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# Management of well barriers and challenges with regards to obtaining well integrity



by  
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# Summary

Well integrity is a result of technical, operational and organizational barriers applied, with the intention to contain and control the reservoir fluid and well pressures. Failure to obtain and maintain adequate barriers could lead to catastrophic events, like demonstrated in the Gulf of Mexico in 2010, with the Deepwater Horizon incident. Since then, the petroleum industry has experienced an increased focus on well integrity.

Recent surveys conducted on the Norwegian Continental Shelf indicate shortcomings and insufficiencies regarding implementation of technical, operational and organizational barriers. Overview of the current well integrity on the NCS was also lacking.

With the expected increase in well-operation activities on the Norwegian Continental Shelf the coming years, ensuring secure wells should be a main priority.

Integrity of well barriers is a factor that must be included from the design and planning phase, and be present throughout the entire lifecycle of the well. Different challenges related to barriers do however present difficulties achieving this. Some of which, include accessibility and understanding of regulations and standards, technical implementation and long term effects of well barriers, and insufficient training and well integrity competence of personnel.

By studying the causes of well incidents and blowouts, and by conducting surveys of wells and operating companies, a better overview of the different challenges and shortcomings resulting in these incidents, can be achieved. In order to prevent major accidents in the future, one must acknowledge and understand the past.





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# Nomenclature

API	American Petroleum Institute
ASV	Annulus Safety Valve
bbbl	Barrels
BHA	Bottom Hole Assembly
BOEM	Bureau of Ocean Energy Management
BOEMRE	Bureau of Ocean Energy Management, Regulation and Enforcement
BOP	Blowout Preventer
BP	British Petroleum
BSEE	Bureau of Safety and Environmental Enforcement
BTC	Buttress threads and coupled
CAL	Connection Application Level
CBL	Cement Bonding Log
CT	Coiled Tubing
CTC	Completion Tool Company
DC	Drill Collar
DEA	Danish Energy Agency
DEPA	Danish Environmental Protection Agency
DFU	Defined Situation of Hazards and Accidents
DNV	Det Norske Veritas
DHSV	Downhole Safety Valve
DWEA	Danish Working Environment Authority
ECD	Equivalent Circulating Density
EDS	Emergency Disconnect Sequence
ESD	Emergency Shut Down
EWCF	European Well Control Forum
FIT	Formation Integrity Test
ft.	Feet
GLV	Gaslift Valve
GoM	Gulf of Mexico
GOR	Gas-Oil Ratio
HPHT	High Pressure High Temperature
HSE	Health, Safety and Environmental
HSE	Health and Safety Executive
I/O	Integrated Operations
in.	Inches
ISO	International Organization for Standardization
ISW	Inhibited Seawater
IWCF	International Well Control Forum
LCM	Loss Circulation Material
LDT	Leak Detection Tool
LMRP	Lower Marine Riser Package
LOT	Leak Off Test
MD	Measured Depth
MGS	Mud-Gas Separator
MMS	Minerals Management Service
MoC	Management of Change
MPD	Managed Pressure Drilling
NCS	Norwegian Continental Shelf
NOK	Norwegian Kroner
NORSOK	The Competitive Standing of the Norwegian Offshore Sector
NPD	Norwegian Petroleum Directorate
OBM	Oil-Based Mud
OCS	Outer Continental Shelf
OGP	Oil-Gas Producers
OLF	Norwegian Oil Industry Association

P&A	Plug and Abandonment
PLT	Production Logging Tool
PSA	Petroleum Safety Authority Norway
psi	Pounds per Square Inch
RNNP	Risikonivå i Norsk Petroleumsvirksomhet
ROV	Remote Operated Vehicle
RRC	Texas Railroad Commission
s.g	Specific Gravity
SCP	Sustained Casing Pressure
SSSV	Subsurface Safety Valve
TBL	Federation of Norwegian Manufacturing Industries
TJ	Tubing Joint
TVD	True Vertical Depth
UK	United Kingdom
UKCS	United Kingdom Continental Shelf
WBE	Well Barrier Element
WBS	Well Barrier Schematic
WIF	Well Integrity Forum
WL	Wireline



## **Chapter 1. Introduction**

---

Whenever a well is being planned, drilled, operated or abandoned, well integrity is always one of the most critical factors involved.

The overburden rock which once held the formation fluid trapped in the reservoir is now being replaced with a hole in the ground. This hole will now act like a continuation of the reservoir itself and with the immense pressure a reservoir might exhibit, the need for well control is always a first priority.

Without pressure containment, the well could start to leak or in worst case turn into a blowout. A situation as such would have major impact of economic and political proportions for a company, and also present a huge health and safety risk for the working personnel. It is therefore crucial to obtain and maintain proper well control in a safe manner in all phases of the wells life.

Recent discoveries from surveys conducted on the Norwegian continental shelf (NCS) has in the recent years shown a negative trend with increasing well control incidents, hydrocarbon leakages and increased risk of major accidents. This is something the industry must address as the petroleum activities are expected to increase the coming years. The Deepwater Horizon incident in the Gulf of Mexico in 2010 reminded the world and the petroleum industry of the importance of well barriers and consequences of inadequate well integrity.

Historically the primary focus has been on the construction phase of the well, with the goal of generating income. Little concern has been given to the final stages of the wells life, the plugging and abandonment (P&A), as this is a pure expense, nor how aspects in the operational phase affects well integrity.

As a result, several of the operational and plugged wells on the NCS have insufficient well integrity and could present major issues in the time to come if they start to leak. Gaining access to many of these wells may be difficult, and remedial work could prove to be very costly.

This thesis presents some of the aspects of well integrity to consider for obtaining and maintaining adequate well integrity throughout the lifecycle of the well.

Chapter two presents some of the factors to consider to achieve well integrity throughout the lifecycle of a well and gives an overview of the current well integrity on the NCS obtained through surveys conducted by the Petroleum Safety Authority and Well Integrity Forum. Annual surveys conducted the last decade have revealed trends in risk factors and well integrity issues affecting the Norwegian petroleum industry.

In chapter three, a review of non-physical barriers is presented.

Various countries regulatory regimes are discussed and some of the commonly used industry standards related to well integrity are presented. Other external barriers like controlling documents, procedures and new innovations are also presented with their related challenges.

Chapter four goes into detail about the physical well barriers present in the well and the importance and challenges tied to these.

There is also, in chapter six, case studies about some of the iconic blowout and well incidents the recent years, including the recent Elgin blowout, and how these happened as a result of barriers breaches.

## Chapter 2. Well Integrity

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Well integrity is a factor present in all the different phases of a well and relies on the existence of technical, organizational, and external barriers. Although no global definition of well integrity exists, one definition commonly used is found in the NORSOK D-010 standard; *“application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluid throughout the life cycle of a well”*.

To maintain adequate well integrity, special attention has to be made from the drilling/construction phase, through production/ injection/intervention phase, and even after plugging and abandoning the well. Problems can arise anywhere in the wells lifecycle, and can be as a result of formation induced problems, operation induced problems and human factors. Hydrocarbon leaks are one of the more serious problems that can occur, and could turn into a full blowout if it is not controlled or stopped. One of the biggest well control incidents in recent time, the Deepwater Horizon incident, stands as an example of how such a situation can unfold.

A leak could be discovered by initial testing of a component, during the continuously monitoring during production or injection, or by a routine component leak test. Hydrocarbon leaks could occur as a result of wear, erosion, corrosion, fatigue, and could present itself in the casing, tubing, cement, BOP, packers or any other downhole equipment. Operational changes, causing change in pressure and temperature, could also result in a leak. Possible events where this could occur could be startup of production/injection, changing the production rate or shutting in the well.

The well integrity management within a company should identify all potential hazards and problems for all the different phases of the well, in order to avoid and mitigate these. In order to do this, the wells pressure and temperature status should be continuously monitored, and routinely inspections should take place. Regulations and standards should also be understood and followed by all involved personnel dealing with well integrity.

The past years, well integrity has gotten increasingly more focus, and experience based on recent events shows that even more focus is needed, as the oil industry faces an all-time high with regards to activity, both in drilling and plugging & abandonment. Focus should be added to qualification and long-term integrity of well barriers, and making sure regulations, standards and procedures are understood and followed.

## 2.1 WELL INTEGRITY IN A LIFECYCLE ASPECT

Historically, in terms of well integrity, the main focus has been on the planning and construction phase of the well, like where to place the casing shoes and what mud density should be used etc. (Lunde, 2012).

In recent times, more focus has also been added to the plug and abandonment (P&A) phase as a lot of the older mature wells are in the process of being abandoned, and new technology and procedures within P&A are now starting to appear on the market.

From the ‘Well integrity life cycle’ presentation, given at the Well Integrity Workshop in May 26<sup>th</sup>, 2011 (Lunde, 2012), it is proposed that the focus should not only be on the construction or the P&A phase of the well, but on the entire lifecycle. This includes the operational phase of the well, as aspects in each of the wells lifecycle phases affect the wells integrity, even after they are plugged and abandoned.

Listed below are some key points to keep in mind throughout the life of the well in order to obtain and maintain adequate well integrity (Lunde, 2012) (Aadnøy, et al., 2009) (Rygg, 2006).

### 2.1.1 Design & Planning

- Design of the well should be optimized with respect to the formation in a specific area (Have integrity in all layers)
- The design envelope should be fit for the planned purpose of the well
- Casing design should take into account; Kick tolerance, Shallow Gas scenarios and Uncertainty of available data
- Material selection with respect to corrosion/erosion
- Avoidance of sustained casing pressure (SCP), cross flow and collapses

- Monitoring capabilities in the well
- Equipment reliability
- Include well integrity personnel during the planning phase of the well
- Plan should be revised by key personnel involved
- Continuously revision of the plan in order to be one step ahead
- Errors in the planning phase could be enhanced/magnified by insufficient well control knowledge during an operation
- Insufficient organizational control/quality could cause or aggravate an incident
- Contingencies should be in place at all times and well known in order to prevent unplanned quick fixes
- Emergency response plans should be specified to the relevant well (Max blowout rates, possible kill methods and volumes, relief well placements, available rigs for relief well drilling)

### **2.1.2 Placement of casing shoes**

- Placement of casing shoes has a big influence in both the drilling phase and the well integrity in a lifecycle approach
- Casing shoes set in formation with enough strength to withstand reservoir pressure, gives increased safety, prolonged well life, reduced P&A costs and options with regards to reservoir barriers.
- Placement of casing shoes and the isolation of these is deciding factor to avoid sustained casing pressure

### **2.1.3 Isolation**

- The most important well barrier element and most difficult to establish and verify
- Good isolation reduce the overall risk, including the possibility of SCP
- Good isolation can increase lifetime of the well and reduce cost of workovers (WO) and P&A
- Need more available types of isolation tools/medium to increase quality of isolation

### **2.1.4 Operating envelope**

- All personnel involved should have adequate well integrity competence
- Every well should have clear operating envelopes and stay within these
- Does change in drilling conditions affect initial plans?
- Incidents going beyond the operating envelope shall be documented, reported and investigated
- Avoid unneeded strain on well
- Use the well for its designed purpose

### **2.1.5 Systems and maintenance during operations**

- Preventive maintenance program on all relevant equipment optimized for the well
- Knowledge of well safety and well control (Training of personnel)
- Competent personnel and enough resources to maintain wells
- Adequate well integrity management system (Task Force with sufficient technical competence formed in case of an incident?)
- Proper handover process and documentation, procedures, steering documents and standards.
- Experience transfer and knowledge sharing

### **2.1.6 Slot recovery and P&A**

- Design, drilling, completion, operating, intervention and maintenance influence the P&A phase
- P&A should be done as soon as possible once the well has stopped producing
- Perform good P&A on existing wellbores before slot recovery.
- Good isolation in well construction phase could reduce cost in P&A phase

## 2.2 WELL INTEGRITY STATUS ON THE NORWEGIAN CONTINENTAL SHELF

The Norwegian Petroleum Safety Authority (PSA) has a vision of “*Only secure wells on the Norwegian continental shelf*”, and launched in 2006, a seminar with focus on well safety and the challenges the industry faces to prevent any major accidents from occurring (Ptil, 2006). The seminar had representatives from several companies and disciplines and discussed topics as increased attention to well safety, taking the whole life cycle of the well into account, but also sharing knowledge and experiences in order to increase the awareness and understanding around well integrity.

Based on the issues discussed, it was concluded that:

- The overview of well integrity and barriers is lacking in many cases, which could lead to serious well incidents if not addressed.
- The increased complexity of wells requires increased competence of personnel and more advanced software in order to provide proper barriers for these wells.
- Knowledge sharing and openness in the petroleum industry should be improved in order to increase our general understanding and competence around well integrity. Governmental cooperation across borders, with regards to regulations and standards would also contribute greatly to this.

One of the subjects presented on the seminar was the well integrity pilot survey done by PSA in 2006 on the NCS. In addition to this, data has the recent years been collected continuously and published in annual PSA reports called Risikonivå I Norsk Petroleumsvirksomhet (RNNP). Results from the pilot survey and the most recent RNNP report, published April 25<sup>th</sup> 2012 are presented below.

### 2.2.1 Pilot survey conducted on the NCS - 2006

The pilot survey was done based on a list of several issues that pointed to a lack of understanding and control around well integrity in the industry today. Information from the United Kingdom (UK) and Gulf of Mexico (GoM) indicated that several wells were suffering from integrity issues like structural failures, causing them to be shut in (Andreassen, 2006).

On the NCS there have also been several cases of well barrier failures happening in all stages of the wells life, and also an unsatisfied availability to critical information about the wells, like the wells integrity status and important well data. The purpose of the survey was to promote a more open discussion and knowledge sharing around these issues, in order to prevent any major accidents from happening in the future.

The survey was based on around a fifth of the active producing and injecting wells on the NCS, adding up to 406 wells, divided amongst seven operating companies.

### Physical well barrier issues

Out of the 406 wells investigated on the pilot survey, 75 wells (18.5%) presented with well integrity issues (Vignes, et al., 2006). Figure 1 show the amount of wells with issues or uncertainty related to specific Well Barrier Elements (WBE).

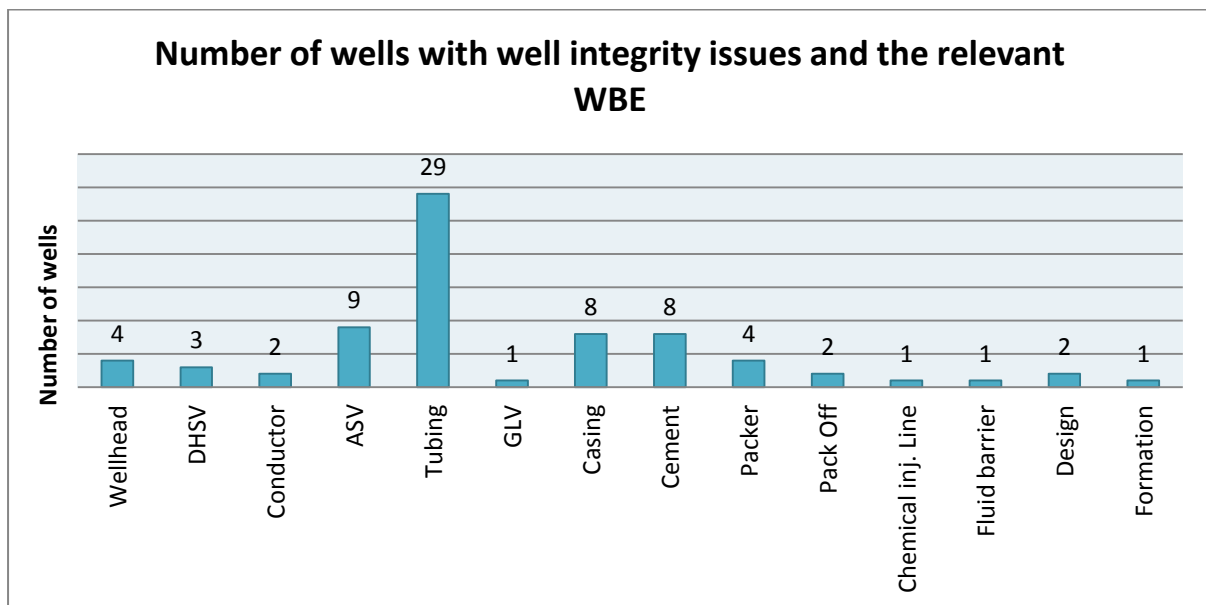


Figure 1: Number of wells with related WBE issues [Based on (Vignes, 2012)]

Tubing stands out as the WBE with most related issues, caused primarily by tubing leaks. The Annular Safety Valve (ASV), were reported with failures or leakages. Casings had reported leakages which were most likely due to non-gas tight connections. Some collapsed casings were also reported. The cement issues included lack of cement behind the casings, insufficient height of cement, and cement leakages due to either improper bonding to formation/casing or by micro annulus in the cement. Reported wellhead issues included inadequate sealing in the wellhead which caused leakages from A to B annulus.



Subsea wells had a low number of reported well incidents which could be explained by difficulties/limitations regarding monitoring. A lot of these wells could potentially have well integrity issues without being known.

**Non-physical barriers – Improvement potential**

A questionnaire were sent out to the operators in order to try to map how well the companies scored on organizational well integrity aspects and find out if there was room for improvement. The survey covered documentation, adherence to standards and defined practices, performance and competence. Figure 2 presents the areas where the companies had room for improvement regarding organizational barriers.



Figure 2: Room for improvement – Organizational barriers [Based on (Vignes, et al., 2006)]

The most frequent issues were regarding well documentation, well handover documentation, regular condition monitoring, NORSOK D-010 standard compliance and well integrity competence.

## 2.2.2 Annual NCS surveys (RNNP) – 2001- 2011

The RNNP reports focus primarily on risk indicators, investigating trends going back to 1996. By looking at the trends for hydrocarbon leaks and well incidents, risk assessments can be made with regards to major accidents, well barrier failures and health, safety and environmental factors. Data is collected through studies, from PSAs databases and from reports received from the companies. Presented below, are results from the most recent published RNNP report.

### **Situations related to risks of major accidents**

One of the more critical trends to investigate was the indicators for major accidents and the frequencies of these. The Deepwater Horizon accident in the GoM in 2010 demonstrates the consequences of such an event where a blowout ignited, causing fire and explosion, resulting in the death of 11 people, and several injuries. This is describes in more detail in chapter six.

Figure 3 shows the trend of major accident risks based on reported DFUs (Defined situations of hazard and accident) (Ptil, 2012). The risk contribution for each of the various DFUs varies.

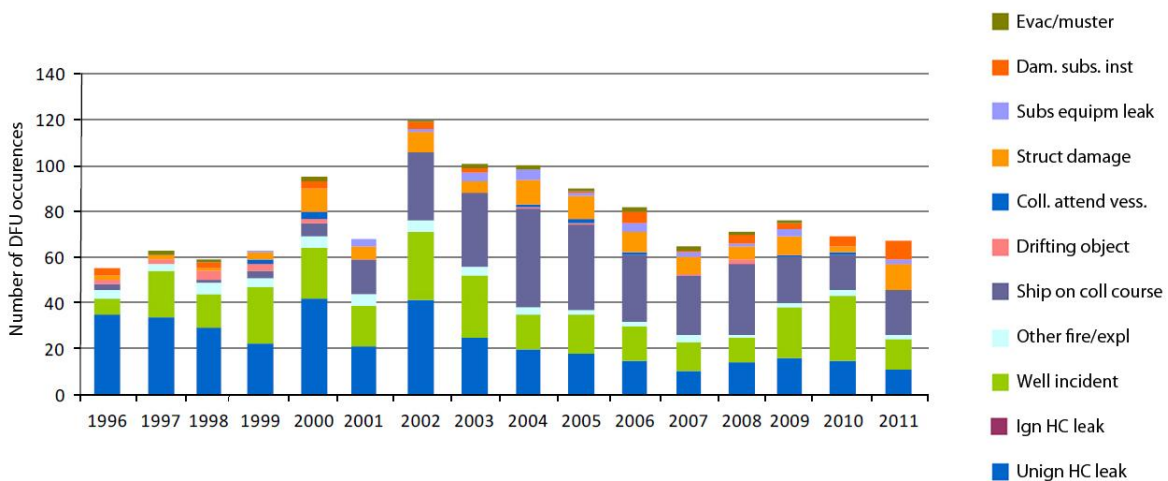


Figure 3: Reported DFUs related to major accident risk (Ptil, 2012)

The trend shows a fairly consistent level of reported DFUs, with a slight increase in the period from 1996-2001. In 2002, the number increased a great deal, which according to PSA, might've been due to underreporting of 'Ship on collision course' incidents prior to 2002. 'Well incidents' (green) and 'Hydrocarbon leaks' (blue) might also been subjected to some underreporting, contributing to the low average in this period, but not to the same extent. The change in amount of reported DFUs from the 1996-2001 period, to the 2002 - 2011 period, is therefore not a good indication of the actual trend.

In the period 2002-2007, a consistent annually reduction can be seen until 2007 where a slightly negative trend appears with increasing amount of reported DFUs. This trend can mainly be explained by the varying level of reported well incidents and hydrocarbon leaks. The negative trend of reported "Well incidents" seems however to have turned and are dramatically reduced in 2011. Reducing the risk of major accidents will continue to be one of PSAs main priorities in 2012.

Looking at Figure 4, an increase in both number of exploration wells and mobile units can be seen, which again increases the possibility of potential well incidents (Ptil, 2012). This could explain the increase in reported DFUs and the increase of minor leaks in the period 2007-2011.

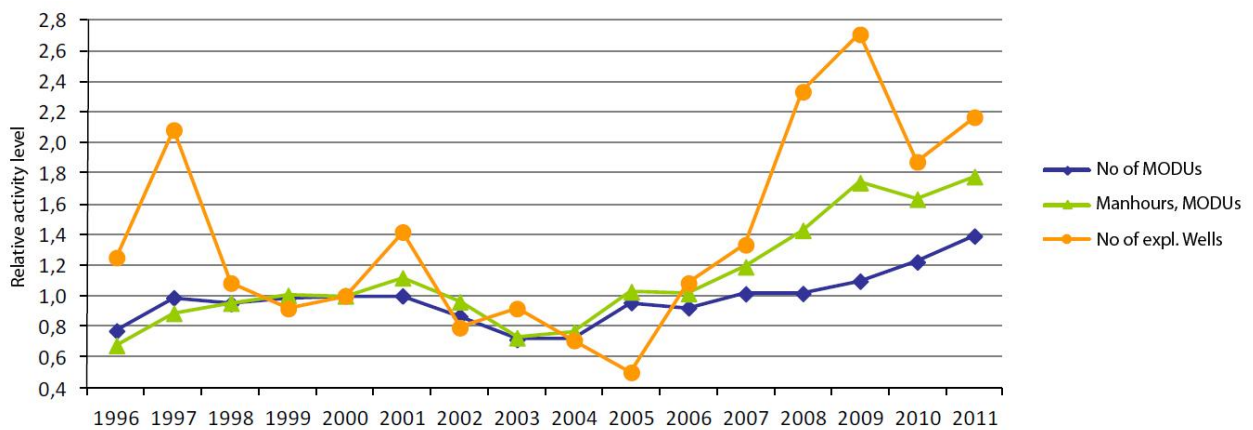


Figure 4: Trend of activity level for exploration, 1996-2011 (Ptil, 2012)

**Number of hydrocarbon leaks in the process area**

A closer look at the hydrocarbon leaks exceeding 0.1 kg/s in the period 1996-2011 reveals a similar trend (Ptil, 2012). These leaks are situated in the process area and not in the wells. The results might go beyond the scope of this paper but the trends are however worth mentioning as they paint a picture of the organizational integrity.

A positive trend with decreasing amount of leaks was seen in the period from 1996-1999, followed by some years with large variations. From 2003-2007 a positive trend was again seen, until 2007 when the trend turned and stabilized at a slightly higher level. The results from 2011 seem to be at the same low level as in 2007, with a shift towards minor leaks.

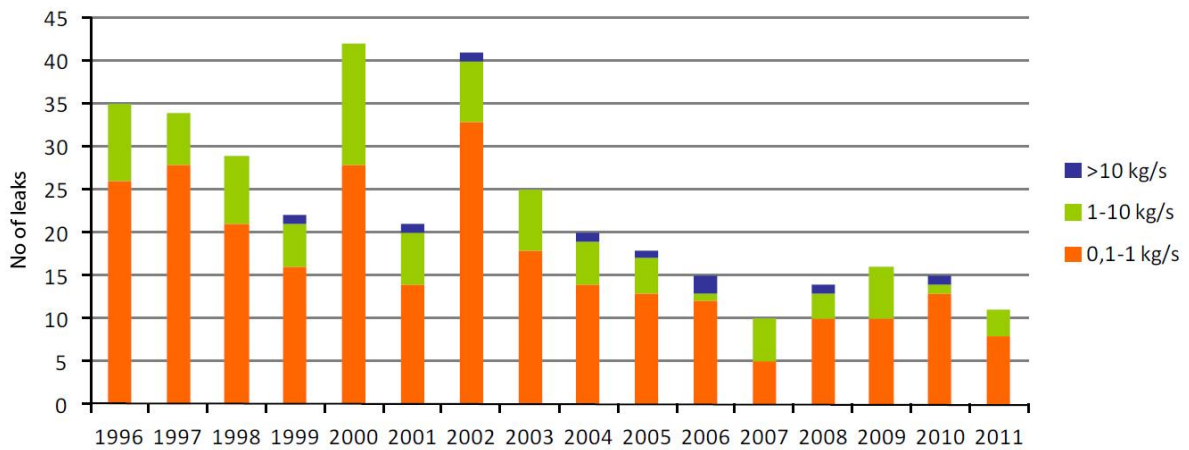
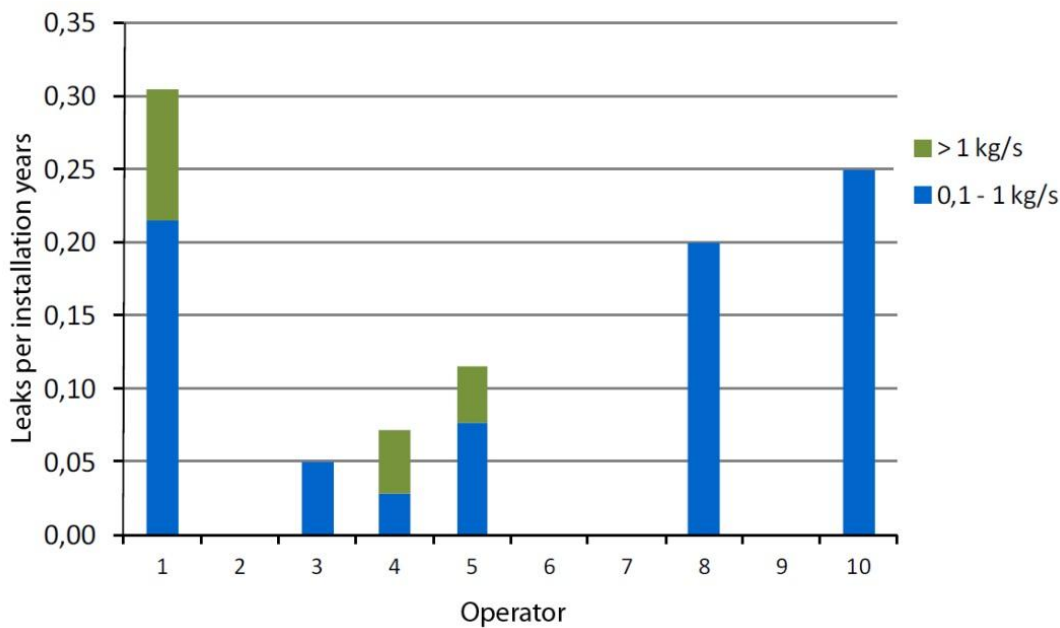


Figure 5: Number of hydrocarbon leaks exceeding 0.1 kg/s, 1996-2011 (Ptil, 2012)

The negative trend the recent years could be explained by the increased activity seen in the previous figure, or by better incident reporting.

There are big differences between operator companies regarding amount of hydrocarbon leaks. Figure 6 shows amount of leaks exceeding 0.1 kg/s for ten different operating companies on the NCS in the period 2007-2011.



**Figure 6: Average leak frequency, 2007-2011 (Ptil, 2012)**

This graph only take into account the last five years, but the differences seen between the companies have remained more or less the same for many years (Ptil, 2012). Looking at individually installations reveals that the five installations with the highest average leak frequencies, accountable for over 30% of the leaks on the NCS in this period, are under the same operating company.

This shows that there is room for improvement and that by knowledge sharing, operating companies could learn from each other in order to reduce the amount of hydrocarbon leaks. Another explanation could be different incident reporting cultures between the companies.

### ***Well control incident – Blowout potential***

As seen previously in Figure 3, the trend for reported DFUs, well incidents contribute a great deal to the observed trend.

Figure 7 and Figure 8 shows the amount of well incidents for both exploration and production drilling per 100 drilled wells in the period, 1996-2010 (Ptil, 2012).

For exploration drilling, big variations can be seen throughout the period. In the period 2005-2008 a positive trend with significantly decreasing amount of well incidents can be observed, followed by a sharp increase in well incidents the latest years from 2008. This is the result of a significantly increase in shallow gas incidents reported. The big variations are not surprising, and can be explained by drilling in unknown geology.

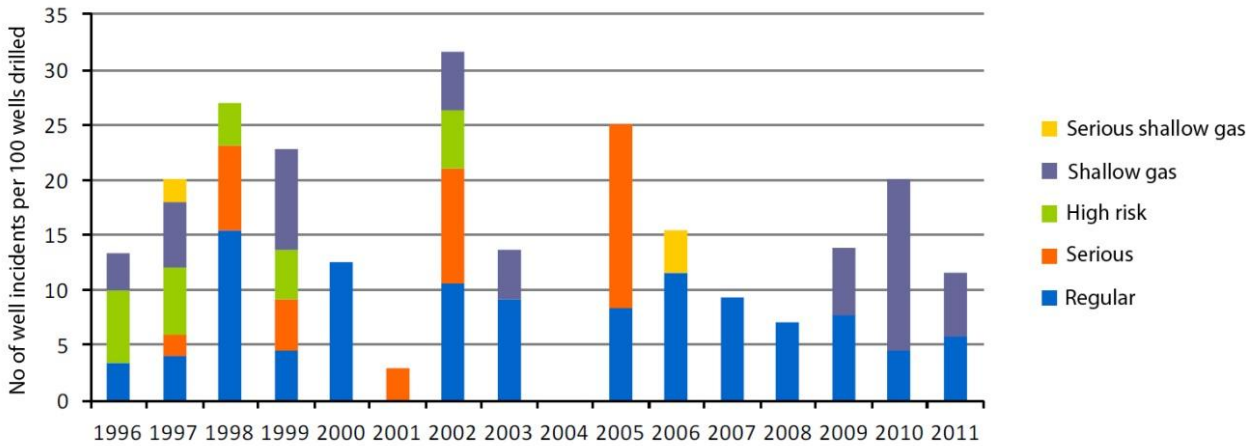


Figure 7: Reported well incidents - Exploration drilling, 1996-2010 (Ptil, 2012)

For production drilling, an increasing trend from 1996 is seen with minor variations, ending with a peak in 2003. In the period 2003-2008 a positive trend with decreasing well incidents is seen with a sharp increase from 2008-2010, mainly caused by an increase in ‘regular’ events. Results from 2011 indicate a very good year with only a few regular events.

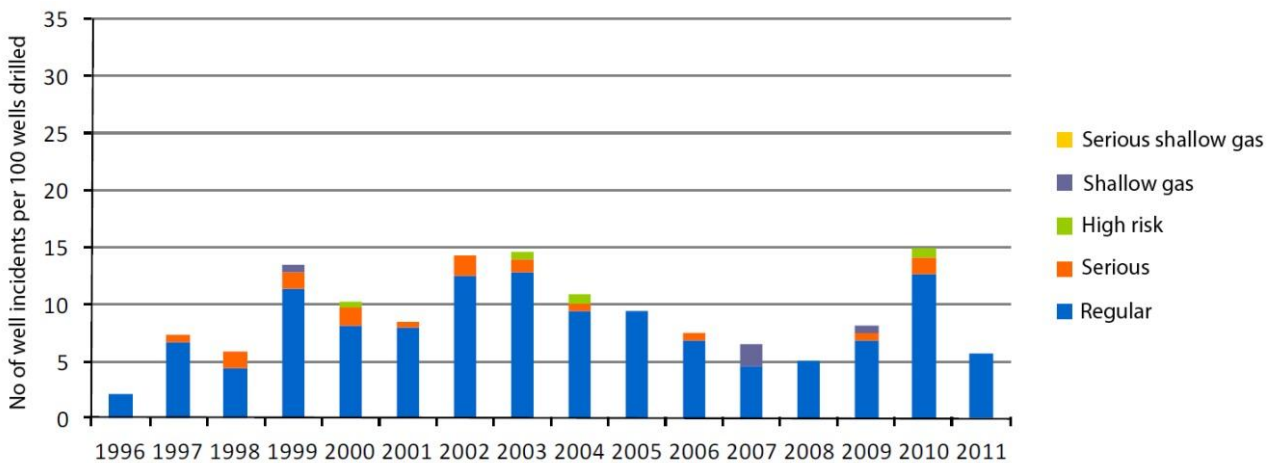


Figure 8: Reported well incidents - Production drilling, 1996-2010 (Ptil, 2012)

### 2.2.3 Classification of wells on the NCS

In 2008, the Well Integrity Forum (WIF) launched a project aimed towards classifying all active wells in terms of the well integrity risk they possess (Ptil, 2012). Ten operating companies contributed with data from 1757 active wells, excluding exploration wells and plugged wells. The following classification were used;

- Red: One barrier failed and the other degraded/unverified or with external leak.
- Orange: One barrier failed and the other intact, or a single fault which may cause leaking into external environment.
- Yellow: One barrier leaking within acceptance criteria or the barrier is degraded, and the other is intact.
- Green: Intact well, with no insignificant integrity factors.

