuous support. A thank also to my girlfriend Mathilde for showing support and understanding during tough and busy days.

I would also like to show my appreciation to my fellow students at PTS, and especially the boys and girls in room 100. Without all the laughters and numerous card games, the semester would certainly have been a sadder one.

A thank also to Birgit Vignes at PSA for providing me with helpful documents and input during the research phase of the thesis.

A special thanks to Callum Smyth at Agora Oil and Mike Pollard at Wintershall Norway for continuously providing me with technical support and feedback.

I hereby certify that this work is solely my own.

Trondheim, May 30, 2012

Henrik Braune

The Dude abides

- Jeff "The Dude" Lebowski

Sammendrag

Den midlertidige pluggingen og forlatelsen (P&A) av gamle brønnbaner, med en påfølgende slissegjenvinning, vil være en viktig faktor for å øke den gjennomsnittlige utvinningsgraden på den norske kontinentalsokkelen. Disse operasjonene står ovenfor utfordringer som høye kostnader, sikkerhetsbekymringer, miljøspørsmål og en voksende etterspørsel. Opprettholdelse av brønnintegritet kan være vanskelig når en skal gå inn i gamle brønner. Etterspørselen for økt effektivitet kan føre til at operatører inngår kompromisser på sikkerheten for å sluttføre prosjekter i tide.

Denne oppgaven forsøker å gi en bred forståelse av brønnintegritetsproblemene på norsk sokkel, og deretter knytte disse funnene rundt begrepet *slissegjenvinning*. Det vil være viktig å forstå de forholdene som påvirker levetiden til en brønn. Spesielt de langsiktige trykk-, temperatur- og kjemiske påvirkningene på foringsrør / produksjonsrør er viktige aspekter å som må forstås. Hvis dette blir gjort kan man øke materialenes levetid i en brønn, og dermed kunne gjenbruke mer av foringsrørne i en slissegjenvinning. Disse tiltakene vil bidra til å holde marginale felt lønnsomme over en lengre periode.

Avhandlingen har også holdt et sterkt fokus på utfordringene med hensyn til planleggingsfasen av en slissegjenvinningsoperasjon. De essensielle faktorene i en slissegjenvinning er å verifisere den gamle barrierekonvolutten, og basert på disse funnene forme en robust operasjonell plan. En av feilene som har blitt gjort i flere slissegjenvinninger er at den operatsjonlelle planen er opprettet før noen tester har blitt utført. Når planen er satt og signert av ledelsen, blir endringer vanskeligere å gjennomføre. Gjennom testing av brønnen dukker det ofte opp uventede faktorer som må tas i betraktning når man planlegger en operasjon.

To separate slissegjenvinningsoperasjoner har også blitt studert. Disse ble nøye utvalgt for å illustrere typiske problemer med en slissegjenvinning, og dermed vise at teorien passer med virkeligheten.

Retningslinjer for en slissegjenvinning er også gjennomgått i avhandlingen. Disse er i dag lite tilpasset en slik operasjon, og det viser seg at kravene og retningslinjene for brønner på norsk sokkel må bli mer tilpasset slissegjenvinningsoperasjoner.

Summary

The temporary plug and abandonment (P&A) of old wells, and the following slot recovery, will be important for increasing the average rate of recovery from the Norwegian Continental Shelf (NCS). However, these operations faces challenges like high costs, safety concerns, environmental issues, and rapidly growing demand. Maintaining well integrity may be difficult when re-entering old wells. The demand for increased efficiency may lead operators to compromise on safety to finalize projects in time.

This thesis tries to give a broad understanding of the well integrity issues on the NCS, and then tie these findings around the term *slot recovery operations*. It will be important to understand the aspects which affects the lifetime of a well. Especially the long-term pressure, temperature and chemical effects on casings/tubings are important aspects to be understood. If this is done, one can increase the material lifetime in a well, and thus be able to re-use more of the casing strings in a slot recovery. These measures will help to keep marginal fields profitable for a longer period.

The thesis has also kept a strong focus on the challenges regarding the planning phase of a slot recovery operation. Of the essential factors in a slot recovery is to verify the old barrier envelope, and based on these findings create a robust operational plan. One of the mistakes which has been done in several slot recoveries is that the plan is created before any tests have been done. Once the plan is set and signed by the management, changes are harder to implement. Testing of the well often reveals unexpected factors which needs to be taken into consideration when planning an operation.

Two separate slot recovery operations were also studied. They were carefully chosen to highlight typical issues with a slot recovery, and thus show that the theory fits with the reality.

The requirements and guidelines for wells on the NCS also needs to be more customized for slot recovery operations.

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1 Introduction

Many production wells dating back to the 70's and 80's on the NCS are facing plug and abandonment due to being non-profitable. The abandonment of old wells, and the following slot recovery operation, will be important for increasing the average rate of hydrocarbon recovery on the NCS. When new technology are developed in the future, these wells may once again be profitable. Hence, in order to keep costs down, the slot recovery operations to re-open the wells should be as effective and swift as possible. However, these operations faces challenges like high costs, safety, environmental issues and a rapidly growing demand. Maintaining the overall well integrity has often proved to be difficult in the past when re-entering old wellbores. Issues like design, completion, operation, intervention and maintenance will all have an influence on the P&A operation, and subsequently the slot recovery operation. The demand for increased efficiency may lead operators to compromise on safety to finalize projects in time.

The Snorre A incident in November 2004 on well 34/7-P-31 A is a horror example of poor well control during a slot recovery. This incident will be thoroughly investigated in this report, and some improvements will be given.

Another known well integrity incident, although not a slot recovery operation, is the Macondo blowout in the GoM in 2010. Eleven people died when the semi-submersible drilling rig Deep Water Horizon (DWH) exploded and sank in the Gulf of Mexico in April 2010. Several others were seriously injured, and the incident resulted in a massive oil spill. Shortly after the accident, PSA established an internal multi-disciplinary project group to evaluate the lessons learned from the accident, and assess similarities and differences with other accidents and serious incidents. The aim has been to develop a basis for improving the audits and implement measures to raise the awareness the health, safety and security in the Norwegian petroleum industry (Anda et al., 2012).
The project team delivered a preliminary status report in the summer of 2011 (Anda et al., 2012). The report is based on investigation reports, and a series of reviews of the accident from several academic institutions. The main findings from the accident in GoM has resulted in several new requirements as i.e revisions of the NORSOK D-010, a revision of API RP 53 which includes implementation of two shear rams instead of one, containment strategy etc. Based on the preliminary DWH report, the PSA has identified four main issues the industry should continue to work with:

- Organization and management

- Risk management
- Management of change
- Barrier control (Anda et al., 2012)

All these elements will also be important when designing a slot recovery operation. In addition, human factors in barrier control and well integrity must not be underestimated. The investigation of DWH pointed out management failures at different levels and in different phases. This was reflected in the decision-making and prioritization processes, management of change processes and organizational changes which led to unresolved liability areas. The incident was also influenced by priorities done by the management which was characterized by a focus on short-term economic gains, and not on safety (Anda et al., 2012).

This thesis will try to keep the focus on these four issues when investigating well integrity during slot recoveries.

Another important issue which will have a strong focus in the thesis is the planning phase of a P&A and a slot recovery operation.

To have slot recoveries in mind when designing a P&A operation will also be beneficial in the future. Safe re-entries of former plugged wells, with respect to well integrity, will be important tasks for operators on the NCS in the following decade as these operations will be more and more common.

Over the last few years, incidents and findings have raised several concerns regarding the well integrity in the design and operation of oil and gas wells on the NCS. Hence may this be an indication that there is a mismatch between the expected quality and the actual performance of a well. Several recompletions and sidetracks have also added to the wear on the existing casing, and this has contributed negatively to the overall lifetime of the equipment. The typical well integrity challenge is a result of marginal well design. Operators often rely on the calculated result for a well design, but in addition there needs to be a practical understanding of well barriers. Once a well design is complete, the industry needs to improve completion design weaknesses. When the well is completed, the barrier validation process has to correspond with the actual acceptance criteria which are given by several NORSOK documents.

PSA believes that the industry must develop a more uniform approach for barrier management in the petroleum industry, which to a greater extent than today maintains the regulatory requirements for well barriers.
The status report from the PSA addresses a number of issues and challenges

related to barrier control for Norwegian petroleum activities, both at a general level and in relation to the need for better and more specific requirements for several well barrier elements.
The summary also confirms that there is still a need for a high priority on the industry's efforts to establish improved barrier control (Anda et al., 2012). Improved barrier control will be further discussed in **section 3.1**.

1.1 General view on well integrity

In NORSOK D-010, well integrity is defined as *application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well* (NORSOK, 2011). The life cycle of a well can again be defined as the process from planning, through operation and completion, production and finally plug and abandonment.

Well integrity is an issue related to the entire life cycle of a well. The meaning of well integrity is to prevent uncontrolled release of formation fluids through technical, operational, and organizational barriers (Vignes, 2011). Well integrity is affected by factors such as human elements, the technology and the organization (HTO). This term will be further discussed in **section 3.5.1**. The human element needs to handle situations related to competency, responsibility, manning, training, communication and team work, operational tasks, planning, transfer of experience and time limitations (Vignes, 2011). The technical element has to handle factors such as equipment and technology and also situations related to well design and limitations, operations, operational tasks, and reservoir behavior (Vignes, 2011). The last factor, the organizational element, has to handle situations related to procedures and standards, responsibility and leadership, organization and manning, competency and training, communication and team work, planning and experience of exchange (Vignes, 2011). This will be more discussed on **page 87**.

Well integrity incidents and accidents occur when the barriers that separate hazards from vulnerable people or assets are breached. Major (well integrity) accidents are often very difficult to control, understand and predict. Several well integrity incidents, such as the incidents on Snorre A in 2004 and Gullfaks C in 2010, shows that there is a need in the oil and gas industry to focus further on the well integrity and the well barrier elements qualification, function, field performance and long-term integrity (Vignes, 2011). These aspects need to be included in all well phases from design to permanent P&A. That also includes all well operations such as drilling, production, injection, well intervention and well control situations. In a slot recovery operation, many of these factors will need to be evaluated in a slot recovery operation, in addition to permanent P&A, since a slot recovery involves P&A of the main wellbore prior to drilling a sidetrack.

Some of the main benefits of having control of the well integrity is:

- Safety - it will reduce the likelihood of hazardous events
- Environment - it will minimize the spills to the environment, including

contamination of sub-surface aquifers as well as releases to the surface

- Production - it will maximize the well availability and hence the production capacity of existing and future assets
- Life-cycle cost minimization - by reducing the costs over the whole life cycle by ensuring correct design, construction and operation, a focus on well integrity will minimize the costs of remedial work and equipment replacement.
- Data availability - it will sustain and provide access to reliable well data to support the decision making process over the well life cycle (Daghmouni et al., 2010).

1.2 What is a barrier?

The NORSOK standard D-010 defines a well barrier as an *envelope of one or several dependent barrier elements preventing fluids or gases from flowing unintentionally from the formation, into another formation or to surface* (NORSOK, 2011).
It is also defined in chapter VIII, §48 in the facilities regulations prepared by PSA that *well barriers shall be designed such that well integrity is ensured and the barrier functions are safeguarded during the well's lifetime. Well barriers shall be designed such that unintended well influx and outflow to the external environment is prevented, and such that they do not hinder well activities* (PSA, 2011b).
The International Organization for Standardization (ISO) has defined a barrier as *measure which reduces the probability of realizing a hazard's potential for harm and which reduces its consequence* (ISO, 2000). The ISO standard also specifies that a barrier may be both physical (*materials, protective devices, shields, segregation, etc.*) and non-physical (*procedures, inspection, training, drills, etc.*).

With a special focus on the petroleum industry, (Rosness et al., 2004) proposed a definition of the barrier term in the following way: *Barriers are actions and functions that are planned to break specific and undesired course of events.*

The purpose of this thesis is mainly to focus on improvements in barriers and well integrity, and especially with regards to specific accidents. Hence, it is reasonable to define a definition for the term barrier throughout the thesis: *Safety barriers can be technical, organizational or other planned and implemented measures intended to break identified or specific course of events* (based loosely on the term presented by (Jersin, 2004)).

Either way, a barrier's main function is to control, prevent or reduce unwanted events. Thus, proper barrier design is one of the most important priorities when planning for a well, and a subsequent safe and effective P&A or slot recovery operation.

1.3 What is a slot recovery operation?

This subsection will give an understanding of what a slot recovery operation is, and most importantly what the advantages are.

But first of all - what is a slot? And why does it need to be recovered? When designing a platform, there must be decided how many *slots* the platform can have. This is basically a huge steel board with a pre-defined number of round holes, which again defines how many different wells the platform can hold, and is known as the *footprint* of the rig. An illustration of this is shown in **figure 1.1** and a real picture of the footprint can be seen in **figure 1.2**. In order to get access to the different slots, the rig is skidded from one slot to another. Skidding means to disconnect rigid attachments from the platform to the rig, and then, by using large capacity hydraulic cylinders, push the rig over greased steel skid beams.

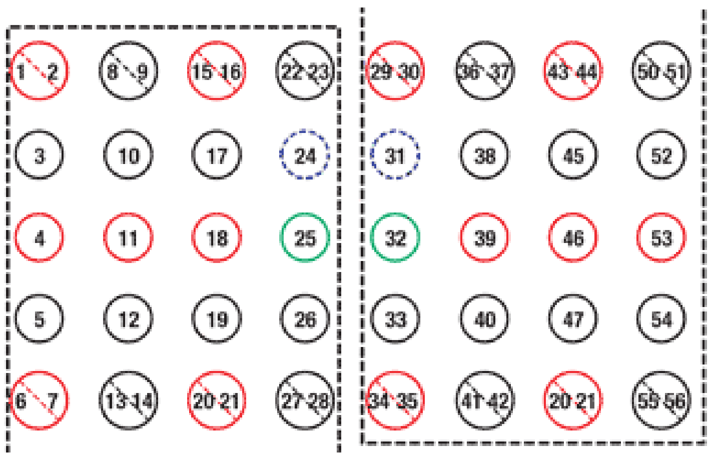

Figure 1.1: The figure shows a 40-slot surface layout, which with combined conductor sharing allows 56 wells to be drilled. Wells include cutting/re-injection candidate wells in green, cellar deck wells shown in red and mezzanine decks wells shown in black (Fu et al., 2009).

Figure 1.2: The figure shows how a slot layout on a platform looks like. Note that there are several free slots on this platform (Claxton, 2012).

This "board" is placed on the cellar deck which is beneath the drill floor. The risers are connected here with the x-mas trees on top of it, and this can be seen in **figure 1.3**.

Figure 1.3: The picture shows the cellar deck. Notice the x-mas trees placed on the top deck with the risers continuing down towards the sea (Fu et al., 2009).

The decision of how many slots a rig can hold is of major importance in the design process of the rig. The number of slots defines how much weight the rig has to withstand. This is again a question of cost. The more slots, the bigger the rig needs to be - hence more expensive. In other words, when designing the rig, considerations of all the future wells must be done. It is not possible to increase the number of slots after the rig is completed. When all the slots on a rig are in use, this forces a need to recover these slots when one or several wells start to become unprofitable. Recovery in this context means to re-use as much of the casing string as possible, and then drill a new wellbore with a new geological well target. There is always a trade-off between closing the slot down, or recover it. If profitability analysis does not show any potential income, the slot will be abandoned.

There are two options available when a slot is no longer profitable. Either by plugging and abandon the well permanently and remove the wellhead, or re-use the slot[1] by plugging the mother well and sidetrack a new wellbore. The latter case is known as a slot recovery.

[1] Usually the upper parts of the wellbore, thus the surface casings of 20" and 30".

Decommissioning

Slot recovery operations will in the future play an important role in connection with the large rate of field decommissioning taking place present. Decommissioning can be defined as the last stage of the economic lifetime of a producing well. The economic lifetime normally terminates once the net cash flow turns negative. If the net cash flow prognosis will be negative for the foreseeable future, the well may be permanently plugged and abandoned. However, if it is believed that the field may once again be profitable, the well can be temporarily abandoned. In the latter case the slot recovery operation will be an important issue the next few decades. When new technology is developed, marginal fields may once again prove to be profitable. Thus will the effectiveness and safety regarding the slot recovery operation prove to play an important role when deciding the profitability of a field.
Ultimately, all economically recoverable reserves will be depleted, and the field will have to be decommissioned.
Most operators face two ways to defer the decommissioning of a field:

- Reduce operational costs
- Enhance oil recovery

Cost effective slot recovery operations will also contribute to a large extent the way operators can increase the lifetime of a field.

1.4 Well barrier elements in well integrity

Referring to the definition in NORSOK D-010, well barrier elements can be defined as *object that alone can not prevent flow from one side to the other side of itself* (NORSOK, 2011). WBEs can include, but are not limited to: tubing or casing string, production packer, tubing/casing hanger packoff, annulus and tree valves, tubing plug installed above the uppermost perforation, closed and tested SSSV, static fluid of sufficient weight to hold the highest bottom-hole pressure (Dethlefs & Chastain, 2011).
The primary and secondary well barrier is according to NORSOK D-010 defined as independent of each other, and this simply means that there are no common well barrier elements between them. If there are one or several WBEs shared between the primary and secondary well barrier, a risk analysis and risk reducing measures have to be performed to reduce the risk to a level which is defined as ALARP (as low as reasonable practicable). More discussion regarding the risk management and ALARP will be done in **section 3.2**.
The well barrier elements must also be illustrated in well barrier schematics (more on this in **section 2.4**).

In section 15 of NORSOK D-010, the acceptance criteria of well barrier elements are listed, including how to perform initial tests and verification. Improved verification of well barrier elements are a key to future slot recovery operations, and will be further discussed in **section 3.3**.

There are also certain requirements to the robustness of well barrier elements, and these are described in the facilities regulations in section 5 regarding the design of facilities: *The facilities shall be based on the most robust and simple solutions as possible, and designed so that: they can withstand the loads, major accident risk is as low as possible, a failure in one component, system or a single mistake does not result in unacceptable consequences, the main safety functions are maintained, materials handling and transport can be carried out in an efficient and prudent manner, a safe working environment is facilitated, operational assumptions and restrictions are safeguarded in a prudent manner, health-related matters are safeguarded in a prudent manner, the lowest possible risk of pollution is facilitated and prudent maintenance is facilitated* (PSA, 2011d).

Well integrity is built on the principles of always having this *robustness* implemented in the design. Another important factor to well integrity is *redundancy* which covers barriers, well barriers and well barrier elements as a safeguard to avoid the release of reservoir fluids. The main principles of *redundancy* and *robustness* will be further discussed in **section 3.5.2**.

In order to accomplish these requirements, the primary and secondary well barrier must secure the integrity of the well, the barrier overview and competence, the testing and verification and the respect and understanding of potential consequences. Several surveys and incident reports have identified that there is a need in the industry to further analyze the reasons for well integrity issues in well barrier elements. The main problems are found in elements such as tubing, casing, valves, cement and BOP. These reasons for leakage will be discussed in **section 2.2**.

1.5 Scope of work

This Master's thesis aims to present the most up-to-date technologies and solutions to well barrier integrity available. This is done in order to give the most accurate answers to the challenges regarding P&A operations and slot recoveries.
The following tasks has been given as a guideline for the thesis:

1. Explain briefly the sequence of events that caused the blow out on Snorre A. Describe technical improvements which could have prevented the incident.
2. Discuss factors influencing the planning face of P&A and slot recovery operations on the NCS.
3. With regards to the current governing regulations, evaluate the well barrier status for P-31 A prior to and during the operation.
4. Choose one or more current slot recovery operations. Perform a study of well integrity status for the case wells.

The last task specifies that a *current* slot recovery operation is to be chosen. The author found it more useful to look at a slot recovery which was completed a couple of years ago. By doing this, the whole operation could be evaluated, hence give a broader perspective and a more accurate conclusion.

The thesis will result in several recommendations to the industry regarding slot recovery operations.

2 Theory and guidelines regarding well integrity and barriers

This section will cover a more general view on well integrity. Every aspect of the operation will be evaluated, from planning to final P&A. Operational requirements from PSA will form the basis for the section, but other relevant papers has also been used in the evaluation. The author of this text finds it important to uncover well integrity issues throughout the whole well life circle, from planning to permanent P&A. This is done in order to get a full understanding of barrier control when performing a slot recovery.
Verification of barriers in old wells has proven to be difficult due to several reasons. Difficulties with barrier verification was one of the issues on both cases which will be discussed in this thesis (in **section 4** and **section 5**). Improvements to the verification of barrier process are discussed in **section 3.3**. The issue with verification of barriers is also linked with poor documentation handover. This will be discussed in **section 3.4**.

This section will focus on reasons for failing barriers throughout the lifetime of a well. This is important because the wells which are in operation today are the candidates for future slot recovery operations. Some statistics will be presented first to investigate well integrity problems on the NCS, and how widespread they are.

2.1 Well integrity issues on the NCS

This first subsection will look on well integrity issues on the NCS, and will be supported with statistics mostly based on Berit Vignes' Ph.D thesis *Contribution to well integrity and increased focus on well barriers from a life cycle aspect*. This subsection aims to discover to which extent well integrity is a problem on the NCS. Only when the problem is identified one can establish countermeasures to it. This investigation will be important to discover where the focus needs to be when planning for a slot recovery operation.

In 2006, PSA performed a well integrity survey in which 406 wells on the NCS were evaluated on 12 selected installations (Vignes et al., 2009). The wells which were evaluated represent a wide range of well types, from oil and gas producers to injection wells. The survey is based on interviews, statistical data and questionnaires, and presents an unbiased[2] view on well integrity issues on the NCS. The main findings was that 18% of the 406 selected wells had well integrity issues (Vignes et al., 2009). The results of the survey are presented in **figure 2.1**. This resulted in a groundbreaking drive on well integrity by the PSA. The underground blowout on SNA in 2004 had already been a serious reminder for both the industry and the government what happens when well barriers fail. The WIF (Well Integrity Forum) was established in 2007 as a subgroup within the OLF to be sure the issues discovered in the survey were followed up. The WIF consists of representatives from nine operating companies (BP, Talisman, ExxonMobil, ConocoPhillips, ENI, Statoil, Marathon, Norske Shell and Total). The WIF established the document OLF guideline #117, which defines well integrity training, well handover documentation, well barrier schematics for the operational phase, the well barrier categorization and well integrity management systems. All these aspects will be discussed in connection with slot recovery operations in respectively **section 3.5.1, 3.4, 2.4, 2.3** and **3**.

[2] PSA is an independent authority, hence unbiased towards any company.

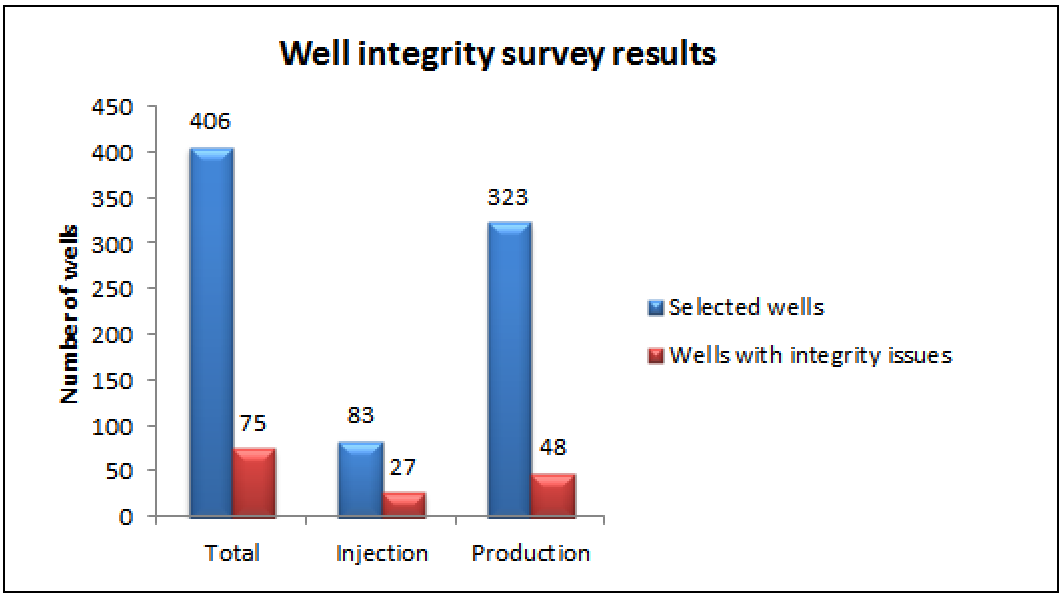

Figure 2.1: The chart illustrates how many of the selected wells which experienced well integrity problems.

As we can see from the **figure 2.1**, as many as 33% of the injection wells had integrity issues of some sort. The chart also shows that the well integrity problems are more seldom in production wells. Compared to the injectors, only 15% of the producers had integrity issues.

The impact that this had on the before-mentioned wells are illustrated in the chart (**figure 2.2**) below. 7% of the wells needed to be shut in, 9% of the wells could function with minor exemptions, while only 2% was working as before. The well integrity issues include well barrier elements such as tubing, DHSV, casing and cement (Vignes et al., 2009).

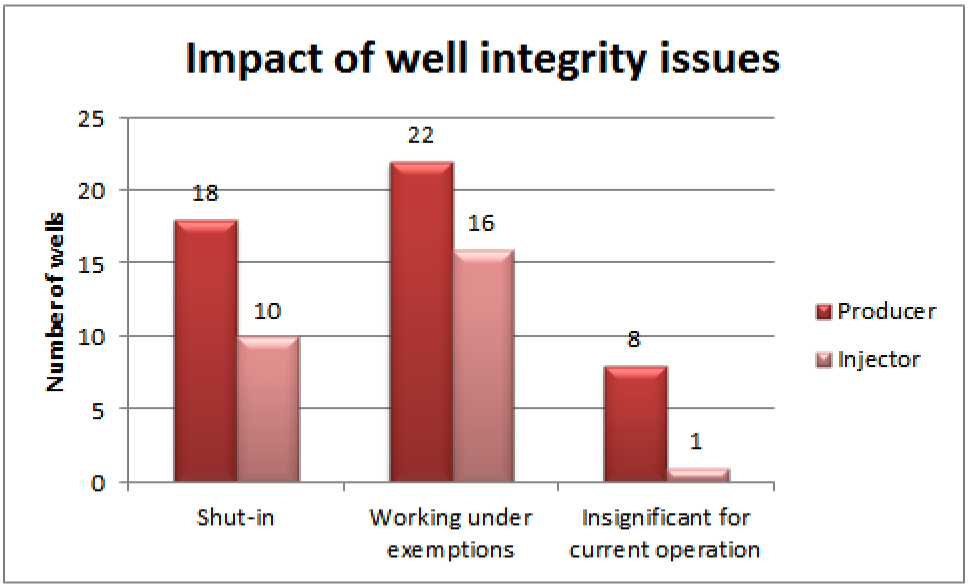

Figure 2.2: The chart illustrates that well integrity issues often have a great impact on the operation.

The chart in **figure 2.3** below illustrates the number of wells and the associated failing well barrier element. These are mostly related to tubing, casing, cement, wellhead and ASV (Vignes et al., 2009).

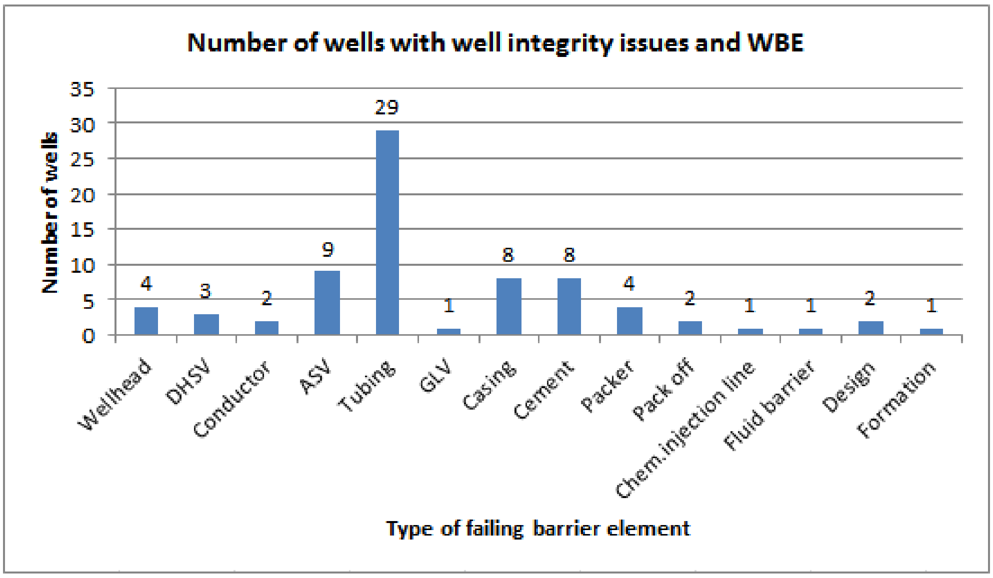

Figure 2.3: The chart illustrates in which WBE the wells with integrity issues experiences problems. Tubing related issues is by far the most distinct problem.

These are again related to the following points:

- Wrong sealing in the wellhead leads to leakage in the wellhead from annulus A to B
- Poor cementing. I.e. no cement behind casing and and above production packer, leakage along cement bonds or through micro annulus between cement and casing due to poor cement job.
- ASV equipment failure
- Leakage in production tubing above the DHSV, tubing to annulus leakage or an internal leakage in the tubing hanger neck seal (Vignes et al., 2009).

Some of the reasons to this will be discussed further in **section 2.2**.

Apart from this study prepared by PSA, both Statoil and Sintef have done similar investigations in 2008. The results can be seen in **figure 2.4** (Randhol & Carlsen, 2007)(Nilsen, 2007). The results show that the number of wells with integrity issues match independently from the different surveys. Hence, we can conclude that these numbers represent the current situation on the NCS - around 17% of the producers and 33% of the injection wells on the NCS experiences some sort of well integrity problems.

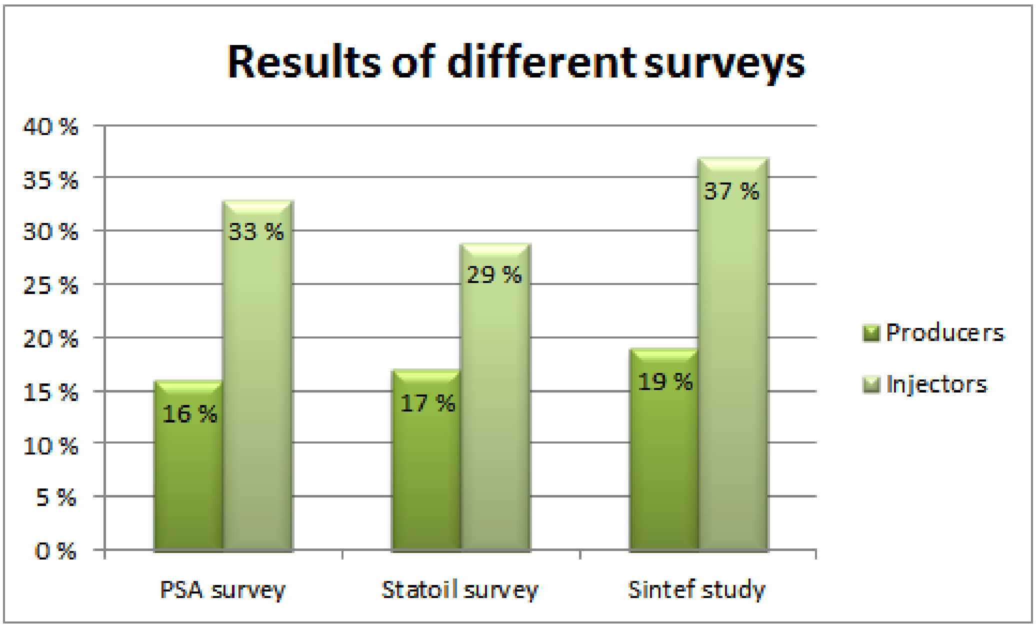

Figure 2.4: The chart illustrates that three independent studies related to well integrity issues concluded with almost the exact same results (Vignes et al., 2009)(Nilsen, 2007)(Randhol & Carlsen, 2007).

In the Statoil survey, 711 of Statoil's own wells were investigated. Sintef examined on the other hand 217 wells from eight different operators. The wells in the Sintef study were observed from 1998 to 2007. As seen in **figure 2.4**, 19% of the producers and 37% of the injectors were identified with integrity issues. **Figure 2.5** illustrates in which WBE caused the leakage.

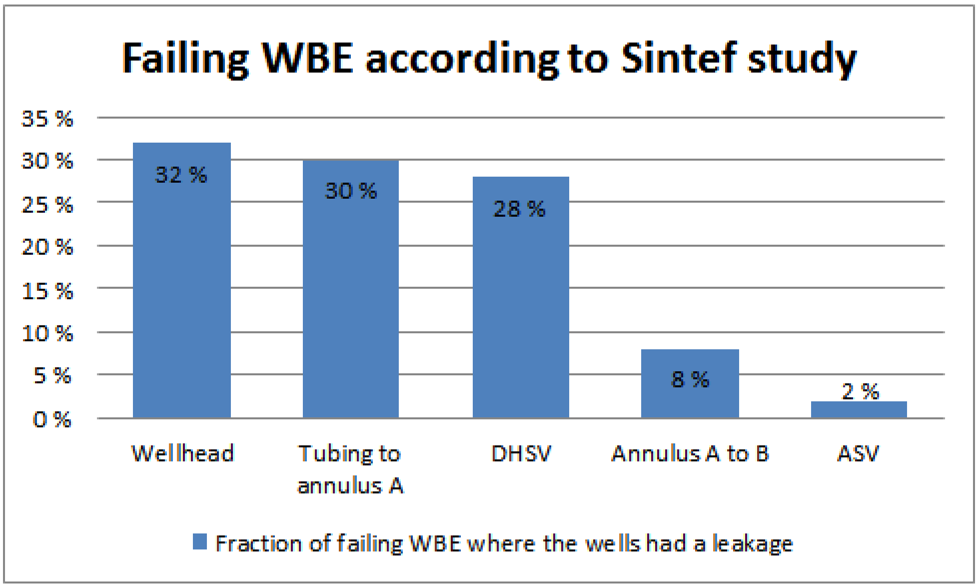

Figure 2.5: The chart illustrates in which WBE the integrity issues occurred in the wells which experienced leakage (Randhol & Carlsen, 2007).

The studies from Sintef show that wells with gas lift often than average showed signs of leakage just two years after gas lift was first introduced (Vignes et al., 2009). This is mostly because the wells were completed with low grade steel and 13% Cr tubing (Randhol & Carlsen, 2007). These wells were initially designed for dry gas. However, during operation these wells often experienced wet gas and more corrosive CO_2 than the design criteria (Vignes et al., 2009). Hence, the leaking wells have been operating outside of the design envelope, and this severely reduces the well lifetime. This seems to be an issue with a major number of wells on the NCS. Wells operating outside of its original design envelope will result in increased abrasion on the casing and tubing, and due to this, slot recoveries will be more challenging since the steel has an unexpected low quality when the re-entry of the well commences. This again shows how important initial design of the well is, and how important it is to keep the well within the design envelope. More on the design phase and well planning with regards to slot recovery operations will be discussed mainly in **section 3**.

The issue with the high number of failing injectors was studied by PSA in 2008. The study represented six operators, and included both water/gas injectors and WAG wells (Vignes & Tonning, 2008). This study showed that the barrier failures were heavily related to the design, injected water, connections and packers. One example of poor design was using a seal stem (PBR

and no production packer. This design includes a dynamic seal between the annulus and tubing. A high difference in temperature between the injected water and the reservoir resulted in movements of the PBR. This has long been a known problem for wells in relation to leakage (Vignes & Tonning, 2008).
Another problem was not choosing the right steel grades in the completion equipment. The oxygen level in the water which was higher than expected caused major corrosion issues. These could have been prevented if a proper completion design was implemented (Vignes & Tonning, 2008).

All of these studies have shown that there are some main issues which needs to be further investigated and improved.

- Integrity issues within barrier elements such as tubing and connection as a result of corrosion.
- Well integrity problems related to ASV, casing, cement and wellhead are the most distinct problems on the NCS. The first two aspects will be addressed in **section 2.2**.
- Poor handover documentation. This will be investigated in **section 3.4**.
- Lack of well barrier schematics, and those presented are often poor. This will be discussed in **section 2.4**.
- Insufficient competence related to well barrier management and well integrity. This will be discussed in **section 3.5.1**.
- The industry is in need of an industry standard and a standardization when it comes to well barrier management (Vignes et al., 2009).

Especially the last point regarding well barrier management will be further investigated throughout **section 3**.

2.2 Causes of failing well barriers

As discovered in **section 2.1**, cement and tubing/casing failure constitutes around 60% of the well barrier elements with issues (seen in **figure 2.3**). This section will present reasons and improvements to these two well barrier elements as they are of high importance when planning for a slot recovery operation.

2.2.1 Tubing and casing failure

This section is especially interesting in a slot recovery perspective as there is a cost saving effect by being able to re-use old casing. Hence, to know *why* casing fails is an important step towards preventing casing failures in the first place. By extending the life time of casing, the operational costs of a slot recovery can be held at a level so that the profitability can be higher. The chart in **figure 2.3** also indicated that tubing and casing accounts for the majority of the well integrity issues on the NCS. Almost 50% of the failing WBEs in the survey were in connection with casing and tubing issues.

