# An Introduction to Well Integrity

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**Preface**

This document has been prepared as a joint project between members of the Norwegian Oil and Gas Association's Well Integrity Forum (WIF) and professors at NTNU and UiS. The intention with the document is to provide a document that can be used in educating personnel in well integrity and especially students at the universities.

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# Index

## List of Abbreviations

**ACV** Annulus Circulation Valve

**AIV** Annulus Isolation Valve

**AMV** Annulus Master Valve

**AP** Applied Pressure

**ASV** Annulus Safety Valve

**Annulus SV** Annulus Swab Valve

**AVV** Annulus Vent Valve

**AWV** Annulus Wing Valve

**BOP** Blowout Preventer

**BSB** Below the SeaBed

**CBL** Cement Bond Log

**CIV** Chemical Injection Valve

**COV, XOV** Cross Over Valve

**DU** Dangerous and Undetected

**DD** Dangerous and Detected

**DHSV** Down Hole Safety Valve

**FIT** Formation Integrity Test

**FBP** Formation Break-down Pressure

**FCP** Fracture Closure Pressure

**FMECA** Failure Modes, Effects and Criticality Analysis

**FPP** Fracture Propagation Pressure

**FRP** Fracture Re-opening Pressure

**GLV** Gas Lift Valve

**HMV** Hydraulic master valve

**HPA** High Pressure Alarms

**LCM** Lost Circulation Material

**LOP** Leak off Pressure

**LOT** Leak Off Test

**MAASP** Maximum Allowable Annular Surface Pressure

**MD** Measured Depth

**MIV** Methanol Injection Valve

**MODU** Mobile Offshore Drilling Unit

**MOP** Maximum Operational Pressure

**MSDP:** Maximum Section Design Pressure

**MWDP** Maximum Well Design Pressure

**PBR** Polished Bore Receptacle

**PIV** Production Isolation Valve

**PLC** Programmable Electronic Controller

**PMV** Production Master Valve

**ppg** parts per gallon

**PSV** Production Swab Valve

**PSA** Petroleum Safety Authority

**psi** pressure per square inch

**PWV** Production Wing Valve

**RKB** Rotary Kelly Bushing

**SCP** Sustained Casing Pressure

**SCSSV** Surface Controlled Subsurface
Safety Valve

**SD** Safe and Dangerous

**SICP** Shut In Casing Pressure

**SIDPP** Shut In Drill Pipe Pressure

**SIV** Scale Inhibitor Valve

**SIWHP** Shut In Wellhead Pressure

**SSSV** Subsurface Safety Valves

**SU** Safe and Undetected

**TAP** Trapped Annular Pressure

**TH** Tubing Hanger

**TP** Thermal Pressure

**TVD** True Vertical Depth

**USIT** Ultra Sonic Imaging Tool

**WBS** Well Barrier Schematic

**XLOT** Extended Leak of Test

**XT** X-mas Tree

# List of figures

## List of Tables

# 1.    What is well integrity? (Well integrity – concepts and terminology)

Well Integrity is defined in Norsok D-010 as: "application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well".

Norsok D-010 is a functional standard and sets the minimum requirements for the equipment/solutions to be used in a well, but it leaves it up to the operating companies to choose the solutions that meet the requirements. The operating companies then have the full responsibility for being compliant with the standard.

Following from this definition, the personnel planning the drilling and completion of wells will have to identify the solutions that give safe well life cycle designs that meet the minimum requirements of the standard.

Another implication is that operating companies and service providers have an obligation to ensure that the equipment planned to be used will comply with the standard and if not, the equipment will need to be improved and qualified before use. Deviations from the standard can be made in some cases when the standard allows this. If a solution selected deviates from the standard, then this solution needs to be equivalent or better compared to what the requirement is.

When selecting technical solutions, it is important to set the right equipment specifications and define the requirements for the well barrier to ensure the well integrity is maintained throughout the well life. Typical things to specify are the BOP rating and size, the casings to be used, the pressure rating on downhole and topside equipment and the material specification of the equipment. These specifications will be set at an early stage of a project and the later selection of equipment will be based on it.

NORSOK D-0101 specifies that: "There shall be two well barriers available during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled outflow from the borehole/well to the external environment". This sets the foundation for how to operate wells and keep the wells safe in all phases of the development. This requirement is also referred to in PSA's Activities and Facilities regulation and it implies that operators have to adhere to the two well barrier philosophies and maintain sufficient adherence in all phases of their operations. Good

operational solutions are also required to ensure that the well integrity requirements are met. A typical example is the requirement to regularly function and pressure test the sub-surface safety valve to ensure it is operational at all times. The operational solution will include procedures for operating valves on a well, flowing restrictions etc. that can have an impact on the integrity of the well and other day-to-day activities to keep a well under control and producing it in a safe manner. Another example is to continuously monitor the pressure in the annuli of a well to ensure a leak or breach of a well barrier is detected early and that corrective action can be taken before the problem escalates.

Organizational solutions are also required to ensure the required well integrity is maintained. This will include, amongst other things, that the operating company ensures that people with the right competence are working with well operations and that they are up to date with the latest well status. Good communication between the parties involved is required so that the correct information is shared and passed on at e.g. shift handovers. In handover documentation, all relevant information with regards to barriers, operational limits, valve status, design of the well etc. has to be compiled as part of a handover package. Many problems and accidents have been due to poor handover documentation or communication, and good routines and organizational solutions for this is required to maintain the required level of safety in offshore operations.

The Petroleum Safety Authority (PSA) have published the regulatory requirements regarding well integrity aspects like organizational solutions, management system, competence and training, work processes, operational organization, emergency preparedness etc.

Well barriers and failure modes of different well barrier elements have been discussed in Chapter 3. A failure of a well barrier element will usually result in a well with reduced integrity. If a well barrier has failed, the only action that can take place in the well is to restore the failed well barrier. Alternatively, the well can be plugged and made secure or in some cases, the well barrier can be redefined and production continued until the failure can be corrected.
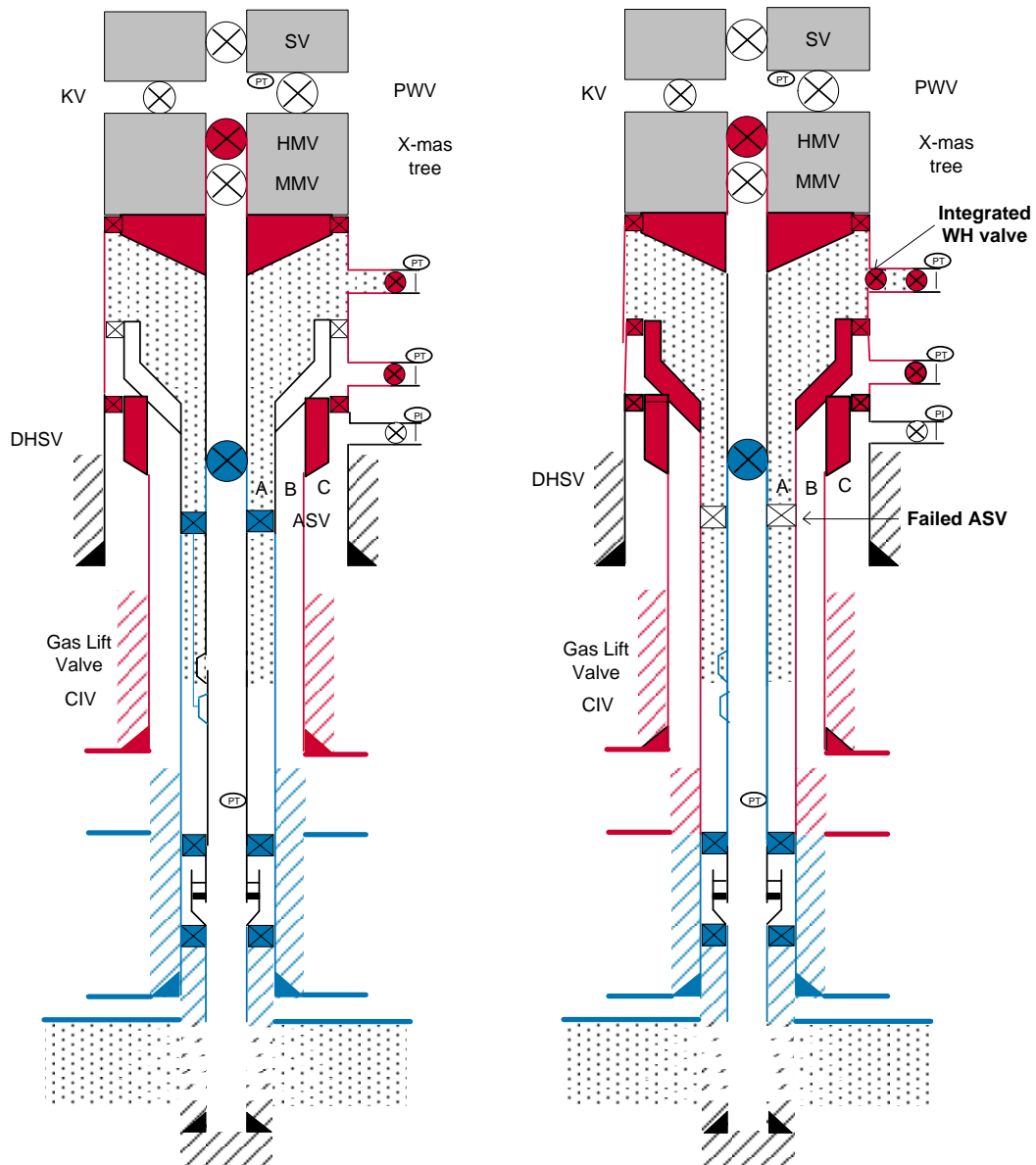
*Figure 1: Example of possible redefinition of the well barriers after failure of the ASV*

Chapter 3 also discusses tools and methods that can be used to identify failures and how failures can be prevented. In some cases where many components fail at the same time or as a result of other components failing, then the well integrity will be lost and the well has to be shut in to avoid further escalation and damage.

## 2.    Background and History

There has been a significant technological evolution in the drilling industry during the past 30years. The early platforms on the Norwegian Continental Shelf were designed for wells with a reach of 3 km from the platform.  To cover a large reservoir often several platforms were required.  Examples are Statfjord A, B and C and Gullfaks A, B and C.  As these platforms were very expensive, alternative solutions were pursued such as subsea installations and extended reach wells.  Today it is possible to reach targets 12 km from the platform.  One new platform can replace three old platforms from a reservoir coverage point of view.

The technical evolution exemplified above requires technology and improvement on very many levels.  Obviously since the wells are much longer, the risk of failure is also increased. Unfortunately, the high number of elements that can possibly fail makes the analysis difficult.

Well Integrity can in its simplest definition be defined as a condition of a well in operation that has full functionality and two qualified well barrier envelopes.  Any deviation from this state is a minor or major well integrity issue.  Common integrity issues are often related to leaks in tubular or valves, but can also be related the reservoir issues as loss of zonal control. Any factor that leads to a functional failure is a loss of well integrity. The challenge is of course to define all possible scenarios.

History shows some severe examples of losing integrity in wells such as the Phillips Petroleum's Bravo blowout in 1977, Saga Petroleum's underground blowout in 1989, Statoil's blowout on Snorre in 2004, and BP's Macondo blowout in the Gulf of Mexico in 2010.  These serious accidents remind us of the potential dangers in the oil and gas industry and they are some of the main drivers for the current focus on well integrity in the industry.

The Petroleum Safety Authority (PSA) initiated a pilot study in 2006, which has resulted in a continuous activity in well integrity.  The pilot study was based on supervisory audits and input from seven operating companies, including 12 offshore facilities and 406 wells and presents a snapshot of the well integrity status of the selected wells at the time.  The results indicated that 18 % of the wells in the survey had integrity failures, issues or uncertainties and 7 % of these were shut in because of well integrity issues.  A later study indicated that each fifth production well and each third injection well may suffer from well integrity issues. An interesting observation was that old wells had few well integrity issues, actually most

problems occurred in the age group 5-14 years. These conclusions are not general but are limited to the studies referred to.

It is clear from the above description that well integrity is an important safety aspect of a well. However, some of the issues are not critical, whereas some may lead to accidents.

## 2.1 What can go wrong in wells?

Many different types of failures can lead to loss of well integrity. The degree of severity is also varying. For each of the blowouts mentioned above, a long chain of events led to the incidents. The simplest approach would be to consider failure of individual well components. Figure 2 shows some results from a PSA study conducted in 2006. Clearly the production tubing is the dominating component with failure. This is not unexpected as the tubing is exposed to corrosive elements from the produced fluids and, the production tubing consists of many threaded connections where the high number of connections gives a high risk of leak. Two well barriers between the reservoirs and the environment are required in the production of hydrocarbons to prevent loss of containment. If one of the elements shown in Figure1 fails, the well has reduced integrity and operations have to take place to replace or restore the failed barrier element.
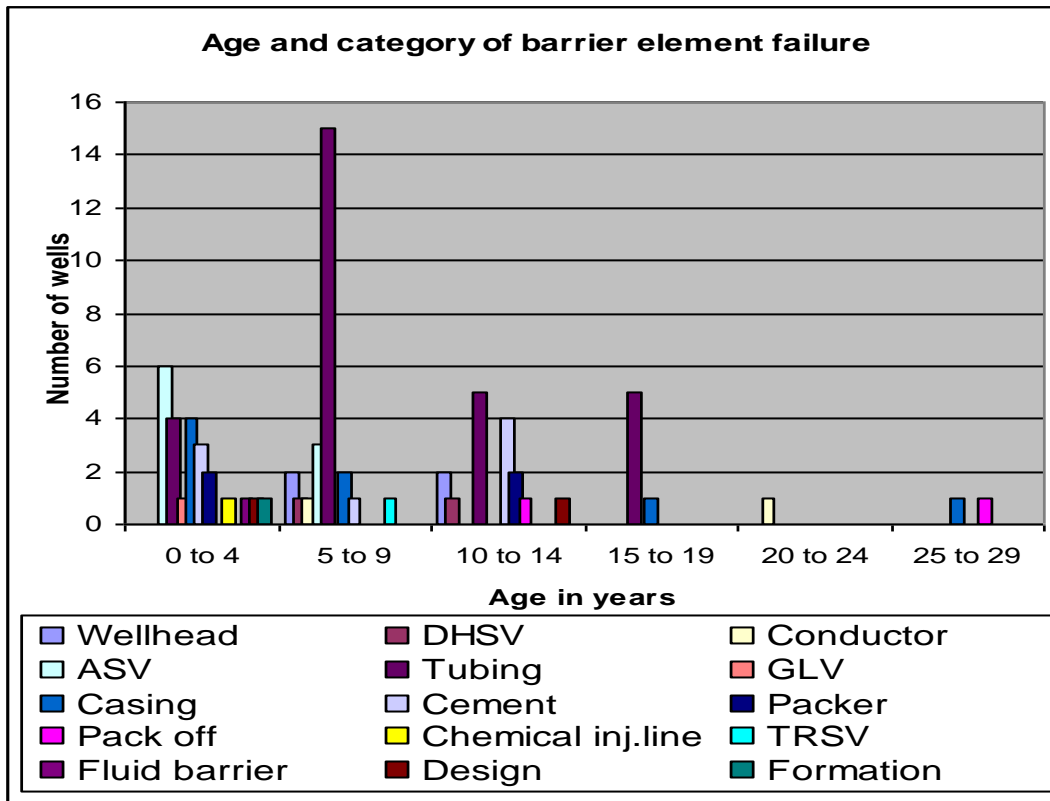
*Figure 2 Example of failure statistics with age.(8)*

Loss of well integrity is either caused by mechanical, hydraulic or electric failure as related to well components, or by wrongful application of a device. An example of the latter is to not close the BOP during a well control incident. This shows that we must go beyond the technical aspects and also consider well management aspects. In hindsight many well incidents have become worse because of wrong decisions. Education and training therefore form an important basis for improved well integrity.

## 2.2 How likely is loss of well integrity?

The likelihood of a failure is connected to underlying causes. One example is a 100 year ocean wave that often is the design criterion for offshore structures. By extrapolating the wave height frequency diagram to 100 years this value is obtained. It is a statistical figure with no correlation to actual events. It gives us a mean to consider the severity of an event to the expected frequency of occurrence.

Likelihood is also important from another perspective, namely if it is realistic. How likely is it that the standby boat collides with the semisubmersible rig during a well control event? We

understand that there is a compromise between the severity threshold and the number of scenarios to consider. The PSA study did not resolve the likelihood issue, but there was some information that is relevant. Figure 3 shows the number of wells with integrity problems from the pilot study.

Of the components identified, the production tubing suffered failure in many wells. Based on the information from Figure 3, there is a high probability that the well will experience a leakage in the tubing during its lifetime. To reduce the risk of failure it is important to control the risk factors and to detect leakages at an early stage (before failure).
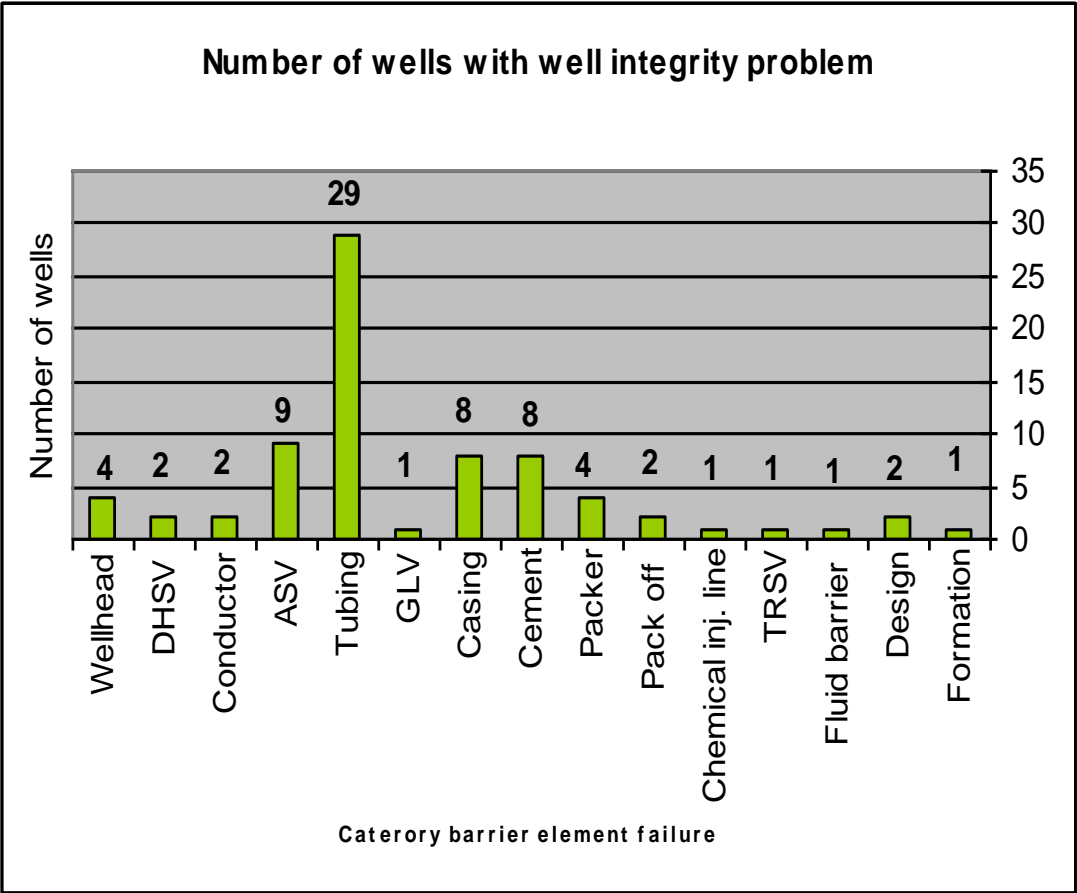


*Figure 3 Example of barrier element failures (8)*

## 2.3   What are the consequences of loss of well integrity?

The obvious consequences are blowouts or leaks that can cause material damage, personnel injuries, loss of production and environmental damages resulting in costly and risky repairs. Knowing that most of the wells in the North Sea have a large production rates, losses due to

production/injection stop may be very costly.  Often these losses exceed the cost of the repair of the well.

This shows that well integrity depends not only on equipment robustness, but on the total process, the competence and resources of the organization and the competence of the individual.  In the following we will approach well integrity from a technical perspective, but keep in mind that any other element like a wrong operational decision may lead to well integrity issues.

### 2.4   Some cases of loss of well integrity

Several audits of well problems have been carried out by the PSA during the last decade. All these problems led to well shut in for some time, and in some cases the entire platform production was temporarily shut in. The cases will show examples of losses of well integrity and the consequences.

### 2.4.1   Case 1: Failure of surface casing and drop of wellhead

A well was shut in for workover.  During the cooling phase of the top of the well it did not contract as expected.  Rather, for a period there was no thermal contraction, then the entire wellhead dropped 54 cm with a shock.  This was 44 cm more than expected.

On this platform the conductor does not carry any load from the wellhead system. The surface casing string therefore carries most of the total weight of the well.  During production some of this is transferred to the intermediate string, while the production casing carries little load.

Investigations revealed that the entire surface casing failed due to corrosion.  Due to loss of mechanical integrity the well was shut in until it was fully restored.

The well was 8 years old.  During installation a cement return port was left open near the seabed.  It is believed that this port gave access to fresh seawater from the shaft of the concrete platform.  Thermal effects and tidal height variations inside the shaft were believed to bring salt water into the surface casing leading to a corrosive environment at the top of the

annulus. To avoid this problem for future wells it was recommended to fill the top of the surface casing annulus with oil, which would coat the exposed tubular and eliminate corrosion. The well is shown in Figure 4.

# Actual Well Schematic



18 5/8" casing 'dropped' 1.37 m during cementing

13 3/8" casing not locked into 18 ¾" housing. Emergency pack-off set

Top of conductor 1.016m above weatherdeck

18 5/8" casing patched at 25m

Level of fluid and fluid type in shaft?

Port Collar at 294 m

Seabed @ 316m

Planned TOC at seabed

No cement to seabed in 18 5/8" annulus

26" conductor shoe at 385.5 m

Original annulus fluid KCl polymer

Stage collar milled at 437 m – open?

Top of cement at 650 mMD/648 mTVD

18 5/8" casing shoe at 892 mMD/874 mTVD

Original annulus fluid 1.4 sg KCl polymer

TOC at 1300 mMD/1195 mTVD

TOC at 1700 mMD/1472 mTVD

Original annulus fluid 1.4 sg KCl polymer

13 3/8" shoe at 1928 mMD/1602 mTVD

9 5/8" shoe at 2130 mMD/1668 mTVD

8 ½" hole/6 5/8" pre-packed screens to 2460 mMD/1670 mTVD

*Figure 4 Failed surface casing and position of open cement return port*

14

The consequences were

- The entire platform production stopped for one month resulting in huge production losses
- The failed well was back into production after one year
- There was a high repair cost for the well
- Future installation procedures will not accept open return ports

### 2.4.2    Case 2: Failure of production casing hanger

Several problems occurred in a production well during a workover.

- The production casing hanger failed during a pressure test
- The tubing hanger failed during a pressure test
- The tubing running tool failed under operation

In the following we will therefore provide a brief description of the events.

*9-5/8" Casing Hanger Failure*

During installation of the 9-5/8" production casing, the casing hanger failed during pressure testing, slipping through the wellhead. The hanger failed due to excessive plastic deformation in the casing hanger system. Casing hangers typically have a taper of about 40 degrees. However, this system was a slim design using a taper of only 8 degrees. Investigations revealed further that the system was designed for an axial load of 350 tonnes, but had been upgraded to 600 tonnes axial load. Obviously axial overload was one of the root causes. Figure 5 shows the casing hanger after failure. The yielded top of the casing hanger is clearly seen in the picture.

*5-1/2" Tubing Hanger Failure*

The tubing hanger also failed as given in the description from the oil company:

"While in the process of installing the completion string, the tubing hanger was locked down with the hold down bolts and a test plug was landed in the tailpipe with the wire connected. After setting the packer, the 5-1/2" x 9-5/8" annulus was pressured to 3500 psi as per standard procedures. When the pressure reached 3500 psi, there was a sudden release of pressure and the landing string moved up 2 feet indicating the hanger had been pushed up past the hold

down bolts. The control line to the SCSSSV also parted above the hanger allowing the SCSSV to close on the wireline. Well control was not jeopardized at any point during this occurrence.

We are currently in the process of retrieving the wireline tools and will then pull the hanger to surface to assess the cause of the failure. Although this does not have a direct relationship to the 9-5-8" hanger failure, it is obvious that we need to investigate the cause of the problem and implement corrective measures as appropriate. We will take up this issue as part of the ongoing investigation."

*Running Tool Failure*

During an attempt to shear the tubing string out of the PBR assembly on the well, the tubing hanger tool parted. The tool was of a different dimension and load capacity than the information provided in the running tool manual. The root cause of this failure incident has been identified as incorrect information of the maximum load rating of the tool. The tool failed because the applied load exceeded the actual strength.



*Figure 5 Deformed casing hanger after failure*

The three incidents on the well described above were all related to axial overload.

The casing hanger failure was caused by overload due to the actual strength of the equipment, compared to the rated strength. It also appears that this casing hanger system has an inherent design problem.

The tubing hanger failed because misalignment during installation led to uneven loading of the lock down bolts.

The tubing running tool failure was due to overloading, because specifications defined a higher strength of the tool.

When upgrading the axial capacity of the casing hanger the manufacturer conducted a test. Even if the material yielded during this test both the manufacturer and the oil company accepted the upgrade.

The consequences were:
- High cost of well repair
- The many wellheads of this type can only be used within original specifications. Axial load upgrade acceptance was reversed; the casing and tubing hangers can only be used with initial specifications.
- Correct specifications for running tools should be used.
- Running and landing procedures for production tubing should be improved.

### 2.4.3 Case 3: Loss of wellbore

A well was drilled and cased according to plan with setting an intermediate liner and a 9 5/8" drill-in liner at the top of the reservoir. The shoe was drilled out and a Formation Integrity Test (FIT) was performed. Then the intermediate liner was pressure tested and the 9 5/8" drill-in liner was inflow tested. The test showed no inflow.

While drilling ahead, total losses were suddenly encountered with high mud losses. The loss rate was gradually reduced as the rig attempted to keep the hole full by filling it with pre-mix and base oil and then eventually seawater. The well was then stabilized by placing Lost Circulation Material (LCM) in the open hole section. The well schematic is shown in Figure 6.

The drill string was round-tripped to lay down a radioactive source. As the string washed down from the top of the 9 5/8" liner, dynamic losses were again induced. At the shoe a flow check gave some gains but this was suspected to be due to ballooning effects. The well was circulated and conditioned before a new flow again gave some gains. Circulation with the well open was performed when a sharp increase in returns was observed. The well was the shut in on the annular preventer on the BOP.

Attempts were made to stabilize the well by circulating out gas through the choke. Returns were again lost and then seawater was bullheaded on the annulus side while the losses continued to increase. Two LCM pills were displaced in an attempt to cure the losses without success. It was then attempted to kill the well by pumping additional water-based mud. During the circulation, dynamic losses were experienced and the returns contained crude oil. After circulating the well full of seawater, another LCM pill was displaced down and squeezed to cure the losses, but this was unsuccessful. It was then attempted to kill the well by circulating mud around through the choke. Due to high gas peaks and unstable returns, the well was shut in and it was attempted to bullhead the gas on the annulus side by additional volumes of seawater and mud.

Gas readings were still high and a gunk pill was pumped through the drill pipe to plug off the open hole. The gunk pill plugged off the drill pipe, thus the ability to circulate the well was lost. The casing pressure continued to rise and an attempt to pressure test the annulus broke down the formation and gave injectivity. The casing pressure was still rising so the annulus was bullheaded with seawater making the casing pressure to drop to 0 pressure. When circulating across the BOP there were still loose sand to stem the losses, an LCM pill was bullheaded down and squeezed into the formation. The well was then shut in and monitored showing a rapid pressure build up on the casing side. The pressure was bled off in an attempt to control the well. At the same time, they started to pump mud on the annulus side to increase the hydrostatic head, while a mix of free gas and mud was bled off.

While continuing to bleed-off and pump/lubricate on the annulus side, wireline equipment was rigged up on top of the drill string. After a wireline drift run, and a tubing perforator mis-run, the drill string was successfully perforated at depth. The surface pressure was then allowed to stabilize, while pressure was maintained on the outer annulus side. Subsequently, the well was killed with mud and full well control regained.

Base oil
and
seawater
in the well

20" casing

13 3/8" casing

TOL 11 3/4"

TOL 9 5/8"

8 1/2" hole
New formation drilled
where losses took place
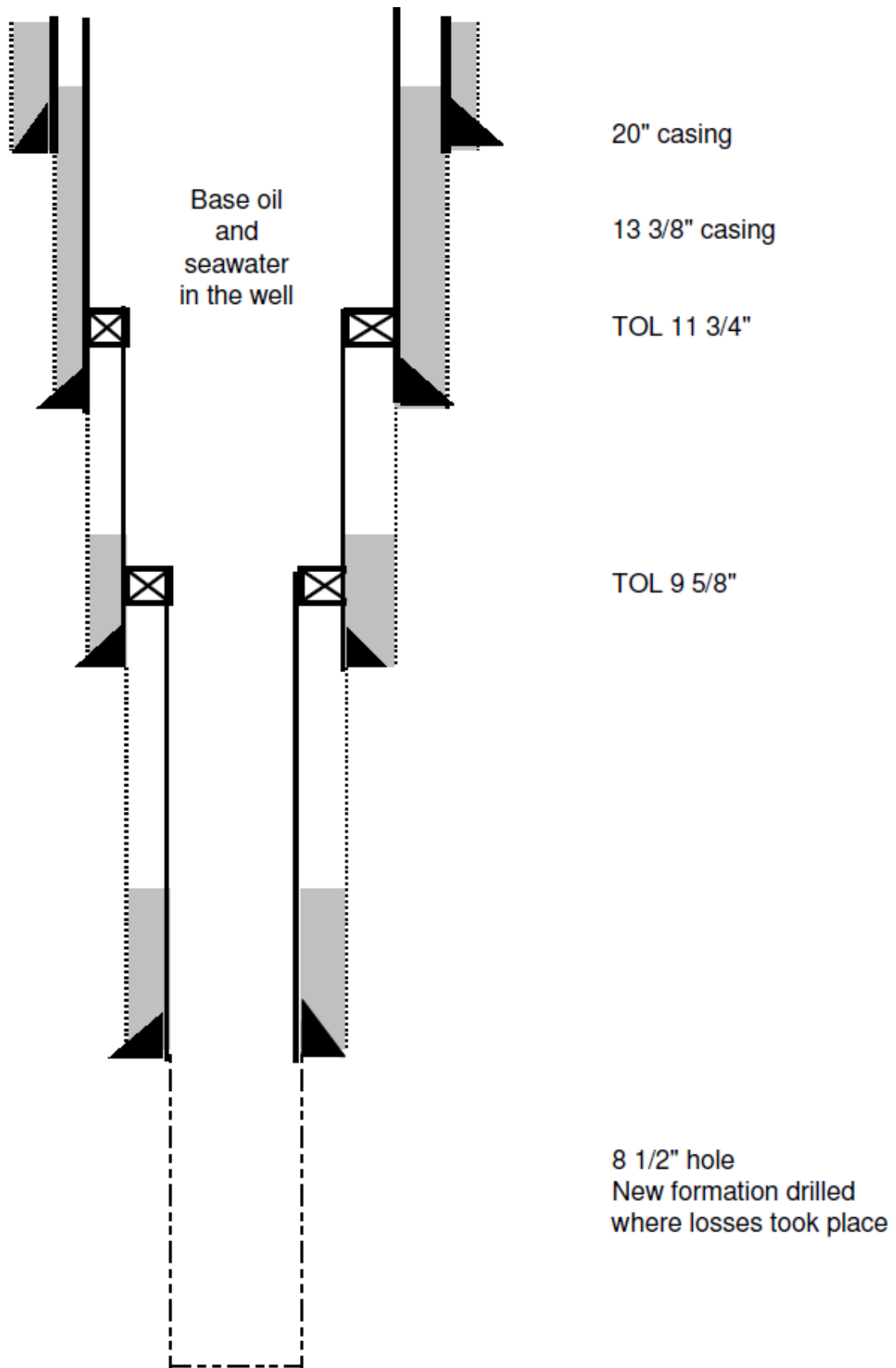
*Figure 6  Well with circulation losses and well control*

The consequences were:

- The well had to be sidetracked at high cost

- During the loss/well control events, well barriers were not in place at all times.