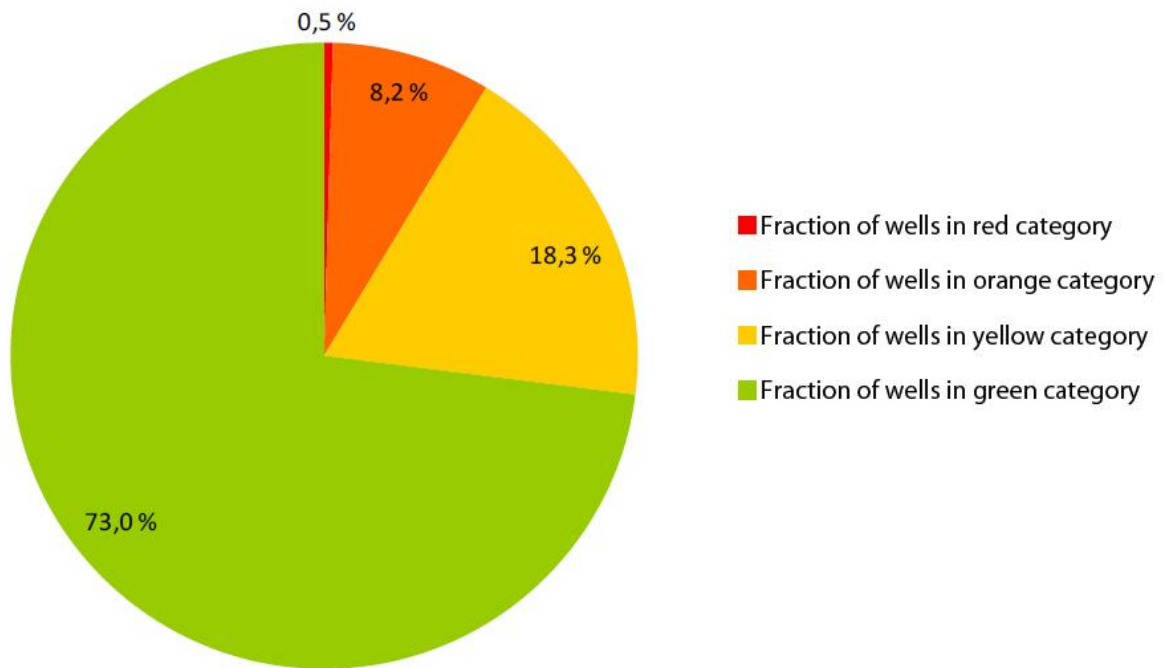


Figure 9: Classification of active wells on NCS – 2011 (Ptil, 2012)

Figure 9 shows the status of the wells on the NCS in 2011, with 8,7% of the wells being in the red and orange category. This signifies 153 wells not meeting the requirements with two

barriers, and therefore being prone to leaking or loss of well control. 18,3%, or 321 of the wells are also in the yellow category, meaning one barrier is degraded or with a small leak, but the operator has implemented compensating measures in order to meet the two-barrier requirements. These could potentially turn into red or orange wells over time.

An example of how a company, ConocoPhillips in this case, document their well classification for a given platform is shown in Figure 10. Wells are listed downwards with a color and comment indicating the well classification according to WIF color regime. All the annuli pressures are displayed and given a color related to the pre-set design pressures.

With this system, the engineers can quickly navigate between platforms and wells and obtain an overview of their status.

Well information and status											
Plant	Well	Well Status	Wellhead (psi)	Annulus A (psi)	Annulus B (psi)	Annulus C (psi)	Annulus D (psi)	Severity	Z3's	ZB's	M1
		GAS_LIFT	300	1,679	1,200	25	-1	130	1	0	
		GAS_LIFT	438	1,715	270	0	-1	140	1	0	
		GAS_LIFT	229	1,731	240	0	-1	120	0	0	
		WATER_IN	4,009	0	66	55	-1	160	1	0	
		WATER_IN	3,924	9	6	0	-1	340	8	0	
		SHUT_IN	316	1,733	560	40	-1	110	0	0	
		WATER_IN	4,000	4	600	25	-1	360	8	0	
		GAS_INJE	3,350	50	0	60	-1	150	1	0	
		SHUT_IN	890	700	650	0	-1	140	3	1	
		GAS_LIFT	250	1,072	950	500	20	140	1	0	
		SHUT_IN	0	100	130	260	0	260	2	2	
		SHUT_IN	1,540	250	50	25	-1	100	0	0	
		WATER_IN	3,300	5	0	215	-1	130	1	0	
		GAS_LIFT	488	1,773	43	30	-1	120	0	0	
		PRODUCIN	1,596	3	187	45	-1	100	0	0	
		GAS_LIFT	310	1,953	940	140	-1	140	1	0	
		GAS_LIFT	250	1,207	1,420	0	-1	190	3	0	
		GAS_LIFT	212	1,810	41	95	-1	120	0	0	
		SHUT_IN	250	1,430	417	130	-1	100	0	0	
		GAS_LIFT	230	1,717	500	70	-1	380	9	0	
		SHUT_IN	1,444	40	1,420	70	-1	170	2	0	
		SHUT_IN	884	1,550	92	30	-1	150	1	0	
		PRODUCIN	230	1,400	1,000	15	-1	120	0	0	
		SHUT_IN	713	375	0	5	-1	140	1	0	
		SHUT_IN	0	0	0	-1	-1	100	0	0	
		GAS_LIFT	259	1,905	447	460	5	520	14	0	
		PRODUCIN	703	18	17	120	-1	110	0	0	

Figure 10: Well classification in ConocoPhillips (ConocoPhillips, 2012)



## 2.2.4 Follow up survey – 2012

After the initial survey done by PSA, a follow up survey including all wells that was not active or permanent plugged, was done by PSA together with SINTEF and Wellbarrier (Vignes, 2012)

It showed that 193 wells in the NCS are today temporary plugged, and some of them have been for over 30 years (Ptil, 2012). This number is about five times the bigger than was previously believed. The companies responsible for these wells include BP, ConocoPhillips, ExxonMobil, Lundin, AS Norske Shell, Statoil, Talisman and Total.

Temporary plugged wells only require mechanical plugs in the wellbore, which are not accepted as barrier elements for permanent plugged wells, and are only meant to be used for a short period. Reducing the amount of temporary abandoned wells is one of the focus points of PSA.

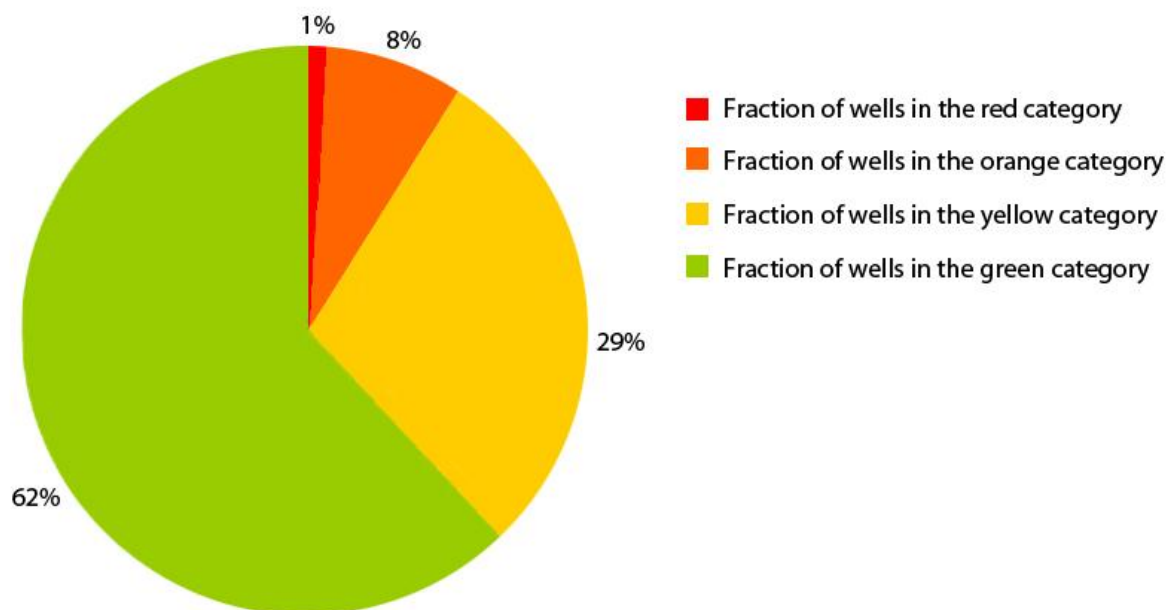


Figure 11: Classification of non-active & non-permanent plugged wells on NCS - 2012 (Vignes, 2011)

The results of the follow up survey can be seen in Figure 11.

62% (119 wells), of the wells looked into are in the green category meaning they have acceptable well barrier status, with minor or no issues. The remaining 38% (74 wells) of the wells have various degrees of barrier failures which could lead to unwanted release of

formation fluids at any time. Of these wells, 29% (57 wells) are of the yellow category, with one barrier degraded and other intact, while 8% (15 wells) are in the orange category, where one barrier has failed and the other intact, or a single failure may lead to leak to surface.

The more alarming number is the 1% (2 wells) that is in the red category, where one barrier has failed and the other is degraded, or both barriers have failed and a leak is present. These represent a big liability for the oil companies and should be dealt with immediately.

After some cooperation between PSA and the relevant operating companies, all the wells in red and orange category are now either permanent plugged or are scheduled for permanent P&A. It's unknown how long it will take until every single one of these wells are secured, but PSA will follow up the progress throughout 2012 (Vignes, 2012).

## **Chapter 3. Barriers in a wider perspective**

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To have full well integrity, implies that well control is obtained and maintained throughout the lifecycle of the well by a set of tested and verified barriers which reduce the risk of uncontrolled release of formation fluids. (NORSOK Standard D-010, 2004)

A barrier is defined as any measure or action done to reduce or prevent an unwanted situation to arise (Ptil, 2012). This could include leakage or spills of hydrocarbons, either to surface or to another formation, or health and safety related incidents to the personnel on the rig.

Barriers are needed even from the planning and early construction phase and all the way through the operational phase and beyond permanent plug and abandonment phase to ensure full well integrity of the well at all times. Barriers can be categorized in many ways and one way is to define them as non-physical barriers (external, organizational and active) and physical barriers (well barriers).

As seen on the surveys conducted on the NCS, there are shortcomings with regards to both physical and non-physical barriers. Some of the non-physical barriers required for well integrity are discussed on the following pages, while the physical barriers are discussed in more detail later on in chapter four.

## 3.1 EXTERNAL BARRIERS

External barriers are measures to ensure well integrity from a superior point of view. These are barriers affecting the industry as a whole and include laws, regulations and standards.

### 3.1.1 Laws and regulations

At the highest level, there are laws and regulations. These dictate the minimum requirements that have to be followed by the industry operating in the respective countries. Every aspect of the industry and every country have their own set of regulations that has to be followed.

#### ***Norwegian regulations***

In Norway the regulations are governed by the Petroleum Safety Authority (PSA).

The following regulations for onshore and offshore petroleum activities in addition to related guidelines apply (Ptil, 2012);

#### **Framework HSE Regulations**

*“Regulations related to health, safety and environment in the petroleum activities and at certain onshore facilities. (Ptil, 2012)”*

#### **Management Regulations**

*“Regulations related to management and the duty to provide information in the petroleum activities and at certain onshore facilities. (Ptil, 2012)”*

#### **Facilities Regulations**

*“Regulations related to design and outfitting of facilities, etc. in the petroleum activities. (Ptil, 2012)”*

#### **Activities Regulations**

*“Regulations related to conducting petroleum activities. (Ptil, 2012)”*

## **Technical and Operational Regulations**

*“Regulations related to technical and operational matters at onshore facilities in the petroleum activities. (Ptil, 2012)”*

The Norwegian regulations are known for being solid and well-established and have high emphasis on occupational health, safety, and environment. The regulations which are mainly based on risk assessments, apply to every aspect of the petroleum industry.

### ***UK regulations***

In the UK, the Health and Safety Executive (HSE) and the Department of Energy and Climate Change (DECC) are the regulators within the oil and gas industry (Oil and Gas UK, 2012). Offshore, onshore and pipeline safety, are all administered by the same authority, but are governed by separate legislations. Regulations are mainly risk based, with some exceptions which are prescriptive, and the operator must prepare and implement a formal safety case and a safety management system (GL Noble Denton, 2010). The concept of reducing the risk to As Low As Reasonable Possible (ALARP) originated in the UK.

### ***Danish regulations***

In Denmark, offshore and onshore facilities, as well as marine matters and vessel regulations, all have separate regulators. The Danish Energy Agency (DEA) is the regulator for all offshore safety matters, while the Danish Environmental Protection Agency (DEPA) and Danish Working Environment Authority (DWEA) regulate onshore matters. Matters regarding marine and vessels are regulated by The Danish Maritime Authority.

The regulations require risk management and use goal-setting processes to achieve this. A great deal of subsidiary legislations, covering very specific aspects of design and operations makes the Danish regime stand out (GL Noble Denton, 2010)

### ***European regulations***

Günther Oettinger, Commissioner for Energy in The European Union (EU), presented in October 2011 a proposal for a set of standardized HSE regulations, applying to all offshore installations in Europe (Førde, 2012). These regulations cover the entire lifecycle aspect of the well, from design of the well to decommissioning and removal of the installation.

The proposal has received mixed responses.

The Norwegian petroleum industry, and the Norwegian Minister for Energy, Ola Borten Moe, are united in the matter and are protesting against this new proposal. It is claimed that the EU has very little competence regarding offshore activities and an intervention might cause negative consequences. It would require changing existing, well established regulations for new regulations, which would be a major risk factor.

The British Minister for Energy, Charles Hendry supports the Norwegian petroleum industry in the protest and claims both the Norwegian and the UK have some of the most solid and robust safety regimes in the world which should not be compromised. He is against a supranational decree, where the EU imposed regulations stand above the national regulations for each country. He is however open for a directive, where countries can pick whatever they feel is relevant and add to their own regulations.

Bellona on the other hand, supports the introduction of common European regulations for offshore installations. This is based on the indicators for major accidents the recent years, as presented in the PSA surveys done on the NCS.

### ***US regulations***

In the US, as of October 2011, the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE), formerly known as the Minerals Management Service (MMS), are the active regulations that apply in the US (Bureau of Ocean Energy Management, Regulation and Enforcement, 2012). In addition to these regulations, every state has a separate set of regulations that apply (Collins, 2012).

**Comparison of regulation regimes, Norway vs. US**

After the Deepwater Horizon accident, Det Norske Veritas (DNV) conducted a study mapping the differences between regulation regimes between the NCS and the US.

A summary of the differences are presented in

Table 1 (Det Norske Veritas, 2010);

**Table 1: Summary of the DNV report – Main differences in regulation regimes**

<b>Main differences in regulation regimes</b>	
<b>Norway</b>	<b>US</b>
Regulations are mainly function based; meaning clear goals are set for safety level and functional requirements.	Regulations are mainly prescriptive.
Regulations are mainly risk based, meaning activities are always built on identified risks, systematic working to reduce risk levels, and priorities should reflect current risk levels.	No such requirements.
The resource management and the health, safety and environmental (HSE) management are separately managed by two authorities.	Both resource and HSE are handled by the same authority.
PSA have a coordinating role in the development and follow up of any HSE implementations.	No coordinating authority.
The operating company has the responsibility that all petroleum activities are in line with the governing regulations.	Responsibility of petroleum activities is shared amongst the operator and the government.

Additional differences were found with regards to management systems for safety and environment, requirements to drilling and well operations, requirements related to equipment. One of the major differences was the systematic use of two independent, tested well barriers for all well operations, which is required in Norway. No similar requirements to well barriers were found in the US regulations.

### **3.1.2 Standards**

Standards are there to ensure continuity of the work being done, in terms of having the right tools for the job, reliable equipment and correct procedures. Standards also work as a sharing of good management practices and technological advances and function as guides for how to meet laws and regulations (Ptil, 2012).

The importance of standards is mostly noticed in their absence, which may lead to poor quality regarding products or work practices, equipment that does not fit or unreliable tools, or in worst case, breach of regulations. Standards exist at different levels, from international to national and industry levels. Listed below are some of the standards related to well integrity being used today.

#### ***ISO (International Organization for Standardization)***

ISO is a network of the national standards institutes, including 163 countries, and is per date the world's largest developer and publisher of international standards with over 18500 standards published (ISO, 2011). The ISO standards are developed by a technical committee comprised of industry experts from various countries. When a new ISO standard is being developed, delegates from various countries have a discussion until they reach an agreement.

#### ***API (The American Petroleum Institute)***

API is a national trade association which represents companies of varying sizes and disciplines in the American oil and gas industry (API, 2011).

Their focus is primarily domestic, but has in the recent years expanded to a more international focus as the industry has grown.

API has extensive experience with development of standards, dating back to 1924 and represents the collective wisdom from the industry. Currently, over 500 standards are maintained. Many of the API standards have lately been adopted by ISO and have also influenced the state and federal regulations.



### ***NORSOK (The Competitive Standing of the Norwegian Offshore Sector)***

NORSOK, as mentioned earlier, was originally a project aimed towards reducing the execution time and cost of any operations on petroleum installations, on the Norwegian continental shelf (Gundersen, 2012). The project was a collaborative between The Norwegian Oil Industry Association (OLF), Federation of Norwegian Manufacturing Industries (TBL) and the Norwegian government. One of the outcomes from this collaboration was a set of standards, which are now being used as internal guidelines for most of the oil companies operating on the Norwegian continental shelf. Standards Norway is responsible for the administration and publishing of these standards, which is available at [www.standardnorge.no](http://www.standardnorge.no).

The NORSOK D-010 standard, “*Well integrity in drilling and well operations*” has its focus on well integrity, and contains definitions, requirements and guidelines for well design, planning and execution of well operations (NORSOK Standard D-010, 2004).

The standard contains well drawings which depicts the barrier status for all the relevant well barrier elements in that particular type of well, and is an example of how a well barrier schematic could be made. This is done for wells with different well configurations and for all the different phases of the well, including drilling phase, well intervention, operational phase and plug and abandonment phase. See Appendix A.

A set of tables describing the acceptance criteria for all the different well barrier elements is also included in the standard. See Appendix B.

The standard is based on the international standards like ISO and API with additional provisions to cover the needs for the Norwegian petroleum industry. As oppose to the international standards, the NORSOK standard is developed by the industry itself to ensure the quality and relevance the industry needs. It is also as far as possible, intended to replace oil company specifications and be used as reference in the authorities’ regulations (NORSOK Standard D-010, 2004).

### ***Standards in global terms***

In many countries, no specific well integrity standard exists. A lot of countries do however use guidelines or standards, but not as detailed and substantial as NORSOK D-010. In the US and UK, the standards are both managed by the same authority as the regulations. Greenland however has started using NORSOK in their drilling operations (Nielsen, 2011).

As of today, no global standard exists. An ideal goal would be to internationalize a standard, and making sure it is easy to understand and use, while maintaining a high quality. The API / ISO standards are very detailed, but are not as user friendly as NORSOK D-010. In addition, the ISO and other standards are not free and available on the web to the same degree as NORSOK is (Enoksen, 2006).

### **3.1.3 International Well Control Forum (IWCF)**

After the formation of the European Union, a committee of National Energy Ministries, Industry Trade Associations and Trade Unions came with recommendations of introducing a standard training syllabus and certification program for drilling, workover and intervention personnel (IWCF, 2010). A few years later, a working party, later known as European Well Control Forum (EWCF), consisting of representatives from seven different countries within Europe was formed to assess the well control skills of the industry in Europe and create a matching well integrity certification program. Throughout this process, input from the international petroleum industry was received. The following years, the number of countries involved grew from seven to sixteen, many of these outside Europe. The working party was later renamed, International Well Control Forum (IWCF).

The IWCF's primary focus remains to administer well control certification programs for any personnel involved in drilling, workover or intervention operations.

This qualified certification program helps to maintain and improve the skills and knowledge about well control for drilling, workover and intervention personnel and contributes positively to the safety in well operations, and is therefore a valued barrier.

The NORSOK D-010 standard is currently being used as curriculum for certification regarding well service operations (well intervention) and is also on the way to become a part of the drilling and well operations curriculum (Sørskår, 2012).

### **3.1.4 Well Integrity Forum (WIF)**

In 2007, a workgroup underlying OLF called Well Integrity Forum (WIF) was established. Its main purpose was to promote open discussions regarding well integrity related issues affecting different operators on the NCS.

One of the key topics initially discussed in the forum was the quality of well integrity training (OLF, 2010). Members of WIF recognized a need for well integrity training for key personnel working with well integrity, both on- and offshore, something that was also found in PSAs earlier well integrity survey.

The relevant personnel consisted of;

1. Production operation personnel offshore
2. Production operation personnel onshore
3. Drilling/completion/intervention onshore
4. Rig Contractors like drillers and tool pushers
5. Service-company engineers and operators with delegated responsibilities in well integrity

A survey was conducted, mapping different operators well integrity practices, experiences and opinions, which would serve as a basis for the well integrity training guideline. As a result, WIF came up with a training course consisting of;

1. Well Integrity fundamentals
2. NORSOK D-010 terminology and principles
3. Company specific training (test procedures, well design and internal requirements)

Another issue discussed in WIF was the handover documentation process. This was also one of the issues raised by PSA in their integrity survey, where the availability, knowledge and content of the well handover documentation could be improved.

A survey done by WIF showed that most companies had exceeded the NORSOK D-010 Standard regarding well handover documentation by also including a Well Barrier Schematic (WBS) which had been developed, using NORSOK D-010 Standard as a basis of design. The structure of the well handover documentation was left for the operators to decide, however a set of minimum requirements was made regarding well construction data, well diagrams, handover certificate and operating input.

In attempts to standardize the WBS and get a common format within the industry, WIF made some guidelines describing a set of common minimum requirements to be included in the WBS;

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 result.

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 labeled 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

ConocoPhillips has in the period 2011-2012 made a new unique tool for generating WBS. This is described in more detail in section “3.2.6 Well Barrier Schematics”.

### **3.1.5 P&A Forum (P&AF)**

In the upcoming years it is expected that a lot of the current wells and installations on the NCS have to be plugged and abandoned. It is approximated that during the period 2011-2040, about 2000 wells are going to be abandoned, in addition to about 200 wells which are temporary abandoned (Ringøen, 2011).

To prepare for the upcoming P&A challenges on the NCS and find cost effective solutions, a Plug and Abandonment Forum was established in November 2009 after an initiative from ConocoPhillips Norway P&A workshop (OLF, 2011). The P&A forum, which is a workgroup underlying OLF, work together with PSA regarding regulation requirements, industry standards and guidelines. The forum also cooperates with the service industry with regards to new requirements, technology, materials and methods, in order to achieve better well integrity. Sharing of case stories between operators also contribute to a better understanding. At the moment, nine operating companies are currently listed as members of the P&A Forum; ConocoPhillips, Shell, Statoil, DetNorske, BP, Total, Centrica Energi, Talisman Energy and Eni.

On the UKCS, a similar work group exists, called Oil & Gas UK Decommissioning Steering Group (Oil and Gas UK, 2010). This forum drives the industry forward with regards to P&A knowledge through sharing of technology, methods, guidelines and case stories. With the rise in P&A operations the industry will face the coming years, the result from this initiative will serve as a solid foundation and barrier towards the challenges the P&A operations presents.

## 3.2 ORGANIZATIONAL BARRIERS

One of the first lines of defense against uncontrolled incidents, both HSE and well integrity related, is by having a solid organization with good standard of quality on everything they do. This includes a variety of aspects, like good working culture and philosophies, good documentation control like detailed and clear well records, good internal standards and so on. Unlike external barriers, the organizational barriers only affect the respective companies. Some of the organizational barriers within a typical company are discussed below.

### 3.2.1 Integrated Operations

Nowadays, a lot of the offshore activities have been moved onshore, by the use of integrated operations (I/O) also known as real time operations. I/O can be defined as *activity where information is transferred through network system to remote users, operators or managing systems in order to tie together different professions and branches and improve capacity and result to a reduced cost* (Kaland, et al.).

Operators onshore may sit in operation centers with all the available data from offshore and more. Here, engineers from different disciplines could work together and make better solutions in real-time.

With these I/O centers, better decisions can be made and help to strengthen the overall safety and reduce cost by saving time.

### 3.2.2 Controlling documents

Controlling documents is a very general term and includes a wide range of processes, procedures, rules & regulations and standards. The controlling documents can be global, national, and local documents, both internal and external and may vary from company to company, or between different nations.

In Norway, the PSA's rules and regulations apply (Ptil, 2012). Regulation guidelines describe how to meet these rules and regulations and also refer to NORSOK standards and OLF guidelines. Additional requirements beyond these standards and guidelines may also apply within a company.

Internal company documents may include procedures and processes and govern well

activities and risk management. Some examples of activities and operations governed by these documents include, drilling, cementing, intervention, well testing. Other documents may include bridging documents, describing procedures for when different rules and standards meet. For instance when a service company operates on a rig, working for an operating company, the bridging documents describes whose rules, standards and procedures to follow.

The controlling documents affect a wide span of aspects, from well integrity, to personnel health and safety, and risk & cost management. Considering how much the controlling documents affects safety, they are very important barriers, both as external barriers and organizational barriers.

### **3.2.3 Management of Change**

A change in procedures and processes could lead to serious safety or operational incidents if the changes are not properly documented and implemented correctly. Management of Change (MOC) is a process of handling these types of changes in a controlled manner where modifications are recognized, documented, reviewed and approved before they are implemented (ConocoPhillips, 2012) (Matre, 2009).

Every company business unit may use their own internal guidelines for MOC, but generally the following steps apply:

1. Initiate/Propose change
2. Define
3. Approve
4. Carry out
5. Follow-up

Minor changes from planned operational programs could be handled by documenting, approving and communicated to the appropriate personnel and might not need a MOC (ConocoPhillips, 2012). For more significantly changes, the MOC procedure should take place.

This includes changes regarding:

- basic well design
- pressure containing envelope
- introduction to new non-routine or unplanned operations that may affect safety
- well control procedures
- key personnel or organizational structure
- contractor agreements
- operational changes
- new equipment or modifications

As MOC could prevent both safety and operational related issues, it is considered to be an important barrier.

### **3.2.4 Audits / Revisions**

According to PSAs Framework regulations, the operator shall follow up and quality check steering documents and procedures in order to ensure that both HSE and well integrity is met in a satisfactory way. This is done by performing audits on the steering documents and procedures and making sure they are followed and understood.

Equipment shall be routinely investigated and tested, as well as the contractors delivering this equipment. The audit of the operator company itself is done internally, as well as being done by the government, operating partners and contractors.

These audits and revisions are an important barrier as they help to maintain a high quality standard of the work done by the operator companies as well as the contractors. It also helps to maintain the integrity of barrier-related equipment and HSE.

### **3.2.5 Well Handover & Documentation**

As a well is drilled and completed, a comprehensive well documentation is made in order to make sure everyone involved knows the status of the well and all the equipment installed.

The handover process consists of several procedures and describes the required information needed, and the people responsible for providing this.



This information includes well characteristics like type of well, depths, casing program, completion equipment, and any non-conformances.

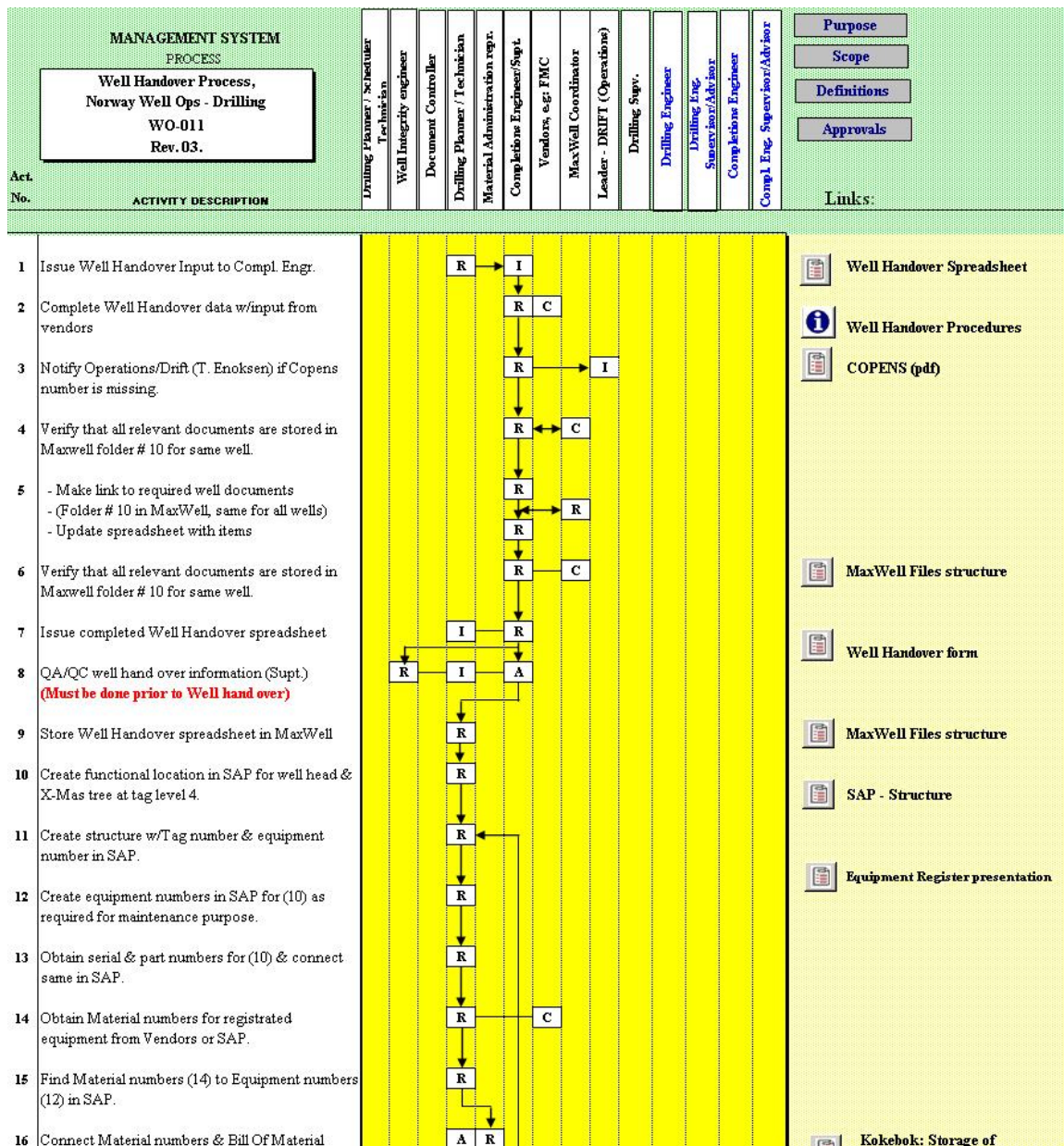


Figure 12: Well handover process for ConocoPhillips (ConocoPhillips, 2012)

This example of a well handover process in ConocoPhillips describes actions to be taken when handing over a well from drilling/completion to operations. The responsible persons are listed on top, connected to various tasks and responsibilities.

Letters describe the level of responsibility (Inform, consult, responsible, accountable), and on the right hand side, links to relevant documents are provided.

### **3.2.6 Well Barrier Schematics**

One of the documents required during well handover is a graphical representation of the well, showing the well barriers, called Well Barrier Schematic (WBS). Examples of how to present a WBS is shown in the Norsok D-010 standard. These are meant as a guideline and show the minimal required expectations. Most companies have their own way to making WBS documents which exceeds what is shown in Norsok D-010.

A WBS should show the well with all the casings installed, and all well barrier elements installed (Norsok Standard D-010, 2004). The primary barrier should be presented in its normal working stage and the secondary barrier in its ultimate stage, which means the shear ram or shear valve is closed. A table of performed pressure tests should also be included.

The WBS is an important document that gives a quick and good overview of the well and the well barriers status.

#### ***Well Barrier Schematic application – ConocoPhillips project***

In 2010, ConocoPhillips Norway started a project aimed towards making Well Barrier Schematics (WBS) more efficiently and more reliable. The goal with the project was to develop an application that would generate WBS's automatically with the latest available data found in the ConocoPhillips' well database, WellView.

Peloton, the provider of WellView, were chosen to develop the WBS software.

#### ***My involvement in the project***

I started working on this project summer 2011 and have been involved with it since.

To make sure the application generated WBS's that met both the Norwegian and ConocoPhillips' standards and requirements, I had to comprehend the complex subject of well integrity principles. This was done by studying the Norsok D-010 standard, Norwegian regulations, OLF 117 – Well integrity guideline and from discussions with the well integrity team and well intervention team at ConocoPhillips.

Together with the software developers from Peloton; the provider of WellView, work began to make sure the application functioned properly and generated acceptable WBS's. This work included thoroughly testing of the software, providing feedback and instructions to the

developers with regards to enhancements and bug-fixing and continuously meetings with developers and well integrity personnel. While doing this, well data had to be added and corrected in Wellview, thus providing ConocoPhillips with a more robust well database. I have also written an extensive user-guide to the add-in, explaining in detail how the program works, which data the program relies on and how to correctly enter these data in order to get the add-in to function properly.

The WBS application is scheduled to be deployed within ConocoPhillips Norway by end of June 2012, and globally within ConocoPhillips by the end of 2012. As the program is developed by a third-party (Peloton), ConocoPhillips does not wish to take patent on the program. This means the add-in will be available for other companies using Pelotons WellView database.

As a result of my work I'm now a member of a global well barrier expert team, whose assignment is to implement the software globally and provide necessary support.

### ***Previously procedure in ConocoPhillips***

Previously, the WBS's were made manually by engineers with programs like Autocad, Completion String Design and most recently, Microsoft PowerPoint (Figure 13).

## Well Barrier Schematic - 2/4 M-30 Production Well

Rev 1

MSL - 232,4 ft RKB  
Mudline - 489,4 ft RKB

X-mas Tree  
FMC 5-1/8" 10K WP

Wellhead  
18 3/4" 10K WP  
Tubing Hanger  
Casing Hanger

ASV set @  
342 ft TVD = MD

TOC 13 5/8" (Calculated) @  
590 ft TVD = MD

LBV @ 658 ft TVD = MD

DHSV @ 810 ft TVD = MD

24" x 20" Conductor @  
1296 ft TVD 1296 ft MD  
LOT 13.0 ppg EMW

10" Liner top packer @  
4824 ft TVD, 6131 ft MD

13-5/8" Production Casing @  
4894 ft TVD, 6240 ft MD  
FIT 16.0 ppg EMW

5-1/2" Tubing String w/ Side  
Pocket Mandrels @  
5006, 7520 & 9400' TVD  
6409, 10348 & 13288' MD

Chemical Injection Valve  
(CIV) @ 10956 ft MD

TOC 10" (Calculated 140 bbl  
in gauge hole)  
@ 12107 ft MD

Production packer @  
9590 ft TVD 13561 ft MD

6 5/8" Back-up liner top  
packer @ 9645 ft TVD  
13649 ft MD, primary  
failed to set  
6 5/8" TOC @ liner top

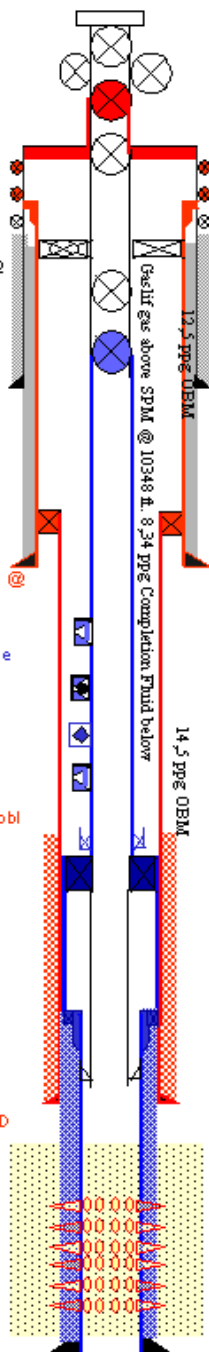
10" Production Liner @  
10227 ft TVD 14824 ft MD

6-5/8" Liner @  
11004 ft TVD, 16123 ft MD

Reservoir

Drilling Eng.

Well Tech Adv.