There is a potential leak point in the premium connections of the tubing and the casing in a well, and one poor connection can disqualify the well string (Vignes, 2011) (Bradley et al., 2005) (Schwind, 1998). A well barrier envelope can include as many as 1000-1200 casing, liner and tubing threaded connections, counting both primary and secondary barriers (Eiane, 2008). The reliability of metal to metal connection may be compromised if the running and installation process is not performed appropriate. It is also important that the thread lubricants (dope), the running equipment and the makeup equipment are selected with the reliability of the connections in mind (Powers et al., 2008).
Several factors contribute to well integrity challenges and leakage in tubing and casing connections. The key to maintain integrity lies in the accurate makeup process of the connections, the testing and qualification, protectors, the type of dope used, the running of the casing and tubing, both the handling and installing of the connections, packer fluids and well stimulation fluids (Vignes, 2011).

From a slot recovery point of view it is crucial to implement the life cycle aspect of a well in the design phase of casing and tubing. In the design phase, the environmental conditions, what type of wear the strings are expected to face and what the lifetime of the strings should be. All of these factors will be important when future slot recovery operations will be planned. If the well

is designed with a slot recovery in mind, more steel can be re-used, which again helps keeping the overall costs down.
The operational aspects which need to be evaluated during the design phase in order to maximize the expected life time of casing and tubing strings includes:

- Run in hole
- Setting of packers
- Pressure tests
- Well killing operations
- Intervention
- Well control incidents
- Pull out of hole (Vignes, 2011)

When choosing the materials, an evaluation must be done regarding

- the produced or injected fluid
- the reservoir fluids
- the completion fluids
- the stimulation fluids (Mack et al., 2002) (API, 2000)

There are also factors which indirectly or directly have an impact on the casing and tubing's "life expectancy", such as formation pressure, loads, expected flow rates and temperature.
The mechanical properties are also important since both leakage and degradation are influenced by factors such as corrosion, erosion, fatigue, burst/collapse, tension/compression and general wear.

This section will now look more detailed on some of the before mentioned factors contributing to well integrity regarding casing/tubing.

Compounds

In the oil and gas industry, different compounds are used on casing and tubings both during storage and when in use. The storage compounds should prevent the strings from corroding, but they are seldom suitable for the makeup process (VamServices, 2011). This means that the storage compounds must be changed when the casings and tubings are to be made up. There are some "rules of thumb" when it comes to well integrity of casing, tubing and liner due to compounds: *never use barite or wire brush to clean* *the connections and never use cleaning agents that may leave a film on the connections. Do not use contaminated thread compound (liquids, solids particles, etc.) and do not allow the mud or drilling/completion fluids to overflow the box connection when filling up or running in hole. Apply the correct quantity of compound to all the thread, seal and shoulder areas and apply thread storage compound on returned pipe in case there is a delay in the restocking* (VamServices, 2011).

There are dope free connections available, and there could be environmental benefits to the use of these (Vignes, 2011). Other benefits related to dope free connections are:

- Easy inspection
- Cleaning
- Minimized handling time
- Less plugging of formation pores
- Increased efficiency during well intervention due to no excessive dope in the well (Vignes, 2011)

However, more analysis needs to be carried out in order to conclude whether dope free connections have a positive effect on long-term well integrity, or not.

Installation

The installation of tubing and casing connections are critical operations related to the performance of the connections (Vignes, 2011). The installation process and the makeup equipment should cause as little damage and marking as possible to the strings.
The makeup torque is especially important since this produces the initial contact pressure between the sealing surfaces (Tsuru et al., 1990). The vendor's uses different maximum, minimum and optimum makeup torque for each type, size, material and connection (Vignes, 2011). The industry usually uses a torque between the optimum and maximum (Vignes, 2011).

Testing and verification

To verify that equipment is properly installed, there must be done some kind of testing and verification work to ensure that the equipment can withstand the calculated pressure. NORSOK D-010 defines the testing and verification as: *initial test and verifications of the casing and tubing to include leak testing* *to maximum anticipated differential pressure and leak testing during completion activities when the casing and liner has been drilled through* (NORSOK, 2011). To verify the tubing and casing string, pressure testing is mostly used in the industry, and is an acceptable form of verification (Eiane, 2008). The operational testing is performed from 0 to 345 bar to verify the casing and tubing integrity[3]. It is also common to test the strings in cyclic conditions, hence testing the well from 345 bar to 0 bar and back to 345 bar (Vignes, 2011). This is done to fully verify the integrity of the string. More on testing and verification of barriers is found on **page 79**.

Long-term effects

This sub-section is especially interesting with slot recoveries in mind as the long-term effects on casing and tubing are of huge importance for the overall well integrity during the life cycle of the well. If the long-term effects on the casing and tubings can be fully understood, there can be implemented measures to increase the life time of the steel, hence decreasing the cost of future (slot recovery) operations.

After extended use, the tubing and casing thread performance, and the long-term effects like seal failure, wear, fatigue and corrosion often shows to be evident. To continually monitor the annuli pressures and logging of the wellbore will be very important to determine the long-time effects of the performance of the well, and from here evaluate if there is a need for operational changes (VamServices, 2008).
There tends to be a deterioration of the thread compounds over time as they are influenced by factors such as pressure, temperature and chemical reactions. There is a widespread use of chemical sealing products in the industry to repair the integrity of casing and tubing, but there is not enough research on the subject to conclude if these mediums provide sufficient well integrity over the long term (Vignes, 2011).

A long term goal in the industry should also be to shift the performance indicators to reflect quality of the well, not the quantities. Today, a well's performance is measured on factors such as drilling days and the direct cost of the well (Dhina et al., 2005). A long term goal should therefore be to focus on the quality of the well and well integrity during the life cycle of the well from design to abandonment (Vignes, 2011).

[3] the string is considered static loaded

Short conclusion to casing and tubing integrity

This short conclusion will sum up the challenges and the need of further work on the subject on casing and tubing integrity in a well.
There are some specific challenges with casing and tubing integrity which have been presented in this section which needs extra focus in the future.

- The well design and the material selection are critical due to the existence of several different fluids in a well. A well will normally be exposed to fluids from formations, completion fluids and stimulation fluids. Also, the corrosion management should be implemented in each well cycle phase.
- There are challenges with the testing and verification of the casing and tubing due to both the static load and the load cycles (including pressure and temperature cycles).
- Challenges regarding dope selection (and even dope free or not).
- Challenges regarding the installation process of casing and tubing (alignment, makeup speed and torque)
- The long-term effects on casing and tubing integrity needs more research (Vignes, 2011).

2.2.2 Cement

This section will cover the challenges regarding cement integrity in a long term perspective. If the cement job is of high quality, this increases the chance for a re-use of the old casing string in a slot recovery operation. The chart in **figure 2.3** also indicates that cement failure is one of the biggest challenges with regards to the well integrity on the NCS. 11% of the total number of wells with issues in the survey had problems with the cement barrier.
The long-term risk phase of the cement integrity starts after the cement has begun to mature and until it sets. There are still several challenges with the long-term cement design in order to make the cement last throughout the lifetime of a well without failing. When the cement sets, it starts to alter in quality, and in some cases the set cement does not stay in a sealing condition throughout the production phase of a well. This may result in a cement sheath failure.
Long-term effects on cement integrity occur due to the change in temperature and down-hole pressures during production of a well. These factors act as

stress generators within the cement. If the set cement is exposed to more stress than it is designed to manage, the result could be fissures in the cement, debonding of cement from the formation or creation of a micro annuli between the casing and the cement. During production, the temperature may change and influence the sheath of the set cement. Studies done by (Goodwin & Crook, 1992) showed that when the cement was exposed to an increase in stress by casing expansion[4], the result was that the cement failed in the lower part of the string. When the temperature difference was even more significant in the upper parts of the well, tensile stress cracks were formed. An increase in the temperature leads to expansion of the casing outwards, and this expansion generates tensile stresses in the cement. The effect on the casing caused by temperature alternation is shown in **figure 2.6**.

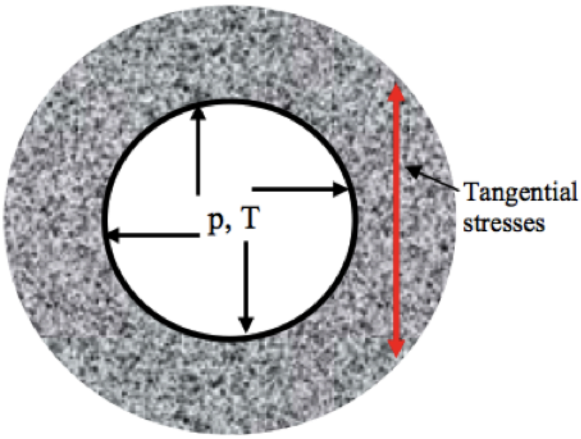

Figure 2.6: The figure shows stresses on the cement when the casing is expanding (Goodwin & Crook, 1992).

Casing contraction occurs when pressure in the wellbore decrease. This will cause the casing to pull away from the cement, and the may cause debonding between the casing and the cement. If this debonding happens, there will be created a micro annuli which makes way for fluids to migrate up the borehole on the outside of the casing.

To avoid failure of set cement, it is important to design cement systems that provides a proper well integrity throughout the life time of a well. In order to achieve this, the expected down-hole pressures and temperatures

[4]the expansion of the casing is mostly a result of alternations in the down-hole temperature

during production must be thoroughly calculated. By having knowledge of the type of fluids which will be run in the well, there can be done accurate simulations of the change in down-hole pressures and temperatures. To know the changes in the down-hole pressures and temperatures which may arise during the lifetime of a well, it is possible to perform computer-aided stress analysis to calculate what the effect this will have on the cement sheath. These simulations may help to identify the most suitable sealant system that can last throughout the lifetime of a well (Goodwin & Crook, 1992).

There are several reasons for how a cement job can fail. The cement can:

- set inside casing/liner
- be pumped too fast, resulting that the plug will not bump and hence the shoe track will not be cemented.
- pumping with too much pressure may cause a fracturing of the formation and which may lead to that the cement does not fulfill its objectives. The cement would not set correctly, and can thus not be approved as a barrier.

CBL logging is one of the few tools which can be used to get a confirmation of the quality of the cement job. The logging can be done with or without pressure. The best practice is with pressure, but this can lead to a micro annulus which can cause a risk in future operations.
Full returns are often used as an indicator that none of the fluids (also the cement) have been lost into the formation. However, full returns give little information about where the cement is located or about cement contamination. There is a need for further technical development in relation to proper cement placement and also on logging tools to verify cement integrity (Vignes, 2011). The Macondo accident is a prime example of what can happen when there is poor cement integrity in the well.

Well integrity issues as a result of bad cement jobs is well documented by the PSA in a survey performed in 2006 (Vignes & Aadnoy, 2008). The cement integrity can be further improved be keeping a focus on the performance of cement operations and by updating cement related standards (Vignes, 2011). In NORSOK D-010, the cement properties should be *impermeable, long-term integrity, non-shrinking, ductile (able to withstand mechanical loads/impact), resistance to different chemicals/substances (H_2S, CO_2 and hydrocarbons) and wetting (ensure binding to steel)* (NORSOK, 2011). Shrinkage is described as the main challenge with regards to cement hydration and *the cement stiffness and low elasticity is the second challenge* (Lende & Mikkelsen, 2010) (Vignes, 2011).

There is also a requirement in the NORSOK D-010 that permanent well barriers, i.e. cement, shall be tested in a long-term integrity perspective, but it is not described how to perform these tests. Thus, long-term integrity testing is a subject that needs further work.

On a side note, there is currently a new type of cement being developed called self-healing cement (SHC) (Bouras et al., 2008). The SHC is capable of being responsive and active even after it is set. The SHC is triggered by the presence of hydrocarbons. When the cement comes in contact with HC, the cement will start to swell. The swelling cement will close the leak paths which have occurred. However, it is important that the surrounding formation is stiffer than the cement to prevent it from expanding outwards into the formation, instead of towards the casing (Bouras et al., 2008). This is shown in **figure 2.7**.

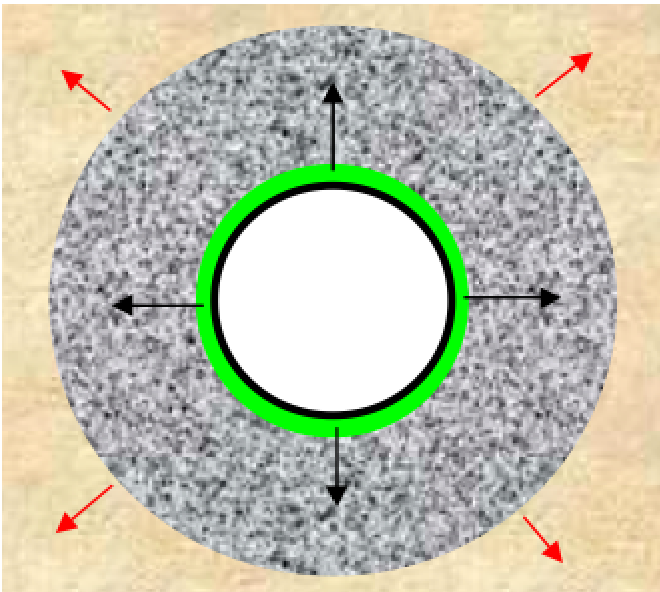

Figure 2.7: The figure shows the effects on the cement when the formation has a lower Young's modulus than the cement (Bouras et al., 2008). Here a micro annulus is created as shown in green due to cement expanding outwards.

The **figure 2.7** shows what may happen if the formation has a lower Young's modulus[5] than the cement. To prevent this, the cement can not only be given

[5]Young's modulus is a measure of the stiffness of an elastic material and is a quantity used to characterize materials (Wikipedia, 2012).

expanding qualities, but also a lower Young's modulus than the formation (Bouras et al., 2008).

More on cement in relation to plugs and casing, and cement acceptance criteria can be found in **section 2.5**.

2.3 Well integrity categorization

Well integrity categorization gives information about the status of a well, whether the integrity of the well is intact or not. The well integrity categorization used on the NCS today was presented by the OLF in 2007 as a response to an interest from both the industry and the authorities (OLF, 2010). This represents an important milestone for the Norwegian petroleum industry, and the step towards a higher focus on well integrity. The well categorization model was introduced in connection with the establishment of WIF (Well Integrity Forum) in 2007 which was a subgroup of the Drillers' Management Forum (a part of OLF).
The categorization matrix is a simple "traffic light" system where there are four different categories based on a double barrier principle; red, orange, yellow and green. The categorization is based on compliance to the barrier policy which is found in the NORSOK D-010 standard. On page 15 in NORSOK D-010 the following is stated: *There shall be two well barriers available during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled outflow from the borehole/well to the external environment.* (NORSOK, 2011). The green and yellow categories refer to either a healthy well where both barriers are intact or where one barrier is degraded. Both are considered acceptable (OLF, 2010). The orange and red categories refer to a well where either one barrier has a failure while the other is intact or both barriers have a failure/degraded. This is illustrated in **table 1**.
It is important to note that the categorization system evaluates all WBEs together. As a consequence of this, if a well has a TRSCSSV with a leak rate outside of the acceptance criteria for a given category (i.e. yellow), the whole well will be categorized in the orange category, even if all other WBEs are in perfect condition. The **figure 2.8** shows a plug which is not sufficient, and hence place the well in category red as shown in **table 1**.

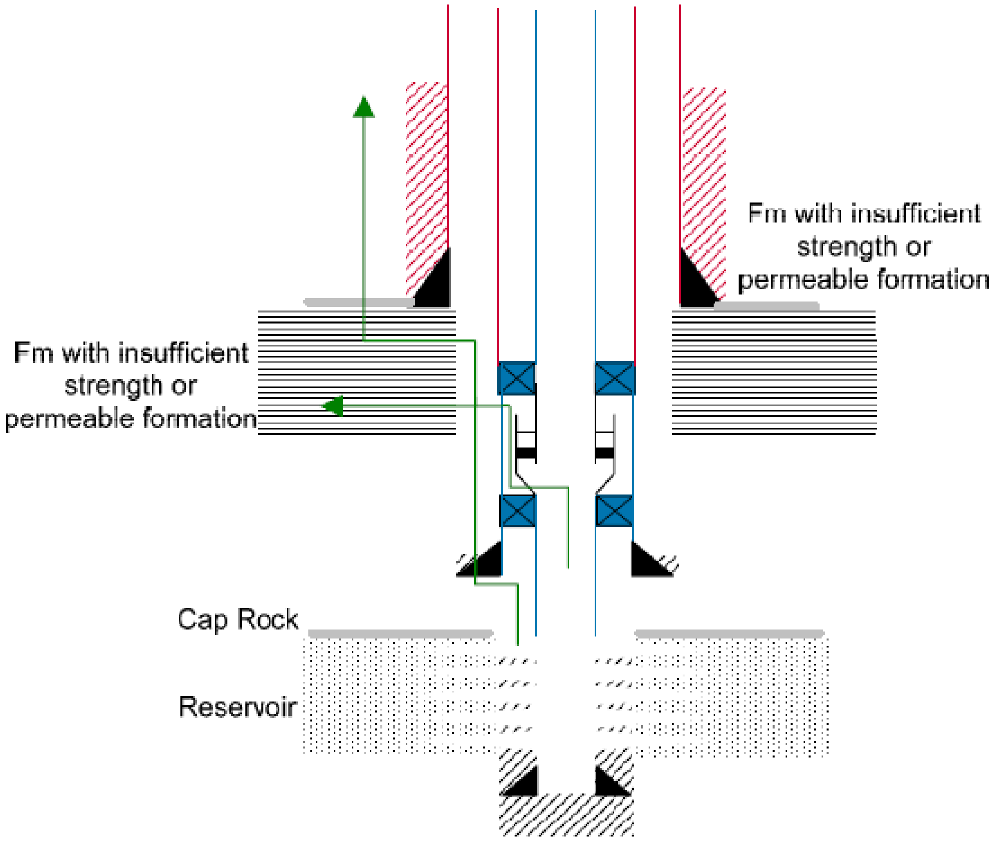

Figure 2.8: The figure shows a well barrier envelope which would qualify for the "red" category (OLF, 2010).

Green	Healthy well
Yellow	One barrier degraded, others intact
Orange	One barrier failure, one intact
Red	One barrier failure, one degraded or unverified

Table 1: The table shows how to determine the condition of a well with respect to barriers (OLF, 2010).

The well integrity categorization was implemented in the Risk Level in the Petroleum Industry (RNNP) in 2008 (Vignes, 2011). The statistics of analysis performed on a large number of wells every year since 2008 can be seen in **table 2**. From a slot recovery perspective it is interesting to look at the numbers from permanently P&A wells. In 2010, of the five wells tested, all were healthy (PSA, 2011f). The number of wells is too small to make any conclusions, but it indicates that knowledge regarding proper integrity measures in P&A operations are good.

Category	2008 (1677 wells)	2009 (1712 wells)	2010 (1741 wells)	2011 (1757 wells)
Red	1,0 %	1,0 %	0,3 %	0,46%
Orange	10,0 %	7,0 %	7,5 %	8,2 %
Yellow	13,0 %	16,0 %	17,8 %	18,33 %
Green	76,0 %	76,0 %	74,3 %	73,02 %

Table 2: Results of the well integrity analysis done by the PSA in 2009, 2010, 2011 and 2012 (PSA, 2009) (PSA, 2010) (PSA, 2011f) (PSA, 2012b).

It is advisable that the well integrity categorization should be included in the performance indicators (KPI) for all operating companies. Including this categorization, along with other HSE performance indicators such as serious incidents, falling objects and recordable injury frequency, it will increase the focus on well integrity issues, and further to prevent major accidents. Several incidents and accidents shows that the oil and gas industry need to have an increased focus on well integrity, barriers and well barrier elements function, qualification and verification including long-term integrity (Vignes, 2011). All of these aspects need to be implemented in all well phases from design to permanent P&A. Furthermore the well integrity focus needs to be imbued in all parts of operation from drilling and production, to injection and intervention to final P&A. The Snorre A and the Gullfaks C incidents and the Macondo accident are good examples that shows that there is a need to focus on well integrity in all phases of the well (Vignes, 2011).
NORSOK D-010 states that well barriers are established to prevent fluids or gases flowing unintentionally from the formation into another formation or to surface. Hence, the well integrity categorization has an association with risk, but it is not an absolute measure, thus it can not replace the risk assessments (Vignes, 2011).

2.4 Well barrier schematics

One major challenge with slot recoveries today is that most of the wells drilled 10-20 years ago have limited or no documentation of the original well barrier design. This makes it hard to keep updated records when intervention and maintenance work is done. The focus was simply not on "health checks" of the wells in the past, and this is emphasized on the data shown in **table 2** on **page 39**. Hardly any "health checks" were done on wells on the NCS prior to 2007. Numerous operations have been done, without any proper documentation, on wells dating back to the 1970's. Due to this, the barrier status is unknown of many of the wells on the NCS.

The importance of detailed well barrier schematics has hence increased during the last couple of years. In the latest draft, even the NORSOK D-010 standard have been updated with pre-defined well barrier schematics for the most common operations (NORSOK, 2011). Well barrier schematics most often describe the well barrier elements which are included in the primary and secondary barrier. The primary barrier is shown in its working stage, which for most situations is the fluid column or a mechanical well barrier that provides closure of the well barrier envelope (NORSOK, 2011). The secondary barrier is shown in its ultimately stage, which in most cases is a situation where the shear ram/valve is closed (NORSOK, 2011).

Several well barrier elements may be available in the well, but they will only serve as a containing barrier when they are interlinked into what is known as a barrier envelope. This is shown in the **figure 2.9** below.

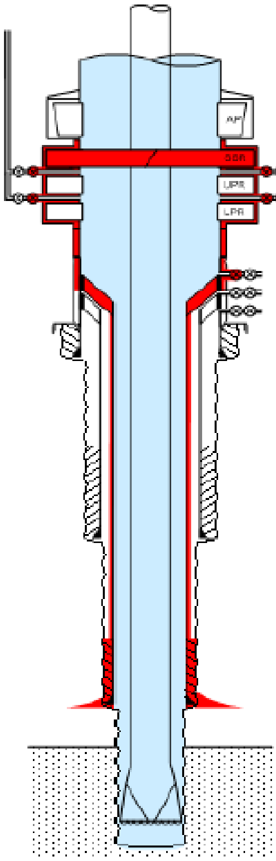

Figure 2.9: In a well drilling situations we see that the fluid column is acting as a primary barrier (blue color), and the secondary barrier (red color) represents the *envelope* consisting of casing, casing hanger, wellhead and BOP with the closed blind/shear rams (WellBarrier, 2012a).

The increased focus on the subject from the authorities emphasizes the importance for implementing robust WBEs in the operation program. This is highly important for future slot recovery operations - both knowing the original state of the well, but also to see an updated view as intervention/sidetracks/maintenance/etc. operations are done.

In the **appendix D** there is provided a checklist to verify the content which should be included when creating well barrier schematic.

Well Integrity Forum (WIF) has created some guidelines in the document *Recommended guidelines for well integrity* of the minimum data which should be included in a well barrier schematic. These are:

1. *The formation strength should be indicated for formation within the*

barrier envelopes.

2. *Reservoir(s) should be shown on the drawing.*
3. *Each barrier element in both barrier envelopes should be presented in a table along with its initial integrity-verification test results.*
4. *Depths should be shown relatively correct according to each barrier element on the drawing.*
5. *All casing and cement, including the surface casing, should be on the drawing and labelled with its size.*
6. *There should be separate fields for the following well information: Installation, well name, well type, well status, rev. no and date, "Prepared by", "Verified / Approved by".*
7. *Include a Note field for important well integrity information* (OLF, 2010).

The Snorre A incident in 2004, which will be discussed in **section 4**, is a prime example of what the causes may be if the well barrier schematic lack proper exchange of experience from operation to operation, or do not meet these guidelines. When the slot recovery operation commenced on SNA, there was little, if any, knowledge of the status of the different barriers.

2.5 Plug and abandonment

The purpose of this subsection is to give an overview of the required well barriers and the use of qualified WBEs during abandonment operations given by the NORSOK D-010 standard. The subsection is divided into three parts, the first dealing with general requirements when performing abandonment operations. The second subsection will be more specific on temporary abandonment of wells where continued operation is planned, while the third part will cover permanent abandonment of wells. The latter part is interesting with regards to sidetracking and slot recoveries since the main wellbore is required to be permanently plugged prior to construction of a new wellbore with a new geological well target.
The focus in this subsection will be on isolation of permeable formations and reservoirs and required barriers for different types of abandonment operations. Requirements for isolation of formations are the same for both temporary and permanent abandonment, but the choice of WBEs may be different depending on the abandonment time (NORSOK, 2011). The ability to re-enter the wellbore or resume operations after some time will also affect the abandonment design. Hence must the material quality used in a permanent abandonment operation be of a higher order than for the case of a temporary abandonment.

A little digging in numbers shows that there are approximately 500 offshore installations on the NCS, and about 2200 wells are to be P&A permanently in the near future (Vignes, 2011). This clearly emphasizes the challenges both authorities and operators are facing when looking for solutions to perform P&A operations safely and in a robust manner. In connection with the field decommissioning which are taking place on the NCS now, the industry is talking about a "big wave" of permanent plug and abandonment of wells. Statoil alone has around 1100 wells which will need to be plugged and abandoned over the next 5 to 25 years. Almost half of these are sub-sea wells (Statoil, 2011a). Several of these wells will qualify[6] for a temporary abandonment, which means they may at some stage be eligible for a slot recovery. Hence must the design of a temporary abandonment be designed to make a possible future slot recovery operation as effective as possible.

Well barrier schematics will be given for different scenarios as defined by the NORSOK standards, and can be found in **appendix A** .

[6] Qualify here refers to a well which has just been shut down due to being unprofitable, but where the reservoir is of a such character that it may once in the future prove to be profitable again

A specific overview of the required barriers in each well section is presented in the **table 3**.

Name	Function	Purpose
Primary well barrier	First well barrier against flow of formation fluids to surface, or to secure a last open hole.	To isolate a potential source of inflow from surface.
Secondary well barrier to reservoir	Back-up to the primary well barrier	Same purpose as the primary well barrier, and applies where the potential source of inflow is also a reservoir (w/flow potential and/or hydrocarbons).
Well barrier between reservoirs	To isolate reservoirs from each other.	To reduce potential for flow between reservoirs.
Open hole to surface well barrier	To isolate an open hole from surface, which is exposed whilst plugging the well.	"Fail-safe" well barrier, where a potential source of inflow is exposed after e.g. a casing cut.
Secondary well barrier, temp. abandonment	Second, independent well barrier in connection with drilling and well activities.	To ensure safe re-connection to a temporary abandoned well, and applies consequently only where well activities has not been concluded.

Table 3: The table gives an overview of the specific barrier requirements given in different sections of the well (NORSOK, 2011).

Several main criteria are to be fulfilled in order to characterize the well as permanently P&A or temporarily abandoned.

1. Length of cement plug in direct contact with a solid fundament.
2. Cross section of cement within acceptance criteria.
3. Positioning of the barrier. They must be placed at a depth with sufficient formation integrity. It is also important to place the barrier as close to the source of inflow as possible[7].
4. Verification of barriers. The above points need to be verified. This is done through logging, pressure testing and by load testing.

The length of the plug varies with different scenarios, i.e. proximity to reservoir, or if the casing shoe is set with a mechanical plug. The requirements

[7] A permeable zone where fluid is expected to flow, not necessarily a reservoir.

from NORSOK are complex, and therefore this thesis will not go into details regarding the necessary plug lengths for different scenarios. They are instead illustrated in **figure 2.10**. The acceptance criteria are listed in **appendix B** for a complete overview.

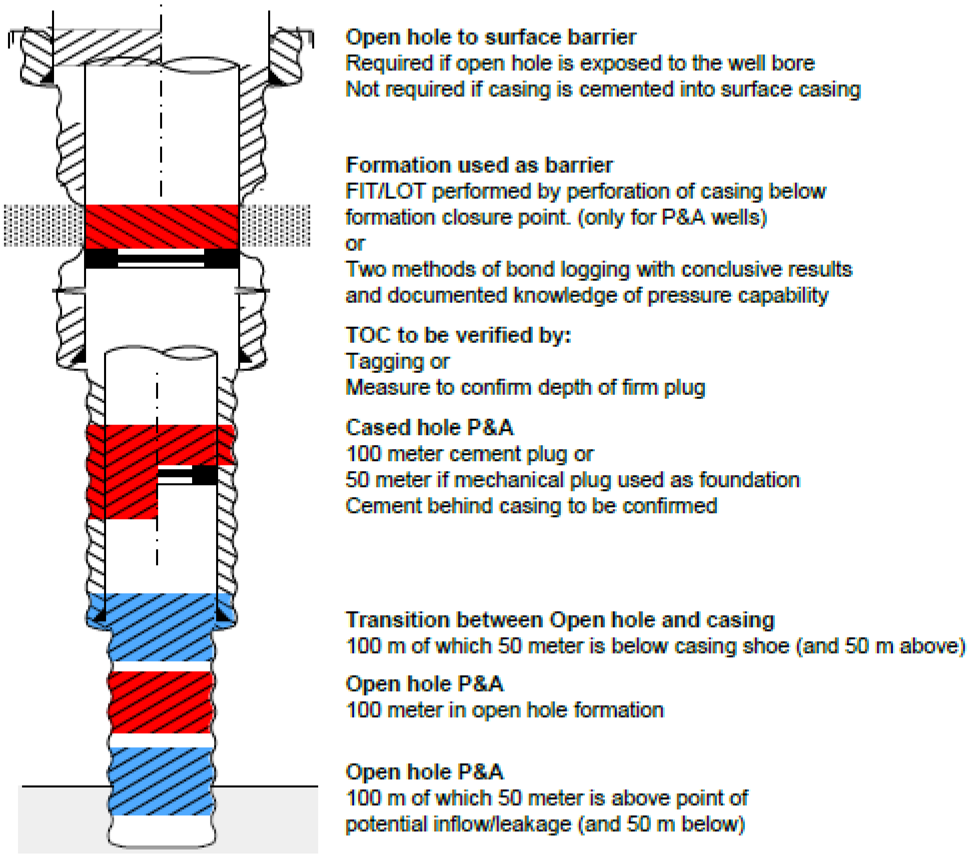

Figure 2.10: The figure shows cement plug criteria as per NORSOK D-010 (WellBarrier, 2012b).

The **figure 2.11** shows an example between a correct set plug as opposed to a plug which is set incorrect.

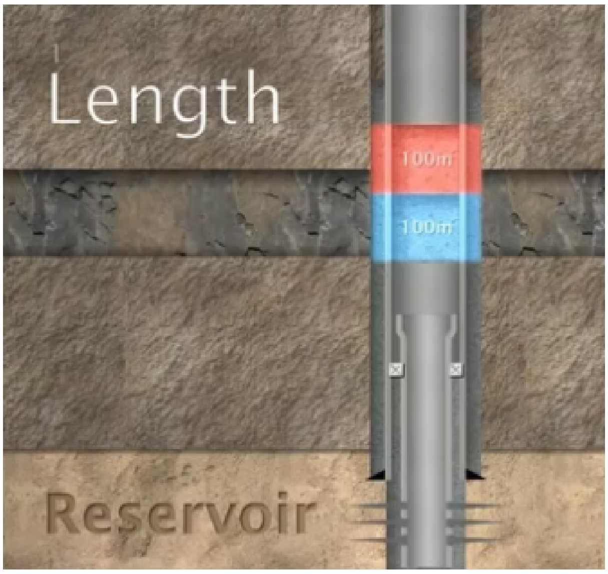

Figure 2.11: The figure shows a cement plug which has acceptable contact to a fundament, and also one which does not meet the acceptance criteria (Statoil, 2011b).

The barrier must extend across the full cross section of the well. This includes all annuli, and it must seal both vertically and horizontally (NORSOK, 2011). This is illustrated in **figure 2.12**.

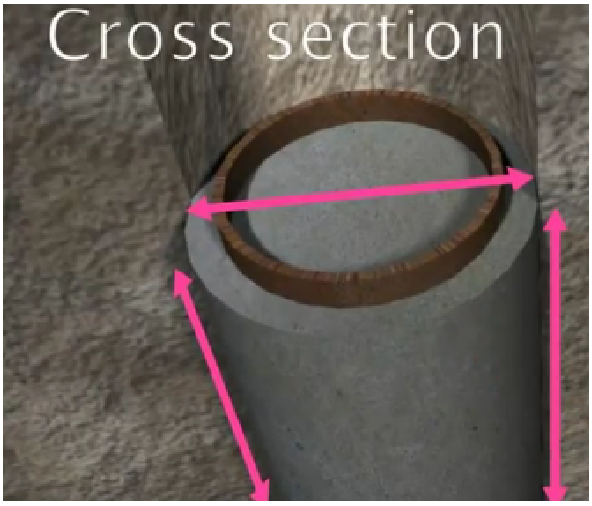

Figure 2.12: The figure shows what it looks like when the well is correctly sealed both across the cross section and vertically and horizontally (Statoil, 2011b).

The **figure 2.13** shows acceptance criteria for cement in connection with the casings.

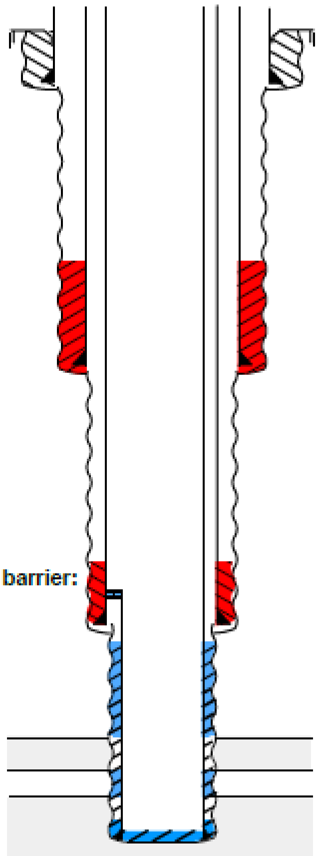

Figure 2.13: The figure shows different casing cement requirements as per NORSOK D-010 (WellBarrier, 2012b).

Figure 2.13 shows different casing cement scenarios with the associated requirements as defined in NORSOK D-010.

The barriers must be placed at a depth with sufficient formation integrity. It is therefore important to know the minimum formation stress at the base of the barrier. It is also essential that the *position* of the barriers is placed so that the estimated formation fracture pressure at the base of the barrier is in excess of the potential internal pressure.
It is a general requirement to place the barrier as close to the source of inflow as possible. They shall also cover all leak paths (NORSOK, 2011).

The mindset of correct barrier placement is shown in **figure 2.14**.

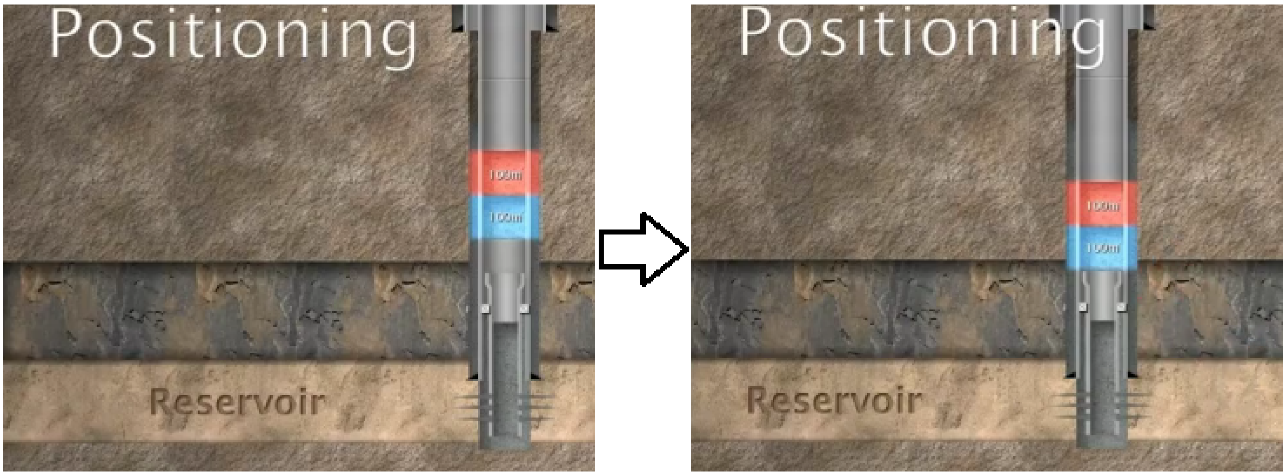

Figure 2.14: The figure shows how to correctly position the barriers. In the case on the left the barrier is placed too shallow, and should be moved deeper as illustrated on the right (Statoil, 2011b).

The three before mentioned requirements, length, position and cross section must be verified. This is normally done by logging, pressure testing and by load testing. An illustration of a pressure test is shown in **figure 2.15**.

Figure 2.15: The figure illustrates a pressure test on the barriers. This is done to verify the integrity of the barriers (Statoil, 2011b).

NORSOK D-010 defines verification of cement plugs in the following manner: *The plug installation shall be verified through documentation of job performance; records fm. cement operations (volume pumped, returns during cementing, etc.). Its position should be verified, by means of: tagging, or measure to confirm depth of firm plug* (NORSOK, 2011).
Receiving full returns is used as an indicator of fluids not being lost into the formation. This also applies to cement which can be regarded as a fluid. What full returns do not give information about is the placement of the cement plug, or its location. Further development work related to cement placement, mechanical properties and design is needed in order to verify cement integrity (Vignes, 2011). More on verification of barriers will be found in **section 3.3**.

2.5.1 Temporary plug and abandonment

Temporary well abandonment is a well status where the well is abandoned and/or well equipment is removed. The intention here is that operation will be resumed within a given time frame[8] (NORSOK, 2011). It must be possible to re-enter the wellbore in a safe manner. If the temporary abandonment is planned to last for a longer period (years), degradation[9] of the casing bodies should be investigated (NORSOK, 2011). This must be done in order to be certain that the casings will not start to leak over a given time period as a result of i.e. corrosion.