- The gunk pill plugged off the drill string, worsening the situation

- The load imposed on the well during the well control incident exceeded the test pressure that had been applied.  The barriers were not verified

### 2.4.4    Case 4: Gas leaks in tubing strings

A major operator reported tubing leaks in 14 subsea wells. The leaks were small not requiring shut-in of the wells. Because the wells are subsea they have less accessibility.  In the following a review will be given.

| Oil producer | Oil producer/Gas injector | Gas injector |
|:---:|:---:|:---:|
| 7 | 3 | 4 |

*Table 1 Number of wells with reported tubing leaks*

**Oil production wells: Possible causes and solutions**

Figure 7 shows retrieved tubing with a big hole. However, leaks in tubing usually start as small leakages and the most common leak path is through the couplings.
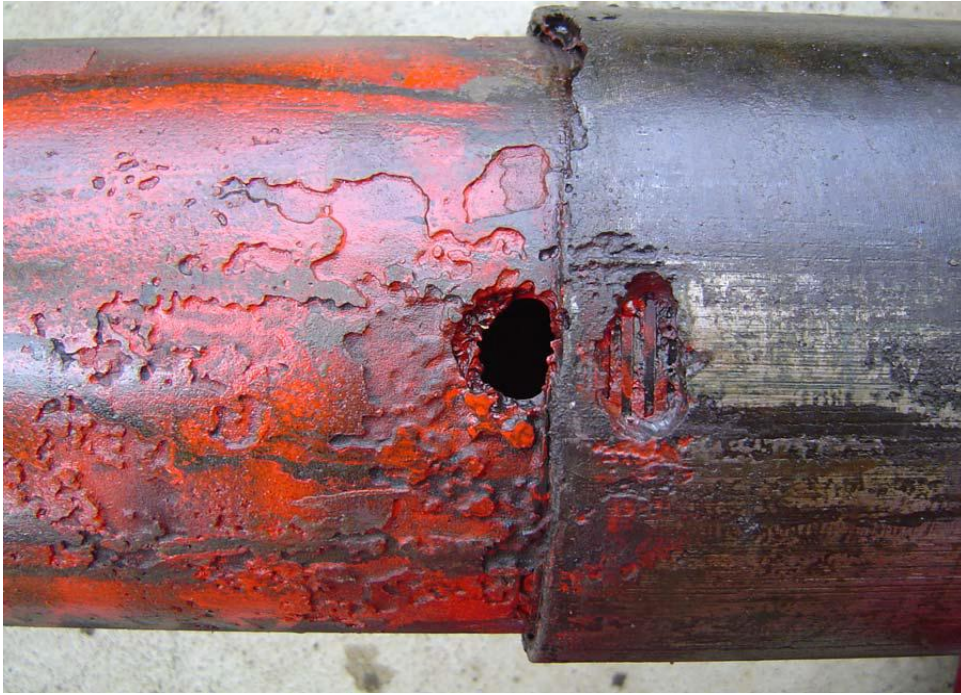
*Figure 7 Hole in the production tubing*

There are many possible sources for leaks and these will be discussed below.

*Leak in subsea valves*

The pressure in the annuli is controlled using 2-1/16" needle valves. Particles in the flow may damage or erode these valves leading to leakage. The following valves are used:

- -annulus master valve (AMV)
- -annulus wing valve (AWV)
- -annulus circulation valve (ACV)
- -cross over valve (COV)
- -annulus vent valve (AVV)

All wells (for the specific field) were equipped with needle valves except in one well where the valves have been replaced with Pacson gate valves.
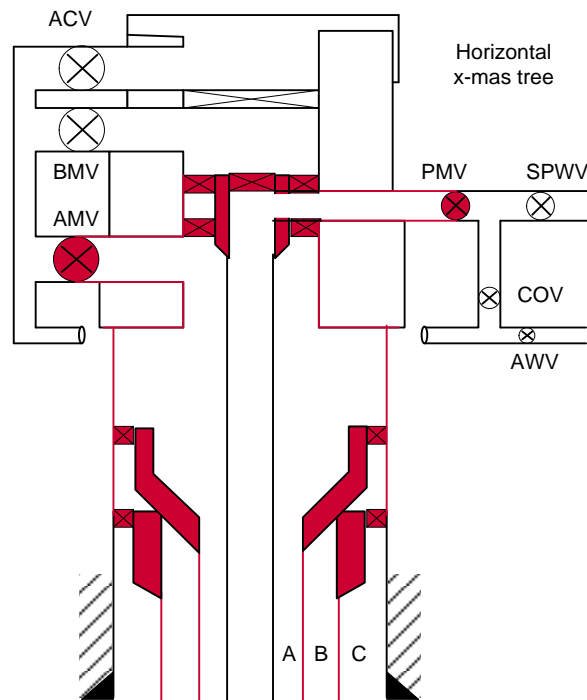
*Figure 8 Sketch of a typical horizontal subsea X-mas tree with valves*

All AWV valves are connected to a common service line, such that all valves are exposed to the same line pressure. The AMV is always open to monitor the A-annulus pressure. To pressure test one specific well, the AWV is closed on all other wells.

The ACV is always exposed to the A-annulus pressure, and in the event of leakage, it will leak to a corrosion cap. The threads on this cap are not leak tight, and the pressure can therefore communicate to the sea. Hypothetically, seawater (36 bar) could leak through the corrosion cap and the damaged needle valve and into the A-annulus, but this has not been observed. Normally, the A-annulus pressure on the specific well was 50 – 90 bar. A leak can occur through the following valves:

- ACV through corrosion cap to the sea
- AVV to the sea
- AWV to the service line
- COV from production tubing to annulus, or opposite

It was not established which valves were leaking. However, a leakage to the sea was observed in one of the wells. A test program was established to identify potential leaks. Also, at future workovers, the needle valves should be replaced with gate valves.

*Leak in the PBR*

All wells have 7" polished bore receptacles (PBR) installed. The installation procedure used is as follows:

- -Perforate in overbalance
- -Run liner stem, tubing plug, production packer and PBR in separate run.
- -Run PBR seal stem and tubing in separate run. Depth based on pipe tally, not on weight.
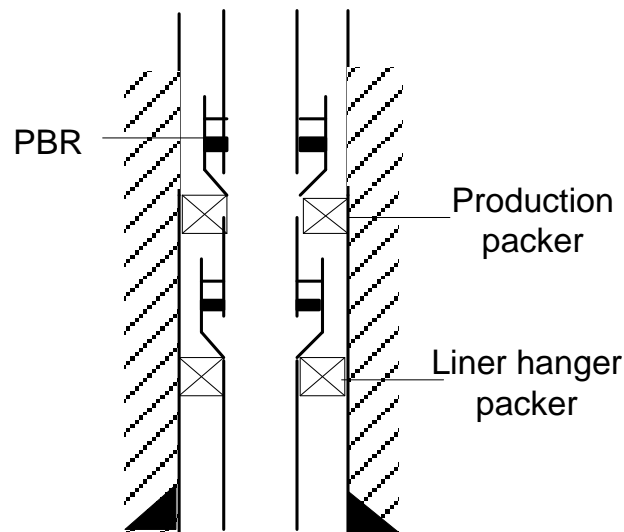


*Figure 9 Sketch showing the tubing stinging into the PBR above production packer*

This implies that the seal stem was not locked to the PBR. Lowering the seal stem 3000 m into the well may lead to wear and debris may be pushed into the PBR, leading to a potential leakage problem. Due to ballooning and temperature effects, the seal stem may move into the PBR. The surface may be corroded and scaling can be deposited.

Most wells had a higher pressure in the A-annulus than inside the production tubing (after reservoir depletion). This was also the case when the wells were shut in. A leakage was therefore possible from the A-annulus, through the PBR and into the production tubing. Several wells had experienced pressure drop in the A-annulus, indicating a possible leakage through the PBR.

*Leakage in tubing and connections due to corrosion and erosion.*

All oil producers were completed using 13 Cr tubing. Corrosion was unlikely for this material. All possible corrosion mechanisms are however, not ruled out. The wells produce

with high GOR, and sand and water is reported in the separator systems. Erosion is most likely to occur at chokes and bends. Measurements were not yet conducted. Some erosion was seen in chokes, but defined as a design problem, it has now been corrected. New Vam threads are used in part of the completion. These are notoriously weak in compression, but there is no indication that they have failed.

The completion string in well A-17 was pulled out for inspection. No corrosion was found, only minor marks on the pipe surface, and some small signs of sand erosion inside. The PBR had many small marks on the seal surfaces, but this is inconclusive with respect to leakage.

**Recommendations:**
- Measure wall thickness in surface bend to see if sand erosion is present.
- Run caliper log/ pipe thickness tool in selected wells.
- Evaluate another thread dope
- Check make-up torque chart for all tubing and assemblies run in the next well.
- Consider sand production reduction measures.
- Analyze the completion string on well A-10 when recompleted.

**Other factors**

The oil wells were perforated in overbalance before placing the completion strings in two runs. The wells were not cleaned out after perforating, which may lead to high skin (wells A-11 and A-18). It is possible that the upper perforation interval or layers of high permeability contributes to the production. The bottom-hole pressure varies 150-200 bars between production and shut-in. This will lead to movement of the PBR, and a risk of leakage. Well A-11 has a leak, and well A-18 has an indication of a leak. In drilling phase 2, alternative completion solutions should be considered.

**The following main recommendations were given:**
- Perform a leakage test program for subsea valves
- Replace needle valves with gate valves at future workovers
- Eliminate PBR where possible. If PBR is required, set new packer and pre-spaced PBR over, alternatively use extended joint.
- Verify metal-to-metal seal and pressure test seal on downhole pressure gauge.

- Verify that thread loadings are within specifications.
- Revise procedure for monitoring the A-annulus pressure in oil wells:
  - A-annulus pressure between 10 and 90 bar
  - Monitor the A-annulus pressure with other production data.
- Measure wall thickness of bends to check for sand erosion.
- Run caliper log/wall thickness in selected wells.
- Consider 13 Cr. Tubing in gas injections wells.

### 2.4.5    Case 5:  Production casing failure

Both the production tubing and the production casing in a North Sea well collapsed and had to be replaced. The events that led to this incident are described below.

The 9-5/8" production casing is installed in two operations. The bottom section is landed from 2515 m to 4815 mTVD and cemented in place.  Then the upper part of the production casing is landed on a PBR, which provides a seal. This is called a tieback solution. Repeated pressure tests were performed after installation because the pressure could not be maintained. This indicated a leak in the system. This leak could be at any location; at the PBR, in a casing connection or in the surface equipment. The surface equipment was thoroughly checked and eliminated. Finally, a couple of pressure tests were performed and accepted and the well was completed for production.

The well was set on production. At a later time it was discovered that the production casing had collapsed at a depth of about 700 m. It was decided to pull out and replace the tieback production casing.

The tieback string was changed according to the plan, and the well is now back in production. A possible root cause of the failure is that there was a leak somewhere in the production casing or at the PBR, such that pressure was built up behind the casing during pressure testing.  During production thermal effects caused the pressure behind the production casing to exceed the collapse resistance of the casing. Repeated casing pressure tests should question the integrity of the casing.

Another root cause was found during inspection of the retrieved casing. Figure 10 shows the deformed tubular. The production casing was a 9-5/8" N80 53.5 lbs/ft. The failed casing was

47 lbs/ft, which has 30 % lower collapse resistance. Only one length of this quality was found, and there were no records showing why one weaker casing length was placed in the production string. The collapse resistance of the 53.5 lbs/ft production casing was 456 bar, whereas the collapse resistance of the 47 lbs/ft casing joint was 328 bar, a reduction of 28 % in collapse resistance.



*Figure 10 Failed production casing and production tubing*

The consequences of this incident were:

- High cost to replace both production casing and production tubing.
- High cost of production loss as the well was shut in for a long time.
- Improve casing test procedures and qualification of casing tests
- Improve casing inspection/control procedures

### 2.4.6    Case 6:  Well failure

This was one of the major incidents in the North Sea area.  During a workover, a gas blowout occurred outside the well from the reservoir to the seabed.  Craters were formed at the seabed template, and gas formed underneath the entire platform.  Most of the personnel were evacuated, and the well crew managed to take control and kill the well. Fortunately, this incident happened on a day with no wind in this part of the North Sea, which is very unusual.

For that reason gas accumulated underneath the entire platform giving it a significant potential for explosion and fire. Luckily the situation was controlled with no further dangers.

There were many elements that contributed to this event. Originally, the well had a hole in the casing that was isolated with a scab liner. During the workover, the scab liner was retrieved without proper barriers in place. When retrieving the scab liner, then the small clearance between the scab liner and the casing lead to swabbing followed by a kick. This happened at the same time as a barrier element of the second well barrier was removed (scab liner).
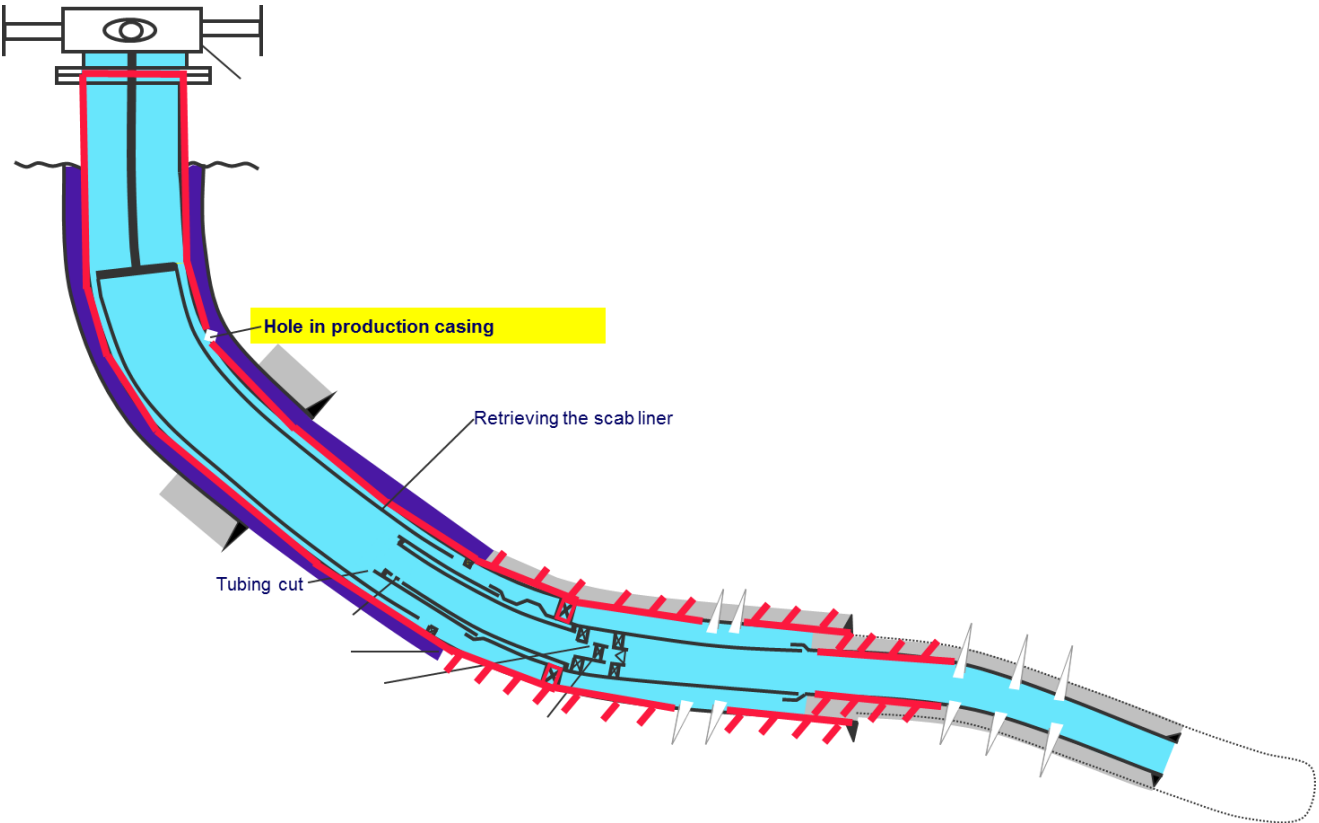


*Figure 11 Sketch of situation when the scab liner was pulled out of hole*

Because gas leaked from the reservoir into the well, out through the casing hole and along the outside of the well up to seabed, both well barriers had failed.  This case shows the importance of knowing the status of the well barriers at all stages of the well operation.

*Figure 12 Washed out formation around the well*

Consequences were severe:

- The entire platform production was stopped for weeks, but not fully restored until after several months, leaving a considerable loss in income.
- The incident occurred due to removal of secondary barrier element (scab liner) and simultaneous failure of the primary mud barrier (swabbing) during the operation.

## 3.   Well Construction and Field Development

### 3.1   Well Types and Well Life Cycle

There are basically two types of wells:

**Exploration well:** The main purpose of an exploration well is to find potential reservoirs for future development and production. These wells are normally plugged after logging / testing.

**Production / injection wells:** After drilling, these wells are completed for production and / or injection. Water or gas is normally injected into the reservoir to maintain pressure. After the production phase has ended, plugging and abandonment of the well takes place.

For offshore field developments, different types of drilling rigs can be used. Examples are bottom-supported platforms like Jack-up rig, steel jacket-based platform, concrete-based platform and Mobile Offshore Drilling Unit (MODU) like semi-submersible drilling rig and drill ship. Field development can be divided into exploration, development, production and abandonment phases.

### 3.2   Subsea drilling

Figure 13 illustrates typical casing program for a subsea well.
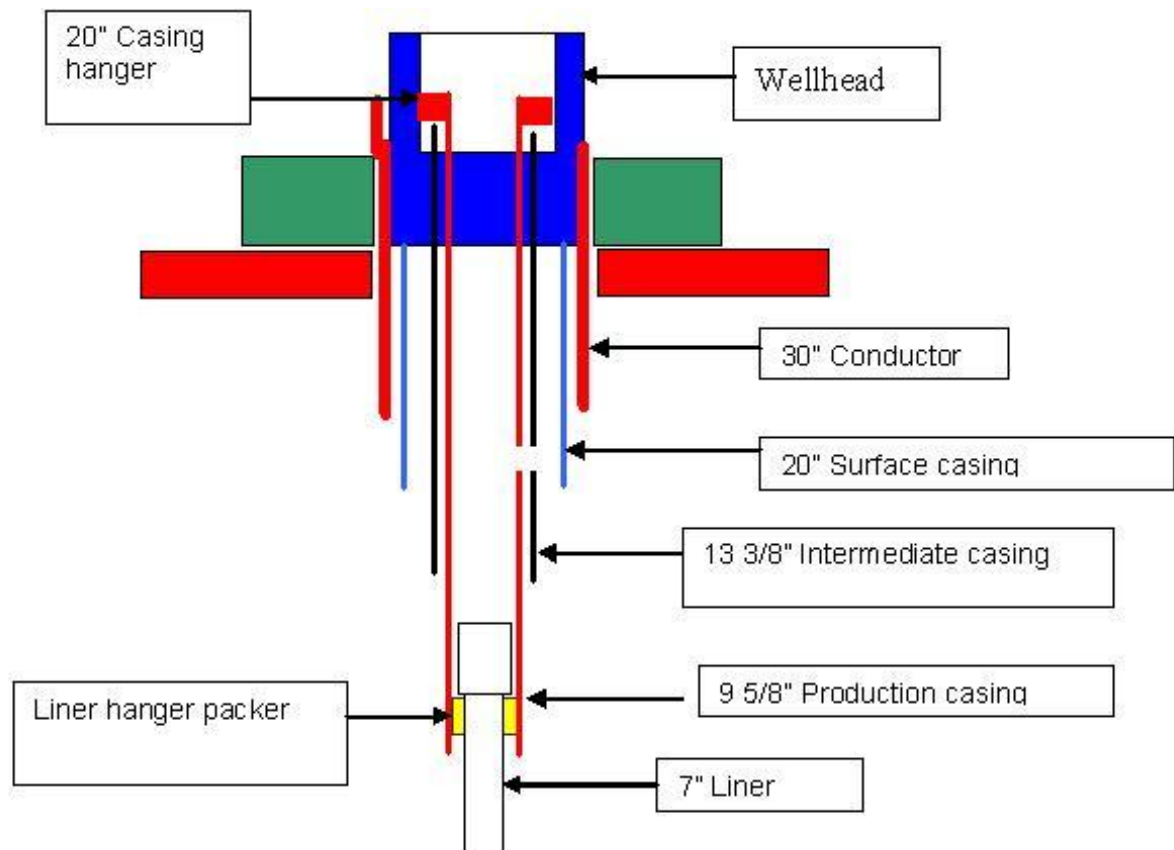
*Figure 13 Typical casing program for a subsea well*

Drilling fluid is circulated through the rotating drill string and the drill bit and through the annulus between the drill string and the borehole. The casing strings are used to stabilize the borehole. The following illustrates a typical casing program for a subsea well. When drilling the 36" hole for the 30" conductor, the drill cuttings from the borehole are circulated and disposed on the seabed. After the hole has been drilled, the 30" conductor casing is run and cemented in place. The main objective of the conductor casing is to isolate the well from unconsolidated surface zones. Then the 26" hole for the 20" casing is drilled with drilling fluid return to seabed (in the past, a marine drilling riser were used for drilling this section). The 20" casing which is connected to the wellhead (often termed wellhead casing or surface casing) is then installed and cemented in place. The main objectives of the wellhead casing are to isolate the well from unconsolidated surface zones, support the weight of the BOP and other casing strings, and protect the well from shallow water and shallow gas reservoirs. Normally, cement is displaced all the way to the wellhead.

Today, mud recovery systems may be used when drilling the top hole sections (holes for 36" and 20" casing string) to avoid drilling fluid return to sea.

After the surface casing is set and cemented, the Blow-Out Preventer (BOP) is run on the marine drilling riser and connected to the subsea wellhead. The drilling riser is used for the return of drilling fluid back to the drilling vessel where the drill cuttings are removed before the drilling fluid is re-circulated into the borehole. The next hole size will typically be 17 ½" and the corresponding intermediate casing string will be 13 3/8". The main objective of the intermediate casing string is to protect zones from circulation losses, isolate zones with low or high pressure  and isolate hydrocarbon formations that might not be produced temporary or permanently. Further, the 12 ¼" bit is used to drill the hole section for the 9 5/8" production casing. The purpose of the production casing, which is typically set in the cap rock above the reservoir, is to protect the production tubing, allowing the hydrocarbons to be produced safely. Finally the 8 ½" bit is used to drill the hole section for the 7" casing string. Normally, the 7" casing string is run as a liner. A liner is a pipe extension from the last set of casing string. A liner is normally extended back to the wellhead using a tie-back string.

The formation pore- and fracture pressure are normally converted to an equivalent mud weight with reference to the drill floor level (RKB). This is illustrated in Figure 14.

The conductor casing is typically set a 50 - 80 m below the seabed (BSB). The casing setting depth is normally dictated by the geology, formation pore/collapse pressure and the fracture pressure. Figure 14 shows a typical pore- and fracture pressure plot. During drilling the mud weight must be kept above the pore pressure and below the fracturing pressure to avoid well fluid influx from the formation (kick) and mud losses to the formation. Losses may reduce the hydrostatic head and overbalance and result in a possible kick. The drilling mud is the primary well barrier during the drilling phase. Typical safety margins for mud used in drilling are 30 kg/m3 and 10 kg/m3 towards the pore pressure and fracture pressure respectively.
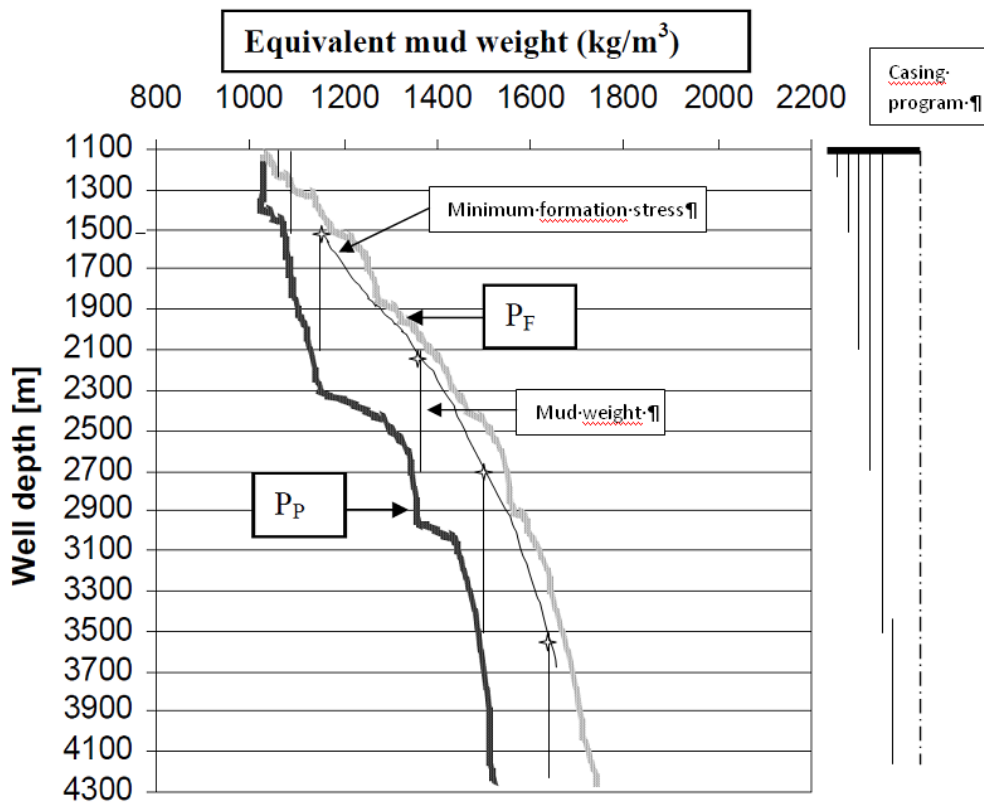
*Figure 14 Equivalent mud weight, equivalent pore pressure (Pp) and equivalent fracture pressure (Pf )/ equivalent minimum formation stress vs. depth (TVD)*

For a well in operation or a well that is to be permanently plugged and abandoned, the integrity of formation as part of the well barrier envelope should be ensured. Information about the minimum formation stress of the formation being a part of the barrier envelope should therefore be gained during drilling and used as baseline for maximum allowed pressure for the formation as barrier in these phases.

The minimum formation stress is the same as the fracture closing pressure, and information about the minimum formation stress is gained through extended leak off testes (XLOT). Figure 15 shows the typical pressure behavior in the well when pressure is exerted to the formation. Any pressure in the well above the minimum formation stress may lead to reopening of fractures and natural faults and lead to leakage to the environment. When the pressure is reduced to the minimum formation stress, the fracture closes and the integrity of the formation is regained.
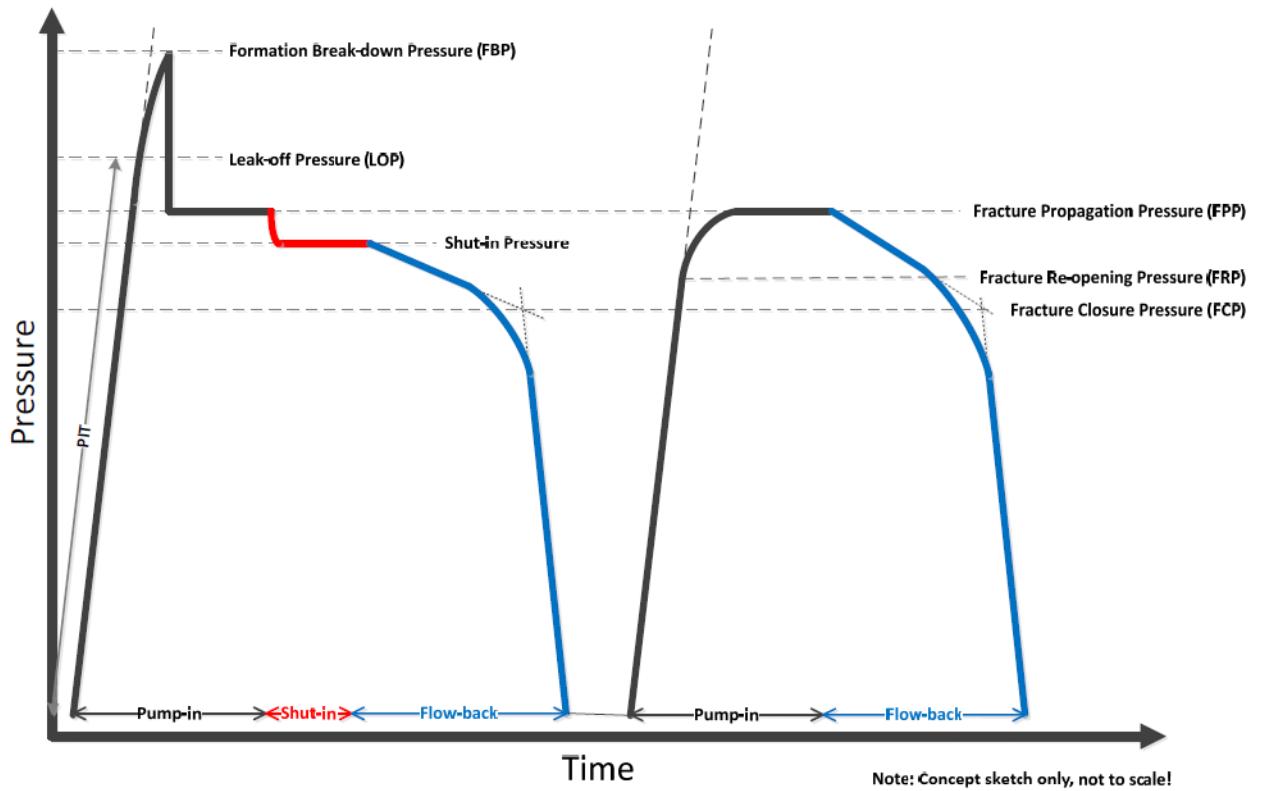
*Figure 15 Typical pressure behavior when performing XLOT*

A well stability plot is shown in Figure 16. It is seen that the mud weight is planned lower than the "Mini frac" test data in the area in the different hole sections.