Comments: Deviated Ekofisk and Tor (we) producer. Primary 6 5/8" liner hanger failed to expand, back-up expandable hanger set with seal stem into primary liner PBR

### Maximum Operating Pressures:

Tubing: 5000 psi	
Annulus (Tbg x 10"):	N/A
A Annulus (Tbg x 13-5/8"):	2000 psi
B Annulus: (13-5/8" x 24"):	200 psi

Barrier Elements	Tests/ Other Verification
<b>Primary Barrier Envelope</b>	
1.1 6 5/8" Reservoir Liner	5000 psi with seawater - 05-09-07
1.2 6 5/8" Reservoir Liner Cement	Verified by cement in returns - 23-08-07
1.3 6 5/8" Reservoir Liner Top Packer	5000 psi with seawater - 05-09-07 Negative test of 1330 psi differential when displaced to seawater - 05-09-07
1.4 10" Production Liner	3500 psi with 14,5 ppg OBM - 18-08-07 5000 psi with seawater - 05-09-07
1.5 Production Packer	5000 psi differential from below - N/A 4500 psi differential from above - 10-09-07
1.6 Production Tubing	5000 psi burst with seawater - 10-09-07 4500 psi collapse with seawater - 10-09-07
1.7 SPM / dummy GLV in MSPM @ CIV in SPM @ 10956 ft	5000 psi differential test - 10-09-07 1000 psi differential test - 16-10-07 700 psi differential test - 26-10-07
1.8 DHSV (TRSV)	2500 psi differential from below - 10-09-07 8000 psi shop test
<b>Secondary Barrier Envelope</b>	
2.1 10" Production Liner	3500 psi with 14,5 ppg OBM - 18-08-07 5000 psi with seawater - 05-09-07 4500 psi with seawater above packer - 10-09-07
2.2 10" Production Liner Cement	2290 psi inflow test differential when 10" shoe drilled - 18-08-07
2.4 10" Production Liner Hanger	3500 psi with 14,5 ppg OBM - 18-08-07 5000 psi with seawater - 05-09-07
2.5 13 5/8" Production Casing	4000 psi with 12,5 ppg OBM - 03-08-07 5000 psi with seawater - 05-09-07
2.6 13 5/8" Production Casing Hanger	5000 psi test - 02-08-07 5000 psi test between seals - 02-08-07
2.7 Wellhead, Valves	5000 psi test - 05-09-07
2.8 Tubing Hanger	4500 psi from below - 10-09-07 5000 psi test between seals - 10-09-07
Xmas tree body & valves	10000 psi test against tree test plug - 11-09-07
<b>Other Elements</b>	
LBV	2500 psi differential from below - 10-09-07 6000 psi shop test
ASV (new PTC design)	2600 psi differential from below - 12-09-07 5000 psi shop test on valve - 15-05-07
24" x 20" Conductor, Wellhead	1000 psi with seawater - 28-07-07
CIV exit block.	2300 psi inflow test - 25-10-07

Figure 13: Well barrier schematic made by PowerPoint (ConocoPhillips, 2012)

Data was first gathered from the ConocoPhillips well database, WellView, and then added to the PowerPoint. Casing strings, cement, tubing string, gas lift valves, packers, reservoir depth, perforations, FIT/LOT data was some of the data that had to be reproduced, in addition to pressure test related to every WBE, a very time consuming process. Secondly, if any changes occurred in the database after the WBS had been made, they would be rendered outdated and incorrect.

### ***Functionality of the new WBS add-in***

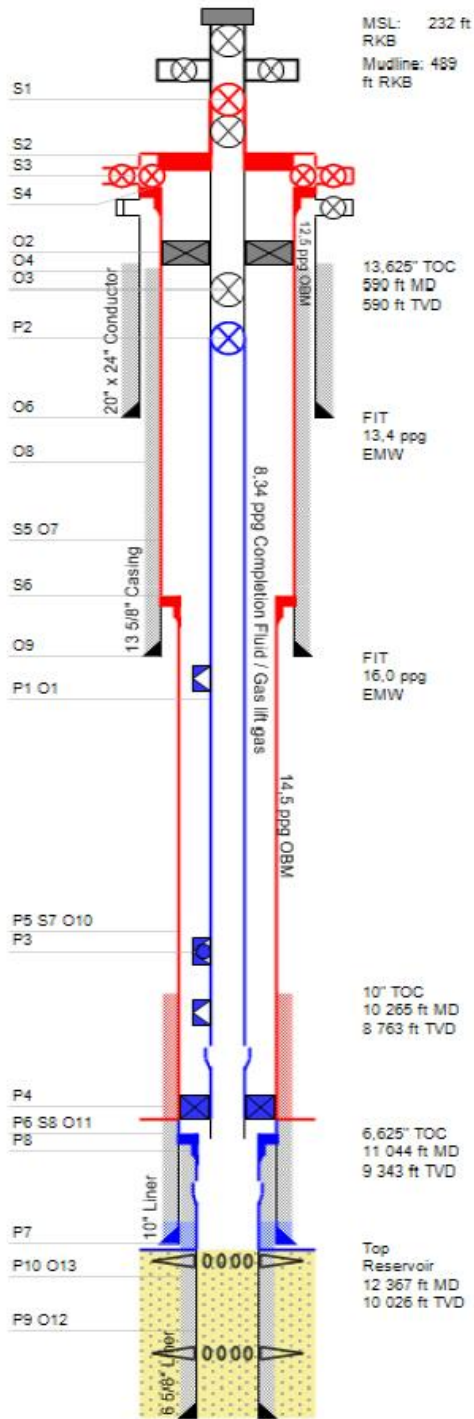
The new WBS application work as an add-in (a software program that extends the capabilities of a larger program (Webopedia, 2012)) to the existing WellView database. By doing this, the application could be linked directly to the well data stored in WellView, ensuring that it always presents the latest available data. Making the add-in reliant on WellView data, forcing engineers to enter data more thoroughly and in the correct data fields, will also work as a quality assurance by building a more complete database.

When the WBS application is run, it gathers the data needed from WellView and renders a complete WBS ready to be verified and signed by engineers. Every relevant well barrier element is drawn at their correct depth and every conducted pressure test is listed in a separate table. Barrier logic is also built into the application, so that the primary and secondary barrier envelopes are immediately recognized and drawn in blue and red, in line with NORSOK D-010. It is designed so that it would not only meet the requirements for the current NORSOK D-010 standard (rev. 3), but also some of the changes that is going to be presented in the next revision of NORSOK D-010 (rev. 4) (Lunde, 2012).

The add-in automatically decides, based on information in the database, if this is a drilling well, production well or a P&A well, thus saving the user time and effort, as different barrier principles and rules apply in the different situations.

This semi real-time function makes this a truly unique and valued documentation tool. Everyone with access to the database would have access to the latest available WBS, a concept that other documentation tools could benefit greatly from.

Well Barrier Schematic - 2/4-M-2 - Producing Well



COMMENTS: ASV failure June 2008. Downhole gauges have failed (gauge carrier @ 10819 ft MD)

	Max Operating Pressures*	Max Design Pressures
Tubing	5 000 psi	psi
A Annulus (5 1/2" Production Tubing)	2 000 psi	psi
B Annulus (13 5/8" Casing)	200 psi	psi

\* These max pressures do not apply to well intervention operations

#	Barrier Elements	MD(ft)	TVD(ft)	Date	Tests / Other Verification
<b>Primary Barrier Envelope</b>					
1	5 1/2" Production Tubing	11091	9375	31.7.06	5000 psi burst with fresh water. 4500 psi collapse with fresh water.
2	Safety Valve	938	838	31.7.06	2500 psi differential from below.
3	GLV	8782	7510	28.4.06	2159 psi differential test.
4	Production Packer	10967	9291	31.7.06	4500 psi differential from above.
5	10" Liner	12309	10001	28.7.06	5000 psi with fresh water.
6	10" Liner Cement	10265	8783	17.7.06	Inflow test
7	10" Liner Shoe	12309	10001		
8	Liner Hanger	11071	9381	24.7.06	6500 psi to set versaflex hanger.
9	8 5/8" Liner	13777	11042	28.7.06	5000 psi with fresh water.
10	8 5/8" Liner Cement	11044	9343	24.7.06	Cement in returns
<b>Secondary Barrier Envelope</b>					
1	X-mas tree	0	0	4.8.06	8500 psi
2	Wellhead	0	0	4.8.06	5000 psi test
3	HASCV & ASCV	0	0		
4	Casing Hanger	130	130	10.7.06	5000 psi between seals, 10 min as per FMC.
5	13 5/8" Casing	5511	4909	28.7.06	5000 psi with fresh water.
6	Liner Hanger	5439	4855	28.7.06	5000 psi with fresh water.
7	10" Liner	12309	10001	28.7.06	5000 psi with fresh water.
8	10" Liner Cement	10265	8783	17.7.06	Inflow test
<b>Other Elements</b>					
1	5 1/2" Production Tubing	11091	9375	31.7.06	5000 psi burst with fresh water. 4500 psi collapse with fresh water.
2	Packer / ASV	370	370	1.8.06	2500 psi differential from above.
3	Lub Valve	687	687	31.7.06	2500 psi differential from below.
4	20" x 24" Conductor	1297	1297	4.7.06	1000 psi with seawater.
6	20" x 24" Conductor Shoe	1297	1297	4.7.06	Perform FIT to 13.4 ppg, surface pressure 130 psi.
7	13 5/8" Casing	5511	4909	28.7.06	5000 psi with fresh water.
8	13 5/8" Casing Cement	590	590	7.9.06	Return to surface
9	13 5/8" Casing Shoe	5511	4909	10.7.06	Perform FIT to 16.0 ppg, surface pressure 383 psi.
10	10" Liner	12309	10001	28.7.06	5000 psi with fresh water.
11	10" Liner Cement	10265	8783	17.7.06	Inflow test
12	8 5/8" Liner	13777	11042	28.7.06	5000 psi with fresh water.
13	8 5/8" Liner Cement	11044	9343	24.7.06	Cement in returns

Figure 14: Well Barrier Schematic made by the new WBS application (ConocoPhillips, 2012)

### **Improvements made to the WBS**

The previous used WBS, made in PowerPoint, was used as a starting point for the new WBS design. However, two major changes have been made. See Figure 14.

The most obvious change is the component annotations on the left hand side.

In the previous WBS, the whole component name was listed as well as the MD and TVD depth of this component. The component name was then duplicated on the right hand side table with the relevant pressure test information and test date.

In the new WBS design provided by the add-in, the component name on the left hand side has been exchanged by a short one-letter annotation in addition to a number. This provides a cleaner look, and makes it easier to read and interpret the well diagram.

The letter indicates the barrier status of the component; Primary (P), Secondary (S), or Other (O), and the number correlates to the components position in the right hand side table. These annotations are re-calculated every time the add-in is launched, so if a barrier element changes barrier status or depth, the annotation will be update accordingly.

The right hand side table now provides all the information; component name, depths, dates and tests conducted. Any additionally annotations or comments can be manually added through the add-ins user interface. Fishes, collapses, leaks, packers etc. can also be added.

The other major change is more subtle, yet very important. In the previous WBS, the barrier logic for each barrier element had to be decided by the person making the WBS, and then later verified by an engineer. This could be a potential source of error, as well barriers is a complex subject, drawing the correct barrier logic for every single component could prove to be a challenge, especially when engineers have different views and opinions of how they should be.

In the new add-in, this problem is solved as the barrier logic is implemented in the code, making no room for error. Exceptions can be made off course, by overriding the automatically selected barrier status through the add-ins user interface. If the status of a barrier element is changed, the add-in re-calculates the barrier status of all the other barrier elements, thus not only providing the user with feedback on how the rest of the barrier elements are affected, but also saving the user a lot of work.

An example of how this works is seen in Figure 15, where the downhole safety valve (DHSV) has been changed from 'Primary' barrier status, to 'Other' barrier status manually through the add-in user interface, indicating a problem with the DHSV.

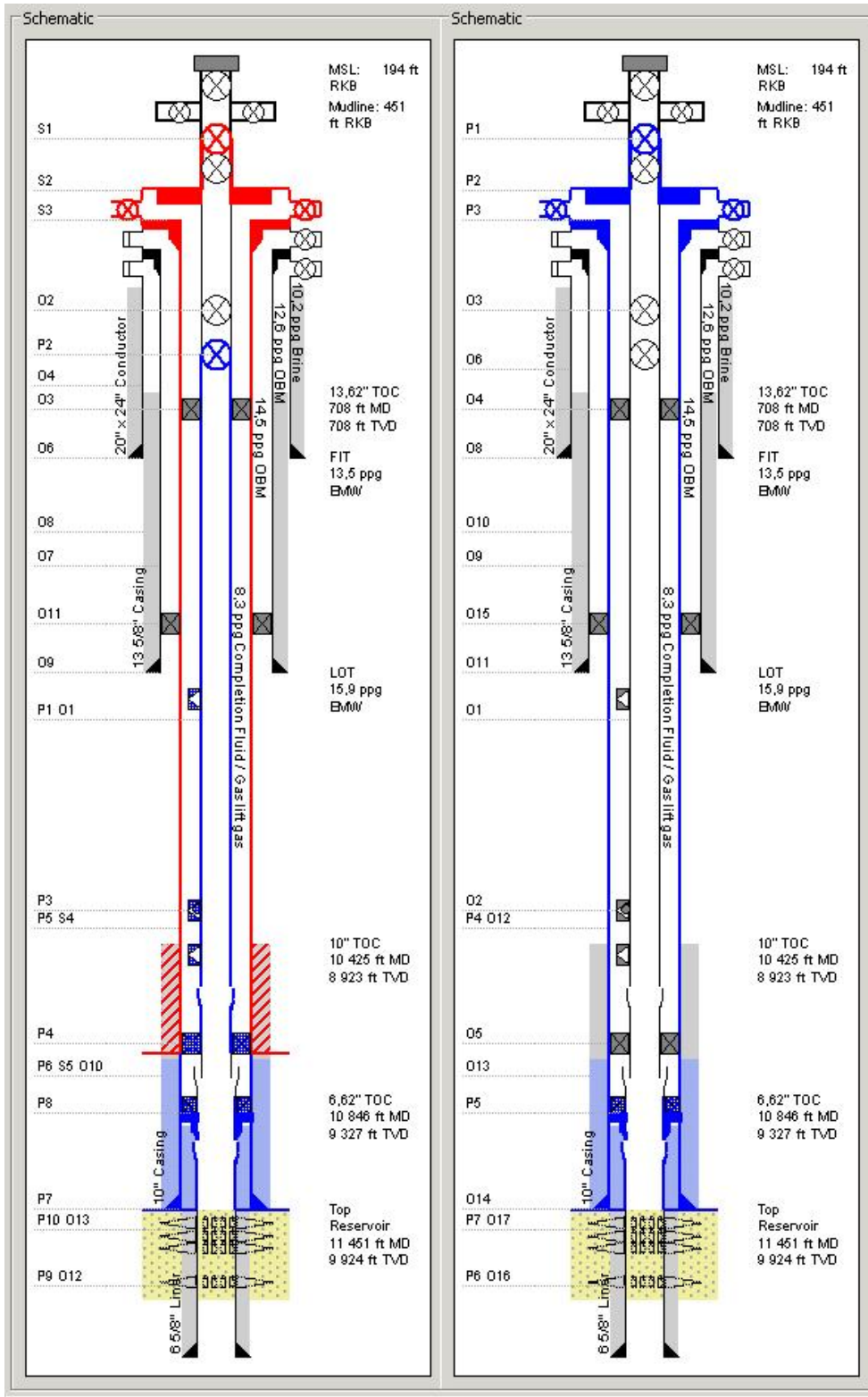


Figure 15: Manually changing barrier status of a well component (ConocoPhillips, 2012)



As seen on the right schematic in Figure 15, the primary barrier envelope is moved out because the tubing no longer functions as a primary barrier, because of a barrier breach in the DHSV. Note that the 13 5/8" casing is not automatically defined as a secondary barrier, because the 13 5/8" casing shoe might not be able to withstand the reservoir pressure. A decision to make this a secondary barrier element could be made by the engineer verifying the schematic.

Also note the striped color on the 13 5/8" casing cement on the left schematic. This indicates that there is cement present here, but the cement does not fulfill the required height of 200m. This is one of the many barrier logics implemented in the add-in. Every height requirement can be changed in a separate file that comes with the program, in case any other business unit has other requirements.

The add-ins logic is mainly based on the current NORSOK Standard D-010 rev.3; however, the add-in also extends beyond what is specified in NORSOK and will implement logic that is likely to be presented in the next revision of NORSOK Standard.

The 'striped' cement is one of the new features this add-in contains. Another feature is having the primary barrier start at the top of the reservoir, as opposed to inside the reservoir as pictured in the NORSOK standard, as it is not a valid barrier element in this section. Also note that primary reservoir barrier (cement), is drawn all the way out to formation to indicate the importance of cement-formation bonding.

### ***Future implementations***

Finishing touches are currently being made to the add-in with regards to its drilling and P&A functionality. This includes bug-testing, adding any additional functionality and finally publishing. Current status of these functionalities can be seen on Figure 16.

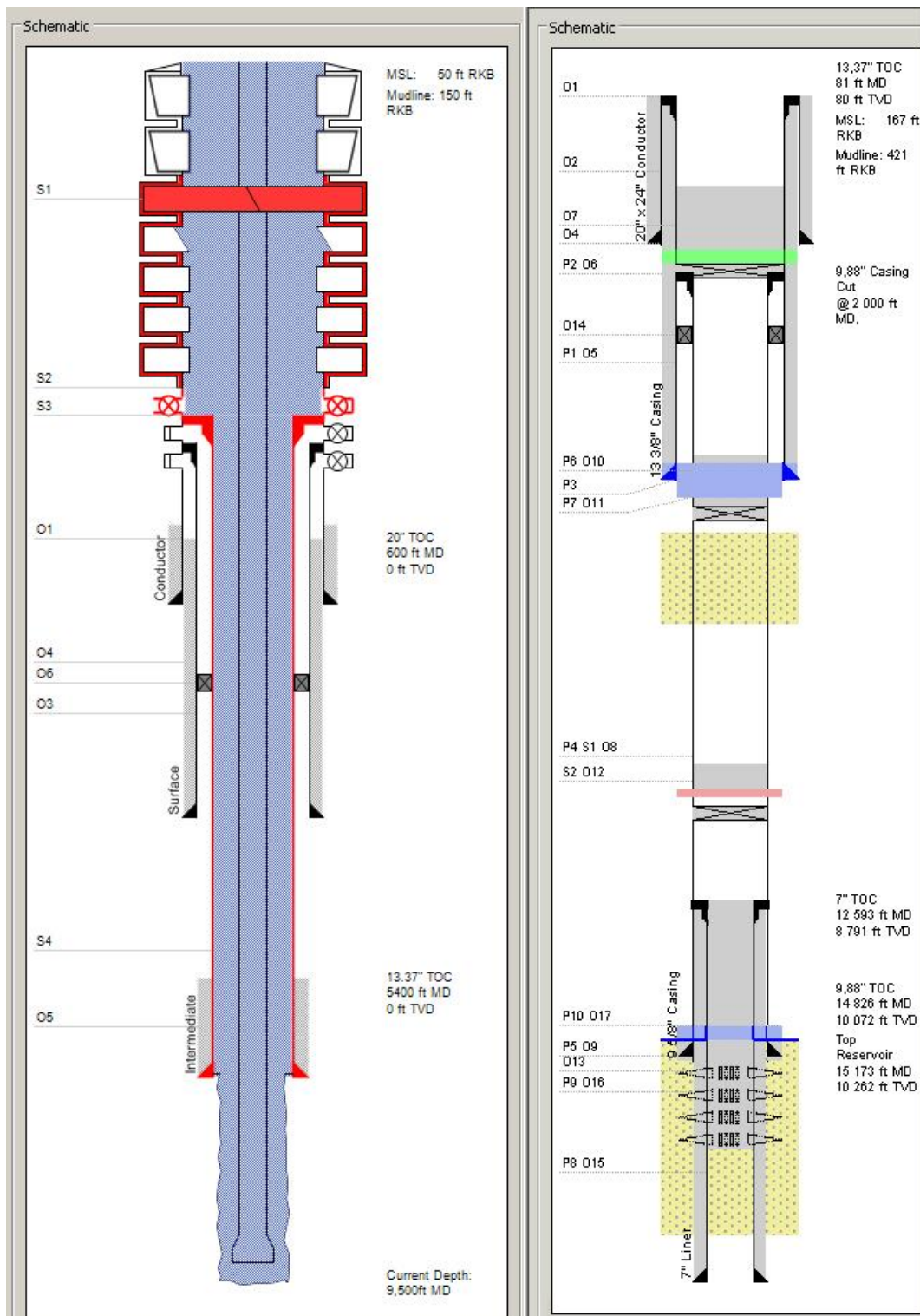


Figure 16: Drilling (left) and P&A (right) functionality of the WBS add-in (ConocoPhillips, 2012)

These modes are designed to be of the same quality as the production-mode. Not only meeting the NORSOK D-010 standard, but going beyond what is required and making sure the barriers are well defined. An example could be the cement plugs in the P&A scenario. Only plugs cemented out to the formation (or with good verified cement outside) are defined as valid barrier elements. The add-in automatically figures out the barrier status of the plugs, based on cement data and milled/under-reamed sections from the well data.

### **Conclusion**

The WBS add-in tool is a very powerful and easy-to-use tool which can be extremely useful, not only for ConocoPhillips but also other companies who uses Pelotons, Wellview database. The add-in not only represents the actual well data in a reliable and effortless way, but also implements complex, up-to-date barrier logic, saving the engineers a lot of work and time. As it relies on good well data, companies are also forced to quality check and control their data, providing a more robust and more reliable database. The add-in does not currently have the functionality to display advanced wells like multi-lateral wells, but this is a function that could be implemented with the next version of WellView (v 9.0) which supports these types of wells.

### Wellbarrier.com – Interactive web illustration tool

The Norwegian company, Wellbarrier, offers a commercially available tool for creating WBS on their webpage; [www.wellbarrier.com](http://www.wellbarrier.com) (Wellbarrier, 2012). The tool displays the well with barriers in blue and red, indicating primary and secondary barriers, and a list of elements with related tests and is customizable to suit the users need, such as company logo or other specific needs.

Well configuration can be chosen from a library containing more than 170 illustrations (Figure 17) which can visualize wells in the construction, operation and maintenance phase and is also in line with the Norsok D-010 Standard. A link between the barrier element and the relevant Norsok D-010 acceptance criteria is available.

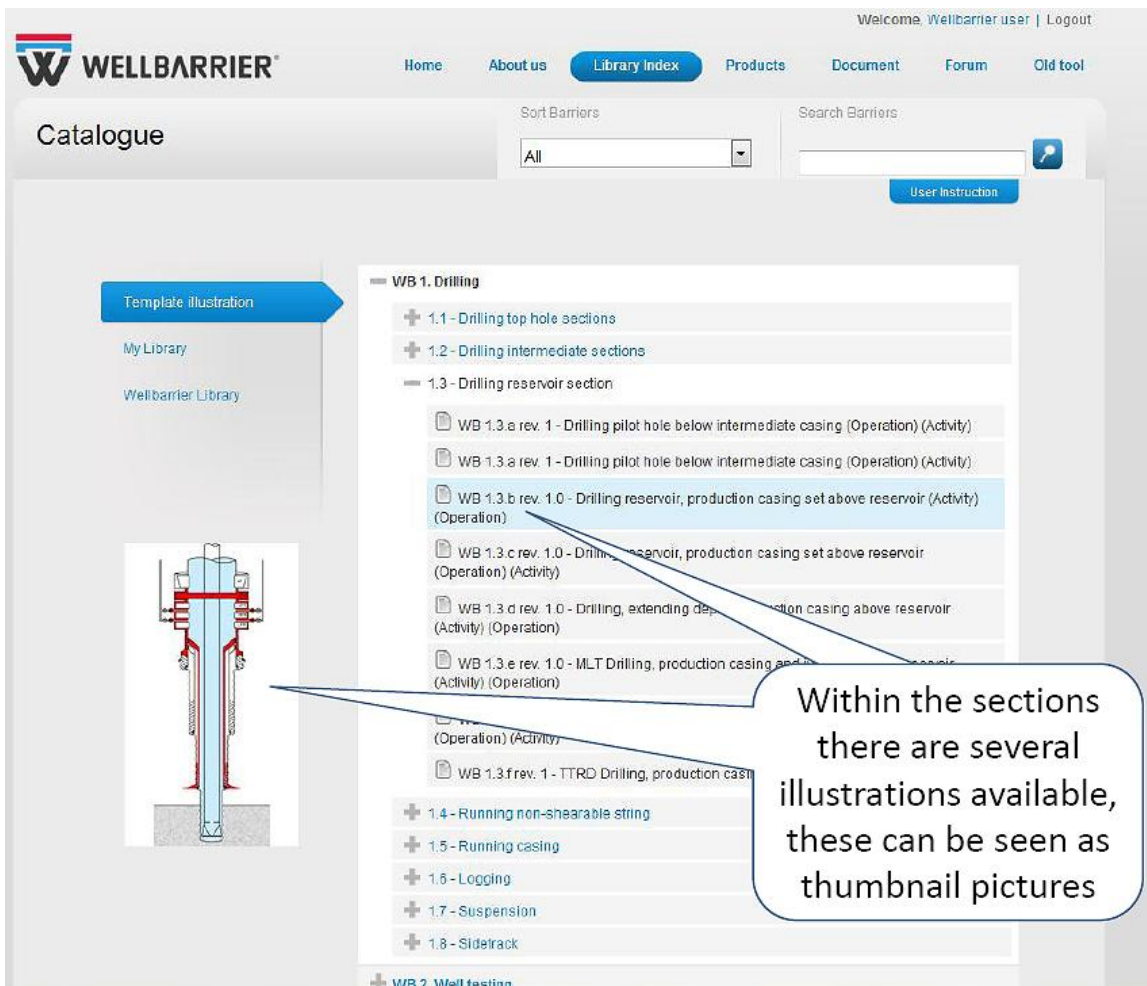
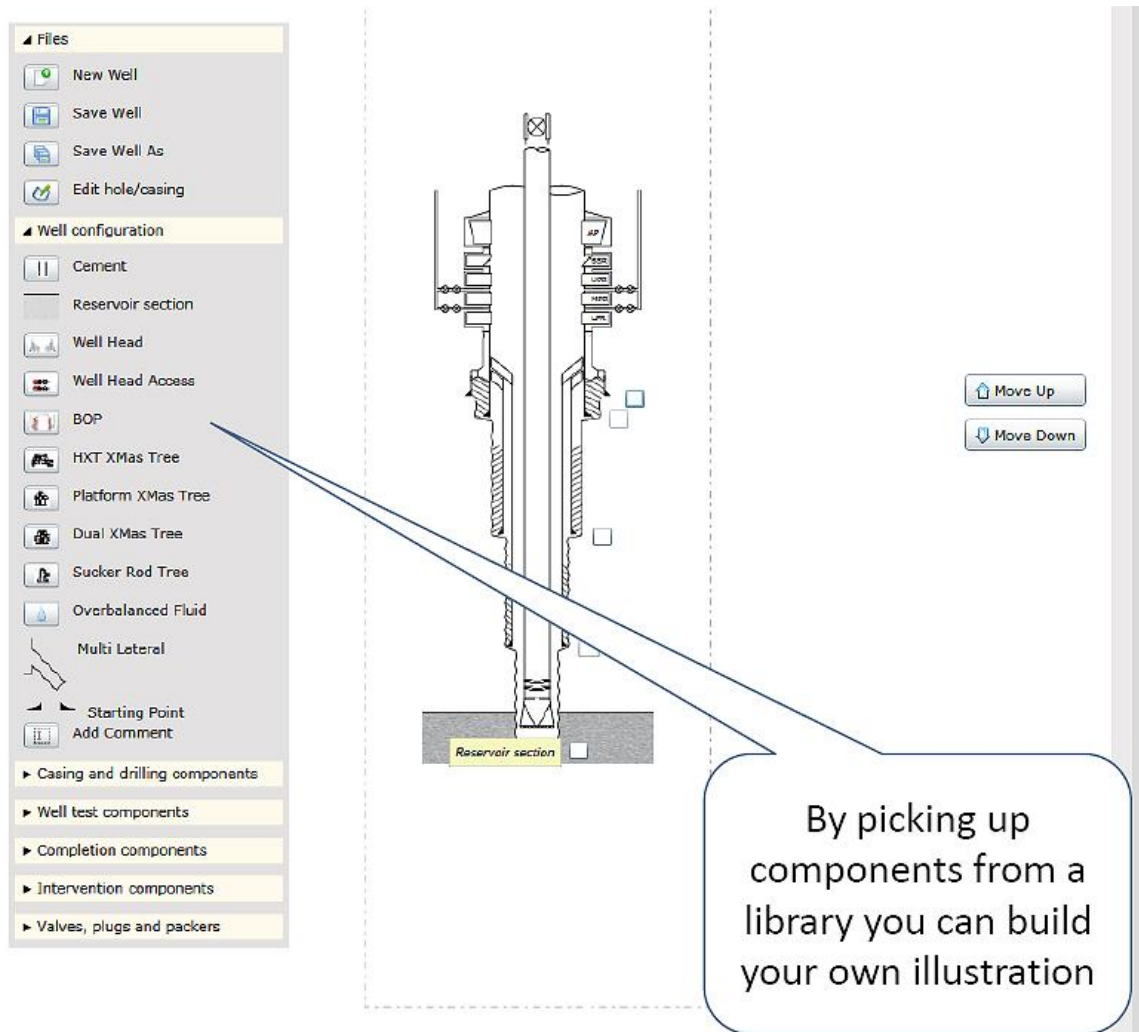


Figure 17: Well configurations on the Wellbarrier tool (Wellbarrier, 2012)

The user can also create the well configuration by “constructing” the well manually, as seen in Figure 18 to if the template is not satisfactory or the well is a special case.



**Figure 18: Manually creating the well configuration and barriers (Wellbarrier, 2012)**

Barrier elements can be modified, such as cement height, BOP configuration or annotations, before finally printing out the schematic as a PDF-file.

Wellbarrier is a powerful online-tool which is easy to use and require little training. It is very versatile as it can be used for almost very well configuration.

The direct link between the barrier elements and the well barrier acceptance table in NORSOK D-010 is a clever way to inform users of different requirements.

The data entered in this tool is however not connected to any company database, and the data is therefore required to be duplicated. This is a potential source of error, as all the data has to be put in manually. Also, the well configuration has to be chosen beforehand or created manually, which requires some work to be done.

Another downside with this is that the data within the schematic is not updated when the data or database is updated, and will require continuously revisions.

## WellMaster – by Exprosoft

WellMaster, by Exprosoft, is a program used for storing, analyzing and reporting well data, and is mainly used to point out any failures in the completion equipment (Exprosoft, 2011) (Figure 19). It can however be linked to other databases, such as WellView, and display completion schematics stored in WellView for any particular well.

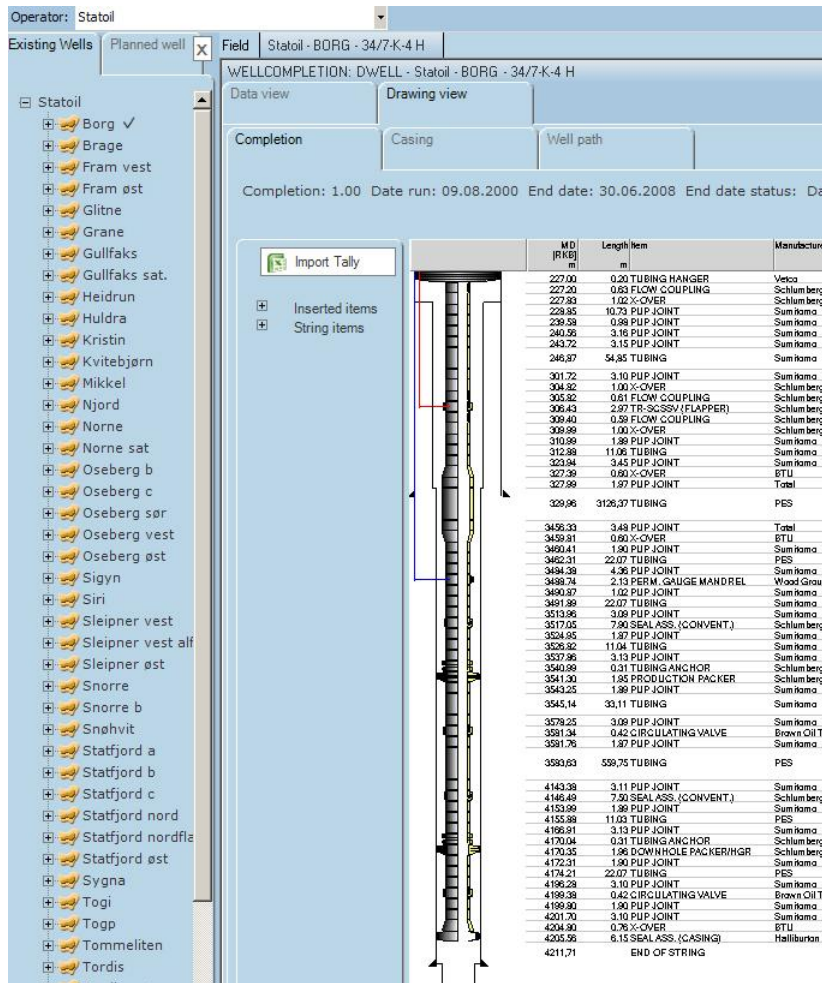


Figure 19: Completion equipment in WellMaster (ExproSoft, 2012)

At the moment, a well barrier schematic option within WellMaster is under development, by request from StatoilHydro. Little information is available about the design and functionality of this well barrier schematic program, Figure 20 show however the preliminary status of the WBS development and by the looks of it, it seems to have a very similar design to what is currently in NORSOK D-010 standard.

From Exprosofts webpage, the following information is available (ExproSoft, 2012);

“The work has included collection and review of relevant data for establishing the necessary well barrier diagrams (WBS) for all Statoil operated wells on the NCS after the merger with Norsk Hydro, and work out the actual diagrams for each individual well (two diagrams per well; As run status, and Monitoring) based on the requirements given in NORSOK D-010 and on detailed additional WBS template requirements set up by Statoil. In all, over 1100 wells have been covered in the project, which was concluded mid March 2010.”