In 2012, PSA published an article about the state of the temporarily abandoned wells on the NCS. It was believed up until 2011 that approximately 40 wells were temporarily abandoned on the NCS (Anda, 2012). The result turned out to be very different after questioning the companies responsible more thoroughly about the state of the wells which was neither active nor permanently plugged. The questionnaire discovered that a total of 193 wells was still being regarded as temporarily abandoned as per 14th of February 2012. Several of the wells had been untouched for 30-40 years, the oldest being abandoned in 1970. This is not in accordance with PSAs understanding of the term *temporarily abandoned* (NORSOK, 2011). The investigation also concluded that as many as 6 wells were in category red, and 15 wells in the orange category[10] as defined by OLF. Both these categories are regarded as unacceptable, and demands immediate action to improve barrier integrity. The result of these investigations might cause a change in the regulations in order to prevent these kind of incidents in the future (Anda, 2012).

Temporarily abandoned	Formation
Two barriers	Permeable or impermeable formation with overpressure or reservoir exposed (HC present)
One barrier	Permeable or impermeable formation with normal pressure (or less)

Table 4: Number of barriers required in a temporary abandonment in wells with specific formations present (Statoil, 2011b).

Table 4 shows an overview of the required number of barriers[11] given differ-

[8]Everything from days to years.
[9]A decline to a lower quality.
[10]See **table 1** on **page 38** for complete overview of the different categories and their meanings.
[11]As given by the NORSOK standards

ent types of formations.

Well barrier schematics for different temporary abandonment scenarios are shown in **figure A.1** and **figure A.2**.

2.5.2 Permanent plug and abandonment

A permanent abandonment is a well status where the well, or part of the well, is to be plugged and abandoned permanently. The intention here is that the main wellbore is never to be used or re-entered again. The permanent plug and abandonment is also done on the original wellbore prior to a slot recovery or a sidetrack as required by NORSOK D-010 (NORSOK, 2011).
A permanent P&A operation is completed by using well barriers consisting of several WBEs which in combination creates a seal that ideally has an eternal perspective.

A permanent WBE shall have the following properties:

- Impermeable
- Long term perspective with regards to integrity
- Non-shrinking
- Resistant to chemicals (be non-reactive with known substances in a well such as hydrocarbons, CO_2 and H_2S
- The material must be ductile[12].
- The material must be wetting to ensure it bonds to the steel (NORSOK, 2011).

A steel tubular is not to be recognized as a WBE unless it is supported by cement (NORSOK, 2011). Also, the materials used for plugging the well must withstand the load and environmental conditions it may be exposed to at the time of abandonment. Tests and loggings should be performed in order to document the long term integrity of the plugging materials used (NORSOK, 2011).

Table 5 gives an overview of the required barriers given different formation types.

[12]Able to withstand mechanical loads and impacts.

Figure A.3, **A.4**, **A.5** and **A.6** shows well barrier schematics for permanent abandonment given different scenarios.

Permanent P&A	Formation
Two barriers	Permeable formation with overpressure or exposed to a reservoir (HC)
One barrier	Impermeable formation with overpressure
One barrier	Permeable formation with normal or less pressure

Table 5: Number of barriers required in a permanent P&A operation in wells with specific formations present. This is applicable for wells where no continued operations are planned or where a slot recovery operation is planned above the original well path.

A more specific overview of the required barriers in each well section is more thoroughly presented in the **table 3** on **page 46**.

Control cables and line shall be removed where permanent well barriers are installed. This must be done in order to prevent vertical leak paths through the well barrier. Removal of down hole equipment, however, is not needed as long as they do not interfere with the integrity of the well barriers (NORSOK, 2011).

There are also some special requirements when dealing with permanent abandonment, and that is when multiple reservoirs are located within the same pressure regime. This type of situation allows the operator to regard the multiple reservoirs as one, thus simplifying the plugging operation (NORSOK, 2011). An example of how this looks is shown in **figure 2.16**.

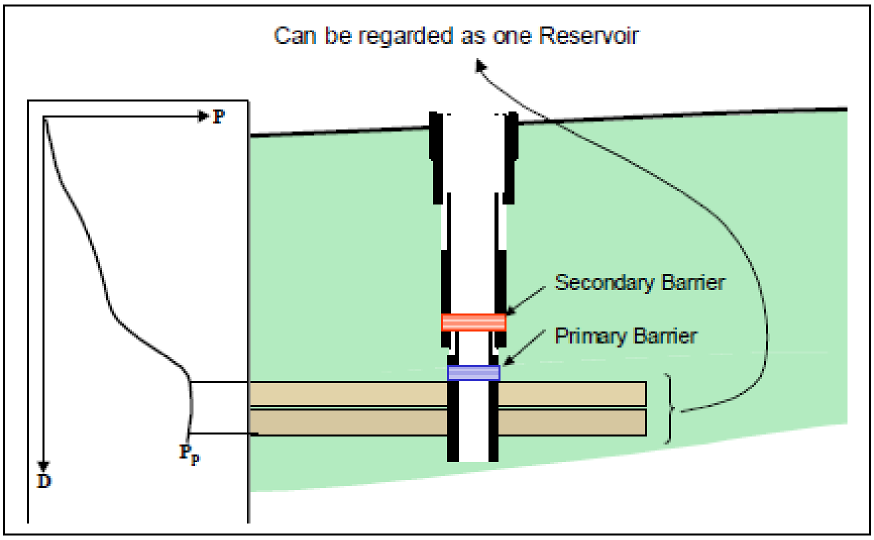

Figure 2.16: The figure shows two separate reservoirs where there pressure in the deepest reservoir is either equal or less than the pressure in the shallower reservoir. They can therefore be regarded as one reservoir in an abandonment perspective (NORSOK, 2011).

3 Well barrier management during slot recovery operations

As mentioned in earlier sections, the hard part about a slot recovery is not necessarily the operation itself. The tricky part is often the knowledge regarding the state of the well, and the current barriers in place. Sometimes even, it may be impossible to get a proper verification of certain barriers. Especially the old wells from the 70's and the 80's have a poor well history documentation, so a re-entry of these kind of well may be like a treasure hunt - you never know what you will find.
This first subsection will include a thought experiment on barrier control to illustrate the importance of future well integrity as well as designing the right well barrier program for today's operations.

Imagine building a fence around a house. The first question would be what the purpose the fence should have. Which needs or tasks should the fence fulfill? You would probably identify some properties which are desirable or expected of a fence. It shall limit the possibility for trespassing, hinder children from getting outside of the garden, or maybe it needs to have an esthetical look to it. Alternatively, the needed properties of the fence may be to scare people from climbing over it, hence it will need barbed wire. In all cases, cost will also be of importance.
The fence serves to illustrate that tools and systems often are met by a series of requirements which needs to be fulfilled. Those who design the task first needs to decide the desired properties, and then identify which properties one can actually fulfill. The final solution will often be a compromise between different interests, but where some properties are not to be negotiated on. One example of this will be that it may be impossible to create a fence which is both esthetical and impossible to climb over.
When the design process is done, and the properties selected, one may have to consider again what has to be done in order to maintain the original properties. You could tell your kids about the consequences of climbing the fence and running out on the streets. This measure would not give the same safety as a very tall fence would give. It will always be a relationship between the risk picture you are facing and those measures you have established to handle this risk picture. There are few, if any, perfect solutions which takes care of all the risk aspects and at the same time maintains all the other properties you would want the fence to have.
When the fence is finally completed, you must essentially ensure that it fulfills the inherent properties as time goes. It is of little help that you once had

a good fence if someone kick or cut it open. Furthermore, the risk picture must be updated, and the fence's properties must naturally follow the risk picture. Maybe new children are born which gives new challenges, or maybe the fence is now too small for the bigger children who are using the fence as climbing equipment. The point is that the risk picture is constantly changing, and the need for risk reducing measures will be changing in a corresponding manner. Lack of monitoring the state of the fence will result in a lack of needed properties when you really want them.

As might guessed already, the fence only serves as a metaphor to the familiar term *barriers*. This section will mostly address well barrier control in the petroleum industry, and all the challenges which are encountered throughout the lifetime of a well. All this will be done with slot recoveries as a basis. As previously mentioned, the real issue with a slot recovery is the lack of a proper well history documentation which makes re-entries of old well slots unnecessarily difficult. The goal of this section is to present ways to make slot recoveries easier in the future, and also what is needed in terms of well integrity, especially with regards to planning, during slot recovery operations. Even though the thought experiment above only serve as a metaphor, it illustrates well the principles and processes which needs to be present for proper well integrity. It is all about understanding the potential dangers which we are facing, and that the risk aspects never are static. The result of this is hopefully that solutions are implemented to reduce the specific risk picture down to an acceptable level, and that potential risks in the future are well considered. There is a need to evaluate the uncertainty constantly, since it is possible that the original barrier design did not consider for all the potential challenges which may be encountered during the lifetime of a well. These uncertainties may show the original design was not so robust as the purpose was.

Proper well integrity is not all about technical and operational solutions in the design phase. It is also about maintaining the solutions over time, and ensuring that those who directly or indirectly, through decisions and actions, affect the risk picture and/or the barrier's properties, has a solid knowledge of the consequences. This is often seen violated against in major accidents as later sections will reveal.

With the metaphor of the fence, it is of little value to expect the fence to be intact in all foreseeable future if there are no inspections or maintenance facilitated on a regular basis, plus allocation of time and recourses needed to close the holes when they are discovered. Proper well integrity is as much about dealing with the current risk picture after the barriers are established, and to ensure that the barriers maintains their properties in the future, as it is about establishing good solutions in the design phase. Good and simple solutions, which gives the barriers inherent and robust properties will contribute hugely when it comes to dealing with the prevailing risk situation, and will also ease the slot recovery operations in the future.

This introduction to barrier control and well integrity is based on the preface of PSA's document (PSA, 2012a).

3.1 Barrier control

As seen throughout this thesis, there are many requirements which can be related both directly and indirectly to barriers. Consistent control of barriers requires a complete understanding of key connections in the regulations.
In §5 of the management regulations on the NCS states primarily:

- that barriers shall be established to reduce the probability of failures and hazard and accident situations developing,
- the barrier function shall be maintained throughout the facility's lifetime.
- there should be performance requirements for technical, operational and organizational elements that are necessary for the individual barrier to be effective,
- there shall be established strategies and principles for the design, operation and maintenance of barriers (PSA, 2011d)

The term *barrier function* has not been specifically defined previously in the thesis, so to avoid any misunderstandings, a barrier function can be something that:

- prevents leaking
- prevents ignition of flammable materials
- maintains proper evacuation etc.

A hierarchy must often be established in order to realize certain barrier functions. An example of this is the above example of *prevention of ignition of flammable materials*. To achieve this there would be a need to detect a leakage, isolate leaking segment, implement depressurization etc. An example of a hierarchy of barrier functions is shown in **figure 3.1**.

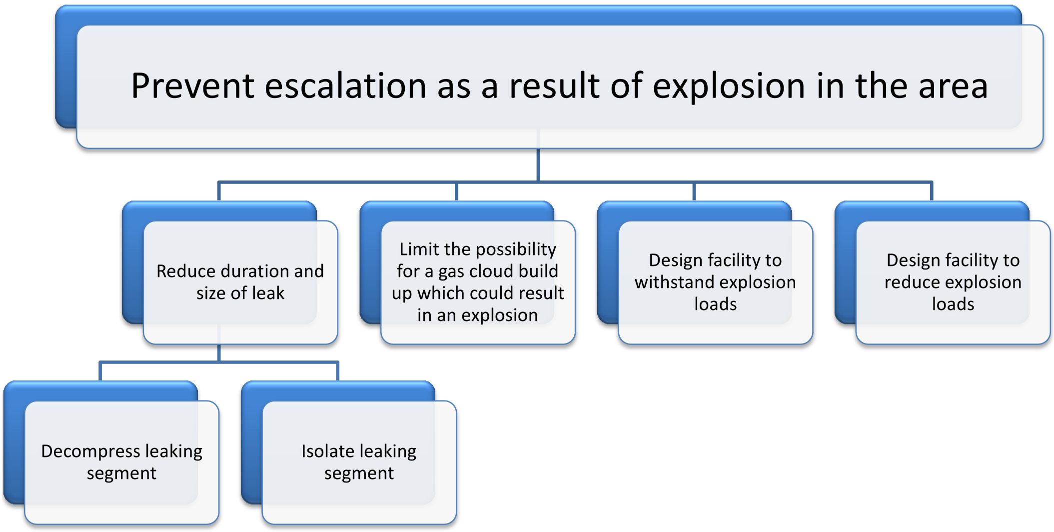

Figure 3.1: The figure shows a hierarchy of barrier functions, and how certain barrier functions are dependent of the implementation of other barrier functions.

The definition of barrier functions is important when the term *barrier control* is to be defined. PSA has established the following definition of barrier control: *barrier control is coordination of activities to establish and maintain barriers so that they at any time maintains its function.* Barrier control includes the processes, systems, solutions and measures which needs to be in place to maintain necessary risk reduction through implementation and supervision of barriers. To handle risks properly, the required barrier functions and barrier elements need to be identified. These aspects has to be based on a specific context and risk picture. The next subsection will cover the whole risk analysis aspect.

The model for barrier control which will be used in this section is seen in **figure 3.2**.

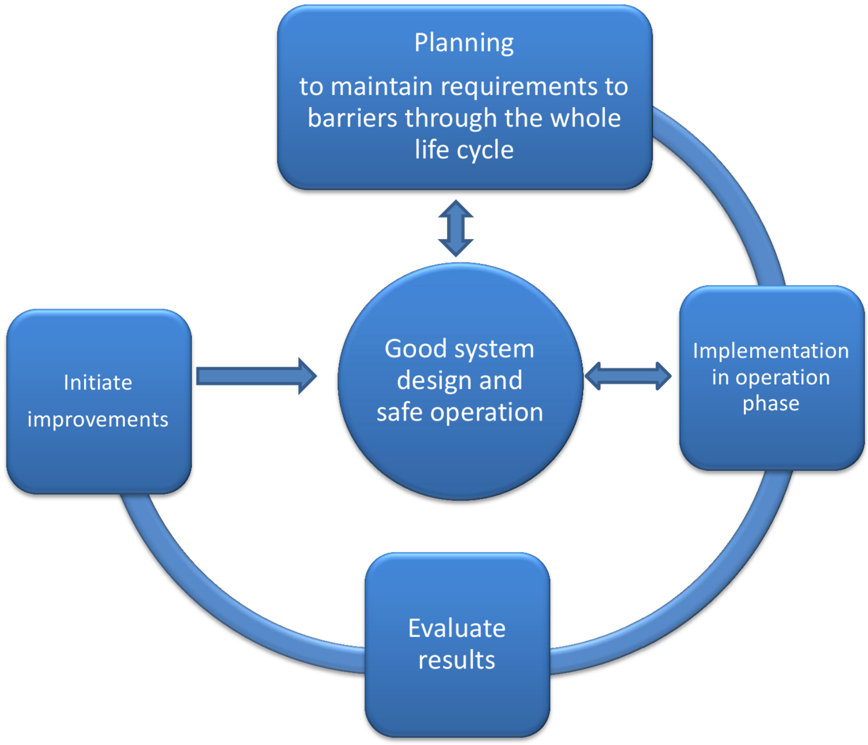

Figure 3.2: The figure shows a model for barrier control. The model is based on models found in (PSA, 2012a).

3.2 Risk analysis

With ISO 31000:2009 (Risk management - Principles and guidelines), the ISO standard 17776:2002 (Guidelines on tools and techniques for hazard identification and risk assessment), NORSOK Z-013 (Risk and emergency preparedness analysis), the NORSOK S-001 (Technical safety - performance standards) and several documents published by the PSA, this section will cover every aspect of risk analysis with regards to well integrity. This investigation will have well integrity during slot recovery operations as a main focus.

The connection between the framework and the processes according to ISO 31000 is illustrated in **figure 3.3** below.

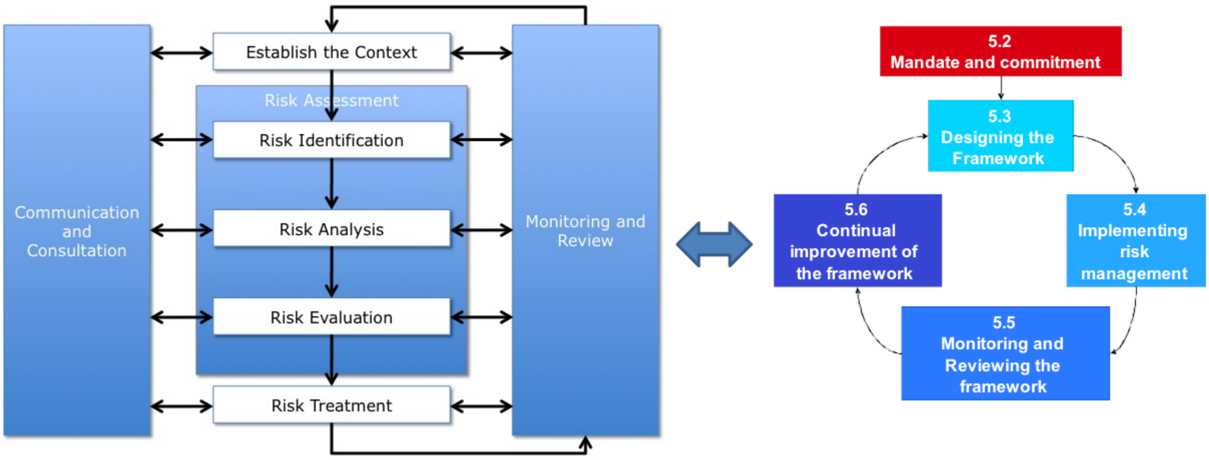

Figure 3.3: The figure illustrates the connection between the different processes in risk management on the left and the framework on the right. The figure is based on models found in (ISO, 2009).

This subsection will mainly discuss the planning phase of barrier control shown in the top box in **figure 3.2**. This planning process is more detailed illustrated in **figure 3.4**. The subsection will discuss several of the different steps in the model, and the connection between them.

The other phases of barrier control shown in **figure 3.2** will be mentioned in later sections.

The context behind the model in **figure 3.4** must be discussed briefly before the investigation of risk analysis in well barrier management can commence.

Context

The context is the framework and guidelines which are of significance for the execution of the other steps in the process. Some elements in a planning phase will be important for the operation, while other elements will be important for the solutions the process results in (PSA, 2012a). In an early phase of the planning process, the possibilities to influence the design and equipment are the best, so an important part of the context will be to describe which parts of the operation are subject to reviews and which are not. An example of this is when planning for an operation on an old rig (which is often the case during slot recoveries). The condition and the layout of the rig will thus be a central part of the context.
To achieve robust and solid solutions which contributes to continuously improvement of the barriers, the requirement of risk reduction[13] must be a part of the context.
By establishing ambitious goals and performance requirements as a part of the context, the future analyses will elucidate that robust solutions have been chosen. This is a problem on the NCS where rigs built on the 70's and 80's were built to last 20 years. Many of these rigs are still operating today, contributing to a high risk factor just by being old and under-maintained. An example of an operation where an old rig was used, and the consequence of that, is discussed in **section 5**. By establishing all the performance requirements late in the planning phase, several cases have shown that cost and time consuming measures had to be implemented at a later stage (PSA, 2012a). These late changes often do not result in equally robust solutions.

[13]often done with the ALARP principle.

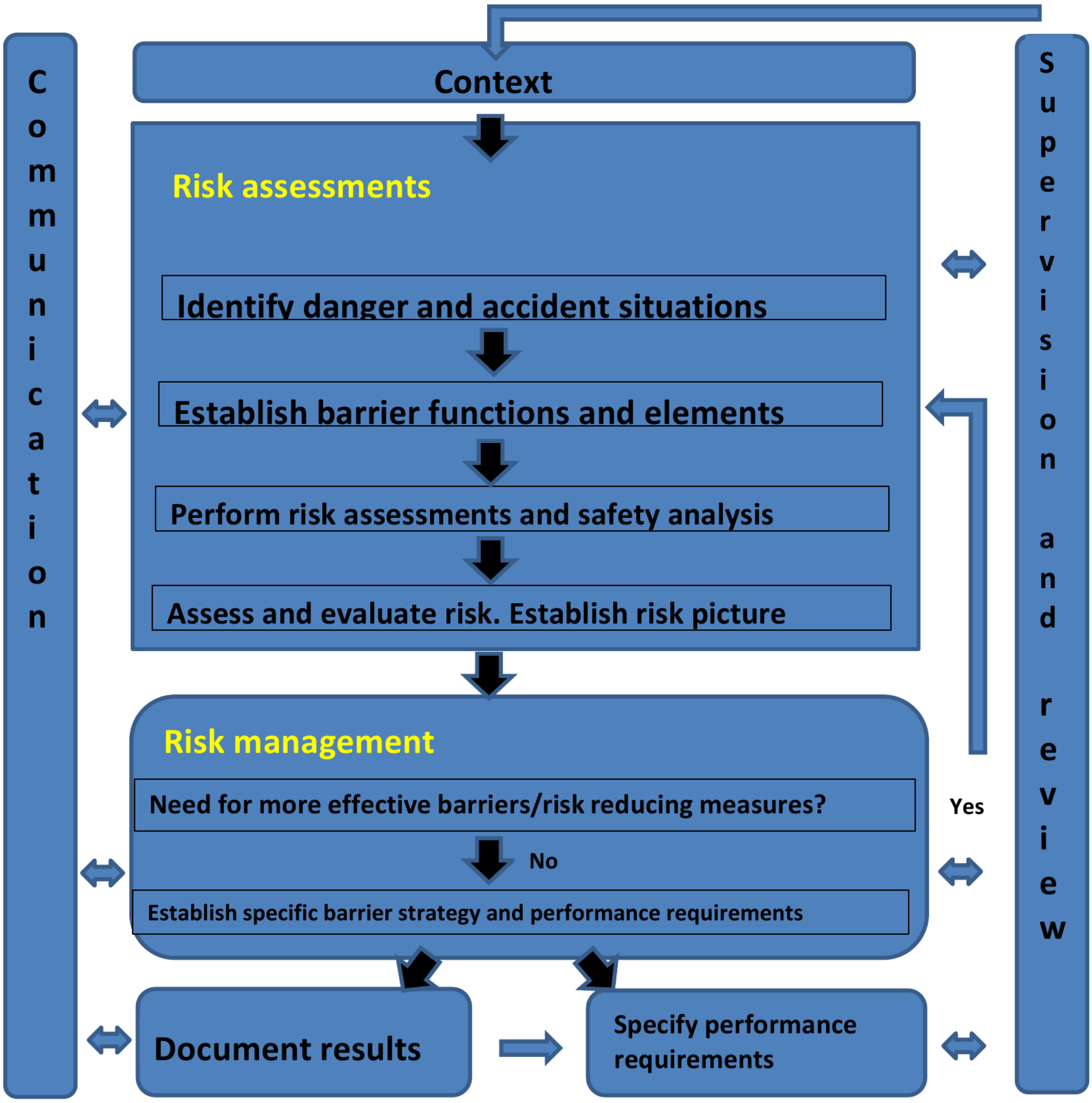

Figure 3.4: The figure shows a barrier control process with the planning phase in focus. The model is based on models found in (PSA, 2012a) and (ISO, 2009).

3.2.1 Risk assessments

The context in **figure 3.4** is now established, so the next level in the model is the risk assessment. The risk assessment's function is to contribute to the identification, establishment and description of barrier functions, and specify the properties of each well barrier element. The umbrella term *risk assessment* includes, as the model in **figure 3.4** implies, the following steps:

- Identify danger and accident situations
- Establish barrier functions and elements
- Perform risk assessments and safety analysis
- Establish risk picture

The following subsections will address these points more thoroughly.

Identify hazardous and potentially disastrous situations

The identification of potential disastrous situations has to be sufficiently detailed in order to clearly document all situations where specific WBEs may contribute. More specific, this means that in most cases the identification takes place in smaller areas, i.e. fire areas. Then it is important to assess the different events which may take place in the area and other events which may indirectly influence the specific area.
The strategy is important in this initial risk identification. The strategy should end up with a documentation of the role of every WBE which are established, and how they will handle the risk picture. To establish a good strategy it is crucial to consider how to collect and document the connection between hazardous situations and the barriers which are established (PSA, 2012a).

According to NORSOK Z-103, a hazard identification shall include:

- *A broad review of possible hazards and sources of accidents, with particular emphasis on ensuring that relevant hazards are not overlooked.*
- *Internal/external incident reports that are applicable.*
- *A rough classification into critical hazards (as opposed to non-critical) for subsequent analysis.*
- *Explicit statement of the criteria used in the screening of the hazards.*

- *Explicit documentation of the evaluations made for the classification of the non-critical hazards* (NORSOK, 2009).

The identification process is often abbreviated *HAZID* in the industry. Recommended tools in a HAZID are found in appendix C and D in the ISO standard 17776:2000, and will not be repeated in this thesis (NORSOK, 2009).

An important factor when performing a HAZID is to have relevant and up-to-date information available. Relevant people with appropriate knowledge of the previous operations should be involved in the identification work (ISO, 2009). In a slot recovery operation planning phase, both these factors can be difficult to achieve. The original wellbore may be up to 30 years old, thus may the people who were involved in the first operations have changed company, retired or otherwise be unavailable to be involved in a new HAZID analysis. Also, the original wellbore may have been exposed to numerous pressure tests, maintenance work, a harsh chemical environment (which may have led to corrosion or otherwise caused a degradation of casing strings), extensive fishing operations etc. Hence, the situation regarding the well barrier status may be very unclear and complex. There may be no updated documents regarding the technical status of the well (as seen on the incident on SNA in 2004). This is a subject of documentation handover which will be discussed in **section 3.4**.

For a slot recovery operation there are numerous potential challenging situations which may occur. The main points will be:

- Identify well barrier status. This is a difficult assessment as several well barrier elements can be hard to test and verify. More on an example of this can be found in **section 5**.
- What is the condition of the rig? Will the rig be able to handle a modern operation? Many rigs have already passed their life expectancy and may break down during operation, thus creating unexpected and possibly dangerous situations.
- Plug and abandonment of the original wellbore. The integrity during P&A of the original wellbore prior to drilling the sidetrack is important due to the fact that several of the WBE may be old, thus very fragile.

Establish barrier functions and elements

When the HAZID is done and evaluated, there is a need to establish barrier functions and elements with the associated technical performance requirements. Much of the topic related to barrier functions and elements are discussed in **section 1.4**, and will not be repeated in this section.

To end up with robust solutions regarding well barrier elements there is a need to establish necessary barriers for different types of events at an early stage in the planning phase. Early in the process there must be awareness around whether sufficient barrier envelopes have been implemented, or not, even though the more specific technical performance requirements are established later in the planning phase.
For a slot recovery operation, the barrier envelope has already been established. The main factor in the planning phase of a slot recovery operation will therefore be to verify that the barrier envelope meets the requirements needed for the operation. The barriers must be tested prior to completing the design of the operation. I.e., if the initial plan is to re-use the original 20" surface casing, but pressure tests show that the casing is degraded (corroded, bursted or otherwise degraded), the initial plan needs to be re-evaluated. A case where the 20" surface casing showed a failure during a slot recovery operation, and the initial plan had to be rejected and edited, is discussed in **section 5**.

Conduct risk assessments and necessary safety studies

The risk analysis are to be used e.g. to identify the need for barrier functions and to establish requirements in relation to the barrier elements. The risk assessments which are to be performed must focus on how to achieve sufficient independence between the barriers and how robust barriers can be established. The part of the risk analysis which assess and clarifies the sensitivity and uncertainties in the operation, and which are later to be included as a basis for further risk assessments, are in this context important (PSA, 2012a).
The risk assessment is an extension of the previous mentioned HAZID. The assessment is more about developing an understanding of the risk (ISO, 2009). The analysis serves as an input to the further risk evaluation to make it possible to take the right decisions on whether risks needs to be treated and minimized, and subsequently what the most appropriate risk treatment and strategies then would be. In a slot recovery there will be several uncertainties and possible areas where risk needs to be minimized, hence a thorough risk

assessment prior to any actual operation on the well is absolutely required.

Evaluate risk - establish a risk picture

The last step according to **figure 3.4** is to evaluate the risk and establish the risk picture. The purpose of the risk evaluation is to assist in the decision making which is based on the risk analysis in the previous step. In the risk evaluation it needs to be decided which risks needs treatment, and which risks to prioritize (ISO, 2009). In (PSA, 2011d) §17 regarding risk analyses, sensitivity and uncertainties shall be evaluated in every analysis. This shall be done so that the users of the analyses gets full knowledge of each analysis' strengths, weaknesses and limitations or assumptions, requirements or assessments which are the basis for the result of the analysis (PSA, 2012a). This is also done in order to make the involved personnel aware of the uncertainty of the risks in the operation.

The risk evaluation forms a basis for the RAC (risk acceptance criteria). The risk acceptance criteria illustrate the overall risk level which is determined as tolerable (NORSOK, 2009). Appendix A in the NORSOK Z-103 includes a comprehensive discussion of aspects related to defining the RAC, and will therefore not be repeated here. Uncertainties uncovered in the risk assessments may be reduced by making sure that the RAC are satisfied with some margin (NORSOK, 2009).

In a slot recovery operation the need to have a complete overview of the situation prior to operation start-up is absolutely necessary. The information regarding the original wellbore may not be stored in one place, but instead scattered around in different physical or digital folders. A 20-year-old well may have undergone several different operations (fishing, maintenance, re-completions etc.) which will alter the initial status of the well. Also, as mentioned earlier, it might be difficult/impossible to get a proper test of each barrier element. This information needs to be implemented in the uncertainties of the operation, and how these uncertainties can be kept to a minimum. I.e., maybe testing of the 20" surface casing proved to be impossible. In a such case, or similar, there must be a back-up plan to handle the situation. This is referred to as a *contingency plan* in the industry. In NORSOK D-010 §4.8 the requirements regarding contingency plans are listed. However, the only requirements in this section is for a worst-case scenario - a blowout.

The Section 4.8.1 states that a blow-out contingency plan shall be established for each installation. This plan shall include:

- *strategy for killing the wells,*

- *requirements relating to position measurements of wellhead and well bore trajectory,*
- *necessary equipment, personnel, services,*
- *measures for limiting the consequences of a blow-out,*
- *guidelines for normalization of the operation* (NORSOK, 2011).

The author believes that contingency plans also should be established within a company for other situations during an operation, not only for a blow-out. This will make an unforeseen situation easier and more effective to handle when/if it occurs.

3.2.2 Risk management

As seen in **figure 3.4**, the risk management will discuss:

- Verification of barriers/risk reducing measures, and how this outcome may result in another risk assessment
- Establishment of a specific barrier strategy.

The section will also briefly discuss the documentation of results, communication, supervision and review and the specification of performance requirements. In addition, management of change is discussed as the author sees this as an underestimated factor of risk management.

According to §11 of the framework regulations prepared by PSA, risk reduction shall always be pursued as far as practicable possible (the ALARP principle) (PSA, 2011c). This means to implement risk treatment. Risk treatment involves selecting one or more options to modify risk, and implement these options. Some of these options are:

- avoid the risk by deciding not to start or continue with the activity that gives rise to the risk
- remove the source of the risk
- change the nature and magnitude of likelihood
- change the consequences
- share the risk with another party or parties
- retain the risk by choice (ISO, 2009).

If the risk evaluation still does not comply with the RAC, there might be a need for establishment of new barriers. This will again create the need for a new risk assessment (see **figure 3.4**).
If the risks are kept within the establish RAC, the next step will be establishment of a specific barrier strategy. This step has two "end products":

- Specific barrier strategy, or documenting results
- Performance requirements (PSA, 2012a).

Specific barrier strategy - documenting results

The result of the risk assessment and the decisions taken in respect to the need for any risk reducing measures should be recorded so that they are available to those who operate the installation, and also to those who are involved in any subsequent operation on the installation (ISO, 2002). These records are referred to as a *strategy* (ISO, 2002).

The following principles should form a basis for a barrier strategy:

- The strategy must be broken down to an appropriate "area level" on each installation/construction, and be maintained at all times.
- The strategy must be designed so that it helps to give everyone involved a common understanding of the basis for the requirements of the individual barrier function (and the associated barrier elements). This includes the relationship between the risk assessments and requirements and to the various barrier functions and associated barrier elements.
- It should be known which accident situations that may occur, the causes of these and the potential consequences that may arise.
- It should be known which task a barrier function has - whether it is to prevent the hazard and accident situations occurring or to limit the damage/loss *if* they occur.
- There must be a visible and clear transition between strategy and established performance standards. The strategy shall provide information on *where* the various performance requirements for each barrier element and each individual barrier function is described (PSA, 2012a).

It is important that the strategies are designed in a format which ensures that the personnel involved, in a simple and easy way, understands the relationship between the hazards and accident situations that may occur, the barrier functions that have been established and the performance requirements applicable to each barrier function (PSA, 2012a). To establish this information and strategy early - already when drilling the original well - will be a huge help for future slot recovery operations. It will often be too late to create this comprehensible strategy for many of the wells on the NCS, but as slot recoveries will become more common in the future due to marginal fields, these strategies are important to implement on the wells drilled today.

Specify performance requirements

Setion 5 in the document (PSA, 2011d) states that there shall be established requirements for the specific perfomance of technical, operational and organizational elements that are necessary to keep individual barriers effective. Performance in this term means the characteristics of a barrier function or barrier element needed to ensure that the individual barrier function is effective. Performance aspects may include capacity, reliability, availability, efficiency, ability to resist loads, integrity and robustness.

It may be appropriate to group the established performance requirements into defined performance standards. The NORSOK S-001 document is built around this idea, and PSA believes this is a good practice. In addition to establishing performance standards for barrier elements, a performance standard should clarify the interface against other systems/functions/barriers (PSA, 2012a). The section 4.3 in NORSOK S-001 states the following regarding the term *performance standard*:

Safety performance standard shall be the verifiable standard to which safety system elements are to perform. The objective of the specific safety performance standards is to add any supplemental safety requirements other than those specified by authority requirements and standards. The performance standards shall be based on the safety strategy document(s) and these should be read in conjunction with each other.

The specific safety performance standards shall ensure that barriers, safety systems or safety functions:

- *are suitable and fully effective for the type hazards identified,*
- *have sufficient capacity for the duration of the hazard or the required time to provide evacuation of the installation,*
- *have sufficient availability to match the frequency of the initiating event,*
- *have adequate response time to fulfill its role,*
- *are suitable for all operating conditions* (NORSOK, 2008).

The establishment of a specific barrier strategy and the associated performance standards will be crucial to achieve an effective barrier control. Specific barrier strategies and associated performance standards may for example be used to:

- Provide input to operational procedures

- Describe and document solutions other than those specified in the standards/codes referred to in the regulations.
- Enter relevant additional documentation in relation to established performance standards.
- Clarify the relationship between specific risk / hazard assessments for each area, the role / task to the barrier functions.
- Provide an overview of performance requirements designed for specific risk profile and strategy.
- Plan and / or perform maintenance to ensure performance of barrier functions and barrier elements in all phases of life. This point is especially important for a slot recovery operation.
- Keeping track of deviations and exceptions.
- Communication and consultation.
- Monitoring and evaluation (PSA, 2012a).

Communication

The responsible party/person shall ensure (and demonstrate) that the communication with both internal and external stakeholders, are appropriate throughout the barrier management process. The purpose is to ensure:

- Good quality - by bringing in relevant expertise and experienced personnel in the entire process, including when establishing a context, the implementation of risk assessments and risk management and to during supervision and monitoring at all times
- Participation and a feel of ownership to stakeholders who will be affected by the decisions in all phases
- Understanding underlying decisions (PSA, 2012a).

Communication and consultation should not be regarded as an independent activity, but something that shall be a basis of the barrier control process in all phases.

Supervision and reviewing

Supervision and reviewing should be a planned part of the risk management process (ISO, 2009).
The barrier function must be maintained throughout the life time of the well, and there shall be established strategies and principles for the design, operation and maintenance of barriers. This means that the requirements for barrier management/control does not end when the steps in **figure 3.4** are completed, but that these constantly shall be monitored and followed up (PSA, 2012a).

In order for the monitoring, testing and verification to have any value, there must be established systems and processes to assess the results of these activities. Furthermore, this has little value if there have not been established systems and processes to identify, assess and manage the changes and deviations from established and assumptions (PSA, 2012a). This means, in other words, that there must be implemented systems and processes to assess and to deal with the significance of deviations from the context (including assumptions) as the basis for the design and requirements for one or more barrier function or barrier elements (PSA, 2012a). For a slot recovery operation, to have such systems and processes already implemented will play an important role in risk reducing measures. The barriers and assessments which have been established at an earlier stage in a operation must constantly be followed up and verified. These processes seemed to be lost during the incident at SNA in 2004, and will be further investigated in **section 4**.

In the **figure 3.4** there is drawn arrows between the "supervision and review" and all the boxes to the left of "supervision and review". This is meant to illustrate that the above mentioned requirement to monitor the risks and condition at all times is done in a proper manner. In some cases there will be a need to rethink parts of the process, while in other cases the entire process must be redone. An example on a re-evaluation of a whole operation is found in the Delta-case found in **section 5**.