# WELLBORE STABILITY PLOT

## Field : Offshore Continental
## Well: ABC Airgap: 25 m   Water Depth: 114 m
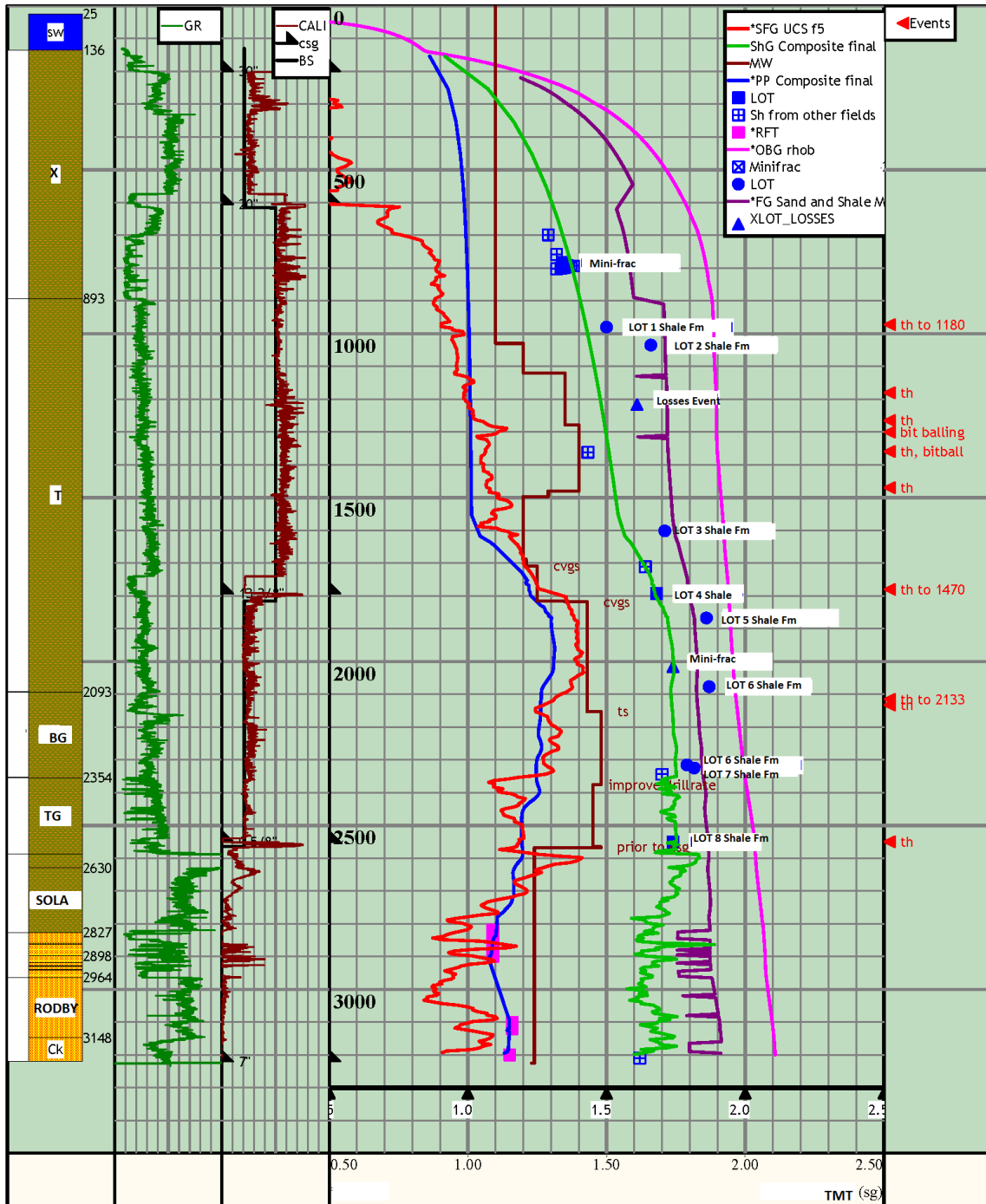


*Figure 16 Example of a wellbore stability plot from the oil industry*

## 3.3    Platform drilling

Drilling a well from a seabed-supported platform is less complicated compared to using an MODU, simply since there is no movement of the vessel, and the BOP is located on the platform making maintenance and operations more convenient. The conductor in normally installed using the hammer technique to drive the pipe into the top hole formations. Then drilling continues more or less as in subsea drilling as discussed above. The main advantages are access for monitoring of the annulus, easy wellhead access and less complicated and lower cost well intervention.

## 3.4    Subsea Well Completion

Well completion takes place in order to prepare the well for production or injection. Typical steps are as follows:

1. A production tubing is RIH, tubing hanger landed and production packer is set.  The completion is then pressure tested to verify integrity, See Figure 17
2. An X-mas tree (steel block) with valves for controlling the fluids is installed on top of the wellhead, See Figure 18
3. A control umbilical is used to control the X-mas tree and downhole functions
4. A pipeline system is connected to the X-mas tree for production or injection
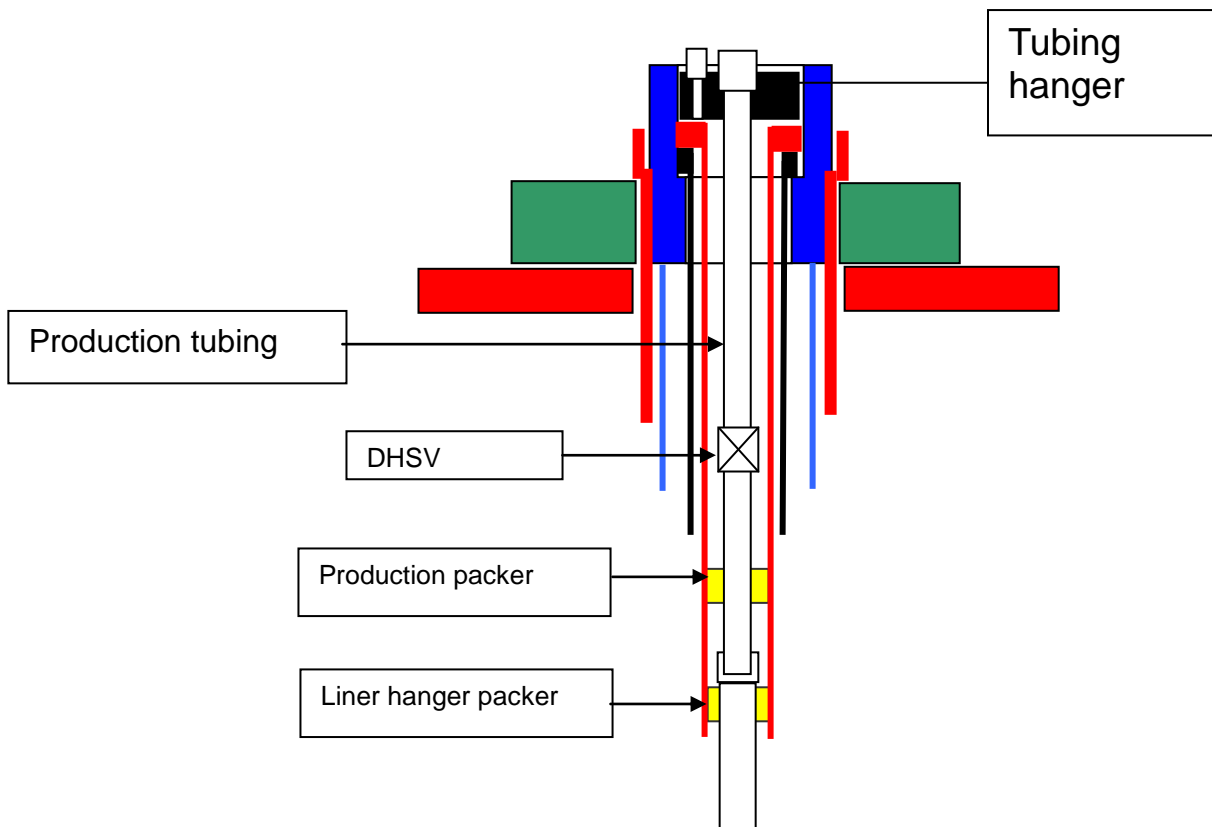
Figure 17 *Example of subsea well with tubing hanger and tubing string installed (for vertical X-mas tree installation)*

### 3.4.1    Types of X-mas trees for subsea wells

The subsea X-mas tree provides the primary method of closing a well and controlling fluid flow during production or injection. A subsea tree is designed to control the flow of hydrocarbons from the well through a collection of valves and fittings. The valves enable the well to be externally shut-in if needed. Some other functions of the subsea X-mas tree include chemical injection point, well monitoring points and vertical access for well intervention.

There are two main types of X-mas tree:

- Conventional (dual bore / vertical) X-mas tree: The tubing hanger and tubing is suspended in the wellhead. See Figure 18
- Horizontal X-mas tree: The tubing hanger and the tubing are suspended in the X-mas tree. See Figure 19
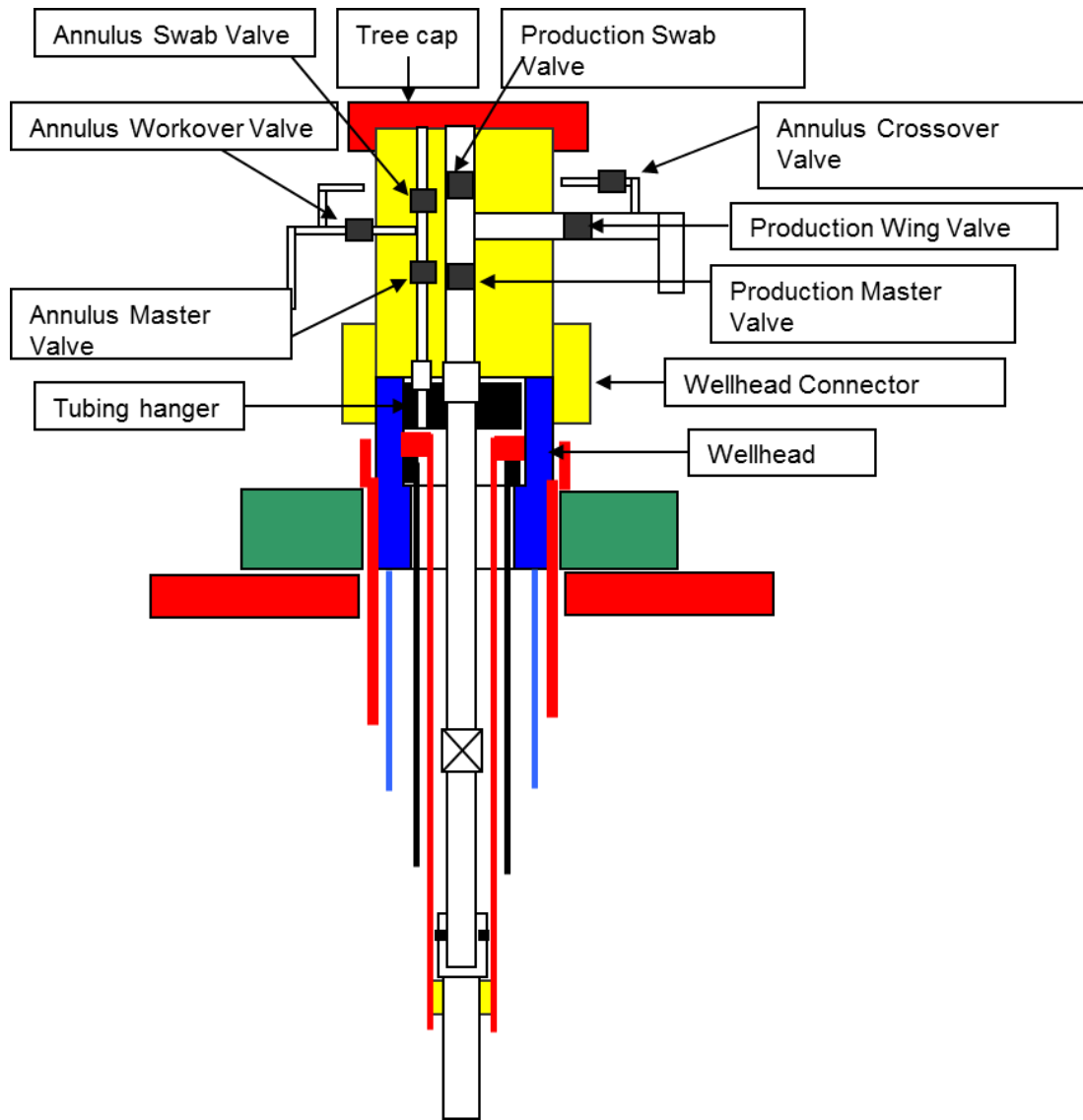
*Figure 18 Subsea well with vertical X-mas tree (dual bore through X-mas tree and TH)*
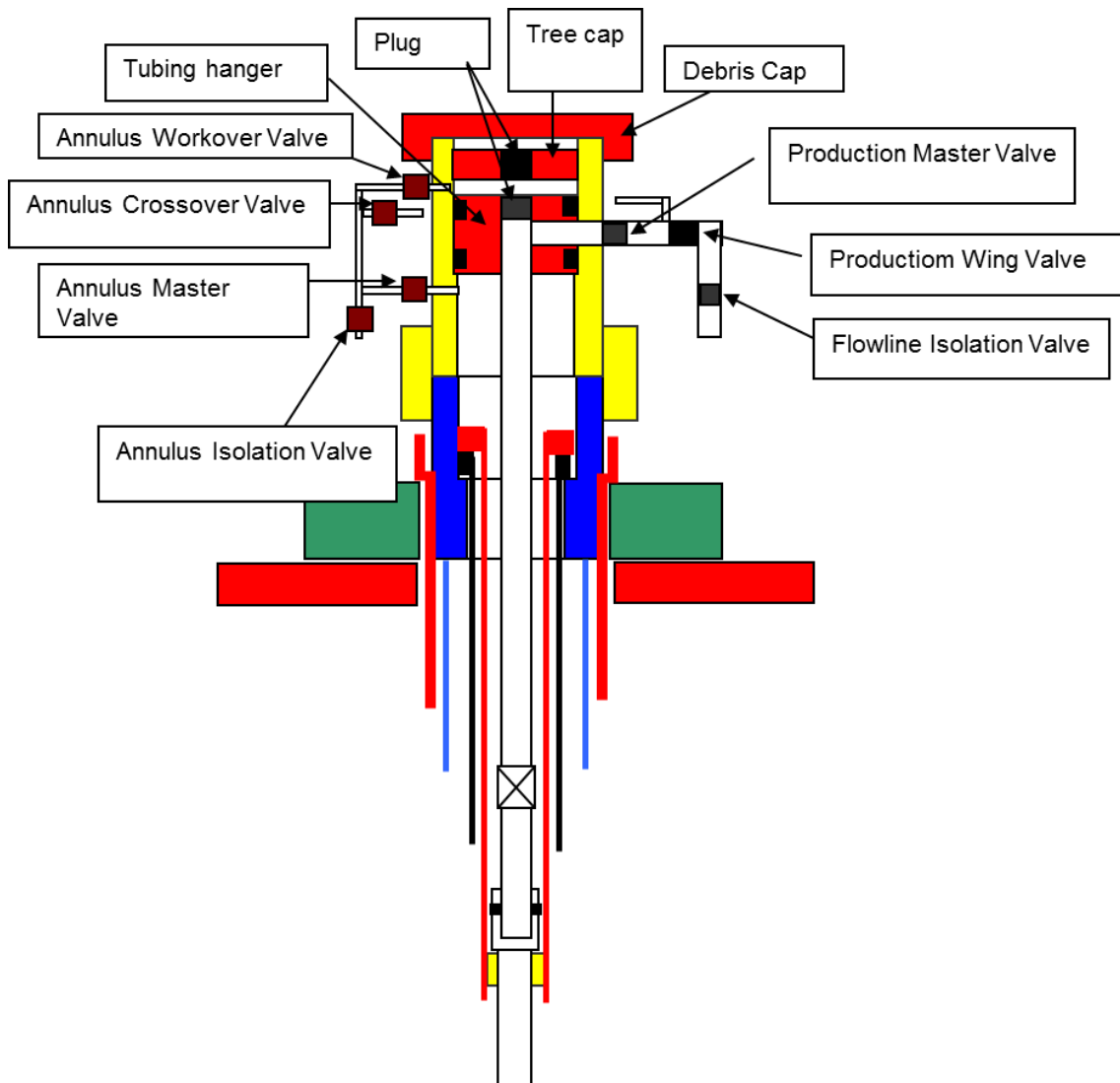
*Figure 19 Subsea well with horizontal X-mas tree*

The most significant differences between the vertical and horizontal tree are the position of the valves and tubing hanger. The X-mas tree is frequently selected out from both configurations. The advantage of the horizontal X-mas tree is that it has the ability to remove the tubing without removing the tree. So, if more frequent replacement of the production tubing is expected compared to the X-mas tree, a horizontal tree may be selected. Installation of a horizontal X-mas tree reduces the amount of equipment needed, time and cost. It also allows easier access for well intervention. A disadvantage is when the tree itself has to be removed. In this case, the upper completion (tubing hanger, tubing, DHSV, etc.) has to be retrieved which is a time consuming and costly operation. Additional disadvantages would be that interventions through the tubing are more difficult than a vertical tree since removing or

installing plugs is more difficult than opening or closing the valves in the conventional X-mas tree.

Below is a description of the main valves in a subsea X-mas trees used for the production phase:

- *Master valve:* It is used to completely shut in the well production tubing/annulus. The valve is usually a 5 1/8" double acting seal valve. The production master valve is situated between the wellhead and the production bore and the annulus master valve is a valve on the bore into the annulus. The annulus master valve is used for shutting in any production or injection in the annulus, i.e. gas lift. The valves are power operated fail-safe closed valves.

- *Wing valve:* The wing valve controls the production/injection or annulus flow. The valve is usually a 5 1/8" double acting seal valve. The valve is usually located downstream of the master valve in the production bore and the annulus bore.

- *Cross over valve (XOV):* This valve provides communication between the annulus and the production bore which normally is isolated.

- *Choke valve:* The choke valve controls the flow and is located downstream of the production wing valve. It is typically operated by a hydraulic stepping actuator. The valve is retrievable and prone to erosion risk.

Typically, smaller pipes are connected to the production tubing branch (between PMV and PWV). Two of these are used for injection of chemicals such as scale inhibitor (SIV) and methanol (MIV).

The X-mas tree valves may need to be closed due to different situations such as functional and pressure tests, shut-down on the platform and deterioration or leakage of subsea equipment. This is why the hydraulic operated subsea X-mas tree valves in the production phase are fail-safe close. This means that the valves will automatically close if the signal or hydraulic control pressure is lost. Usually the valves are closed by a preprogrammed shutdown sequence. If it is impossible to close the X-mas tree valves by using the control system, the hydraulic fluid in the valve actuators may be drained from various places. In this case closing operation will be more time consuming.

## 3.5 Surface well completion

Figure 20 illustrates a surface wellhead system. The different casing strings are supported in the wellhead in separate casing hanger spools with annulus access for pressure monitoring. The X-mas tree is stacked on top of the wellhead as illustrated in Figure 21
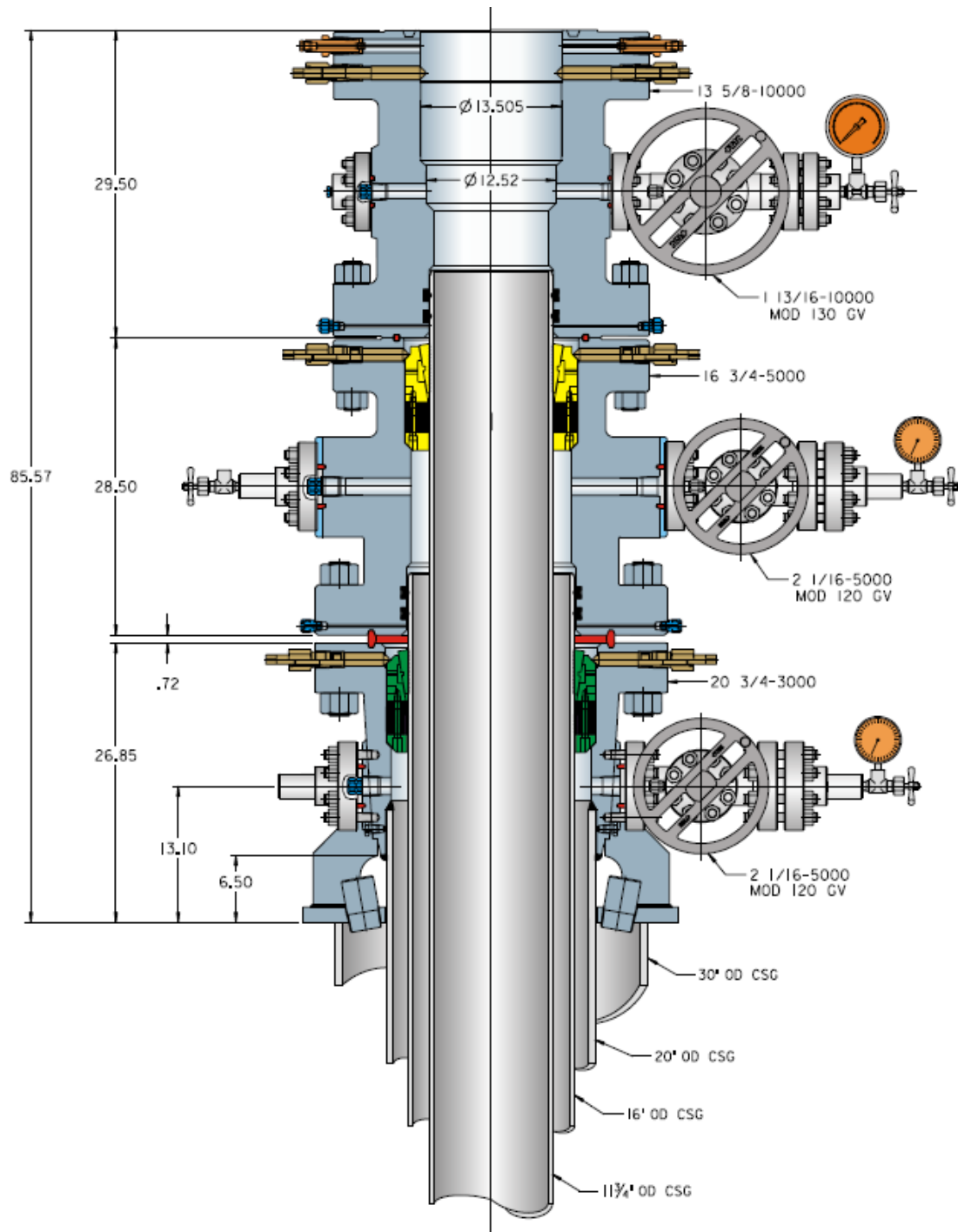
Figure 20 Surface wellhead system (FMC Energy Systems)

The following valves are always to be fail-safe closed:

- Hydraulic master valve (HMV)

- Production wing valve (PWV)

- Exit blocks for chemical injection

The surface X-mas tree usually consists of one solid block with the valves integrated. Figure 21 shows an example where the X-mas tree consists of valves flanged together (not one solid block).
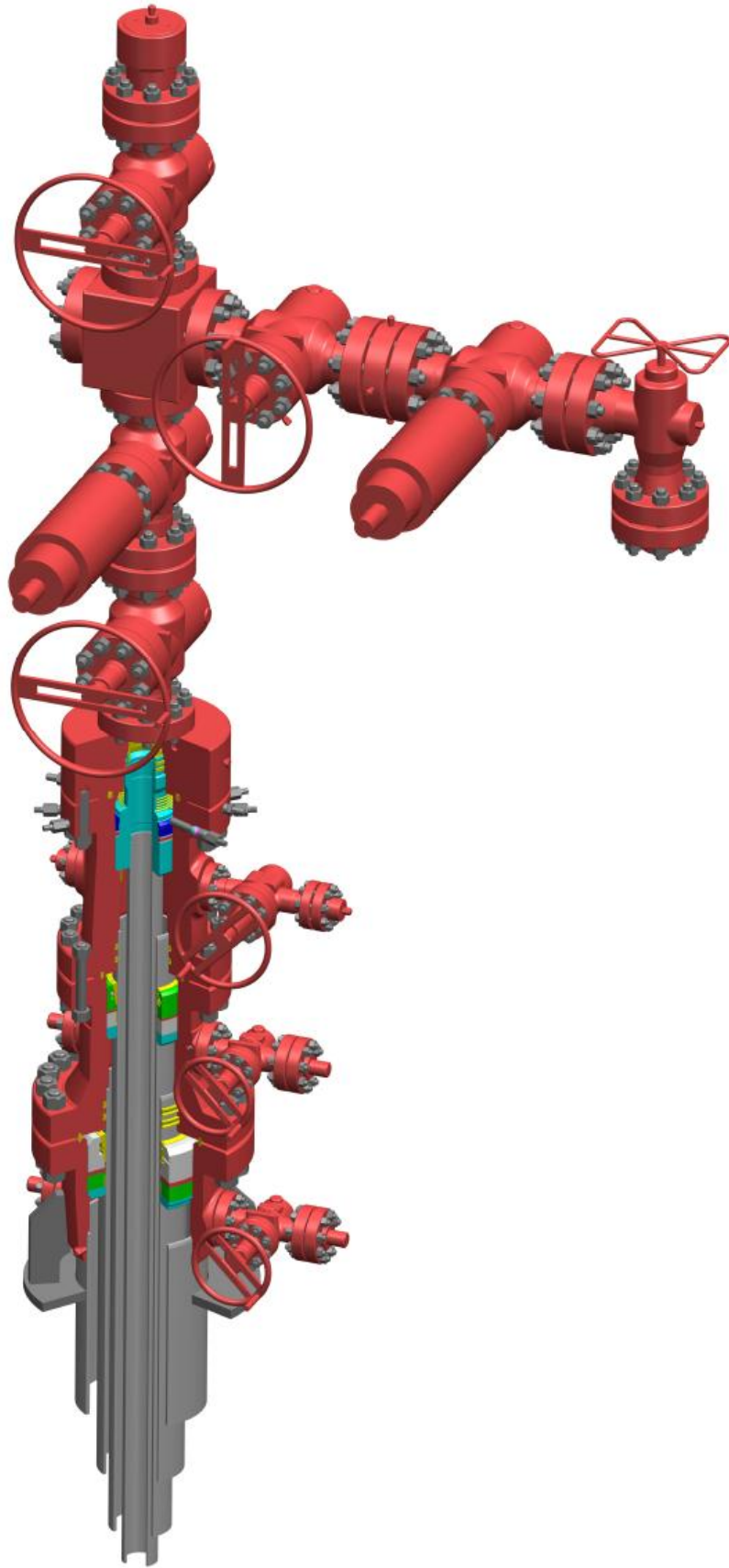
Figure 21 Surface wellhead and X-mas tree (FMC Energy Systems)

For surface completed wells all annuli are usually available through wellhead valves for possible control and monitoring of pressure. For wells with a subsea wellhead with a surface X-mas tree they may have limited access to the annuli outside annulus A. Such limitation is typical for TLP platform wells. The difference is shown in Figure 22
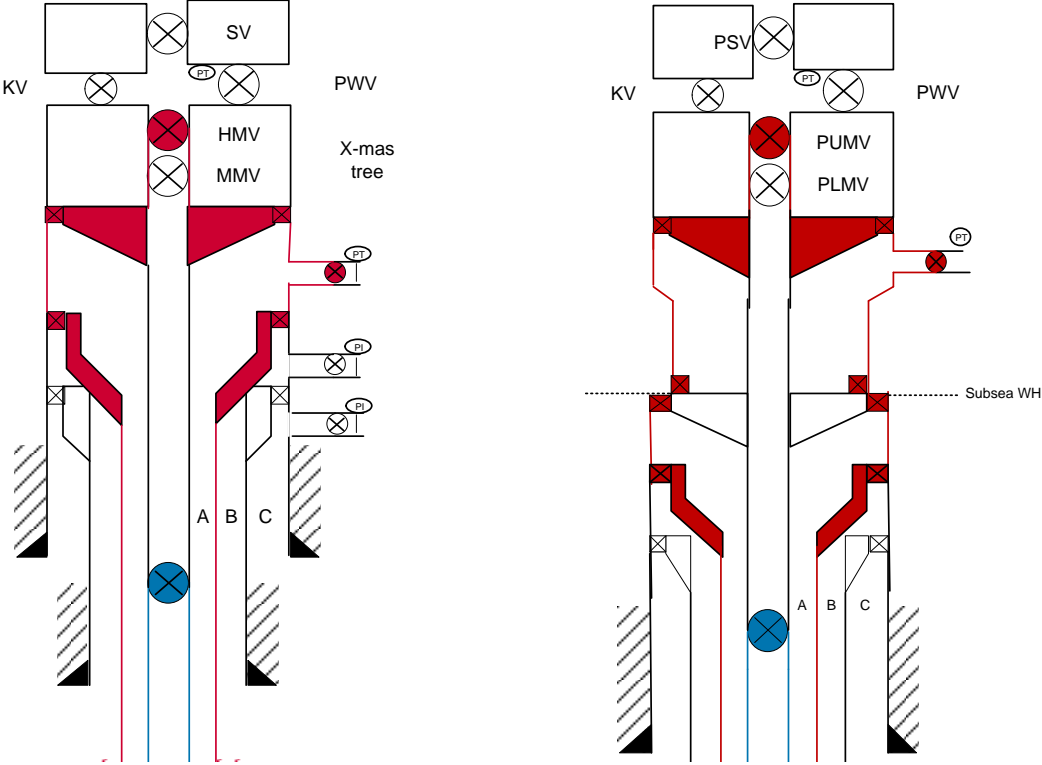


*Figure 22 Typical difference between annulus monitoring possibilities for platform well versus platform TLP well*

# 4. Well Barriers – definitions, classification, and requirements

## 4.1 Key concepts and definitions

Well barriers are used to prevent leakages and reduce the risk associated with drilling, production and intervention activities.

**Well barrier:** Envelope of one or several dependent barrier elements preventing fluids or gases from flowing unintentionally from the formation into another formation or to surface [NORSOK D-010].

The main objectives of a well barrier are to:

- Prevent any major hydrocarbon leakage from the well to the external environment during normal production or well operations.
- Shut in the well on direct command during an emergency shutdown situation and thereby prevent hydrocarbons from flowing from the well.

A well barrier has one or more well barrier elements.

**Well barrier element:** Object that alone cannot prevent flow from one side to the other side of itself [NORSOK D-010].

Some well barriers have several barrier elements that, in combination, ensure that the well barrier is capable of performing its intended function(s).

Events and situations that require a functioning well barrier are called demands. A demand can be instantaneous or continuous. An example of an instantaneous demand is a command from the emergency shutdown system at the platform that requires response from the well barriers. A continuous demand may be a constant high pressure (that the well barrier must withstand).

In general, there are four main ways in which hydrocarbons can leak from the system to the environment:

- Through the downhole completion tubing string
- Through the downhole completion annulus
- Through the cement between the annuli
- Outside and around the well casing system

## 4.2    Well Barrier Requirements

The performance of a well barrier may be characterized by its:

- Functionality; what the barrier is expected to do and within what time
- Reliability (or availability); the ability, in terms of probability, to perform the required functions under the stated operating conditions and within a specified time.
- Survivability; the ability of the barrier to withstand the stress under specified demand situations.

Regulatory bodies give overall requirements in their regulations, and make references to guidelines and recognized national and international standards for more detailed requirements. The Norwegian Petroleum Safety Authority (PSA) uses, for example, the following regulatory hierarchy:

- Regulations
- Guidelines (to the regulations)
- National and international standards that are referenced in the guidelines, such as NORSOK standards, ISO standards, API standards, and IEC standards.

We may distinguish between requirements that apply to barriers in general (e.g., as stated in PSA's Management Regulations, §4 and §5), and requirements that apply to well barriers in particular (e.g., as stated in PSA's Facilities Regulations, §48). The associated guidelines provide further details and give references to specific parts of national or international standards. The guideline to §48 of the Facilities Regulations, for example, refers to specific

chapters of the NORSOK D-010 standard and also to specific sections of the Management Regulations.

From the guideline to §48 of the Facilities Regulations, and the referenced standards, the following requirements can be deduced:

- At least two independent and tested barriers shall, as a rule, be available in order to prevent an unintentional flow from the well during drilling and well activities.

- The barriers shall be designed so as to enable rapid re-establishment of a lost barrier.

- In the event of a barrier failure, immediate measures shall be taken in order to maintain an adequate safety level until at least two independent barriers have been restored. No activities for any other purposes than re-establishing two barriers shall be carried out in the well.

- The barriers shall be defined and criteria for (what is defined as a) failure shall be determined.

- The position/status of the barriers shall be known at all times.

- It shall be possible to test well barriers. Testing methods and intervals shall be determined. To the extent possible, the barriers shall be tested in the direction of flow.

Separate regulations are issued by the PSA for handling of shallow gas in drilling operation. When drilling the tophole section, the gas diversion possibility is regarded as the second barrier. This is, however, not a barrier according to the barrier definition above.

## 4.3    Well Barrier Functions

In the analysis of well barriers, it is important to understand the barrier functions and the possible ways the barrier can fail.

NORSOK D-010 distinguishes between *primary* and *secondary* well barriers. A primary well barrier is the barrier that is closest to the pressurized hydrocarbons. If the primary well barrier is functioning as intended, it will be able to contain the pressurized hydrocarbons. If the primary well barrier fails (e.g., by a leakage or a valve that fails to close), the secondary barrier will prevent outflow from the well. If the secondary well barrier fails, there may, or may not, be a *tertiary* barrier available that can stop the flow of hydrocarbons.