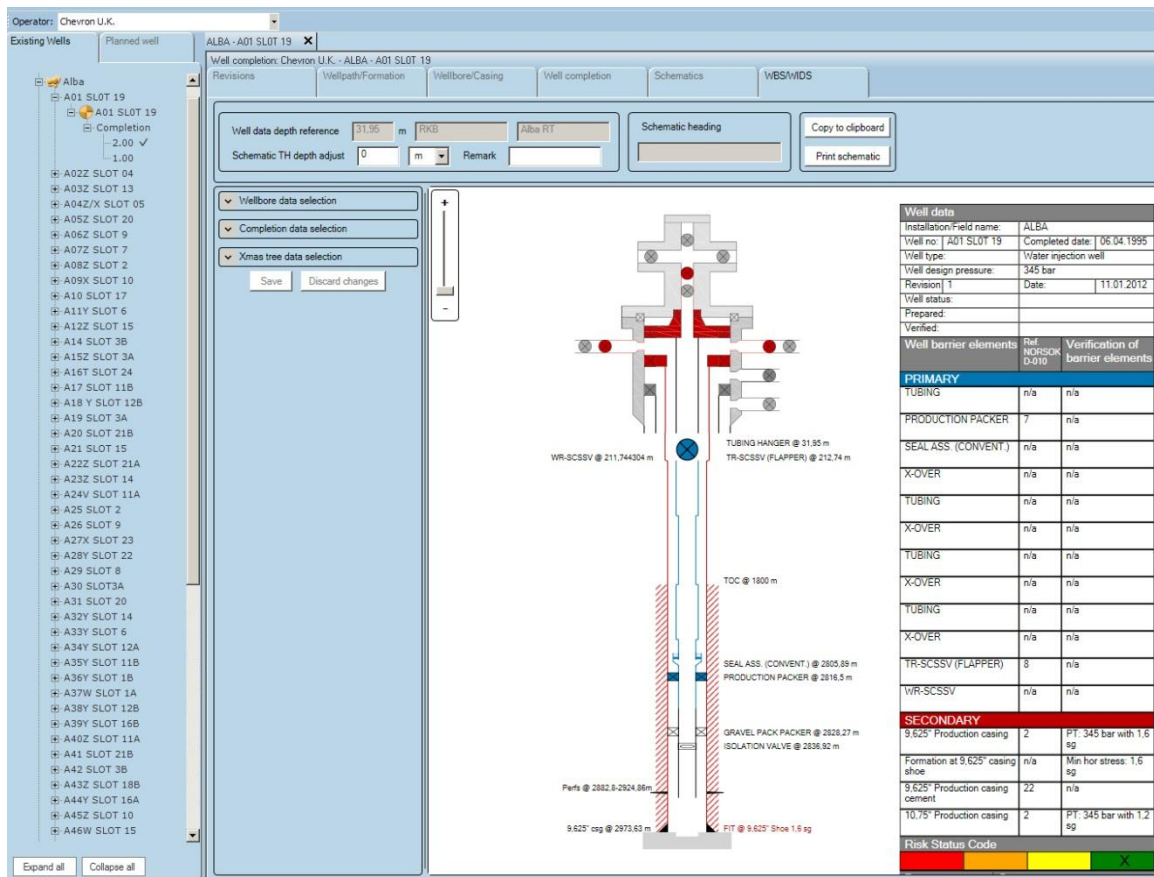


Figure 20: Well barrier schematic function within WellMaster (Exprosoft, 2012)



## **3.3 ACTIVE BARRIERS**

Active barriers are systems or procedures in place that could act as barriers given they are activated or performed. These include amongst other, surveillance, monitoring and alarms.

### **3.3.1 Shutdown systems**

Shutdown systems are safety measures in place to handle incidents like influx, loss of hydraulic pressure, prevent gas from igniting etc. Shutdown systems can be automatically or manually activated and are present in different phases of the wells life, on the BOP during drilling and well service, and on the X-mas tree during production.

### **3.3.2 Alarms**

Alarms can give an early indication of abnormalities, and sudden changes occurring during well operations and alert the well personnel at an early stage, if they are activated. Gas detection, loss of hydraulic pressure or increase in wellhead pressures can be detected before the shutdown system kicks in and give the personnel the opportunity to take preventive measures before an eventual incident occurs.

Alarms can also be added as per well basis and moves the well control from a reactive measure to a proactive measure.

### **3.3.3 Verification of barriers**

According to both NORSOK D-010 and the Norwegian regulations, any WBE has to be verified and tested in order to be classified as a well barrier.

It is therefore important that any WBE is tested or verified according to guidelines and that preventive maintenance and testing is done on equipment regularly to ensure the integrity. It is also important that the operational pressure does not exceed what the relevant WBE has been tested for, as it will no longer be an accepted WBE above this pressure.

An example of an important verification which is often left out is verification of the casing cement. When plugging and abandoning a well, the barriers consist of the cement plug in the wellbore as well as the previous set, casing cement. In most cases, operators do not run a cement bonding log (CBL) to verify the quality of the casing cement in the construction phase of the well. This leads to uncertainty of the barrier integrity in the P&A phase as the presence of good cement all the way out to formation is unknown.

Running a CBL after casing cement might increase the cost of the well slightly, but is far cheaper than having to mill/underream the well later on in order to achieve good cement bonding to formation.

### **3.3.4 Pressure/temperature/flow surveillance**

Pressure, temperature and flow monitoring in wells can provide information regarding the wells integrity and help determine if the barriers are intact or not.

Pressure build-ups in the annulus can occur as a result of poor cement sealing or movement of the casing string due to thermal expansion. This could lead to migration of oil and gas outside the casing, increasing the annulus pressure and in worst case, losing the casing integrity.

#### ***Wireless Pressure Monitoring***

For land wells and offshore wells with dry wellheads, accessing the different annuli is easy and provides the user with vital information and access to make any needed adjustments. In subsea wells, monitoring the B-annulus is challenging as the access is closed off after landing the casing hanger, sealing and casing cement. This is because, according to ISO 13628-4 and API17D, the primary barrier of subsea wells should never be breached (Sultan, et al., 2008).

Emerson Process Management has recently (2012) developed a tool for monitoring annulus B in subsea wells, by using a new wireless pressure sensor system, called, *Roxar Downhole Wireless PT Sensor System*. This wireless system can provide feedback regarding the pressure and temperature of the annulus, and the barriers containing well pressure from the annulus. The system can accurately read pressure of +/- 2.5 psi and temperatures to +/- 0.18 °F (Thomas, 2011).

This new tool could, according to Emerson, provide cost savings because of the over dimensioning of casings that usually takes place to compensate for worst case scenarios. With the added integrity certainty that comes with the permanent annulus monitoring, this could be avoided. Integrity issues could also cause the well to be shut in early, leading to loss of income. The wireless pressure system could also help the engineers with troubleshooting of the wells integrity if any non-conformances occur.

The lifespan of this monitoring equipment is qualified to be 20 years minimum, and are able to withstand pressure up to 10 000 psi and temperatures of 150 °C.

A similar product is also offered by Sensor Developments in cooperation with Statoil, called LinX Annular (Sensor Development, 2012). This is probably something the industry will see more of the coming years, as the technology progresses.



## Chapter 4. Physical Well Barriers

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### 4.1 BARRIER ENVELOPES

The purpose of well barriers is to maintain well control and to prevent unwanted flow of formation fluids to surface or other formations. Norsok Standard D-010 use the following definition of well barriers; *“Well barriers are envelopes of one or several dependent WBEs preventing fluids or gases from flowing unintentionally from the formation, into another formation or to surface.”* (Norsok Standard D-010, 2004)

In this context, well barriers mean physical equipment in the well, acting as barriers.

As defined in the Norsok D-010 Standard, a well barrier consist of one or more well barrier elements, which on their own are not qualified as a well barrier.

The well barrier elements (WBE) are physical objects that form a continuous envelope around the wellbore, enclosing the well and ensuring its integrity. As a well barrier is only as good as its weakest barrier element, it is therefore imperative that the WBE(s) meet the required standards and can withstand the pressure exerted by the well. This is because if a leak or failure occurs in a WBE, there should always be a backup barrier to ensure that there is no leakage or spills to surface.

According to Norwegian regulations (Ptil, 2012) and the Norsok D-010 standard (Norsok Standard D-010, 2004), the well should have at least two tested and verified independent well barriers during all drilling and well activities.

These barriers are called primary and secondary barriers and should to the extent possible not have any common WBE(s) between them. If a common WBE is present, a risk analysis should be performed and mitigating measures applied.

If one of these barriers is breached, all well activities except trying to restore the well barrier should be stopped.

One of the biggest challenges is the requirements for permanent well barriers to have long-term integrity properties. However, no descriptions of how to perform long term integrity test is found in NORSOK D-010 or in any ISO/API standards. As a result, the industry does not perform long term integrity tests on WBE(s) (Vignes, 2012).

### 4.1.1 Primary barriers

The first barrier envelope, usually drawn in blue on Well Barrier Schematics, is called the primary barrier. This is the innermost barrier which will be the first obstacle that prevents unwanted flow of formation fluid.

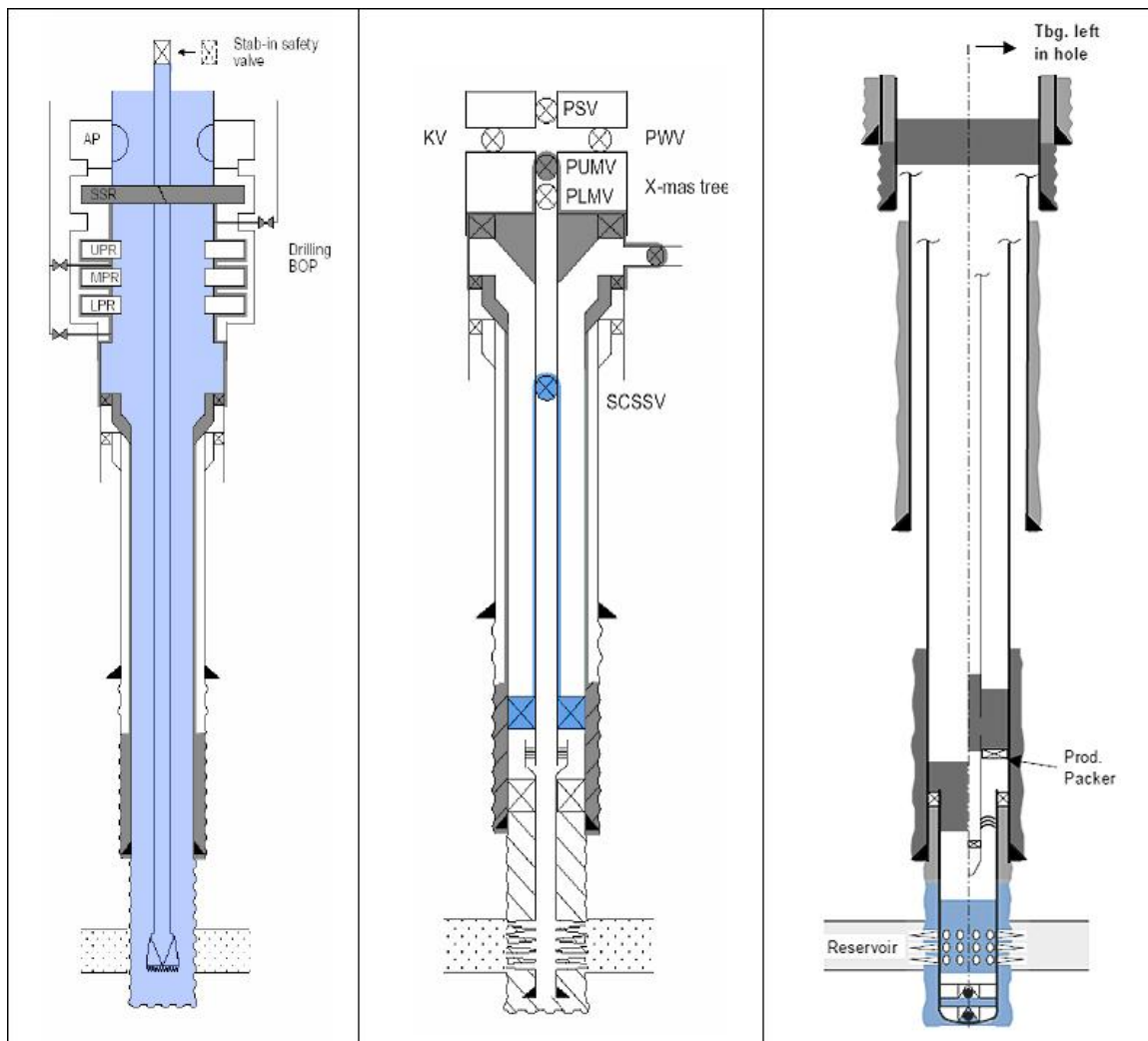


Figure 21: Primary barriers for drilling, operation, and P&A well [Based on (NORSOK Standard D-010, 2004)]

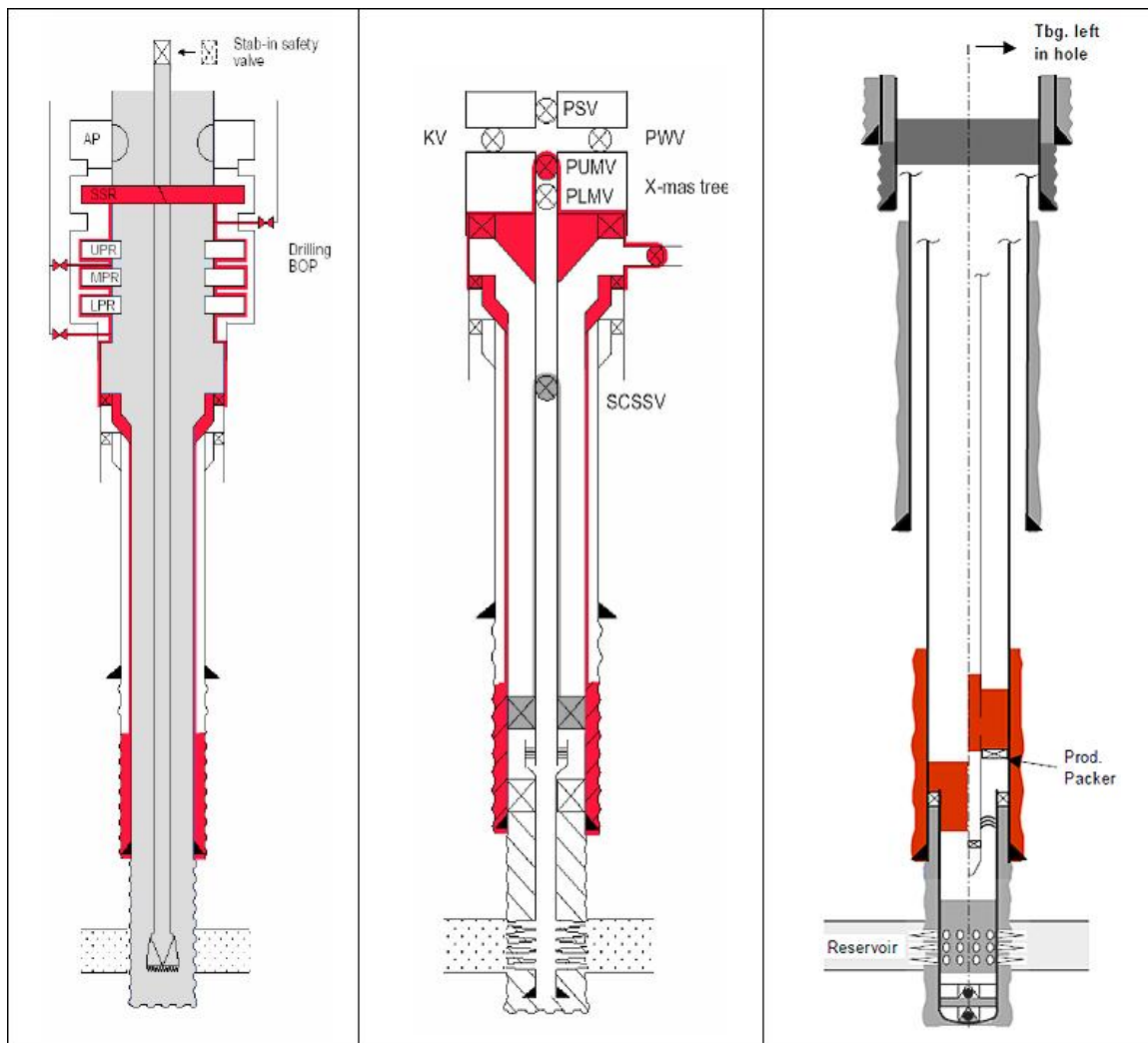
The different operational phases of the well use different types of primary barriers.

During drilling, the mud column acts as the primary barrier. Although this is a single well barrier element it is classified as a complete well barrier envelope.

While producing, the tubing string, together with valves, packers, casing and cement makes up the primary barrier. For permanent plug and abandonment, the cement plug and casing cement isolating the reservoir makes up the primary barrier.

### 4.1.2 Secondary barriers

The secondary barrier envelope, usually drawn in red on Well Barrier Schematics, is located outside the primary barrier envelope, and acts as the backup barrier. While not in direct contact with the formation fluid, it shall be capable of handling the well pressures if integrity of the primary well barrier is lost.



**Figure 22: Secondary barriers for drilling, operation, and P&A well [Based on (NORSOK Standard D-010, 2004)]**

During drilling, the BOP together with casing strings and casing cement makes up the secondary barrier. While producing, the wellhead, X-mas tree, casing strings and casing cement make up the secondary barrier.

For permanent plug and abandonment, a second plug above the primary reservoir plug with related casing cement makes up the secondary barrier.



## 4.2 WELL BARRIER ELEMENT DESIGN CRITERIA

Design criteria for well barrier elements can be found in NORSOK D-010 and states that the well barrier should be selected and constructed so that (NORSOK Standard D-010, 2004):

- *It can withstand the maximum anticipated differential pressure it may become exposed to.*
- *It can be leak tested and function tested or verified by other methods*
- *No single failure of well barrier or WBE leads to uncontrolled outflow from the borehole / well to the external environment.*
- *Re-establishment of a lost well barrier or another alternative well barrier can be done.*
- *It can operate competently and withstand the environment for which it may be exposed to over time.*
- *Its physical location and integrity status of the well barrier is known at all times when such monitoring is possible.*

The well integrity and physical position of the well barrier elements should be known at all times, and should be monitored whenever possible.

In order to ensure the quality of the WBEs, testing procedures and operational requirements are described in the NORSOK D-010.

NORSOK D-010 Standard, Chapter 15 contains 50 acceptance tables for the various WBE(s), with provided description for the functionality of the barrier element, the design criteria, how to perform initial testing and verification, proper use and monitoring and any potential failure modes. These are based on API standards, ISO standards and NORSOK standards.

## 4.3 WELL BARRIER ELEMENTS AND RELATED CHALLENGES

Well barrier elements (WBE) make up the well barrier envelopes and represent the physical barriers in the well. All the barrier elements have to be tested or verified before they can be classified as a barrier element. Some WBE's are used in the entire life of the well, like casing and cement, while others are more situational like drilling mud and tubing string.

For a component to be a permanent well barrier element, as required in permanent P&A wells, it is required that it inhabits long term integrity properties. This is however a challenge as no guidance is given in NORSOK D-010 for how to perform long term integrity testing, and no one knows for sure how materials behave at reservoir conditions over a long period.

Today, most of the tools and equipment have not been tested for long term integrity, but are still being used as permanent well barrier elements in active wells.

Some new products being offered, like the new isolation materials ThermaSet and Sandaband are said to inhabit these long term integrity properties, but the industry have not yet fully embraced these materials.

### **4.3.1 Blowout preventer**

A blowout preventer (BOP) is a type of equipment installed on the wellhead and is primarily used to contain the pressures in the well in order to avoid kicks and blowouts, and to control & monitor the well. The BOP also prevents casing, tubing, tools and well fluids from being blow out of the wellbore and is therefore a critical well barrier element regarding the safety of the rig and the crew. The BOP is most often a secondary well barrier in the well.

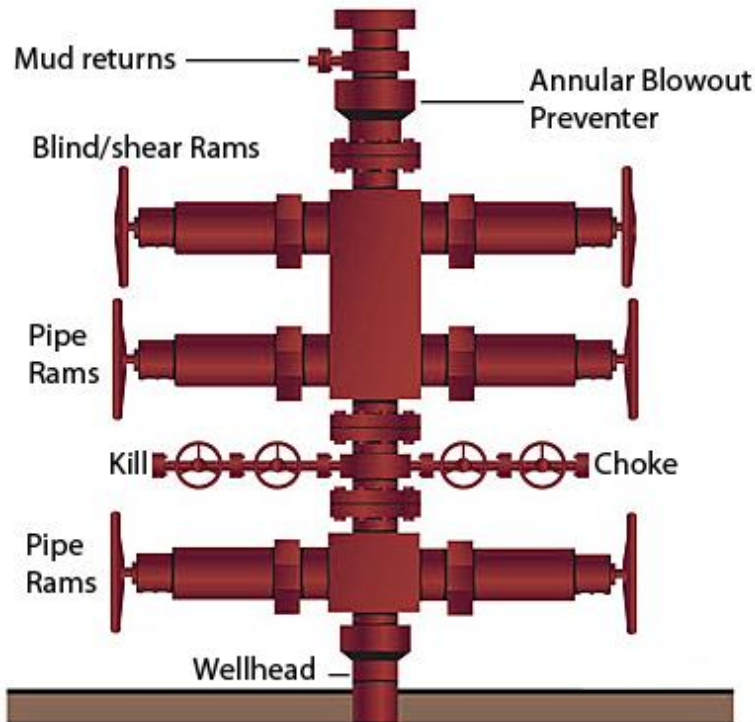


Figure 23: A typical BOP-stack [Based on (AskChesapeake, 2012)]

Different types of BOP's exist, with various sizes, configurations and pressure ratings. The type of BOP used is based on which operational phase the well is in; drilling, completion, testing or workover, the characteristics of the well, and whether it's an onshore/offshore/subsea well.

The BOP contains several rams which serves different functions.

In the case of a kick, the BOP has the ability to contain it, by sealing the annulus around the drill pipe with a pipe-ram, before initiating well kill procedures.

Alternatively this can be done by the use of an Annular Blowout preventer, a donut like rubber seal, which can seal around various pipe sizes.

If needed, the BOP can also cut the drill string, coiled tubing (CT) or wire line (WL), and seal the entire wellbore, with a blind shear ram.

The BOP can be controlled by hydraulic pressure from remote accumulators or manually if the well is an onshore well or drilled in shallow waters, where the BOP and wellhead is above the water.

For deeper offshore wells, there are four main ways to control the BOP;

1. Electrical signal through cable from surface.
2. Acoustic signal sent from surface.
3. ROV intervention, mechanically control valves
4. Deadman Switch, automatic shearing in case of loss of control, power or hydraulic pressure.

According to Norwegian regulations, an extra casing shear ram is required, while the US regulations does not require any (Det Norske Veritas, 2010). It is also, by Norwegian regulations, required that there exist an alternative activation system for the BOP and a system that detaches from the riser before it reaches a critical angle. In the US, no such requirements are in place.

Since the BOP is such an important well barrier element, they are regularly inspected and tested. According to API 16A and ISO 13533 standards, the parts of the BOP containing and controlling pressures should be tested and qualified by being exposed to the wellbore fluid. It is a normal industry assumption that the wellbore fluid does not include gas, and so the pressure containing parts of the BOP are not exposed, tested or qualified with gas.

The ram type BOP is according to API 16A/ISO 13533 (ISO 13533, 2002), tested for the sealing characteristics, fatigue test, stripping life test, shear ram test, hang-off test, ram access test and ram locking device test for ram type BOP's. while for annular type BOP's, it is tested for its sealing characteristics, fatigue test, packer access test, stripping life test, locking mechanism for hydraulic connectors and sealing mechanism for hydraulic connectors (Vignes, 2012).

Long term integrity testing is at the present time not defined in any of the API, ISO or NORSOK standards. The BOP is however only installed for a relative short amount of time, and most likely does not require long term integrity.

### 4.3.2 Casing

While drilling, steel tubular (casing strings) are run in hole in order to protect the formation as the weight of drilling mud increases to compensate for the high pore pressure.

There are several factors regarding the casing string that can affect well integrity;

#### ***Casing connections***

One of the most important key factors to casing integrity is the casing connections and the process of handling, make-up, testing and qualification of these, as well as the compound used in the connections threads.

According to studies (Schwind, 1998), estimates show that 85 to 95% of all failures related to tubular are related to connections. These are often neglected are given little attention when designing tubular, possibly from a lack of understanding of the connection importance. One of the main reasons for the connection failures is the fact the connections experience the same loads as the tubular itself, but is often weaker in tension, compression, pressure or bending (Aadnøy, et al., 2009). If only one casing connections is leaking, it could compromise the entire string, and disqualify the casing as a barrier.

The two major types of connections used in the oil industry today are proprietary and API connections. The proprietary, also known as premium connections, and are designed and manufactured by commercial manufactures with capability of handling greater depths with higher pressures and temperatures and have higher capacities than API connections. The price for the premium connections, range from two to five times the cost of API connections. The API connections are designed in accordance with tolerances specified by API, and were intended to standardize pipe sizes and connections to favor interchangeability.

The problem with the specifications in the API standard is that there is a certain tolerance allowed with regards to size to the pin and box connections.

#### *Example from the industry;*

ConocoPhillips once ordered a CTC (Completion Tool Company) packer joint which was to be delivered from the US (Blaauw, 2012). The buttress and coupled (BTC) connections used, tested OK in the lab in the US, but as it was run in hole in the well in Norway, the joint started to leak.

It was tested again in the lab in US, indicating no problem. After several rounds of this, back and forth it was finally decided to test the joint at Weatherford in Norway.

The test concluded with that the joint was leaking.

The reason for the inconsistency proved to be the tolerances stated in the API standard. The connections used in the Norwegian testing lab, and in the well, was at the one side of the allowed tolerance spectrum, while the ones used in the US was from the opposite side of the spectrum. This tolerance was enough to allow the join to leak at the connections.

Another consideration regarding the API connections is the need for a compound to seal the leak path in the connections. The compound deteriorates over time and at high temperatures and loses its sealing properties. At temperatures of 121 °C the compound will even start to evaporate, dry out and shrink, making the connection more likely to leak (Aadnøy, et al., 2009). The type of compound and quantity and where it should be applied, shall be specified by the connection manufacturer. The manufacturer shall also provide pictures showing the minimum and maximum thread compound. The same specifications shall be used for testing purposes.

There are four levels of casing and tubing connection test classes (ISO 13679, 2006). These are called the Connection Application Level (CAL), and are sorted by the severity of their applications. The reason for testing the casing and tubing connections is to determine the galling tendencies, the mechanical properties and the sealing properties of the connections.

CAL IV and CAL III for casing and tubing connections are accepted as well barrier elements. The CAL IV and CAL III tests, as well as the CAL II test, are conducted by using gas as medium. The CAL I test which uses liquid.

Table 2 displays the testing requirements for these four types as defined in ISO 13679:2006 standard; Procedures for testing casing and tubing connection.

**Table 2: Connection Application Level (ISO 13679, 2006)**

<p>CAL IV</p>	<ul style="list-style-type: none"> <li>• <i>Intended for production and injection tubing and casing for gas service</i></li> <li>• <i>Connections exposed to cyclical test loads including internal pressure, external pressure, tension, compression and bending.</i></li> <li>• <i>Exposure to extensive thermal and thermal/pressure-tension cycling incurring a cumulative exposure of about 50 h to gas at an elevated temperature of 180°C and pressure.</i></li> <li>• <i>Limit load tests to failure conducted in all four quadrant of the axial-pressure load diagram.</i></li> </ul>
<p>CAL III</p>	<ul style="list-style-type: none"> <li>• <i>Intended for producing and injection tubing and casing for gas and liquid service.</i></li> <li>• <i>Connections exposed to cyclical tests loads including internal pressure, external pressure, tension and compression. Bending is an optional load for CAL III testing.</i></li> <li>• <i>The test procedure for thermal and thermal/pressure-tension cycling incurring a cumulative exposure of 5 h to gas at an elevated temperature of 135°C.</i></li> <li>• <i>Limit load tests to failure conducted in all four quadrants of the axial-pressure load diagram.</i></li> </ul>
<p>CAL II</p>	<ul style="list-style-type: none"> <li>• <i>Intended for production and injection tubing and casing, protective casing and for gas and liquid service with limited exposure to significant pressure.</i></li> <li>• <i>Connections exposed to cyclical test loads including internal pressure, tension and compression. Bending is an optional load for CAL II testing and external pressure is not included.</i></li> <li>• <i>The test procedure for thermal and thermal/pressure-tension cycling is the same as for CAL III.</i></li> <li>• <i>Limit load tests for CAL II to failure are conducted with internal pressure and axial load.</i></li> </ul>
<p>CAL I</p>	<ul style="list-style-type: none"> <li>• <i>Intended for liquid service.</i></li> <li>• <i>Connections exposed to cyclical test loads, including internal pressure, tension and compression, using a liquid test fluid. Bending is optional of CAL I testing and external pressure is not included.</i></li> <li>• <i>Testing is conducted at ambient temperatures.</i></li> <li>• <i>Limit load tests are conducted in two quadrants of the axial-pressure load diagram.</i></li> </ul>

Make-up torques is an important aspect of casing and tubing connections. The recent years, drilling has become more aggressive and challenging, and by the use of top drives instead of rotary tables, higher torque output has been made available. If too little torque is applied, the

connection might not provide the required sealing properties. If too much is applied, it might break the threads.

During operations, connections are often tightened above the recommended make-up torque in order to make sure the connections are tight. In 2005, a study was done to investigate the effect that increased make-up torque had on rotary shouldered connection performance (Breihan, et al., 2005). Sets of connections were tested for various bending stress levels at different torque values until failure or until 20 million cycles were reached. The study concluded that caution should be taken with regards to applying make-up torque above the API recommendations, as this had a negative effect on fatigue life.

As stated in ISO 13679:2006 standard, the manufacturer shall specify the rotational frequency range for the make-up, as well as the maximum and minimum recommended torque. Casing and tubing connections are through testing, subjected to internal and external pressures, tensional and compression forces, bending and make-up torsion.

To avoid compromising the integrity of casing and tubing connections, having requirements as opposed to recommendations regarding make-up torque, could prove beneficial.

Exposure to corrosive fluids that might be present during well services is however not a factor during connection tests. Long term integrity testing of casing connections is also not done and is not defined in any standard.

One of the challenges the industry have today is that many wells are using casing and tubing connections that are not qualified for gas, despite the fact that these are being used or can be used for gas-lift or otherwise being exposed to gas. This could be result of inadequate well design or lack of available gas tight connections when the well was constructed. This may prove to be a problem on many of the two-string-design wells.



### ***Corrosion / Erosion / Wear***

Degradation of the casing can lead to weak spots and allow for the possibility of bursted casing. With the increased exposure to acids, H<sub>2</sub>S and gas-lift gas used in wells, corrosion is an increasingly problem. The casings are as previously mentioned not tested for these types of fluids.

For wells producing from sandstone reservoirs, erosion caused by sand-production is a big factor, but could be mitigated through means of sand packs. During drilling phase, contact between the rotating drill-string and the casing could cause tear at certain points which could lead to a reduction of the wall thickness and cause lower internal pressure ratings for the casing.

### ***Placement of casing shoes***

The setting depth of the casing shoe is a critical factor for maintaining the formations integrity during drilling, but they also play a role for well integrity during its production phase.

A loss of circulation or a kick situation may lead to high burst or collapse loads on the casing string. Smart design of casing shoe placement is needed in order to prevent the casing from losing its integrity.

The resulting burst load of the casing is the inside pressure minus the outside pressure. If a kick occurs, the casing might be filled with gas or very light fluid. The pressure inside the casing will at worst case be the reservoir pressure minus the hydrostatic pressure exerted by the fluid column. A gas or light fluid will not provide a lot of pressure, especially at the top. The weak point will therefore be at the wellhead.

It is important to design the well so that if a weak point is present, it should be located below the casing shoe. This is an acceptable state of reduced well integrity (Aadnøy, 2010).

A weak point at the wellhead could lead to a blowout and have disastrous consequences.

During the production phase, the casing shoes should be able to withstand the reservoir pressure in order to qualify as a well barrier.

If the primary barrier envelope is compromised, the secondary barrier envelope should be there as back-up. This presents a challenge in two-string design wells, where the 13" casing shoe, which is exposed to the A-annulus, normally don't have the required strength to withstand formation pressure, and can therefore not be qualified as a barrier element.

### **4.3.3 Well Isolation**

To ensure the integrity of the casing strings in the well, they are cemented to the formation. The cement not only keeps the casing strings in place, but holds the important function of isolating the wellbore between the formation and the casing in order to try to restore the initial sealing property which the formation previously had. With proper sealing, it also prevents influx from the reservoir or any shallow gas zones, into the annuli which could lead to sustained casing pressure or unwanted casing strains. This isolation is present as both a primary and a secondary barrier in the well; both during construction and operation phase, as a vertical barrier, and in the P&A phase, as both a vertical and a horizontal barrier.

Different materials are also used for temporary plugging, either as the primary plugging material or in aiding additional plugging material.

The importance of the isolation makes this a critical well barrier element which should be chosen, tested and verified to ensure long term integrity.

Listed below are some of the challenges related to well isolation as well as a discussion regarding isolation solutions available on the market.

#### ***Sustained Casing Pressure***

Sustained casing pressure (SCP) is a major challenge on several wells, and has been given more attention the recent years, as incidents caused by SCP are reported by operators (Wojtanowicz, 2001). Sustained casing pressure means that the pressure in any annuli rebuilds after being bled down, and is not caused solely by temperature fluctuations or imposed by the operator. In most cases the SCP is manageable by the casing strength and does not pose any big issue, but in some cases there is a risk of hydrocarbon leak to surface, causing pollution to sea or aquifers. This makes these wells risky to produce from, and should have their excessive casing pressure eliminated before P&A take place.

SCP is mainly caused by migrating gas through the casing cement as a result of poor cement job, so having a good quality of the cement job is crucial. The gas causing SCP could also seep through the formation, meaning placement of the casing shoe should also be taken into account and be set in a strong enough formation. Other possible causes of SCP include defect and leaking equipment/seals due to corrosion, erosion or temperature/pressure fluctuations or other well integrity failures.

SCP can occur anytime in the wells lifecycle and will manifest itself at the wellhead. For subsurface wells this presents a real challenge as casing pressure monitoring is unavailable in many wells. Emersons, *Roxar Downhole Wireless PT Sensor System*, as mentioned previously, or similar solutions, could solve this issue.

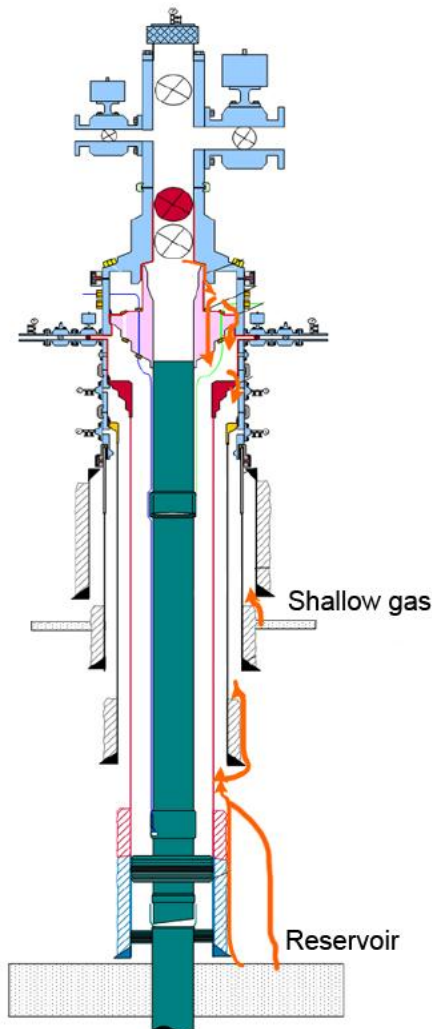


Figure 24: Potential leaks paths resulting in SCP [Based on (Sæby, 2011)]

Figure 24 shows an example of how SCP can occur in a well. Gas can migrate through micro-annuli in the cement, through improper cement-formation bonds, through the formation or through leaking seals and faulty equipment. Arrows indicate possible migration paths.