Management of change

Changes of a temporary or permanent character of the organization, staffing, systems, processes, procedures, equipment, products, operations, materials, fabrics, laws or regulations should not be performed unless there has been a *management of change* process (BP, 2012). In this thesis, especially the part regarding operations and procedures are of interest.
When it is necessary to carry out changes to an operation, the following actions must be performed:

- a risk assessment carried out for all those affected by the change
- a preparation of a work plan which clearly specifies the time scale for the change and potential control measures that must be implemented with regards to:
  - equipment, facilities and process
  - operation, maintenance and inspection procedures
  - training, personnel and communication
  - documentation of the changes
- the responsible person/persons approval of the work from start to completion (BP, 2012)

3.3 Measurement and verification of performance of barriers

As mentioned numerous times throughout the thesis, the verification of insitu barriers is of huge importance for future slot recovery operations.
In order to increase the possibility of a successful verification, the reliability of mechanical barriers is of importance. To influence the quality of barriers, factors such as material quality, the design and manufacturing process, shop testing, inspection and proper field installation must be done in order to increase the reliability (BSEE, 2011). In a slot recovery perspective, the field performance history is also a key indicator of the reliability which can be expected of a barrier.

Mechanical barriers are mainly designed to provide isolation within the wellbore or annular spaces (BSEE, 2011). The acceptance criteria should therefore be established to verify the integrity for each barrier (more on acceptance criteria and verification of barriers are found on **page 46**, **page 51** and also testing and verification of tubings/casings on **page 29**). The best level of verification of a barrier is to pressure test to the maximum expected pressure in the direction of the potential fluid flow (BSEE, 2011). In order to test a barrier in the anticipated flow direction, the hydrostatic barrier (the mud) is reduced to maintain the required "negative pressure differential". However, as previously discussed in the thesis, a qualification of a barrier at the highest level may prove to be impossible. In such cases there are other methods of verification which are illustrated in **figure 3.5**.

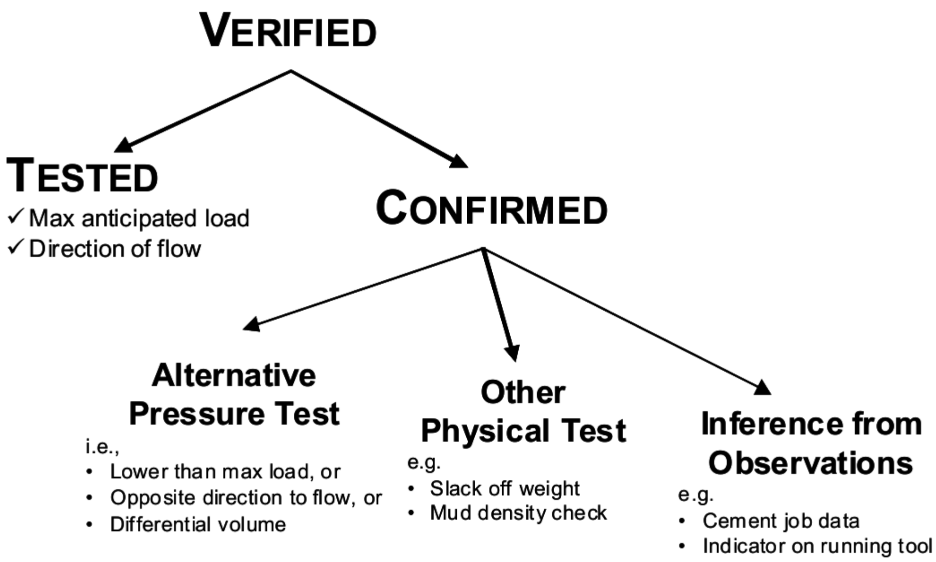

Figure 3.5: The figure shows different ways to either verify or confirm in-situ barriers (BSEE, 2011).

As the figure shows, the verification of a barrier can be accomplished through pressure testing or through other confirmation processes (BSEE, 2011). A positive pressure test of a in-situ barrier is achieved by applying surface pressure over the fluid in the wellbore for a specified period of time. These results should be recorded in a chart and/or a digital format (BSEE, 2011). The current regulations require that dual barriers shall be pressure tested. If the deeper barrier is successfully tested, its integrity will prevent the pressure verification of the upper barrier (BSEE, 2011). This may cause a problematic situation if the deeper barrier fails, and the upper barrier later proves to be degraded.

For some properties, and especially properties of the technical barrier elements, tests and maintenance activities, are in many cases a suitable solution to verify the condition and the compliance with established performance standards. For a number of other features, however, there will be a need for other systems and processes to verify performance. The industry has currently not established/implemented an adequate set of performance requirements for required barrier functions and associated barrier elements. This applies especially to the operational and organizational barrier elements. The industry should aim to make a significant effort in this area (PSA, 2012a). Experiences from the last couple of years of serious incidents in the petroleum industry, both nationally and internationally, indicates that is precisely within the operational and organizational relations a need for a significant improvement (from the PSA report regarding Deepwater Horizon ((PSA, 2011e) and (Anda et al., 2012))).

In addition, there is no accepted industry standard when concluding with a "negative pressure test" of down-hole barriers (BSEE, 2011). Such standards should be developed in conjuction with the NORSOK D-010. The subsection **well integrity training** in **section 3.5.1** also mentions the need for specific guidelines in the case of a negative pressure test. Accepting a negative pressure test was one of the causes for the incident on Snorre A in 2004 (discussed on **page 132**).

There are access limitation which prevents the physical testing of some annuli barriers. When a pressure test is not possible or practical, the quality of the annular cement must be inferred from different operational indicators (logs or other forms of measurement) (BSEE, 2011).

There are several tools which can be used to verify a barrier. These may be:

- System for measuring the technical condition
- Maintenance history
- System for measuring performance influencing conditions
- Follow-up on previous incidents
- RNNP data (Risk level in the Norwegian Petroleum Activities)
- Event history of previous operations on the well (PSA, 2012a)

Table 6 lists briefly the verification methods of the most important well barrier elements (for a slot recovery operation) as according to NORSOK D-010.

Well barrier element	Test and verification
Fluid column	1. Stable fluid level shall be verified. 2. Critical fluid properties, including density shall be within specifications.
Casing	1. Casing/liner shall be leak tested to maximum anticipated differential pressure. 2. Casing/liner that has been drilled through after initial leak test shall be retested during completion activities.
Drilling BOP	See **appendix A.1** in NORSOK D-010
Deep set tubing plug and production packer	1. It shall by preference be leak tested to the maximum expected differential pressure in the direction of flow. 2. Alternatively, it shall be inflow tested or leak tested in the opposite direction to the maximum expected differential pressure, providing that ability to seal both directions can be documented.
Tubing hanger	1. The primary seal shall be tested in the flow direction. 2. The hanger seal can be tested against the flow direction. 3. If only single seals are used in the tubing hanger, annulus is to be tested. In the case of double seal, an in-between seal test might be performed.
Casing cement	1. The cement shall be verified through formation strength test when the casing shoe is drilled out. Alternatively the verification may be through exposing the cement column for differential pressure from fluid column above cement in annulus. In the latter case the pressure integrity acceptance criteria and verification requirements shall be defined. 2. The verification requirements for having obtained the minimum cement height shall be described, which can be: • verification by logs (cement bond, temperature, LWD sonic), or • estimation on the basis of records from the cement operation (volumes pumped, returns during cementing, etc.). 3. The strength development of the cement slurry shall be verified through observation of representative surface samples from the mixing cured under a representative temperature and pressure. For HPHT wells such equipment should be used on the rig site.
Cement plug	See **section 2.5** or **table 24** NORSOK D-010
Completion string	1. Pressure testing to METP. 2. HPHT: The tubular load bearing component of the completion string should be MPI inspected prior to HPHT exposure.

Table 6: The table shows some tests and verification requirements as listed in NORSOK D-010

3.4 Documentation handover

Proper documentation handover is very important when planning for a successful slot recovery operation. Lack of this was one of the causes for the SNA incident in 2004.

When handing over wells, from one organization to another, there shall be a test of the barrier status. The well barriers shall also be verified and documented (NORSOK, 2011) (OLF, 2010). This documentation handover applies when handing the well over from one organization to another (e.g. from drilling to operation), and from shift to shift at crew change (Vignes, 2011). However, documentation handover from one company to another is, unfortunately, not included in the requirements. Statoil will in the future try to offload several of their marginal fields in order to be able to operate the major fields, and especially the new Johan Sverdrup field. Proper documentation handover will be a key success factor for the new operators as several of the wells on the marginal fields will be eligible for a slot recovery operation. Without knowledge of the well status history, these operations will be nearly impossible to complete successfully.
Due to this fact, the author believes that this is something that should been implemented in the requirements. The well integrity management system in OLF should define which information is to be transferred in the documentation handover process, and how this handover should be done. In the OLF guidelines #117, it is stated that the handover documentation should contain well construction information, well barrier schematics, the completion schematics, a handover certificate which presents the status of the valves, pressure and fluids and an overview of the operational limitations. This thesis recommends that for documentation handover between companies, documents relating to risk assessments and updated documents of the well barrier status and well barrier elements with associated barrier functions, among other documents, should be included.

In section 8.7.1 of NORSOK D-010, the *current* handover documentation requirements are listed:

1. *An installation certificate shall be issued, including well completion data, well barrier test charts, equipment tag number, valve and fluid status.*

2. *Recommended minimum and maximum operating annulus pressure shall be presented.*

3. *Recommended guidelines for starting up gas lift with or without liquid*

in the annulus shall be available as part of the handover documentation.

4. *Recommended procedure for closing and opening of SCSSVs as part of normal operation and leak testing shall be included.*
5. *Acceptance criteria for leak rate while leak testing valves in the well or production tree shall be converted to pressure units per time unit and be included in the handover documentation. The effect of variation of gas oil ratio or media composition over time needs to be accommodated for.*
6. *Non-compliance or deviation from the established requirements and guidelines should be discussed with the well construction team* (NORSOK, 2011)

WIF has also established four requirements regarding what type of information which should be available during a documentation handover. This is:

1. Well construction documentation which includes the following data:
   - *Wellhead data with schematic*
   - *Xmas tree data with schematic*
   - *Casing program (depths, sizes)*
   - *Casing and tubing data, including test pressures*
   - *Cement data*
   - *Fluid status, tubing and all annuli*
   - *Wellhead pressure tests*
   - *Tree pressure tests*
   - *Completion component tests*
   - *Perforating details*
   - *Equipment details such as identification or serial numbers* (OLF, 2010).
2. Well diagrams which includes:
   - *Well barrier schematic with well barrier elements listed*
   - *Completion schematic* (OLF, 2010).
3. A handover certificate which should include:

- *Valve status*
- *Pressure status*
- *Fluid status* (OLF, 2010).

4. Operating input which should include:
   - *Tubing and annulus operating limit*
   - *Test and acceptance criteria for all barrier elements (could be referenced to valid internal company documents)*
   - *Deviations which are identified and valid for the well* (OLF, 2010).

These requirements are listed in this section in addition to the requirements in NORSOK D-010 since they provide a very specific overview of what type of information a documentation handover process should include.

Section 4.3 of NORSOK S-001 presents the industry's own requirements regarding experience transfer, and how to take advantage of "lessons learned". The section states that *To ensure transfer of technical safety experience from relevant installations in operation, an experience transfer activity prior to start of detail engineering should be carried out* (NORSOK, 2008). Sources of the necessary experience should include:

- operational experience of relevant installations,
- project execution of relevant installations and modification to these,
- good technical solutions,
- solutions/equipment to be avoided (NORSOK, 2008).

These factors serves as good practices when planning/designing a slot recovery operation.

3.5 Human factors

There has been an increased focus on human factors related to well integrity in the last couple of years. This section will cover different aspects of human errors and the link between human factors and well integrity. This Master's thesis will also investigate one well integrity incident during slot recovery operations caused primarily by human errors, the Snorre A incident in 2004, and one slot recovery operation which failed due to technical difficulties, the Delta case in 2008. This will be done in **section 4 and 5**.

This section will cover three subsections which together will cover the relationship between human factors, well integrity and ways to establish countermeasures to human errors being the cause of major accidents.

3.5.1 Human factors and HTO method

Human factors, hereafter abbreviated HF, focus on humans and their interactions with products, machines, environment, facilities, procedures and tools (API, 2005). These human factors seeks to improve things people use and also the environment in which the things are used in order to better match the capabilities, limitations and needs. Human factors are important when designing a working environment because it affects work performance. The HF theory provides a systematic approach which includes knowledge between humans, technology and organization (HTO). This tool can be used to analyze and improve the interactions between humans, technology and the organizations. HF focus on the human aspect which is competence, abilities, needs and limitations. The technological element includes design, functionality, usability, integration and how the technical element supports the operators to perform their work safely and effectively. The organizational element includes manning, support, management and organizational structure (Vignes, 2011). However, it is mainly the human element which will be discussed in this section.
Human errors can be very hard to predict, and a number of factors outside the control of the individual may be involved in an incident. This makes describing human factors in relation with well integrity difficult. The key to a learning process is to take all the human elements into consideration when designing equipment and planning an operation. This needs to be done in order to make systems able to handle errors. In general, the actual work performance has to be better understood in HTO context to reduce system vulnerability, and to improve performance in a safety point of view.

The human element in relation with well integrity

In HTO theory, it is common to relate the human element to challenges such as human limitations, skills, knowledge, competency, training, experience etc. It is also important to regard the stress and time pressure factor, and how this affects human performance (Bailey, 1996). Do deal with human errors, the focus in the future will have to be on training and gaining knowledge about well integrity and well control.

Well control training

Handling pressure control is one of the most important aspects when drilling a well. Improper pressure detection may lead to kicks or even blowouts which, in the most severe circumstances, turns into a catastrophic accident. Blowouts may be a result of either a mechanical failure or human error(s). In order to prevent the latter case it is important to have a proper focus on well control training. Well control training must include all positions from well designers to drilling crew, and also all service personnel (NSOAF, 2005). NSOAF has identified several challenges related to well control management, competence, training and quality of training. The NORSOK D-010 standard also require regular and realistic well control drills in order to properly train the crew so that they are able to detect and prevent loss of barriers (NORSOK, 2011). These training sessions should also include a part where previous accidents are discussed. In the future, well planning, well construction and well integrity should be included in training programs since well control decisions require strong knowledge of these subjects (OLF, 2010).

Well integrity training

In the document *Recommended guidelines for well integrity* published by OLF, there are given several examples of what to include in a well integrity training, which position should participate and what type of training which is preferred. The document is published in order to improve the well integrity on the NCS (OLF, 2010). The well integrity fundamentals, NORSOK standards and company-specific requirements are often part of a well integrity training. Some operators perform such well integrity seminars every second year (Vignes, 2011). These seminars may include operational cases related to well integrity, regulations, NORSOK D-010 standards and well integrity categorization (more on well integrity categorization on **page 37**). The seminars should also provide a better knowledge of the human perspective towards well integrity. There is one very good example of the need for a focus on the human factor, and that is the performance of the negative pressure test in the Macondo accident. One of the barriers in the Macondo accident was the negative pressure test that included failures during the evaluation of several test results (Vignes, 2011). The conclusion BP presented in their report was that requirements and guidelines on what a negative pressure test is should be evaluated (Vignes, 2011) (Graham et al., 2011). The Macondo accident also shows the need for improving well integrity knowledge. There is a need in the industry to start asking question like *why are these test performed?*, *what does these tests tell us?* and *what are the consequences if we accept a non-acceptable test?*. Overall, there is a need for well integrity training and an improvement of the personnel's competence on well control (Vignes, 2011).

3.5.2 HRO theory

To get to the bottom of countermeasures to human errors, it is important to carefully analyze the underlying theory first. There are two core concepts that are important when talking about underlying causes, namely the "barriers" and "defenses". Barriers are used for security analysis, but include any technical measures. The technical barriers are discussed thoroughly throughout the thesis, hence they will not be further investigated in this subsection. It is the context behind the term "defense" which will be reviewed in this subsection, especially the relationship between organizational, technological and operational measures. These relationships are very important in order to protect human, environmental and economic losses and damages (IRIS, 2011). It is particularly these "defenses" which will be addressed in conjunction with HRO theory.

Within the "High Reliability Organization Theory" the defenses are divided into two categories - the "hard" and "soft" (Reason, 2004) (IRIS, 2011). Hard defense deals with all kinds of technical devices to prevent incidents, but simultaneously warn people in the organizations about it. Examples of hard defenses are automated security systems and access codes. The soft defenses refers to a little more hidden measures, such as all the organizational measures to reduce the risk of adverse events, such as legislation, monitoring, practices, procedures, training etc. (IRIS, 2011).

It is precisely this interplay between hard and soft defenses that make up the total *robustness* of the organization or the technological system. According to HRO theory, it is the human actions and decisions that are the main cause of accidents. This is because people continually commits unsafe acts and active production process errors (IRIS, 2011). Accidents happen in the "sharp end" of the organization - in the operation, such as the cockpit in a plane or in a control room. In an ideal organizational model the interplay between the soft and hard system functions perfectly so that the error or the action is hindered immediately. In a real world, a system will consist of a number of weaknesses or "holes". In a best case scenario, the first defense fails, but the next will pick up the error and prevent the incident. These weaknesses in the defense referred to as *latent conditions*. It is only when the latent conditions in each defense act together and form a continuous chain, that a serious accident may occur (IRIS, 2011). This type of event is illustrated as the now famous Swiss cheese model (Reason, 1997). When all of the present barriers fail, the single event propagate in the system and a major accident may be the outcome (IRIS, 2011). And it is here the root causes behind accidents are really well illustrated. It is the *latent conditions* behind the chain of causes that can be described as the root causes. It is never these conditions which are directly the causes the error, but if they had been identified in an early stage, they would have prevented the accident. And it is precisely here, in the latent conditions, many of the accidents on NCS, such as those on Snorre A and Gullfaks C, started. More on this can be found in **section 4**.

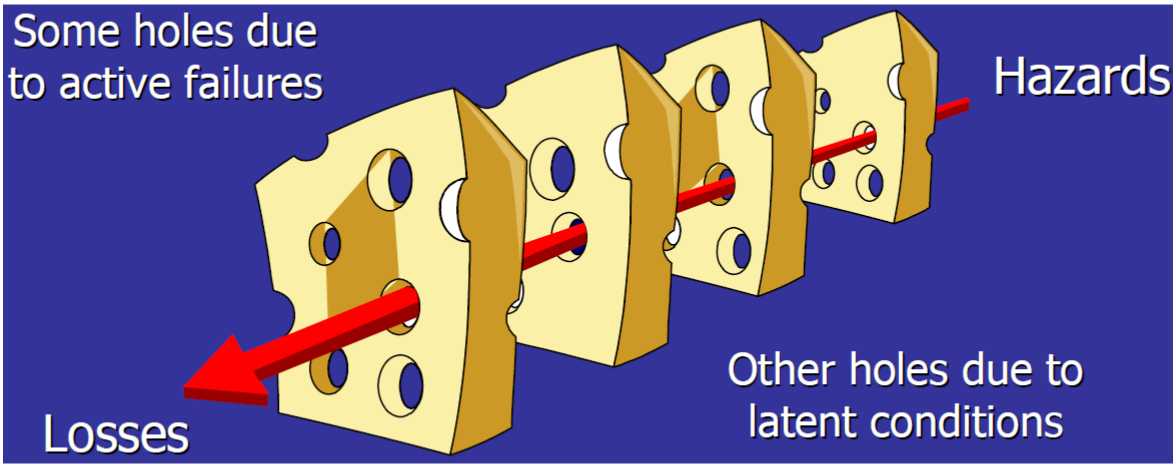

Figure 3.6: Illustration of the Swiss cheese model as it was presented for the first time by James Reason in 1990. The idea is that an accident is often the result of several latent conditions that are triggered synchronously (Reason, 2004).

A good example of the underlying factors which explains a major accident was given by the chief examiner at Chernobyl, Valeri Legasov, in 1988.
Having been in Chernobyl, I drew the unequivocal conclusion that the accident

was (...) top of all the erroneous handling of the economy that had been going on in our country for many years (Reason, 1997). Hence are studies made on root causes are not only investigations of the sharp end of the organization and technical terms, but also examination of the management, regulations, legislation and economic conditions (IRIS, 2011).

To illustrate the thinking around improvement measures relating to human errors, there are few who says it better than Professor Jan Hovden at NTNU when he says: *Safety should be created and recreated every day. There are no final solutions. Unfortunately* (Hovden, 2011). A main goal for every company who wants to increase its *robustness* against incident, and also increase the overall well integrity, one must look at what the HRO theory describes as *organizational redundancy.* Organizational redundancy can best be defined as*patterns of interaction which makes an organization capable of performing tasks more reliable than individuals can* (Sintef, 2001). HRO theory explains that organizations who achieved low overall risk of operations were those organizations which were adept at developing organizational redundancy. Organizational redundancy is created simply by the fact that people consult with each other, checking each other and correct each other (Sintef, 2001). In example, in the aftermath of Statoil and Hydro's merger, it seems that this disappeared from the organization. Relevant project groups were not involved in the processes, and the company already here lost important factors in the planning phase as this phase is an important defense against adverse events. This seems to have been the background for the incident on Snorre A in 2004, and will be more discussed on **page 93**. Hence, it seems clear to the author that it is here, early in the operation processes (planning phase), measures should be implemented.

Organizational redundancy is largely based on people correcting each other's assessments and actions. Two conditions must be in place before this can be done: The initial conditions are the instrumental. People who takes care of critical tasks, must have the opportunity to observe each other's actions and listen to each other's reasoning. At the same time, one must have some form of overlap in knowledge about the task at hand.
This is best illustrated with an example, such as the cockpit of a large airliner. Here there are two people who master the tasks to be performed. The most important instruments for a safe flight is duplicated. This way you ensure that both pilots have immediate access to critical information. Both pilots can hear the communication with the tower. The main control instruments are either duplicated, or placed so that both pilots can reach them. In addition, the procedures and checklists are available at all time so that

the two pilots are able to check and correct each other continuously (Sintef, 2001). This feature appears to be lacking in a no coincidental way in many accidents on the NCS (IRIS, 2011). Again, the Snorre A incident is a good example of this. There were clearly not an adequate number of risk meetings prior to the operation start-up. If these meetings had been carried out, the incident could have been avoided.

Statoil is a big company, but this fact makes it even more important to implement such management systems as seen in a cockpit on a plane. It has been found in investigation reports that much of the work in Statoil is done by individuals who designs various operational plans, and important double-check and risk meetings are given a low priority (Brattbakk et al., 2005). This is obviously due to tough deadlines and heavy workloads, but it is precisely this which has caused many of the unwanted incidents in Statoil the last 10 years - as both the Gullfaks C (2010) and the Snorre A (2004) incidents have shown. These deficiencies of organizational redundancy have led to latent conditions, which turns out to major incident when they happen synchronously.

4 Well 34/7-P-31 A, the Snorre A incident

4.1 Introduction

On the 28th of November 2004, an uncontrolled situation occurred during operation on the P-31A well on Snorre A (hereafter abbreviated SNA) while preparing for a sidetrack. The situation developed into an uncontrolled gas blowout to the seabed, resulting that gas migrated to and around the facility. All personnel were evacuated to nearby facilities by helicopter, except for those who stayed behind to mitigate the situation. The work to gain control of the situation was complicated, and the severity level stayed high as large amounts of gas continuously flowed to surface. This prevented supply vessels to approach SNA to upload additional drilling mud needed to gain control. On November 29th, the well was stabilized after bullheading[14] the last reserves of mud, and hence work to secure the barriers could commence.

The incident is regarded as one of the most serious incidents on the NCS. This is reflected by the overall severity and potential impact of the incident, all as a result of failure of important barriers both during planning and operation (Braune, 2011).

Figure 4.1: The majestic Snorre A platform in operation with nearby supply vessels in standby.

[14]If there is a sudden need to kill a well quickly, bullheading may be used. This involves simply pumping the kill fluid directly down the well bore, forcing the well bore fluids back into the reservoir.

4.2 Status before the incident

The well 34/7-P-31A was from the beginning troublesome, and several problems occurred during drilling and completion. To get the full picture of the incident, a look at the challenges that were encountered during drilling of the first well path, the P-31, is necessary. This will be followed by a look at the completion of the sidetrack P-31A. The following list of events address the main problems, and some of these will later be related to the direct cause of the incident:

- During drilling of P-31 in 1994, problems occurred when the 13 3/8" casing was to be cemented in the 16" section. The casing was cut, and the well was sidetracked before the observation well was completed. The 30" conductor, the 18 5/8" casing and the above mentioned 13 3/8" csg were re-used when drilling the sidetrack P-31A.

- During cementation of the 5 1/2" liner in the sidetrack in 1995, a stuck pipe situation occurred. Several stands of 5 1/2" liner were attached to a running tool for installation, and the liner was successfully installed in the reservoir zone, cementing it to the surrounding rock commenced. The cement was mixed, but due to bad weather it took some hours before it was pumped into the well. The result of this was that the cement set before the job was finished. The whole liner was cemented inside the string before the cement entered the annulus. The running tool was now stuck inside the 9 5/8" casing. The upper part of the running tool was successfully unscrewed at 3524 m, but a main bearing cracked, and no additional tools could be attached. This left about 150 m of the running tool in the well, now stuck in the cement. This required a milling and fishing job, which ultimately turned out to be a prolonged operation which led to comprehensive wear on the 9 5/8" casing. Logging showed that the wear on casing was up to 40 % (Wackers & Coeckelbergh, 2010).

  Later the 9 5/8" casing received more damage when the well was completed. When cleaning the wellbore, a washing tool was used. During some other maintenance work on the drill floor, the washing tool kept running in the hole by a mistake, causing flushing of perforations in the casing. Logging later showed that there were 2-3 holes in the casing at 1561 mMD (shown in **figure 4.2**) that could be linked to the incident.

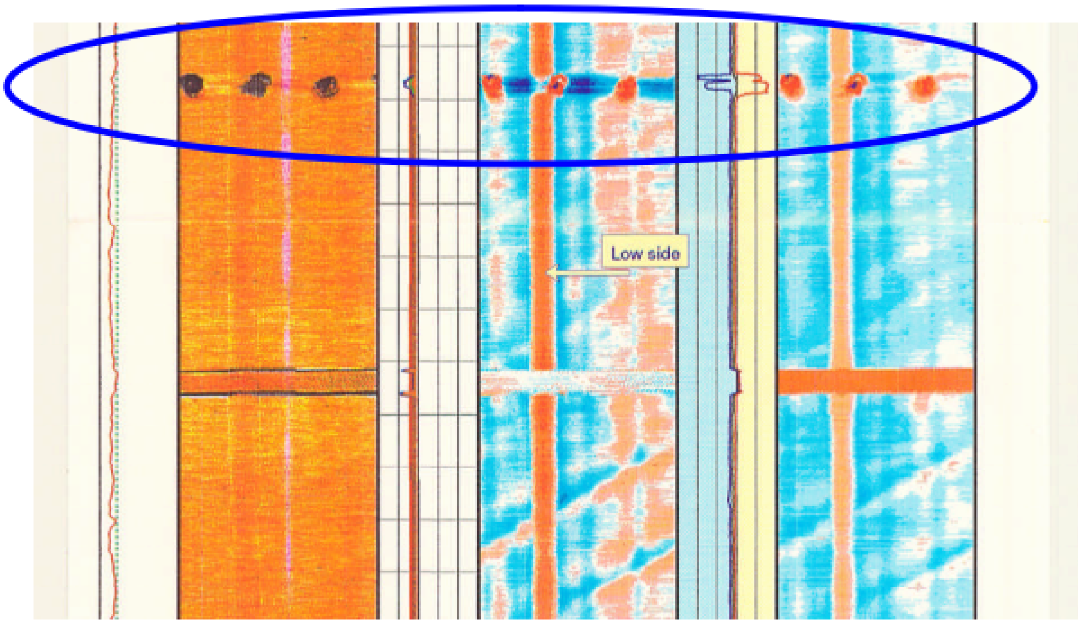

Figure 4.2: The figure shows the three holes created by the high-pressure washing tool. The image is created from a USIT/CBL log (Brattbakk et al., 2005).

- To increase the integrity throughout the wellbore, a 7 5/8" scab-liner[15] was set at 2578 m to secure the damage in the 9 5/8" casing. This type of liner is shown in **figure 4.3**. This solution, however, led to another problem. When initiating a pressure test of this section, the pressure test only reached 254 bar, as opposed to the planned 345 bar (Brattbakk et al., 2005). No official documentation of why this happened, or why no questions were raised, has been found. The well was later completed with a 5 1/2" tubing, and the well was started up in May 1995 (Brattbakk et al., 2005).

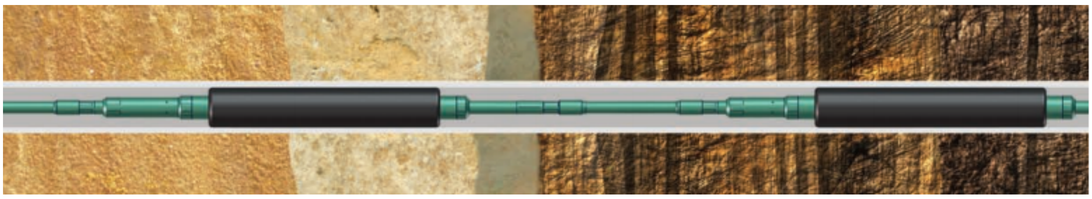

Figure 4.3: The figure shows a scab-liner, and how it seals off troublesome areas (WorldOilTools, 2011). The figure is rotated 90° to fit the text better.

[15]Scab-liners are designed to be run in wells where specific zones require isolation.

- Norsk Hydro started in June 2001 a well campaign which aimed to discover holes and corrosion in casings, tubings and liners. The results for well P-31A were negative, showing corrosion in the production tubing and leakage between the tubing and the annulus. To improve the well integrity, a 4" straddle packer[16] in the lowermost section of the production tubing was installed.

  Later it was discovered that this mitigation had not been successful. A leakage was once again observed between the tubing and the annulus in 2003.

  During this period, intensive pressure tests were performed. Unfortunately, these tests resulted in a burst of the 9 5/8" casing. No official statement has been given to why this was done, as the 7 5/8" scab-liner acted as a barrier to the already proven damaged 9 5/8" casing. The author of this project suspects that these pressure tests were the reason for the damaged 13 3/8" casing at 510 m MD RKB[17]. As the 9 5/8" already was weakened from the holes caused by the washing tool, there is reason to believe that the casing would not have sufficient integrity to withstand a pressure test. Most likely, the cut holes had been filled up and partly closed in by circulation of particles, making a weak seal. When applying the pressure test, this weak seal withstood for a short time, but finally gave in as seen by the pressure drop[18]. This allowed fluids under high pressure to move up to the weaker 13 3/8" casing, and eventually bursted the casing at 510 m MD RKB. This is discussed more thoroughly on **page 134** and also in **section 4.5.1**.
  Statoil decided to shut in the well, and work to establish new barriers commenced. The new solution to secure the well was mainly to set a cement plug directly above the reservoir section. The well was filled with brine with SG[19] 1.47 prior to the operation (Brattbakk et al., 2005).

Due to several factors, the well was considered to be complex. These factors are illustrated in **figure 4.5**. The complexity was related to the following

[16]A straddle packer is two packers separated by a spacer of variable length. Used to isolate certain areas of perforated casing from the rest of the perforated section (OilGas-Glossary, 2011).

[17]An adapter that serves to connect the rotary table to the kelly. The kelly then turns the entire drill string because it is screwed into the top of the drill string itself. The term is used as a reference point for depth measuring

[18]The pressure dropped from 194 bar to 94 bar, indicating that the weak seal bursted

[19]Specific gravity is the ratio of the density (mass of a unit volume) of a substance to the density (mass of the same unit volume) of a reference substance.

factors:

- Conditions giving the well reduced integrity (ref. the above mentioned corrosion and leakage problems)
- Unconventional completion with several small completion elements, such as the scab-liner and the straddle packers.
- Down hole safety valves[20] placement (see **figure 4.4** for a sketch of the DHSV) (Brattbakk et al., 2005).

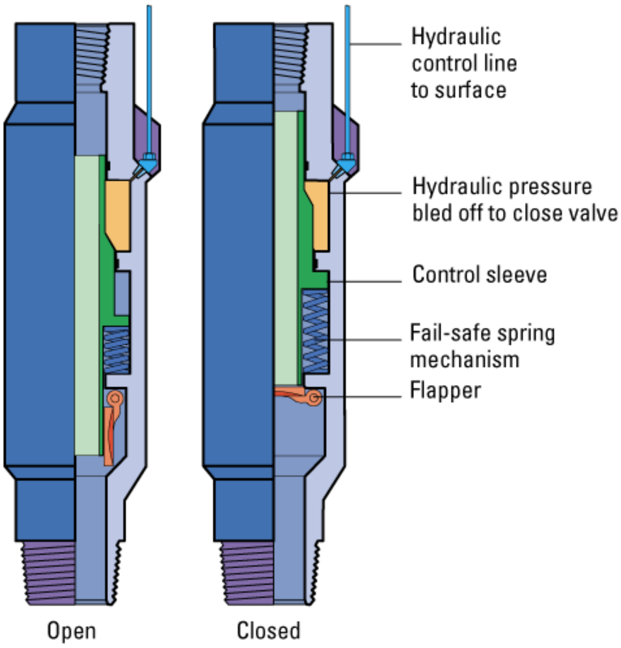

Figure 4.4: The figure shows in a simple way the principle of a down hole safety valve in an open and closed position.

[20]A down hole device that isolates wellbore pressure and fluids in the event of an emergency or catastrophic failure of surface equipment.

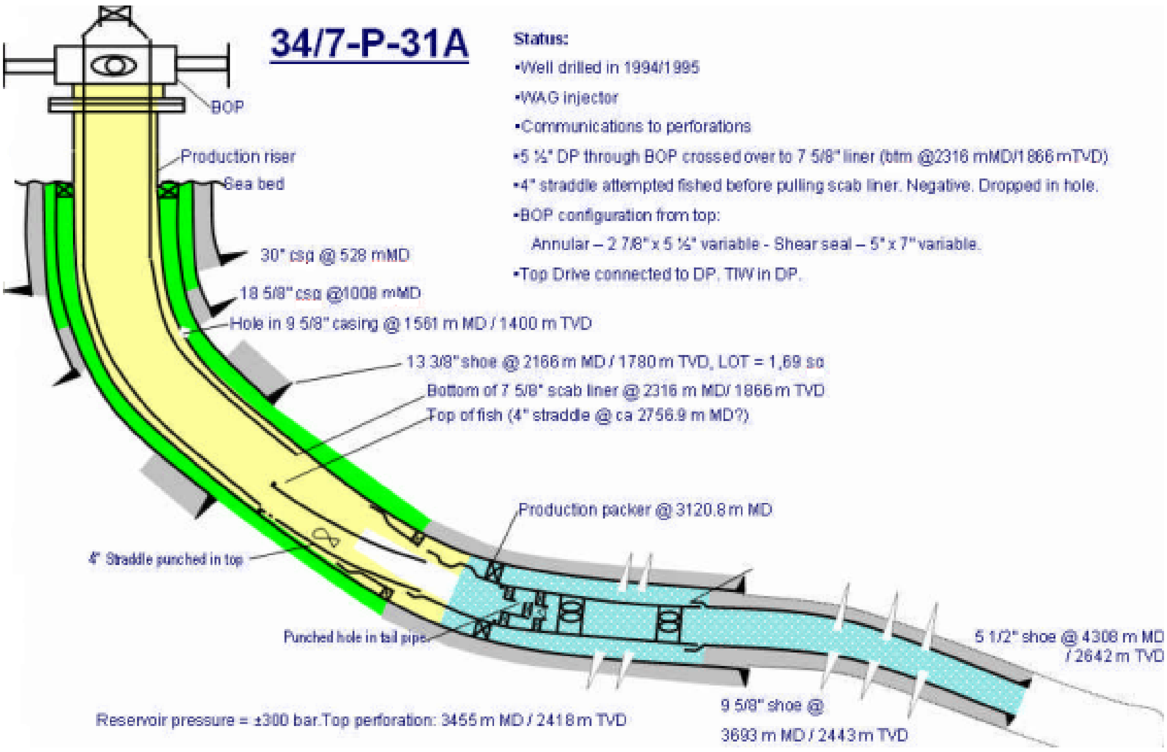

Figure 4.5: The figure shows status before the incident took place. The most notable things to observe is the punched hole in the tail pipe and the hole in 9 5/8" csg at 1561 m MD (Brattbakk et al., 2005).

4.3 Events

This section will present the actual chain of events. These are based on logs and interviews with personnel who were present on SNA when the incident occurred.

The section has four main parts. The first will focus on the well planning phase, mainly from spring 2004 to drilling commenced 16.11.2004, but will also involve some strategies which may have been influential prior to spring 2004.

The second section will concern the drilling phase from when the drilling commenced, 16.11.2004, up until the incident.

The third section will describe the events starting when swabbing[21] first occurred, and the 24 following hours. The last section will try to summarize all of the events with two figures which illustrates the chain of events.

4.3.1 Planning phase

In December 2003, well P-31A was confirmed damaged and shut in. No gas was injected in P-31A from December 2003 to November 2004, and during this period a slot recovery[22] was planned. This slot recovery was done in order to prepare for a sidetrack, the well P-31B. In the initial slot recovery plan made in September 2004, consideration regarding the well integrity had been performed. The reservoir section was not to be opened and cemented. The plan was to set an additional plug above the cut in the production tubing to give a more robust solution. During October 2004 this plan was changed. The reason for this was that Statoil's own reservoir group, SNA RESU, proposed that the reservoir section in P-31A should be cemented using the technique *pressure cementing*. The purpose of this solution was to avoid communication with the sidetrack P-31B. This potential connectivity could lead to unpredictable flow patterns and poor oil recovery. The solution was not wanted by the drilling and well department, as it would make the planning and execution more complex, but was accepted 27.10.2004 (Brattbakk et al., 2005). The solution involved punching a hole in the tail pipe (see **figure 4.5**) in order to be able to pump cement into the reservoir section.