**Examples:** For operations in a killed well, the hydrostatic pressure is regarded as the primary

barrier, and the topside equipment, usually a BOP, is regarded as part of the secondary barrier together with cemented casing and sufficient casing shoe formation strength (See Figure 23 )
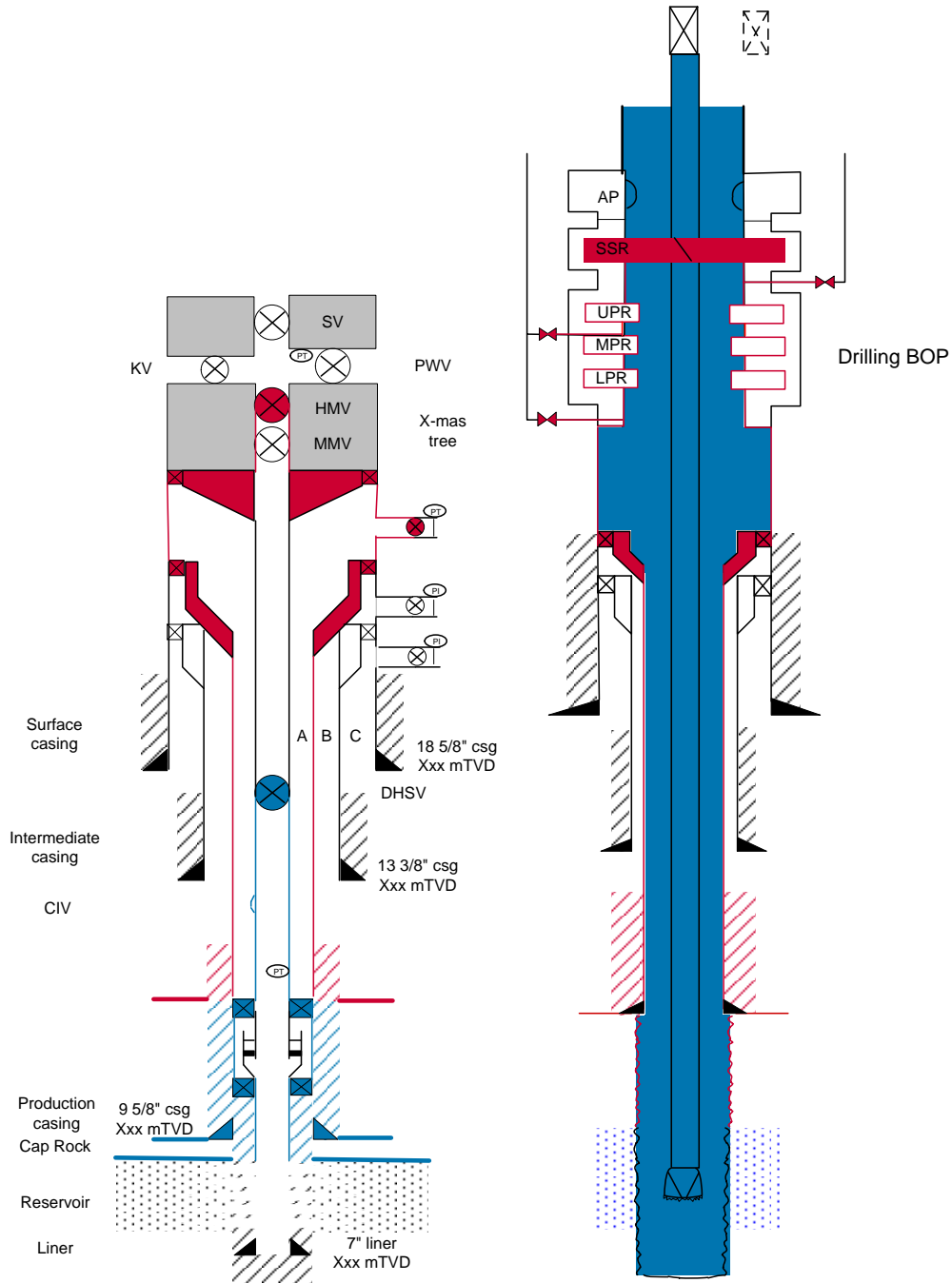


*Figure 23 Primary and secondary barriers in production and drilling mode*

Barrier elements that involve electrical, electronic, and/or programmable electronic technology are referred to as safety-instrumented functions. An example of a safety-

instrumented function is the DHSV, which is only activated upon signal from sensors or manual pushbuttons. Safety-instrumented functions are carried out by a safety-instrumented system with three main subsystems:

- Input elements; sensors (for automatic activation) or push-buttons (for manual activation)
- Logic solver(s); an electronic or non-electronic device that process the signal(s) from the input elements and send signals to the relevant final elements
- Final elements; physical items that interact with the well, for example valves, such that loss of containment is stopped or avoided.

Several safety-instrumented functions may be built into the same safety-instrumented system. The same logic solver may, for example, be used to activate several isolation valves. However, there are some important design considerations: Functions that shall respond to the same event (e.g., well kick or choke collapse) should not share components. This means that if the primary and secondary barriers have safety-instrumented functions, they need to be placed in two different (and independent) safety-instrumented systems to avoid that a failure of the logic solver causes simultaneous failure of the primary and the secondary barrier. On an oil and gas installation, there are several safety-instrumented systems with names related to their essential function: emergency shutdown systems, process shutdown systems, fire and gas detection systems, and so on.

## 4.4   Well barrier schematics and diagrams

Well barriers and their role in preventing or acting upon leakages from wells may be illustrated in many different ways. We distinguish between:

- Well barrier schematics
- Barrier diagrams

Well barrier schematics and well barrier diagrams are important tools for reliability and risk assessments of the well in all phases of its life cycle – and for well integrity assessments.

**Well life cycle**: The time interval from a well's conception until it is permanently abandoned.

### 4.4.1　Well barrier schematics

A well barrier schematic (WBS) is a static illustration of the well and its main barrier elements, where all the primary and secondary well barrier elements are marked with different colors. A well barrier schematic (WBS) is shown for a standard production well in Figure 23 This well has six *primary* well barrier elements:

- Formation /cap rock above reservoir
- Casing cement
- Casing
- Production packer
- Completion string (below the DHSV)
- Surface controlled subsurface safety valve (DHSV)

- and six *secondary* well barrier elements:

- Formation above production packer
- Casing cement
- Casing with seal assembly
- Wellhead
- Tubing hanger with seals
- Annulus access line and valve
- Production tree (X-mas tree) with X-mas tree connection

Examples of well barrier schematics for a wide range of well situations are established and evaluated in NORSOK D-010.
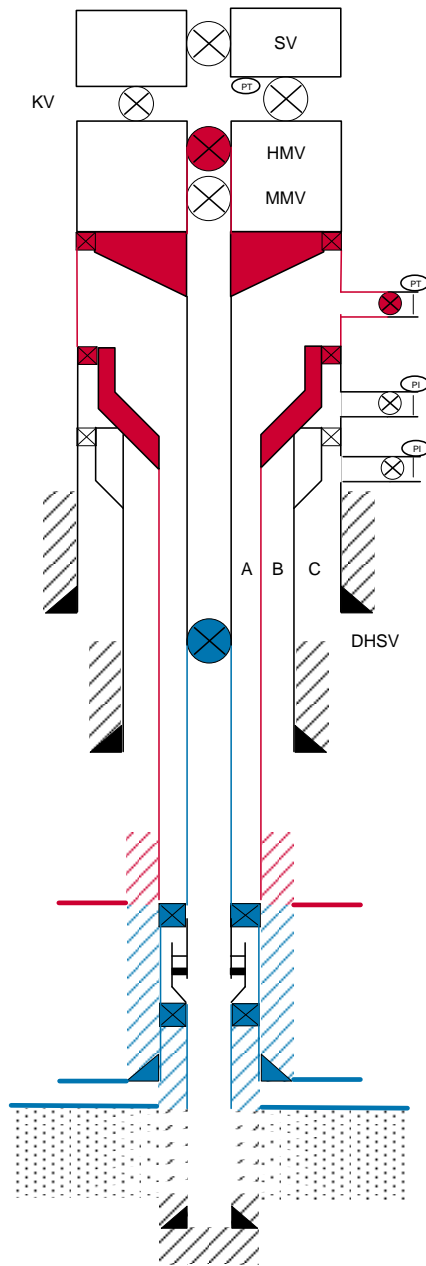
*Figure 24 Well barriers schematic for a standard production well.*

### 4.4.2    Well barrier diagrams

The well barriers can also be illustrated by a well barrier diagram. The well barrier diagram is a network illustrating all the possible leak paths from the reservoir to the surroundings. What is meant by surroundings depends on the situation and may be the external environment (e.g., the sea for a subsea well, the platform deck for a topside X-mas tree), or some parts of the system (e.g., the flowline from a subsea well). A well barrier diagram for the production well in Figure 24 is shown in Figure 25.
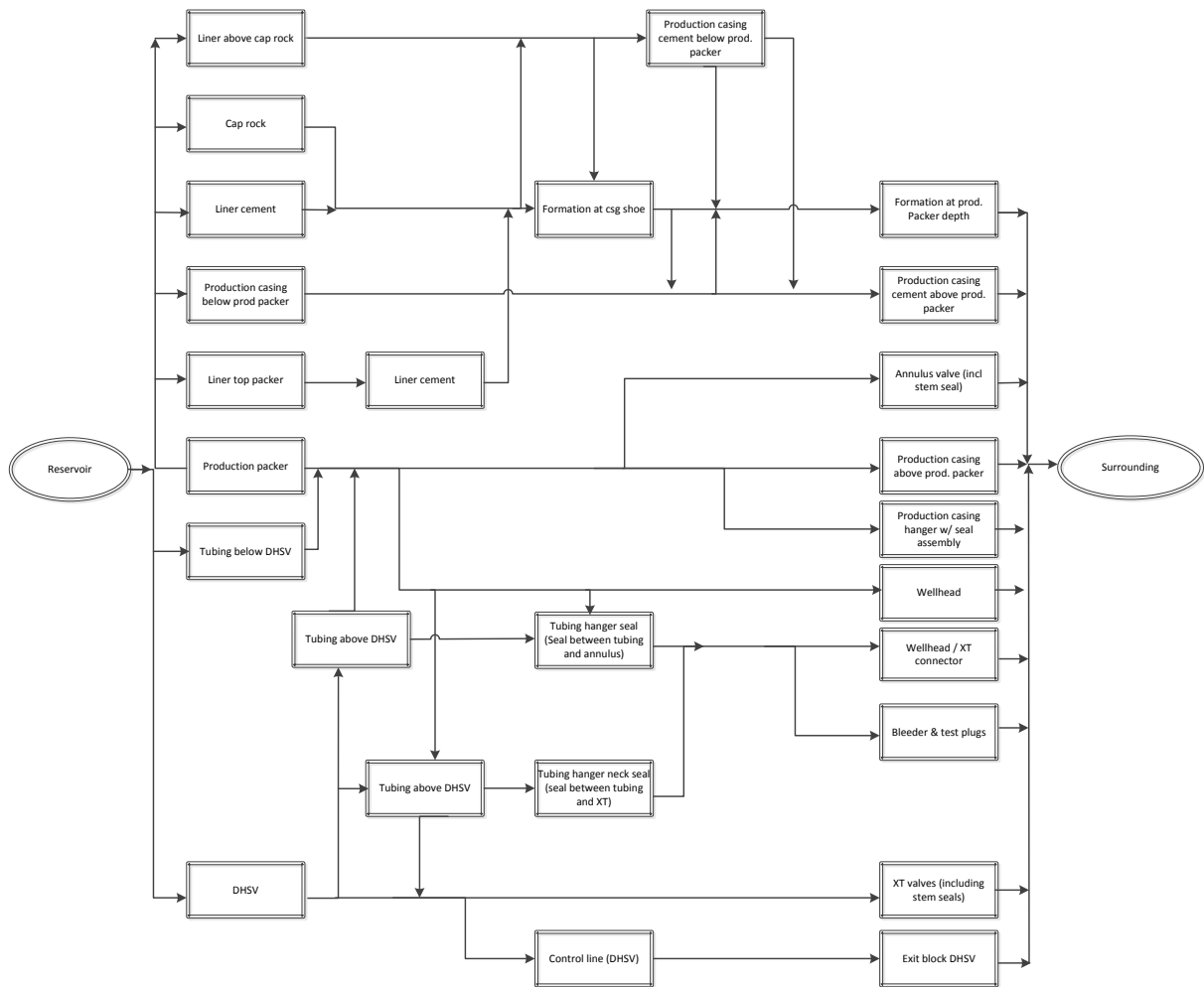
*Figure 25 Barrier diagram for the production well in Figure 24.*

All the paths from the reservoir to the surroundings in Figure 25 are possible leakage paths. If, for example, the DHSV and the X-mas tree valves (including the stem seals) both have critical failures (i.e., fail to close or leakage in closed position), there is a leakage from the reservoir to the surroundings. A barrier diagram may be drawn in many different ways; an option is to draw the diagram vertically with the reservoir in the bottom and the surroundings in the top. The logic of the diagram should, however, be the same in all options.

A well barrier diagram for a complex well situation may be rather complex with many possible leakage paths. Well barrier diagrams are best suited for static situations, i.e., for wells in production. Barrier diagrams are useful for keeping an overview when analyzing various well barrier arrangements and for analyzing the reliability of the barriers.

## 4.5    Reliability analysis and methods

The term reliability conveys failure-free operation and confidence in the equipment. Formally, reliability is defined as the ability of a system to perform its intended functions, under given environmental and operational conditions and for a stated period of time (IEC 600050-191). The ability can be studied qualitatively, for example by identifying the combination of component failures that may lead to system failure, or quantitatively, by calculating the probability or frequency of system failures.

### 4.5.1    Reliability analysis of well barriers

In the context of well integrity, we will introduce reliability analysis methods that can be used to identify and assess the impact of failures of well barrier elements. Such analyses are useful for:

- Comparing different well completion alternatives with respect to blowout probabilities
- Evaluating the blowout risk for specific well arrangements
- Identifying potential barrier problems in specific well completions
- Assessing the effect of various risk reduction methods
- Identifying potential barrier problems during well interventions

After many incidents and accidents in relation to well integrity, more focus has been directed towards assessing the reliability of well barriers. The purpose of this section is to describe some of the methods that can be used to analyze well integrity – qualitatively as well as quantitatively. To be able to perform quantitative analysis it is necessary to have a background in system reliability theory. The quantitative part is therefore limited to giving a small practical example with basis in available well performance data. To give a thorough basis for system reliability theory is outside the scope of this compendium. Readers who want to get a deeper understanding of this subject may consult Rausand and Høyland (2004) or some other textbook on reliability theory.

### 4.5.2    Analysis steps

A well barrier analysis should be structured and may include the following steps:

1. Define and become familiar with the system.

   This step includes the definition of the operational situation, review of well schematics, construction of barrier diagram, and listing of barriers and their barrier functions.

2. Identify failure modes and failure causes

   The main method for failure identification is the failure modes, effects, and criticality analysis (FMECA). The objective of the FMECA is to identify all the failure modes, their causes, and effects for each of the barrier elements of a well barrier system.

3. Construct a reliability model of the well barrier system

   There are several alternative models available, and the choice of models should be based on what type of system states we want to study and the access to relevant data to support the models. We recommend, however, fault tree analysis, since this method is intuitive and easy to understand (at least for the qualitative parts) for those who do not have a background in system reliability theory. A fault tree is a graphical model that illustrates all the combinations of failure events that may lead to a system failure (i.e., leakage to the surroundings). The fault tree is easy to establish from the well barrier diagram.

4. Perform a qualitative analysis of the fault tree

   All the information about the causes of system can be summarized in the *minimal cut sets* of the fault tree. A minimal cut set is (a smallest) combination of failure events that may give a system failure. A system failure occurs when all the failure event of a minimal cut set occurs, and minimal cut sets with few failure events are therefore more important than minimal cut sets with many failure events. Algorithms for identification of minimal cut sets are available. With basis in the minimal cut sets, we can discuss issues such as critical components or elements, vulnerability to common cause failures. This type of information may be useful when planning well operations, well barrier maintenance, and training of personnel.

5. Perform quantitative analysis of the fault tree

By combining reliability theory and reliability data with a fault tree, we can determine a number of reliability parameters of interest, for example the probability of primary barrier failure, failure rates for primary and secondary barriers, time to first failure of primary and/or secondary barrier, and so on.

System reliability analysis is based on statistical models and methods. This means that the results are subject to uncertainty, due to modeling assumptions, adequacy of data, and the spread in possible outcomes that follows the distribution of, e.g., time to failure that is recorded for similar systems and components.

6. Report results

It is important to document all results, including assumptions and limitations that have been made. Recommendations that require further follow-up, whether it points back to necessity to redesign or to update planning, operating, or maintenance procedures need to be sufficiently highlighted. Recommendations should always be assigned responsible persons or departments.

## 4.6 Identification of barrier functions

In order to understand how a system can fail, it is necessary to first identify the system functions. A well barrier system may have several functions, and it is often useful to distinguish between essential functions, information functions, and protective functions.

The essential function of a well barrier is more or less obvious. This is the function that corresponds to the main purpose of the barrier, that is, the reason why the barrier is installed. For any well barrier we may state that the essential function is to separate the well fluids from the environment/surroundings. Loss of this function gives a possible leakage path to the environment.

Information functions provide information about the state and/or status of a well barrier. The information may, for example, be the position of a gate valve in a X-mas tree, provided by the position indicator of the valve. Various sensors may give information about temperature, pressure, flow rate, and so on. Loss of information functions may give the operating personnel

insufficient information about degradation of the main function and thereby prevent necessary maintenance from being performed, or lack of required information to manage an abnormal situation.

Instrumented well barriers often involve electrical, electronic, or programmable electronic technology with protective functions to avoid that any electrical arc result in ignition of hydrocarbon gases. Loss of the protective functions may generate new hazards and hazardous events at the rig, even if the well integrity as such may be unaffected. It should be noted that some well barriers, such as for well intervention, are not designed "fail-safe"[1]. Loss of electrical power, for example, as the result of lost overpressure in a work-over container, may result in a disconnection of power to all electrical equipment in the container, including the programmable electronic controller used to operate valves and rams in the lower riser package.

The main function of instrumented well barriers is partly implemented by hardware (e.g., valves, solenoid valves) and software. While hardware functions normally are rather straightforward to test for conformity to requirements, the software functions are more complex and it can be difficult to reveal any unwanted side effects of unfortunate software instructions. This is the case, even if the hardware containing the software, such as a programmable electronic controller (PLC), is supplied with a safety certificate. Instrumented well barriers should be subject to proper qualification before installation and a management of change system while in use. This also applies to systems that are temporary used at the rig for one specific activity, e.g., well intervention.

## 4.7　Failure and failure analysis

### 4.7.1　Key terms and definitions

All well barrier elements are installed to perform one or more functions. A function is usually accompanied by performance criteria. These criteria may, for example, be related to closing

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[1] Design principle that ensures that the item, upon predefined fault situations like loss of electrical power, responds in a way that will cause no harm or minimum of harm to personnel, environment, and/or facility. A shutdown valve is often designed to close upon loss of electrical power, while blow-down valves may be designed to open in the same situation.

time for a valve and maximum allowed leakage rate. At the moment one of the functional criteria is not fulfilled we say that we have a failure.

**Failure**: The termination of an item's ability to perform a required function (IEC 60050-191).

A failure is therefore an *event* that takes place at a specific time. After a failure, the item is in a fault state.

**Fault**: The state of an item characterized by its inability to perform a required function, excluding the inability during preventive maintenance or other planned actions, or due to lack of external resources (IEC 60050-191).

A fault may be manifested in many different ways. The term *failure mode* is used as a description of the fault and how the fault is observed. Failure mode is a commonly used term in the industry, but fault mode would have been a more precise term in light of the definitions of fault and failure.

**Failure mode**: The effect by which a failure (or fault) is observed on the failed item (IEC 60050-191).

Some failures are due to natural degradation and cannot be easily avoided, while other failures are due to inadequacies in design, construction, installation, or operation and maintenance. One example is that new failures are introduced during modifications and minor rebuilding, due to inadequate understanding of the system or lack of updated (and correct) documents for the system in question. To understand why failures occur and how they can be avoided, it is important to understand the failure causes.

**Failure cause**:  The circumstances during design, manufacture or use that have led to a failure (IEC 60050-191).

Failure causes may be split into two different levels; failure mechanisms and root causes.  A failure mechanism is in IEC 60050-191 defined as the physical, chemical or other process, which has led to a failure, and is the most immediate explanation of the failure. Examples of

failure mechanisms are corrosion, erosion and fatigue. The failure mechanism is the cause to look for in order to make an immediate repair/restoration of the failed item.

Correcting a failure based on the failure mechanism alone seldom prevents similar failures from reoccurrence. For long term and permanent defense measures against failures, it is necessary to look for the underlying and fundamental causes, often called the *root causes*. Many methods are available for this purpose under names, such as *root cause analysis*.

### 4.7.2    Classification of failure modes

Failure modes may be classified in many different ways, depending on their criticality and extensiveness. Rausand and Høyland (2004) distinguish between:

- *Intermittent failures*; failures that result in lack of some function only for a very short period of time. An intermittent failure will normally "disappear", and the item will restore itself to a full operating state. This category of failures is common with programmed functions, and a relevant failure mode for drilling and well control and shutdown systems.
- *Extended failures*; failures that result in the lack of some or all functions and which will continue until the item is repaired or replaced. Here, we may introduce two sub-categories of extended failures:
  - Complete failures
  - Partial failures

Failure modes may also be classified into *sudden failures* and *gradual failures*. Gradual failure is perhaps a confusing term (either it should be a failure or not a failure), but the notation is used with system states that are starting to drift out of the normal and expected values. Sensor signals that are drifting off or corrosion that is developing over time are examples of gradual failure (modes).

Extended failures that are complete may have two effects, on the item level (locally) and on the system (rig or platform) level. It can be distinguished between (OREDA, 2009):

- Critical failures, which are the immediate and complete loss of an item's capability of providing its output. An example may be a valve that does not start to close when requested.

- Degraded failures, which are not critical, but prevents equipment from providing its output within specifications. An example could be a shutdown valve that uses slightly longer closure time than what is specified.

- Incipient failure: A failure which is not critical, but which, if not attended to, could result in a critical or degraded failure in the near future.

Standards for design and operation of safety-instrumented systems, such as IEC 61508 and IEC 61511, use the classification of safe and dangerous failures.

**Safe failure**: Failure of an element and/or subsystem and/or system that plays a part in implementing the safety function that:

- Results in the spurious operation of the safety function to put the system under protection (e.g., the well) into a safe state or maintain a safe state; or

- Increases the probability of the spurious operation of the safety function to put the system under protection (e.g., the well) into a safe state or maintain a safe state

**Dangerous failure**: Failure of an element and/or subsystem and/or system that plays a part in implementing the safety function that:

- Prevents a safety function from operating when required (demand mode) or causes a safety function to fail (continuous mode) such that the system under protection (e.g., the well) is put into a hazardous or potentially hazardous state; or

- Reduces the probability that the safety function operates correctly when required

*Safe* and *dangerous* failures may be split further into *detected* and *undetected* failures. A detected failure is a failure that is *evident* (during non-demand situations) or is detected by online diagnostics. It is assumed that a detected failure is revealed shortly after it has occurred. An undetected failure is a failure that is hidden under non-demand situations and is only revealed by a proof test or while responding to a demand. A failure, which is both *dangerous* and *undetected,* is referred to as a dangerous undetected (DU) failure. A failure that is *dangerous* and *detected* is called (DD). The similar notations apply for *safe* failures (SU- and SD-failures).

**Example**.

The failure modes of an DHSV may be classified as:

- Fail to close on demand (FTC): DU

- Leakage in closed position: DU

- Fail to open (FTO): SU

- Spurious (premature) closure: SU

Our main concern is obviously directed to DU- and DD-failures in relation to maintaining well integrity. The presence of DU- and DD-failures reduces the safety performance of the system, making it less capable of performing or maintaining the well integrity. The negative impact of DD-failures on system safety is reduced if the DD-failures are corrected within short time. In this case, the DU failures remain as our main concern with respect to safety performance.

## 4.8 FMECA

Failure modes, effects, and criticality analysis (FMECA) is a widely used method for system reliability assessment. The method provides an intuitive and structured approach to failure analysis, and FMECA is therefore adopted in many industry sectors. An FMECA is carried out to answer the following questions:

a. In what ways can system components fail?
b. What are the underlying causes of failures?
c. How can failures be detected?
d. What are the failure effects, on the failed component and on the system as such?
e. How critical are the failure effects, in terms of damage to humans, the environment, or material assets?

An FMECA performed without considering question (e) is sometimes referred to as a failure modes and effect analysis (FMEA). In practice, FMECA and FMEA are used interchangeably without reflecting any difference in the scope of the analysis.

The core of an FMECA is the FMECA *worksheet*, which is filled in during an FMECA session, a meeting where relevant personnel are gathered. There is no unique and widely accepted layout of the FMECA worksheet, and many variants are therefore found in companies and in standards and textbooks. The main elements are, however, the same in all variants. In some cases, it is important to highlight failures that are classified as DU, DD, and so on. In this case, the failure effects should be classified accordingly.

### 4.8.1 FMECA procedure

An FMECA is easy to conduct and easy to comprehend without any advanced analytical skills. The easiness of using the method may become a false comfort, if not performed or led by qualified persons. An FMECA is not a one person's task, but requires the involvement of persons with overall system knowledge, persons with detailed knowledge on the construction of the individual components, and a FMECA facilitator. The person facilitating the FMECA session should have a basic knowledge of the failure concepts and analysis, including the understanding of main terms such as:

- Failure modes
- Failure mechanisms
- Root causes
- Failure classification strategies that are commonly used in the industry
- Modes of operation

The main steps in an FMECA are described in the following. It is assumed that an FMECA facilitator has been identified and that this person is responsible for the preparation, execution, and documentation of the results.

1. Preparation
   a. Identify relevant persons (according to competence) for the FMECA session

b. Identify relevant documentation of the system that is to be analyzed

c. Identify supporting information, such as reported failures of similar systems, experience transfer from other FMECA sessions.

d. If necessary, perform a pre-meeting with some of the identified persons to participate in the FMECA session to verify that relevant information has been collected.

e. Select a FMECA worksheet with appropriate columns.

f. Decide if a pre-FMECA session is needed to perform steps 2a)—2e), as an input to more detailed FMECA session(s) that covers steps 2f) – 2h).

g. Send out the invitation to the participants, including a brief selection of documentation, and a clear statement about the purpose of the session.

2. Execution of FMECA session(s)

a. Define the system and its boundaries.

i. This step concerns the identification of what components to include (and which ones to exclude) in the FMECA. This is not always an easy task, as most systems are not stand-alone but interfacing other systems. Care should be taken to not exclude components that could be very determinative for the system performance. Such components may, for example, be associated with utility supplies (e.g., hydraulics, power). Excluded components and systems should be commented in the list of assumptions and limitations of the study.

b. Define the main function (or mission) of the system.

i. This step concerns the overall description of system mission. The function may be described in terms of a verb plus a noun, e.g., *to activate shear-ram*. It is also useful to add some criteria that would describe the successful performance of this function, e.g., to activate shear ram *within 10 seconds upon drillers (manually initiated) command*.

c. Describe the operational modes (modes of operation), including operational and environmental stresses.

      i.  The causes and effects of failures may be different in different modes of operation. Each operating mode may also be subject to different operational and environmental stresses. For example, the ability of the pipe ram to perform isolation is highly impacted by what is going through the BOP.

     ii.  In some cases, an operational mode may be broken down into several sub-modes. In a demand situation (where a closure of the shear ram is required), the sub-modes may be: open, moving (towards closed position) and closed.

d. Break down the system into subsystems and prepare a complete component list.

      i.  It is possible to fill in the FMECA table for the overall system function. However, in many cases it is required to perform a more detailed analysis of the various system components. A well barrier comprising several barrier elements may therefore be studied in separate FMECA worksheets. The purpose of this step is to identify these system elements.

e. Define the interrelationship between the various subsystems (and sub-functions), using, for example, a functional block diagram.

      i.  This step is important in order to relate the detailed assessment results (i.e., results of FMECA for each subsystem) to the overall performance of the system.

f. Fill in the FMECA worksheet

      i.  See an example of an FMECA setup in**Feil! Fant ikke referansekilden.**.

g. Review the results

      i.  The purpose of this step is to review the results in light of the main objective of the session. Have all relevant limitations been sufficiently documented

h. Agree upon follow-up of identified design deficiencies, important test criteria and so on.

| Description of item | | | Description of failure | | | Effect of failure | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Ref. no | Function | Operational mode | Failure mode | Failure cause or mechanism | Detection of failure | One the subsystem | On the overall system | Failure rate | Severity ranking | Risk reducing measure | Comments |
| | | | | | | | | | | | |

*Table 2 FMECA worksheet*

| | |
|---|---|
| **Ref.no** | The ref.no provides a unique reference to the item that is to be analyzed. If a tag number system has been established for the system, the ref.no may be a tag number, but may also be a label referencing to a particular drawing |
| **Function** | Overall function or sub-function, according to the item selected |
| **Operational mode** | Relevant operating modes may be normal production, well intervention, and so on. Each mode, e.g., normal operation, may be split into sub-modes, such as well integrity maintained, well integrity degraded, and well integrity is lost. |
| **Failure mode** | Failure modes associated with the item in question. A valve failure mode may, for example, be fail to close, fail to open, spurious closure, leakage in closed position, leakage to environment, and so on. |
| **Failure cause or mechanism** | Failure causes may be physical (e.g., corrosion, erosion, fatigue) or human errors. |
| **Detection of failure** | Detection may be defined as undetected or detected, alternatively as hidden or evident. |
| **Effects on the subsystem (item)** | Effect may be classified as either safe (does not lead to an unsafe state) or dangerous (does lead to an unsafe state due to e.g., the item function not being carried out). Other classifications may also apply, depending on the type of item. |
| **Effects on the system** | Same classification as for subsystem, but the effect is on the overall function, or alternatively for the whole plant/rig. |
| **Failure rate** | Failure rate may be identified in relevant data sources or according to Table 12.3. |
| **Severity ranking** | Severity ranking may be according to Table 12.3. |
| **Risk reducing measure** | Risk reducing measures may be identified that may prevent the failure, or reduce the severity of the failure effects. |

*Table 3 FMECA explanation*

| Failure rates | | Severity (of failure effects) | |
|---|---|---|---|
| Very unlikely | Once per 1000 years or more seldom (unlikely to be experienced at all) | Catastrophic | The failure will directly lead in deaths or injuries or prevent performance of the intended mission |
| Remote | Once per 100 years (may occur once in a life time) | Critical | The failure will degrade the system beyond acceptable limits, so that deaths or injuries may occur if no further action is taken (assuming there is time available to do so). |
| Occasional | Once per 10 years (may occur a few times during a life time) | Major | The failure will degrade the system beyond acceptable limits, but adequate countermeasures are available to control the possible unwanted effects of the failure |
| Probable | Once per year | Minor | The failure does not degrade the overall performance beyond acceptable limits, or results in an automatic transition to a safe state. |
| Frequent | Once per month or more often | | |

*Table 4 Classification of failure rates and severity effects*

*Note*: Some FMECA worksheets have a column for the resulting risk, expressed through a risk priority number (RPN) or from a risk matrix. In the context of well integrity, we are concerned with accidental risk. The classification of risk is useful in order to prioritize the effort of design improvements so that the system is sufficiently safe.

| Description of item: DHSV | | | Description of failure | | | Effect of failure | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Ref. no | Function | Operational mode | Failure mode | Failure cause or mechanism | Detection of failure | One the subsystem | On the overall system | Failure rate | Severity ranking | Risk reducing measure | Comments |
| 1 | Stop flow | Valve in open position | Fail to close | Sticking seals<br><br>Blocked return of hydraulics | No (U)<br><br>No (U) | D | D* | Occasional | Catastrophic | Regular check, calibration<br><br>Focus in planning procedure<br><br>Regular testing | |
| | | | Fail to open | Not relevant (in this operational mode) | | | | | | | |
| | | | Delayed start | Inadequate depressurization capacity (hydraulics) | Yes (D) | D | D* | Occasional | Minor | Regular testing (to avoid sticking) | |
| | | | Leakage in closed position | Damaged seals | No (U) | D | D* | Probable | Critical | Regular inspection of seat<br><br>Replacement after a certain number of operations | |
| | | | Spurious closure | Spurious loss of hydraulics | No (U) | D | D* | Probable | Minor | Redundancy in hydraulic supply<br><br>Monitoring of hydraulic pressure | |

*Table 5 FMECA worksheet for DHSV*

*Severity is reduced due to the redundancy provided by PMV or PWV. However, for highest level of ESD (most severe situation), the closure of DHSV is required.