BOEM and BSEE, formerly known as MMS, have in their regulations, a have a zero tolerance of SCP. Waivers can however be granted to allow operation on wells with small SCP problems, based on casing pressure diagnostic tests.

In Gulf of Mexico (GOM) there are believed to be over 8000 wells with SCP and present a major challenge with regards to keeping well integrity (Wojtanowicz, 2001). No data with regards to SCP has yet to be presented for wells on the NCS, making the magnitude of this issue unknown (Lunde, 2012) (Sæby, 2011).

According to NORSOK D-010, the pressure in the A annulus shall be monitored and maintained at all times (NORSOK Standard D-010, 2004). In gas-lifted and multipurpose wells, the B-annulus pressure shall also be continuous monitored. Because of the challenge of monitoring pressure in subsurface wells, the B-annulus is normally designed to withstand the thermal pressure build up or have an acceptable pressure management system.

The API RP-90 standard state that if an annulus casing pressure is below 100 psi, it presents little risk and monitoring the pressure is sufficient. If the pressure is greater than 100 psi and the casing annulus has been diagnosed with SCP, it has to be bled down to 0 psi. Annulus pressure which does not meet these requirements should be judged on a case-by-case basis by the use of risk assessments (API RP 90, 2006).

Requirements and guidelines about management of SCP were in the past very limited, and with the increasing attention on SCP, it became clear that a set of guidelines had to be made in order for operators to approach the issue in a more consistent way. In 2010, WIF made a plan to update the well integrity guideline document, OLF 117, to include a chapter about recommendations and best practices regarding SCP.

A dedicated group with representatives from BP, ConocoPhillips, Shell and Statoil worked together and in May 2011 the SCP guideline were completed (Sæby, 2011).

The guideline describes SCP management protocols, for both platform and subsea wells, with regards to monitoring, detection, evaluation, acceptance criteria and mitigating measures. It also describes design of new wells and intervention in existing wells with regards to prevent and eliminate SCP.

## **Cement**

Cement has been the used isolation material in wells, since the beginning of the oil industry. The knowledge and experience by using cement is therefore extensive, and a more optimal material has yet to be found. Although new solutions and materials are being offered, one of the big challenges is that the petroleum industry is often very hesitant to use them and rely very much on the cement. Compared to various other isolation material introduced in recent times, like ThermaSet and Sandaband, cement is still cheaper, more accessible and more trusted, which may be some of the reasons why it is still preferred.

Previously, the companies performing the cement job worked by the motto;

*“Mix it grey, pump it away!”* The importance of a good quality cement job with regards to well integrity was not well known, a challenge the industry has to face today with many of the old wells being affected by inadequate cement jobs.

Today however, more care is carried out with regards to cement quality, density measurements, volume control, testing and monitoring. A good cement job is crucial for the wells integrity, and can provide major obstacles down the line if not done correctly. Cement integrity issues like micro annuli and improper formation bonding can be difficult or impossible to mend and can turn out to be a costly affair.

The main challenges today which affect the cement integrity include hole cleaning, circulation of cement, centralization of casings, setting time of the cement, logging, testing and verification (Vignes, 2012).

Before pumping of the cement commence, is it important that the well has been cleaned properly as swarf and other remains could cause major increase to pump pressure due to frictional forces. This increased pressure could cause difficulties lifting the cement or in worst case fracture the formation if the well is drilled with small margins to the fracture gradient.

Another factor important to consider in the planning phase of the cement job, is the use of acid treatments planned for the well. The corrosive environment could affect the cement quality over time, and should be mitigated by ensuring that there is a sufficient length of unaffected cement to compensate for the poor.

Running cement logs to verify the quality of the cement is however not normal procedure as per date, but could uncover challenges like cement centralization, bonding, contamination, channeling and micro annulus. These are issues that could cause sustained casing pressure or render the cement useless as a barrier.

Improper casing centralization, as seen in Figure 25, could lead to reduced cement integrity due to the reduced thickness of the cement.



**Figure 25: Bad casing centralization (WellCem, 2012)**

For a well which is being permanent plugged and abandoned, the casing, casing cement, and cement plugs in the well are meant to ensure full well integrity for an infinite amount of time. Age and stress tests have been conducted on cement plugs, but these tests are limited and no one knows for sure how the cement plugs will hold up after thousands of years. It is a fact that the cement does not fulfill the long term integrity requirements that a permanent WBE shall have according to NORSOK D-010.

The lack of long term integrity testing and properties of permanent well barriers is one of the big challenges in the industry today. On new isolation materials like ThermaSet and Sandaband, which are discussed later, long term integrity tests are performed. The industry still relies mostly on cement as their primary isolation material, even though it does not fulfill the permanent isolation requirements. The integration of the new isolation materials might be a long and slow process, but could eliminate challenges the industry has with regards to long term integrity.

### **Packers and Bridge Plugs**

Packers and plugs are tools set to isolate a part of the wellbore and can be both permanent and temporary. In order to ensure integrity of these tools, an international standard of design validation grades have been made in order to categorize the different packers and plugs. These grades vary from V6-V0, with V0 as the most secure, and provide the user with a choice of requirements or specific application that the plugs should be applicable for. Bridge plugs may be tested and run without axial load.

- V6:** *Supplier/manufacturer-defined*
- V5:** *Liquid test*
- V4:** *Liquid test + axial loads*
- V3:** *Liquid test + axial loads + temperature cycling*
- V2:** *Gas test + axial loads*
- V1:** *Gas test + axial loads + temperature cycling*
- V0:** *Gas test + axial loads + temperature cycling + special acceptance criteria (V1 + zero bubble acceptance criteria)*

Testing procedure is specified in ISO 14310 and verification and periodical testing are specified in NORSOK D-010. No long term integrity testing is however defined in these standards.

The challenge in the industry today is the packers and plugs which are not qualified as being gas-tight (V3-V6) and the use of these where they might be exposed to gas medium. The wells which currently use these packers and plugs as a part of their barrier envelope may be under a false sense of security.

### **Barite Plugs**

A barite plug is a slurry mix made up of barite, complex phosphate thinner and water, preferably fresh water. This is pumped down the drill pipe and set in the bottom of the well to form an immovable sealing column. Its main purpose is to initially, kill the well, and secondly, form a mechanically block as the barite is settling (Messenger, 1981) (MI Swaco, 2012) (ConocoPhillips, 1997).

Normally, barite plugs are used in emergencies or in extreme conditions where it is important to seal the wellbore. An example of such a situation could be when encountering a kick.

Normal procedure would be to build up the mud weight to control the kick, however, sometimes a situation arise where both kicking and loss of circulation occur at the same time or in worst case, an underground blowout. This is a very dangerous situation, and placing a plug in order to run in a casing safely is desirable.

This is one of the main uses for barite plugs.

Some situations where barite plugs are applicable (ConocoPhillips, 1997);

- Kicking from lower zone and losing circulation to an upper zone
- Abandonment procedure allowing safe withdrawal of dill pipe to allow setting of cement plug
- Withdrawal of drill pipe to either set casing or repair existing casing strings
- Plugging drill pipe in emergency situations
- High pressure salt water flows where required kill mud weight approaches or exceeds the formation breakdown equivalent at some point in the open hole, usually last casing string

Killing the well with a barite plug is straightforward and only requires that enough slurry is pumped down the well for the bottom-hole pressure to exceed the reservoir pressure. Issue arise however if the reservoir pressure is unknown, or if the formation cannot withstand the amount of slurry required.

The relief well used to kill Sagas 2/4-14 underground blowout is an example of a successful well-kill using barite plug. This is discussed later on in Chapter 6.

Ensuring a mechanical block is made is more challenging. The general method consists of making a slurry where the barite starts to settle particles into a firm plug. Settling rate is often easy to predict as it is independent of the slurry height, allowing small scale tests to be done beforehand. In oil based mud (OBM), the settling rate is affected by factors such as density/concentration of weight material and concentration of oil-wetting agents.

Another way to form a solid plug is through dehydration, caused by the barite plugs high filter loss.



Tests conducted show that densities of 2.04-2.16 s.g. mud provides optimum conditions for settling rates, while higher density mud will lead to a significantly reduction in settling rates. This is due to the fact that as the amount of solids in the mud increase, the mud is transformed from a liquid to a plastic state, resulting in high viscosities. The density where this occurs is known as the packing fraction.

For lower densities, the reduction of weighting agent concentrations will lead to reduced settling rates. To avoid movement or migration of the plug after it has been set, a density of 0.06-0.12 s.g. higher than the fluid in the hole is desirable.

The initial settling rate is constant, but only last a short time. As more and more particles fall out of suspension, the settling rate decreases. Having an optimum settling rate is important in terms of having a successful plugging operation. The length of the required compacted barite plug varies based on the severity of the situation, and to calculate the length of the compacted plug, the following formula is used (MI Swaco, 2012);

$$L = m / (sg \times V)$$

where,

*L = Length of compacted plug (m)*

*m = Kgs of barite (kg)*

*sg = Specific gravity of barite (4.2 kg/ltr)*

*V = Volume per meter of hole (ltr/m)*

The total length of the slurry should not exceed the distance between the kicking zone and the loss circulation zone. This is to avoid losing slurry to the formation, and also to avoid having to withdraw the drill string a great distance. If the formation pressure is known, the required length of slurry to balance the pressure can be calculated.

While displacing the slurry, having 1 m<sup>3</sup> more inside the drill pipe than outside is desirable, in order to allow the drill pipe to be withdrawn with a natural slug, and also to minimize contamination caused by movement of the slurry.

Once the plug has been set, tripping should be done as soon as possible and the plug should be allowed to settle for several hours. When the plug has been set, a cement plug can be set on top to secure the well safely.

**ThermaSet**

ThermaSet, a resin based sealant made by WellCem is one of the alternative isolation materials available. The development of ThermaSet started in 1990 through the research group, SINTEF. Studies of several materials were conducted in order to investigate the endurance, and sustainability of the materials, under well conditions. A thermosetting material, later called ThermaSet was chosen as the best solution (WellCem, 2012).

ThermaSet can be designed so that it remains in liquid form until it reaches a certain temperature. This provides opportunities to pump the material through narrow channels before the material solidifies. It can be designed within a range of different densities and viscosities, and once it's set, it will remain viable for up to 500°C. The fact that the setting temperature along with viscosity and density can be regulated makes this a very unique product. The setting temperature, for when the material starts to solidify, can be within the range of -9°C to 135°C.

Some of the applications for this material include curing loss of circulation, permanent and balanced plugs, sealing of micro channels, zone isolation, and fast setting kick off plug which can be pumped through the drill bit.

An ageing test was performed at SINTEF. Results from the ageing test displayed in Table 3:

**Table 3: Properties of ThermaSet vs. Standard Cement**

Properties	ThermaSet	Portland G Cement
Compressive Strength (MPa)	77 ± 5	58 ± 4
Flexural Strength (MPa)	45 ± 3	10 ± 1
E-modulus (MPa)	2240 ± 70	3700 ± 600
Rupture Elongation (%)	3.5	0.01
Tensile Strength (MPa)	60	1
Failure flexural strain (%)	1.9 ± 0.2	0.32 ± 0.04

The results show that ThermaSet exhibits a far higher tensile strength than Portland G cement. It also shows a superior flexural strain and elasticity. A low tensile strength could cause the material to fracture as a result of casing expansion caused by heat flow from the producing fluid, especially when combined with a low rupture elongation. Cement is inferior to ThermaSet on these areas and could cause fracture problems, as seen on Table 3.

ThermaSet has also been V3 tested successfully, which is a liquid penetration test conducted by subjecting a sample to axial loads and temperature cycles. This has yet to be accomplished by traditional cement.

Based on these studies, ThermaSet is claimed to be the only product that fully comply with NORSOK D-010 standard as a permanent well barrier material (WellCem, 2012).

There have been a lot of documented cases when ThermaSet has been used successfully.

### ***ThermaSet Case Study – Ekofisk C-19***

When ConocoPhillips were to P&A 2/4 C-19 on Ekofisk, they used a cement plug as plugging material (WellCem, 2012). After the setting time, the plug was tested as per procedure but yielded a negative result. A leak in the cement plug inside the tubing was the cause.

They decided to go for a ThermaSet plug, and a batch of 1.1sg density ThermaPlug was selected to match the existing well fluid. The plug was designed to solidify after one hour in an 80°C environment, and was placed on top of the cement plug. As a result the tubing was plugged and the leak in the cement plug was mended. The plug was then tested to 4000 psi, and the P&A operation were continued.

From this study, the use of ThermaSet proves beneficial as an isolation material. Here, ThermaSet was used as a plug. It is also, according to WellCem, possible to use ThermaSet for casing cementing, however, no case studies are available regarding this yet.

### Sandaband

Sandaband is a sand-slurry consisting of about three quarters sand particles and one quarter water and other additives (Sandaband, 2006) (Sandaband, 2012) (Sandaband, 2012). The product was developed in Norway to meet the increasing demands of an everlasting plugging material. Sandaband possesses the properties as a Bingham fluid (Figure 26) and act as a deformable solid when it's stationary, but as a liquid when in motion.

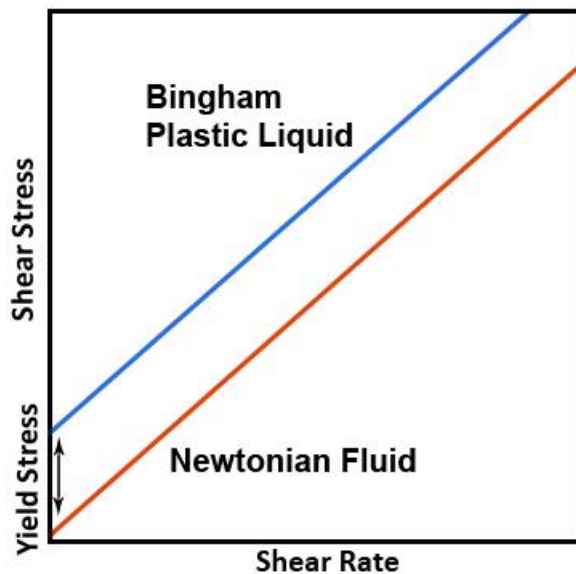


Figure 26: Characteristics of a Bingham fluid [Based on (Schlumberger, 2012)]

The sand slurry is also incompressible and gas tight, and does not shrink, fracture or segregate. It does however require a solid foundation, as it will sink if placed on another fluid. The Sandaband mixture can be used as both temporary and permanent plugging material, as fill behind the casing or as loss circulation material (LCM).

NORSOK D-010 has requirements regarding permanent P&A plugs which say that a permanent well barrier should have the following properties:

- a) Impermeable.
- b) Long term integrity.
- c) Non-shrinking.
- d) Ductile – able to withstand mechanical loads/impact.
- e) Resistance to different chemicals/substances ( $H_2S$ ,  $CO_2$  and hydrocarbons).
- f) Wetting, to ensure bonding to steel

Sandaband claims to cover these criteria,

a) It is claimed to be gas tight in accordance with API spec10 (Vignes, 2012), based on the fact that in the solid state, the sand particles remain fixed because of the tight packing. This, combined with the low porosity, leads to a permeability of less than 0.1 mD.

The API 10A standard describes testing of cement and cannot be directly comparable with testing of Sandaband,

b) Based on the characteristics of the sand slurry and its properties, it is indicated to have long term integrity properties. A long term integrity test has also been performed where the product was tested from -10 °C to 250 °C (Vignes, 2012).

c) The sand slurry is incompressible based on the fact that there is no chemical reaction between the solid particles and the liquid phase and is therefore non-shrinking.

d) It acts as a Bingham fluid and is fluidized when subjected to a pressure above its yield point. This ductile behavior means that the sand slurry will never fracture or create micro annuli.

e) The particles are mainly quartz, which is chemically stable even in contact with CO<sub>2</sub>, H<sub>2</sub>S or reservoir fluids.

f) Sandaband exhibits wettability properties towards the casing.

### **Sandaband Case Study – Embla D-07**

ConocoPhillips introduced Sandaband in one of their wells, Embla D-07 as a mean to provide a temporary plug to secure the well (Sandaband, 2010).

Embla D-07 was drilled in May 2005, but encountered a pressure build up in A-annulus and tubing, due to tubing-annulus communication, and was shut in, January 2006.

The pressure built up to 4900 psi and was at the time being, the highest risked well in ConocoPhillips. Using a temporary plug was suggested, for later allow workover and re-use the well. Several products were evaluated, and a decision to use Sandaband was made. It was estimated to be the biggest and most complex Sandaband job performed to date.

The results of a cost analysis for the project are presented below:

#### Cost of the temporary abandonment using Sandaband:

Total cost: 6.5 million NOK

Estimated days: 7 days

#### Cost of temporary abandonment using traditionally P&A:

Total cost: 19 million NOK

Estimated days: 30 days

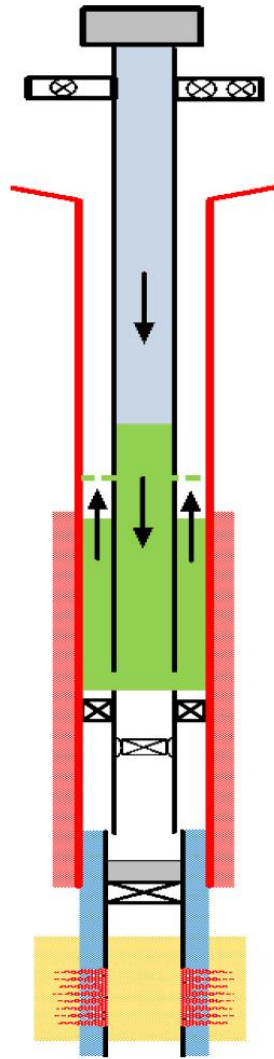
A leak detection tool (LDT) was run to identify the leak point.

The production packer was found to be leaking, and as an attempt to temporary secure the well, two permanent bridge plugs was set in the reservoir liner, with 15 ft of HipMix cement dumped on top of the upper plug. The upper plug and cement was tested ok, however, 3-5 months later the pressure started to build up again.

The A-annulus still had a pressure of 4900 psi and was bleeding off oil. The cause was believed to be either a leak in the liner hanger or a leak in the plug & cement.

A wire line set EOF (Baker Hughes internal grading) plug was placed in the tailpipe nipple. The EOF seating nipples are specifically designed for high pressure, high temperature (HPHT) wells (Baker Hughes, 2010). The Model V bottom check valve placed in this nipple allowed an upwards flow, but prevented a downwards flow.

Large holes were punched in the tubing, followed by displacing the tubing and annulus with inhibited seawater (ISW). The tubing was then cut above the production packer and Sandaband was pumped down the well, displaced by ISW. See Figure 27.



**Figure 27: Embla D-07 - After tubing has been cut – Circulating Sandaband [Based on (Sandaband, 2010)]**

The inhibited seawater contributes with a hydrostatic pressure of 3820 psi, while the Sandaband contributed with a hydrostatic pressure of 4155 psi and a yield pressure of 4055 psi. With a reservoir pressure of 10800 psi, this results in a positive overbalance pressure of 1230 psi. By including a safety factor of 30%, a positive pressure of 294 psi is seen (Sandaband, 2010). See Appendix C for details.

The Sandaband job was performed with no downtime or HSE incidents and placed according to plan. The well is now currently ready for permanent P&A or for a workover. Figure 28 shows the current well barrier schematic for Embla D-07.

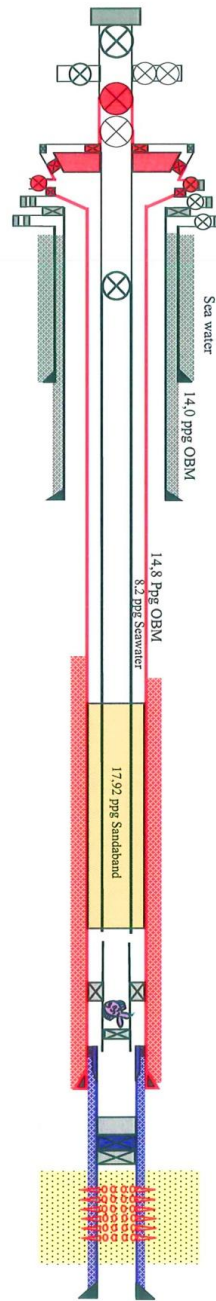
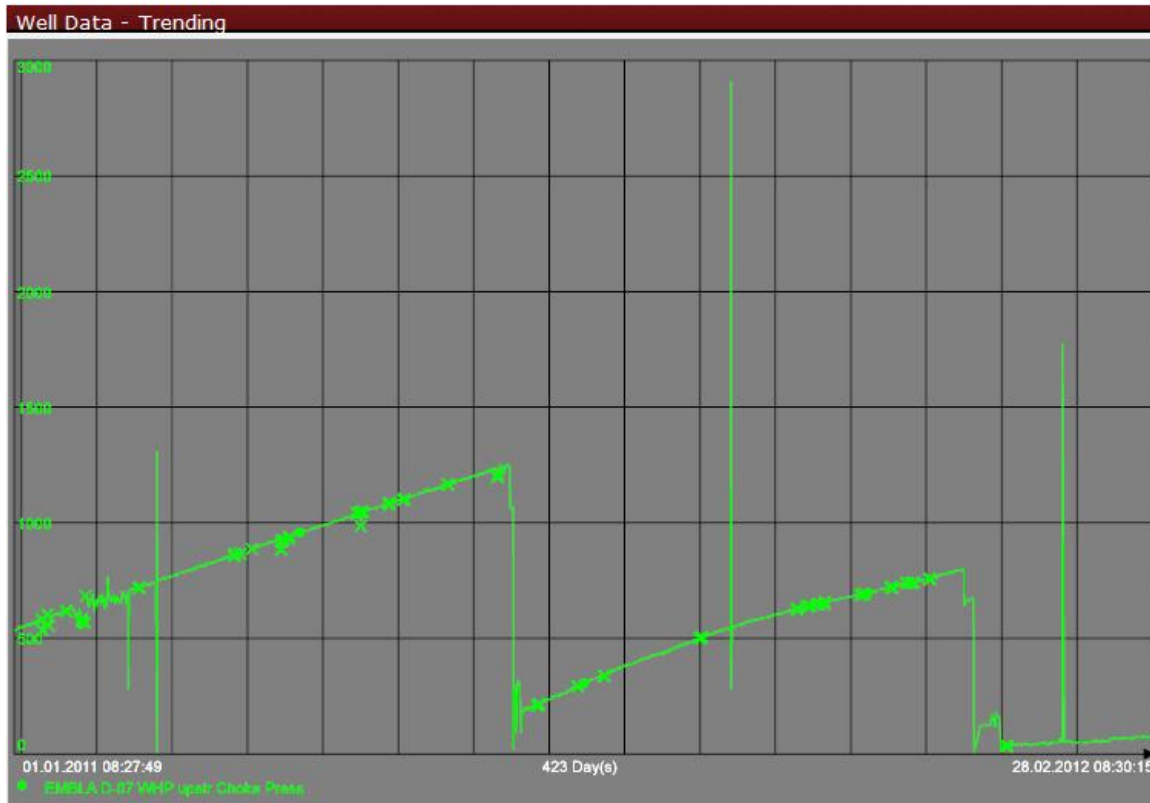


Figure 28: Well barrier Schematic of Embla D-07 – After Sandaband plug [Based on (ConocoPhillips, 2012)]



The well pressure in Embla D-07 has been monitored since the setting of the Sandaband plug. Although the plug was set without complications, there is however, still a pressure build-up in the A-annulus, indicating that the Sandaband plug is not as impermeable as advertised. Figure 29 shows the pressure build in the well from 1<sup>st</sup> January 2011 until present day.



**Figure 29: Wellhead pressure monitoring on Embla D-07 – 01.01.2011 – 28.02.2012 (ConocoPhillips, 2012)**

The annulus pressure regularly builds up to around 1000 psi over a period of 6 months, before it is bled off. The pressure increase is around 3.75 psi/day. Based on this data, the Sandaband does not seem to be suited as a permanent P&A plug, as it does not fulfill the NORSOK D-010 requirements of being impermeable and having long term integrity. It can however be used as a temporary plug, as in this case, if monitored and maintained.

### **CannSeal**

AGR offers an epoxy-based solution to well isolation, called CannSeal, mainly intended for isolation of the annulus (AGR, 2009) (AGR, 2012) (Gunnarsson, 2011). The epoxy can be pumped into the annulus, by perforating the casing string, circulate and clean, and then set the CannSeal plug. The properties of the epoxy, such as setting temperature, elasticity and viscosity, can be tailored to suit the users need.

Some of the applications of CannSeal include;

- Seal off/reduce unwanted water and gas inflow behind liner/pip/screen.
- Injected into a gravel matrix under high x-flow.
- Seal off leaking packers.
- Seal off annulus between two pipes.
- Replace ‘spot on’ cement squeeze.
- Provide spot acidizing.

The CannSeal tool have been tested and approved to temperatures up to 120 °C and pressure up to 345 bar, and is run in hole with a single wire line run.

The development of the CannSeal technology started in 2005 and was supported by companies such as Demo2000, Statoil, Eni, Total and Shell. The final product was launched in 2010.



**Figure 30: Epoxy sealing material used with CannSeal (AGR, 2009)**

As of today however, CannSeal cannot promise a long term integrity barrier, and is therefore not suitable for permanent P&A (CannSeal, 2012).

### **Formation / Shale as annular barrier**

Sometimes when drilling through certain formations, the rock moves inward enclosing the well, and creates a barrier by sealing the annulus (Williams, et al., 2009).

This is due to a reaction between the mud in the well and shale formations, making the shale swell. The following displacement mechanisms can be observed:

- Shear or tensile failure
- Compaction failure and / or consolidation
- Liquefaction
- Thermal expansion
- Chemical effects
- Creep

During drilling and running casings, this is an unwanted effect that might cause issues.

However, after the casing has been set, natural annulus barriers caused by shale swelling could reduce complex remedial work and substantial cost savings, by acting as an additional annular barrier.

For the shale to be qualified as a barrier it must possess certain characteristics, such as a uniform displacement around the well and at a sufficient interval. It must also have sufficient rock strength and extremely low permeability to hinder any fluid from escaping.

Qualification of these shale barriers has been done by bond logging and pressure testing and has shown that the shale has sealed off certain zones for over 40 wells by creating an annular barrier with good bonding.

Observations supporting good formation bonding:

- Good bond log response far above the theoretical top of cement
- Good quality bond correlates with shale rich intervals
- Large and sometimes frequent changes in bond log response at the same depth as geological changes.
- Above the casing shoe of an outer casing string the log response changes from good quality bond to free pipe as the formation can no longer impinge onto the inner casing string.
- Sinusoidal patterns on ultrasonic bond log images imply geological beds impinging on the outside of the casing

Prior to P&A jobs, it is important to make sure good quality cement is present on the outside of the casings where the plugs are placed. Methods of achieving this include perforate casing and squeezing cement, cutting and pulling casing followed by placing a long cement plug or section milling at least 50m of casing before placing a long cement plug. By using the natural shale as an outside isolation instead of cement, a substantial amount of work and money can be saved.

In order for the shale to act as a permanent barrier element, the position of the displaced formation shall be identified and its seal ability verified.

A methodology has been created for doing this:

- Position and extent of collapsed formation shall be identified through appropriate logs.
- Two (2) independent logging measurements/tools shall be applied.
- Logging tools shall be suitable for applicable well conditions e.g. number of casing strings, casing dimensions and conditions, fluid types and densities.
- Logging tools shall be properly calibrated.
- Logs shall be interpreted by personnel with sufficient competence.
- Log response criteria for good bonding shall be established prior to initiating the logging operations.

To verify the formation as a barrier element both the log measurements/tools should show a continuous good bonding of minimum 50m. If the formation seal is less than 50m, a pressure test or inflow test should be conducted to verify.

By using shale as an annular barrier instead of creating plugs for plug and abandonment, saves the company a great deal of time, money and effort due to reduction in rig time and operating costs. The shale barrier is also a self-healing, making it extremely durable and can prolong the well life and the quality of the well integrity. During 2007 and 2008, over 40 P&A operations were conducted using formation as annular barrier with a success rate of over 90%.

#### 4.3.4 Tubing / Completion String

The tubing string is placed into the reservoir to produce the reservoir fluid and is in many ways similar to a casing string. Consequently, it shares a lot of the same challenges as a casing string does, including integrity of tubing connections, wear, tear, corrosion and erosion issues. The tubing string is acting as a primary barrier during production, so the well barrier elements related to the tubing is of high importance and requires full integrity.

##### **Safety Valve**

The subsurface safety valve (SSSV) also known as Downhole Safety Valve (DHSV) is defined by API 14A as a *device whose design function is to prevent uncontrolled well flow when closed* (API 14A, 2006). It can be installed and retrieved by wire-line, coiled tubing or as an integrated part of the tubing string.

For the safety valve to be in accordance with the international standard, it has to conform to one of four classes of service;

##### **Class 1: Standard Service:**

*This class of SSSV equipment is intended for use in wells which are not expected to exhibit detrimental effects defined by classes 2, 3 or 4.*

##### **Class 2: Sandy Service**

*This class of SSSV equipment is intended for use in wells which are where particulates such as sand could be expected to cause SSSV equipment failure.*

##### **Class 3: Stress cracking service**

*This class of SSSV is intended for use in wells where water containing corrosive agents can cause stress cracking and be manufactured from metallic materials that are demonstrated as resistant to sulfide stress cracking and stress corrosion cracking.*

##### **Class 4: Mass loss corrosion service**

*This class of SSSV equipment is intended for use in wells where the corrosive agents could be expected to cause mass loss corrosion and be manufactured from metallic materials that are resistant to mass loss corrosion. No national or international standard exists for the application of metallic materials for this class.*

The safety valve has to be tested, according to Norsok D-010, every month until three consecutive qualified tests have been performed. After this, the valve shall be tested every three months until three consecutive tests have been performed and finally every six months thereafter.

Acceptance criteria are stated in API 14B, ISO 10417 and Norsok D-010.

No procedures for long term integrity testing are however described for this item.

### **Gas Lift Valve**

The gas lift valve (GLV) is a valve used in the completion strings in wells on gas lift, in order to control the flow of gas-lift gas from the annulus into the tubing. As this provides direct communication between the annulus and tubing, it is a critical well barrier element.

Norsok D-010 Section 15, Table 29 defines the well barrier acceptance criteria for completion string components. It is stated: *“For gaslift valves to qualify as a well barrier there shall be a qualification test demonstrating the valves ability to be gas tight over an operator defined number of cycles. The valve shall be subject to frequent testing with acceptable results similar to resting of SCSSVs.”*

The statement is somewhat contradicting and the SCSSVs are not gastight (Vignes, 2012). In addition, no specifications regarding leak testing of the GLV is described in Norsok D-010. As a consequence, operators have used different test methods and different acceptable leak rates. Since the industry does not currently have a common qualification method, they use a variety of standards including; API 11D1/ISO 14310, API 14B/ISO 10417, API 11V1, ISO 17078-2, API 14A/ISO 10432 and the Norsok D-010 (Vignes, 2012).

It is clear that there is a potential for improvement in the Norsok D-010 standard regarding testing and qualification of GLVs.

### **4.3.5 Annulus Safety Valve**

During gas-lift of wells, the annulus is filled with gas which amplifies the risk and consequences of any potential blowout. The function of the Annulus Safety Valve (ASV) is to be a well barrier against the gas in the annulus in order to prevent leakage, in addition to being a well barrier against the reservoir. Consequently, the ASV is a part of the primary barrier during gas-lift operations, as defined in Norsok D-010.

Gas lift is used to make the produced fluid lighter, when the reservoir pressure does not provide the required pressure. As reservoirs continue to get depleted, an increased use of gas lift on the NCS is expected. Ever since the Piper Alpha incident in 1988, where the ignition of a gas leak resulted in 167 casualties and total destruction of the platform, an ASV has been a required well barrier element for any wells on gas-lift (Ptil, 2012).

The PSA/NPD have the recent years received applications for exemptions related to HSE issues regarding the use of ASV in gas lift wells and as a result, a survey was conducted amongst operator companies to discuss the amount of applications for exemptions to the PSA/NPD, the regulations concerning ASVs and the ability to meet these and the accuracy of risk assessments done (Ptil, 2004).

It was clear from the survey that the installation and workover phase of ASVs significantly contributed to the total risk regarding gas lift operations, and that in subsea installations, the ASV had insignificant risk reducing effects.

Some of the key risk factors with regards to ASV include (Ptil, 2004) (Zwaag, 2004);

- *Type of installation*
- *Type of operations*
- *Number of gas lift wells*
- *Annular Volumes and pressure conditions*
- *Production volumes*
- *Production phase and remaining reservoir energy*
- *Other work (interventions, workovers)*

The industry had together identified and tested other compensating measures to reduce the risk, including (Ptil, 2004) (Zwaag, 2004);

- *Reinforced double block valves*
- *Check valves integrated in the wellhead*
- *Shorter test intervals for double block or check valves*
- *Deep-set safety valves (below production packer)*
- *Automatic depressurization system*
- *Use of inert lifting gas (particularly relevant for intermittent gas lift)*

- *Dual string completions*
- *Gas cap gas lift*
- 

It was concluded with, that a change should be done to the Facilities Regulations regarding the requirement for an Annulus Safety Valve, as the ASV operations could have negative impact on well integrity, and because of the amount of risk compensating measures available. 1st January 2005, the regulation was changed to exclude the specific ASV requirement. The new regulation now read; “*Completion strings shall be equipped with necessary downhole safety valves (SCSSV) in the well flow line and in the production annulus*”

Another factor to consider is the setting depth of the ASVs. Normally the ASV is installed a few hundred feet below sea level. Benefits can be had by moving the setting depth of ASV further down, sub-surface.

The required amount of gas-lift gas required in the annulus is reduced which means the risk related to this gas is reduced. For deep wells this equates to big volumes of gas.

Another risk related to ASV setting depth, is the possibility of vessels colliding with a wells on gas-lift, which could release huge amount of gas to surface. By moving the ASV setting depth further down, the integrity of the annulus containing gas-lift gas is improved.

#### **4.3.6 Wellhead and Xmas tree**

The Wellhead serves as a suspension point casing strings and seals, and as a platform for surface equipment such as X-mas tree. The most common issues regarding the wellhead are leakages from annulus A to annulus B, caused by ineffective sealing in the wellhead.

The X-mas tree is a type of equipment placed on top of the wellhead after completion of the well and consists of an assembly of valves whose primary function is to control the flow of the produced fluid. The X-mas tree is also used for monitoring and measuring purposes.

One of the main well integrity issues regarding the X-mas tree is leaking valves.

In order to mitigate this problem, routinely audits should be done in order to discover leaks, and routinely maintenance should be conducted in order to prevent leaks from occurring and to discover other issues like scale build-up.



Another common problem which affects the X-mas tree is corrosion which may come as a result of the producing fluid. For wells producing from sand-reservoir, erosion caused by sand production could become an issue.



## **Chapter 5. Other factors affecting well integrity**

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In addition to the pre-mentioned well integrity issues, other issues may occur during the lifecycle of a well. These include operational issues, challenges related to geology and human factors. This thesis will however not go into the details of these challenges.