[21]Swabbing is a term used when fluids from the formation enter the wellbore when moving a pipe upwards.

[22]A process which involves removal of old and used conductor along with the inner strings of casing

The following operations were now planned and approved in the slot recovery program:

1. Puncturing the tail pipe
2. Change brine with SG 1.47 with OBM
3. Cutting and pulling of 5 1/2" production tubing
4. Cutting and pulling of the unconventional 7 5/8" scab-liner. This study will unveil that this is the very operation where the incident happens.
5. Cementing the reservoir section
6. Cutting and pulling the 9 5/8" csg

4.3.2 Slot recovery operation start up

The work with the well P-32 went faster than expected, and due to this, the rig was skidded[23] on location, and the operation commenced 16th of October, twelve days before the incident.

After installing the BOP and the marine riser on the 19th, the slot recovery operation was ready to begin. On the same day, a planned review regarding risk analysis was cancelled.

Later that day, the 2 7/8" tail pipe was punctured, which established communication between reservoir pressure and the wellbore pressure, thus allowing hydrocarbons to be in contact with the mud. The primary barrier was at the time the brine with SG 1.47.

The next step was to bullhead the brine into the reservoir and replace it with OBM. With 100 bar pump pressure, the brine was replaced with OBM, and a new primary barrier was established.

Although the first steps went well, problems occurred fairly early in the slot recovery operation. When cutting the 5 1/2" production tubing (#3 in above mentioned program) on the night of October 21st, a mud kick was observed containing both diesel and gas. The situation was quickly brought under control.

On the night of 24th of October, the 5 1/2" production tubing was pulled, but it later showed that the cutting was misplaced such that some of the 4" straddle packer which was fit into the 5 1/2" tubing followed along during

[23] Term used to explain that the rig is moved

the pull. There was no equipment on the rig making it possible to pull the 4" packer through the BOP, so this type of equipment was ordered from onshore. Due to this induced delay it was considered to run the lower part of the 5 1/2" production tubing with the 4" straddle back into the well.

During the next days (23^{rd} - 25^{th}) the slot recovery program was altered to handle the problems encountered when trying to cut and pull the production tubing. Following changes were made:

3. Cutting and pulling procedure of the production tubing will be adjusted due to problems which occurred during cutting operations. It was decided to drop production tubing and straddle packer back into the well.
4. The procedure of cutting and pulling of the scab-liner to be split into two separate operations, now consisting of:
   (a) Puncture the scab-liner.
   (b) Cut and pull the scab-liner

   The purpose of operation 4.a was to equalize possible gas pressure behind the scab-liner (Brattbakk et al., 2005).

On the 25^{th} of November, the production tubing and the straddle were untied from the work string and dropped into the well.

Scab-liner was punctured on the 27^{th}, and the following hour after the puncture, the crew observed the well for possible gas return. As no gas was observed, the liner hanger on top of the scab-liner was cut and pulled. The crew then started to pull the scab-liner itself out of the anchor point.

An expected "u-tube effect"[24] due to the fact that the brine behind the scab-liner was heavier than the mud, was not observed. In the drilling program, this effect should account for a pressure increase of 32 bar in the mud system. This was not registered. During the pull the crew constantly checked for volume changes.
It was later revealed that the casing spear which attached the work string to the scab-liner had a defect seal. A "u-tube-effect" could therefore not be observed.

The same night, swabbing was registered for the first time. During the first phase of a pull, swabbing was not regarded as un-normal. Approximately 2

[24] The height of one leg of fluid is changed by altering the density of some of the fluid in the other leg.

m^3 of reservoir fluids[25] was swabbed into the well in the 2^{nd} and 3^{rd} stand. To compensate for the swabbing the pulling was slowed down.

On the night of 28^{th} the top of the scab-liner reached the BOP. Before the crew pulled it through the BOP, they flow checked the well, but no change in the mud pit was observed. The scab-liner was then pulled through the BOP, and during this operation, the shear and blind rams in the BOP were blocked.

In the period between 8 a.m. and 3.15 p.m. the crew continued to pull the scab-liner out of the BOP. Swabbing was again observed, and measured to approximately 4 m^3 and a mud loss of 31 m^3 was also registered. During this period, several flow checks were done. After every flow check, the well was regarded to be stable.

4.3.3 Well control incident develops

At 3.15 p.m. the annular preventer in the BOP was closed for the first time due to influx. This valve type was the only safety valve out of 3 which was applicable in the BOP. A kelly cock and a top drive was installed.
After a short period with pressure build up, the well suddenly started to take losses. One hour after the shut in, the BOP was once again opened to compensate for the mud loss. A total of 25 m^3 mud was pumped into the working string and the annulus. The well was circulated, but no mud return was registered. At 6 p.m. another 13 m^3 was lost into the formation.
The well was then reverse circulated, and now back flow of well fluids was observed. This back flow was developing in the wrong direction, so the BOP was once again shut in. The instability of the well was discovered to be a heavy pressure build up, which was measured to be around 130 bar over a period of two hours.
At 7 p.m. SNA had approximately 250m^3 of OBM available, and the crew started mixing an additional 40 m^3 OBM. A bullhead operation could commence.

At this point, the annular preventer in the BOP was closed, so the annulus could be circulated through the choke line or the kill line. Neither the cutting function, pipe ram nor the kelly cock were available. The kelly cock was covered by the skirts surrounding the top drive, and could therefore not be

[25] 2m^3 of gas equals approximately 200 m^3 at atmospheric conditions

operated. The kelly cock must be closable in order to install a kill stand with an internal BOP in a pressurized system (Brattbakk et al., 2005).

At 7.05 p.m. a silent alarm via personal beepers was sent out due to the situation on the rig.

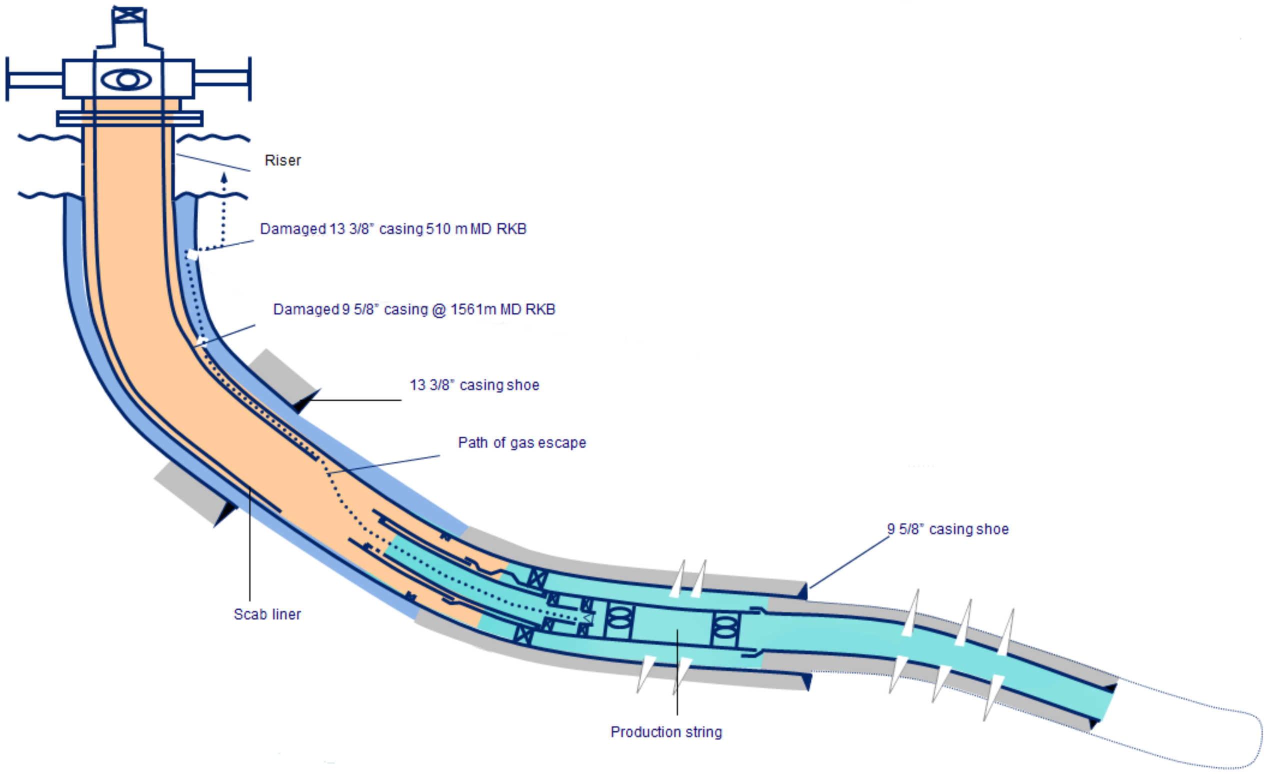

Figure 4.6: The figure shows how the gas escapes the wellbore through damaged parts of the casing (Petersen et al., 2006).

Ten minutes later gas was detected in the cooling water returns from the Vigdis subsea production facility. It was believed that this was a subject of internal leakage. Although no formal explanation was given on this regard, the author of this text strongly believes that this gas came from the blowout on SNA, and that the situation already at this time was a lot more severe than the crew at SNA was aware of. To avoid main power shutdown, the crew on SNA switched off the gas detectors. Anonymous sources claim that this was normal procedure, but this only confirms a sloppy safety culture on the SNA.
Production from Snorre and Vigdis UPA were shut down at this point.

Due to the unresolved situation with the well the platform superintendent ordered manual process shut down at 7.30 p.m. At the same time all staff not directly involved in the mitigation of the situation mustered to the life boats.

A transcript of the incident log from the control room shows that gas was detected in the following modules (also see **figure 4.7**): module W07 (room W-38 1st deck underneath the drill floor), externally on module W-11 (basement deck west) and the modules P17 and P18 (on the Vigdis module close to the flare in 7th and 8th floor). A detector in room W38-1, beneath the drill

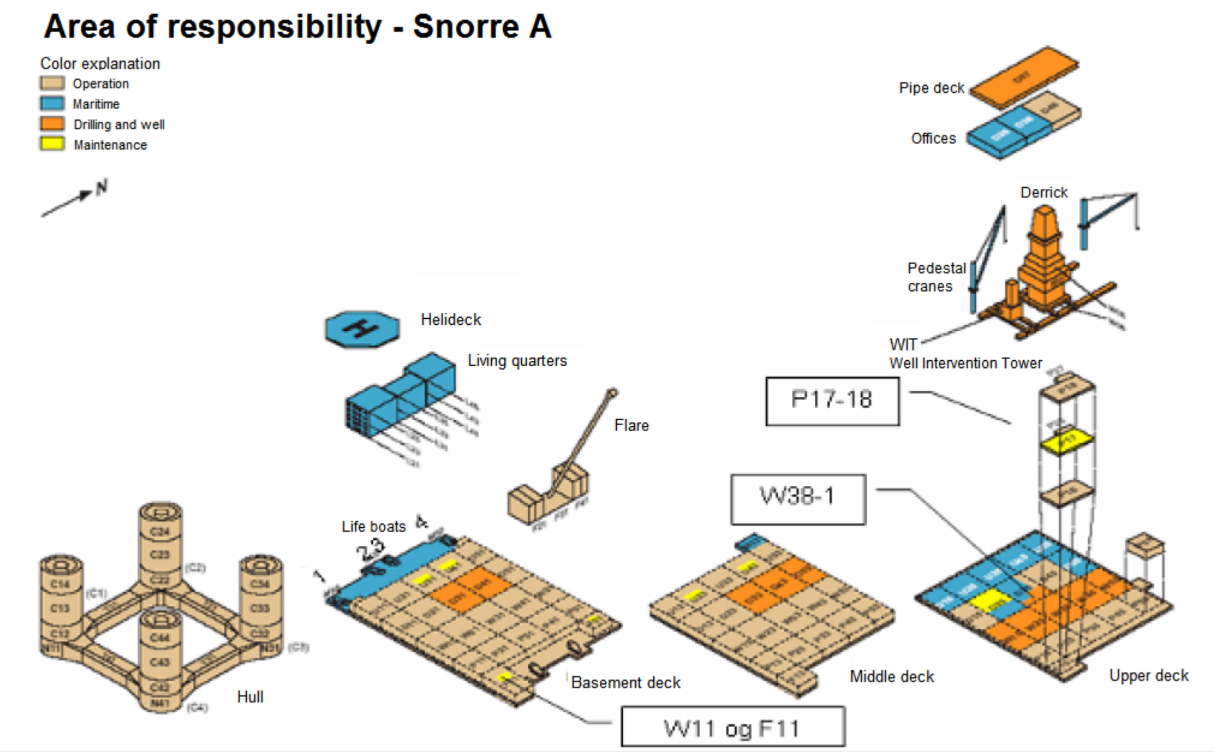

Figure 4.7: The figure shows different modules on the rig, highlighting the modules were gas was detected (Brattbakk et al., 2005).

floor showed at 7.42 p.m. over 60 % LEL[26]
The reason for gas on the rig was that the annular safety valve in the BOP did not provide enough pressure so gas was allowed to slip through and further out the bell nipple (see **figure 4.8**). This gas leak was stopped by increasing

[26]The lowest concentration (percentage) of a gas or a vapor in air capable of producing a flash of fire in presence of an ignition source (arc, flame, heat). At a concentration in air below the lower explosion limit there is not enough fuel to continue an explosion.(Wikipedia,

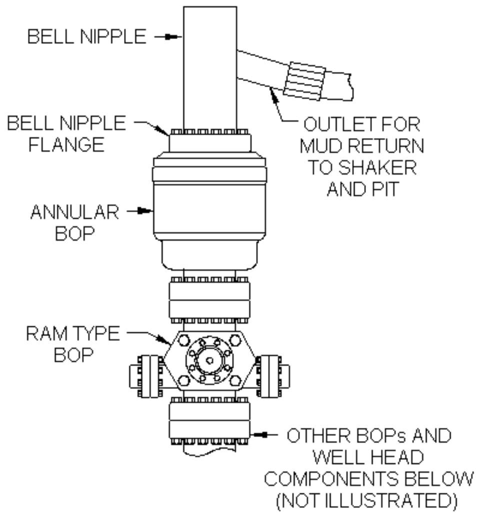

Figure 4.8: The figure shows a simple schematic of where the bell nipple is located (Co USA, 2011).

the hydraulic pressure in the annular safety valve from 1000 psi to 1500 psi.

With the situation still not clarified, the evacuation process commenced approximately at 8.30 p.m. The purpose of this was to get non-essential personnel away from the facility. The POB was ready by 8.42. p.m., 72 minutes after the alarm had been initiated. The reason for updating the POB so late was primarily large crew activity on the drill floor.

Evacuation of personnel commenced at 8.58 p.m., and the crew was reduced from 216 to 75 people. The crew who remained on the rig was part of the well killing operation, plus personnel from the emergency response center.

Around 9 p.m. the wave height was measured to 2.1 - 3.4 m, wind speed of 15 knots to the north and the visibility was good. The air temperature was 7°C and the sea temperature was 6°C.

The well killing operations continued during the evening, and the only possible measure was to pump mud through the work string and with the scab-liner and/or down the annulus. At 9 p.m. the crew had reduced the pressure in the drill string and annulus from 130 bar and 80 bar to 10 bar and 4 bar respectively (see **figure 4.10**).
At the same time, the skirts around the top drive were confirmed dismantled, and the kelly cock was closed at 9.10 p.m.

2011)

Gas was detected outside module F11 (see **figure 4.7**) at 9.20 p.m. In the following minutes, several external gas alarms were activated in the same area. Rig crew was sent to investigate this, and during this check, they observed that gas was boiling in the ocean underneath the rig (see **figure 4.9** for a night vision photography taking from one of the helicopters which shows the heat emitted from the gas). When the emergency response team was notified about this, the emergency shutdown (NAS 2) was activated manually. This also led to main power shutdown. The rig now continued on emergency power, which made most of the rig systems powerless. This was mainly to avoid possible ignition sources. The NAS 2 emergency shutdown also leads to ventilation halt and the fire pumps are started automatically.

Figure 4.9: The picture taken by a night vision camera on board one of the helicopters approximately at 2 a.m. captures the heat of the gas underneath the rig (Statoil, 2005).

The crew on board was aware of that a gas blowout on the sea floor could lead to loss of stability of the rig. One person from the crew observed continuously the tensile force in each leg. Although the official report says "no change in the tensile force was seen", anonymous witnesses claim that one of the legs in the northwestern direction started to become looser due to heavy gas flow in the anchor to the northwest. This emphasizes the severity of the incident.

At 9.25 p.m. the drilling module also started to run on emergency power. Well killing operation immediately lost its efficiency due to reduced power supply to the draw works, mud pumps and rotation of the work string. Up until midnight the pump rate was not sufficient to counteract the influx.

In this phase of the operation, several alternative solutions to the well killing were discussed, among others full cementing. The cementing pumps were run by diesel engines, and therefore independent from the main power. The diesel engine used air from underneath the rig, and as this air was filled with flammable gas, it could not be used. Work to change the direction of the air supply commenced so that they could be used on a later occasion.

Manually depressurization commenced at 9.50 p.m.

After the kelly cock was closed, the kill stand with an internal BOP could be installed. After the kill stand was installed, the kelly cock was once again opened at 9.55 p.m.

Due to lack of power to kill the well, it was decided to start up the main power at 10.45 p.m. At this point the two only options were to evacuate or start up the main power again. The reason for choosing the latter was that no gas had been detected onboard since 9.33 p.m. Although choosing to restart the main power, the decision was regarded to be critical.

A ROV was considered used, but the ROV available on one of the supply boats was limited by the 600 m power line. Considering the water depth of 310 m and the flammable gas surrounding the rig, this operation was regarded to be too risky.

At 11.52 p.m. the critical work of restarting the main power commenced. At the same the wind shifted to a western direction and calmed down, so that by midnight, it was almost windless. The crew on SNA was for the second time prepared for full evacuation.

At 12.17 a.m. Statoil asks PSA to extend the safety zone. This is accepted to a radius of 2000 m and a height of 3000 feet[27].

Pressure readings at midnight showed a SIDPP of 154 bar and a SICP of 46 bar. Now that the main power once again was available, the WS could be stripped in the well at 12.15 a.m. The pipe ram was subsequently closed around the WS.

In the period from 1.25 to 1.30 a.m. an additional evacuation of 40 people was done, leaving 35 crew members on the rig.

At 1 a.m. mud was again bullheaded into the formation, and the pressures fell to some extent up until 2.30 a.m. when the last reserves of mixed OBM was used. In the period from 2.30 to 4 p.m. the crew could only observe the

[27]Normally, the safety zone has a radius and height of 500 m.

well while new OBM was mixed. During this period the pressures increased to 120 bar in the DP and 84 bar in the annulus.

The flare was not confirmed put out before 3.15 a.m., making coincidences such as wind direction and wind speed the main reasons for avoiding a large fire. At this time the wind shifted towards southwestern direction with a speed of 19 knots. At 4 a.m. 80 m^3 of mixed mud was completed and bullheaded into the well until the mud tanks were empty for the second time during killing operations. After 5.30 a.m. there was no available OBM left on SNA. Due to gas in the air and in the sea no supply boats could dock SNA to provide it with much needed mud. At this time following pressures were measured: 32 bar in the WS and 55 bar in the annulus. At this point several alternative measures were discussed - full cementing, use of sea water to kill the well or mixing emergency mud with all remaining additives available on SNA. It was decided to start mixing 160 m^3 with 1.8 SG of WBM with the following additives: water barite and bentonite. Once again during mixing the crew could only observe the well. The use of WBM was regarded as the last counteract to the influx. If this failed, full evacuation would be carried out. The reason for waiting almost four hours for new kill mud was that the crew wanted to be sure sufficient mud volumes were available on this last bullheading.
Before the bullheading commenced a pressure read was taken showing a SIDPP of 156 bar and a SICP of 72 bar. Bullheading commenced at 9.15 a.m., and at 10.22 a.m. the well was confirmed killed with a SIDPP and SICP of 0 bar (all the pressure readings are presented in the **figure 4.10**. The full data table for the pressures are also presented in **section C**. The data for mud volume which was bullheaded into the formation is given by **figure 4.11** and in the **table 10**. 8 m^3 of mud remained in the mud pit, a volume which is regarded as non-retrievable. In other words - the well was killed with the last drop of mud available. No mud was available at this time on SNA whatsoever. The next step of action would have been full evacuation and loss of the rig.

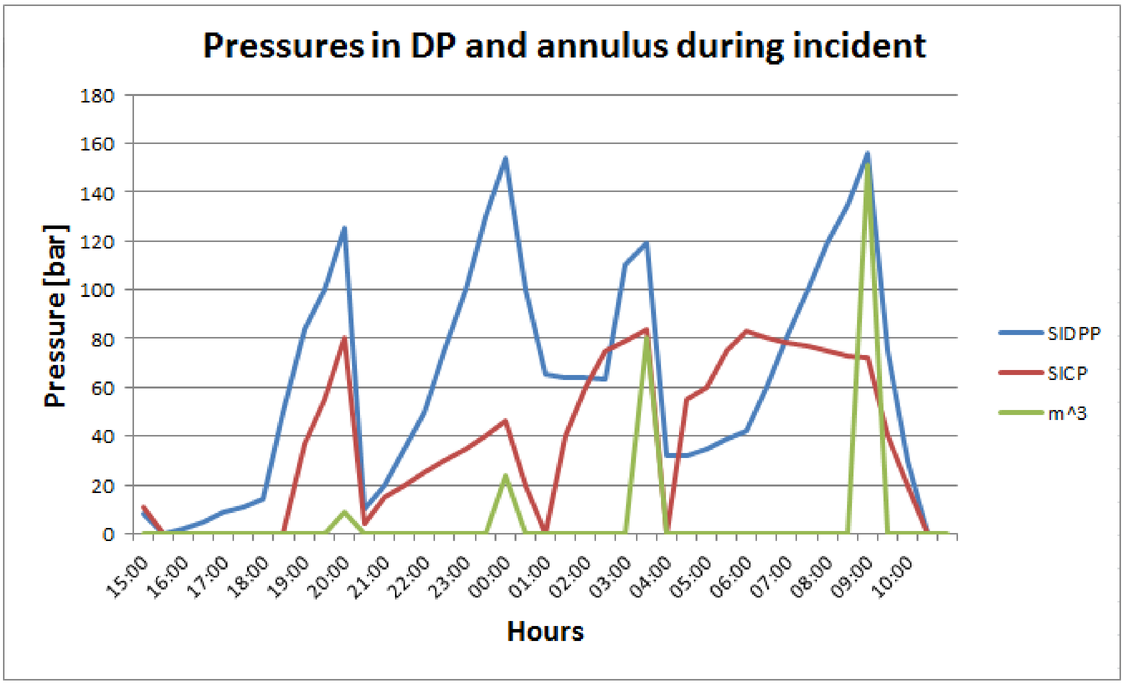

Figure 4.10: The graph shows how the SIDPP and SICP behaved during the incident. The green curve shows when mud was bullheaded into the formation.

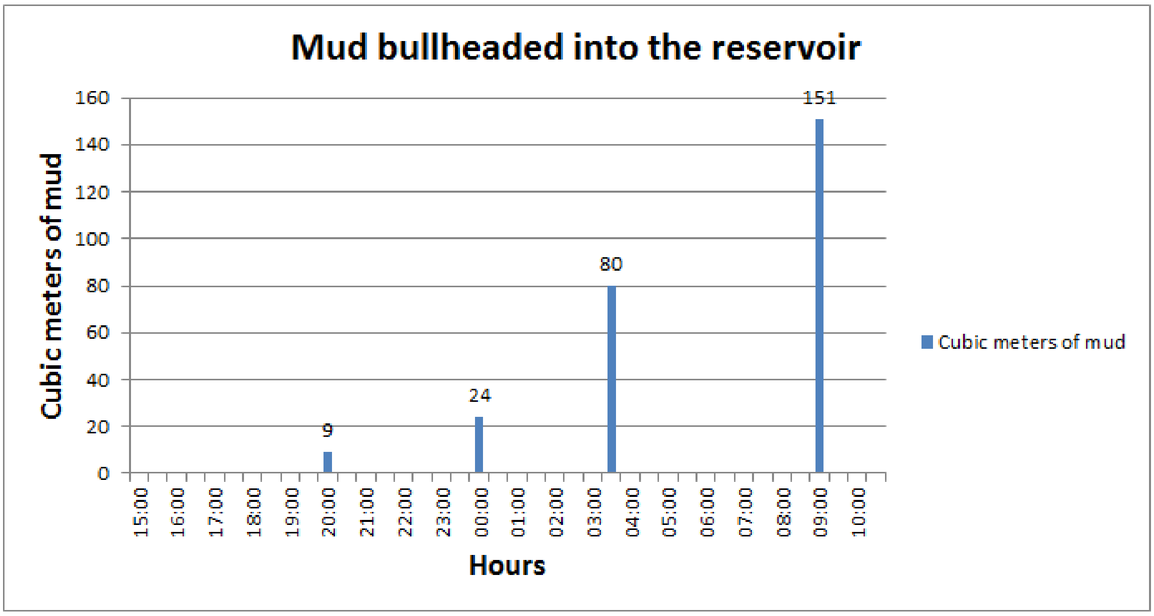

Figure 4.11: This graph shows the amount of mud bullheaded into the formation. These numbers are inserted into figure 4.10 to give a more precise view of how the pressure behaved when bullheading mud.

4.4 Summarization of critical events

The following two sections are meant to further investigate which cause of actions the crew did in terms of mitigating the situation. The first section will cover how the situation on the drill floor unfolded, while the second section will deal with the whole rig, and how one cause led to several consequences for the rig and how this made the situation so critical and tough for the crew.

4.4.1 Situation on drill floor

This section will deal with the situations on the drill floor, with a special focus on causes and consequences of the actions the crew did on the drill floor. The basics of this section is presented in **figure 4.12**, but will in addition be presented more thoroughly through this section. When the well got out of control, one of the consequences of this was that gas was allowed to reach the drill floor. The cause of this was that the annular preventer in the BOP did not work properly. The main cause for the annular preventer to not work as planned was that no pipe rams were installed.
Large concentration of gas on the drill floor heavily restricted personnel to enter the area, thus making work on the drill floor impossible. Not being able to work on the drill floor made the kelly cock unavailable which again led to the consequence of not being able to strip in. Also, the kick stand could not be made up.

The author of this text wants to applaud the rig crew for making the right decisions when this was needed. It is beyond any doubt that the following decisions were the direct causes to the final, positive outcome of the incident.

In order to bring control to the situation, crew wearing breathing apparatuses was allowed to enter the drill floor. Now the crew could increase the closing pressure from 1000 psi to 1500 psi, preventing gas to reach the rig through the riser system. An important note here is that gas was still flowing from huge holes in the sea bottom. This measure only counteracted gas reaching the drill floor in specific.

With the drill floor once again available for work, the kelly cock could be reached. Work on the DDM (or top drive) commenced immediately, removing the skirts on the top drive to get to the kelly cock. Once the kelly cock was closed, a kick stand could be picked up, allowing stripping of the work pipe. The main problems on the drill floor were now considered to be under control.

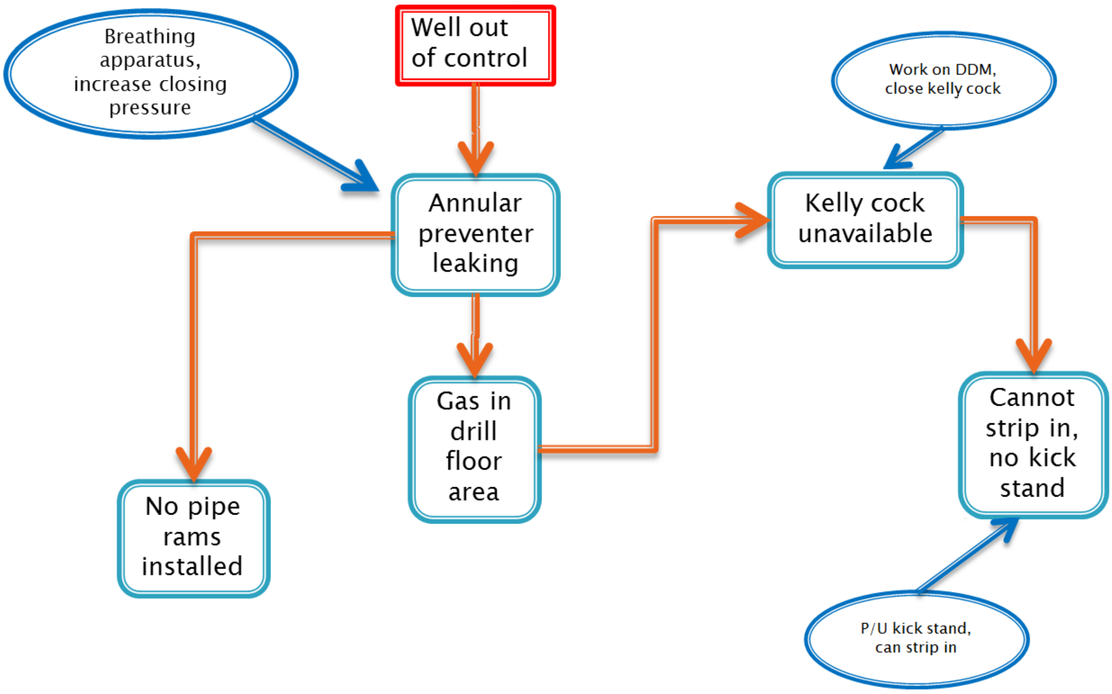

Figure 4.12: The schematic shows in a simple way the causes and consequences to the problems on the drill floor.

4.4.2 Situation on rig

This section elaborates around the slightly more complicated situation on the rig itself, and all of its systems. The basis for this subsection is shown in **figure 4.13**.

When the well got out of control, one of the consequences was, as thoroughly described before, an underground blowout. This immediately led to both gas on/around the rig and in the sea. Gas in the sea meant that no supply vessels could dock SNA and provide it with mud, and the stability was threatened due to gas possibly entering the suction anchors on the sea floor. Gas in the sea also meant that no fire or cooling water were available as this was heavily contaminated by the flowing gas.

Gas on the platform led to even more consequences, foremost that the main power was shut down. This limited the pumping capacity, which again made it impossible to kill the well with bullheading.
With the main power down, the crew could not extinguish the flare which contributed as a major ignition source. Only a beneficial wind direction

hindered the large quantum of gas catching fire.

Gas on the platform also led to gas in all the air intakes. This meant no ventilation on board the SNA. It also meant that the backup cement unit which was run with diesel could not be employed as this used air from underneath the rig.
On the other hand, with the ventilation at halt, cooling of the control systems proved to be very difficult. This could ultimately have led to shutdown of all systems.

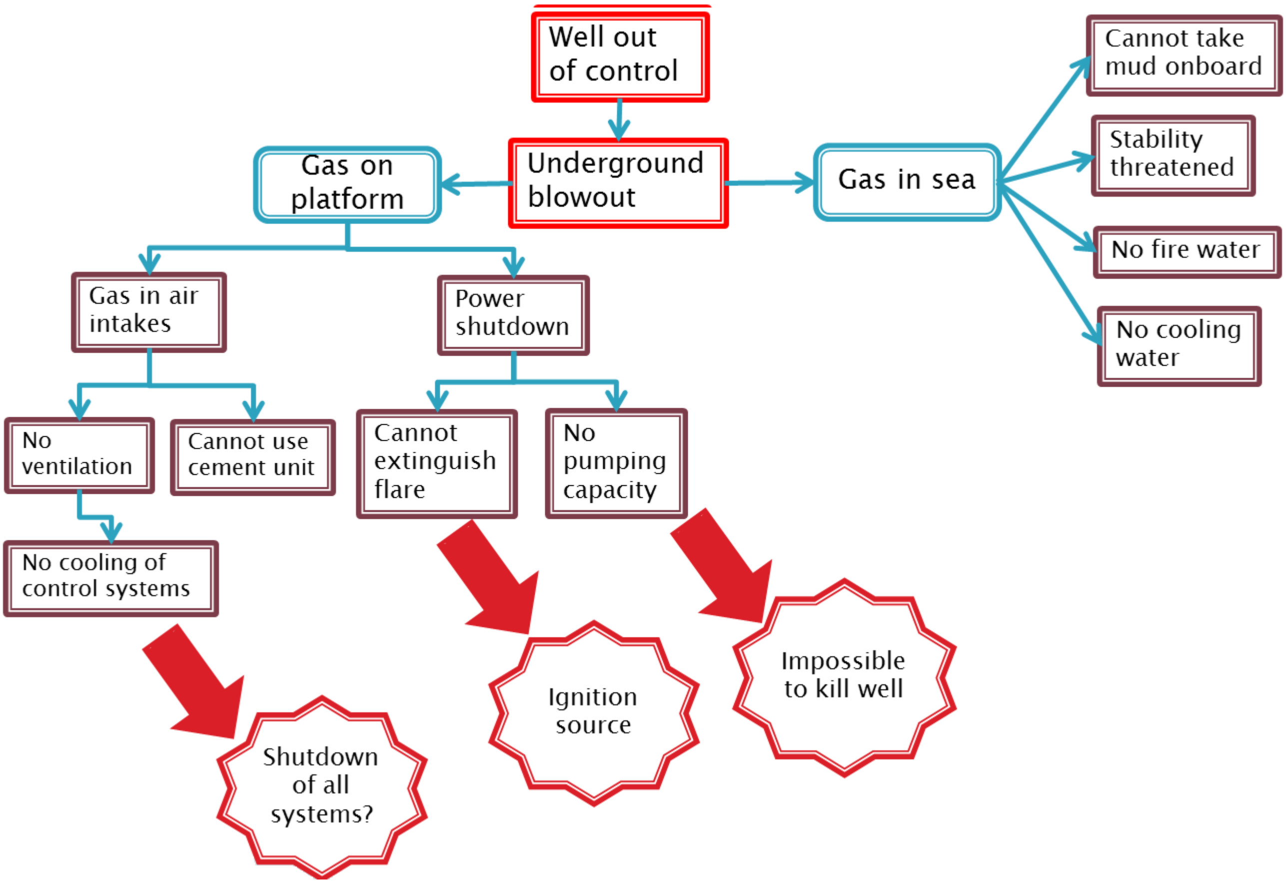

Figure 4.13: A slightly more complex schematic of how the problems developed on the rig itself, and how limited measures for the crew were.

4.5 Barrier evaluation

This section will, according to the governing regulations of NORSOK D-010, evaluate the barrier status of P-31A both prior to the incident, and also how the barriers changed during the operation.
An important note is that some of these findings are based on the author's own assumptions, and are not necessarily proven by any reports, mostly because no investigation regarding barriers has been done. The section still aims to give a realistic picture of the barrier status development prior to the slot recovery start up in 2004.

All paragraphs mentioned in this section is quoted from NORSOK D-010 unless otherwise stated.

4.5.1 Prior to the incident

This subsection will mainly be based on information already presented in **section 4.2**, but aims to present the specific barrier development more clearly. The well barrier development is listed orderly in the **figure 4.14**.

The well integrity for the well P-31A was troublesome from the beginning. After the well P-31 failed to be properly completed, the well P-31A was sidetracked out of a window in the 13 3/8" casing in the P-31, and later tried to be completed with a 5 1/2" tubing. During the cementation of the tubing, the DS got stuck, and this resulted in a prolonged fishing operation which caused severe wear on the 9 5/8" casing. The subsequent clean-up with a high pressure washing tool left 3 holes in the 9 5/8" casing as shown in **figure 4.2**. According to NORSOK D-010 §4.2.3.2, which states that there shall be two well barriers available during operations where uncontrolled outflow is possible, the well is at this stage outside of the acceptance criteria. A look at the well categorization table on **page 38** shows that the well is in category orange at this point, hence unacceptable according to standards defined by OLF. It is, however, worth noting that the well was soon after installed with the 7 1/2" scab liner as according to §85 in (PSA, 2011a) which states that *if a barrier fails, activities shall not be carried out in the well other than those intended to restore the barrier* (NORSOK, 2011). This, along with proper barrier monitoring as stated in NORSOK D-010 §4.2.3.7, proves that Statoil initiated the proper countermeasures to the failed barrier (the weakened 9 5/8" casing).

The installation of the scab liner led to another problem. Though the scab liner was correctly function tested as stated in §4.2.3.5.5 and pressure tested as mentioned in §4.2.3.4, the well was only pressure tested to 255 bar as opposed to the original 345 bar (the 9 5/8" casing). As discovered in **section 4.6**, the reservoir pressure was 325 bar. This must be seen as a clear violation of §4.2.3.5.6 which says that *all well integrity tests shall be documented and accepted by an authorized person* (NORSOK, 2011). This can not have been done. This also violated the section 4.2.3.3. regarding well barrier design. This section clearly states that a well barrier shall be designed, selected and/or constructed such that *it can withstand the maximum anticipated differential pressure it may become exposed to.* With a reservoir pressure of 325 bar, and a tested barrier at 255 bar, this requirement seems to be violated.