## 4.9    Fault tree analysis

A fault tree can be used for qualitative as well as quantitative analysis of system reliability[2]. The main purpose of a fault tree is to explain why a system failure can occur. In our context, the system failure may be "leakage to environment" in a particular operating situation. In the fault tree terminology, this system failure is called the TOP event of the fault tree. The causes of the TOP event are identified and combined by logic gates.

Fault tree construction is a deductive approach. With basis in the defined system failure, we ask iteratively what type of events (component failures, human errors, etc.) that may result in the system failure. A fault tree comprises the following main elements:

- **The TOP event:** This is a precise description of the system failure, and should explain what the system failure is (e.g., leakage to environment), where the failure occurs or is observed (e.g., from the wellhead), and when the failure may occur (i.e., the operational situation we are looking at). In our context, the TOP event may be "leakage to environment through the wellhead during normal production".

- **OR and AND gates:** A fault tree applies two main types of logic gates: OR gates and AND gates. Most fault trees suffice with these two logic gates, but several other gates are available for specific purposes. In this compendium, however, we only consider OR- and AND gates.

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[2] An alternative to constructing a fault tree is to use a reliability block diagram. In a reliability block diagram, we take the opposite approach and ask for events and conditions that ensure a successful performance of a system function.
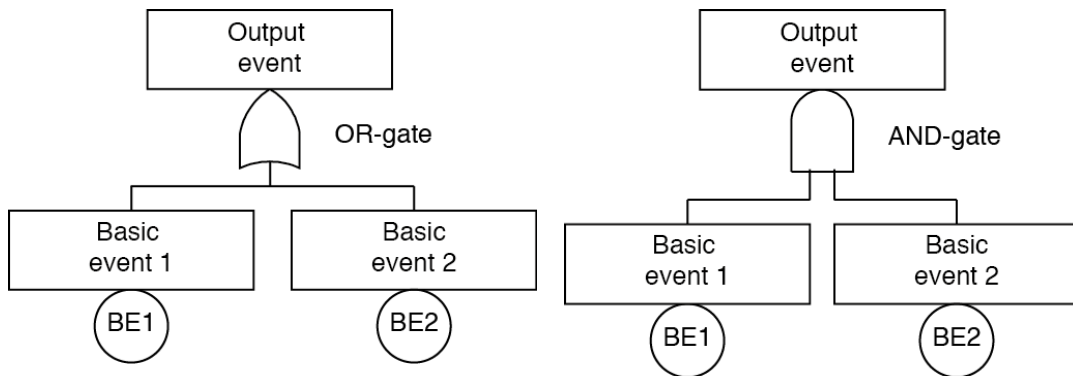
| **OR-gate**: The output event occurs when one or more of the basic (input) events occur, i.e., the output event occurs when basic event 1 OR basic event 2 occurs. | **AND-gate**: The output event occurs when all the basic (input) events occur at the same time, i.e., the output event occurs when basic event 1 AND basic event 2 occur. |

*Table 6 Explanation of OR and AND gates*

- **Basic events:** Basic events conclude the fault tree development and represent the lowest (modeled) level of events (component failures, human errors, external event) that may initiate the development of a system failure. There is no specific rule to what should be defined as a basic event. For example, one may define the failure of DHSV as a basic event, or break the item into sub-items (e.g., seal, flapper, and actuator) and define these as basic events. The level of resolution is often linked to the availability of reliability data to support the quantitative analysis (e.g., failure frequencies). If data is not available for the sub-components, but for the DHSV as a total, it is most feasible to choose DHSV failure as a basic event.

  Note that when we define "DHSV failure" as a basic event, we point at those failure modes of interest for the failure of DHSV in the context of causing leakage to environment, i.e., the fail to close (FTC) and the leakage in closed position (LCP) are the most relevant failure modes in this context.

Additional information about fault trees (and system reliability theory in general) may be found in Rausand and Høyland (2004).

### 4.9.1    Fault tree programs

Fault trees for practical systems will usually become rather comprehensive and it is therefore beneficial to use a dedicated fault tree program. Several programs for fault tree construction and analysis have been developed. In Norway, two such programs are commonly used:

- CARA FaultTree, which is available from ExproSoft (www.exprosoft.com/products/Cara.aspx)
- RiskSpectrum, which is available from Scandpower (www.riskspectrum.com)

Links to several other programs for fault tree construction and analyses may be found on (www.ntnu.edu/ross/info/software).

### 4.9.2    Fault tree construction

The events in a fault tree are described in rectangles. For basic events, a circle is drawn beneath the rectangle and a unique identificator of the basic event is entered into the circle. The identificator is an alpha-numeric code and the maximum number of symbols is determined by the computer program used. It is wise to select a code that gives a meaningful reference to the basic event.

The barrier diagram is a good starting point for constructing a fault tree and the transformation from a barrier diagram to a fault tree is fairly simple. We will illustrate the procedure by using the well barrier diagram in Figure 25.

- We always start with the TOP event, which in this case is "Leakage to the surroundings" In the well barrier diagram in Figure 25 this is represented by the node "Surroundings" which is the terminal node of the diagram
- As seen from Figure 25, there are ten different arrows (representing flow paths) pointing into the terminal node. For simplicity, we refer to these flow paths as flow path 1, flow path 2, and so on, where we number the paths from 1 to 10, beginning from the top of the diagram.
- If at least one of the flow paths is leaking, then we have leakage to the surroundings. This means that there is an OR-relationship: Hydrocarbons will

reach the "Surroundings" if "Flow path 1 is leaking" OR "Flow path 2 is leaking" OR and so on, as illustrated in the top section of the fault tree in Figure 26.
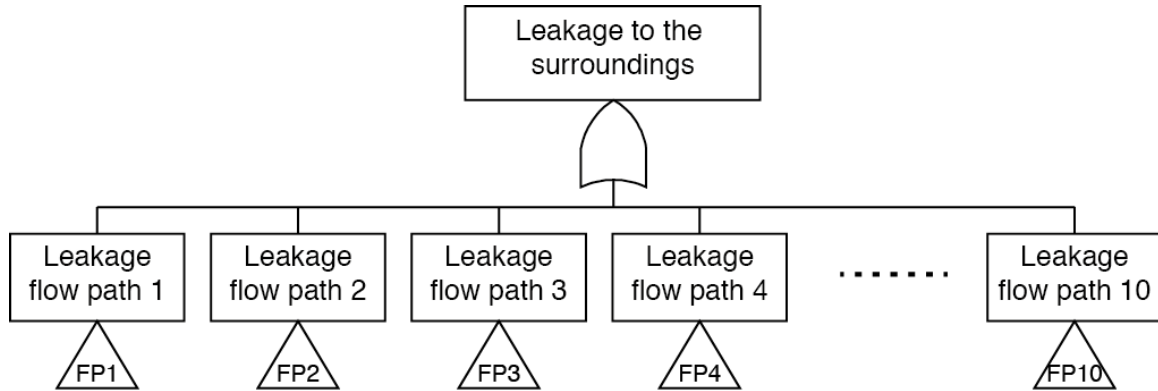


*Figure 26 Top structure of fault tree for "Leakage to surroundings".*

The triangles beneath the rectangles describing the events indicate that the fault tree is not complete and that we need to continue the evaluation of the event on a separate page.

- A separate fault tree has to be constructed for each of the ten events in Figure 26. Let us take flow path 6 as an example. To have leakage through this flowpath, the wellhead must be leaking AND there must be flow (i.e., pressurized hydrocarbons) to the wellhead. The start of this fault tree is therefore as shown in Figure 27.
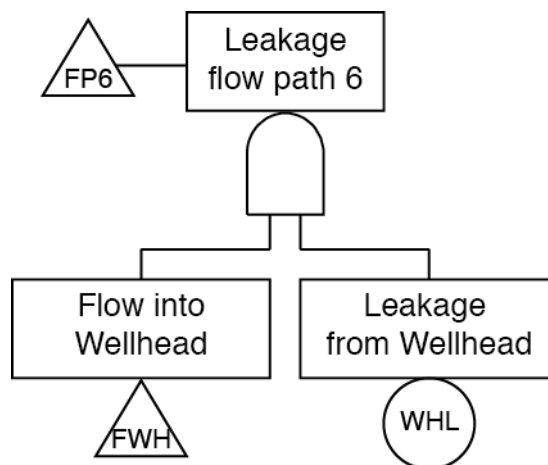


*Figure 27 Fault tree (top structure) for "Leakage flow path 6".*

The triangle in the top of Figure 27 indicates where this fault tree shall be input (appended) to the top structure fault tree in Figure 26. The event on the left-hand side "Flow into Wellhead" need further development and is therefore marked with a triangle. The event "Leakage from Wellhead" is here considered to be a basic event and is therefore marked with a circle with the alpha-numeric code WHL (i.e., abbreviation for wellhead leak). We might have developed this event further, for example by distinguishing between the wellhead seals that may be leaking.

- The event "Flow into Wellhead" must be developed further. From the well barrier diagram in Figure 25, we note that if the production packer OR the tubing below the DHSV OR the tubing above the DHSV leaks, then there is "Flow into Wellhead". This can be drawn as a separate fault tree or we can extend the fault tree in Figure 27. Here, we chose the lat option and the resulting fault tree is shown in Figure 28.
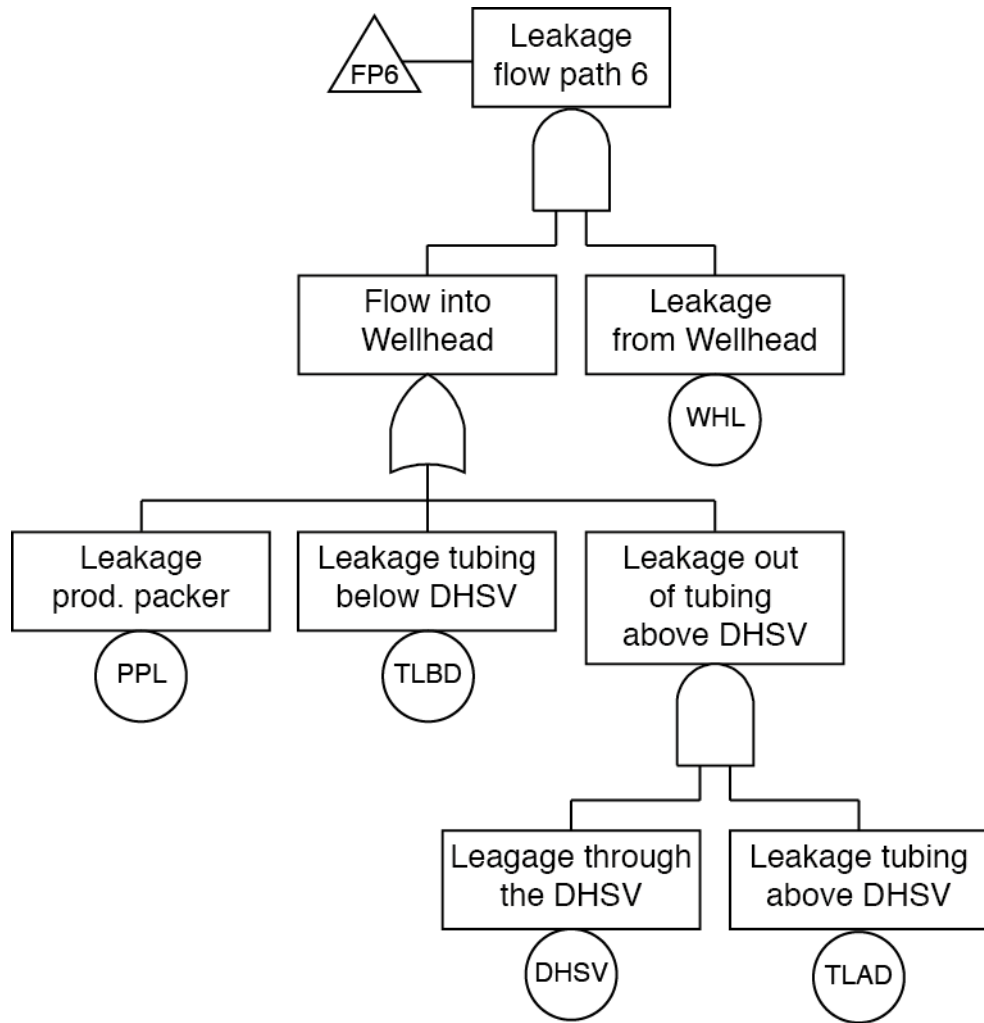
*Figure 28 Complete fault tree for "Leakage flow path 6".*

All the events are now considered to be basic events, the fault tree is therefore complete and we do not need to develop it any further. Note that all the basic events are given codes. These codes are used in the analysis of the fault tree.

- Fault trees for the other nine flow paths can now be constructed in the same way. The total fault tree will be rather big and a dedicated fault tree program, such as CARA FaultTree will be almost required.

### 4.9.3 Fault tree pros and cons

The fault tree can be constructed directly, or based on a well barrier diagram. The fault tree is always started by the TOP event that we want to investigate. For well integrity studies, this event will usually be "Leakage to the surroundings". The fault tree is developed step by step from the TOP event by repeatedly asking: "How can this event happen?" The answer to this question for the TOP event is found by identifying all the possible places the leakage can come out, i.e., the ten flow paths. Then we study each and every of these flow paths and again ask: "How can this happen?" and so on. The fault tree construction is based on a very simple procedure and it is therefore suitable for brainstorming sessions involving people that have not been trained in fault tree construction.

A negative point is that the resulting fault tree often becomes big and many pages of paper are needed to draw the complete fault tree. It is therefore easy to lose oversight. One should, however, remember that the fault tree is a logic structure and that it is fully okay to have the same event many places in the fault tree. In the further analysis, this taken care of by the fault tree logic.

We may ask why we should use fault tree analysis and not suffice with a well barrier diagram – since the well barrier diagram is more compact and it is easier to see the leakage paths. The main reason is the intuitive logic of the fault tree and its capabilities for both qualitative and quantitative analysis.

### 4.9.4 Qualitative analysis of the fault tree

A complete fault tree shows all the failure combinations or causes that lead to a specified failure or dangerous situation. These combinations can be investigated for the TOP event or for one of the intermediate events (e.g., "Leakage flow path 6"). Most computer programs for fault tree analysis can list all these combinations, which are referred to as *cut sets*. Some cut sets will contain basic events that are superfluous and if these are removed from the set, the set will still be a cut set. When all of the superfluous basic events are removed, the cut set is called a *minimal cut set*. For big fault trees, it is a hard job to identify all the minimal cut sets manually.

> **Cut set:** A cut set in a fault tree is a set of basic events whose (simultaneous) occurrence ensures that the TOP event occurs.
>
> **Minimal cut set:** A cut set that cannot be reduced (Rausand and Høyland, 2004)

The minimal cut sets related to the event "Leakage flow path 6" in Figure 28 are seen to be

{WHL, PPL} i.e., wellhead is leaking AND production packer is leaking

{WHL,TLBD} i.e., wellhead is leaking and the tubing below the DHSV is leaking.

{WHL, DHSV,TLAD} i.e., wellhead is leaking AND the DHSV is leaking (or cannot be closed) AND the tubing above the DHSV is leaking.

A minimal cut fails if and only if all the basic events of the minimal cut set occur. This means that if at least one of the basic events does not occur, then the minimal cut does not fail. If at least one of the minimal cuts fails, the TOP event will automatically occur. It is obvious that a minimal cut set with few events is more important than a minimal cut set with many events. A minimal cut set with only one basic events means that there is only one barrier between the reservoir and event we are studying. A minimal cut set of two basic events means that two barriers have to fail to give the event we are studying.

### 4.9.5    Failure rate, mean time to failure, and survival probability

The term *failure rate* has been mention several times without any proper definition or explanation. Failure rate is a rather complex concept, but is here used in a rather simple manner. In this compendium, the failure rate of an item is denoted $\lambda$ and indicates how often the item is expected to fail. The failure rate $\lambda$ is given as number of failure per time unit in service. The time unit is often given a million hours (or $10^6$ hours). A failure rate of, for example, $\lambda = 5.5 \times 10^{-6}$ per hour, means that we, on the average, should expect 5.5 failures during a period of one million hours in service.

A related concept is the mean time to failure (MTTF), which is the expected (or average) time from start-up of an item until the first failure of this item occurs. The MTTF is given by

$$MTTF = \frac{1}{\lambda} \qquad (0.1)$$

We may also write $\lambda = 1/MTTF$, such that we can determine the failure rate from the MTTF (the average time to failure). This means that an item that has an average lifetime of half a year will have a failure rate of 2 per year.

An item with failure rate $\lambda = 5.5 \times 10^{-6}$ per hour will hence have an MTTF of

$$MTTF = \frac{1}{\lambda} = \frac{1}{5.5 \times 10^{-6}} = 181818 \text{ hours} \qquad (0.2)$$

That is, approximately 21 years in continuous service. This means that the item, on the average, will fail after 21 years in continuous service.

Another important concept is the *survival probability* $R(t)$, which is the probability that an item will survive a specified time period of length $t$ without failure. The survival probability is given by

$$R(t) = e^{-\lambda t} \qquad (0.3)$$

An item with failure rate $\lambda = 5.5 \times 10^{-6}$ per hour will therefore survive a period of 5 years (i.e., 43800 hours) with probability $R(t) = e^{-5.5 \times 10^{-6} \times 43800} = 0.786$. This means that after 5 years in service, the item will still be functioning with probability 78.6% and have failed before 5 years with probability 21.4%.

### 4.9.6 Well barrier performance data

Quantitative analyses about well integrity cannot be made without access to relevant reliability data such as failure rates and MTTFs for technical components, human error probabilities, and so on. Data collection initiatives are therefore needed in order to collect information about how frequent well barrier elements fail and why.

The main source of reliability data for well equipment is the WellMaster database, which is operated by ExproSoft (http://www.exprosoft.com). The database provides:

- Failure causes for each specific component and failure mode

- Mean time to failure (MTTF) for each failure mode

- Failure rate estimates for each failure mode

- Survival probabilities, i.e., the functions describing the probability of surviving a certain time $t$.

Another valuable source of reliability data for XT components and downstream equipment is the OREDA database (http://www.oreda.com). OREDA does not supply reliability data for well equipment, so these two databases supplement each other. The data in OREDA is based on maintenance records and provides the same type of data as WellMaster. The presentation formats are, however, different.

For safety-instrumented systems (if relevant), the best reliability data source is the PDS Data Handbook (http://www.sintef.no/Projectweb/PDS-Main-Page/PDS-Handbooks/PDS-Data-Handbook/).

Reliability data for general mechanical equipment may be found in the MechRel database (http://www.mechrel.com/).

A survey of available reliability data sources may be found on the web page http://www.ntnu.edu/ross/info/data.

### 4.9.7    Quantitative analysis

Quantitative fault tree analysis would require some basic knowledge in system reliability theory. The purpose of this section is not to provide this knowledge, but to show how some reliability measures can be calculated and what type of input data that is needed to support such calculations.

The formulas given below are based on the assumption that all the basic events are statistically *independent*. This implies that if one basic event has occurred, this will not influence the probability that other basic events occur. This is not always realistic since the same stresses or same events may influence several items in the well barrier system. If, for example, the production wing valve fails to close due to formation of hydrates, it is very likely that the production master valve will have the same problem. In this case, the formation

of hydrates is a common cause and if both valves fail due to this cause, we have a common cause failure. Analysis of common cause failures is an important aspect of the reliability of the well barrier system, but is beyond the scope of this compendium.

Let TOP denote the TOP event of the fault tree. The probability that the TOP event occurs at time $t$ is denoted $Q_0(t)$. Further, let $q_i(t)$ denote that basic event $i$ occurs at time $t$. Since a minimal cut set fails only when all the basic events of the minimal cut set occurs, the probability that minimal cut set $j$ fails at time $t$ is given by

$$\breve{Q}_j(t) = \widetilde{\bigcirc}_{i \in C_j} q_i(t) \tag{0.4}$$

Equation (1.1) may seem difficult, but is in fact rather simple. It only says that you must multiply the probabilities of all the basic events of minimal cut set $j$.

The TOP event occurs when at least one of the minimal cut sets fails. The probability of the TOP event $Q_0(t)$ can be written

$$Q_0(t) \pounds 1 - \overset{k}{\underset{j=1}{\widetilde{\bigcirc}}} (1 - \breve{Q}_j(t)) \tag{0.5}$$

Equation (1.2) is called the "upper bound approximation" formula and the development of this formula is too complicated to be fully explained in this compendium[3]. The formula is, however, easy to use and is also used by almost all computer programs for fault tree analysis.

If we can find the probabilities $q_i(t)$ of all the basic events ($i = 1, 2, \cdots, k$), we can use equations (1.1) and (1.2) to determine the TOP event probability.

The problem is now how we can find the probabilities of the basic events. This will depend on the type of the basic event, and we distinguish between the following types:

a) *Non-repairable*. This type means that we consider an item that is not repaired upon failure − except by a full workover intervention. In this case, the probability of the basic event is

$$q_i(t) = 1 - e^{-\lambda_i t} \gg \lambda_i t \tag{0.6}$$

---

[3] Interested readers may consult Rausand and Høyland (2004) for further information.

b) *Repairable*. This type means that we consider an item that is repaired upon failure. The failure is detected immediately and the mean downtime for the item is MTTR (mean time to repair). In this case, the probability of basic event is

$$q_i \approx \frac{MTTR_i}{MTTF_i + MTTR_i} \approx \lambda_i MTTR_i \qquad (0.7)$$

c) *Periodic testing*. Many of the barrier elements are passive items where dangerous failures are only detected by a proof test (e.g., the failure mode "fail to close" for a DHSV or a XT gate valve). When the time between two consecutive proof tests is $\tau$ (e.g., 6 months), the probability of the basic event is

$$q_i \approx \frac{\lambda_i \tau}{2} \qquad (0.8)$$

d) *On-demand*. Some basic events are so-called on-demand events, meaning that a specific event occurs in a specific situation. This event may be a human error, an environmental condition, or a specific well event. The probability of such an event is usually given as a fixed probability $q_i$. An example may be that the driller fails to activate a specific pushbutton

When CARA FaultTree has been used to construct the fault tree, you can double-click on a basic event symbol to enter the required data. You will then first be asked to choose the type of event and thereafter be prompted for the required input values. When all the required data has been entered, the TOP event probability is calculated by pressing a button. CARA FaultTree and the other fault tree programs can also provide many other reliability measures, such as

- The mean time until the TOP event occurs
- The importance of the various basic events for the TOP event probability
- The uncertainty of the TOP event probability based on the uncertainty of input data
- and so on

# 5. Technical well barriers

## 5.1 Well barrier philosophy

It is a general philosophy that the wells are to be equipped with sufficient mechanical well barriers preventing uncontrolled outflow from the reservoir. In addition it is a general rule that no single failure of a component is to lead to unacceptable consequences.

For wells this means in practical terms that a well is to be equipped with two well barriers against the reservoir, and that the well barriers are to be as independent of each other as possible. In addition it will be required to have sufficient barriers in place against limited volumes as e.g. against outflow from annulus A in gas lifted wells.

For wells in operation and plugged wells, two independent well barriers are to be in place. For wells that are being drilled or intervened, it is not always possible to assure complete independence. For wells without complete independence of the well barriers, extra reliability of the common well barrier elements will be required as well as stronger requirements in emergency response plans.

### 5.1.1 Fail-safe functions:

For a well in operation some barrier elements need to be in an open position to be able to produce the well. This is typically the DHSV, PMV and PWV. It is therefore critical that these valves automatically close in situations when power or hydraulic supply is lost, or if a fire should occur. It is a general requirement that these valves are to be fail-safe, meaning that the valve is designed to move to the safe position when such a failure occurs.

To ensure the fail-safe function, it is critical that correct design calculations are done. An example is for instance that a DHSV needs to have strong enough spring ensuring the valve will close with the highest possible pressure on the control line after control line failure.

### 5.1.2 Safety systems

Safety systems are needed both to ensure operational limits are not exceeded, and to ensure that the well is closed in potentially dangerous situations.

Typically safety systems are needed to ensure that any injection in the well will not be with higher pressure than the well barriers are constructed for. In this case it is very important to safeguard the well barrier that two levels of safety system are implemented:

1. Automatic shut in of the well when a certain pressure is reached.
2. Automatic bleed-off of the injection pressure to a safe area if a certain injection pressure is reached.

As unintended shut down is to be avoided, there will be implemented alarms at certain pressure levels, allowing time to manually take action and regulate the pressure.

Other typically safety systems are safeguarding against thermal effects on closed volumes, ref Chapter 6. When the annulus pressure becomes too high due to warming up during well startup, a safety system ensuring that the well is closed in automatically at a certain annulus pressure will then prevent the risk of barrier failure due to the temperature effect and lack of manual pressure regulation.

It is critical to have safety systems to ensure that the well is closed in when emergency situations occur on the installation. Also safety systems closing the well in when the pressure in the well becomes too low are to be implemented, as such low pressure would indicate a leak.

There can be need for more or less safety systems than the examples mentioned above. The general need for safety systems is very much dependent on the risk.

### 5.1.3 Fire resistance

It is crucial that the well barrier envelope is fire resistant in case a fire occurs in the wellhead area. Therefore all the barrier valves shall automatically move to safe position ensuring fire resistance in such cases. In addition all XT and wellhead seals that are part of the barrier envelope shall be fire resistant.

Any lack of fire resistance will increase the risk of a fire, as the risk of putting the whole well on fire will become evident.

### 5.1.4    Well barrier schematics

Well barrier schematics, according to NORSOK D-010, are developed as a practical method to demonstrate and illustrate the presence, or non-presence of the required primary and secondary well barriers. An example of a well barrier schematic of a production well is shown in Figure 29. This is a template typically used for illustrating the well barrier schematic. In the real barrier schematic for a specific well all the data are given

# WELL BARRIER SCHEMATIC
Planned/As built

8.8.1a) Typical platform production/
injection well capable of flowing



| Well data | | | |
|---|---|---|---|
| Installation/Field name: | | xxxxx | |
| Well no: | xx/xx-xx | Completed date: | DD.MM.YYYY |
| Well type: | | Oil producer, water injector, etc. | |
| MWDP: | | xxx bar | |
| Revision no: | x | Date: | DD.MM.YYYY |
| Well status: | | Eg. operational/temp. plugged etc. | |
| Prepared: | | xxxxx (Name and signature) | |
| Verified: | | xxxxx (Name and signature) | |

| Well barrier elements | Ref. WBEAC tables | Verification of barrier elements |
|---|---|---|
| **PRIMARY - reservoir** | | |
| Cap rock | 51 | $\sigma_{min}$: x.xx sg EMW. Method: XLOT/minifrac/field model |
| Liner cement | 22 | Length: xx mMD > res. Method: volume control/logs |
| Liner | 2 | PT: xxx bar with x.x sg |
| Liner top packer | 43 | PT: xxx bar with x.x sg |
| Formation at casing shoe | n/a | $\sigma_{min}$: x.xx sg EMW. Method: XLOT/minifrac/field model |
| Production casing cement * (shoe to prod.packer) | 22 | Length: xx mMD, shoe to prod.packer Method: volume control/logs and FIT/LOT to x.xx sg EMW at casing shoe |
| Production casing (below prod.packer) | 2 | PT: xxx bar with x.x sg |
| Production packer | 7 | IT: xxx bar (or PT: xxx bar with x.x sg) |
| Production tubing | 25 | PT: xxx bar with x.x sg |
| CIV | 29 | IT low: xxx bar, IT high: xxx bar |
| DHSV/Controllines | 8 | IT low: xxx bar , IT high: xxx bar |
| **SECONDARY - reservoir** | | |
| Formation at prod.packer | 51 | $\sigma_{min}$: x.xx sg EMW. Method: XLOT/minifrac/field model |
| Production casing cement * (above prod.packer) | 22 | Length: xx mMD > prod.packer Method: volume control/logs |
| Production casing (above prod.packer) | 2 | PT: xxx bar with x.x sg |
| Production casing hanger with seal assembly | 5 | PT: xxx bar with x.x sg |
| WH/Annulus valve | 12 | PT: xxx bar with x.x sg |
| Tubing hanger with seals | 10 | PT: xxx bar with x.x sg |
| WH/X-mas tree Connector | 5 | PT: xxx bar with x.x sg |
| Tubing hanger neck seal | 10 | PT: xxx bar with x.x sg |
| X-mas tree valves | 33 | PT: xxx bar with x.x sg |

Noes:

| Disp. no. well integrity issues | Comment |
|---|---|
| None | |
| | |
| | |

*Figure 29 the schematic indicates the first and secondary well barriers with their barrier elements. Through this kind of illustration it is possible to verify the status of the barriers and whether it is critical or not. Future operation of the well is greatly dependent on these assessments. Control and monitoring may be planned based on these assessments to maintain the barriers*

The colors represent the different well barriers according to NORSOK D-010. The blue lines indicate the primary well barrier with its barrier elements and illustrate the *"normal working stage, which for some situations is the fluid column or a mechanical well barrier that*

*provides closure of the well barrier envelope"* (NORSOK D-010). The red lines indicate the secondary well barrier with its barrier elements and illustrate the *"ultimate stage, which in most cases describes a situation where the shear ram/shear valve is closed"* (NORSOK D-010). Well barrier schematics shall be complemented by tables showing the WBEs that are found as primary or secondary barriers. A production well barrier schematics with indicated WBEs and envelops is illustrated in Figure 30. The schematic presents a well shut in and capable to produce. The blue line indicates the primary barriers: production packer, completion string (tubing section between the downhole safety valve and production packer), and the valve itself. The red line envelope includes the casing cement, casing, wellhead, tubing hanger, annulus master valve and production tree with the production master valves.