### **5.1 OPERATIONAL CHALLENGES**

Scaling, wax deposits and gas hydration may occur during both drilling and production phase and could cause pressure fluctuations and blockages in pipelines and equipment. A proactive approach, by chemical inhibitors and routinely maintenance is desirable.

Sand production could occur from sandstone reservoirs and could erode pipelines and equipment and affect the casing integrity. Also here, a proactive approach is recommended by using proper sand-control methods in order to reduce sand-production issues.

### **5.2 GEOLOGICAL CHALLENGES**

When hydrocarbons are produced from a reservoir, a reduction in reservoir pressure is seen. This may call for the need of artificial lift methods, like injection or gas-lift to maintain production. A secondary consequence as the liquid is removed is the compression of the pores in the rock, which could lead to a subsidence of the entire field. A subsidence of the reservoir causes a ripple effect where even the seabed subsides. This affects both platforms and wells and could cause major well integrity problems.

In the mid-1980s, this phenomenon was observed in the Ekofisk field which led to an operation, where the platforms on the Ekofisk field had to be jacked up 6 meters, an operation later known as the ‘great jack-up’. Re-injection could however slow down the subsidence. This is also something that could be taken into account when designing new fields and platforms.

A more situational dependent issue is tectonic movement and earthquakes, which could cause displacement of well and consequently lead to well integrity related issues.

## **5.3 HUMAN FACTORS**

In almost every well incident and major blowout that has occurred, the human factor has always played a vital role. In order to reduce the influence of the human factor in well operations, it is important that the people involved have sufficient well integrity competence.

Proper training of personnel could act as a strong barrier against unwanted accidents. Another factor that improves safety is a broad, collective group-experience, meaning the personnel as a whole has experience and competence from different types of operations or have various professional backgrounds. In recent years this factor has been covered by the use of integrated operations where information is shared amongst several experts with different backgrounds.

## **Chapter 6. Blowouts**

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Exploration drilling, workover and development drilling are the operations most prone to blowouts and kicks, due to drilling into high pressure zones, swabbing effects, formation breakdown or barrier failures. Having reliable information about formation pressure and planning accordingly is a vital preventive step.

Well control is continuously improving by enhanced technology and required blowout schools, but the challenge of detecting, handling and controlling kicks for offshore workers remain more or less the same. Technology might improve safety and productivity, but also pushes the boundaries with respect to what is controllable. Drilling in deeper waters, forcing a deeper setting point of surface casings, combined with diverter-less drilling will increase the risk, and are often not met with corresponding procedures for kick detection and killing procedures. Big improvements have however been made the last decades with respect shallow gas safety, like shallow seismic and kick detection for floating rigs.

## 6.1 BLOWOUT DATABASES

Lessons can be learned by looking at some of the common causes for blowouts and well releases, and by sharing this knowledge perhaps reduce the probability of such events happening in the future. As a result of this, blowout databases can prove to be a useful tool for analyzing blowouts and trends, and building an understanding so that blowout can be avoided.

### 6.1.1 Gulf Coast Blowout database

To further understand and mitigate blowouts in order to avoid costs and loss of lives, a study initiated by Hughes, Podio and Sepehroori was conducted in the Gulf coast area and adjoining states (Skalle, et al., 1998). The aim of the study was to create a database with blowout data.

From the period 1960-1996, blowout data from over 800 blowouts was gathered by contributions from the companies;

- State Oil and Gas Board of Alabama
- Louisiana Office and Conservation
- Mississippi State Oil and Gas Board
- Texas Railroad Commission (RRC)
- Minerals Management Service (MMS) (Outer continental Shelf)

Well reports were not mandatory in the US before 1973 and data gathered from before this time is often insufficient or inaccurate. A distinction between well kicks and blowout was also not clear at this time, and were often reported together. Well events from before 1960 was therefore excluded from the database. Data quality was however improved later on, especially after 1973 when reports were made mandatory.

Kicks causing extraordinary problems like stuck pipe, loss of circulation, and underground communication have been included in the database while well kicks circulated out in a controlled manner have not.

As of December 2011, 17 companies are contributing data to this database.

**Drilling activity vs. Blowouts**

By analyzing the database, trends and statistics are revealed. As seen in Figure 31, numbers of blowouts were at its highest in the early 80s. This corresponds to the high level of well activity in this period as seen on Figure 32.

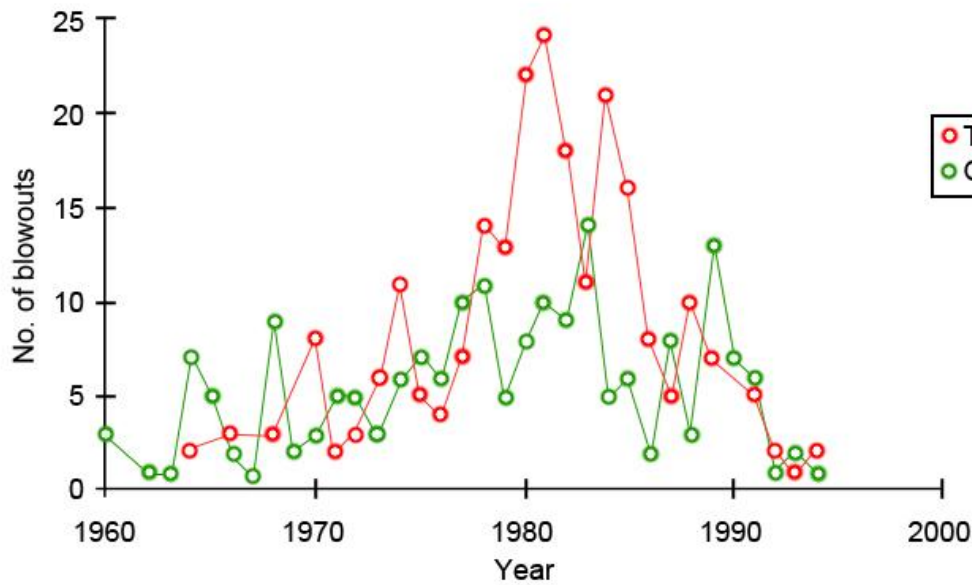


Figure 31: Blowout frequency in the US [Based on (Skalle, et al., 1998)]

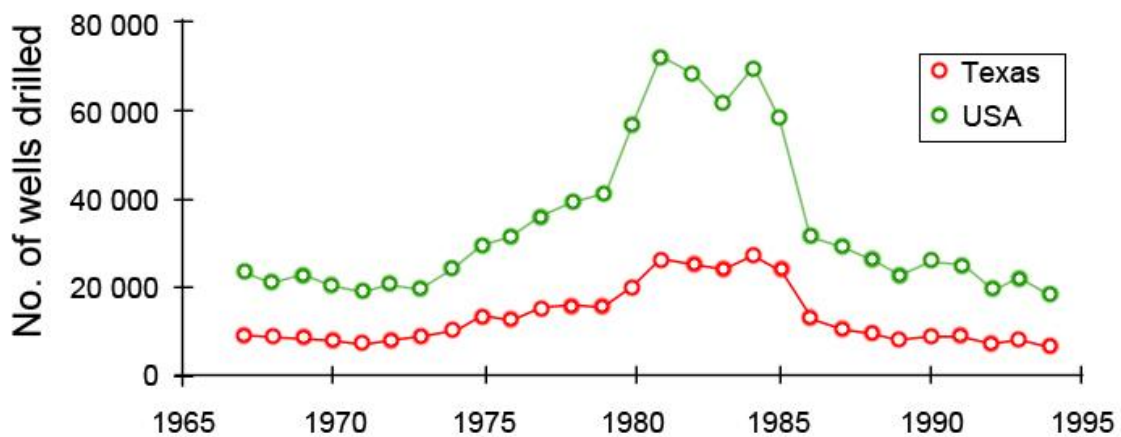


Figure 32: Well activity in the US [Based on (Skalle, et al., 1998)]

As seen in Table 4, Texas contributes to around 50% of the total amount of blowouts in the database, when looking at blowouts between 1960 and 1996.

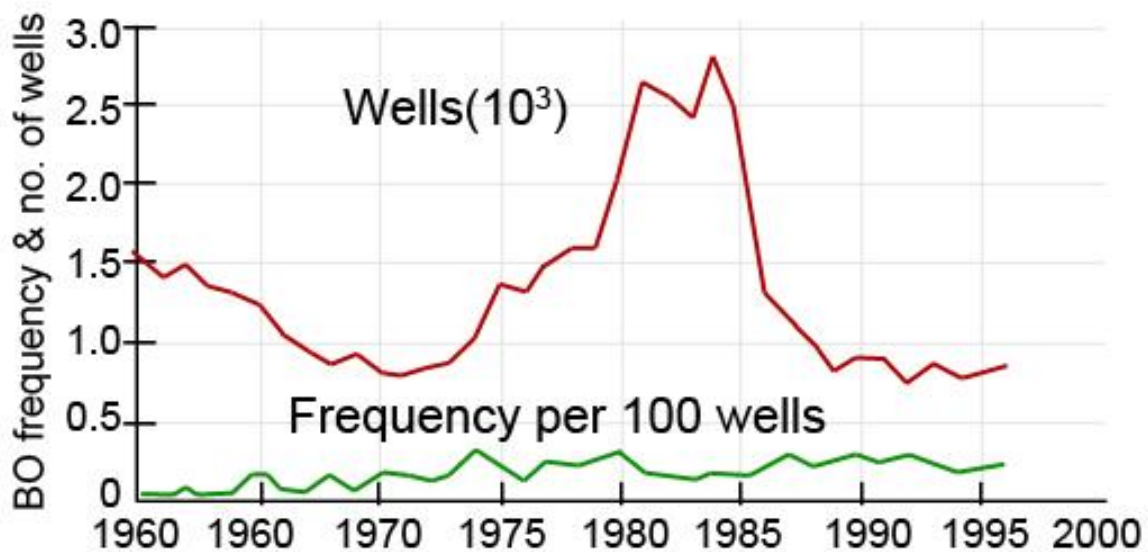
**Table 4: Overall activity and no. of blowouts between 1960 and 1996 [Based on (Skalle, et al., 1998)]**

Area	No. of blowouts	No of drilled wells	Footage drilled	Blowouts pr.	
				100 wells	1000 ft
Alabama	9	**	**	**	**
Louisiana	123	29 000		0.42	
Mississippi*	20	11 000		0.18	
OCS*	245	180 000		0.14	
Texas*	450	310 000		0.15	
All	847	530 000		0.16	

\* Estimated value before all data has been compiled.

\*\* Missing data.

By normalizing well activity and number of blowouts, a blowout risk assessment can be made. This is done by dividing blowout frequencies on amount of wells being drilled. In Figure 33, blowout frequencies for Texas are presented.



**Figure 33: Blowout frequencies for Texas [Based on (Skalle, et al., 1998)]**

As seen, the blowout frequency in Texas is stable and seems independent of the activity level, despite the fact that Texas contributes to around 50% of the activities.



During this period, improvements were done to regulations, equipment inspection and blowout prevention training for drillers and supervisors. Despite the improved this made in kick detection and kick control, no noticeable improvements were observed.

This could be explained by the fact that the drillers were paid per foot drilled, and therefore might've compromised the increased kick safety by increasing drilling rate, reducing non-productive time, tripping too fast or check for minor influxes in order to maximizing revenue.

**Blowout depths**

Blowouts in Texas and Outer Continental Shelf (OCS) were also compared to the depths at which they occurred.

Deeper wells experience greater well pressure from high pore pressure gradients, increased exposure time from open-hole sections, increased tripping time and are more prone to lost circulations problems. They should in theory experience more blowouts than shallow wells.

From

Figure 34 however, it is observed that most blowouts occurred at shallow depths.

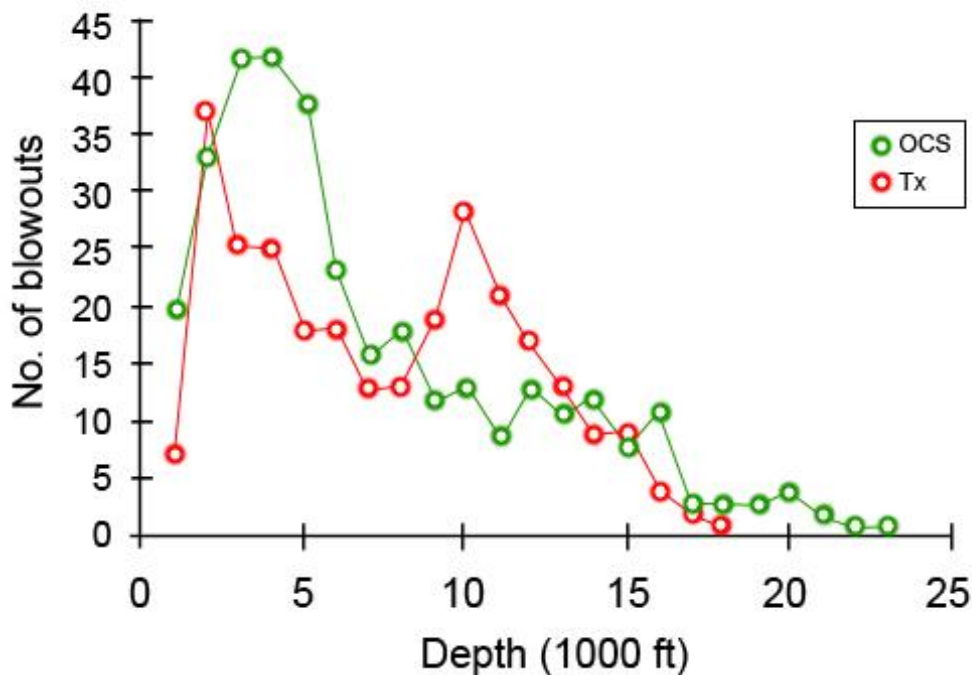


Figure 34: Blowouts in Texas and OCS vs. Depth [Based on (Skalle, et al., 1998)]

This can be explained by the fact that the number of wells drilled at this depth, heavily outweighs the number of deeper wells, and therefore are more likely to experience a blowout. By looking at the last casing set before the blowout occurred (Figure 35), and thereby

excluding the number of wells factor, it is observed that blowout frequencies are greater for smaller casing diameters, i.e. deeper wells, as expected.

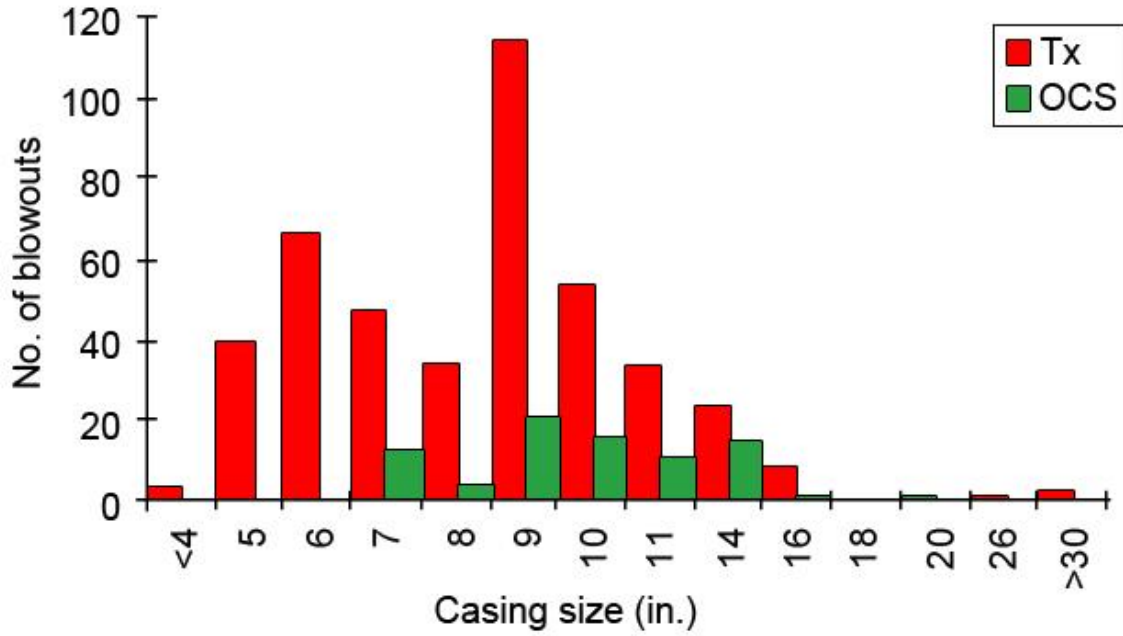
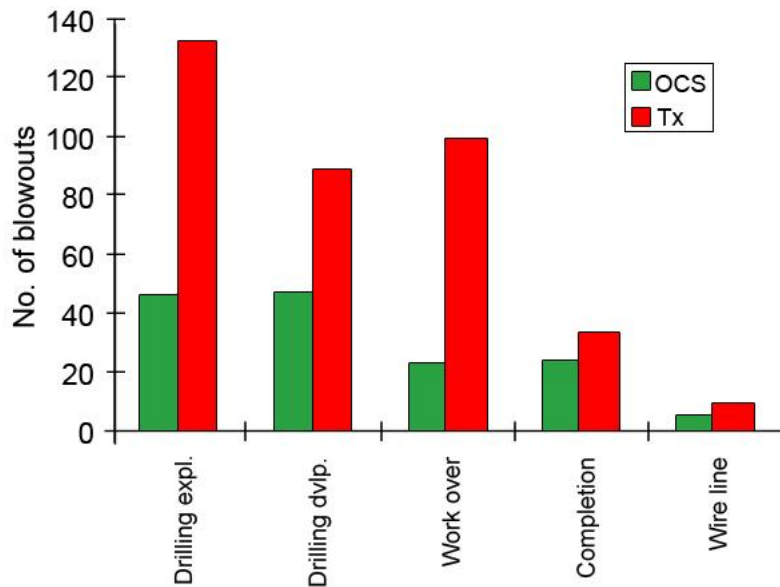


Figure 35: Number of blowouts in Texas and OCS vs. casing size [Based on (Skalle, et al., 1998)]

**Type of Operation**

Blowout frequencies heavily depend on what type of operation which is active. In Figure 36, number of blowouts is shown vs. various active operations, such as exploration drilling, development drilling, workover, completion and wire line operations.



**Figure 36: Blowouts vs. operation type for Texas and OCS wells [Based on (Skalle, et al., 1998)]**

As observed, most blowouts occur in the drilling phase, specifically during drilling into unknown geology, tripping and being out of the hole. Drilling into unknown geology might present a challenge with regards well control, due to higher formation pressure than expected, combined with low mud weight, gas cut or swabbing. Another common issue is formation breakdown due to high ECD, causing fractures and loss of circulation.

A full list of barrier failure frequencies causing blowouts is presented in Table 5.

**Table 5: Most frequent barrier failures for all phases (Louisiana + Tx + OCS) [Based on (Skalle, et al., 1998)]**

Primary barrier	BO	Secondary barrier	BO
Swabbing	158	Failed to close BOP	78
Low mud weight	50	Rams not seated	14
Drilling beak/ unexp. high pressure	45	Unloaded too quickly	13
Formation breakdown/Lost circ.	43	DC/Kelly/TJ/WL in BOP	5

Wellhead failure	40	BOP failed after closure	66
Trapped/expanding gas	40	BOP not in place	43
Gas cut mud	33	Fracture at casing shoe	38
X-mas tree failure	23	Failed to stab valve/Kelly/TIW	34
While cement setting	20	Casing leakage	23
Unknown why	19	Diverter – no problem	21
Poor cement	16	String safety valve failed	19
Tubing Leak	15	Diverter failed after closure	17
Improper fill up	13	Form. Breakdown/Lost circ	15
Tubing burst	10	String failure	13
Tubing plug failure	90	Casing valve failed	11
Packer leakage	6	Wellhead seal failed	10
Annular losses	6	Failed to operate diverter	7
Uncertain reservoir depth/pressure	6	X-mas tree failed	7

### ***Improvements***

In order to break the trend discussed earlier to maximize revenue by ignoring well safety, Wylie & Visram made suggestions that could improve well safety offshore.

By changing footage-contract for day work contracts, workers would no longer take unnecessary risks in order to make profit (Skalle, et al., 1998). Operators could also take greater care by specifying minimum mud density, as this is one of the main causes of well kicks, as seen in Table 5. A bonus program, focusing on minimizing kicks could also prove useful.

Better reporting of well kicks was also proposed. Every kick report should be made public and reviewed and analyzed. In that way they could provide the industry with better understanding and knowledge of well kicks, which could then be used to improve understanding and mitigation of well kicks and blowouts.

## 6.1.2 SINTEF Blowout Database

SINTEF initiated in 1984 a blowout database, containing well description, drilling and production data, with input from several companies (Holand, et al., 2011). The data contributed are of wells from all over the world, but data from the NCS and the GoM are more substantial and can therefore provide a better picture of trends in these places. In order for the database to have consistent data, a set of definitions have to be in place.

### **Blowout definition**

The SINTEF blowout database uses PSAs definition of a blowout, found in “Activity Regulations”; *“A blowout is an incident where formation fluid flows out of the well or between formation layers after all the predefined technical well barriers or the activation of the same has failed”* (Ptil, 2012).

### **Well release definition**

An incident is a well release if oil or gas flowed from the well from some point where flow was not intended and the flow was stopped by use of the barrier system that was available on the well at the time the incident started.

### **Shallow gas definition**

Any gas zone penetrated before the BOP has been installed. Any zone penetrated after the BOP is installed is not shallow gas.

This is the typical Norwegian definition, but for some GoM incidents this is not valid because the reservoir there varies greatly in depth, and sometimes the wells are drilled deep before the BOP is installed, or a diverter is used.

It is therefore not easy to differentiate between shallow gas and blowout in many cases.

### **Database structure**

To build up a detailed and descriptive database of the blowouts, several fields of data have to be entered. 51 fields, grouped into six main categories are used to describe the blowouts in detail:

“1. Category and location”, describes the severity of the well incident, whether it’s a well leak or a blowout, the location of the well, operator, type of installation and water depth.

“2. Well description” is more detailed information about the well, such wellbore and casing depths, casing size, mud weight, pressures, Gas Oil Ratio (GOR) and formation data.

“3. Present operation” describes what kind of phase (exploration, workover etc.), operation (running casing etc.) and activity (cementing etc.) that was active when the blowout occurred.

“4. Blowout causes” describes any potential external causes for the blowout, loss of any barriers and explanation of how these were lost, and any relevant human factors.

Human factors are often not regarded as reliable info as these data are frequently masked.

“5. Blowout characteristics” describe aspects like flow-path, flow-rate, release point, ignition type, duration, fatalities and losses.

“6. Other” includes control method, remarks that describe the incident, data quality, revision date and references.

The purpose of the database is to give an overview of the offshore blowouts, well release characteristics and frequencies. By analyzing data with regards to blowout frequencies, a risk assessment can be made and estimate the likelihood of a blowout to occur.

When analyzing frequencies of blowouts it is practical to compare installations with similar standards. The SINTEF Blowout database uses the North Sea Standard as one measurement of the quality, a standard which can be applied to both North Sea and GoM installations (OGP - Risk Assessment Data Directory, 2010).

The result of the International Association of Oil & Gas Producers (OGP) risk assessment report is presented in Figure 37 . It shows blowout frequencies from offshore installations from GoM, OCS, UKCS, and NCS from the period 1<sup>st</sup> January 1980 to 1<sup>st</sup> January 2005.

The numbers presented are from installations with North Sea Standard and should only be used as a risk assessment tool for NCS and GoM installations. It could also be used for non-North Sea installations, given that the standard is on the same level.

Blowout and Well Release Frequencies for Offshore Operations of North Sea Standard						
Operation	Category	Frequency				Fraction Subsea
		Average	Gas	Oil	Unit	
Exploration Drilling, shallow gas	Topside Blowout		$6.0 \times 10^{-4}$	-	per drilled well	
	Diverted Well Release		$8.3 \times 10^{-4}$	-	per drilled well	
	Well Release		$9.3 \times 10^{-5}$	-	per drilled well	
	Subsea Blowout		$9.8 \times 10^{-4}$	-	per drilled well	
Development Drilling, shallow gas	Topside Blowout		$4.7 \times 10^{-4}$	-	per drilled well	
	Diverted Well Release		$6.5 \times 10^{-4}$	-	per drilled well	
	Well Release		$7.3 \times 10^{-5}$	-	per drilled well	
	Subsea Blowout		$7.4 \times 10^{-4}$	-	per drilled well	
Exploration Drilling, deep (normal wells)	Blowout	$3.1 \times 10^{-4}$	$3.6 \times 10^{-4}$	$2.5 \times 10^{-4}$	per drilled well	0.39
	Well Release	$2.5 \times 10^{-3}$	$2.9 \times 10^{-3}$	$2.0 \times 10^{-3}$	per drilled well	0.39
Exploration Drilling, deep (HPHT wells)	Blowout	$1.9 \times 10^{-3}$	$2.2 \times 10^{-3}$	$1.5 \times 10^{-3}$	per drilled well	0.39
	Well Release	$1.6 \times 10^{-2}$	$1.8 \times 10^{-2}$	$1.2 \times 10^{-2}$	per drilled well	0.39
Development Drilling, deep (normal wells)	Blowout	$6.0 \times 10^{-5}$	$7.0 \times 10^{-5}$	$4.8 \times 10^{-5}$	per drilled well	0.33
	Well Release	$4.9 \times 10^{-4}$	$5.7 \times 10^{-4}$	$3.9 \times 10^{-4}$	per drilled well	0.33
Development Drilling, deep (HPHT wells)	Blowout	$3.7 \times 10^{-4}$	$4.3 \times 10^{-4}$	$3.0 \times 10^{-4}$	per drilled well	0.33
	Well Release	$3.0 \times 10^{-3}$	$3.5 \times 10^{-3}$	$2.4 \times 10^{-3}$	per drilled well	0.33
Completion	Blowout	$9.7 \times 10^{-5}$	$1.4 \times 10^{-4}$	$5.4 \times 10^{-5}$	per operation	0
	Well Release	$3.9 \times 10^{-4}$	$5.8 \times 10^{-4}$	$2.2 \times 10^{-4}$	per operation	0
Wirelining	Blowout	$6.5 \times 10^{-6}$	$9.4 \times 10^{-6}$	$3.6 \times 10^{-6}$	per operation	0
	Well Release	$1.1 \times 10^{-5}$	$1.6 \times 10^{-5}$	$6.1 \times 10^{-6}$	per operation	0
Coiled Tubing	Blowout	$1.4 \times 10^{-4}$	$2.0 \times 10^{-4}$	$7.8 \times 10^{-5}$	per operation	0
	Well Release	$2.3 \times 10^{-4}$	$3.4 \times 10^{-4}$	$1.3 \times 10^{-4}$	per operation	0
Snubbing	Blowout	$3.4 \times 10^{-4}$	$4.9 \times 10^{-4}$	$1.9 \times 10^{-4}$	per operation	0
	Well Release	$1.8 \times 10^{-4}$	$2.6 \times 10^{-4}$	$1.0 \times 10^{-4}$	per operation	0
Workover	Blowout	$1.8 \times 10^{-4}$	$2.6 \times 10^{-4}$	$1.0 \times 10^{-4}$	per operation	0
	Well Release	$5.8 \times 10^{-4}$	$8.3 \times 10^{-4}$	$3.2 \times 10^{-4}$	per operation	0
Producing Wells (excluding external causes)	Blowout	$9.7 \times 10^{-6}$	$1.8 \times 10^{-5}$	$2.6 \times 10^{-6}$	per well year	0.125
	Well Release	$1.1 \times 10^{-5}$	$2.0 \times 10^{-5}$	$2.9 \times 10^{-6}$	per well year	0.125
Producing Wells, external causes	Blowout	$3.9 \times 10^{-5}$	$3.9 \times 10^{-5}$	$3.9 \times 10^{-5}$	per well year	0.125
	Well Release	-	-	-	per well year	-
Gas Injection Wells	Blowout	-	$1.8 \times 10^{-5}$	-	per well year	0.125
	Well Release	-	$2.0 \times 10^{-5}$	-	per well year	0.125
Water Injection Wells	Blowout	$2.4 \times 10^{-5}$	-	-	per well year	0.125
	Well Release	-	-	-	per well year	-

Figure 37: Blowout and well release frequencies for offshore operations (Holand, et al., 2011) (OGP, 2010)

As seen from Figure 37, in deep exploration wells, almost 2% of the wells experience well releases. At worst, almost one out of every thousand exploration wells experience shallow gas blowouts. The room for improvement is definitely present.

## 6.2 REPORTED BLOWOUTS & WELL INCIDENTS

Below, some of the major accidents and blowouts the recent years are presented, starting with the Ekofisk Bravo blowout in 1977, to the more recent gas blowout in Totals Elgin field in 2012.

### 6.2.1 Ekofisk B-14 – 1977

#### **Summary**

On April 22<sup>nd</sup>, 1977, the production platform B-14 on the Phillips Petroleum Norway operated (Now ConocoPhillips); Ekofisk field experienced an oil and gas blowout (Granskingskommisjonen oppnevnt ved kongelig resolusjon, 1977).

The incident happened during a workover when 10 000 feet of production tubing was to be pulled out of the well. Before pulling the tubing, a Downhole Safety Valve (DHSV) was planned to be installed, followed by removal of the X-mas tree and finally installation of the BOP.

In the time period between removing the X-mas tree and installing the BOP, the only barriers in the well are the DHSV and the heavy mud. It was in this time period the blowout occurred.

The DHSV was later found on deck without visible damage; it had been blown out of the tubing. This finding lead to the conclusion, that the DHSV had not been locked into the seating nipple during the installation. There were two warning signs however, which meant the blowout could've been avoided if proper actions had been taken.

1. Mud was observed flowing out of the control line from the DHSV.
2. After removal of the X-mas tree, mud was seen flowing up through the tubing.

A follow-up on any of these warnings could've resulted in ceasing of the operation.

A workover program, approved by the Norwegian Petroleum Department (NPD), had in 1976 been made where it was stated that a back pressure valve was to be installed in the tubing



hanger. No drawings or documentation were made to determine whether or not the tubing hanger used on the B-14 well were of the type where this was possible. It was therefore decided to use a DHSV instead. In addition, the already approved well kill program was changed. The NPD was not informed of any of these changes, which is a violation of the regulations.

It was also discovered in the report following the blowout, that it required seven attempts to install the DHSV, and that the work was characterized by improvisations and disagreements between the crew. On the final attempt of installing a DHSV, technical difficulties occurred which lead to the DHSV not being locked in place. This was not done, and the DHSV was also not pressure tested. At this point, the operator had not slept for over 30 hours, and may have played a part in the decision making process.

The installation of the BOP was also a process that was slowed down, as this was dismantled into two parts when the X-mas tree was removed. The time period between the removal of the X-mas tree and the installation of the BOP should be as little as possible as this is a very critical time frame. Had the BOP been installed earlier, the blowout might've been prevented.

### **Conclusion**

The following barriers were breached on the Bravo-14 well:

**Table 6: Bravo-14 barrier breaches**

Barriers breached / Causes	Comments
Regulations	❖ Insufficient reporting of changes
Organization	❖ Improper documentation ❖ Weaknesses in the WO program ❖ Improper planning of work
Human factor	❖ Improvisation of procedures ❖ Misjudgment of critical situations ❖ Weak leadership and control
Valves	❖ DHSV not properly locked in place

## 6.2.2 Saga 2/4-14 – 1989

### **Summary**

In October 1988, Saga Petroleum drilled a wildcat subsea exploration well, 2/4-14, with the semi-sub Treasure Saga (NPD, 2012) (Ølberg, et al., 1991) (Leraand, et al., 1992) (Aadnøy, et al., 1990). Drilling went on without problems until they reached the 8 ½” section at a depth of 4713m near the top of reservoir, where the pore pressure increased rapidly from 1,65 s.g. to 2.11 s.g. The return mud became significantly less dense than it should be; indicating a gas cut had been made. The gas reading was 68% at the highest.

Mud weight was increased to 2.10 s.g., giving the mud a weight close to the fracture gradient, and an equivalent circulating density (ECD) above the fracture gradient, at the given pump rate.

Several weak formations were encountered, resulting in a small margin between potential influx and lost circulation. After a well kick occurred at 4734m with a 6.5m<sup>3</sup> gain, the well was shut in. Attempts were made to regain control but were unsuccessful.

It was decided to cement the bottom-hole assembly and sidetrack.

During pumping of the cement, the drill pipe became plugged, and coiled tubing was run in to clear the obstructions.

During this period, well control was lost, causing the shear-rams to cut the drill pipe, leaving approximately 4500m of drill pipe with coiled tubing in the hole (Figure 38). With the BOP closed, the shut in wellhead pressure reached 10 000 psi.

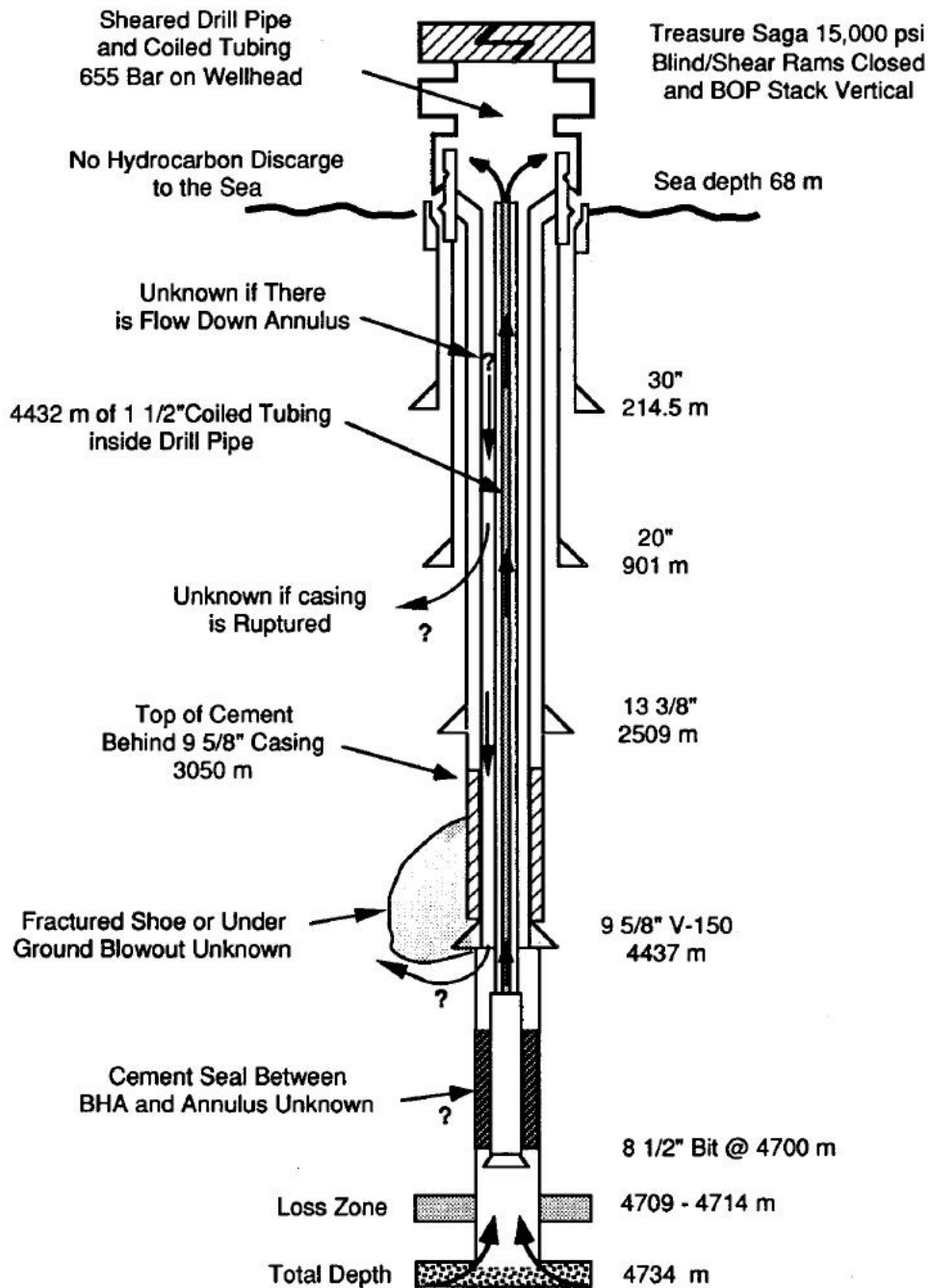


Figure 38: Status of well 2/4-14 after BOP closed (Ølberg, et al., 1991)

The well was now turning into an underground blowout, a situation where the uncontrolled reservoir fluid flows from one reservoir, along the wellbore and into another reservoir (Schlumberger, 2012). These blowouts are generally a more expensive affair than surface blowouts and a second relief or kill well are often necessary to regain control.