In 2001, Norsk Hydro carried out a campaign on the NCS to reveal wells with degraded or un-intact well barriers. The problematic P-31A was tested, and it showed comprehensive corrosion in the production tubing. In addition there was confirmed TAC. The fact that Statoil was not able to detect this degradation of a barrier again violates the NORSOK D-010 standard, this time in §4.2.3.7 regarding well barrier monitoring. However, the proper countermeasures according to (PSA, 2011a) was once again done with the installation of the 4" straddle packer in the lower parts of the production tubing to repair areas with more than 30 % corrosion damage (Kjeldstad et al., 2005). The corroded production tubing also shows that it was not suited for the environment it was placed in. It was installed only 6 years prior to this, and shows that the design of the well was not carried out properly. This is also mentioned in §4.2.3.3: *. . . it can operate competently and withstand the environment for which it may be exposed to over time* (NORSOK, 2011). It is known that the tubing was originally designed for production, but the well was in 1996 converted into a WAG injector. The author of this text finds this transition questionable as it may had a huge impact on the well integrity (as mentioned on **page 24**). This is also mentioned in §4.3.2 regarding design basis: *the following items should be assessed and documented: (. . .) b) purpose of well* (NORSOK, 2011).
A study performed by (Vignes & Tonning, 2008) regarding integrity issues with injection wells on the NCS concludes that *on WAG wells it is reported leakage between the tubing and the annulus. Also it is reported gas leakage in tubing hanger seal when the well injects gas. One of the main reasons is that the wells have experienced high physical stress because of high temperature differential.*

In December 2003 TAC was once again observed. A pressure test of 9 5/8" x 7 5/8" annulus was performed to analyze the integrity of the well, with the result that the pressure rose to 194, and then suddenly, and without notice, leaked off to 94 bar. Due to this, the 9 5/8" casing was confirmed bursted. No conclusion regarding the cause was reached. In the **section 4.2**, the author speculated in that this pressure test leaked off through the holes (as seen in **figure 4.2**) in the 9 5/8" casing. Most likely the holes had been filled up, and partly closed in, by circulation of particles, thus making a weak seal. When applying the pressure test, this weak seal withstood for a short time, but finally gave in as seen by the pressure drop. The theory is then that the pressure traveled up through the annulus between 9 5/8" x 13 3/8", and then bursted the weaker 13 3/8" casing at 510 m MD. This theory is also supported by experienced personnel who were working on SNA at the time of the incident (interviewed personnel wished to be anonymous).

It is important to note that this is not the only theory. The other theory is of course that the pressure test bursted the 9 5/8" casing, and that the gas blowout then traveled through the 9 5/8" X 13 3/8" annulus and bursted the 13 3/8" casing at its weakest point (at 510 m MD). No final conclusion was given on why the 13 3/8" casing failed.
As a result of the bursted 9 5/8" casing (and probably the 13 3/8" casing), the well was correctly shut in as stated in section 4.6: *activities and operations should cease when having a weakened/impaired well barrier/WBE or failure/loss of a well barrier/WBE* (NORSOK, 2011).

The barrier status prior to the slot recovery start up in 2004 is according to the author that the primary barrier (the brine with SG 1.47) is intact, while the casing and BOP barrier envelope is degraded/un-intact, thus a well category orange.

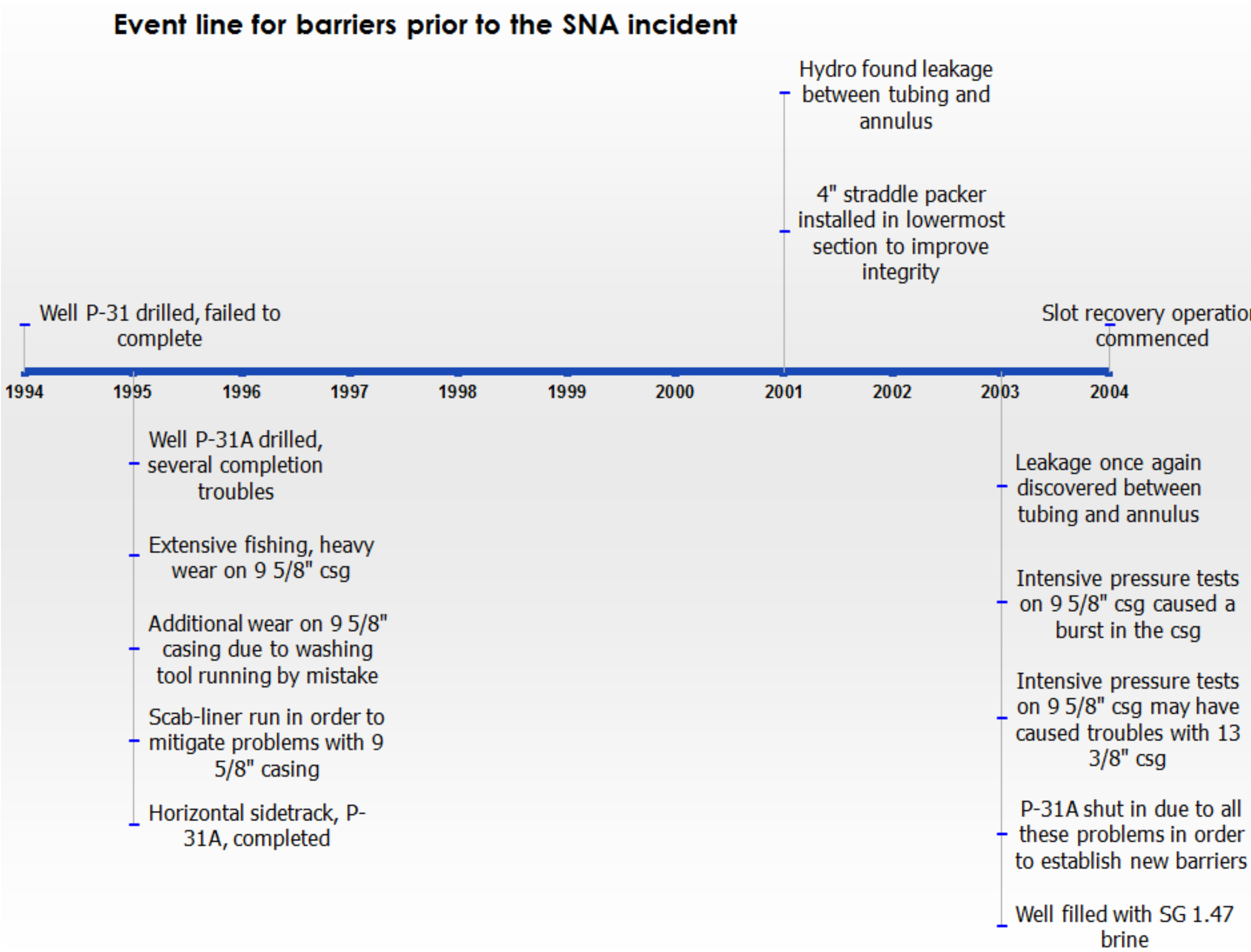

Figure 4.14: The figure shows a time line of how the barriers developed prior to the slot recovery operation start-up in 2004.

4.5.2 During operation

This subsection collects information mainly from **section 4.3**, but will isolate the subject of barriers. The time line of the changes in barriers during the operation is shown in **figure 4.15**.

As discovered in the **section 4.5.1**, the barrier status before the slot recovery start-up in November 2004 was that only the primary barrier was intact. It is important to note that the crew at this point believed that the 13 3/8" casing was intact, as opposed to what the author suggests. Unfortunately, this was about to change during the operation.

In the planning process of the slot recovery operation, several opportunities to discuss risk was dismissed (as investigated more thoroughly in **section 4.6**). This violates §27 in (PSA, 2011a) and §16 in (PSA, 2011d) which state that *it shall be ensured that critical activities are carried out within the operational restrictions set during the engineering phase and in the risk analyses as mentioned in Section 16 of the Management Regulations* and *the responsible party shall ensure that analyses are carried out that provide the necessary basis for making decisions to safeguard health, safety and the environment.* It is also mentioned in NORSOK D-010 that risk verification methods should be conducted for a *change in actual conditions which may increase the risk.* Opening for reservoir pressure in the well must be regarded as a condition which could have increased the risk, hence would a risk assessment meeting be required.

The slot recovery operation program was altered in the last minute, and it was decided to perforate to the reservoir prior to pulling the scab liner. With swabbing being a known problem on SNA (as discussed in **section 4.8**), this alteration should have been dismissed through a management of change process (**section 3.2.2**).
Also, the odd decisions made in the planning phase makes it natural to question if the requirement in §4.3.2a: *the following items should be assessed and documented: a) current well status* was met (NORSOK, 2011). The decisions which was taken seems to have been made with poor knowledge of the well status. The section 4.10.3 also states which well integrity information that should be documented. Proper documentation handover is one example in the section where the planning of the slot recovery operation seems to have failed.

As the scab liner was cut and pulled, swabbing was quickly observed. As a countermeasure, the pulling of the scab liner was slowed down. At this point the primary barrier is also in danger. Whether it was the correct decision to slow the pulling down instead of stopping it completely is uncertain, but it would meet the requirement in §85 in (PSA, 2011a). Again it is worth noting that the crew assumes the secondary barrier to be intact, hence the swabbing would be controllable. During the period 12 a.m. to 2.15 a.m., the crew pulled one single pipe, but swabbing continued. The operation was correctly stopped at this point.

At 0500 a.m. the 28$^{\text{th}}$ of November, the scab liner reaches the top of the BOP. Before pulling the scab liner through the BOP, the well was flow checked as mentioned in §15.1 F.3: *flow checks should be performed upon indications of increased return rate (. . .), flow on connections or at specified regular inter-*

vals. When pulling the scab liner through the BOP, the shear and pipe rams were blocked. This is a violation of §4.2.3.3 which states that one of the well barriers should have a WBE (the BOP in this case) that can *shear any tool that penetrates the well barrier and seal the wellbore after having sheared the tool. If this is not achievable, well barrier descriptions for operational situations which do not require shearing of tools shall be identified* (NORSOK, 2011). An e-mail from the drilling supervisor on SNA to a program engineer onshore dated 23rd of November was sent with an inquiry if an exemption application had to be made for pulling the scab liner through the BOP without functioning rams. The answer was "that this should be OK as long as the liner is not out in an open hole" (Brattbakk et al., 2005). This is another violation of the before mentioned requirement.

The same day, at 3.30 p.m., the annular preventer in the BOP was closed for the first time due to inflow. This was the only valve available on the BOP at the time. During the evening, the well continued to be unstable (the development in events are more thoroughly presented in **section 4.3**, and will therefore not be repeated here). Gas was detected at 7.14 p.m.at Vigdis UPA, and the author believes that this gas originates from a blowout at SNA. Gas below the rig was not identified before 9.20 p.m. The next couple of hours involved installing a kill stand to be able to commence with killing procedures, and pumping mud through the WS and/or down the annulus. The re-establishment of the fluid barrier, as this was lost due to swabbing, is mentioned in §4.2.7.2. There is no indications that these requirements were not followed during the bull heading operation.

The well barrier situation after the loss of the primary barrier due to swabbing that both barriers were degraded or un-intact, placing the well in a category red (as defined in **table 1**). The barrier envelope consisting of casings and BOP was breached through the holes in the 9 5/8" casing and further through the burst point in the 13 3/8" casing, and the fluid column barrier was breached due to pressure loss caused by swabbing. With both barrier un-intact, the gas could escape freely through the perforated tubing, up in the 7 1/2" scab liner X 9 5/8" casing annulus, through the holes in 9 5/8" casing, up in the 9 5/8" X 13 3/8" casing annulus and finally through the burst point in the 13 3/8" casing at 510 m MD. Needless to say, the loss of both barriers numerous times during the evening and night of 28th of November violates several of the before mentioned requirements in the NORSOK D-010.

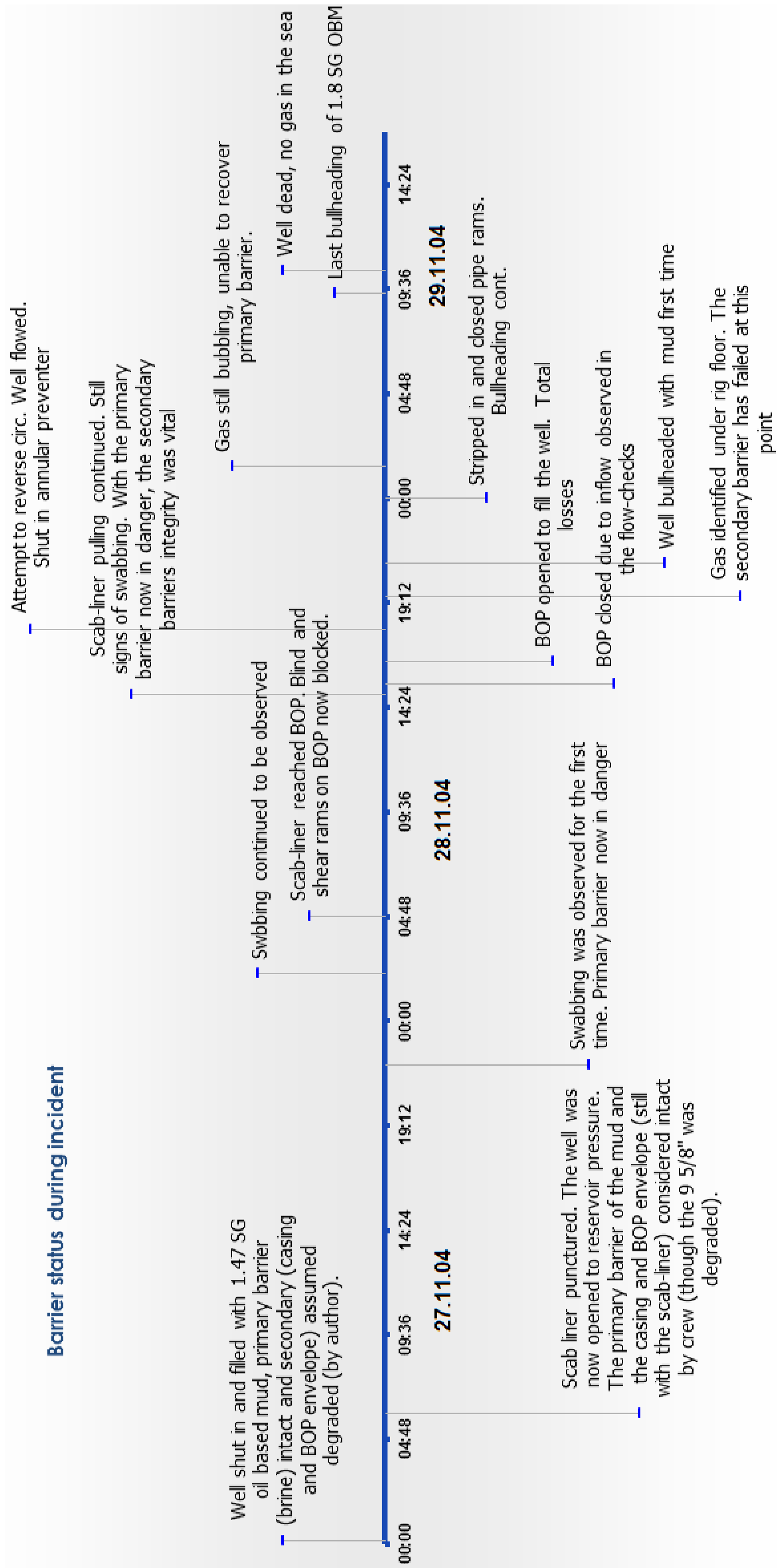

Figure 4.15: The figure shows a time line of the development in barrier status during the SNA incident.

4.6 Observations and improvements

This section will present different observations, mostly regarding failed or successful barriers during the operation. It will also discuss how these barriers reflect the NORSOK standard which is the governing document to all activity on the Norwegian continental shelf. The main focus will be on the NORSOK D-010 document which concerns well integrity in drilling and well operations.

This section will concern the barriers which failed during the slot recovery operations, and which led the incident to be so close to catastrophic.
A total of 28 minor or major discrepancies were made, both during planning and operations (Brattbakk et al., 2005). These discrepancies involve violation of the requirements to well barriers, inadequate control and execution of governing documents, lack of involvement from the management and inadequate comprehension of risk analysis.

Only three out of the total 28 discrepancies were a direct cause to the incident, and all of them are related to breach of well barrier requirements. Although the 25 remaining discrepancies were not directly the cause of the incident, these were formed in the planning phase, and made the foundation to the incident. When the slot recovery operation started to face problems, these 25 factors were a significant contribution to the event.

This project will not go into detail on all of the 28 factors, but will mainly focus on the well barrier breaches.

4.6.1 Poor planning regarding well barriers when puncturing the tail pipe and cutting the scab-liner

The first discrepancy which is to be investigated by this report involves the planning regarding well barriers during the first and fourth section in the slot recovery program (see **section 4.3.1**).

During the planning of the slot recovery, a decision to puncture the 2 7/8" tail pipe was taken 2nd of November 2004 (Brattbakk et al., 2005). As mentioned in an earlier section, this was to be done before pulling the scab-liner. When puncturing the tail pipe, this would open communication with the reservoir pressure of 325 bar. At this time, the brine with SG of 1.47 was the primary barrier, and the secondary barrier, the 9 5/8" casing was tested in December 2003 to withstand a pressure of 94 bar. No actions were taken to analyze or improve the barrier specifications regarding the secondary barrier before the tail pipe was punctured. The tail pipe puncture was planned without

new testing of the secondary well barrier. This is a clear violation of the regulations of activity given by PSA.
The slot recovery program also lacks reflection of the knowledge of the poor integrity of the well. This is shown by data available from December 2003. The management had full knowledge of the secondary barrier, and the weakness it had. It was tested to 94 bar, but this fact was never regarded in the final program. This lack of experience transfer is covered in (PSA, 2011d), §19. This section states that *'The party responsible shall ensure that data of significance to health, safety and the environment are collected, processed and used for: (...) implementing remedial and preventive measures, including improvement of systems and equipment. Requirements shall be set as regards the quality and validity of the data, based on the relevant need.'* (PSA, 2011d).

In §29 in (PSA, 2011a) it is also stated that *'When scheduling activities on the individual facility, the responsible party shall ensure that important risk contributors are kept under control, both individually and overall. (...) The planning shall consider the status of important risk contributors and changes in risk evident from the risk indicators.'*

Also, in the document regarding regulations to design of facilities (the facility regulations), section §48 we find proof of poor planning. The section states both that *'well barriers shall be designed such that well integrity is ensured and the barrier function are safeguarded during the well's lifetime'* and that *'well barriers shall be designed such that unintended well influx and outflow to the external environment is prevented, and such that they do not hinder well activities.* Neither of these important requirements had a high priority when planning the slot recovery program.

Proof of this is obtained by looking back on the planning phase where several risk analysis meetings were scheduled:

1. In the third planning meeting, held 2nd of November, the puncture of the tail pipe with the subsequent pulling of the scab-liner was discussed. Also the potential problems regarding the holes in the 9 5/8" casing when puncturing the tail pipe was mentioned. No risk or barrier violation was identified during this discussion. In the aftermath of the incident, it is easy to point out that this should be a key point to focus on during the puncture of the tail pipe. In reality, the contrary happened. No documentation of such risk investigation has been found, and therefore this has almost certainly never been brought up for a technical discussion.

2. A risk analysis meeting for the whole slot recovery program was to be held the 12th of November 2004. This meeting was delayed due to other meeting activity. Bearing in mind that this was only four days before the slot recovery program commenced, a risk evaluation at this point in the process could have prevented the incident altogether. The 19th of November, one week after the delayed risk review and only nine days before the incident, the risk analysis meeting was once again scheduled. This time it was canceled due to not being prioritized by the participants.

3. The 25th of November a well engineer in the well control group from the headquarters and an engineer responsible for the slot recovery program discussed the operation regarding puncturing and pulling of the scab-liner. Again, the focus is on the operation itself and not the risk consequences.

4. In the period between 23rd and 25th of November, the operative detail plan for the points 3 and 4 in the slot recovery program altered (this is mentioned more thoroughly in **section 4.3.2**). Again, the risk evaluations were neglected. The program engineer for the slot recovery and the drilling supervisor decided to remove the risk analysis from the program (Brattbakk et al., 2005). The reason for this is not documented.

With so many chances to review the risk picture, and none of them taken, this incident was just waiting to happen.

4.6.2 Discrepancies regarding the puncture of the tail pipe

This section will look on the first operation in the slot recovery - the puncture of the tail pipe (full list in **section 4.3.1**). In §85 regarding well barriers, the document clearly specifies that during drilling and well activities one must at all times have at least two tested well barriers with sufficient independence after the surface casing has been set (PSA, 2011a). Sufficient independence refers to requirements in NORSOK D-010, §4.2.3.2 (NORSOK, 2011), which states that the two barriers should act entirely on their own, meaning that if the primary well barrier fails, the secondary barrier will provide an adequate safety margin to restore the primary barrier. In (PSA, 2011a), §85, it also says that if a barrier fails, no activity should be carried out besides restoring the barrier. There is no documentation of such work. When investigating the primary barrier, the brine, a clearer conclusion to this discrepancy can be done.

Applying the equation,

$$P(z) = \rho g z \tag{1}$$

for the TvD at 2418 m MD (see **figure 4.5** regarding the well status) where one of the perforation to the reservoir was done, we obtain the hydrostatic pressure given by the brine;

$$P(2418\ m) = 1470\frac{kg}{m^3} \times 9.81\frac{m}{s^2} \times 2418\ m = 34.87MPa = 348.7bar \tag{2}$$

Knowing that the reservoir pressure would provide a pressure of 325 bar, there is no doubt that the primary barrier was intact, though it could not prevent the incident due to the swabbing. Considering that swabbing was a known effect to the crew on SNA, the swab effect seen on SNA this day should therefore not be regarded as the main reason for the incident, only the final piece of the puzzle. The poor handling of the swabbing effect is discussed in **section 4.6.4**.

4.6.3 Poor execution of cutting and pulling the scab-liner

The scab-liner was punctured and cut according to the program the 27$^{\text{th}}$ of November. The same day the pulling commenced. This operation led to changes regarding the well barriers. There is no documentation of testing the new secondary barrier which would be the 9 5/8" casing after pulling the scab-liner. This violates §85 in (PSA, 2011a) which states that there shall be two independent and tested barriers present after cementing the surface casing in place.
In §5 in (PSA, 2011d) it clearly states that the crew must be aware of barriers which are out of function or weakened.

The crew also failed to facilitate measures needed to establish effective and immediate well kill actions. In the drilling contractor's (Odfjell Drilling) 'golden rules' there are specific requirements that the kill stand should be accessible when the top of the scab-liner reaches the BOP. This was not the case (Brattbakk et al., 2005). It also stated clearly in the facilities regulations §49 that well control equipment should be desgned and able to activate such that both well integrity and well control are maintained (PSA, 2011b).

On the moring of 28$^{\text{th}}$ of November, the scab-liner reached the BOP. When the scab-liner is pulled through the BOP this blocks the upper and lower pipe rams and also the shear ram. Hence, there was no ability to neither cut nor hold the scab-liner.

4.6.4 Poor risk analysis regarding swabbing

When planning the pull of the scab-liner the party responsible never investigated the full risk picture of this operation. Pulling of the scab-liner would most certainly influence the risk profile due to swabbing resulted by the slim clearance between the scab-liner and the 9 5/8" casing. When looking at the final plan, no such change of the risk picture has been evaluated. This is also covered in §29 in (PSA, 2011a).

The crew observed swabbing for the first time on November 27th during the pulling of the scab-liner. Several known factors could increase the risk of swabbing, especially the before-mentioned clearance between the scab-liner and the 9 5/8" casing. Swabbing is a suction effect, and when there is communication between the reservoir and the well, this effect will lead to suction of hydrocarbons into the well. The gas will mix with the drilling fluid and reduce its specific gravity. This reduction in SG will again lower the pressure in the wellbore so that more gas in the reservoir will enter the well. If this cycle is not stopped, either by increasing pumping pressure and thus increase ECD or by altering mud properties, a blowout may occur. With high probability, this is exactly what happened on SNA on November 28th.

By investigating the difference in pressure, a more precise conclusion can be given regarding the swabbing effect.
The difference between reservoir pressure and the well can easily be found;

$$\Delta P_{total} = P_{well} - P_{reservoir} \tag{3}$$

By applying what we know from **section 3.1.2** and using the data obtained in equation (1), we find the differential pressure;

$$\Delta P_{total} = 348.7bar - 325bar = 23.7bar = 2.37MPa \tag{4}$$

The decrease of the mud's specific gravity likely to be caused by the influx gas can now be obtained:

$$\rho = \frac{\Delta P_{total}}{gz} \tag{5}$$

$$\rho = \frac{2.37MPa}{9.81\frac{m}{s^2} \times 2481m} = 99.9\frac{kg}{m^3} \simeq 100\frac{kg}{m^3} \tag{6}$$

It is likely to believe that the swabbing caused a decrease in the mud's SG of at least $100\frac{kg}{m^3}$, so that the mud had a weight of maximum $1370\frac{kg}{m^3}$ at the time of the incident. It is also reasonable to believe that the total hydrostatic pressure column given by the brine was well below the reservoir pressure of

325 bar. This fact states that also the primary barrier was violated during the pull of the scab-liner, making the blowout unavoidable given the fact that also the secondary barrier did not function properly. Failure of the primary barrier, the mud column, after swabbing can therefore be regarded as one of the direct causes to the incident. The crew never restored the primary barrier after the first signs of swabbing.
During interviews of the crew and in the daily drilling reports it is found that the drilling management was uncertain of the status of the primary barrier. Thus, a flow check was initiated. These measures proved to be inadequate. Simultaneously to the flow check, other work than restoring the barrier was done, thus violating §85 in (PSA, 2011a).

4.6.5 Barriers which did not fail during operations

This subsection will present some of the barriers which prevented this incident from reaching its full potential. Some of the points which will be mentioned are:

- Emergency response and evacuation
- Technical equipment
- Well barriers

Statoil showed during the incident that they had safe and proper routines for evacuating crew. Few negative thing can be said about the emergency response. Manning the emergency response center and the mustering of the crew went according to plan (Brattbakk et al., 2005). Proper handling of the situation with the right judgments during the night seems to have prevented a negative development of the situation. Every step of the emergency response was followed according to established plans.
Also, the judgment regarding the wind direction was important for keeping the situation under control. Evacuation of personnel was needed to be done with helicopters, and due to favorable wind direction this could be done with a high enough safety margin.
Evacuation of 181 crew members left 35 left on SNA. All of these worked to remedy the situation. This also meant that a final evacuation could be done a lot more effective if the gas had ignited and the rig confirmed lost.

Some of the technical equipment was necessary for regaining control of the well bore. Both the monitoring system and the manual emergency shutdown functioned properly.

Eventually, some of the well barriers present at SNA needed to stop the gas from flowing freely. The BOP withheld the pressure in the well after shut-in. The only exception was that the sealing element in the annular valve experienced leakage in the hydraulic control system. This created some uncertainty regarding the annular valve as a temporary barrier, but was eventually solved by increasing the closing pressure (as mentioned on **page 107**).

4.6.6 Improvements

In this subsection some improvements to the operation will be given. These improvements are based on much of the work done in the previous sections.

There were three direct causes to the incident on SNA. This was:

- Execution of the tail pipe puncture
- Puncture, cutting and pulling operations of the scab-liner
- Poor evaluation of the swabbing risk contribution

Before the improvements of the slot recovery operation will be discussed, the project will turn to look at the decision to install the scab-liner in 1995. Other measures were available, so this section aims to conclude if this was the right decision.

First of all it is important to emphasize that the 9 5/8" casing was beyond repair. During the fishing operation (described on **page 95**) for the liner hanger running tool, the 9 5/8" casing had been badly worn by excessive rotation at around 9.5 m (one stand) intervals when milling tool joints. The wall thickness of the casing was seriously reduced in many areas over thousands of meters. In addition came the holes flushed by the washing tool (see **figure 4.2**). A localized repair of these holes could have been done with a straddle packer or other sealing methods. But since most of the 9 5/8"casing was badly worn, and would need a serious re-dating, the only real option was to cover the hole area with a scab-liner. It was the most obvious solution then, and would most likely be the solution today. Hence, the decision to strengthen the secondary barrier using a scab-liner seems correct.

The first discrepancy this project will investigate is the decision to puncture the tail pipe in the slot recovery program. It may be easy to call this a bad judgment in the aftermath of the incident, but there are several reasons why this this decision should be avoided in the first place. The decision to perforate *before* pulling the tubing and scab-liner was made based on the probable difficulties with getting a perforation gun through 9 5/8" casing and into the perforated 5" tubing section. By puncturing the tail pipe and thus establishing communication between reservoir pressure and well bore pressure, the secondary barrier was non-existing. As mentioned in **section 4.2** the scab-liner was only tested for pressures up to 254 bar. This was below the reservoir pressure at ~325 bar. Hence, the decision to puncture the

tail pipe without reinforcing the secondary barrier prior to the slot recovery operation was wrong.
With risk management in mind, the decision making should have been based on either of the following points:

1. Pull the scab-liner and then attempt to get a wireline tool (tractor or similar) centralized so that the tool can get into the tail pipe.

2. Pull the scab-liner and then attempt to get a pipe conveyed perforation tool down to the tail pipe to punch holes.

3. Pull the scab-liner and then make a best attempt to perforate the tail pipe. If this cannot be done the tail pipe should be left in the hole.

By taking a look back at **section 4.3.1** on **page 101** it is described that a request from RESU (the reservoir group) to pump cement into the reservoir was approved. This was a last minute request that should have been rejected through a management of change process. The reason for this is that the solution to perforate the tail pipe, and subsequently cement the entire open hole section below is a very poor solution. The result of this would have been, almost certainly, a fracture of the reservoir at the point of lowest depletion (Snorre A is a compartmentalized, depleted reservoir (Cubitt et al., 2004)) with all the cement going out through this fracture rather than filling up the open hole. The whole slot recovery operation seems to be poorly planned already from the beginning. If Statoil were serious about abandoning the open hole section, they should have removed the tail pipe and plugs entirely (e.g. milling on DP) to get proper access to the perforations, and then cement them.

Looking with hindsight, the drilling department ought to have challenged the request from the reservoir group through a management of change process. However, if the request had been maintained, a plan to abandon the reservoir section by getting access via DP (milling out the plugs) should have been developed, and thus got the job done properly. The time and cost estimate for doing this job would most likely have put this request in a different light, and probably have killed this idea. After all, the whole operation seems to be characterized by being done in a hurry. The Snorre reservoir is a problematic area with respect to swabbing. Due to swabbing, it has been a nightmare on some wells after perforating on DP when pulling out of the hole. This happens mostly when pulling the 5" DP out of a 7" liner. The swabbing effect is significantly higher when pulling a 7 5/8" liner out of a 9 5/8" casing as the case was on SNA.

It is important to bear in mind that the proper homework regarding the well

history had been neglected during the planning of the operation. One of the evidences of this is the pressure test which was done as described in **section 4.3.1** on **page 97**. The attempted pressure test was only done months prior to the operation start-up, and was probably an attempt to qualify the 9 5/8" casing as a barrier. What they were in effect doing was testing the 13 3/8" casing, through the holes in the 9 5/8" casing, against the 7 5/8" scab-liner. The pressure built up to 194 before suddenly dropping to 94 bar. The 94 bar could be the leak off to the formation, through a failed 13 3/8" casing. This could have been one of the possibilities, and would explain the direct access to the formation through the holes in the 9 5/8" casing, which is assumed to be the path of the gas from the well to the seabed. Thus was this pressure test destined to fail, and was the probable cause of the troubles to the 13 3/8" casing @ at 510 m MD.
If they actually were unaware of the holes in the 9 5/8" casing or the serious wear, then the swabbing may have been evaluated as manageable by normal well control techniques. With a perforated secondary barrier, the 9 5/8" casing, normal well control techniques were doomed to fail.

4.7 A second look at the SNA incident and the aftermath

This subsection is exclusively included in the thesis as the bulk part of the Snorre A chapter is gathered from the author's project work done in the autumn semester of 2011. It is included here to act as a second look at the incident as the author now has had the time to let the incident truly sink in.

There is one factor the author wants to focus on in this section, and that is the human factor through the incident. Several times the author has had thoughts in the direction of *how did the crew manage such a complex situation under stressful conditions?*, *why didn't the platform manager abandon the rig to be absolutely certain that all human lives were spared?* and *why on earth did the last 35 crew members stay put on the platform through the dangerous incident?*.

Luckily, these questions were answered by Ger Wackers, a Dutch scientist now working at the college of Narvik. He personally interviewed key personnel involved in the incident and presented this in the report *Vulnerability and robustness in a complex technological system: Loss of control and recovery in the 2004 Snorre A gas blow-out.*

Wackers reported that when the platform manage activated the crisis management organization, just around when gas was first seen in the sea, the decision power shifted from the SNA onshore operations unit to the platform manager himself. Statoil had a good pre-established policy for the management when unforeseen crisis situations appeared (Wackers, 2006). Statoil called this *pro-active management*. The main principles for this management system was to always plan for the worst case scenario. There should external resources mobilized, thinking ahead and prioritize regaining control while at the same time keeping retreat options open. This process was done fast and cyclic, Wackers reported, and included the following steps:

1. assessing the situation and deciding on countermeasures in focus meetings between the platform manager, the heads of various technical disciplines and safety manager;
2. informing personnel on board over the personal address system or by sending people to the life boats;
3. constantly reporting to the second emergency tier center on land;
4. collecting observations when the situation developed and the effects of countermeasures (Wackers, 2006).

The report by Wackers also tells a story on how the platform manager used rich pictures based on previous events to make sense of the situation and to communicate what he thought to the crew. One of the scenarios he used was the Bravo oil blow-out in 1977 and several of the well which were destroyed during the Gulf War in Kuwait. One of the reasons for not choosing full evacuation immediately was the thought of oil flowing freely into the sea for months. This would have been an enormous disaster for both the environment and Statoil themselves.

One of the problems the platform manager contemplated was that he wanted to make the crew stay *voluntarily* during the critical phase of the incident. To achieve this, he used the Piper Alpha disaster in 1988, where 165 persons were killed in a hydrocarbon fire, as a comparison. He compared the likeliness of an ignition of the gas cloud, taking both wind direction, wind speed and presumed gas density in the air into account. He finally concluded that *there will be a dull plop, but not the blasting, violent release of energy that you see in an explosion.(...) Being dispersed by the wind, this gas will burn away quickly without an explosion. Hence, you will not die in an explosion* (Wackers, 2006). By communicating this to the crew, they felt safer, thus staying voluntarily.

The platform manager also had to contemplate the possibility that the crew could be killed by the heat if the gas had ignited under the rig, and started to burn like torches from the surface of the sea beneath the rig. Thus, helicopters and fire fighting ships were mobilized so that there was a reasonable expectation amongst the crew that they would be evacuated in case of such a fire (Wackers, 2006).

There was nobody who were physically injured in the Snorre A blow-out. Also the platform itself survived the incident without any major damage. Statoil resumed some of the production from a limited number of wells in February 2005. Later on, Statoil started an upgrade of Snorre A to prepare the platform for continued production despite of falling reservoir pressure (Rosness et al., 2010).

The blow-out was investigated by the police, the Petroleum Safety Authority (PSA) and by Statoil themselves. As mentioned earlier, the PSA characterized the incident as one of the most serious to occur on the Norwegian shelf. The main conclusions from the report was:

- Failure to comply with governing documentation
- Deficient understanding and implementation of risk assessments

- Deficient involvement of management
- Breach of well barrier requirements (Brattbakk et al., 2005) (Kjeldstad et al., 2005) (Rosness et al., 2010).

None of the crew members were prosecuted after the event, but Statoil as a company received a fine of NOK 80 million by the state attorney of Rogaland which they accepted (Rosness et al., 2010).

4.8 Discussion and case conclusion

This section is written mostly based on PSA and Statoil's own incident reports, but it is also supplemented by independent sources and reports to make it as un-biased as possible. In addition the author has spoken with people who were directly involved in the operation on the SNA during the time of the incident. This has hopefully resulted in a project which is as precise as possible.

This projects aim was to give a thorough understanding of the incident, and subsequently what the consequences could have been. In addition technical improvements have been presented. The author of this project has not come across such a complete study during the research to this project work, and thus this project may be unique on some areas.

The incident on SNA was not a result of a one-time safety slip. A lack of focus regarding safety increased over a longer period, and important information handover almost seemed to be non-existing. It is assumed that the well history and the former problems with the 9 5/8" casing had been neglected and ignored during the planning of the slot recovery operation. No details or analysis regarding the risk picture when pulling the scab-liner can be found. An operation like this was supposed to be easy, and the focus was to get the job done as soon as possible. Many of the crew members had been working on SNA for several years, and the platform superintendent was one of the most experienced men in the whole company. Hence, the operation was regarded as a routine job, and this may very well have been the reason for canceling all of the planned risk analysis meetings (as described on **page 126**). A quick review of the well history would have discovered that the slot recovery program was inadequate, and should have been rejected and edited prior to operation start-up.
Onboard personnel interviews revealed a solid companionship between the crew, but it also discovered an increasingly smaller focus on safety compared to previous years. Despite the fact that the slot recovery operation involved work with open sections to the reservoir, the operation never seemed to have any priority within the company. It is possible that re-organization, use of consultants and change of the drilling contractor may have affected the priority of resources during the planning. It is also found from minutes of meetings documents that the attendance was low during planned meetings.
Odfjell Drilling took over for Prosafe as the new drilling operator on SNA in late October 2004, though 80% of the Prosafe crew remained on SNA. In the aftermath of the incident, Statoil reported that the drilling superinten-

dent from Prosafe participated on several meetings prior to the slot recovery operation. This cannot be found in any documentation. Hence, it is reason to believe that the drilling contractor did not participate in any part of the planning which is Statoil's own internal requirement. It is therefore assumed that no document handover regarding the slot recovery program was done between Prosafe and Odfjell during the re-structuring. Odfjell Drilling was given an uncompleted version of the slot recovery program in early November, just weeks away from the operation start-up.