# WELL BARRIER SCHEMATIC
Planned/As built

## 8.8.1a) Typical platform production/ injection well capable of flowing



| Well data | | | |
|---|---|---|---|
| Installation/Field name: | | xxxxx | |
| Well no: | xx/xx-xx | Completed date: | DD.MM.YYYY |
| Well type: | | Oil producer, water injector, etc. | |
| MWDP: | | xxx bar | |
| Revision no: | x | Date: | DD.MM.YYYY |
| Well status: | | Eg. operational/temp. plugged etc. | |
| Prepared: | | xxxxx (Name and signature) | |
| Verified: | | xxxxx (Name and signature) | |

| Well barrier elements | Ref. WBEAC tables | Verification of barrier elements |
|---|---|---|
| **PRIMARY - reservoir** | | |
| Cap rock | 51 | $\sigma_{min}$: x.xx sg EMW. Method: XLOT/minifrac/field model |
| Liner cement | 22 | Length: xx mMD > res. Method: volume control/logs |
| Liner | 2 | PT: xxx bar with x.x sg |
| Liner top packer | 43 | PT: xxx bar with x.x sg |
| Formation at casing shoe | n/a | $\sigma_{min}$: x.xx sg EMW. Method: XLOT/minifrac/field model |
| Production casing cement * (shoe to prod.packer) | 22 | Length: xx mMD, shoe to prod.packer Method: volume control/logs and FIT/LOT to x.xx sg EMW at casing shoe |
| Production casing (below prod.packer) | 2 | PT: xxx bar with x.x sg |
| Production packer | 7 | IT: xxx bar (or PT: xxx bar with x.x sg) |
| Production tubing | 25 | PT: xxx bar with x.x sg |
| CIV | 29 | IT low: xxx bar, IT high: xxx bar |
| DHSV/Controllines | 8 | IT low: xxx bar , IT high: xxx bar |
| **SECONDARY - reservoir** | | |
| Formation at prod.packer | 51 | $\sigma_{min}$: x.xx sg EMW. Method: XLOT/minifrac/field model |
| Production casing cement * (above prod.packer) | 22 | Length: xx mMD > prod.packer Method: volume control/logs |
| Production casing (above prod.packer) | 2 | PT: xxx bar with x.x sg |
| Production casing hanger with seal assembly | 5 | PT: xxx bar with x.x sg |
| WH/Annulus valve | 12 | PT: xxx bar with x.x sg |
| Tubing hanger with seals | 10 | PT: xxx bar with x.x sg |
| WH/X-mas tree Connector | 5 | PT: xxx bar with x.x sg |
| Tubing hanger neck seal | 10 | PT: xxx bar with x.x sg |
| X-mas tree valves | 33 | PT: xxx bar with x.x sg |

Noes:

| Disp. no. well integrity issues | Comment |
|---|---|
| None | |
| | |
| | |

*Figure 30 Well barrier production schematic illustration,*

In addition, primary and secondary well barriers can be illustrated using the Swiss cheese model, as it was performed for Macondo field accident in Figure 31. As shown in the figure

below, some other blocks that represent defensive physical (e.g. BOP) or operational barriers (e.g. well monitoring) that mitigate hazards could be added in the Swiss cheese model.
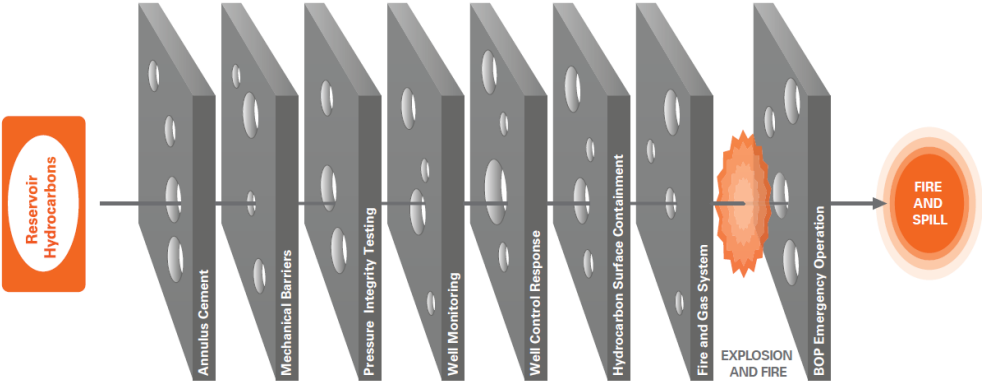


*Figure 31 Swiss cheese model - barriers breached in Macondo field (Ref BP report).*

## 5.1.5 **Drilling phase**

# WELL BARRIER SCHEMATIC
5.8.1 Drilling, coring and tripping with shearable drill string
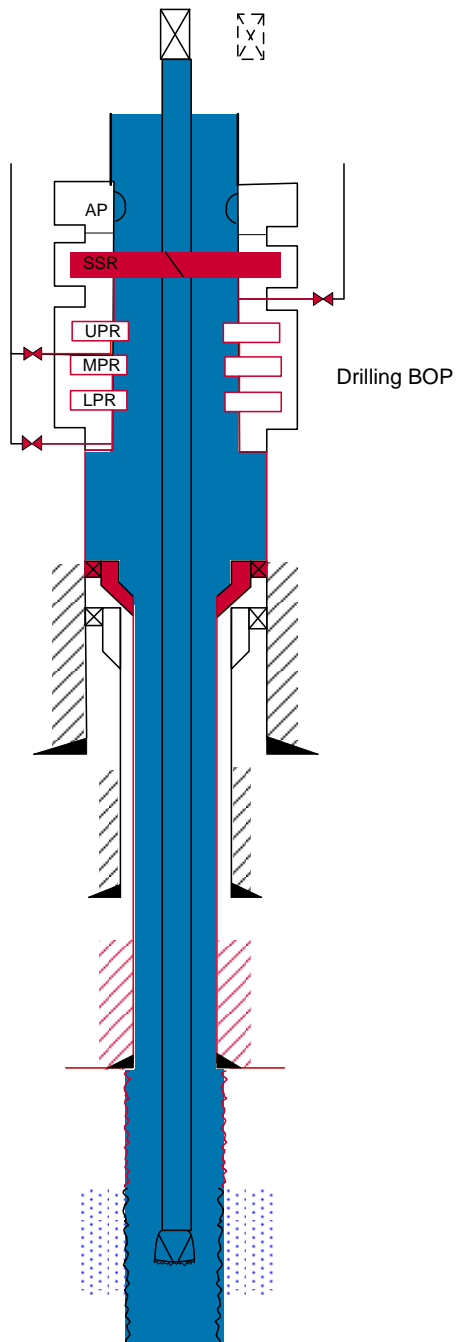


Drilling BOP

| Well data | | | |
|---|---|---|---|
| Installation/Field: | | xxxxx | |
| Well no: | xx/xx-xx | Drilling start date: | DD.MM.YYYY |
| Well type: | | e.g. oil producer | |
| MSDP: | | xxx bar | |
| Revision no: | x | Date: | DD.MM.YYYY |
| Well status: | | Drilling. | |
| Prepared: | | xxxxx (Name and signature) | |
| Verified: | | xxxxx (Name and signature) | |
| Well barrier elements | | Ref. WBEAC tables | Verification of barrier elements |
| PRIMARY - reservoir | | | |
| Well fluid | | 52 | Flow checks/ stable fluid level |
| SECONDARY - reservoir | | | |
| Formation at casing shoe | | 51 | FIT to x.xx sg EMW. |
| Production casing cement | | 22 | Length: xx mMD > casing shoe Method: volume control/logs and FIT/LOT to x.xx sg EMW at casing shoe |
| Production casing | | 2 | PT: xxx bar with x.x sg |
| Production casing hanger with seal assembly | | 5 | PT: xxx bar with x.x sg |
| WH | | 5 | PT: xxx bar with x.x sg |
| High pressure riser | | 26 | PT: xxx bar with x.x sg |
| BOP | | 4 | PT: xxx bar with x.x sg |
| Notes: | | | |
| Disp. no. well integrity issues | | Comment | |
| None | | | |
| | | | |
| | | | |

*Figure 32 WBS for the drilling phase*

During the drilling phase well integrity is mainly associated with keeping the formation under control and ensuring that the casing used is suited for the well, so that the forces exerted on the casing string do not compromise its integrity. Examples of such forces can be collapsing formation, thermal expansion of fluids trapped in the annulus or dynamic loads experienced during run in hole of the casing. Casing wear caused by long time drilling and rotating in the last set of casing is also something that will affect the well integrity if not taken into consideration during the design phase. Casing wear is something to be particularly aware of when drilling long horizontal wells were the drill string will wear on the casing for an extended period of time.

The above well barrier schematic shows the typical setup for the drilling phase, where the primary barrier is the fluid column in the well. The secondary barrier is the last set and cemented casing, along with the BOP, casing hanger and wellhead. All barrier elements, fluid column, production casing etc., found in the primary or the secondary barrier have a demand for verification. This verification can be found in the rightmost column and it is typically a test that needs to be done on the installed element, for instance a pressure test of the BOP. Other verifications can be to monitor the status of the well barrier, i.e. the mud weight during drilling.

One important thing in the WBS is the part describing any well integrity issues with the well. Here limitations can be written about for instance production rate, annulus pressure build up etc. These limitations/issues will be important for those who will operate the well on a daily basis. Restrictions such as these are becoming more and more important over the lifetime of the well since equipment deteriorates and is more sensitive to high loads. The restrictions put on the well will vary from well to well and for what purpose it was designed for originally.

### 5.1.6 Completion phase

# WELL BARRIER SCHEMATIC
7.8.2 Running non-shearable items through BOP
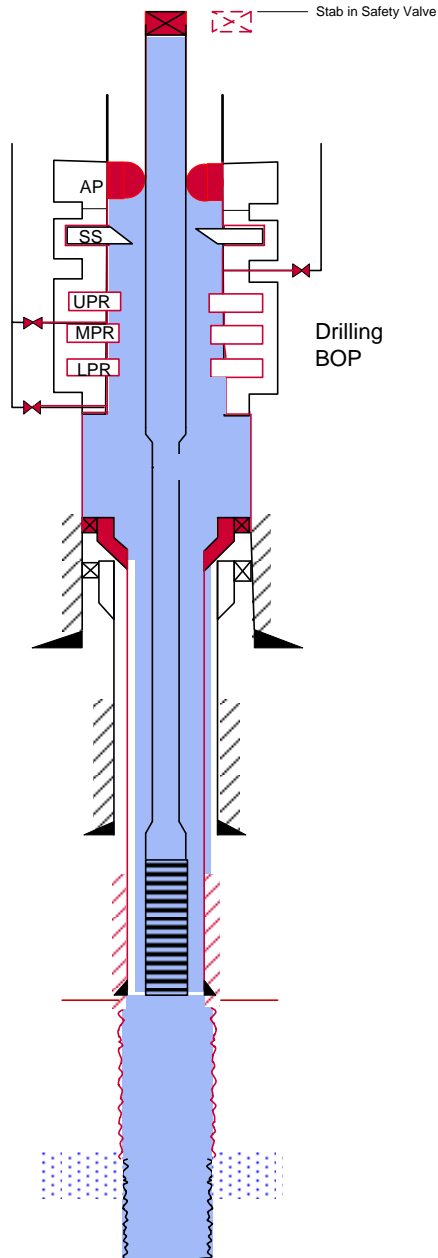


| Well data | | | |
|---|---|---|---|
| Installation/Field: | | xxxxx | |
| Well no: | xx/xx-xx | Drilled Date: | DD.MM.YYYY |
| Well type: | | e.g. oil producer | |
| MWDP: | | xxx bar | |
| Revision no: | x | Date: | DD.MM.YYYY |
| Well status: | | Completion phase | |
| Prepared: | | xxxxx (Name and signature) | |
| Verified: | | xxxxx (Name and signature) | |

| Well barrier elements | Ref. WBEAC tables | Verification of barrier elements |
|---|---|---|
| **PRIMARY - reservoir** | | |
| Well fluid | 52 | Flow checks/ stable fluid level |
| **SECONDARY - reservoir** | | |
| Formation at casing shoe | 51 | $\sigma_{min}$: x.xx sg EMW. Method: XLOT/minifrac/field model |
| Production casing cement | 22 | Length: xx mMD > casing shoe Method: volume control/logs and FIT/LOT to x.xx sg EMW at casing shoe |
| Production casing | 2 | PT: xxx bar with x.x sg |
| Production casing hanger with seal assembly | 5 | PT: xxx bar with x.x sg |
| WH | 5 | PT: xxx bar with x.x sg |
| High pressure riser | 26 | PT: xxx bar with x.x sg |
| BOP | 4 | PT: xxx bar with x.x sg |
| Completion string | 25 | PT: xxx bar |
| Stab in safety valve | 40 | PT: xxx bar |

Notes:

| Disp. no. well integrity issues | Comment |
|---|---|
| None | |
| | |
| | |

*Figure 33 WBS for the completion phase*

In the above, the WBS running of screens for an open hole completions is shown, with associated barriers. It has the same barrier envelopes as the above drilling phase. Specifications for equipment used in the completion are very important for the overall well

integrity, since this equipment is most exposed to the well fluids over the life of the well. So if the selected completion equipment is not properly designed well integrity problems will arise because of this. When selecting the components for a completion many things have to be taken into consideration, such as lifetime of the well, fluid composition, pressure and temperature. All these things will influence the well integrity and make the life of the well shorter or longer. In general for new field developments one can say that the completion equipment is designed for a working life of roughly 20 years, though this might vary from field to field and with the purpose of the well. A good job in pre-engineering and design of wells will prevent future well integrity problems.

### 5.1.7 Production phase

## WELL BARRIER SCHEMATIC
Planned / As built

8.8.1a) Typical platform production/
injection well capable of flowing



| Well data | | | |
|---|---|---|---|
| Installation/Field name: | | xxxxx | |
| Well no: | xx/xx-xx | Completed date: | DD.MM.YYYY |
| Well type: | | Oil producer, water injector, etc. | |
| MWDP: | | xxx bar | |
| Revision no: | x | Date: | DD.MM.YYYY |
| Well status: | | Eg. operational/temp. plugged etc. | |
| Prepared: | | xxxxx (Name and signature) | |
| Verified: | | xxxxx (Name and signature) | |

| Well barrier elements | Ref. WBEAC tables | Verification of barrier elements |
|---|---|---|
| **PRIMARY - reservoir** | | |
| Cap rock | 51 | σ_min: x.xx sg EMW. Method: XLOT/minifrac/field model |
| Liner cement | 22 | Length: xx mMD > res. Method: volume control/logs |
| Liner | 2 | PT: xxx bar with x.x sg |
| Liner top packer | 43 | PT: xxx bar with x.x sg |
| Formation at casing shoe | n/a | σ_min: x.xx sg EMW. Method: XLOT/minifrac/field model |
| Production casing cement * (shoe to prod.packer) | 22 | Length: xx mMD, shoe to prod.packer Method: volume control/logs and FIT/LOT to x.xx sg EMW at casing shoe |
| Production casing (below prod.packer) | 2 | PT: xxx bar with x.x sg |
| Production packer | 7 | IT: xxx bar (or PT: xxx bar with x.x sg) |
| Production tubing | 25 | PT: xxx bar with x.x sg |
| CIV | 29 | IT low: xxx bar, IT high: xxx bar |
| DHSV/Controllines | 8 | IT low: xxx bar , IT high: xxx bar |
| **SECONDARY - reservoir** | | |
| Formation at prod.packer | 51 | σ_min: x.xx sg EMW. Method: XLOT/minifrac/field model |
| Production casing cement * (above prod.packer) | 22 | Length: xx mMD > prod.packer Method: volume control/logs |
| Production casing (above prod.packer) | 2 | PT: xxx bar with x.x sg |
| Production casing hanger with seal assembly | 5 | PT: xxx bar with x.x sg |
| WH/Annulus valve | 12 | PT: xxx bar with x.x sg |
| Tubing hanger with seals | 10 | PT: xxx bar with x.x sg |
| WH/X-mas tree Connector | 5 | PT: xxx bar with x.x sg |
| Tubing hanger neck seal | 10 | PT: xxx bar with x.x sg |
| X-mas tree valves | 33 | PT: xxx bar with x.x sg |

Noes:

| Disp. no. well integrity issues | Comment |
|---|---|
| None | |
| | |
| | |

*Figure 34 Well barrier schematic for a well in the production phase*

During the production phase the WBS will be quite different from when drilling/completing the well. In this phase more equipment is installed down in the well and the X-mas tree is present on the top of the well. Although more equipment is present for keeping the well under control during production, most of the well integrity issues arise when the well is producing. That is because the drilling and completion phase is a small part of the life of a well compared to the production phase. Also in the production phase fluid flows through the well with different temperatures, pressures and viscosity than what was used for drilling the well.
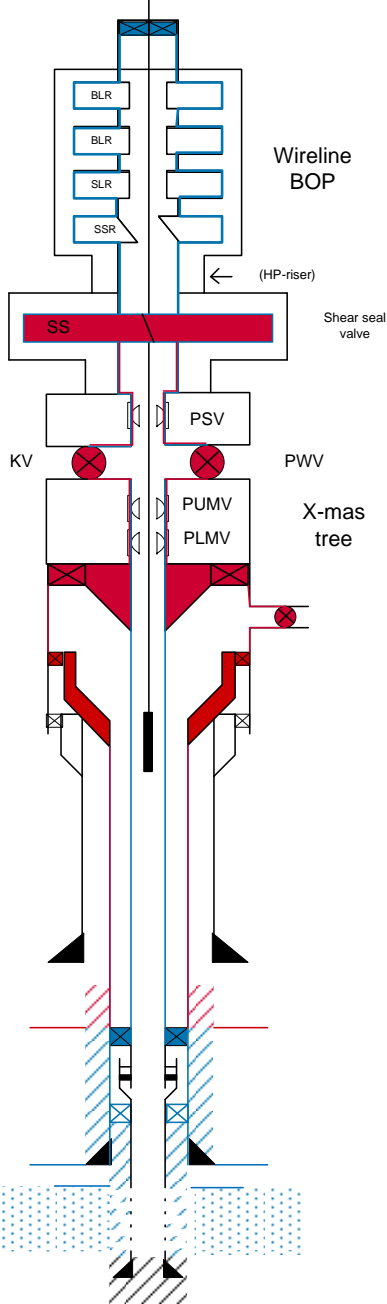
## 5.1.8    Intervention phase



*Figure 35 WBS drawing for intervention phase*

During intervention of a live well an intervention package is installed on top of the X-mas tree to be able to lubricate the intervention toolstrings into the well. The intervention package also enables you to run in and out of hole to working depth maintaining the hydrocarbons inside the well.

The WBS for the well intervention utilizes most of the well barrier elements used for the production phase but the primary barrier is extended into the well intervention package as the downhole safety valve is out of function as a barrier if you have e.g. wireline cable or coiled tubing across it.

Typical for a well intervention WBS is the number of common well barrier elements are increasing due to the common elements in tubing hanger and the X-mas tree. It is very important to perform a detailed risk assessment for the actual job and implement risk reducing measures to reduce the risk to a minimum.

### 5.1.9    P&A phase



*Figure 36 WBS drawing for the P&A phase, temporary and permanent*
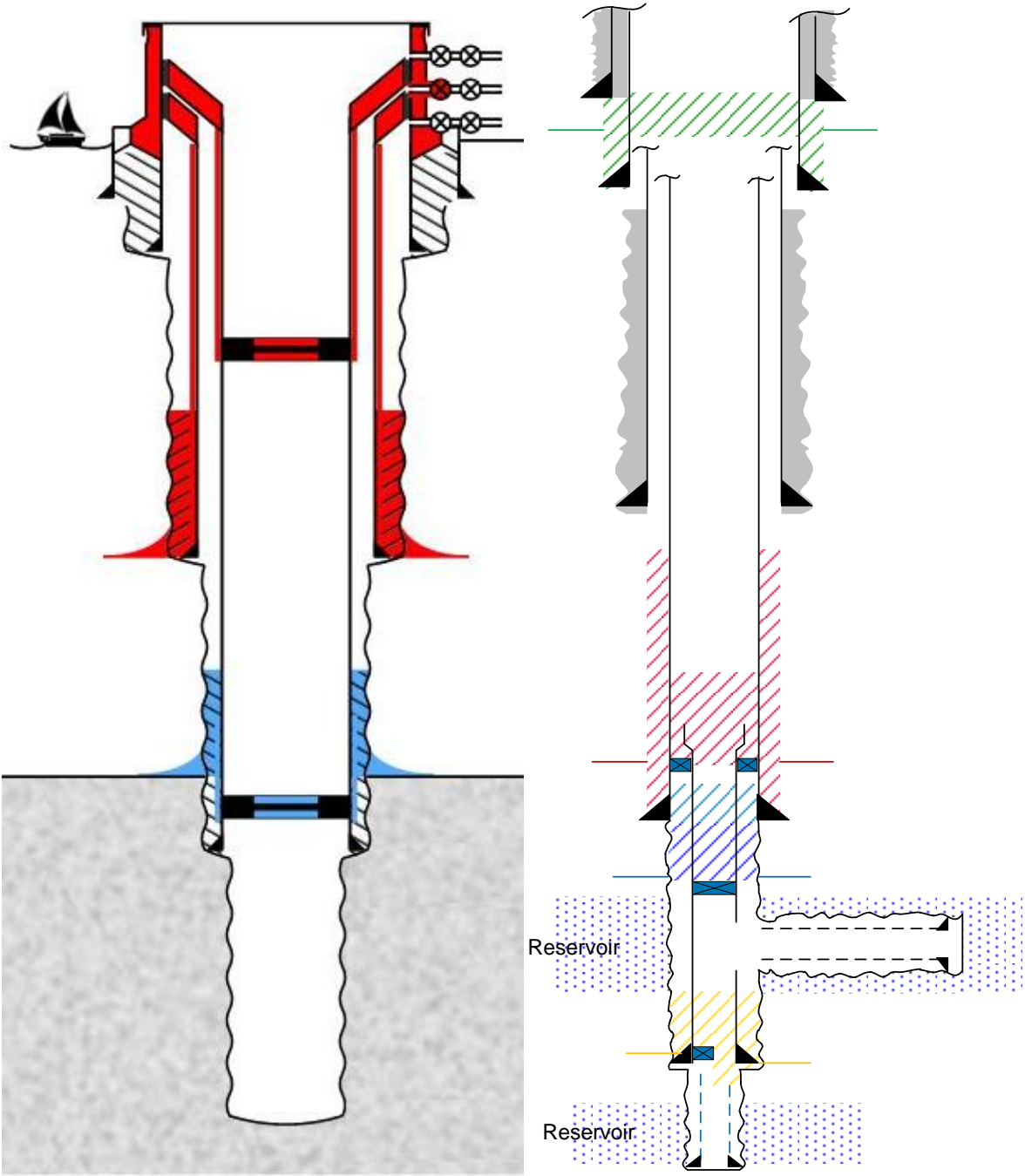
A WBS for a temporary abandonment is showing the primary and secondary barrier if the well is temporary plugged for a short or longer term.  The equipment used as temporary well barrier elements needs to be designed for the expected duration of the abandonment phase. It is important that the equipment is designed and installed in the well in such a way that a safe

re-entry is possible after the abandonment period. Qualified mechanical barriers are allowed to be used as barrier elements for temporary abandonment.

A permanent abandonment differs from temporary abandonment as it has an eternal perspective. Mechanical barrier elements are not allowed to be used as barrier elements alone as they can degrade over time. Permanent well barriers as shown on the WBS shall be placed as close to the source of inflow as possible and as a minimum at a depth which have sufficient formation strength. It is important that the cement or alternative plugging material is covering the full cross section of the well including all annuli and seal both vertically and horizontally. As the wellhead and casings will be cut below seabed as a part of the permanent abandonment it will be very difficult to re-enter the well afterwards

## 5.2 Barrier design, construction and qualification of barriers for life cycle

When the well is constructed it is important to focus on the well barriers for the whole well life cycle. Therefore well barrier schematics illustrating the well barriers for the different life cycle phases are to be developed for all the different phases. The drawings must also have information about how the different well barrier elements will be tested and verified, and how they will be monitored which is especially relevant for the operational phase.

NORSOK D-010 defines well integrity requirements for the different life cycle phases, and also has a chapter with a well barrier acceptance criteria table for each of the typically well barrier elements defining specific design, construction and monitoring requirements. The tables also contain important references to existing standards to be used in addition.

A general and important principle for all barrier elements is that they are to be designed to withstand all the possible loads they can be exerted to during the well lifecycle. For the different load cases minimum design factors or other equivalent acceptance criteria are to be pre-defined for:
- Burst loads
- Collapse loads
- Axial loads
- Tri-axial loads

### 5.2.1   MWDP or MSDP

In addition to verifying that the well is designed for the load cases, all well barrier elements are to be pressure tested to the maximum pressure that the barrier elements may be exerted to when a well kill operation is ongoing, or during injection (whichever is the highest pressure). For control lines, the test pressure will be the highest possible operating pressure. For valves the test pressure for closed valves will be the highest possible differential pressure.

For a well completed for operation, all the well barrier elements then need to be qualified for the maximum well design pressure (MWDP). The MWDP is the same as the highest pressure of the following:

- **Kill pressure.** The kill pressure chosen is to be the highest possible kill pressure needed. This means the highest possible wellhead shut-in pressure plus the additional pressure needed to be able to kill the well. When calculating the highest possible shut-in pressure it is important to calculate with the highest possible reservoir pressure through the whole well lifecycle, and with the lightest fluid density (usually the reservoir gas) filling the wellbore.

- **Injection pressure.** This is to be the highest possible injection pressure that the wellhead can be exerted to. If the compressors or pumps are able to feed very high pressures, safety systems need to be implemented ensuring that there is a maximum level that can be reached. The maximum injection pressure is then to be the highest possible pressure after the PSV has opened. The PSV is a pressure safety valve that will automatically open at a certain pressure level and start bleeding-off the pressure.

For a well that is drilled the term MSDP (Maximum section design pressure) is used. Each well barrier element needs to be verified and tested to minimum MSDP before drilling out the shoe and starting on a new section. For barrier elements that also are to be a part of the barrier envelope for a well in production, the barrier elements will be tested to MWDP before drilling out the shoe. The MSDP will be the highest possible pressure the barrier elements will be exerted to if a kick occurs and killing of the well is needed. In the drilling phase it is not possible to have sufficient formation strength for a gas filled hole and kill margin for all the sections, and for these sections it is therefore crucial to detect the kick as early as possible and within the calculated kick margin to avoid a possible underground blowout.

## 5.3 Description of typical barrier elements and important qualification issues

In this section the focus will only be on some of the typical well barrier elements that are important in the operational phase and permanent plug and abandonment phase.

### 5.3.1 Formation

In most all barrier envelope drawings you will see that the formation is part of the envelope. Not all formations are necessarily suitable for this purpose. In order to use the formation as

part of the barrier envelope it is important that it will not allow gas or fluids to percolate through within the time span it is used as part of the barrier. This means that the formation property must be (for its purpose) impermeable and not contain vertical, open fractures or faults across the sealing interval.

There is general consensus in the oil industry that we have two different scenarios where two different requirements to formation integrity apply.

1. You have access to the well and you can observe the pressure behavior, typically in the drilling phase.
2. You have no ready access to the well and may not be able to monitor all pressure changes, typically in the production / injection phase.

During (1) you can act on demand and to some extent manipulate the downhole conditions, through changing the wellbore pressure, adding particles or chemicals, changing temperature conditions etc. Therefore somewhat loosely defined terms like "Fracture Pressure / Fracture gradient" are used to address the formation integrity. In this context it basically means the wellbore pressure you think the wellbore wall can withstand without breaking down and creating a loss situation.

Where the well is not easily accessible or you may not be able to monitor changes in the situation as in (2) you need to be more precise about how you define the formation integrity. The minimum formation stress as the fundamental formation integrity together with the formation properties are therefore the safest to use. In this case the formation will not allow undetected leaks of reservoir fluids to develop into uncontrolled underground migration of reservoir fluids.

Information about the minimum formation stress is gained through extended leak off tests. Field models may be used if sufficient data are obtained for the field.

The minimum formation stress will as a minimum need to be the same or higher than the reservoir pressure or any higher well pressure. For injection wells, the injection pressure will also need to be considered to avoid any out of zone injection.
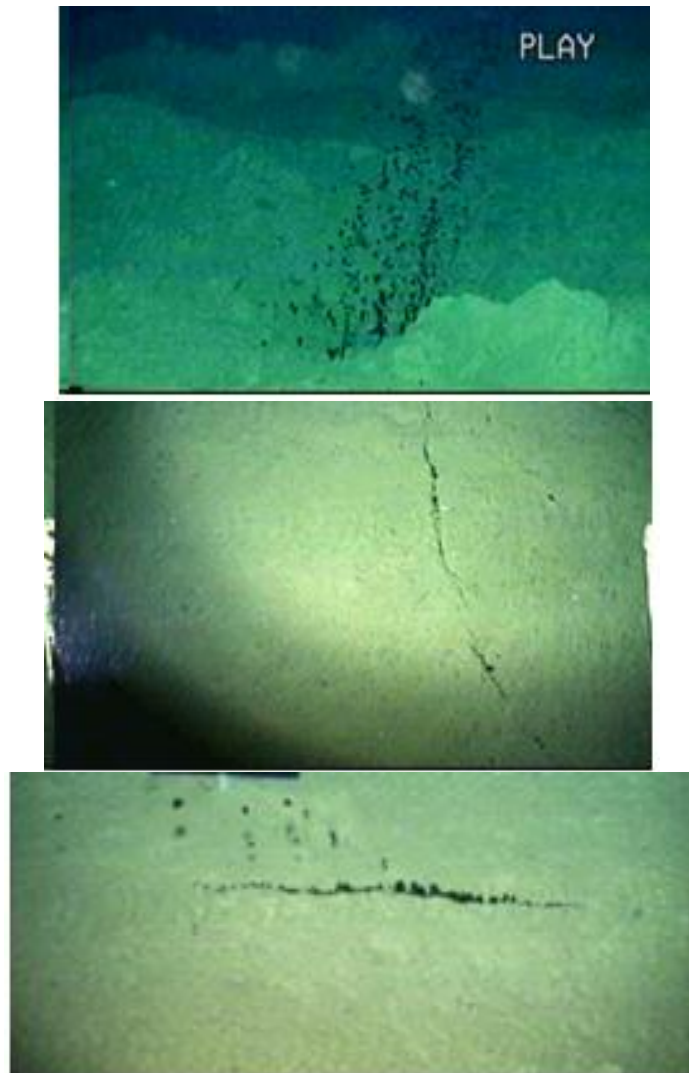
*Figure 37: Example of leak to seabed due to injection pressure being higher than the re-opening pressure of deep faults, allowing faults to propagate to the seafloor*

**Formation replacing casing cement**

The formation may also in some cases replace casing cement as barrier element. It is a well-established fact that some rock has the ability to creep, due to their plastic properties. The best known example is deeply buried rock salt, but also other formations, like clay, has this property.

The plastic properties allow clay to creep into the wellbore where it is no longer held back by the pressure exerted by the mud column. Over time the formation may bond onto the casing and form a barrier against flow outside the casing.

Clay as barrier material has some benefits compared with cement: It is natural part of the succession, it is inert to chemical corrosion and it is ductile.

If you need a barrier and for some reason casing cement is not present, formation creep may provide you with a good alternative. However, this is only possible if you are able to prove bonding and pressure integrity.

**Confirmation of formation barrier replacing casing cement:**
- The interval must have a formation stress higher than the pressure it can be exposed to, which typically is the extrapolated reservoir pressure.

- The same requirement as for cement applies for the interval length of bonded formation.

- Two independent logging tools must be run inside the casing and both verify the formation bonds against the casing. At present a cement bond log (CBL) and a sonic tool (USIT) have been the preferred logging tools.

- If the logged response is indicative of bonding formation, then a pressure test through perforation might be required. This could possibly be done by testing the logging response for all new formations with a LOT through a perforation at least 5 m above the base of the bonded interval. The stable pressure during the shut-in phase of the LOT must be above the required pressure the barrier is to withhold.

### 5.3.2    Casing Cement

Casing cement used as a well barrier is an extremely important well barrier element as this has to act as a well barrier element throughout the operational phase and later when the well is permanently plugged and abandoned. In order to ensure integrity it is crucial that the cement is bonding to the formation with integrity, as well as to the casing. To verify that the cement is bonding to the casing without channels, two logging tools are needed. These tools are typically cement bond log (CBL) and a sonic tool (USIT). For wells that are permanently abandoned it is important that such logging is performed to verify the integrity before the inside cement plug is set for permanent abandonment. For wells in operation it is critical to log the cement if the casing cement is acting as both the primary and secondary barrier, due to the fact that a pressure test of the cement will not verify the integrity of the cement except at the csg shoe depth, ref Figure 38. The distance between the primary and secondary barrier

must also be evaluated, such that any risk of formation collapse does not crack both the primary and secondary cement column.

According to NORSOK D-010 the cement barrier must have the following properties:

a) Impermeable

b) Long term integrity

c) Non-shrinking

d) Ductile – (non-brittle) – able to withstand mechanical loads/impact

e) Resistance to different chemicals / substances ($H_2S$, $CO_2$ and hydrocarbons)
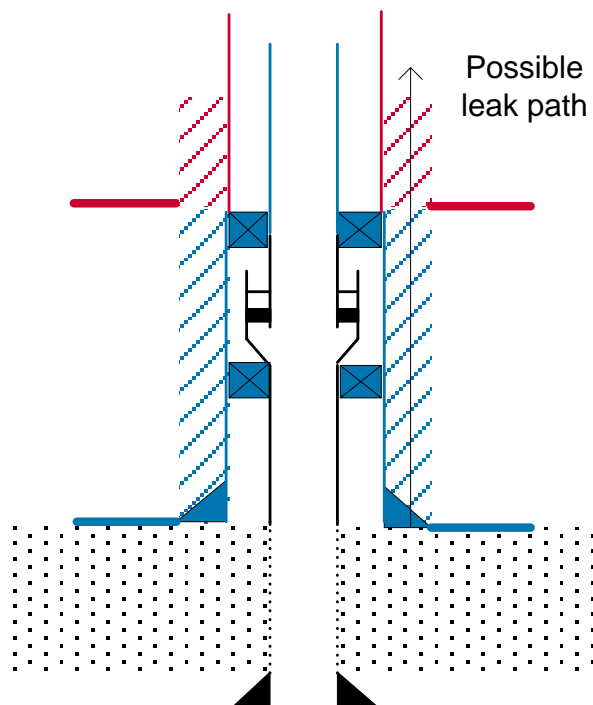
f) Wetting, to ensure bonding to steel.