A bull heading operation with heavy mud was attempted down the kill line but the flex hose burst. A safety plug and a no-go cap was placed in the BOP and the annular preventer (AP) was closed. The well was now suspended, awaiting re-entry by a different rig. Treasure Saga was pulled off location.

A plan was made to start a high pressure snubbing operation, in order to fish the tubing and CT out of the hole so it could be plugged satisfactory. Parallel to this, a kill well was being drilled (2/4-15S), in case killing the well with 2/4-14 was unsuccessful.

January 31<sup>st</sup> 1989, Treasure Saga started drilling the relief well, 2/4-15S, about 1 km south of well 2/4-14.

The well was planned as build, hold and drop well as seen in Figure 39.

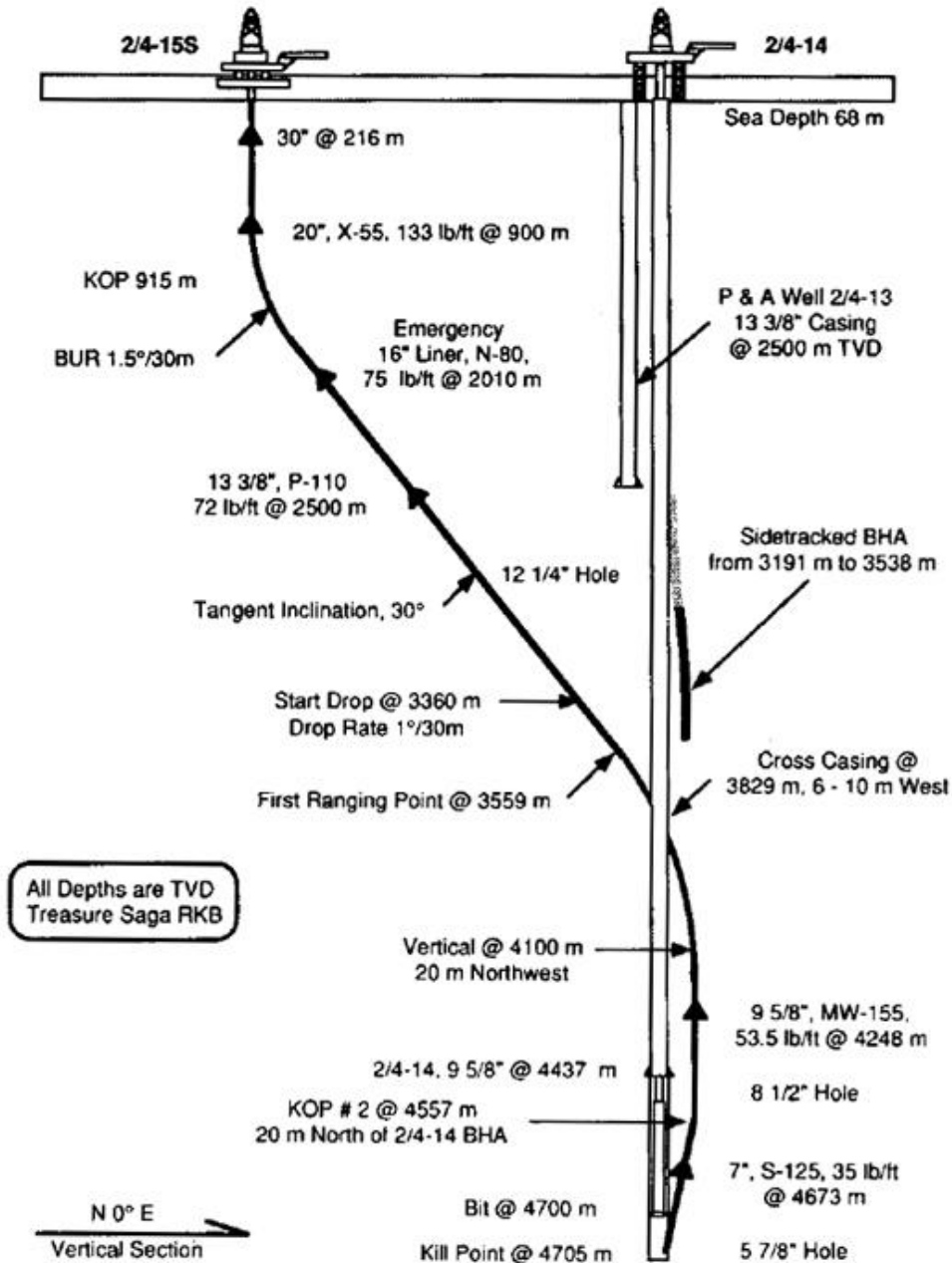


Figure 39: Planned well trajectory of the relief well (Ølberg, et al., 1991)

The relief well was considered a challenging operation because of the great depth, high temperatures, unknown reservoir parameters and the fishing operation needed in well 2/4-14.

May 1<sup>st</sup> 1989, re-entry of 2/4-14 well commenced, using the jack-up drilling rig, Neddrill Trigon. It was discovered that the wellhead pressure had decreased from 10 000 psi to 2800 psi.

Five possible explanations were presented;

- 1) An underground cross flow below the 9 5/8" casing shoe.
- 2) Bridging of the well after fracture of the 9 5/8" casing shoe.
- 3) Bridging of the well after bursting of the 9 5/8" casing.
- 4) Underground blowout through the bursted 9 5/8" casing.
- 5) Initial gas on top of the well had gone back into solution after the well had bridged.

Option #2 was elected the most likely scenario based on the design parameters of the 9 5/8" casing and the stability of the pressure.

May 9<sup>th</sup> 1989, the drill pipe was reconnected and three days later, fishing of the coiled tubing started. Indications of well flow were seen, and to verify, a packer was set in the drill pipe below the packoff overshot. This packer was blown out of the drill pipe. A production logging tool (PLT) was run inside the drill pipe which confirmed the leak in the overshot with a flow of 2900 m<sup>3</sup>/d (18 000 bbl/d). Shallow seismic were shot and indicated an anomaly in the sand formation at 828-878 m depth. It was concluded that an underground blowout was happening, with the 9 5/8" and the 13 3/8" casing most likely bursted.

In the relief well, 2/4-15S, the 9 5/8" had now been set. As the work began to replace the leaking packoff overshot in well 2/4-14, a sharp increase in gas readings were observed in the relief well. This was believed to be caused by either fractures around the 9 5/8" casing shoe, representing a permanent communication, or by the pressure increase in bottom hole pressure in 2/4-14 as a result of the bullheading operation. To verify, drilling of the relief well was suspended for five weeks, and gas readings were observed. It was concluded that the increase in gas readings were due to the bullheading operation and that there were no permanent communication.

To kill the well, it was decided to use both 2/4-14 and 2/4-15S together.

In 2/4-14, a tieback string with a purpose built packer was planned to be run. A sliding sleeve installed above the packer could be set at an open position, allowing the tie back string to be run in the hole without the experience of a massive differential pressure.

The drill pipe had by this time been cemented, and cut at 4061m.

A PLT run showed that the well was flowing through the bottom hole assembly (BHA) and cut drill pipe with a flow of 5100 m<sup>3</sup>/d (32 000 bbl/d) and a pressure of 3770 psi.

By October 15<sup>th</sup> 1989, the cut drill string had been fished out of the hole, and as a last preparation before running the tie-back and packer, a milling assembly was run in order to verify that no obstructions were left in the hole. When pulling the milling tool out of the hole, it came apart above the back pressure valves resulting in a minor blowout. The shear rams were activated and the well was shut it.

The situation now worsened as not only the drill pipe had to be recovered, but the 9 5/8” casing had also parted, preventing the tieback plan (Figure 40).

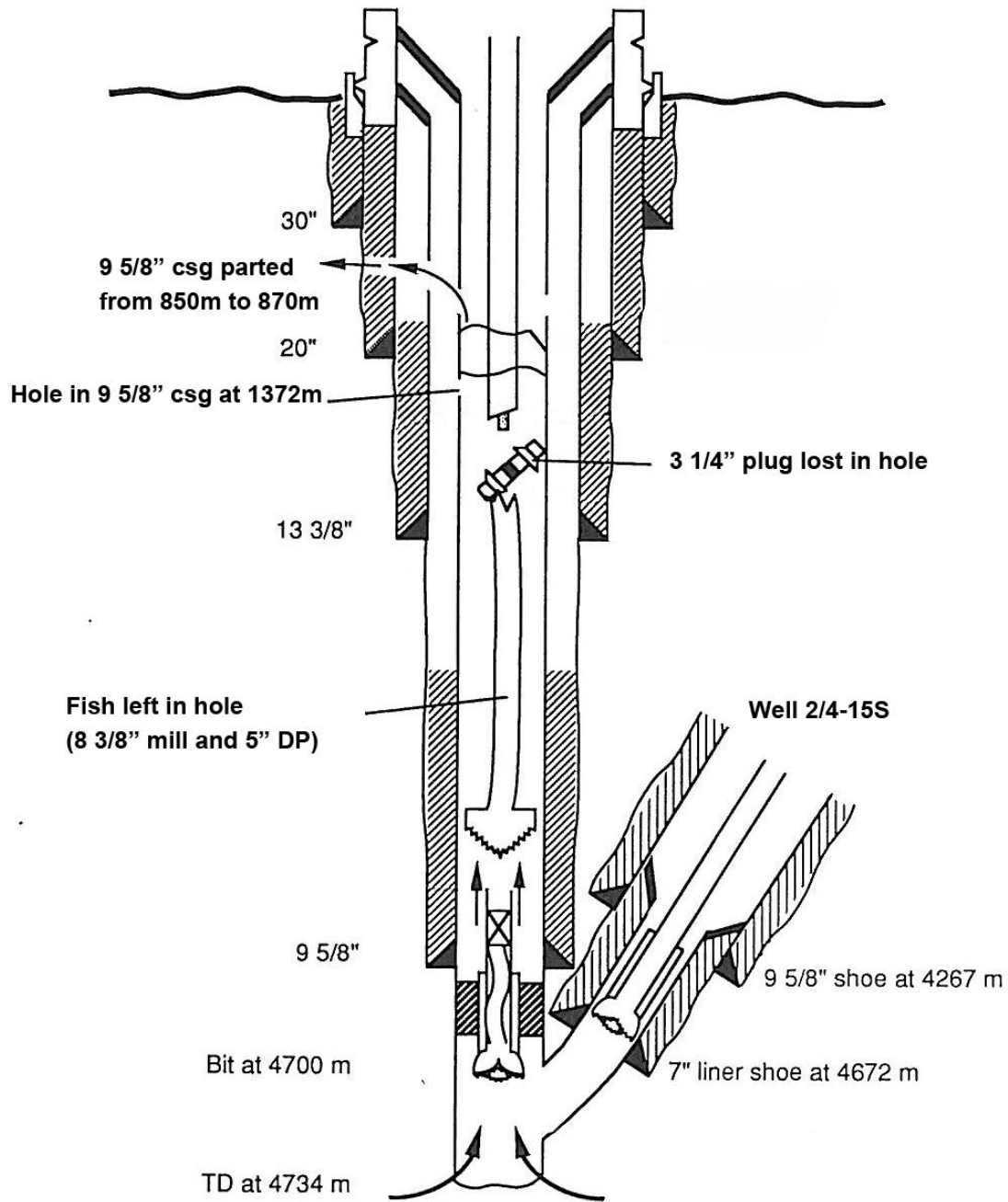


Figure 40: Status of the wells before kill operation started [Based on (Hide, 1994)]

Initially, a dynamic kill operation was planned, and a two-phase pipe flow simulation was run to more accurately determine the needed kill fluid volumes, duration of pumping periods and time plots of important parameters. A dynamic kill uses frictional pressure as a supplement to the hydrostatic pressure in order to kill the well.

The stimulation vessel Big Orange 18, and the supply boat Far Scotchman, were aiding in the kill operation by providing additional storage and pumping of kill mud.



A 2.25 s.g. leakoff test (LOT) was performed in the relief well. A mud weight of 2.25 s.g. was planned for the well kill so a high LOT was essential. A special made drill bit with increased nozzle flow area was used, in order to avoid any potential plugging if pumping of loss circulation material (LCM) was needed.

As drilling of the relief well, 2/4-15S continued, an instant 1m drop of the drill bit occurred at 4705m TVD. Return of mud ceased, indicating that communication between the two wells was established. Mud was lost from the relief well at a rate of 12 barrels per minute but was constantly topped up with 1.95 s.g. mud.

After a PLT showed that all the mud lost from the relief well were entering the 2/4-14 well, 2.25 s.g. kill mud was pumped down the well followed by a temperature degradable mud plug. The hydrostatic pressure killed the well.

The work now began to clear the well for all junk. By March 2<sup>nd</sup> 1990, the parted 9 5/8" casing had been recovered down to 890m and the well cleared to 3650m. By April 14<sup>th</sup>, 1990 the well was finally plugged and abandoned.

One of the success factors for this operation were the continuously maintenance and developing of contingency plans. The use of a kill simulator proved a valuable tool for planning of the kill operation. The chosen relief well path showed a reduced ellipse of uncertainty, giving a high probability of hitting the main well.

During the handling of this blowout, a rock mechanics theory, regarding borehole breakthrough was developed. Borehole breakthrough occurred when the wellbores were approximately 1m apart, and nearly instantly. Communication between the wells as a result of fracturing is unlikely. Because of the high hoop stress around the flowing well, a fracture would most likely bypass it (Figure 41).

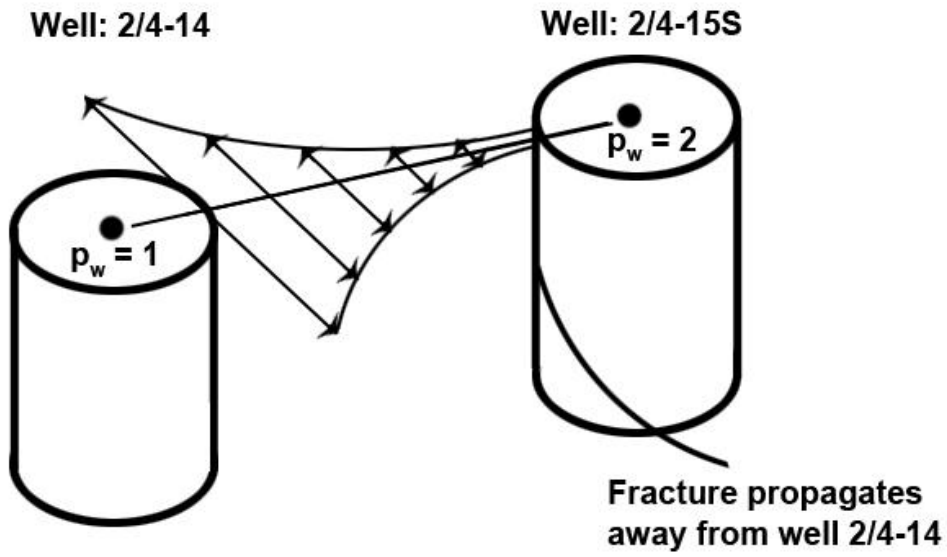


Figure 41: Effect of hoop stress on propagating fractures [Based on (Aadnøy, et al., 1990)]

### Conclusion

The following barriers were breached on the Saga 2/4-14 well:

Table 7: Saga 2/4-14 barrier breaches

Barriers breached / Causes	Comments
Organization	<ul style="list-style-type: none"> <li>❖ Risk management / Well planning</li> <li>❖ Insufficient contingencies (?)</li> </ul>

### **6.2.3 Snorre A – 2004**

#### **Summary**

The Snorre field has been an oil and gas producing field since 1992. The field was operated by Saga Petroleum, until 1999 when Norsk Hydro took over. By the end of 2002, Statoil became then operator of the field. Snorre A is a floating rig, managing drilling and production as well as accommodation facilities.

November 28<sup>th</sup>, 2004, during preparations to drilling a sidetrack, a scab liner was pulled out of the hole, causing gas to enter the well (Brattbakk, et al., 2005) (Ptil, 2004) (SINTEF, 2011).

A scab liner is a repair technique used to isolate a breach or to seal off old perforations and consist of a smaller diameter pipe with packers on top and bottom (SPE, 2012).

The scab liner was initially placed in the well back in 1995 to isolate holes in the 9 5/8” casing as a result of a stuck pipe and related cleanup operations. The breach of the 9 5/8” casing was known to Statoil, and by pulling the scab liner, they were in fact compromising their secondary barrier.

As the liner was removed, gas flowed freely through the hole in the 9 5/8” casing hole, and continued through an unknown breach in the 13 3/8” casing.

This caused a gas seabed blowout to occur (Figure 42), compromising the safety of the 216 people on board the rig. Non-critical personnel were evacuated shortly after the blowout, while the remaining people carried out the emergency response. The situation was under control the following day, and no personnel were injured.

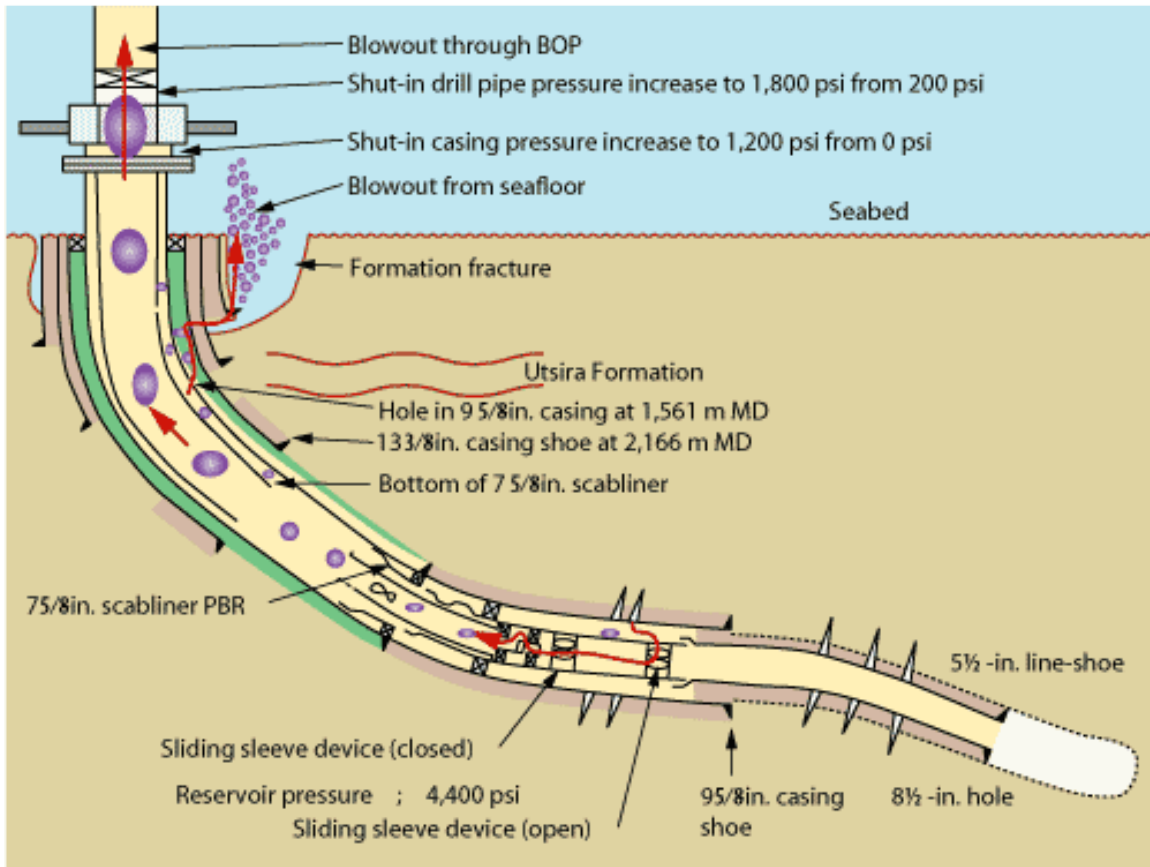


Figure 42: Snorre A – Shallow gas blowout (Wackers, et al., 2008)

The blowout was later characterized by the Norwegian Authorities as the most serious incident to ever have occurred in the North Sea. This was based, not because of the direct consequences of the incident, but of the destructive potential this incident had.

### ***Investigation reports by PSA and Statoil***

An investigation of the incident was launched by PSA, where several flaws in Statoil's organizational barriers was found, including inadequate risk analysis, failure to follow governing documentation, flaws in the management involvement and well barrier breaches (Statoil, 2005). Statoil was ordered by PSA to perform an investigation as well, figuring out what went wrong, and implement measures to prevent similar situations to arise again.

The investigation made by Statoil was based on reviews of documents, questionnaire surveys and by interviewing of involved personnel, both onshore and offshore. Data acquisition was based on the pentagon model, covering;

- Technology and operations
- Formal organization (structure, governing regulations)
- Values, attitudes and competence
- Social relations and network
- Work processes (cooperation, communication, incentive structures, and leadership)

As a result of the investigation, the report painted a picture of a platform, working with a high operational risk where relatively low safety margins were accepted in terms of reviewing potentially risky operations. Reports of serious incidents and near-incidents on Snore A prior to this incident was also brought to light as well as frequent equipment breakdowns and operating problems.

The platform was deemed to be in a reduced technical condition. Statoil had plans to renew the platform, but at the time of the incident, little had been done regarding this.

This was thought to affect attitudes and working habits, which consequentially influenced attention to risk assessment.

It was also reported that knowledge and familiarity with governing documentation varied amongst the workers, due to lack of training or general ignorance, even within their own area of work.

### ***Actions taken and actions planned***

As a result of the investigation, measurements to improve planning, risk assessment and management involvement in drilling operations was implemented by Statoil (Pettersen, et al., 2006). The subsurface group was also strengthened by adding several expert positions.

To increase the awareness and expertise of well integrity control on Snorre, compulsory well integrity seminars has been introduced, which focuses on knowledge transfer and well control. Work has also begun regarding reviewing the well integrity status of Snorre as well as other Statoil operated wells on the NCS.

To improve cooperation and communication between onshore and offshore, Snorre started with daily operational meetings with onshore personnel, discussing drilling programs and

related risks. This way, offshore personnel are more actively involved in preparations regarding well planning and drilling programs.

A subsurface support centre was introduced, providing support, following drilling operations on a day-to-day basis and making sure expertise and knowledge is utilized in well planning and operations.

Other actions were also planned, like upgrading the Snorre platform to ensure it is technical safe and more robust. Personnel with drilling and well expertise were to be added to the subsurface group, to improve quality assurance and risk assessments.

Governing documentation was going to be simplified, and unnecessary documents removed, in addition to implement further training programs to raise the awareness and expertise around this.

Management training and reorganizing of the administrative duties was also planned in order to reduce the work load of operational managers so that they could take a more active part in well planning and management of resources.

**Conclusion**

The following barrier breaches caused the Snorre A incident;

**Table 8: Snorre A barrier breaches**

Barriers breached / Causes	Comments
Casing	❖ Unknown breach in 13 3/8" casing
Regulations	❖ Did not meet barrier requirements ❖ Several other (28 found by PSA) violations of regulations
Organization	❖ Insufficient use of controlling documents / WBS ❖ Insufficient understanding and execution of risk management. ❖ Inadequate management involvement.
Human factors	❖ Bad decision making

## 6.2.4 Montara – 2009

### Summary

On the August 21<sup>th</sup> 2009, the Montara well located in Western Australia experienced a blowout which led to loss of the platform, loss of the *West Atlas* drilling rig, and an oil spill which caused major environmental damages (Australian Government, 2011) (SINTEF, 2011).



Figure 43: Montara well incident (PTTEP Australasia, 2011)

Montara was a suspended well without tested or verified barriers, and one of the barriers that should've been installed was missing (Vignes, 2012). The 9 5/8" casing had been cemented, but even though some challenges occurred during the cement job, no pressure tests were conducted, leaving this "barrier" unverified. Two pressure controlling anti-corrosion caps (PCCC) acting as secondary barrier elements were planned to be installed. However, according to the manufacturer of the PCCCs, these were not suitable as well barrier elements.

Only one (9 5/8") of the planned PCCCs was installed, and this was left untested.

As a result of this, the 13 3/8" casing threads corroded and had to be cleaned, which meant the 9 5/8" PCCCs had to be removed. This meant the well was now left with no tested barriers and only the untested 9 5/8" casing shoe cement remained as a barrier against the reservoir. The fluid left inside the casing, acting primary barrier during drilling operations, was thought to have sufficient overbalance pressure to the pore pressure. This was however not the case, and the fluid was also not monitored.



15 hours after the 9 5/8" PCCC was removed, hydrocarbons started to flow at a rate of an estimated 400 barrels per day. The point of leak was through the cemented casing shoe, and up through the 9 5/8" casing. At this point, the situation was as seen on Figure 44 (PTTEP Australasia, 2011);

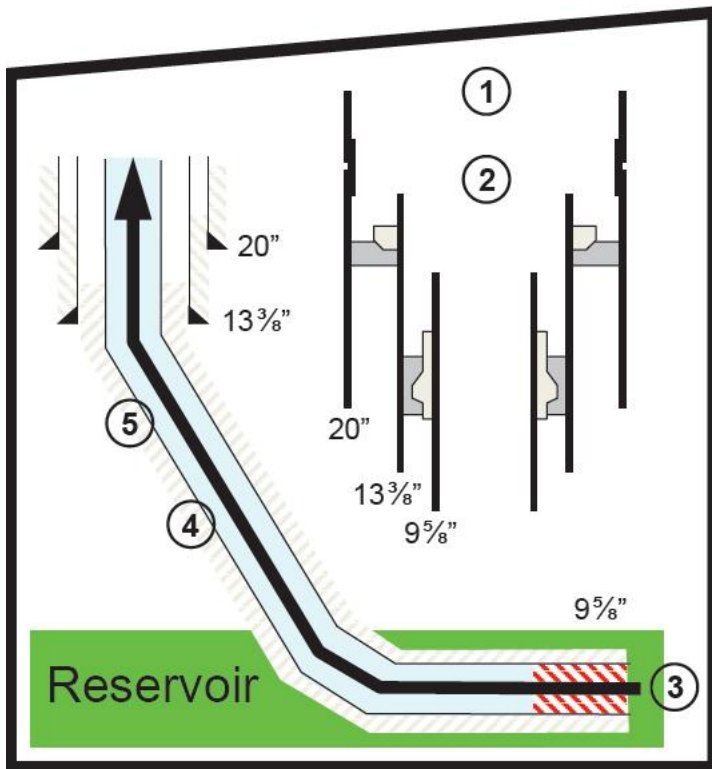


Figure 44: Montara well at the time of the incident (PTTEP Australasia, 2011)

1. No BOP in place
2. No PCCC had been re-installed – well was open to atmosphere
3. There was no effective barrier in the shoe track
4. There was no completion Brine – Casing was filled with seawater
5. There was no isolating cement plug in the upper wellbore

On September 14<sup>th</sup>, 2009, drilling of a relief well started using the *West Triton* rig and after five weeks, the well was successfully intercepted. On November 1<sup>st</sup>, a fire broke out on the West Atlas drilling rig and Montara platform but 2 days later the fire was extinguished and the well killed.

**Conclusion**

The following barriers were breached on the Montara well:

**Table 9: Montara barrier breaches**

Barriers breached / Causes	Comments
Regulations	❖ Failure to maintain two well barriers
Human factor	❖ Failure to verify barrier ❖ Bad decision making.
Organization	❖ Insufficient well integrity competence. ❖ Shortcomings regarding procedures and steering documents. ❖ Lack of communication.

## **6.2.5 Deepwater Horizon - 2010**

### ***Introduction***

One of the most talked about accident the recent years is the Deepwater Horizon accident from April 20<sup>th</sup> 2010. The Macondo exploration well was drilled by a semi-submersible to a depth of approximately 18000 ft. in the Gulf of Mexico when a series of accidents occurred, causing one of the biggest accidents and oil spill in history with a discharge of almost five million barrels during the course of 87 days. In addition to the environmental damages, 11 lives were lost as a result of the fire and explosion (SINTEF, 2011).



**Figure 45: Deepwater Horizon Incident – 2010 (Neatorama, 2010)**

May 22<sup>nd</sup> 2010, president Obama announced the creation of the “National Commission on the BP Deepwater Oil Spill and Offshore Drilling”, an impartial commission in charge of analyzing and finding the cause of the accident, improving the country’s ability to respond to such events and to recommend reforms to make offshore production safer.

As a result of this analysis, a detailed report was made to the president (The bureau of ocean energy management, regulation and enforcement, 2011).

From the report it was concluded that this accident could've been prevented and several identifiable mistakes by BP, Halliburton and Transocean were discovered (BP, 2010) (Hubbard, et al., 2010). Eight critical barrier breaches was said to be the cause of the blowout, which were also found to be the case in BP's official report.

### **Summary**

The well has had some issues in the past; In October 2009 it experienced a kick during a drilling operation. March 8<sup>th</sup>, 2010 another kick was taken, causing the drill pipe to become stuck, leading to cutting of the drill pipe and sidetracking the well.

Once it reached the depth of 18360 feet, slightly shallower than originally planned, the production casing was run. A debate arose because of the design and lack of sufficient centralizers on the production casing. The design indicated that 21 centralizers were needed, but only 7 centralizers were initially supplied. The remaining centralizers were shipped to Deepwater Horizon from Halliburton, but these were thought to be of incorrect size and were not used.

The casing and hydrocarbon formation was cemented and the well was prepared for temporary abandonment to be completed by another rig.

Here, the first barrier was breached. The cement used to on to cement the production casing and hydrocarbon section was not tested before use. Later laboratory tests indicate that the cement used was unstable at these depths and pressures. The cement slurry had high emphasis on preventing loss to formation, compromising important factors like foam stability and contamination. It was believed that a nitrogen breakout occurred in the shoe track, allowing communication between the wellbore and the hydrocarbon formation.

The float collar, a valve allowing fluids to be pumped down, but not up, was not working, and cause hydrocarbons to enter the well undetected.

As per procedure, a positive pressure test was performed. Following this, a negative pressure test was performed in order to test the barriers for high differential pressures.

Fluid returns were higher than expected, indicating breach of barriers; this was however not

recognized by the rig crew. Witnesses also report that the rig crew did not use BP's provided procedure when conducting the pressure test, a nonconformity picked up by the well site leader. The crew continued the pressure test using BP's procedure, a procedure unfamiliar to them, which may have compromised the crew's ability to perform and interpret the test.

During the pressure test, the drill pipe line experienced a pressure of 1400 psi. This was believed by the tool pusher to be caused by a 'bladder' effect. This was accepted by the site leaders and work continued.

As the well become underbalanced again, more hydrocarbons flowed into the well. This influx went undetected, possible caused by simultaneous ongoing operations which distracted the crew from monitoring the well. Drill pipe pressure continued to increase, indicating that hydrocarbons had reached the riser. Well control actions were now taken.

As mud flowed uncontrolled onto the drill floor, the annular preventer was closed, however it did not seal properly. The hydrocarbons were then diverted to the mud gas separator (MGS), a system designed for low pressures only. High pressure gas was discharged from the MGS, and gas alarms were activated. The rig lost power soon after this, following two explosions.

The fires may have caused damage to the Emergency Shutdown (ESD) cables, as the shear ram did not did not activate properly, when ESD was initiated by the supervisor.

A system called AMF (Automated Mode Function) is in place in case of failure to close the BOP. The AMF is controlled by control pods placed on the BOP; these did not active either due to a failed solenoid valve and a battery with insufficient charge.

A third option is to active the BOP from a remote operated vehicle. This did close the seal rams, but they did not seal the well properly, and the well was still flowing.

### ***Results from the investigation***

There was no single event that caused the Deepwater Horizon accident, but instead a series of both organizational and mechanical barrier breaches.

Eight separate critical events caused the major accident.

1. The annulus cement did not isolate hydrocarbons due to nitrogen breakout in the cement (Figure 46).

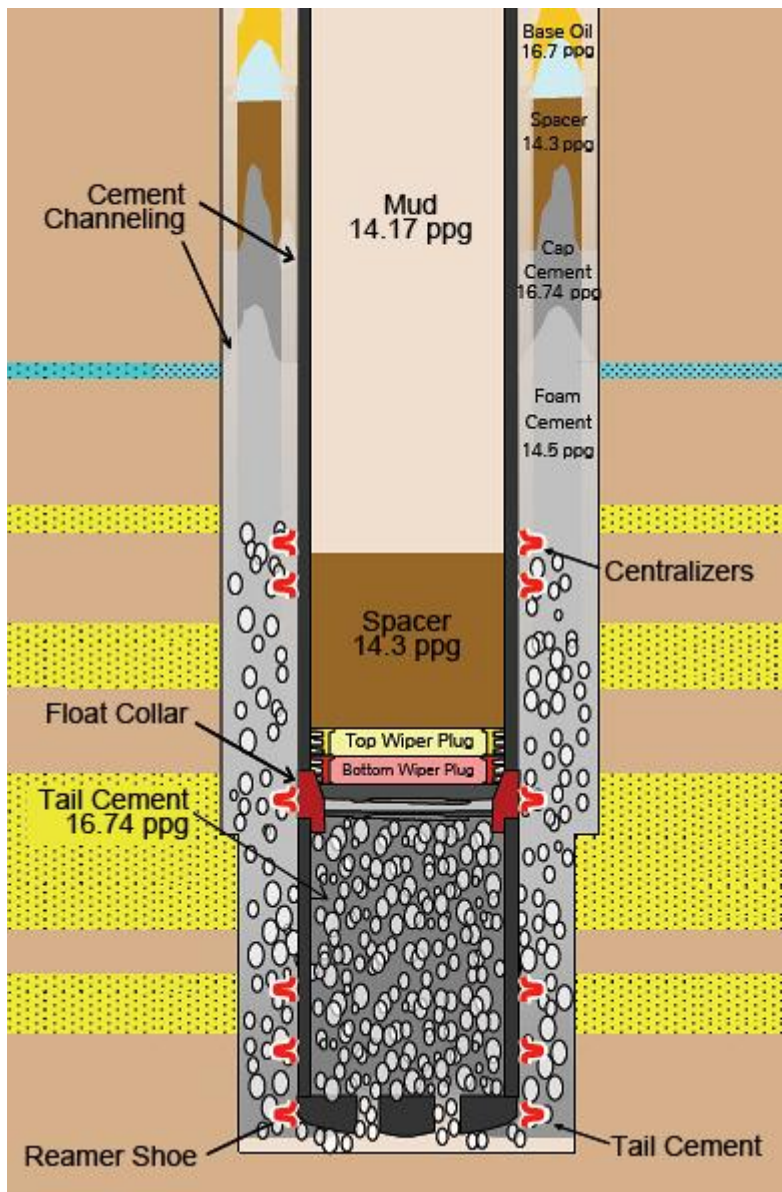


Figure 46: Nitrogen breakout in the cement [Based on (BP, 2010)]

The report shows that there was little focus on foam stability and contamination and that the cement was not tested beforehand. Running a cement bonding log (CBL) was discussed, however it was decided to not run a CBL.