Even though Saga merged with Hydro in 2000, and Statoil obtained most of Hydro's oil and gas industry in 2003, most of the organization remained intact. To a large extent, the organization consisted of former Saga personnel. Unfortunately, by 2004, the competence from the Statoil main office and the rest of the company had still not been properly implemented by the old Snorre organization. Hence, it seems that the restructure to Statoil's own governing documents took too long, or was given a low priority.

The engineer who designed the slot recovery program was hired as a consultant for Statoil. The planning was done almost without any supervision or involvement from the management. In addition, the planning was rushed due to the early completion of the well P-32. The result of this was that the slot recovery operation on P-31A was brought forward, and may have led to a stressed overall situation.

All of these organizational issues must have played a part when the slot recovery program was approved. As mentioned on **page 101** Statoil's own reservoir group trumped through the suggestion to puncture the tail pipe prior to pulling the scab-liner. The drilling department should have foreseen the risk picture with this solution and opted to change it. The technical improvements should have included one of the solutions presented on **page 133**.
As swabbing also was a known problem on the Snorre Field, the solution to open for pressure communication between the reservoir and the wellbore can only be viewed as hazardous. The crew was aware of the swabbing issue, but never managed to control it. Given normal circumstances the swabbing effect would be manageable, but with the 9 5/8" casing in the state it was during the incident, conventional killing methods were doomed to fail.

Over a period of time during the incident, the status on SNA was that none of the qualified well barriers were working properly. A blowout to the drill floor was only prevented by the annular safety valve and the back pressure from the mud pumps. The pressure readings from the well also suggest that the blowout had a significant energy. The evacuation reports show that Statoil immediately regarded the incident to be serious. The evacuation of the crew is one of the few things that went according to plan.

In general, it is safe to say that Statoil can count themselves lucky for not experiencing a more severe situation.

The list below sums up the main findings of the incident:

- The incident on SNA cannot be regarded as a one-time slip-up from Statoil. It must be viewed as a result of a longer period with a lack of safety priority.
- The solution to install the scab-liner in 1995 was a correct decision. The slot recovery program solution to replace it and reinforce the well was not, and should have been changed through a management of change process.
- The incident should have been avoided by prioritizing proper risk analysis reviews.
- The changes to the planned slot recovery operation should have included one of the following points:
    1. Pull the scab-liner and then attempt to get a wire line tool (tractor or similar) centralized so that the tool can get into the tail pipe.
    2. Pull the scab-liner and then attempt to get a pipe conveyed perforation tool down to the tail pipe to punch holes.
    3. Pull the scab-liner and then make a best attempt to perforate the tail pipe. If this cannot be done the tail pipe should be left in the hole.
- No injuries was reported during the incident, but the consequence of a worst case scenario would have been fatalities.
- The economic loss for Statoil is mostly related to loss in revenue due to total production shut-in for almost three months. If the rig had been lost, and a major oil spill had taken place, it is reason to believe that Statoil would struggle to cover the cost and the clean-up job alone.
- The environmental damage is limited to the spill of 211 m^3 of OBM and the gas discharge of over 1 million kg. The potential consequences given a worst case scenario would be comparable to the Macondo incident.

5 The Delta well, 211/19-M75z

5.1 Introduction

The Delta discovery was found through the well 33/9-6 in 1976, 4,5 km east of the Murchison platform (seen in **figure 5.1**) (CNR, 2008). It was evaluated for development on an early stage, but was considered both difficult technical and economically un-viable. Technical development, available well slots on the Murchison rig and high oil price made it possible to pursue an appraisal 30 years later.
The objective of the operation was to drill an appraisal well to Delta that could be converted into a permanent production well, since there was positive indications of commercial value (CNR, 2008).

Figure 5.1: The figure shows the Murchison rig offloading the supply vessel *Northern Gambler* (OilRigPhotos, 2012).

Due to marginal in-place volumes and moderate reservoir quality the project was regarded to be very sensitive to well cost. The well objective was to recover the slot in well M-75 back to the 20" casing shoe, and then sidetrack to a new Delta target. The M-75 sidetrack was suggested to be a potential cost effective approach to drain oil by sidetracking the well M-75 from the Murchison platform.

The well and rig data for the operation can be found in **appendix E**.

The M-75 well
The 211/19-M75 well was drilled as a sidetrack from M-31 out of a window in the 13 3/8" casing in August 2006 (CNR, 2008). It was drilled down to 18 052 feet, but was not economical. The well was displaced with seawater. The M-31 was originally drilled out as a sidetrack for the well M-12 which was completed in August 1988. The 20" surface casing which would be re-used in the M-75Z dates back to the original M-12 well. In other words, the 20" casing had nearly 20 years of operation prior to this slot recovery operation.

The status of the M-75 prior to the slot recovery startup can be seen in **figure 5.2**.

The M-75 was abandoned with 3 cement plugs inside the 9 5/8" casing shoe with TOC at 15 508 ft MD, where the upper plug was inflow tested. All three plugs can be viewed in more detail in **figure 5.2**. The 20" casing was pressure tested to 200 psi in January 2008 to prove its integrity was not breached by corrosion, especially near the sea level. It was also supposed to be no integrity issues from the conductor and down to the 13 3/8" casing shoe (CNR, 2008).

All the relevant data for the M-75 well is listed in **table 7**.

Wellhead Type	McEvoy
9 5/8 inch casing specification	47ppf, L80 from surface to 8,048.46 ft MD, 53.5ppf, L80 from 8,048.86 to 16,063 ft MD, **Note: a 14.3 ft length 53.5 ppf casing pup is run below the hanger from 62.35 to 76.65 ft MD.**
9 5/8 inch Installation date	16.08.2006
TTOC outside 9 5/8 inch casing	13,100 ft MD
Most recent 9 5/8 inch casing test	2000psi with 12.8 ppg mud in hole (Sep 2006)
Annuli Integrity	13.3/8 inch x 20 inch annulus was tested to 200 psi on 16/01/08, 13.3/8 inch x 9.5/8 inch annulus was bled off and showed no pressure increase.
SICP	0 psi 17/01/08
TOC across reservoir	15,508 ft MD (M75 abandonment)

Table 7: The table shows relevant data for the M-75 well (CNR, 2008).

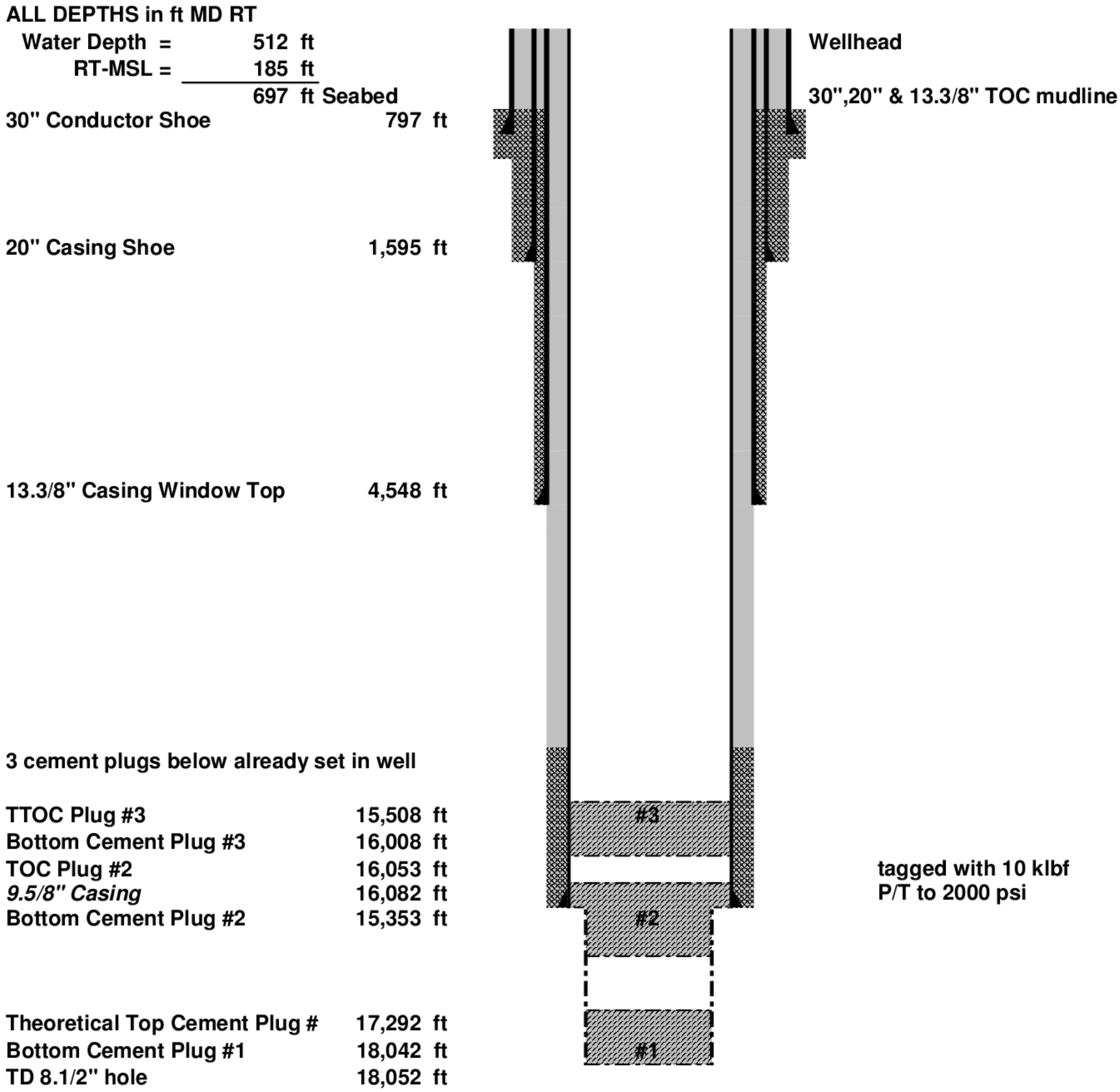

Figure 5.2: The figure shows the status of the M-75 well prior to the slot recovery startup (CNR, 2008).

5.2 Slot recovery program

A slot recovery operation was planned from the mother-wellbore, the M-75, to allow the M-75RD to be drilled from below the existing 20" surface casing shoe at approximately 1750 ft MD. The 20" casing shoe was placed at 1595 ft MD. The slot recovery required the 9 5/8" casing to be cut and retrieved. The 13 3/8" casing was cemented to the seabed, which required milling of the casing.
The 20" surface casing which would be re-used in the sidetrack was successfully tested to 200 psi on the 16th of January 2008. Both the annuli between 13 3/8" x 20" and 9 5/8" x 13 3/8" showed no pressures (CNR, 2008).
The plan was to set a bridge plug[28] at 2435 ft MD (mid joint) (see **figure 5.3**) before retrieving the 9 5/8" casing and milling out the 13 3/8" casing. A 500 ft cement plug was to be set on top of the bridge plug across the 9 5/8" casing cut. No reports were available on neither the 13 3/8" casing tally nor the cementation, so a cement bonding log had to be done prior to the retrieving of the 13 3/8" casing. The plan after this was to cut and retrieve the 13 3/8" casing above TOC prior to milling out the rest of the casing to approximately 1850 ft MD. Another 500 ft cement plug was to be set across the 13 3/8" casing cut and cemented back inside the 20" casing shoe (CNR, 2008).

The operation would then turn to drill the well M-75z from the mother well, the M-75 from slot 23 on the Murchison rig (CNR, 2008). The kick-off of the new 17 1/2" section would be below the 20" casing shoe at 1750 ft MD.

The final well design after the slot recovery and abandonment of the M-75 can be fully viewed in the **figure 5.3**.

[28]A down-hole tool that is located and set to isolate the lower part of the wellbore. Bridge plugs may be permanent or retrievable, enabling the lower wellbore to be permanently sealed from production or temporarily isolated from a treatment conducted on an upper zone (Schlumberger, 2012).

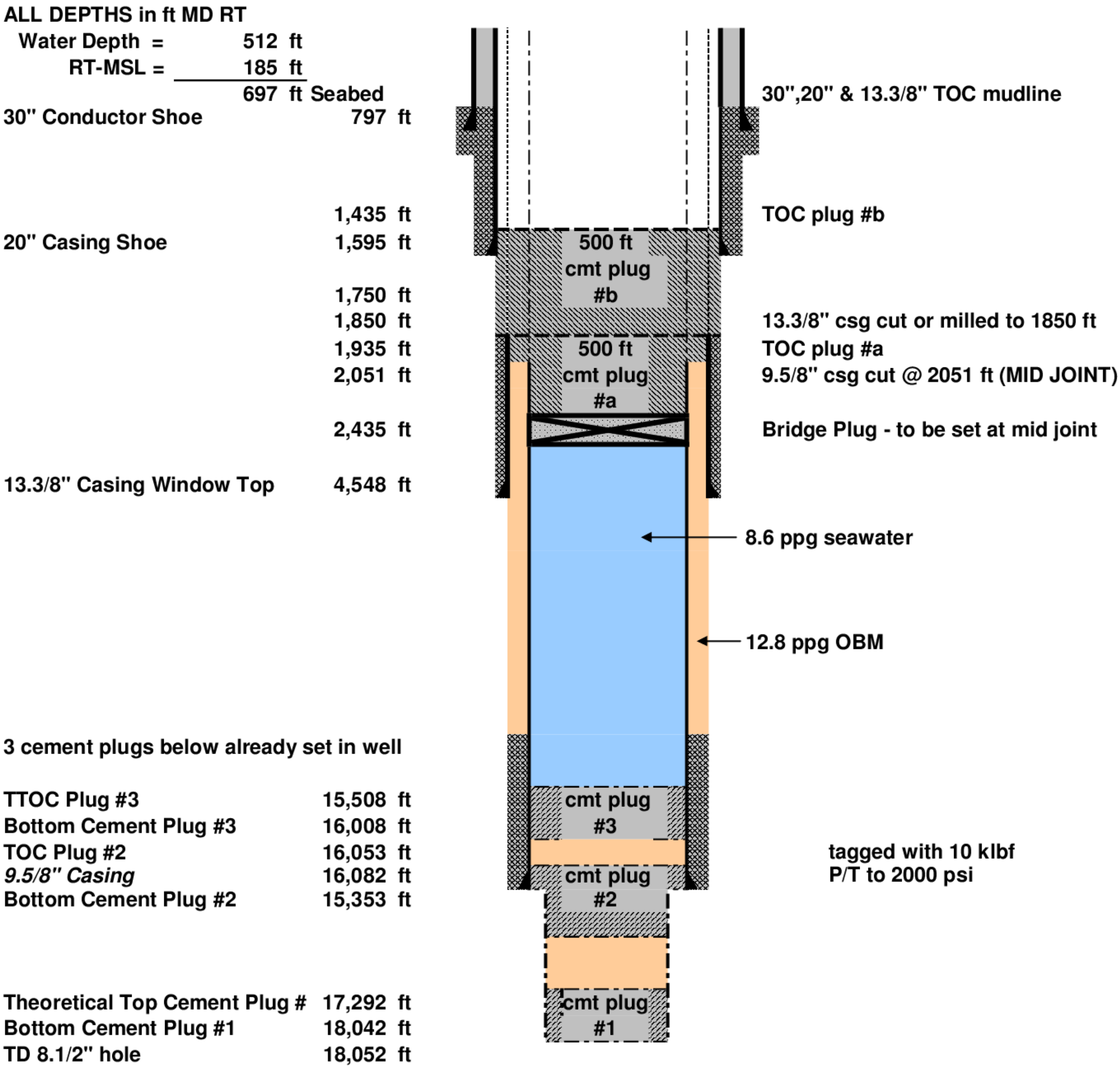

Figure 5.3: The figure shows the M-75z abandonment design after the slot recovery of the M-75 (CNR, 2008).

The complete outline of the operation can be found in **appendix E.1**. The total timing estimate of the operation can be seen in **appendix E.2**.

5.3 Failure of 20" surface casing

This case is included in the thesis due a failure in the 20" surface casing. The case proves many of issues regarding slot recovery operations which are highlighted in the thesis. The 20" surface casing was successfully tested to verify its integrity prior to operation start-up, but this still proved insufficient. This shows how difficult it may be to verify old well barriers, and also shows the importance of a contingency plan if something unforeseen happens. The importance of contingency plans is discussed in **section 3.2.1**.
This case is also a prime example of the **figure 3.4** and the importance of both **section 3.2.1** and **section 3.2.2**. The **figure 3.4** shows how risk management should pick up the need for more effective/working barriers, and if yes, make sure the right assessments were done. In this respect the case represents a proper way of dealing with technical issues. More on this in the following sections.

These investigations have been done with a great help from the Project Manager of the Delta well, Callum MacQueen Smyth.

5.3.1 Discovery of failure in 20" surface casing

The 9 5/8" casing was recovered as per plan. The well was then successfully abandoned with 3 cement plugs (RevusEnergy, 2008).
However, the 13 3/8" cement top was difficult to identify with the CBL. Multiple cuts in the 13 3/8" casing had to be done, but the crew were unable to pull the hanger with the casing stumps attached. The hanger was then cut below the wellhead and recovered.
Jarring was then used to retrieve the 13 3/8" casing stumps. While jarring the casing stump between 80 and 211 ft, the 20" casing failed. See **figure 5.4** for a detailed overview of the situation at this point.

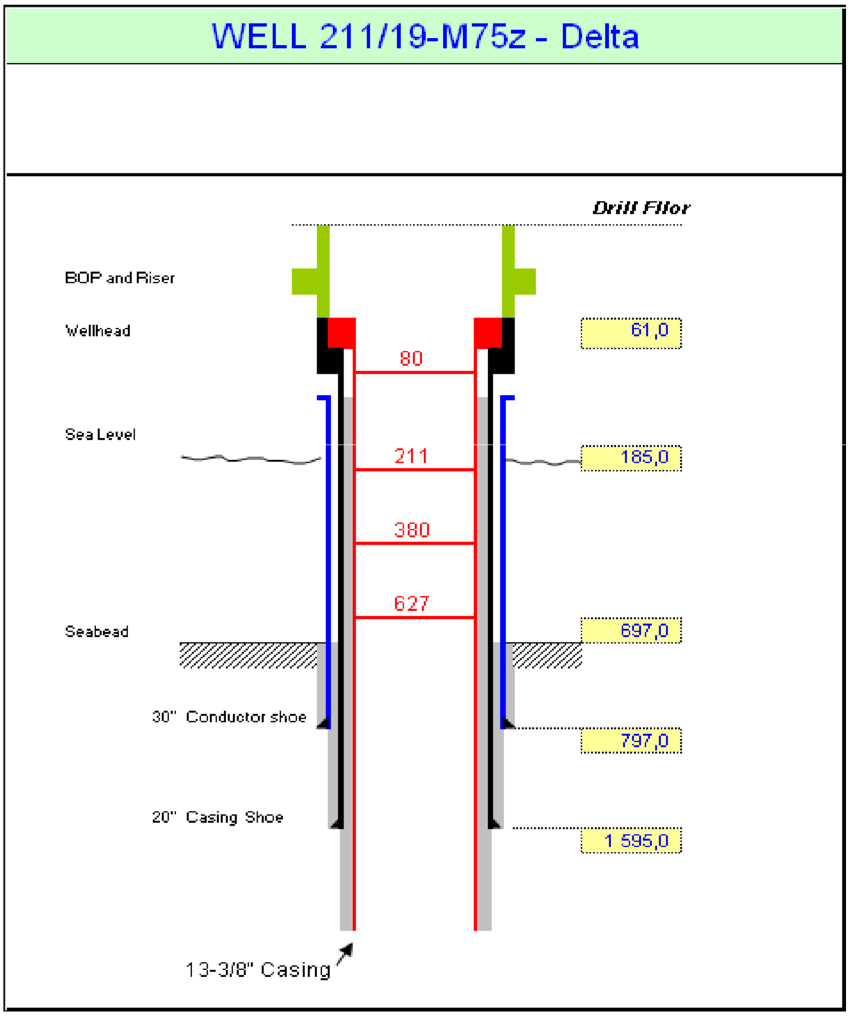

Figure 5.4: The figure illustrates in which area of the well the jarring took place when the 20" casing failed (between 80 and 211 ft). All depths are shown in feet (RevusEnergy, 2008).

The failure was suspected to be at sea level as the 20" pipe failed at only 22% of yield. Corrosion was the probable reason for the failure (RevusEnergy, 2008). More on the reason to the corrosion will be discussed in **section 5.4**. **Figure 5.5** shows the situation right after the failure.

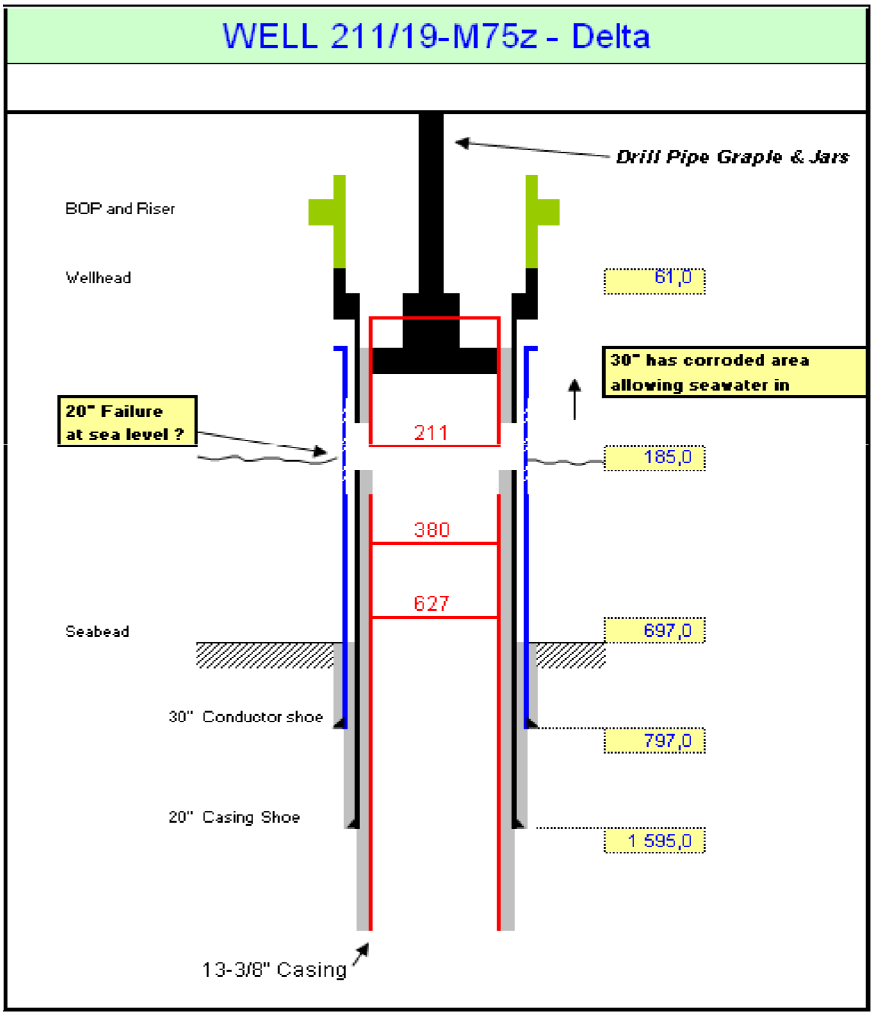

Figure 5.5: The figure illustrates where the 20" casing failed (around sea level). All depths are shown in feet (RevusEnergy, 2008).

5.3.2 Countermeasure to the failed 20"

When the 20" casing failure was confirmed, a new design had to be planned. Both the 13 3/8" and the 20" had to be cut and recovered with the wellhead and 20" section attached. The crew then went back over the well and dressed off the casing stumps of the 20" and ran a new wellhead with a new 20" section. This was done with an overshot seal system which was tested to ensure that there was a return path up the 20" when the 17 1/2" section would subsequently be drilled (Smyth, 2012).
After this, the rest of the 13 3/8" casing was milled away down to a depth

were the crew could kick-off at around 1750 ft and drill the new 17 1/2" hole. Once at TD, a new 13 3/8" casing was set, and hence a new well towards the geological target was set. The deepening of the well, with the 12 1/4", 8 1/2" and finally the 6" hole, went smoothly (Smyth, 2012).

5.4 Case conclusion

As mentioned in **section 5.3**, this case proves how important it is to have a proper risk assessment prior to operation start-up. Situations regarding failing casings are one of the biggest problems for a slot recovery operation. The **figure 2.3** also shows how large percentage the casing/tubing accounts for with regards to well barrier elements with issues. This is no doubt due to the hostile environment these elements suffer. Top this with the fact that many of the wells are operating outside of its design envelope (both the designed lifetime and the environment the casings are exposed to), and that cheap solutions have been made to keep projects as profitable as possible, and you have the answer to why a slot recovery operation is so hard to predict. One of the reasons for this is that a proper integrity test on just the right well barrier elements is very difficult to achieve.
This was also the case with the Delta well. As mentioned in the introduction of this section, the 20" casing was pressure tested to 200 psi in January 2008 to prove its integrity was not breached by corrosion, especially near the sea level. The test was concluded to be successful and sufficient. When the 20" casing fails due to corrosion just at sea level, it is timely to ask *how is it possible to make such a wrong conclusion?*.

The short answer to this is that the pressure test was mistakenly accepted. Bear in mind that the 20" surface casing was nearly 20 years old at the time of the operation.
The 20" was tested to make sure it would provide a sufficient barrier for the new well. In the aftermath of the operation, it was concluded that the test volume which was used in the pressure test was too small. By too small, this means that the cement top inside the casing was high (above the break), so all that was tested was the cavity between the wellhead and the TOC (Smyth, 2012). Once the drilling of the cement commenced, the corroded area was exposed, and the jarring finally tore it apart. The reason for the corrosion of the 20" was later concluded (with a ROV) to be due to a corroded area in the 30" conductor which allowed seawater into the 30" X 20" annulus (Smyth, 2012).

The project team concluded that the testing volume was the missed bit of evidence. If the pumped and returned volume had been properly understood, the risk would have been taken more seriously (Smyth, 2012). When the lessons learned were assessed, the project team agreed that if this operation would be planned again, two different campaigns would have been discussed - one to get the real status of the well, and then another campaign to do the work of re-using the slot (Smyth, 2012).

This discussion has shown that the Delta operation is a prime example of how difficult it is to predict a re-entry of a well slot. Every pressure test and other indications (e.g. the confirmation that all annuli had zero pressure prior to removing the suspension cap) pointed towards a well where the well integrity was intact. When the well once again experienced heavy work (the jarring), the weakness in the 20" surface casing became evident.

Some final conclusion to the case:

- When looking back, more effort on scoping the well status should have been done.
- The Murchison rig is an old rig, built in 1979-80, and it was at its limits during the slot recovery operation (Smyth, 2012). The rig kept breaking down during the operation, and this is also a risk issue which needs to be taken into account during the planning. Many of the rigs on the NCS dates back to the early 80's and will experience the same problems as the Murchison did in this case.
- Due to the failure of the 20" casing, the total project cost was 3 times more than planned. The NPT was significant, but this is not easy to predict. In order to get the project through the management, the cost estimation was logical (Smyth, 2012).
- This really leads on to the final question - *did this well make any money?*. After all, slot recoveries are done in order to "squeeze" the last money out of marginal fields. As of today in 2012, the well is still flowing, and the break-even point[29] was reached in February 2012 . The volumes were small, so the profitability of the project was considered marginal already in the planning phase (Smyth, 2012). With operation costs around three times more than planned, it is necessary to evaluate if the project was a success. Even though the well is now starting to build a profit, the profit will be slim. Maybe other projects would have been a better option. These questions are important to ask prior to a slot recovery start-up, and may be very hard to answer. To keep the operational costs down along with having good prospects regarding the remaining HC volumes will play an important role in making a slot recovery project a success.

[29] when a project turns from taking a loss to start making profit.

6 Discussion

This thesis have tried to cover the whole specter of the term *well integrity*, and implement the term more specifically into slot recovery operations. This theory have subsequently been supported and investigated through two different cases - the slot recovery incident on Snorre A in 2004 and the Delta slot recovery on UK sector in 2008.

This section will discuss the findings with regards to well integrity, barriers and barrier control. These findings will be important to fully explore the challenges related to slot recovery operations. It is of relevance to investigate the general status of the well integrity on the NCS in order to pinpoint where the main focus should be when evaluating a possible slot recovery "candidate". In other words - it is important to understand the issues today in order to plan for the future operations. All of these aspects will be tied up with slot recoveries specifically.

The second section of the thesis first presented some statistics regarding well integrity issues on the NCS. This was done to get a picture of the well barrier status of wells on the NCS today. The analysis discovered several interesting factors.
The first discovery was that injector wells showed a far higher issue-percentage than production wells. This is shown in **figure 2.1**. The main reason for this is that the there seems to be a mismatch between the well design and the actual operation for many wells on the NCS. A well may be completed as a producer, but are later, due to decreasing pressure in the reservoir, converted into an injector. With the introduction of injected water, the injector may suffer from corrosion due to being originally completed with low grade steel. Hence, the wells have been operating outside of the design envelope, and this will ultimately reduce the lifetime of the well. The lifetime of a well will be an important aspect when planning for a slot recovery. If documentation shows that the well has been operated outside of its design envelope, this has to be taken into consideration.
The well on SNA which is discussed in **section 4** is a well which was completed as a producer, but later converted into a WAG injector. Some of the integrity issues in the well may be linked to this fact.
This section also uncovered that the well barrier elements with most issues was tubing/casing elements and cement. The importance of maintaining these barriers, and how to do it, will be discussed later.

In the last part of the section, the reasons for the high percentage of failing injectors was investigated. The findings, expectantly, pointed towards poor design and the amount injected water. These findings are also backed up by the discovery that the wrong steel grade in the completion equipment often was chosen. A higher oxygen level in the water than expected is reported to be some of the explanation of the major corrosion. The author also believes that the cost factor was, and still are, the main drive for choosing the lower grade steel, and that this "triumph" the expectations of oxygen level in the water. These design errors will have a huge impact on subsequent operations.

The next section investigated causes of failing barriers. The thesis focused on the barrier elements which has the greatest impact on a slot recovery - tubing and casing failure and issues with the cement. These elements are hard/impossible to replace/maintain over a longer period of time. Most likely when planning for a slot recovery, both the cement and the casings/tubings will date back to when the moter well was drilled. This fact poses a great integrity threat when re-using the slot.

As discovered in **section 2.1**, casing and tubing elements represented almost 50% of the well barrier elements with issues on the NCS (seen in **figure 2.3**). As mentioned in **section 2.2**, there are several factors which contributes to well integrity with regards to tubing and casing elements: the accurate make-up process of the connections, testing and qualification, the type of dope, the running of the casing strings and selection of well fluids are all important factors to implement a robust integrity solution down-hole.

One of the more interesting findings in this subsection was regarding the long-term effects on casing and tubing integrity. There tends to be a deterioration of thread compounds over time as they are influenced by factors such as pressure, temperature and chemical reactions. Chemical sealing products exists to countermeasure these deteriorations, but there is little research available to conclude whether these mediums provide sufficient well integrity over the long term. Overall, there is a need in the industry to fully understand the challenges regarding dope selection, the installation process, the testing and verification of casing barriers and the material selection. More research is needed especially on the long-term effects on casing and tubing integrity. To understand the long-term effects of pressure, temperature and chemical reactions on casing strings will help to plan for robust slot recovery operation. The other challenges regarding the tubing / casing elements are listed on **page 31**.

The second subsection in the section regarding causes of failing barriers, covered cement issues in the wellbore. As seen in **figure 2.3**, cement issues represents almost 11% of the total amount of elements with issues. The section discovered that long-term effects on cement was a great challenge in old

wells. The main problem is the creation of micro annuli after the cement sets. After the cement sets, the cement starts to alter in quality. In several cases the cement does not stay in a sealing condition throughout the lifetime of a well. The challenges for the cement is the temperature and pressure changes which takes place down-hole. These factors both act as stress generators within the cement. If the cement is exposed to more stress than it is designed to manage, the cement can fail. This may create the unwanted micro-annuli due to fissuring and de-bonding. The micro-annuli represent a threat since it creates a way for the HC to travel freely between the casing and the cement up to formations with lower formation strength. This situation may lead to an underground blowout.
To avoid failure of the cement, it is important to design the cement to provide proper well integrity during the life-time of the well. To achieve this, the expected down-hole pressure and temperatures must be measured and calculated on a regular basis. It is also important to keep the well operations within the design. If the well is set to different operations, this may have a huge impact on the well integrity in general, and the cement element specifically.
The section also discussed the importance of how a cement job can fail. These factors are listed on **page 33**. In order to increase the success rate of cement jobs, there has to be developed tools which in a more definite way can verify the placement of the cement. The CBL tool only gives a good indication of the placement, but are not accurate enough. This was the situation in the Delta-case on **page 143**. A slot recovery often involves cutting and retrieving of casings and tubings, hence it is important to locate the TOC. If this can be located faster than with todays technologies, there are time and money to be saved.
A paragraph regarding a new type of cement, the SHC was also implemented in this subsection. This type of cement have the ability of being responsive and active even after it sets. These types of qualities may in the future be a huge step towards increased integrity with regards to the cement element.

The section then turns to look at well barrier categorization. This was introduced by the OLF in 2007, and has contributed towards a greater focus on well integrity. The introduction of this "traffic light" system was a result of an increasing number of well integrity incidents in the early 00's, with the incident on SNA as the most alarming.
The **table 2** shows results of the status of well barriers as defined within the "traffic light system". The trend is clear - there is no significant change in the results since 2007. Hence, the problems are revealed in a greater scale than before, but little has been done to improve the situation. Almost 9% of

the tested wells on the NCS was unacceptable according the defined criteria given by the system. The categorization system is nevertheless a good way of increasing the awareness regarding well integrity.

The next subsection investigates the importance of keeping updated well barrier schematics. Prior to 2007, no organized "health checks" were carried out, hence there was little knowledge of the wells on the NCS before the introduction of the "traffic light" system. One countermeasure to the high number of wells in the "red" and "orange" category will be to keep updated records of the well barriers, and that these are kept in an orderly one-page-format so that the information is easily accessible.
One of the issues with keeping updated records is that the information regarding a well may be scattered around in several places, both in physical and in digital folders. Prior to the introduction of the computer as a key work tool, the operation files were kept in large folders. As different operations were performed during the life time of the well, the experience transfers were often missing. Hence, it was hard to know the current status of the well barriers. The WIF forum has developed some guidelines regarding the minimum data which should be included in a well barrier schematics. These guidelines can be viewed on **page 42**.
This section also discovered that there was a lack of well barrier schematics, and that those presented often were poor. When planning for a slot recovery operation, an updated view of the well barriers are highly important. If information is missed in the planning phase, unexpected issues are more likely to occur. The importance of proper well barrier schematics and suggested improvements were discussed in **section 2.4**.

The last subsection discussed in particular the challenges regarding plug and abandonment. The plug and abandonment operation is important for a slot recovery since the mother wellbore needs to be P&A prior to sidetracking the new well path. The P&A operation is in this respect an integral part of a slot recovery operation. One of the most important requirements with respect to a slot recovery operation is found in **table 3**, and relates to an open hole scenario. This requirement states that must be a barrier to isolate an open hole from the surface. This needs to be a "fail-safe" barrier against a potential source of inflow. Open hole sections are often "created" when cutting and retrieving casing strings which is done in a slot recovery operation.
The section defined the acceptance criteria for plug and abandonment for several scenarios (whether the plug was set above a reservoir, open hole etc.). The most important factor is to verify the integrity of the plugging, and this will be discussed later.

The term temporary abandonment is included to highlight the difference between temporary and permanent abandonment. Research carried out by the PSA showed that the temporary abandonment, which is a cheaper operation, is sometimes misused, and serves as a permanent solution in some wells on the NCS. Hence, the author found it suitable to define the difference as only the permanent plugging is sufficient in order to sidetrack a new well path.
The main difference is that there are stricter requirements regarding the acceptance criteria when performing a permanent plug and abandonment operation. The well barriers in a permanent abandonment operation needs to consist of several WBEs which in combination creates a seal that *ideally* has an eternal perspective. The list of the material requirements in relation to a permanent P&A operation is seen on **page 53**.

The next main section explores the difficulties regarding well barrier management in a slot recovery operation. An important note with respect to slot recovery operation, taken from the introduction of the section, is that proper well integrity is as much about dealing with the current risk picture, as it is to establish good solutions in the design phase. Continuous monitoring of the barriers, and hence understanding of the well barrier status, seems to have been given a low priority prior to the establishment of the WIF forum in 2007.

The subsection regarding barrier control introduces how to to manage all the requirements involving barriers. The term *barriers* was defined in **section 1.2**. To get more hold of the term *barrier control*, the subsection first needed to define what a *barrier function* is. Several barrier functions needs to be organized in a hierarchy. I.e., in order to achieve full isolation of a leaking segment, a barrier function which shall reduce the leak must first be established (as seen in **figure 3.1**). This will again achieve the main goal in this scenario - to prevent escalation of an explosion in an operation area.
The term *barrier control* can therefore be seen as the coordination of activities to establish and maintain barriers so that they at any time maintains its function. This is a broad term, and a figure (**figure 3.2**) was created in order to put the term into context, and relate it to a operational flow chart. This thesis' main goal was to investigate the challenges in the planning phase of a slot recovery. Hence, **section 3** focused on the upper box seen in **figure 3.2**.

In order to organize the processes in a planning and early operation phase, the **figure 3.4** was created. All these processes was then thoroughly discussed with several documents as a basis for the investigation. This discussion will not repeat each subsection, but instead give a short summary of the main findings with respect to slot recovery operations.

The subsection regarding risk assessments pointed on the importance of having relevant people and up-to-date information available in the planning phase of a slot recovery. Both these factors may be a challenge:

- The people involved in the original well operation may somewhat be unavailable during the planning phase.
- The wells can often be old, and a well could therefore have no up-to-date status of the barriers.