*Figure 38: Casing cement acting as part of both the primary and secondary well barrier*

The integrity of the casing cement is tested through a pressure test after drilling out the shoe. This test is typically an FIT test.

To ensure sufficient cement height, it is usual to place double the required cement volume. The required cement height is dependent on the pressure, but some minimum cement heights are normally required as given in NORSOK D-010. The casing cement is acting as a vertical barrier, not a horizontal one, so it is the vertical height that needs to be assessed when deciding the volume of cement to be placed.

*Figure 39: Picture of cut and retrieved intermediate casing, cemented production casing and tubing string with control line*

### 5.3.3 Casing Cement Plug

The casing cement plug is normally used as barrier element for permanent abandonment together with the cemented casing string and outside formation integrity. The properties of the cement are to therefore be the same as described for casing cement.

The cement plug is to be placed at a depth where the casing string is cemented and the formation outside has formation integrity. The cement plug will act as a barrier element preventing leakage across the plug. The length required to set is dependent on the pressure and vertical depth, as similar for casing cement. NORSOK D-010 describes the minimum depth requirements.
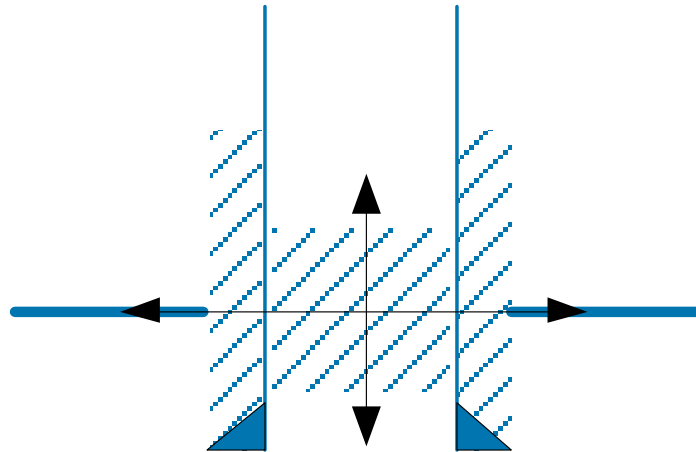
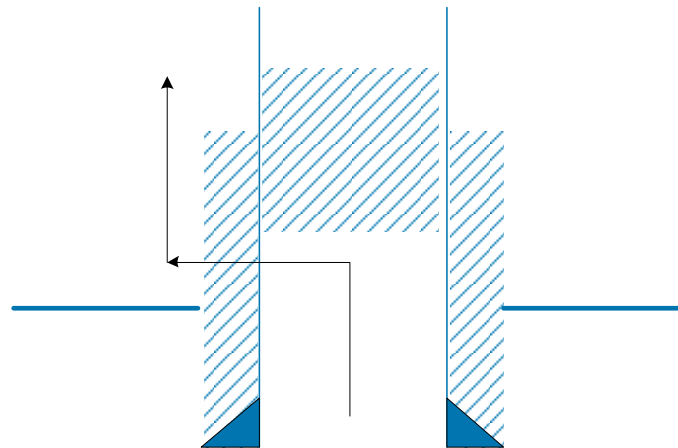*Figure 40: Principle of the casing cement plug setting depth*



*Figure 41: Possible leak path if the cement plug is set too shallow. Not according to requirement for permanent abandonment.*

The integrity of the cement plug is to be verified by pressure testing and tagging.

### 5.3.4. Casing/Tubing

The casing or tubing as a barrier element must be of a material quality compatible with the expected exposed fluid. Typically a grade for more aggressive fluids than for the casing is needed for the tubing that is continuously exposed to production/injection.

The casing or tubing is made up of typical approximately 12 m long casing connected joints. Each connection is a possible potential leak point, and it is therefore vital that the make-up torque is correct and that the seal is not damaged.
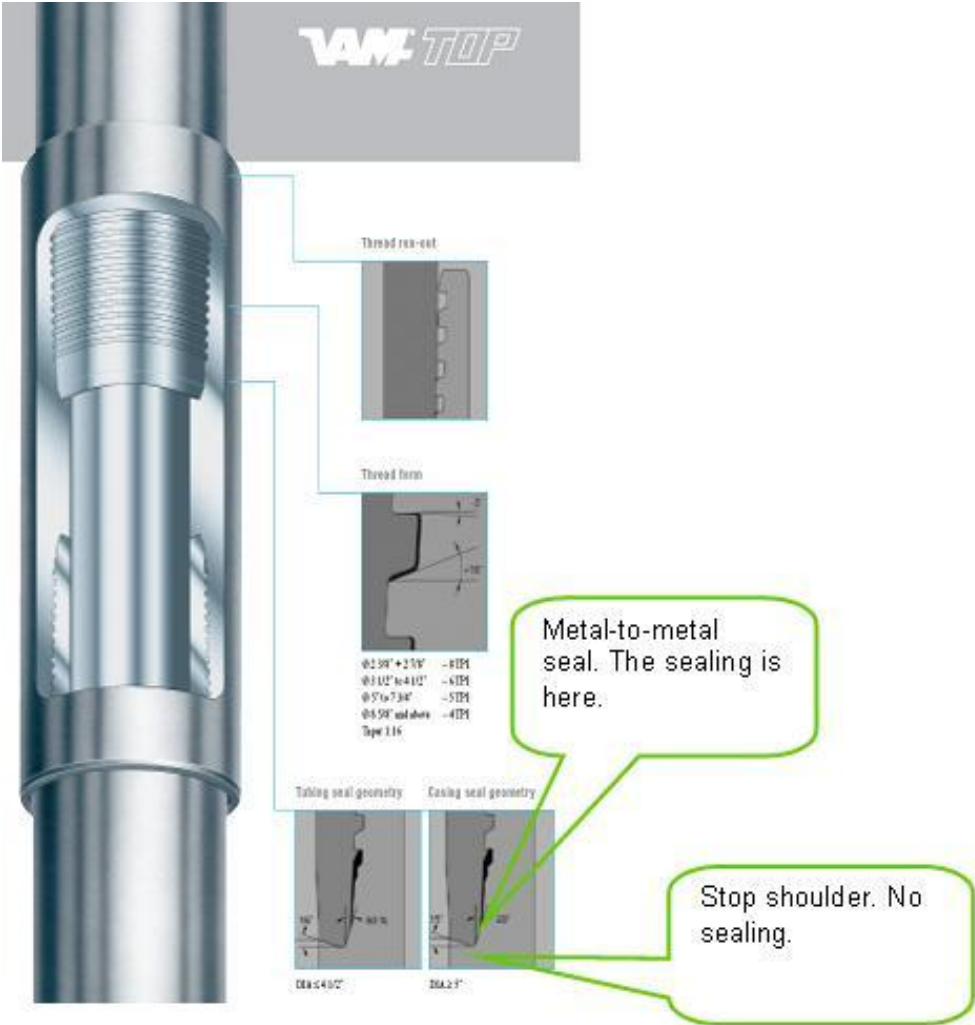


*Figure 42: Principal of casing/tubing connection sealing*

The casing/tubing is to be strong enough to hold all the forces it will be exposed to and load calculations confirming that there is sufficient strength must be carried out. Loads to be accounted for are typically burst, collapse, axial and tri-axial yield loads.

After installation the casing/tubing is to be tested to the maximum anticipated differential pressure. The production casing is to be retested in the completion phase due to possible damage and wear that has occurred during the drilling phase. It must be accounted for some wear, and if the well section is long (relevant for long horizontal wells) it is normal to log the

casing to detect areas with extensive wear. Some wear should therefore also be accounted for in the load calculations.



*Figure 43 Corroded tubing due to incompatibility between the tubing material and injection water quality*

### 5.3.5. Production packer

A production packer is a standard component of a completion string in a well and provides a seal between the outside of the production tubing and the inside of the casing or liner. The production packer is run in the casing on production tubing or wireline and it is usually placed close to the bottom end of the production tubing and above the top of the perforations in a well.

The production packer is used to protect the casing from pressure and produced fluids and in most cases, it will be part of the primary barrier in a well. It is therefore extremely important that the production packer is properly set in the casing/liner in order to maintain well integrity and have a safe well.

The production packer is designed to grip and seal against the casing ID. Gripping is accomplished with metal slips that have teeth and dig into the metal of the casing while sealing is accomplished with rubber elements. In situations where the sealed pressure is very high, metal rings are used on either side of the elements to prevent the rubber from extruding. The slips and rubber element are expanded outward to contact the casing. Axial loads are applied to push the slips up and compress the rubber element, causing it to expand outward. The axial loads are applied either hydraulically, mechanically or using an explosive charge.

Production packers may also be used to isolate sections of corroded casing, casing leaks or squeezed perforations, and isolate or temporarily abandon producing zones.
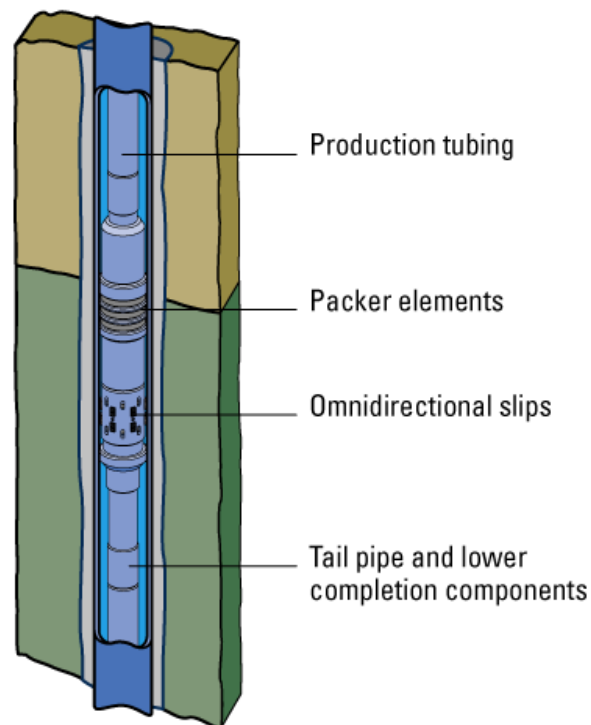


*Figure 44 showing a production packer installed downhole in a well*

### 5.3.6. DHSV

A downhole safety valve (DHSV) is part of the completion string and it is one of the most important well barrier elements in a well. It is a valve that closes automatically if pressure is lost in the hydraulic control line that operates the valve. When closed, the valve will be part of the primary barrier envelope and it will isolate the reservoir fluids from the surface.

The DHSV is installed to prevent the uncontrolled release of reservoir fluids in the event of an emergency shutdown or worst case scenario such as an explosion on the platform topside where the wellhead integrity is lost. It is a vital component in the completion and usually consists of flapper valves that open downwards, such that the production flow will try to close it while pressure via a hydraulic control line from surface pushes it open. Most downhole safety valves are controlled hydraulically from the surface, i.e. they are opened using pressure via a hydraulic connection that is linked directly to a well control panel at the surface. When hydraulic pressure is applied down the control line, the hydraulic pressure forces a sleeve in

the valve to slide downwards. This movement compresses a large spring and pushes the flapper downwards to open the valve. When hydraulic pressure is removed, the spring pushes the sleeve back up and causes the flapper to shut. In this way, it is fail safe and will isolate the wellbore in the event of the loss of the X-mas tree or wellhead. The location of the downhole safety valve within the completion is determined to optimize the safety of the well. Usually the DHSV is placed in the completion between 100 m and 500 m below the seabed.
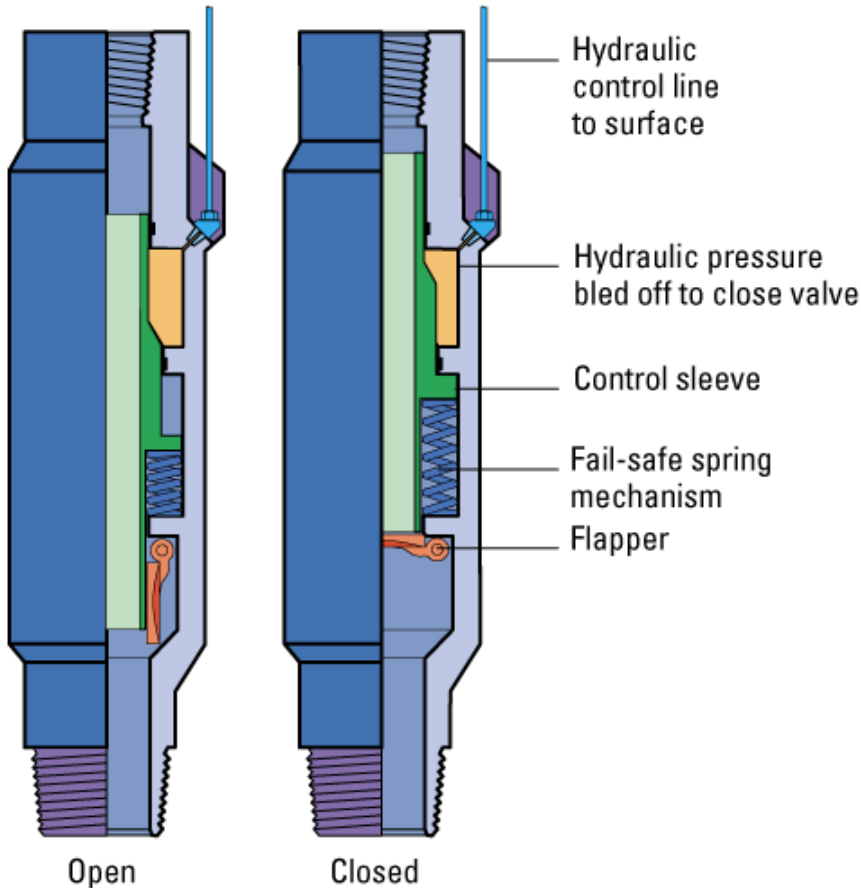


*Figure 45 Schematic of a Downhole Safety Valve (DHSV) in open and closed position.*

### 5.3.7. CIV

Chemical injection valves or CIVs are often run as part of the completion in a well. The chemical injection valves are used to inject chemicals into the tubing to prevent or control corrosion, to prevent the formation and/or deposition of scale, to prevent the formation of emulsions, to treat paraffins, to dissolve salt or to prevent hydrate formation in wells. The main function of the CIVs is to control the amount of fluids injected into the production stream at valve depth.

The valves can be run on the tubing or on wireline and they can be placed inside a side pocket mandrel which is run as part of the well completion. The valves consist of spring loaded check valves where the spring force is such that the valve is normally in a closed position.

The chemicals enter the valve from the casing annulus or from a separate injection line attached to the appropriate side pocket mandrel. As injection pressure overcomes the preset spring force plus the tubing pressure, the spring compresses and moves the stem tip down and off the seat. Chemicals then flow through the seat, past the reverse-flow check valve, and into the production tubing.

The CIVs are sometimes part of the primary or secondary barrier in a well. They sometimes leak and in this case the well barrier will be deteriorated or have failed. The valves are therefore regularly tested for leaks and defect valves will have to be fixed or replaced to maintain the well integrity.
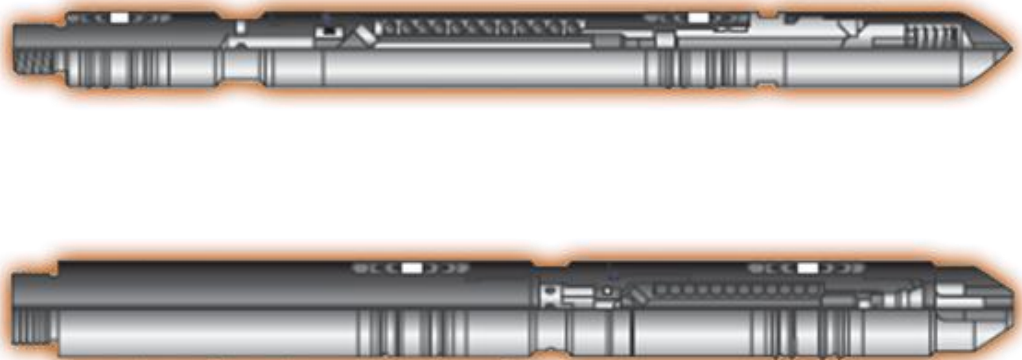


*Figure 46  Examples of Wireline retrievable Chemical Injection Valves (CIV's)*

### 5.3.8. Casing hanger seal

The casing hanger is the portion of a wellhead assembly which provides support for the casing string when it is lowered into the wellbore. It serves to ensure that the casing is properly located. When the casing string has been run into the wellbore it is hung off, or suspended, by a casing hanger, which rests on a landing shoulder inside the casing spool. Casing hangers

provide a seal between the casing hanger and the spool and are usually part of the secondary well barrier envelope in production wells.

Casing hangers are installed to support the individual casing strings in the well. It is the landing base or the casing head. It is usually welded or screwed to the top of the surface casing string. The surface casing serves as a foundation pile for the well which transfers the hanging load to the earth. The casing head is prepared with a bowl into which the slips sit and chuck the casing in place. Most casing heads allow for the pressure readings to be taken on the annulus and provide the means to pump out or into if necessary. The top of the casing string and annulus is usually sealed.
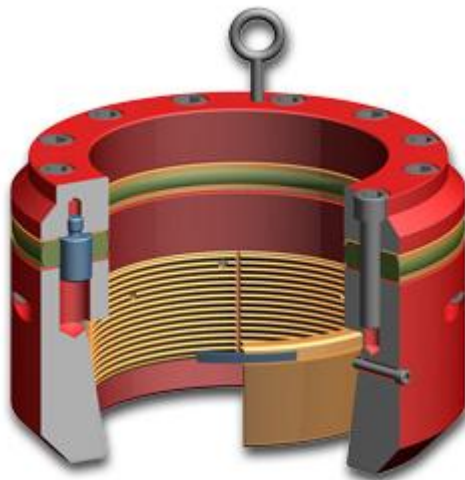


*Figure 47 Example of a casing hanger with sealing elements*

### 5.3.9. Wellhead

A wellhead is a general term used to describe the components at the surface of an oil or gas well that provide the structural and pressure-containing interface for the drilling and production equipment. The primary purpose of a wellhead is to provide the suspension point and pressure seals for the casing strings that run from the bottom of the hole sections to the surface pressure control equipment. The wellhead seals are usually part of the secondary well barrier envelope in the wells.

Once the well has been drilled, it is completed to provide an interface with the reservoir rock and a tubular conduit for the well fluids. The surface pressure control is provided by a Christmas tree, which is installed on top of the wellhead, with isolation valves and choke equipment to control the flow of well fluids during production (see figures below).

Wellheads are typically welded onto the first string of casing, which has been cemented in place during drilling operations, to form an integral structure of the well. Offshore, where a wellhead is located on the production platform it is called a surface wellhead, and if located beneath the water then it is referred to as a subsea wellhead or mudline wellhead.
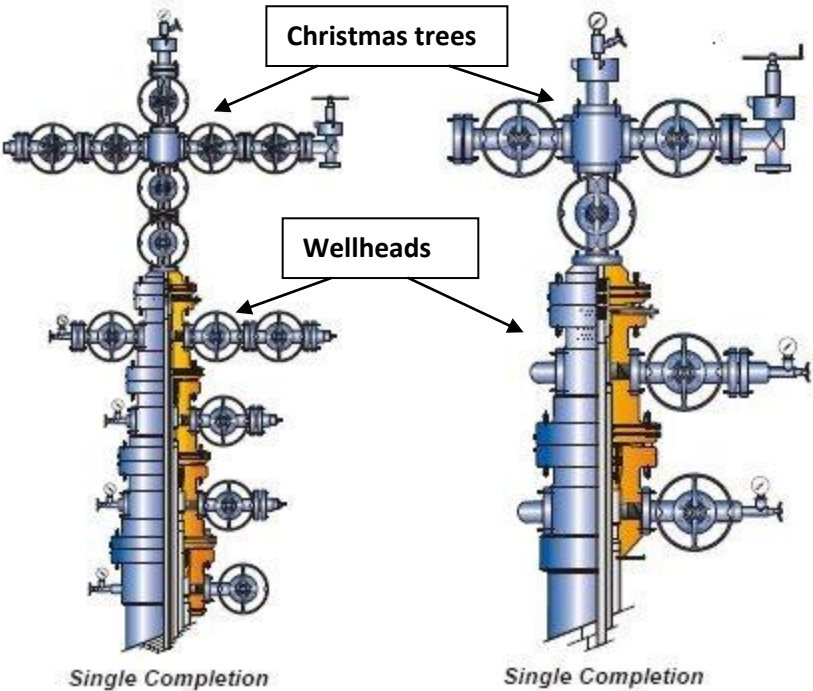


*Figure 48 Examples of wellheads with Christmas trees installed.*

### 5.3.10. Annulus valves

For a dry wellhead the annulus valves are used to access the different annuli in between tubing and casing and between the different casings in the well. Depending on well configuration one or several of the annulus valves are often a barrier element in one of the barrier envelopes against the reservoir.

The wellhead is often equipped with two bores into each annulus where two annulus valves are installed onto one bore and one valve and pressure cap is installed on the other side. The exact valve configuration will vary from field to field. In order to be able to monitor the pressure there is normally a pressure and temperature gauge installed in between the two valves and valve closest to the well is kept open to allow monitoring.

The valves are also used to increase or reduce the pressure in the annuli and if needed also top up the fluid level. During re-completion the annulus valves are used to circulate in heavy brine or mud in the well before retrieving the completion.

For subsea wells the annulus valves are normally integrated as a part of the subsea X-mas tree. On horizontal X-mas trees it is only possible to access the annulus between the production tubing and the production casing. Monitoring of the other annuli is for the time being only possible with wireless pressure and temperature gauges, but R&D work is ongoing to improve this.

The annulus is also normally equipped with two valves where the valve closest to the well is kept open for monitoring purposes. One or several temperature and pressure gauges are installed in between the two valves in X-mas tree annulus block.

The annulus valves on the subsea trees are used in the same way as for the dry wellheads, but normally they all are automated.
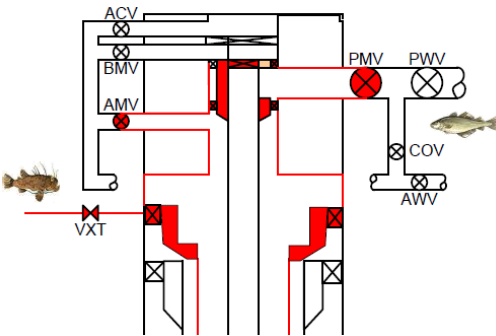


*Figure 49 Annulus master valve as part of secondary barrier envelope on horizontal XT.*

### 5.3.11. XT-connection

The XT connection is the connection between the XT and the wellhead and is normally part of the secondary barrier envelope.

For dry trees there is normally a seal installed between the top of the tubing hanger and the XT inner bore and a seal between the wellhead and the XT body. It is normally possible to leak test in between the two seals before an internal test is performed by pressuring up the inside of the production tubing and the XT production bore. The XT tree is locked to the wellhead either by using locking screws or a clamp.
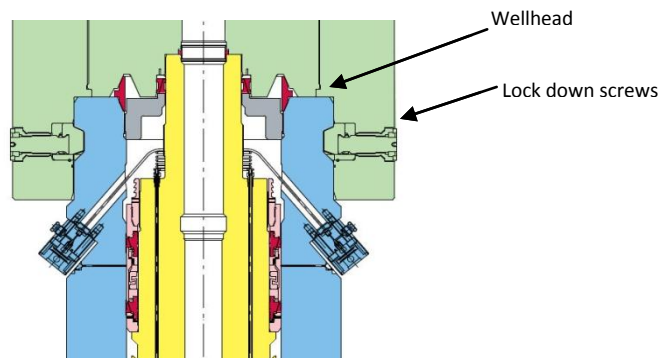
*Figure 50. Drawing showing XT tree locked to the wellhead by lock down screws (Cameron).*

For subsea trees the XT is locked onto the wellhead by using a hydraulic locking mechanism controlled from the surface.

### 5.3.12. Tubing hanger with seals

The tubing hanger consists of a steel body with external seals and normally one bore in the middle, but it can also consist of several bores. The tubing hanger often has an internal profile for a plug to be installed.

The function of the tubing hanger is to:

- Support the weight of the tubing string

- To isolate the A annulus and the tubing bore at the wellhead

- Provide  seals between:

    i. Production tubing and wellhead

    ii. Production tubing and x-mas tree

- Allow for control line penetration with seals for e.g. downhole safety valve, downhole pressure and temperature gauges and provide a profile for a tubing hanger plug.
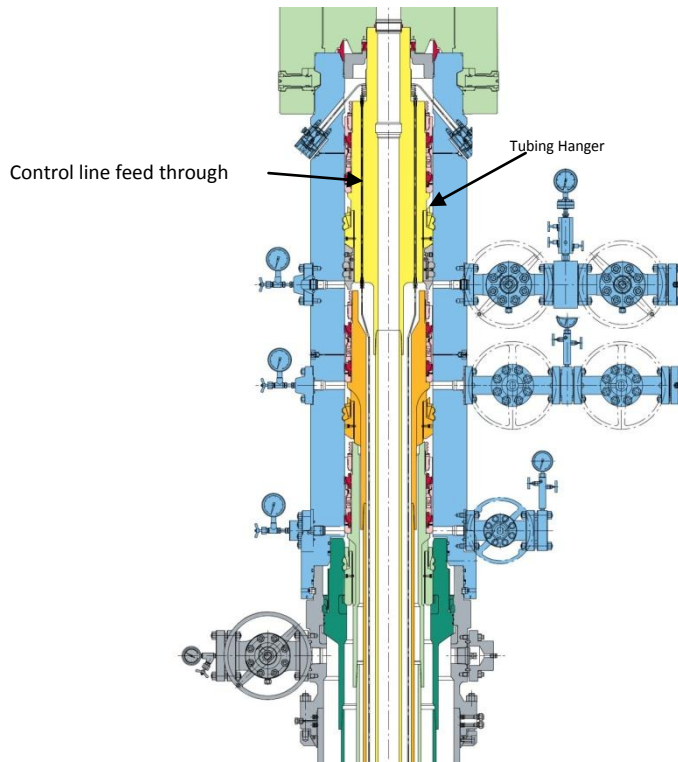
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*Figure 51 Tubing hanger installed in dry wellhead with control line feed through (Cameron).*
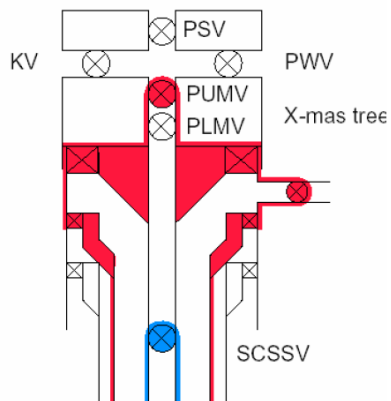


*Figure 52 Tubing hanger as part of secondary barrier envelope on vertical dry XT.*

### 5.3.13. X-mas Tree (with XT valves and exit blocks)

The modern X-mas tree normally consists of a main housing with annulus and production blocks directly mounted onto the main housing with large bolts. The main housing and blocks have internal bores which are fitted with integral valves. The X-mas tree is equipped with a connector at the bottom which is used to attach it to the wellhead or tubing head either with a clamp or locking screws.

Dry X-mas trees have a connection at the top for the installation of intervention stacks for doing wireline, coil tubing and snubbing operations and subsea horizontal trees have a connection at the top to install high pressure intervention risers or a subsea BOP.

The X-mas tree is normally equipped with pressure and temperature monitoring and a facility to inject corrosion/scale inhibitor and MEG/methanol for hydrate inhibition during shut in and testing.

The function of the X-mas tree is to:

- Provide a flow conduit for hydrocarbons from the tubing and into the surface lines with the ability to stop the flow by closing the flow valve or the master valve.

- Provide vertical access into the wellbore.

- Provide an access point where kill fluid can be pumped into the tubing.
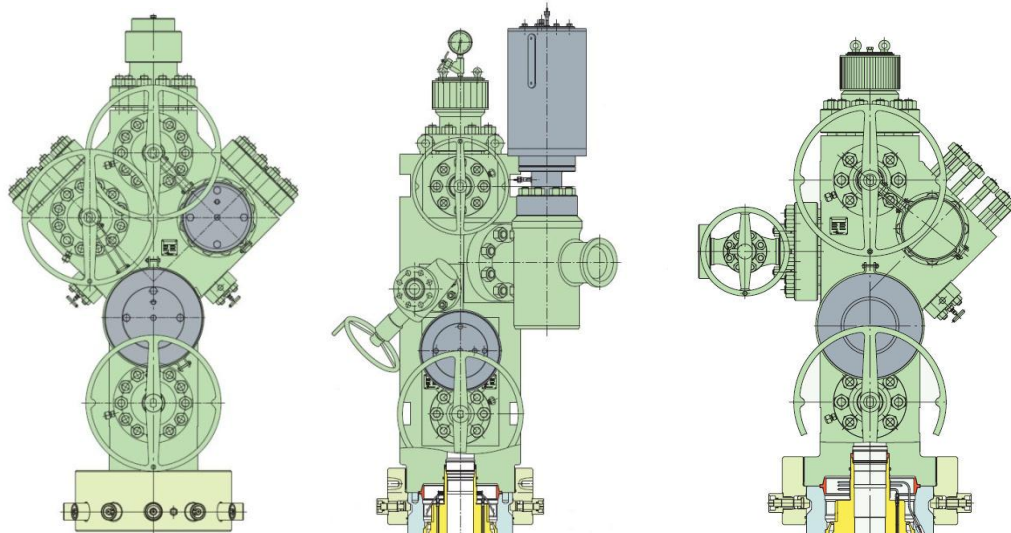
*Figure 53 Different types of dry X-mas trees (Cameron).*
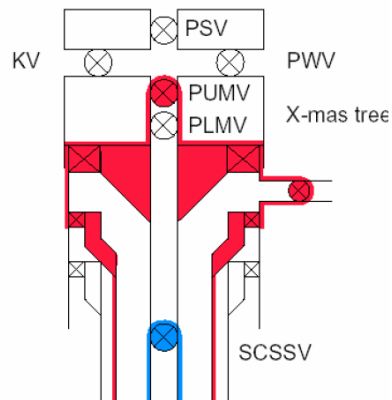


*Figure 54 X-mas tree and production upper master valve as part of secondary barrier envelope on vertical dry XT.*

## 6. Operational

### 6.1. General

The status of well barriers is to be known by monitoring the individual Well Barrier Elements (WBE) of the Well Barrier Envelopes during the production life of the well.

*Well barrier integrity is commonly monitored by registration of annulus pressure and frequent leak testing of well barrier elements.*

*The following requirements have been specified in NORSOK D-010:*

 a) *Downhole safety valves, production tree valves and annulus valves shall be regularly leak tested. Leak test acceptance criteria shall be established and be available.*

 b) *The pressure in all accessible annuli (A, B and/or C annuli) shall be monitored and maintained within minimum and maximum pressure range limits as defined in the completion design and presented in the hand-over or other relevant field documentation for the well.*

 c) *Registered anomalies shall be investigated to determine the source of anomaly and if relevant, quantify any leak rate across the well barrier.*

 d) *Upon confirmation of loss of the defined well barrier, the production or injection shall be suspended and shall not re-commence before the well barrier or an alternative well barrier re-established*

Individual well barrier elements are to be regularly function and leak tested in accordance with given test criteria. Generally, all well barrier elements are to be tested for leaks while valves that are included in the well barrier envelopes, e.g. downhole safety valves and Christmas tree valves are also to be function tested regularly as per a pre-defined frequency. There are to be no leaks to the environment from the wellhead, X-mas tree, valves or instrument connections.