Another fact to consider is that Deepwater Horizon was 41 days behind schedule, and that this might've influenced the decision making.

2. The shoe track barrier consisting of shoe track cement and check valves, was breached.

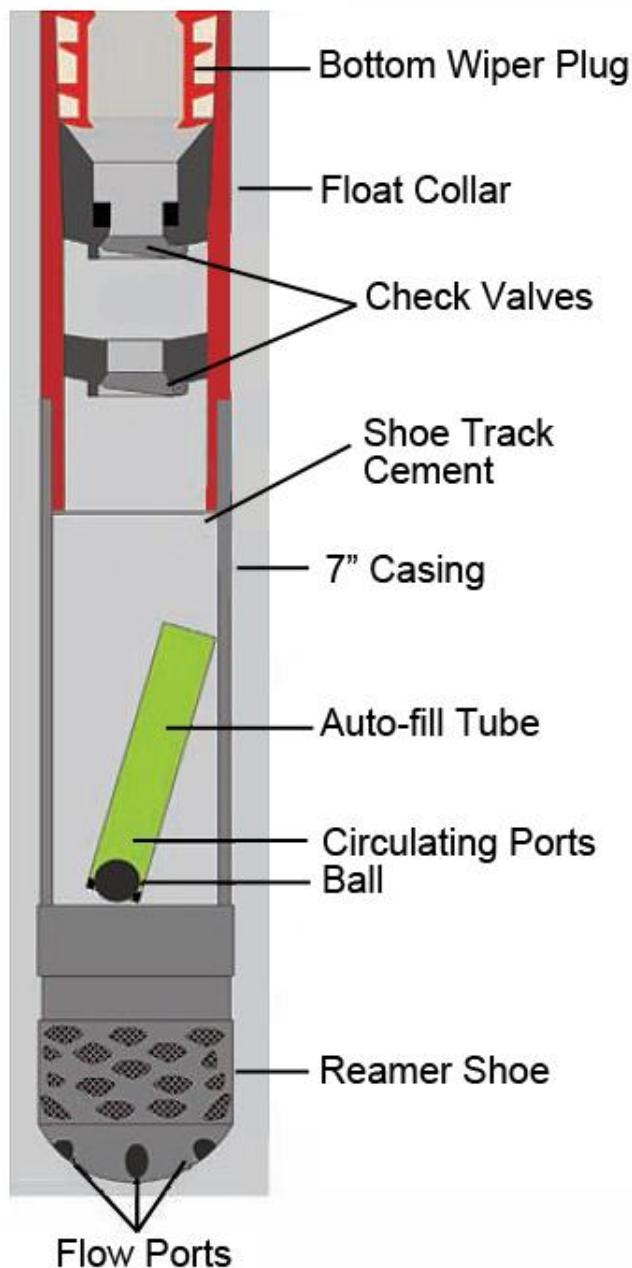


Figure 47: Shoe track barriers [Based on (BP, 2010)]

Some possible causes were identified but not verified;

a. Shoe track Cement:

1. *Contamination of shoe track cement due to nitrogen breakout.*
2. *Contamination of shoe track cement due to mud in the wellbore.*
3. *Inadequate design of the shoe track cement.*
4. *Swapping of the shoe track cement with mush in rat hole.*
5. *A combination of these factors.*

b. Float collar:

1. *Damage caused by high load conditions required to establish circulation.*
2. *Failure to convert float collar due to insufficient flow rate.*
3. *Check valves did not seal.*



3. Negative pressure test.

The rig crew were not familiar with BP's operation guidelines for pressure testing, which stated that the kill line should be monitored, and not the drill pipe pressure which was the rig crews preferred practice. The negative pressure test was accepted despite high pressure increase, explained as "bladder effect". A clogged kill line may also explain why there was no pressure relief when the well was bled off.

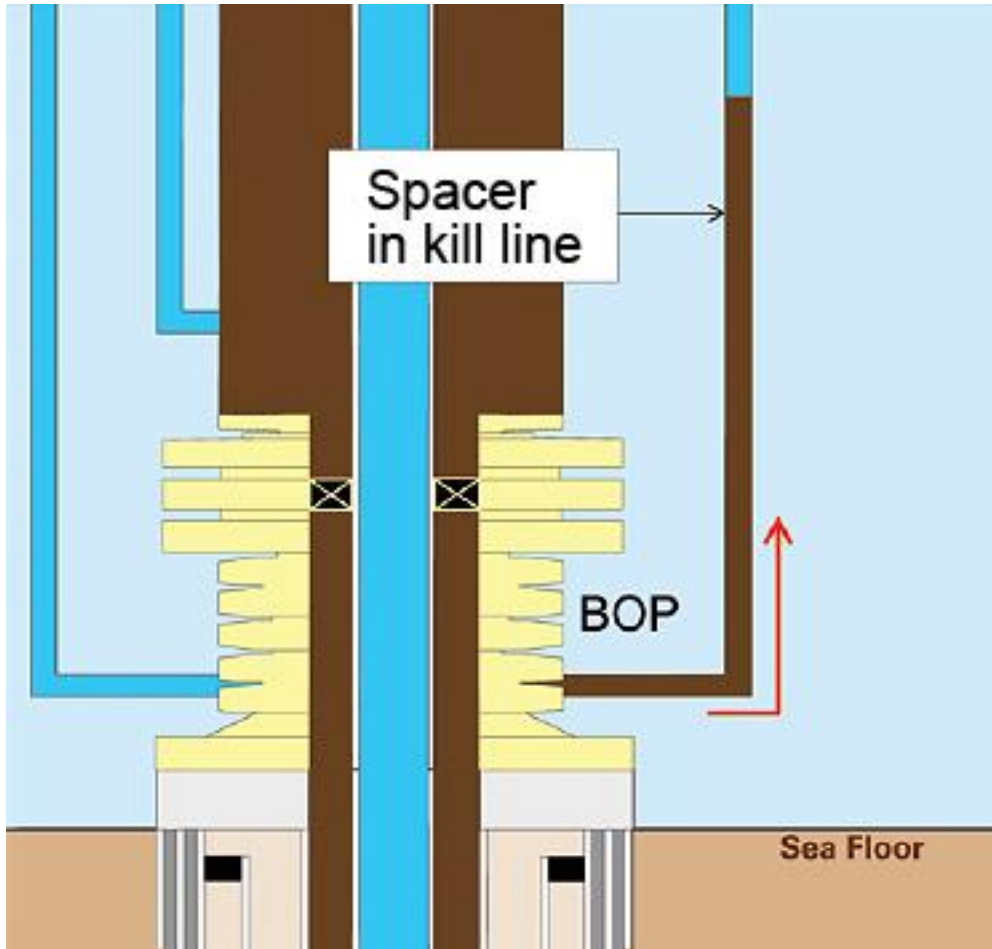


Figure 48: Conditions during negative pressure test (BP, 2010)

4. Influx was not recognized until hydrocarbons were in the riser.

Analysis show that flow in the well could be seen from real-time data at 20:58 hours, however this went unnoticed and no actions were taken until 21.41 hours. The Transocean Well Control Handbook states that there should be well monitoring at all times, however there was no current policy for how to monitor the well during in-flow testing, cleanup or other end-of-well activities.

5. Well control response failed to gain control.

This was partly due to the late response of well control. The annular preventer did not seal the annulus straight away allowing further flow of hydrocarbons.

It appears from reports and the investigation that the crew was not fully prepared for situations like these due to insufficient training.

6. Diverting flow to Mud-gas-separator resulted in gas venting onto the rig.

The MGS is designed to handle small amounts of gas, and not appropriate for high flow conditions like this situation. Had the flow been diverted overboard instead of to the MGS, it could've bought the rig crew some more time to react, and avoided gas

7. The fire and gas system did not prevent ignition.

The fans in Deepwater Horizons engine room was not designed to automatically activate if gas was detected, this had to be done manually. As this was not done, the hydrocarbon gas was able to reach ignition sources.

8. The BOP emergency mode did not seal the well.

None of the three ways to activate the BOP was successful. The Emergency Disconnect Sequence (EDS), meant to close the shear ram and disconnect the lower marine riser package (LMRP) did not work due to possible damage on the multiplex cables from the fire.

The automated mode function (AMF) required at least one working control pod, but these were later shown to be inoperable due to lack of battery charge and failed solenoid valve.

The shear ram was finally closed by means of remotely operated vehicle, but for some reason the well was not sealed completely. Possible reasons for this could be due to prevailing flow conditions in the BOP, insufficient hydraulic power or a non-shearable section across the shear ram.

Later investigation show signs of lacking maintenance on the BOP and its systems, and inaccurate maintenance records.

**Conclusion**

**Table 10: Deepwater Horizon barrier breaches**

Barriers breached / Causes	Comments
Well isolation	❖ Insufficient quality of cement (No pre-test or CBL run).
Valves	❖ Check valves did not seal.
Human factors	<ul style="list-style-type: none"> <li>❖ Crew did not follow procedures stated in controlling documents regarding how to perform inflow test.</li> <li>❖ Late response - Crew did not recognize influx and did not act on it in time.</li> <li>❖ Bad decision making – Diverting to mud-gas-separator when this did not have the require capacity.</li> <li>❖ Fire and gas detection system was not activated – This had to be done manually</li> </ul>
BOP	<ul style="list-style-type: none"> <li>❖ Failure to active EDS and AMF</li> <li>❖ Did not seal well properly</li> </ul>
Organization	<ul style="list-style-type: none"> <li>❖ Insufficiencies with practices and procedures regarding well control</li> <li>❖ Insufficient well integrity competence</li> <li>❖ Inadequate barrier verification and audits</li> </ul>

## 6.2.6 Gullfaks C – 2010

### **Summary**

In 2010, the Gullfaks C 06A well operated by Statoil, was close to developing into a serious well incident (Statoil, 2010) (Statoil, 2010) (Bjørheim, 2010) (SINTEF, 2011). The 19<sup>th</sup> May, the alarm on the already troubled well went off during hole-cleaning of the reservoir section. The casing string was breached and a big part of the mud column providing bottom-hole pressure was lost underground, resulting in loss of a very important well barrier.



**Figure 49: Gullfaks C platform (Bjerke, 2011)**

Gas from the reservoir section started to uncontrolled flow into the well and up on the drill floor. Work began to regain control but the situation worsened the following day, leading to evacuation of all non-critical personnel.

The work to regain the lost barrier and obtain well control went on for over two months. Later reports indicate that the gas on the drill floor reached a level where the risk of an explosion was present.

The fact that the casing breach was the cause of the mud loss was not known at this time, providing a challenging operation when trying to regain control of the well. This was the third critical incident happening on this well in five months.

Weaknesses about the breached casing string were known to Statoil already in the fall 2009, but no action was taken at this time. Later reports show that there were indications of pressure build up in the well as early as April due to the leaking casing string; however, this was not observed and acted on by Statoil.

The well was drilled with MPD (Managed Pressure Drilling), a method of drilling in zones where the pressure window is narrow (SINTEF, 2010). The objective is to accurately manage the pressure profile in the annulus by means of adjusting backpressure, variable fluid density and rheology and circulation friction.

Previous experiences with MPD wells gave the indications that it was not feasible to perform an MPD operation successfully the way the Gullfaks C well was designed. This safety evaluation was disregarded.

### ***Investigation reports by PSA and Statoil***

PSAs report shows that there were serious shortcomings regarding the planning of drilling and completion phase on the Gullfaks C 06A well, and that this easily could've become a major accident, had the circumstances been just a little different.

The shortcomings included aspects like risk management, management of change, experience sharing and transferring and knowledge and use of steering documents.

Statoils internal investigation focused on processes and requirements regarding MPD operations, and the need to involve relevant personnel with the required competence when executing drilling operations (Subsea World News, 2011). The investigation also showed areas of improvement regarding well monitoring. In retrospect of the incident, there is now more focus on well integrity on the Gullfaks field, and as a result, 20 wells has been closed down and are now having their well integrity evaluated.

**Conclusion**

Actions taken in retrospect of the Snorre A accident in 2004 did not seem to have the desired effect. In the report from PSA it is concluded that the Gullfaks accident might've been avoided if lessons learned from the Snorre A accident were taken into account.

The following barriers were breached on Gullfaks C:

**Table 11: Gullfaks C barrier breaches**

Barriers breached / Causes	Comments
Casing	❖ Weakness / breach of casing
Human factor	❖ Fail to observe/act on pressure build-up
Organization	<ul style="list-style-type: none"> <li>❖ Shortcomings in planning of drilling/completion phase.</li> <li>❖ Insufficient risk management regarding drilling and operations.</li> <li>❖ Insufficient experience transfer and use of relevant competence regarding MPD operations.</li> <li>❖ Lack of knowledge and use of steering documents.</li> <li>❖ Insufficient MOC documentation.</li> </ul>

## **6.2.7 Elgin – 2012**

### **Summary**

On 25<sup>th</sup> Mars, 2012, a gas leak was reported after a well operation on a platform in the Elgin field on the British sector of the North Sea, leading to evacuation of 238 workers. The well in question was a plugged well located at 4000m depth, but 1500m above the main reservoir. The gas is believed to originate from a rock formation above the well which then may have migrated to the well (Total, 2012).

In an article mapping the Elgin field's challenges after start of production, it's stated that the well did not have sufficient barriers, something that has been known since 2006. The article explains how Total has been dependent on a constant pressure in the annulus, by means of a fluid column, in order to avoid gas influx from a secondary formation above the reservoir. It's clear that Total has for many years, been aware of a leak from the secondary reservoir. The leak is the result of a micro-annulus between the casing and the cement, most likely due to variations in temperature. Several wells in the area have also taken damage due to depletion and subsidence of the main reservoir, although the extent of these is unknown (Manglet barrierer på Elgin - Teknisk Ukeblad, 2012).

Two ongoing operations are underway in order to regain control of the well which was initially releasing 200 000 m<sup>3</sup> of gas every day;

A kill operation by pumping kill mud from the wellhead, and drilling of two relief wells in order to intercept the well and pump kill mud directly down in the formation.

On May 15<sup>th</sup>, the well intervention operation was completed and the leak was sealed. Once a cement plug has been placed, drilling of the relief wells will be stopped.

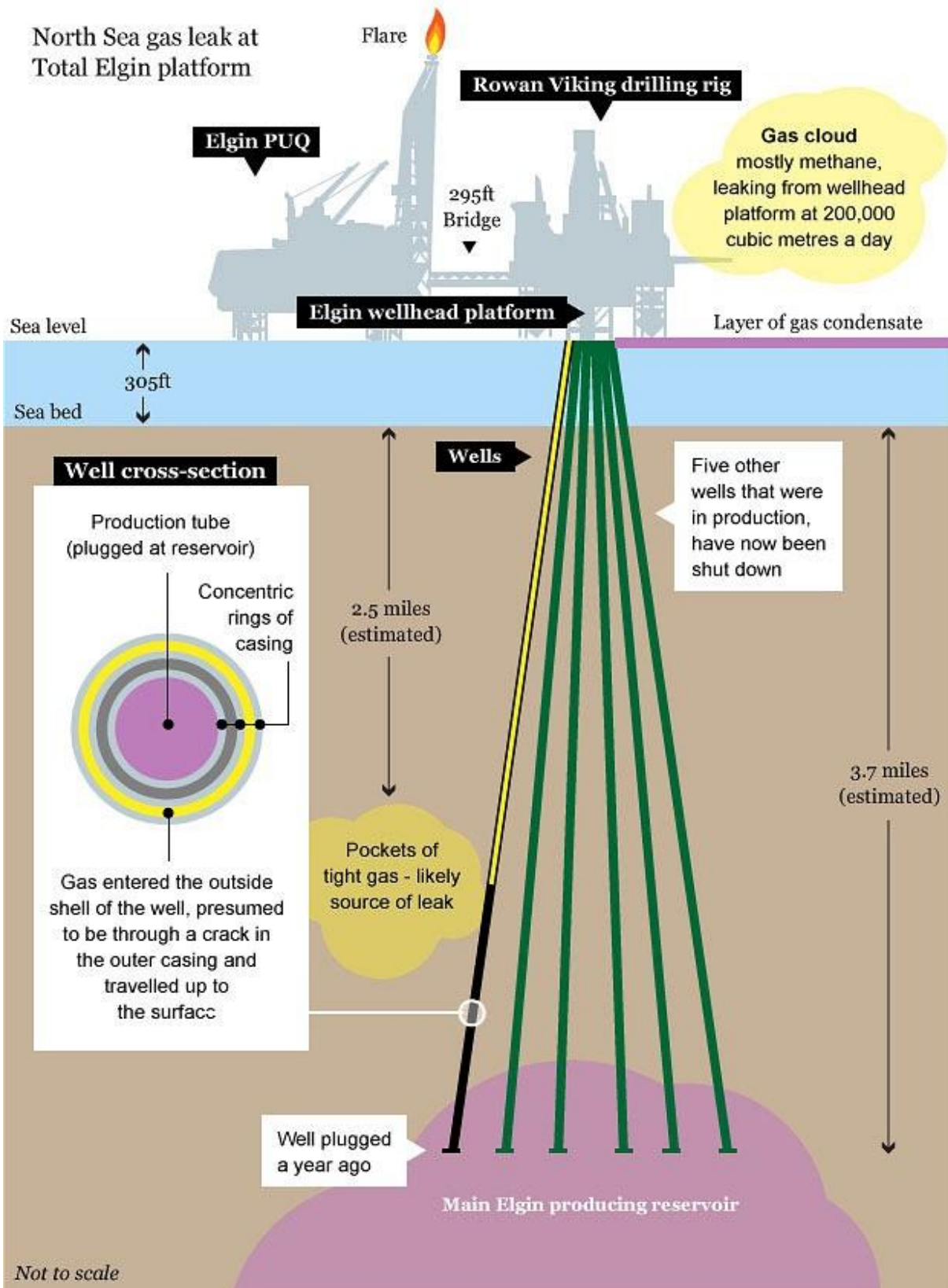


Figure 50: Elgin blowout (Gosden, 2012)



**Conclusion**

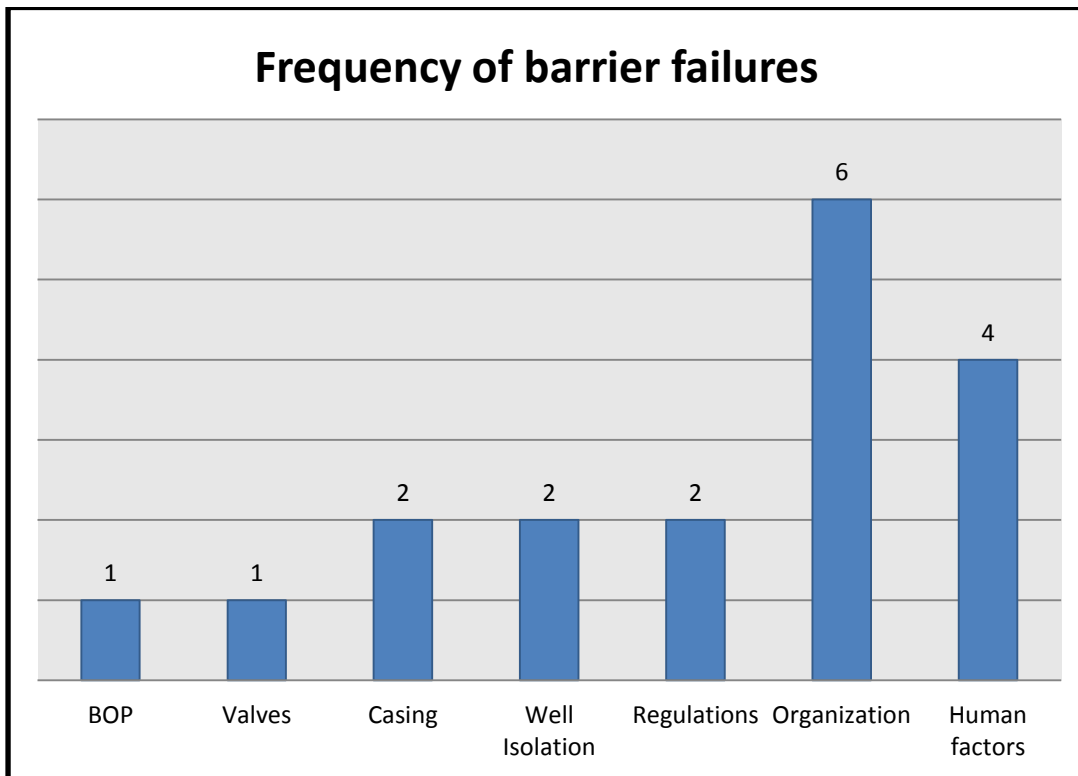
The full extent of the barrier failures are at this time not known. The following barrier breaches are currently known:

**Table 12: Elgin barrier breaches**

<b>Barriers breached / Causes</b>	<b>Comments</b>
Well Isolation	❖ Micro-annulus in cement
Organization	❖ Breach of regulations by not fulfilling 2-barrier-requirement

## 6.3 SUMMARY OF BLOWOUTS & WELL INCIDENTS

The graphs on Figure 51 represent different barriers that were breached and on how many of the discussed well incidents they occurred on. The amount of breaches within each barrier per well is not listed however. The physical barrier elements usually only fail once per well, as oppose to the organizational barriers where multiple breaches may occur per well.



**Figure 51: Sum of barrier failures / causes of well incidents**

As seen on Figure 51, the majority of barrier breaches are related to the organizational barriers and human errors. Every well incident discussed, could be linked to inadequate organizational barrier integrity. In addition, several of these breaches often occur on each event. This indicates that even though the physical well barriers may be a direct cause of a well incident, there are usually flaws with the organizational procedures and human factor that are the underlying cause.

## **Chapter 7. Conclusion**

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The few well incidents discussed in Chapter 6 only represent a small fraction of the number of blowouts and well incidents happening around the world. With the upcoming increase in petroleum activity, especially in the NCS, well integrity will be a crucial factor for avoiding well incidents and preventing major disasters and loss of human life.

It has been claimed by several people, both politicians and leading persons within the petroleum industry that the Deepwater Horizon accident would not have happened in Norway due to the regulations and standards in use here and the way the drilling operation was performed. This leads to an interesting discussion whether a set of standardized regulations within the petroleum industry would be to prefer. At the moment, every country uses their own set of regulations, even UK and Norway who both operate in the same areas on the NCS. In the US, in addition to the federal regulations, every single state also has their own set of rules. This leads to inconsistencies with regards to safety within the industry, something that should be equally important no matter where in the world the operation takes place.

This could be taken even further and include a common set of standards to be used, as many countries and operators don't even have standards with regards to well integrity.

At the very least, well integrity standards on par with NORSOK D-010 should be required. NORSOK D-010 is an excellent example of how a standard should be constructed, as it is a cooperative between the government and the industry itself. This leads to a standard of high quality, and makes the standard more relevant and easier for the industry to follow.

There are several aspects of a business unit or a company that can promote higher degree of well integrity and safety. In the past, the aspect of well safety and integrity was normally included under the drilling & operation department. The concept of having a separate well integrity department within a BSU is fairly new, but could contribute immensely as the focus and expertise is only directed towards well integrity. The use of real-time operations, or Integrated Operations, is also a fairly new concept that primarily focuses on increased efficiency and reducing cost. However, by moving personnel from offshore to onshore, and

by having multiple engineers with different disciplines with access to all available data, will also improve safety for the personnel offshore as well as improving the well integrity.

Companies are required to hand over reports to the government which includes the well design of any planned wells as well as daily drilling reports. The actual data, which are only available after the well has been drilled, are not required to be reported to the government. Well pressures, temperature and loads and other well integrity related data are not reported. An example is the presence of H<sub>2</sub>S gas which can be difficult to predict, which affects the casing and equipment integrity, another example could be the quality of the casing cement job or other well barrier elements. This means that the government might not have the correct data when verifying and overseeing the well integrity of companies in countries where this is required. Maybe more well integrity related data should be required to report.

Previously, many wells have been drilled and completed with insufficiencies regarding well barriers. Especially well isolation, or cement, has not been adequately to secure the well. Companies have often used sub-par solutions and equipment or insufficient cement height in order to save money. Something to consider is that the amount of money saved by avoiding a well incident or a blowout greatly outweighs the cost of an extra barrier, better equipment or an extra person.

Hopefully the importance of well integrity will continue to grow throughout the industry the coming years, as well as the knowledge and competence of everyone involved, from a global and national level, down to company and personal level. Perhaps one day, major well incidents like the Deepwater Horizon and those similar will be a thing of the past.

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# Appendix A

## 8.8 Well barrier schematic illustrations

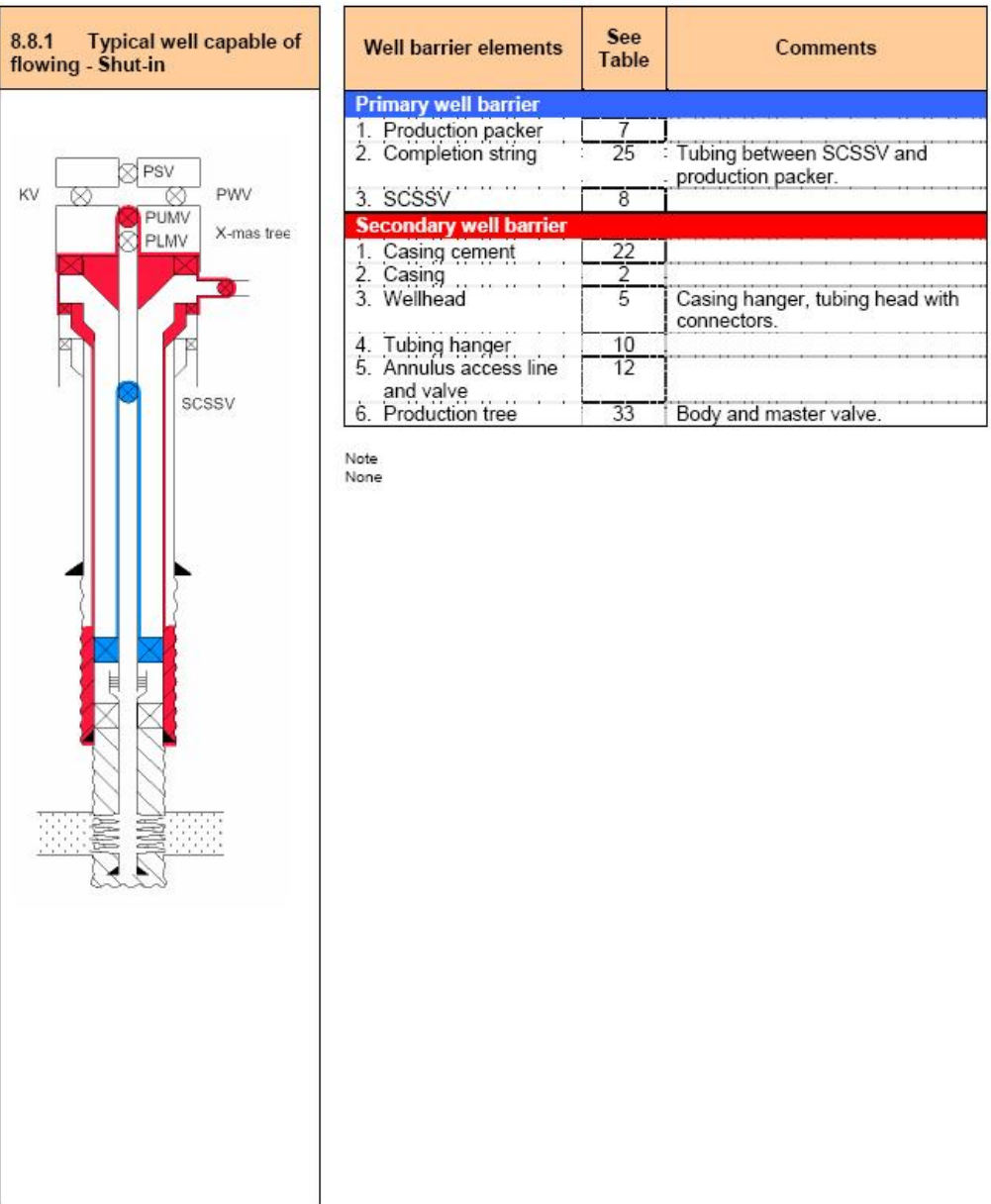


Figure 52: Well Barrier Schematic illustration in NORSOK D-010 (NORSOK Standard D-010, 2004)



# Appendix B

**15.22 Table 22 – Casing cement**

Features	Acceptance criteria	See
<b>A. Description</b>	This element consists of cement in solid state located in the annulus between concentric casing strings, or the casing/liner and the formation.	
<b>B. Function</b>	The purpose of the element is to provide a continuous, permanent and impermeable hydraulic seal along hole in the casing annulus or between casing strings, to prevent flow of formation fluids, resist pressures from above or below, and support casing or liner strings structurally.	
<b>C. Design, construction and selection</b>	<ol style="list-style-type: none"> <li>1. A design and installation specification (cementing programme) shall be issued for each primary casing cementing job.</li> <li>2. The properties of the set cement shall be capable to provide lasting zonal isolation and structural support.</li> <li>3. Cement slurries used for isolating permeable and abnormally pressured hydrocarbon bearing zones should be designed to prevent gas migration.</li> <li>4. The cement placement technique applied should ensure a job that meets requirements whilst at the same time imposing minimum overbalance on weak formations. ECD and the risk of lost returns during cementing shall be assessed and mitigated.</li> <li>5. Cement height in casing annulus along hole (TOC):               <ol style="list-style-type: none"> <li>5.1 <b>General:</b> Shall be 100 m above a casing shoe, where the cement column in consecutive operations is pressure tested/the casing shoe is drilled out.</li> <li>5.2 <b>Conductor:</b> No requirement as this is not defined as a WBE.</li> <li>5.3 <b>Surface casing:</b> Shall be defined based on load conditions from wellhead equipment and operations. TOC should be inside the conductor shoe, or to surface/seabed if no conductor is installed</li> <li>5.4 <b>Casing through hydrocarbon bearing formations:</b> Shall be defined based on requirements for zonal isolation. Cement should cover potential cross-flow interval between different reservoir zones. For cemented casing strings which are not drilled out, the height above a point of potential inflow/ leakage point / permeable formation with hydrocarbons, shall be 200 m, or to previous casing shoe, whichever is less.</li> </ol> </li> <li>6. Temperature exposure, cyclic or development over time, shall not lead to reduction in strength or isolation capability.</li> <li>7. Requirements to achieve the along hole pressure integrity in slant wells to be identified.</li> </ol>	ISO 10426-1 Class 'G'
<b>D. Initial verification</b>	<ol style="list-style-type: none"> <li>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.</li> <li>2. The verification requirements for having obtained the minimum cement height shall be described, which can be               <ul style="list-style-type: none"> <li>• verification by logs (cement bond, temperature, LWD sonic), or</li> <li>• estimation on the basis of records from the cement operation (volumes pumped, returns during cementing, etc.).</li> </ul> </li> <li>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.</li> </ol>	
<b>E. Use</b>	None	
<b>F. Monitoring</b>	<ol style="list-style-type: none"> <li>1. The annuli pressure above the cement well barrier shall be monitored regularly when access to this annulus exists.</li> <li>2. Surface casing by conductor annulus outlet to be visually observed regularly.</li> </ol>	WBEAC for "wellhead"
<b>G. Failure modes</b>	<p>Non-fulfilment of the above requirements (shall) and the following:</p> <ol style="list-style-type: none"> <li>1. Pressure build-up in annulus as a result of e.g. micro-annulus, channelling in the cement column, etc.</li> </ol>	

**Figure 53: Example of a Well Barrier Acceptance table in NORSOK D-010 (NORSOK Standard D-010, 2004)**

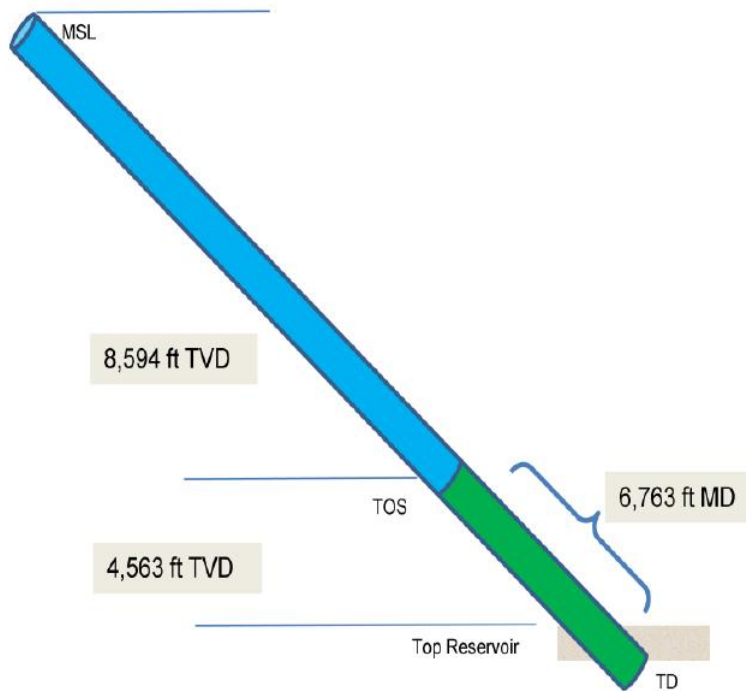


## Appendix C

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The total downwards pressure in the well is given by;

$(\text{Water gradient} * \text{TVD Water}) + (\text{Sandaband gradient} * \text{TVD Sandaband}) + (\text{Sandaband Yield} * \text{MD Sandaband})$



**Figure 54: Pressure calculations for Embla D-07 Sandaband (Sandaband, 2010)**

Water gradient:	0,445 psi/ft → 3820 psi
Sandaband gradient:	0,931 psi/ft → 4155 psi
Yield (with safety factor):	4055 psi/1,3 → 3119,2 psi
Total downwards pressure (with SF):	11094,2 psi
Reservoir pressure:	10800 psi
<b>Net overpressure:</b>	<b>294,2 psia</b>