The last point especially addresses the challenge regarding documentation handover which will be discussed later.
Some other aspects/challenges to consider in an assessment can be:

- to identify the well barrier status. This is a difficult assessment as several well barrier elements can be hard to test.
- to investigate the condition of the rig. Will the rig be able to handle a modern operation? Many rigs have already passed their life expectancy and may break down during operation, thus creating unexpected and possibly dangerous situations.
- reveal the operation history on the wellbore, i.e. any maintenance work / fishing operations / extensive testing / re-completions / conversions of the original design etc. which may have had an influence on the well integrity.

Since the well barriers already have been established when planning for a slot recovery, the an important matter in the planning phase will be to test and verify the barriers in the well, especially the WBEs which are to be re-used in the sidetrack.

A well operation such as the slot recovery will always have some uncertainties latent in the design. These uncertainties needs to be kept at a minimum in the planning phase in order to increase the possibility of a successful operation. One way of keeping these uncertainties is to make sure the risk acceptance criteria (RAC) are set with a margin. The aspects related to RAC is found in appendix A in NORSOK Z-103.
If some of the uncertainties turns out to be difficult to handle, a contingency plan needs to be available. The factors which needs to be covered in a contingency plan can be found on **page 71**. The next subsection takes a step further from planning, and involves the management of the risks and risk picture which were established in the planning phase. To ensure that

those who carries out the operation fully understand the risk picture, the barrier strategy and design needs to be in a understandable and pre-defined format (preferably a fixed template). The full list of the principles of a barrier strategy is seen on **page 74**.

The process flowchart in the **figure 3.4** should have been followed during the original operation of the main wellbore. This would, according to the figure result in a set of performance standards for the well. These performance standards/requirements, which are created for the specific wellbore, will be of high value for subsequent operations, such as the slot recovery. The term *performance standards* is defined in the NORSOK S-001 which is a document created by several operators on the NCS, and not PSA. This means that the standards are empirical, and serves as a good practice. These standards are given in full on **page 75**.

An operation must constantly be supervised and reviewed in accordance with the given plan. Plans often need an evaluation where parts of the design must be thought over. This may lead to changes of the original plan. Changes of a plan are a subject of the term *management of change*. This is an important aspect which have gotten an increased focus in the aftermath of especially the SNA incident in 2004. The management of change principle allows for several actions do be carried out in case of changes in an operation. Every time a change is done on the original operational design, the following actions must be done:

- a risk assessment carried out for all those affected by the change
- a preparation of a work plan which clearly specifies the time scale for the change and potential control measures that must be implemented with regards to:
  - equipment, facilities and process
  - operation, maintenance and inspection procedures
  - training, personnel and communication
  - documentation of the changes
- the responsible person/persons approval of the work from start to completion.

One of the main challenges of an slot recovery operation is the testing and verification of existing barriers, and is seen in both cases in the thesis. These cases emphasizes the need for tools which can accurately provide information regarding the integrity of a barrier. It also shows that there is a need to improve the requirements regarding a negative pressure test. As of 2012, there is no standard for this.

Figure 3.5 shows different ways to either verify or confirm in-situ barriers. On **page 81**, several tools to verify a barrier are given. Especially the field history can provide relevant information when planning for a slot recovery operation.
The challenges with verifying barriers also points towards the need for improved tools in the industry. One of the tools mentioned in the thesis is the CBL tool. The CBL logging tool is important when verifying the cement placement, and hence the integrity of the cement element. In this regard, the CBL tool is also important to locate the TOC. The TOC must be located prior to the cutting and retrieving of casing strings which is done in a slot recovery.
Due to several difficulties regarding verification of old and existing barriers, this thesis recommends that a slot recovery should be split into two separate campaigns, one to get a proper verification of the well barrier status, and one to perform the re-use of the slot.

The next subsection discusses the importance of proper documentation handover. The handover of relevant documentations has proved to be a weak spot in the planning phase of a slot recovery. This process is simply not adhered well enough in the industry, with the result that important information is left out when documents are passed from one organization to another. By organization, the requirements in NORSOK D-010 mean a subgroup within a company (drilling department, operational department etc.). These requirements are listed on **page 83**.
However, there are no requirements related to documentation handover between companies. With the discovery of the Johan Sverdrup field, Statoil will most likely seek to offload many of their mature and marginal fields, simply because they do not have the capacity to operate them (the Johan Sverdrup field will demand lots of personnel). Smaller companies will seek to make money out of these marginal fields. Several of the fields will be profitable if new wells are drilled to drain the reservoir completely. Since these rigs probably are at capacity, the only solution will be to perform slot recoveries. Hence, there should be implemented requirements regarding documentation handover between companies in the NORSOK standards.

The last subsection involves human factors, and serves to emphasize that well integrity is not just about technical barriers. PSA has especially focused lately on the term HTO (MTO in some literatures). The HTO theory states that where human behavior is a barrier function, technology and organization must be organized so that people who perform the operation are given the necessary support in order to understand the situation correctly, and act in accordance with safety requirements.

Note that all these findings have been investigated throughout the thesis, and that every aspect is in connection with each other. For this reason, the author has found it necessary to first dedicate a whole section to well integrity in general, and then tie this theory around the slot recovery term in **section 3**.

The discussion and conclusions regarding the two cases are given in the respective sections, and will not be repeated here.

7 Conclusion

The thesis has tried to cover a large amount of information regarding well integrity and barrier control, and then try to put this is the context of slot recovery operations. This final section will specifically deal with the findings regarding slot recoveries, and not well integrity and its requirements in general. The thesis aims to provide some good practices, both organizational and technical, when planning for and operating a slot recovery.

This final conclusion will be given in some keywords.

- The typical well integrity challenge is a result of marginal well design. Operators often rely on the calculated result for a well design, but in addition there needs to be a practical understanding of well barriers. Once a well design is complete, the industry needs to improve completion design weaknesses. When the well is completed, the barrier validation process has to correspond with the actual acceptance criteria which are given by several NORSOK documents.
- The well categorization analysis, which shows a steady amount of wells with integrity issues, needs to be follow up to a greater extent than today.
- More research needs to be carried out regarding the long-term effects on casings/tubings and cement. To understand these effects will contribute to plan for a robust slot recovery operation. The understanding will also help to combat the reasons for material degradation which may result that longer parts of the casing strings can be re-used in slot recoveries. This is a cost saver, and may make additional wells profitable.
- Guidelines when performing a negative pressure test needs to be established. The scenario of a negative pressure test will be a likely outcome in many slot recovery operations. Hence, it will be beneficial to implement specific guidelines regarding this outcome.
- Requirements regarding documentation handover between companies needs to be implemented in the NORSOK D-010. As of today, there are only requirements of this process within a company. This should be done since especially Statoil will try to offload some of their mature and marginal fields in the near future.
- Wells need to be properly designed given the operational environment they are exposed to. If wells have been operating outside of its design

envelope, this will have a huge impact on the well integrity, which again will have an impact on subsequent operations.

- A slot recovery should be divided into two independent campaigns. The first should be set out to get a proper verification of the barriers in the well. This will give many answers when planning for the slot recovery operation.
  One mistake which tends repeat itself in slot recovery operations, is that the operational plan of a slot recovery is created prior to any verification or testing of the in-situ barriers. This often leads to unexpected situations when the barriers are tested with the result that the plan needs to be altered. This can be prevented if a slot recovery operation is split in two.

- There needs to be more definite ways to verify an in-situ barrier. In order to achieve this, more research and development must be done with regards to verification tools.

- Management of change processes, and a proper contingency plan in case of unexpected incidents, will contribute in keeping risks in slot recoveries down. Both these processes have been thoroughly discussed in the thesis.
  Today there are only requirements in relation to contingency plans regarding worst case scenarios (blow-out). The author believes that contingency plans also should be established within a company for other situations during an operation, not only for a blow-out. This will make an unforeseen situation easier and more effective to handle when/if it occurs.

- Understanding the human factors of well integrity will be a key factor to avoid incidents in the future.

- Another aspect with a slot recovery operation is the fact that the new geological target (hopefully) has a higher pressure than the reservoir where the original wellbore is located. This needs to be taken into consideration when performing tests on the casings. The in-situ barriers may hold the current pressure, but what about a significantly higher one?

8 Future work

The conclusion serves in many ways as an indication of what the focus should be regarding future work/challenges with respect to a slot recovery operation. Hence will this section not repeat some of the recommendations given in the previous section.

Abbreviations and list of symbols

ALARP	As Low As Reasonable Practicable
API	American Petroleum Institute
ASV	Annular Safety Valve
BOP	Blow Out Preventer
CBL	Cement Bond Log
Csg	Casing
DDM	Derrick Drilling Machine
DHSV	Down Hole Safety Valve
DHSV	Down hole Safety Valve
DP	Drill Pipe
DS	Drill String
DWH	DeepWater Horizon
ECD	Equivalent Circulating Density
GoM	Gulf of Mexico
HAZID	Hazard Identification
HC	Hydro Carbons
HTO	Human, Technology and Organization
IRIS	International Research Institute of Stavanger
ISO	The International Organization for Standardization
KPI	Key Performance Indicator
MD	Measured Depth
METP	Maximum Expected Tubing Pressure
MPI	Magnetic Particle Inspection
NAS	Nødavsteningssystem / Emergency Shutdown System
NCS	Norwegian Continental Shelf

NORSOK	NORsk SOkkels Konkurranseposisjon / The Norwegian shelf competitive position
NPT	Non Productive Time
NSOAF	North Sea Offshore Authorities Forum
OBM	Oil Based Mud
P&A	Plug and Abandonment
PBR	Polished Bore Receptacle
PIF	Performance Influencing Factors
POB	Personnel On Board
PSA	Petroleum Safety Authority
RAC	Risk Acceptance Criteria
RESU	Reservoarutvinning/Reservoir Recovery
RKB	Rotary Kelly Bushing
RNNP	RisikoNivÃ¥ i Norsk Petroleumsvirksomhet Risk level in the Norwegian Petroleum Activities
RNNP	Risk Level in the Petroleum Industry
ROV	Remote Operated Vehicle
SCSSV	Surface Controlled Sub-Surface Valve
SG	Specific Gravity
SHC	Self-Healing Cement
SICP	Shut In Casing Pressure
SIDPP	Shut In Drill Pipe Pressure
SNA	Snorre A
SSSV	Sub Surface Safety Valve
SSW	Sub Sea Well
TAC	Tubing to Annulus Communication
TOC	Top Of Cement
TRSCSSV	Tubing Retrievable Surface Controlled Sub Surface Valve
UPA	Undervannsproduksjonsanlegg/Subsea Production Facility
USIT	Ultra Sonic Image Tool

WAG	Water Alternating Gas
WBE	Well Barrier Element
WBM	Water Based Mud
WBS	Well Barrier Schematics
WS	Work String

List of symbols

This is a list of different symbols used in the thesis. SI units given in [...] where applicable.

Δ - Difference

g - Earth's gravitational pull $[\frac{m}{s^2}]$

z - Depth [m]

Ft - Feet [1 feet = 0.3048 m]

Pa - Pascal $[\frac{kg}{ms^2}]$

Psi - Pound per Square Inch $[\frac{lb}{in^2}][1Psi = 145 \times 10^{-6} Pa]$

M - Mega/million $[10^6]$

B - Billion $[10^9]$

bar - Pressure [1 bar = 10^5 Pa]

NOK - Norwegian Kroner

$ - United States Dollars

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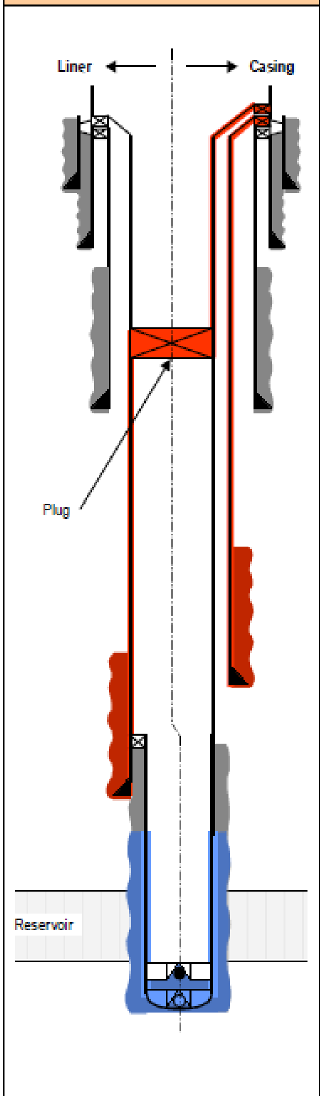
A Well barrier schematics

A.1 Well barrier schematics for temporary abandonment, non-perforated well

9.8.1 Temporary abandonment – Non-perforated well

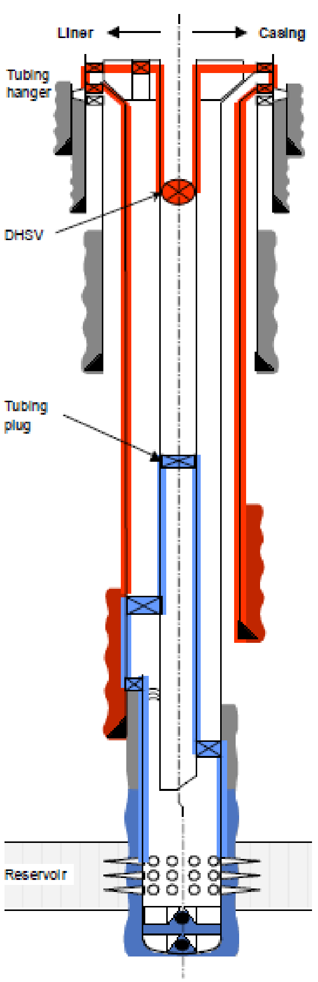


Well barrier elements	Comments
Primary well barrier, last open hole	
1. Cement plug	At shoe track
2. Casing (liner) cement	
3. Casing (reservoir liner)	Un-perforated with 2 each float valves
OR	
1. Cement plug	At shoe track
2. Casing cement	
3. Reservoir casing	Un-perforated with 2 each float valves
Secondary well barrier, temp. abandonment	
1. Casing	
2. Casing cement	
3. Cement plug or mech. plug	Shallow plug
OR	
1. Casing cement	
2. Casing	Intermediate
3. Wellhead	
4. Casing	Production casing
5. Cement plug or mech. plug	Shallow plug

Figure A.1: Barrier requirements for liners on the left, and barriers for casings on the right (NORSOK, 2011).

A.2 Well barrier schematics for temporary abandonment, perforated well

9.8.2 Temporary abandonment – Perforated well with BOP or production tree removed

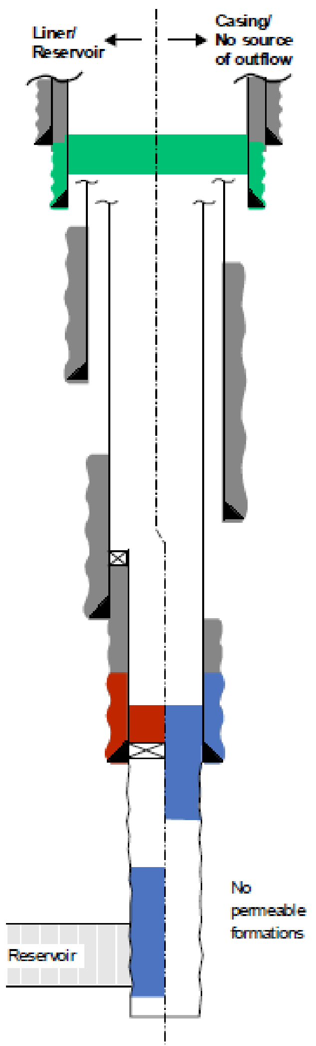


Well barrier elements	Comments
Primary well barrier	
1. Casing (liner cement)	
2. Casing (liner)	Liner above perforations
3. Liner top packer	
4. Casing	Below production packer
5. Production packer	50 m below TOC in casing annulus
6. Completion string	
7. Deep set tubing plug	
OR	
1. Casing cement	
2. Casing	Avove perforations
3. Production packer	
4. Completion string	
5. Deep set tubing plug	
Secondary well barrier, reservoir	
1. Casing cement	Above production packer
2. Casing	Common WBE between liner top packer and prod. packer
3. Wellhead	
4. Tubing hanger	
5. Tubing hanger plug	For SSWs
6. Completion string	Down to SCSSV
7. SCSSV	
OR	
1. Casing cement	Intermediate casing
2. Casing	Intermediate casing
3. Wellhead	
4. Tubing hanger	
5. Tubing hanger plug	For SSWs
6. Completion string	Down to SCSSV
7. SCSSV	

Figure A.2: Barrier requirements for liners on the left, and barriers for casings on the right (NORSOK, 2011).

A.3 Well barrier schematics for permanent abandonment, open hole section

9.8.3 Permanent abandonment - Open hole



Well barrier elements	Comments
Primary well barrier	
1. Cement plug	Open hole
OR	
1. Casing cement	
2. Cement plug	Transition plug across casing shoe
Secondary well barrier, reservoir	
1. Casing cement	
2. Cement plug	Cased hole cement plug installed on top of a mechanical plug
Open hole to surface well barrier	
1. Cement plug	Cased hole cement plug
2. Cement casing	Surface casing

Notes

a. Verification of primary well barrier in the "liner case" to be carried out as detailed in Table 22.

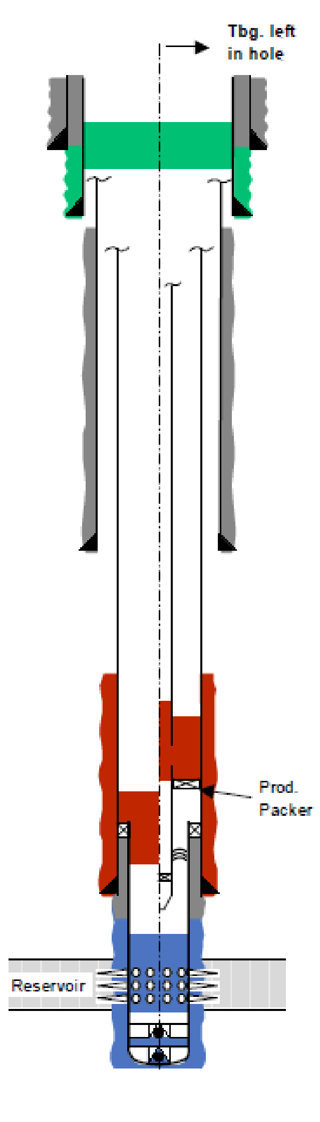
b. The well barrier in deepest casing shoe can for both cases be designed either way, if casing/liner cement is verified and O.K.

c. The secondary well barrier shall as a minimum be positioned at a depth where the estimated formation fracture pressure exceeds the contained pressure below the well barrier.

Figure A.3: Barrier requirements for liners when a reservoir is prestent on the left, and barriers for casings when no permable formations are present on the right (NORSOK, 2011).

A.4 Well barrier schematics for permanent abandonment, perforated well

9.8.4 Permanent abandonment - Perforated well



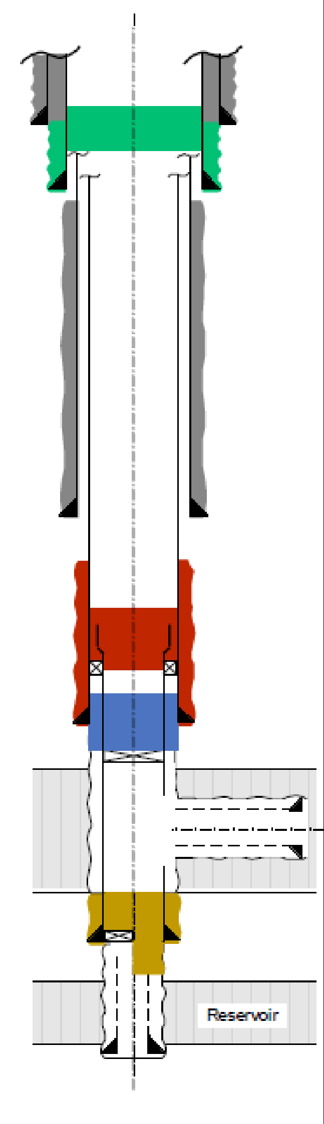
Well barrier elements	Comments
Primary well barrier	
1. Liner cement	
2. Cement plug	Across and above perforations
Secondary well barrier, reservoir	
1. Casing cement	
2. Cement plug	Across liner top
OR, when tubing left in hole:	
1. Casing cement	
2. Cement plug	Inside and outside of tubing
Open hole to surface well barrier	
1. Cement plug	
2. Cement casing	Surface casing

Notes
1. Cement plugs inside casing shall be set in areas with verified cement in casing annulus.
2. The secondary well barrier shall as a minimum be positioned at a depth where the estimated formation fracture pressure exceeds the contained pressure below the well barrier.

Figure A.4: Barrier requirements for liners on the left, and barriers when the tubing is left in the hole on the right (NORSOK, 2011).

A.5 Well barrier schematics for permanent abandonment, multibore well

9.8.5 Permanent abandonment - Multibore with slotted liners or sand screens



Well barrier elements	Comments
Barrier between reservoirs	
1. Casing cement	
2. Cement plug	Cased hole
OR	
2. Cement plug	Transition plug across casing shoe
Primary well barrier	
1. Cement plug	Across wellbore and casing shoe
Secondary well barrier, reservoir	
1. Casing cement	
2. Cement plug	Casing plug across liner top
Open hole to surface well barrier	
1. Cement plug	Cased hole cement plug
2. Casing cement	Surface casing

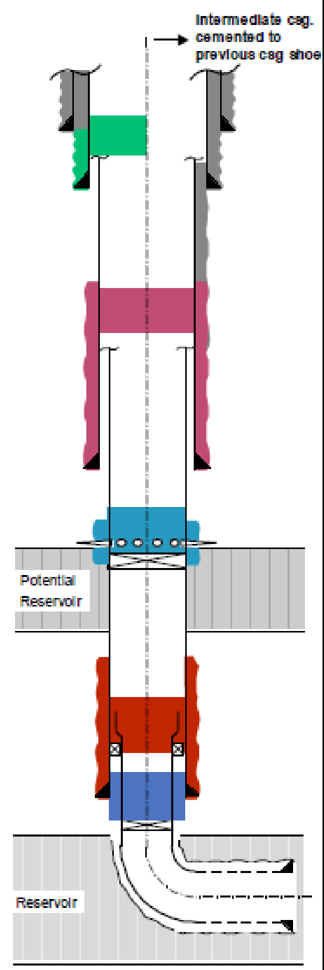
Notes

1. The “well barrier between reservoirs” may act as the primary well barrier for the “deep” reservoir, and “primary well barrier” may be the secondary well barrier for “deep” reservoir, if the latter is designed to take the differential pressures for both formations.
2. Secondary well barrier shall not be set higher than the formation integrity at this depth, considering that the design criteria may be initial reservoir pressure, as applicable in each case.

Figure A.5: Barrier requirements for cased hole scenario on the right and the use of a transistion plug on the left (NORSOK, 2011).

A.6 Well barrier schematics for permanent abandonment, slotted liners and mulitiple reservoirs

9.8.6 Permanent abandonment - Slotted liners in multiple reservoirs



Well barrier elements	Comments
Primary well barrier, deep reservoir	
1. Cement plug	Through liner and across casing shoe/open hole transistion
Secondary well barrier, reservoir	
1. Casing cement	
2. Cement plug	Across liner top
Primary well barrier, shallow reservoir	
1. Cement plug	Squeezed into perforated casing annulus above potenial reservoir
Secondary well barrier, shallow reservoir	
1. Casing cement	
2. Cement plug	
Open hole to surface well barrier	
3. Cement plug	Cased hole
4. Casing cement	Surface casing

Notes

1. Secondary well barrier shall not be set higher than the formation integrity at this depth, considering that the design criteria may be initial reservoir pressure, which may develop over time.
2. The case on the right hand side indicates that the intermediate casing string is cemented into surface casing, i.e. with no open annulus to surface. Hence, no open holes to surface well barrier is required.

Figure A.6: Barrier requirements for intermediate casing cemented to the previous casing shoe on the right (NORSOK, 2011).

B Acceptance criterias for cement plugs

<table>
<tr><th>Features</th><th>Acceptance criteria</th><th>See</th></tr>
<tr><td>A. Description</td><td>The element consists of cement in solid state that forms a plug in the wellbore.</td><td></td></tr>
<tr><td>B. Function</td><td>The purpose of the plug is to prevent flow of formation fluids inside a wellbore between formation zones and/or to surface/seabed.</td><td></td></tr>
<tr><td>C. Design, construction and selection</td><td>1. A design and installation specification (cementing program) shall be issued for each cement plug installation.
2. The properties of the set cement plug shall be capable to provide lasting zonal isolation .
3. Cement slurries used in plugs to isolate permeable and abnormally pressured hydrocarbon bearing zones should be designed to prevent gas migration.
4. Permanent cement plugs should be designed to provide a lasting seal with the expected static and dynamic conditions and loads down hole
5. It shall be designed for the highest differential pressure and highest downhole temperature expected, inclusive installation and test loads.
6. A minimum cement batch volume shall be defined for the plug in order that homogenous slurry can be made, to account for contamination on surface, downhole and whilst spotting downhole.
7. The firm plug length shall be 100 m MD. If a plug is set inside casing and with a mechanical plug as a foundation, the minimum length shall be 50 m MD.
8. It shall extend minimum 50 m MD above any source of inflow/ leakage point. A plug in transition from open hole to casing should extend at least 50 m MD below casing shoe.
9. A casing/ liner with shoe installed in permeable formations should have a 25 m MD shoe track plug.</td><td>API Standard 10A Class 'G'</td></tr>
<tr><td>D. Initial verification</td><td>1. Cased hole plugs should be tested either in the direction of flow or from above.
2. The strength development of the cement slurry should be verified through observation of representative surface samples from the mixing cured under a representative temperature and pressure.
3. The plug installation shall be verified through documentation of job performance; records fm. cement operation (volumes pumped, returns during cementing, etc.).
4. Its position shall be verified, by means of:
<table>
<tr><th>Plug type</th><th>Verification</th></tr>
<tr><td>Open hole</td><td>Tagging, or measure to confirm depth of firm plug.</td></tr>
<tr><td>Cased hole</td><td>Tagging, or measure to confirm depth of firm plug
Pressure test, which shall
a. be 7000 kPa (~1000 psi) above estimated formation strength below casing/ potential leak path, or 3500 kPa (~500 psi) for surface casing plugs, and
b. not exceed casing pressure test, less casing wear factor
which ever is lower
If a mechanical plug is used as a foundation for the cement plug and this is tagged and pressure tested the cement plug does not have to be verified.</td></tr>
</table></td><td></td></tr>
<tr><td>E. Use</td><td>Ageing test may be required to document long term integrity.</td><td></td></tr>
<tr><td>F. Monitoring</td><td>For temporary suspended wells: The fluid level/ pressure above the shallowest set plug shall be monitored regularly when access to the bore exists.</td><td></td></tr>
<tr><td>G. Failure modes</td><td>Non-compliance with above mentioned requirements and the following:
a. Loss or gain in fluid column above plug.
b. Pressure build-up in a conduit which should be protected by the plug.</td><td></td></tr>
</table>

Figure B.1: The complete overview of the different acceptance criterias for cement plugs as given by NORSOK D-010 (NORSOK, 2011).

C Data for SNA incident

C.1 Data for SICP and SIDPP during SNA incident

Table 9: Table showing all SICP and SIDPP during SNA incident

Time	SIDPP [bar]	SICP [bar]
15:00	8	11
15:30	0	0
17:30	11	0
18:00	14	0
18:30	50	0
19:00	84	37
19:30	100	55
20:00	125	80
20:30	10	4
21:00	20	15
21:30	35	20
22:00	50	25
22:30	75	30
23:00	100	35
23:30	130	40
00:00	154	46
00:30	100	20
01:00	65	0
01:30	64	40
02:00	64	60
02:30	63	75
03:00	110	79
03:30	119	84
04:00	32	0
04:30	32	55
05:00	35	60
06:00	42	83
07:30	100	77
08:00	120	75
08:30	135	73
09:00	156	72
09:30	75	40
10:00	30	20
10:30	0	0

C.2 Mud volume bullheaded into the formation during SNA incident

Table 10: Table showing the amounts of mud bullheaded into the formation during the SNA incident

Time	m^3
15:00	
15:30	
17:30	
18:00	
18:30	
19:00	
19:30	
20:00	9
20:30	
22:00	
22:30	
23:00	
23:30	
00:00	24
00:30	
01:00	
01:30	
02:00	
02:30	
03:00	
03:30	80
04:00	
06:00	
06:30	
07:00	
07:30	
08:00	
08:30	
09:00	151
09:30	
10:00	
10:30	

D Checklist when creating well barrier schematics

Operator		Field		Well	

Form and header information

- ☐ Field or installation (rig in brackets) stated
- ☐ Well number stated
- ☐ Descriptive title and subtitle
- ☐ Well type (separate line or in title)
- ☐ Prepared by
- ☐ Validated by
- ☐ Preparation date
- ☐ Revision number
- ☐ Reservoir pressure
- ☐ Design pressure
- ☐ Category class stated for wells in operation
- ☐ Notes
  - o Anomalies and/or dispensations
  - o Installation and/or suspension date

General

- ☐ Are all relevant reservoir sections shown?
- ☐ Are two independent barrier envelopes defined?
  - o All well barrier elements listed in table with correct name
  - o Cement show correctly with TOC
  - o Risk analysis made if common barriers
- ☐ Are adequate qualification requirements stated for each well barrier element?
- ☐ Are adequate monitoring descriptions presented for each well barrier element?
  - o Acceptance criteria in Bar/min
- ☐ Requirements to gas lift wells
  - o Gas lift pressure
  - o If gas-lift valve is defined as barrier element, is this qualified for this purpose?
  - o Is ASV installed or documented not needed
  - o Is production casing cemented into intermediate casing or formation strength sufficient for a leaking casing scenario?

Illustration annotation

- ☐ Components correctly shown with individual relative depth
- ☐ Casing size and depth for casings used as well barriers (also TVD for deviated wells)
- ☐ Formation integrity – FIT, LOT or $\sigma_{h\ min}$
  - o Use s.g. for operations with fluid as barrier
  - o Use bar/psi for all other conditions
- ☐ Permeable and over-pressured reservoir sections shown
- ☐ Anomalies highlighted

Primary barrier

- ☐ In contact with pressure source (as close to source as possible)
- ☐ Tubular
  - o Burst test pressure stated
  - o Thread type premium/gas tight _________
- ☐ Cement qualified
  - o Sufficient length _________
  - o Verified

Secondary barrier

- ☐ Ultimate well barrier – last resort
- ☐ Tubular
  - o Burst test pressure stated
  - o Thread type premium/gas tight _________
- ☐ Cement qualified
  - o Sufficient length _________
  - o Verified

Notes

Limit the Well Barrier Schematic (WBS) to information directly relating to the well barrier elements.
The presented ratings shall precondition that the engineer has performed the necessary material selection and calculations leading to the presented figures, and that this documentation is available upon request.

Figure D.1: The table shows a checklist when creating well barrier schematics (WellBarrier, 2012c).

E Data for Delta operation

Quadrant / Block	211/19
Field Name	Murchison
Proposed Well Intent	Development
Expected Duration of Operations	108 days (23 days including clean up & completion).
Water depth MSL	512 ft MSL
RT / Mudline	697 ft
Platform	Murchison
Slot	23
Slot History	M12, M31, M75
Well Type	Producer
Drilling Fluid	KCl Polymer and Versaclean OBM
Planned Total Depth of Pilot Hole	20,581 ft MDRT
Final Inclination (Max Inclination)	65.6°(65.6°)
Reservoir Pressure Primary	Top Brent: 6272 psi at 9718 ft TVDSS
Reservoir Temperature	Circa 245°F @ 10,172ft TVDSS
Planned Total Depth of Delta Well	21,225 ft MDRT
Final Inclination (Max Inclination)	89°(89°)
Reservoir Pressure	Brent: 6272 psi at 9718 ft TVDSS
Reservoir Temperature	240 - 260°F @ 9,842 ft TVDSS
Production Liner	7 inch, 29ppf, L80, VAM TOP, Top of liner @ 16,900ft MDRT (500ft liner lap), TD @ 21,220 ft MDRT
Proposed Completion Tubing	Tubing 5 1/2 inch 17ppf, L80 13-Cr, KS Bear, Note 9 5/8 inch production packer to be set at circa 16,800 ft MDRT, Tailpipe 4 1/2 inch 12.6 ppf, L80 13-Cr, KS Bear c/w TCP guns

Table 11: Well and rig data for the Delta operation (CNR, 2008).

1. Check and report offline 9 5/8” casing and 9 5/8” x 13 3/8” and 13 3/8” x 20” annuli pressures offline. Bleed off and lubricate as required.

2. Skid rig over slot 23.

3. Remove suspension cap and rig up Diverter/Hydrill. Pressure test same to 200 psi

4. RIH with 9 5/8” casing bridge plug/cement retainer and set at 2435 ft MD.

5. RIH with 9 5/8” casing cutter and cut casing at 2,051 ft MD.

6. Bullhead 9 5/8” x 13 3/8” annulus content of OBM (circa 122 bbl) with seawater into formation below 13 3/8” casing window at 4548 ft MD.

7. Pull and lay down 9 5/8” casing. Inspect casing hanger for damage.

8. RIH 600 ft of cement stinger to 2,430 ft, tag bridge plug at 2,435 ft and set 500 ft cement plug across 9 5/8” casing stump.

9. Nipple down Diverter/Hydril BOP then remove McEvoy speed head.

10. Install and test diverter/hydril.

11. Rig up e/line and run CBL to maximum 1850 ft MD. Establish 13.3/8” casing TOC and 13 3/8” casing couplings depth. Prognosed TOC according to records is seabed @ 697 ft MD.

12. RIH with 13 3/8” casing cutter and cut 13 3/8” above TOC or at 1850 ft, which ever depth is the shallowest.

13. Established circulation and circulate annulus volume (10.3 ppg WBM) to seawater taking returns to a separate pit. Check for oil content.

14. If 13 3/8” casing has been cut above 1,850 ft MD RIH with 13 3/8” milling assembly and mill 13 3/8” casing to 1,850 ft MD.

15. RIH 600 ft cement stinger and set 500 ft cement plug back inside the 20” casing.

16. Pressure test 20” casing to 200 psi.

17. Make up 17 1/2” BHA and drill 17 1/2” hole to 5,300 ft MD.

18. Run and cement 13 3/8” casing.

19. Nipple down diverter/Hydrill.

20. Install new McEvoy Speedhead.

21. Install suspension cap.

E.2 Timing estimate for Delta operation

	OPERATION	NET TIME (HRS)	RISKED TIME (days)
	Preparation (offline)		
1	Bleed any gas from annulus and lubricate with seawater		
2	Monitor Annuli pressures		
	Preparation (online)		
3	Skid rig to slot 23		
4	Remove wellhead flange & install/test Diverter/Hydril		
	RECOVER SLOT BACK TO 20" SHOE		**22**
5	RIH, set bridge plug/cement retainer in 9.5/8" casing @ 2435 ft		
6	RIH, Cut 9 ⅝" casing (2051 ft), POOH, recover & lay out same		
7	RIH, set 500 ft cement plug across 9.5/8" csg stump		
8	Run CBL		
9	RIH. Cut 13.3/8" csg above TOC, recover and lay out same		
10	RIH, mill 13.3/8" csg to 1850 ft		
11	RIH, set 500 ft cement plug across 13.3/8" stump and back inside 20" shoe		
	DRILL NEW WELL TO DELTA TARGET		**41**
	Drill 17½" Hole section		
12	Make up & RIH with Directional BHA, Drill cement to KOP @ circa 1750 ft MD		
13	Drill 17½" hole section from 1,750 ft to 5,300 ft MD		
14	Circulate clean and Pump out to shoe, POOH to surface		
	Secure 17 ½" Hole		
15	Run & cement13⅜" casing. Displace cement with mud.		
16	Pressure test casing & Install & Test BOP		
	Drill 12¼" Hole section		
17	RIH with Drilling BHA. Displace to & Condition OBM (Perform FIT to 14.4 ppg EMW)		
18	Drill 12¼" Hole section from 5,300 ft to 18,400 ft MD		
19	Circulate clean and Pump out to shoe, POOH to surface		
	Secure 12¼" Hole		
20	Run & cement 9⅝" liner. Displace cement with mud.		
	Drill 8 ½" Pilot Hole		
21	RIH with Drilling BHA. Displace to & Condition OBM (Perform FIT to 14 ppg EMW)		
22	Drill 8½" Hole section from 18,400 ft to 20,582 ft MD		
	Abandon Pilot Hole		
23	Set abandonment cement plugs across reservoir and set kick off cement plug back inside 9.5./8" casing shoe.		
	Drill 8 ½" Hole Sidetrack (assumption Delta location based on logging)		
24	RIH with Drilling BHA		
25	Drill 8½" Hole section from 18,400 ft to 21,225 ft MD		
	Secure 8½" Hole		
26	Run & cement 7" liner. Displace cement with mud.		
	COMPLETE WELL		**17**
	Clean Up		
27	Perform Well Clean Up		
	Run Completion		
28	Run 5½" completion.		
29	Nipple Down BOPs and Nipple Up Xmas Tree.		
30	Flow well for clean up		
	NPT Allowance at 35%		**28**
	TOTAL TIME ESTIMATE [Days]		**108**
	Most Likely Estimate Cost		**130 MNOK**

Figure E.2: The table shows the timing estimate for the Delta operation (CNR, 2008).