Primary and secondary well barriers installed to facilitate the removal of a X-mas tree; the BOP or suspension flange are to have been tested and confirmed as leak tight.

Testing of a barrier should be in the direction of anticipated flow if possible.

'

'

## 6.2. Valves and Christmas Trees

### 6.2.4. Valve Test Criteria

The acceptable leak rate of a valve or well barrier element is to be zero, unless specified otherwise.

The petroleum industry has only one defined leak rate, which is the maximum leak rate for SSSVs. This is defined in API Recommended Practice 14B, Design, Installation, Repair and Operation of

Subsurface Safety Valve Systems (5th edition, October 2005 (ISO10417 of 2004)). According to API 14B, the allowable leak rate of SSSVs has been defined as:

- *0.42 Sm3/min (25.5 Sm3/hr) (900 scf/hr) for gas*
- *0.4 l/min for liquid*

The API 14B criteria can also be used as allowable leak rates when testing other valves such as production tree valves, annulus access valves, and CIVs providing the observation volume is adequately large to give meaningful tests and the valves are connected to a closed system.

For situations where the leak-rate cannot be monitored or measured, a criterion for maximum allowable pressure fluctuation is to be established.

The commonly accepted way of determining leak rates through SSSV and X-mas tree valves is by:

- *Bleeding down pressure above (downstream of) the valve*

- *Closing in the volume above the valve and then monitoring the rate of pressure build up in that volume*

- *Converting the pressure rise into a volume leak rate*

When testing valves for leaks, the status of all the valves in the system must be known, the temperature has to be stable and the differential pressures between the valves should be known. A minimum differential pressure should also be specified.

Function testing of the valves is to be performed:

- *After installations*
- *After having been subjected to abnormal loads*
- *After repairs*
- *Routinely (as defined in the NORSOK standard)*

### 6.2.5. Subsurface Safety Valves (SSSV)

For Subsurface Safety Valves (SSSVs), the following requirements apply:

- *The valves are to be leak tested at specified regular intervals*
- *Acceptance of downhole safety valve tests is to meet API  RP 14B requirements*
- *If the leak rate cannot be measured directly, indirect measurement by pressure monitoring of an enclosed volume downstream of the valve is to be performed.*

When applying the well barrier acceptance criteria, the liquid/gas composition above the valve to be tested is to be known with certainty. For gas-liquid combinations special calculation formulas need to be developed. The acceptance criteria should be converted to basic pressure per time units for the individual wells or fields.

When testing X-mas tree and SSSV valves, the minimum test period should be as follows:

| DHSV (production) | 30 minutes |
|---|---|
| DHSV (injection) | 10 minutes |
| X-mas tree valves | 10 minutes |

*Table 7 Test duration for XMT and DHSV, API 14B*

For all valves on the XMT, the maximum acceptable *internal* leak rate is as specified as per API 14B (see Section 6.2.1. above).

A typical procedure for testing a valve is to bleed down the pressure downstream of the valve (to be tested) to a preset pressure and measure the pressure build up within the test period. However, when testing of XMT valves, the small volume between the valves (test volume) is a limitation. In the following only gas leakage is considered.

**Example:**

Calculate the maximum allowable pressure build up above the DHSV, as part of the monitoring. See Figure 1. The calculation is based on the following equation in API RP 14B:

$$q = 2{,}84 \times 10^3 \left( \Delta \frac{p}{Z} \right) \left( \frac{1}{t} \right) \left( \frac{V}{T} \right) \qquad \text{(SI units)}$$

$$q = 35{,}37 \left( \Delta \frac{p}{Z} \right) \left( \frac{1}{t} \right) \left( \frac{V}{T} \right) \qquad \text{(USC units)}$$

where

$\left( \Delta \dfrac{p}{Z} \right)$ is the final pressure $p_f$ divided by final $Z_f$ minus initial pressure $p_i$ divided by initial $Z_i$;

$q$ is the leakage rate, m$^3$/min (SCF/min);

$p$ is the pressure, in MPa (psi);

$Z$ is the compressibility factor;

$t$ is the build-up time, in min, to reach a stabilized pressure;

$V$ is the volume of the tubing string above the SSSV, in m$^3$, (ft$^3$);

$T$ is the absolute temperature at the SSSV, in °C + 273 (°F + 460).
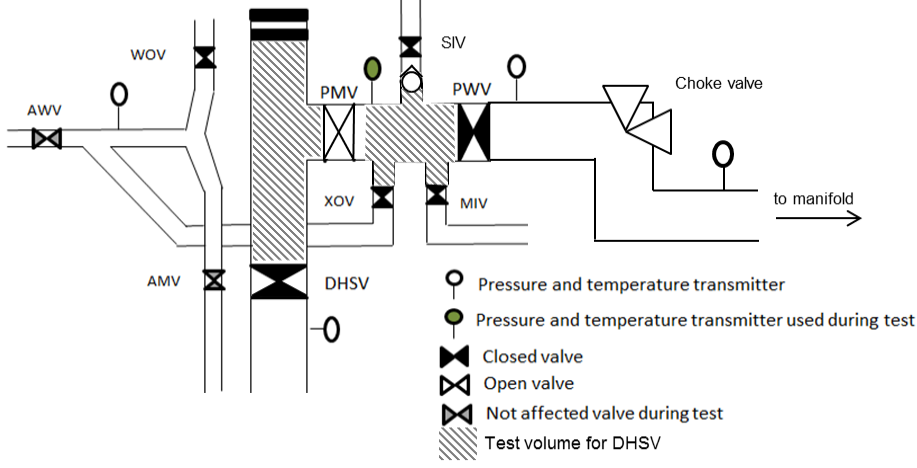


*Figure 55 Leakage testing of DHSV (SCSSV)*

A typical differential pressure across the valve to be tested is as follows;

| P@DHSV (upstream) | 300 bar |
|---|---|
| P test volume (down strem) | 230 bar |
| $\Delta p$, Valve $=$ | 70 bar |

| Test of DHSV | | |
|---|---|---|
| Constants | | |
| Z | 0.9 | |
| t | 30 | min |
| Q | 0.42 | m³/min |
| V | 1 | m³ |
| T | 80 | $C^0$ |

$\Delta P = q/2{,}84\text{x}10^3 * \Delta z * t * T/V = 0.42/2{,}84\text{x}10^3 * 0.90 * 30 * (80+273)/1{,}0 =$

1.41 MPa  per 30 min

1 MPa = 10 bar. 1.41 MPa per 30 min = 14.1 bar per 30 min.

So, the maximum acceptable final pressure build up upstream of the valve is follows:

$P_F = \Delta P + P$ (downstream) =14.1 bar +230 bar = 244.1 bar

### 6.2.6. Annular Safety Valve (ASV)

In gas lifted wells, it is also required that the annulus containing hydrocarbons is to be equipped with a downhole safety valve (i.e. an annular safety valve – ASV). NORSOK D-010 specifies that an ASV should be installed in the completion string for wells:

1) *With a potential of hydrocarbon flow in the annulus, i.e. perforations above the production packer and injection into the annulus which might temporarily supercharge a formation.*

2) *Where the A-annulus is used for gas lift unless there is any other downhole device that is qualified as a well barrier in addition to what is found in the wellhead area.*

3) *When analysis and/or risk assessment shows that any hydrocarbon volume in the annulus might have unacceptable consequences if the wellhead/surface well barrier is lost*

### 6.2.7. X-mas tree

For surface and subsea X-mas trees, the production tree valves are to be tested in the direction of flow. If a well does not have a positive closed-in pressure, then testing the master valve in the direction of flow may not be practical. In this case, the master valve may be inflow tested. Acceptance of production tree valve tests may utilize the API PR 14B requirements providing the observation volume is adequately large to give a meaningful test.

Regarding testing of X-mas tree valves, NORSOK D-010 states:

1. *The principal valves acting as barriers in the production tree shall be tested at regular intervals.*

2. *If the leak rate cannot be measured directly, indirect measurement by pressure monitoring of an enclosed volume downstream of the valve shall be performed.*

X-mas tree valve leakage is to be measured as either a volumetric leak rate or the rate of pressure change in a closed volume associated with the valve.

Surface safety valves are to close within a predefined time of an emergency shutdown (ESD) demand. The actuated master valve should also respond by a similar predefined time.

### 6.2.8. Annulus Valves

A positive pressure should generally be maintained in each annulus with a pressure difference between annulus strings in order to provide ongoing assurance of annular integrity as any pressure drop or rise or equalization between annuli is then obvious to the extent that investigation action can be requested.

"B" and "C" annuli valves are to be tested at regular frequency. Where an annulus is pressurized, the valves are to be tested for leakage. Annulus valves are to be tested to the leak criteria defined in API 14B.

### 6.2.9. Gas Lift Valves

Where Gas Lift Valves (GLVs) are included as WBEs, they should be tested along with the routine well integrity tests. If a GLV is part of a well barrier and the valve is leaking, then it should be considered as a reduced or failed well barrier that needs to be restored.

## 6.3. Pressure Monitoring

### 6.3.1. Annulus Pressure Surveillance Principles

The principle of Annulus Pressure Management revolves around the fact that a well is in effect made up of pressure vessels (completion and inner annuli) within other pressure vessels (outer annuli) and that each pressure vessel must be managed within operational limits.

Norsok D-010 states that pressures in all accessible annuli shall be monitored and maintained within minimum and maximum operational pressure range limits to verify that the integrity status of well barriers is known at all times. Since the monitoring of well parameters is critical, it is important that the monitored values are recorded with appropriate frequency and

that they are representative and correct. Norsok D-010 states the A-Annulus pressure for all wells and B-Annulus pressure for multi-purpose and annulus gas lift wells shall be monitored through continuous recording of the annulus pressure to verify the integrity of the well barrier.

Well parameters such as temperatures and rates shall also be monitored to facilitate correct interpretation of pressure trends and identification of abnormal pressure behavior.

### 6.3.2. Types of annular pressures

There are three main types of annular pressures encountered in wells, i.e. Thermal Pressures, Applied Pressures and Sustained Casing Pressures. These will be discussed below:

*Thermal Pressure (TP)*

Wells with fluid filled enclosed annuli will exhibit thermal pressure changes during warm-up and cool down periods.

During normal trouble-free operation the annuli pressures will show a clear and predictable dependency mainly on the well temperature, but also on pressures in adjacent annuli or tubing and the flow rate.

For example, during the startup of a producer, as the well is warmed up, it is expected that the annulus pressure for a liquid filled annulus increases.

The opposite is expected when the same well is shut in. When the temperature and flow rate are stable the annuli pressures should also be stable.

The expected annulus behavior for injection wells will depend on the difference in temperature between the injection fluid and the surroundings of the well. For wells where the injection fluid has a lower temperature than the surroundings the annuli pressures can increase significantly when the well is shut in and the temperature increases.

After a startup of a well it is expected that the annulus pressures stabilize at the same values as before the well was shut in if no top ups or bleed downs have been done and the stabilized temperature is the same.

It is important to recognize the effect of changing temperatures and monitor annulus pressure closely during the startup of new wells. Pressure should not be bled off in this instance unless the MOP is breached (see below). It is vital to monitor annulus pressure closely during initial startup of new wells as pressure can build up rapidly and result in over-pressurized annuli. The increase in pressure and changes in fluid density due to thermal effects are illustrated in the figures below.
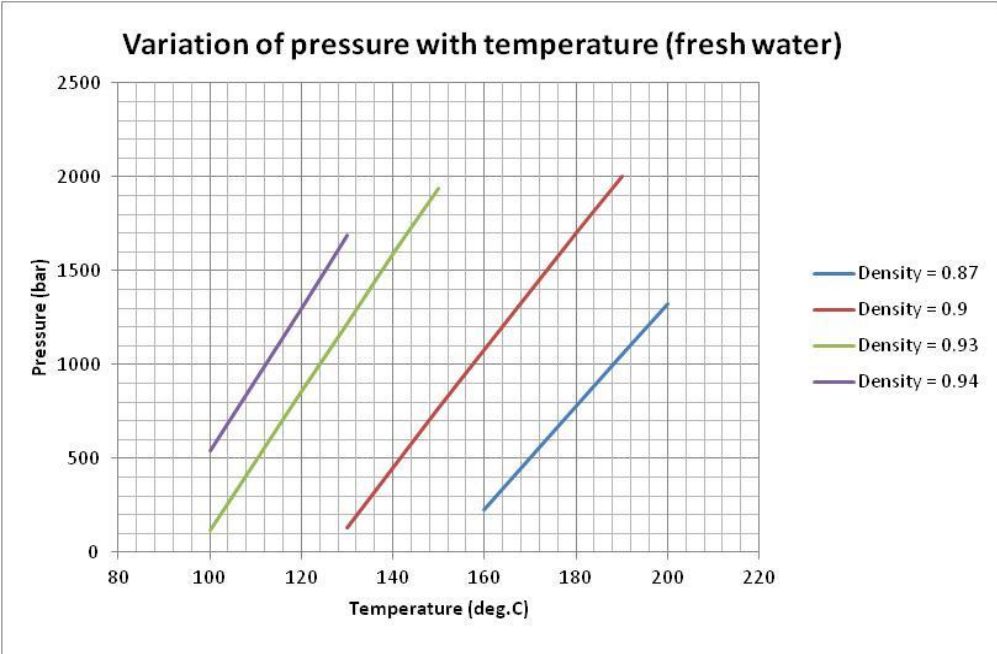


*Figure 56 Variation of pressure with temperature for fresh water in an enclosed system*
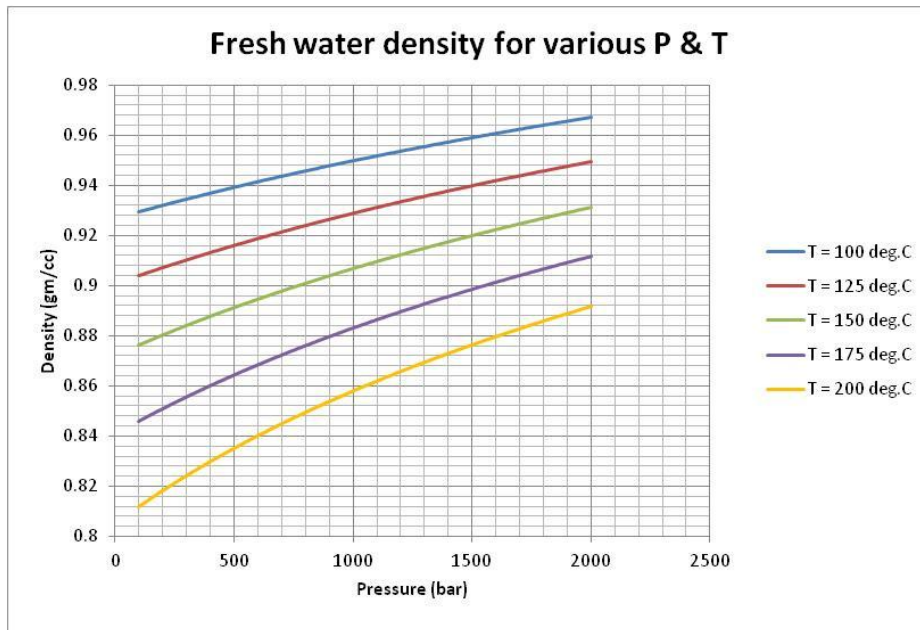
*Figure 57 Fresh water density as a function of pressure variations for various temperatures*
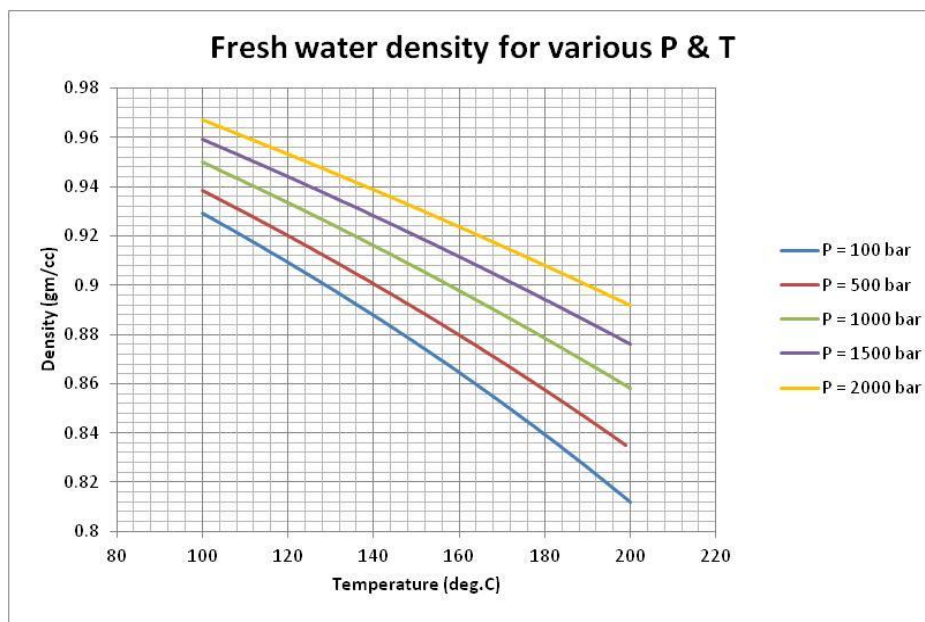


*Figure 58 Fresh water density as a function of temperature variations for various pressures*

As it is shown in the above figures, the variation in density can be significant even for a relatively small increase in temperature. For an enclosed system where the fluid cannot expand, the density will remain constant and the increase in temperature will therefore result in a significantly increased pressure. If the increased pressure cannot be bled off, the trapped annular pressure may therefore result in burst or collapsed casing or tubing and subsequent loss of well integrity. The effect with brine filled annuli will be larger than with fresh water.

**Temperature induced B-annulus pressure**

During well testing and production a significant amount of heat is transported up the wellbore. The temperature will increase throughout the well. If closed annuli are present, the temperature expansion of fluids inside these can cause a significant pressure rise. In extreme cases, temperature expansion can cause casing strings to burst or collapse.
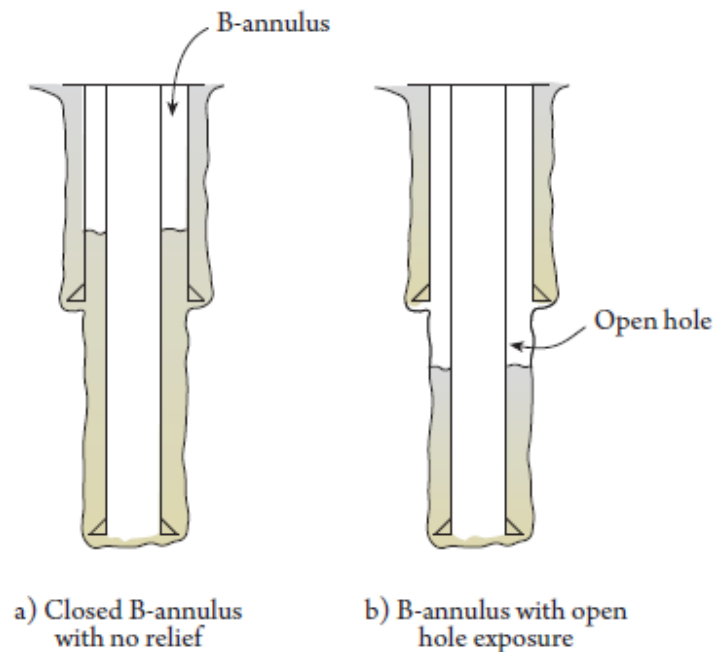


*Figure 59: Situations where temperature induced pressure may/may not cause casing failure*

Figure 59 illustrates the problem. Here the inner casing string is cemented above the previous casing shoe. Provided a high quality cement job is performed, this annulus (B-annulus) is considered closed. In subsea exploration wells there are usually no venting possibilities. Therefore, one must always check the expected pressures and the casing strength in these cases.

The common way to reduce temperature induced pressures is shown in Figure 59. The cement for the next casing string is not covering the previous shoe. It is believed that the exposed open hole section may allow for a small fluid loss, which will lead to reduced pressure. The

pressures should also be checked against the fracturing gradient of the section, which should act as a safety valve. The following demonstrates temperature induced pressures by giving an example.

Figure 60 shows the temperature profiles during casing installation, and also the profile during a well test. These are considered the two extreme cases. Assuming a linear temperature profile, the changes in temperatures can be expressed as:

at wellhead: $\Delta T_1 = T_3 - T_1$

at well bottom: $\Delta T_2 = T_4 - T_2$ (4.5)

Having a total volume V in the annulus, free expansion of this volume subjected to the temperature change of Equation (4.5) yields:

$$\frac{\Delta V}{V} = \frac{1}{2}\alpha(\Delta_1 + \Delta T_2)$$

or if we insert the actual temperatures from Equation (4.5), we obtain:

$$\frac{\Delta V}{V} = \alpha\left\{\frac{T_3 + T_4}{2} - \frac{T_1 + T_2}{2}\right\}$$ (4.6)

We observe that the volume change is proportional to the average temperature change.

To consider the pressure element, first imagine that the fluid is allowed to expand freely according to Equation (4.6). Then, the fluid is compressed back to its initial volume. The pressure required is:

$$\Delta P = \left(\frac{-1}{c}\right)\frac{\Delta V}{V}$$

or by inserting Equation (4.6),

$$\Delta P = \left( \frac{-\alpha}{2c} \right) \{ (T_3 + T_4) - (T_1 + T_2) \}$$  (4.7)

where: $c$ = compressibility of the fluid

$\alpha$ = heat expansion coefficient

Equation (4.7) gives an estimate for the temperature induced pressure in a closed annulus, assuming that the mass of the fluid remains constant. In the example above, only the fluid behavior is studied. Although the casing and the rock have less effect, their compressibility could be included as well.
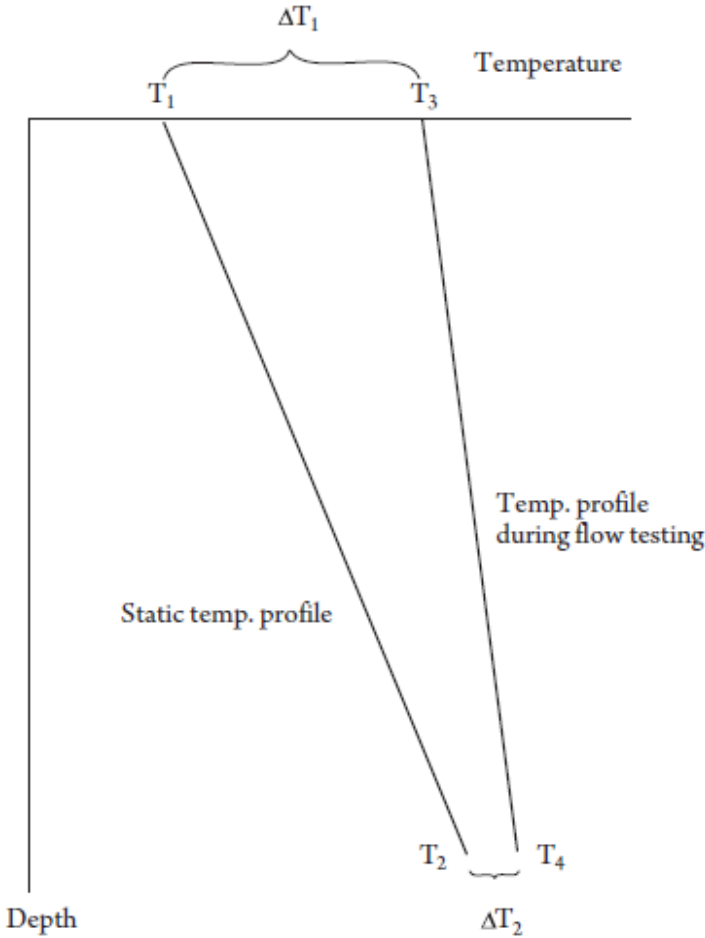


*Figure 60: Simplified temperature profiles in a well during various phases*

Figure 61a shows an example from an exploration well. Figure 61b shows the estimated temperature profiles before and after testing.  The expected pressure increase from Equation (4.7)  is:

$$\Delta P = (3 \times 10^{-4}/2 \times 3 \times 10^{-5})\{(134+180 - (4+180)\} = 650 \text{ bar}$$

Comparing this excessive pressure to the strength of the casings, results in:

Collapse strength of 7-5/8 in casing: 985 bar > 650 bar

Burst strength of 10-3/4 in. casing:   835 bar > 650 bar

We conclude that the design is acceptable because both casing strengths exceed the expected pressure increase.  Also, the 7-5/8" production casing is considered most critical, and we observed that failure would in any case occur in the outer intermediate string before the production casing.

Halal & Michell (1994) propose a casing design procedure for trapped annular pressure buildup.
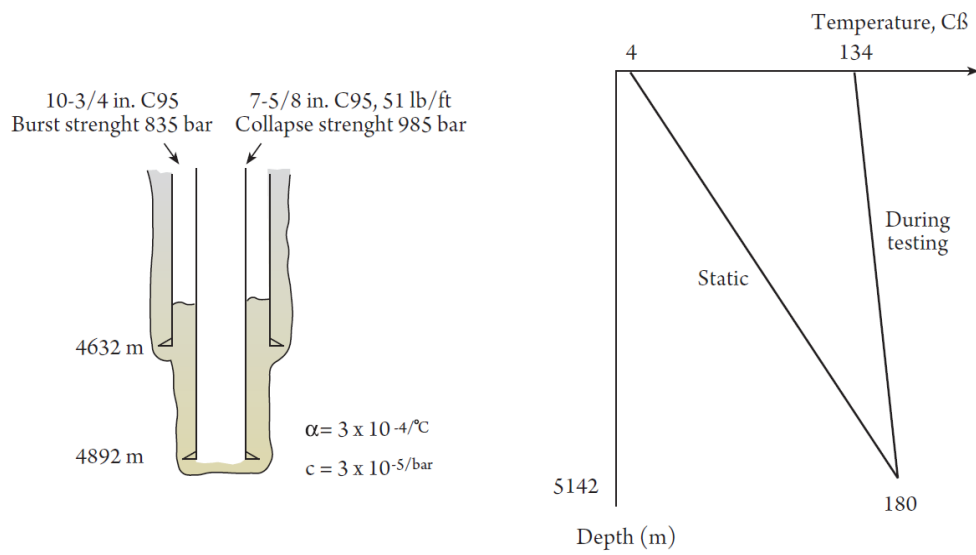
a) Well configuration          b) Temperature profiles

*Figure 61 Data for an exploration well*

*Applied Pressure (AP)*

Pressure may be applied to an annulus for various purposes, including gas lift, cuttings re-injection (CRI), compensating for bullheading loads or assisting in annulus monitoring. The applied pressure may also come from pressure containment tests. Care must be taken to ensure this pressure is bled down after testing to a suitable value to ensure that thermal pressure does not result in MOP being exceeded.

*Sustained Casing Pressures (SCP)*

Any deviations from the expected annulus pressure behavior can indicate the presence of Sustained Casing Pressure (SCP). SCP comes from a pressure source such as the reservoir or an adjacent annulus and is to be investigated whenever suspected or where the origin of the observed pressure is not known.

SCP can arise for a variety of causes, including degradation or failure of well barriers, and can occur throughout the lifetime of the well. SCP may be the result of leaks e.g. through casing or tubing, through cement or through wellhead seals, but it can also be leaks directly from the formation.

Figure 62 illustrates some of the potential leak paths that can be present in a well. The figure is an example for illustrative purposes only.
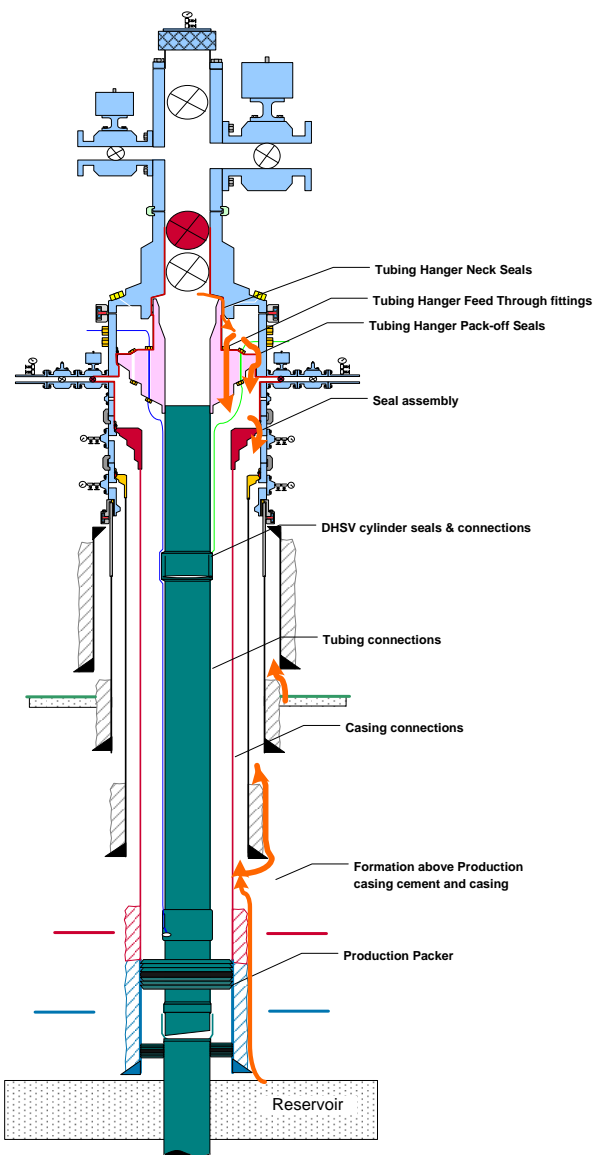
*Figure 62  Examples of potential leak paths resulting in SCP*

Appropriate monitoring and routines to aid early detection of SCP are an important part of the management of SCP. Assessments of parameter trends over longer periods (e.g. months) are required to make it possible to identify slow pressure build ups over time as it can be difficult to detect the onset of SCP based on parameter behavior over short periods.

The ability to detect SCP will improve with increasing monitoring frequency. Therefore continuous remote monitoring of all accessible annuli is considered best practice.
The quality of the recorded values should be appropriately ensured through regular calibration, inspection and function testing of the monitoring equipment.

Bleed downs and top ups should be recorded to facilitate:

- correct interpretation of annulus pressure behavior
- detection of foreign fluids
- annulus content is known

The minimum information that should be recorded is:

- annulus pressure before and after the activity
- duration of the activity
- the fluid type
- volume introduced or removed from the annulus (if practical)
- pressure behavior of other annuli and tubing

Operating wells with positive annuli pressures and differences in tubing and annuli wellhead pressures will facilitate detection of abnormal pressures.

*Trapped Annular Pressure (TAP)*
In some cases the annulus pressure is allowed to build due to thermally induced or sustained pressures (e.g. subsea wells) and is controlled only by venting to an open subsurface formation or entirely trapped by cemented casings. This will have to be taken into account in the well design to prevent the occurrence of excessive pressure that may have an impact on well integrity.

### 6.3.3. Calculation of MAASP

There is to be a continuous surveillance program of all accessible annuli in the well (flowing, closed-in or suspended) to ensure their safe operation and the maintenance of well integrity. Well annuli pressures are to be monitored and maintained within the maximum allowable annular surface pressure (MAASP).

The MAASP is the absolute maximum pressure for a given annulus that is not to be exceeded at any time, since it represents the integrity limit for that annulus.

For each annulus, the initial values for the MAASP need to be calculated. An example for A-annulus MAASP calculation is given below. Key parameters for calculation are the minimum values of mechanical properties (casing/tubing collapse & burst, accessory- and packer rating, pressure on casing hanger area etc.) and formation strength at shoe.

*Calculation Method*

The mechanical integrity of the five components that define the boundary of an annulus will limit its MAASP:

- Collapse of inner casing
- Burst of outer casing
- Wellhead  rating
- Formation strength.
- Completion components – where applicable

An example of A-annulus MAASP calculation with the formulas for the various calculation points is given in the figure below.
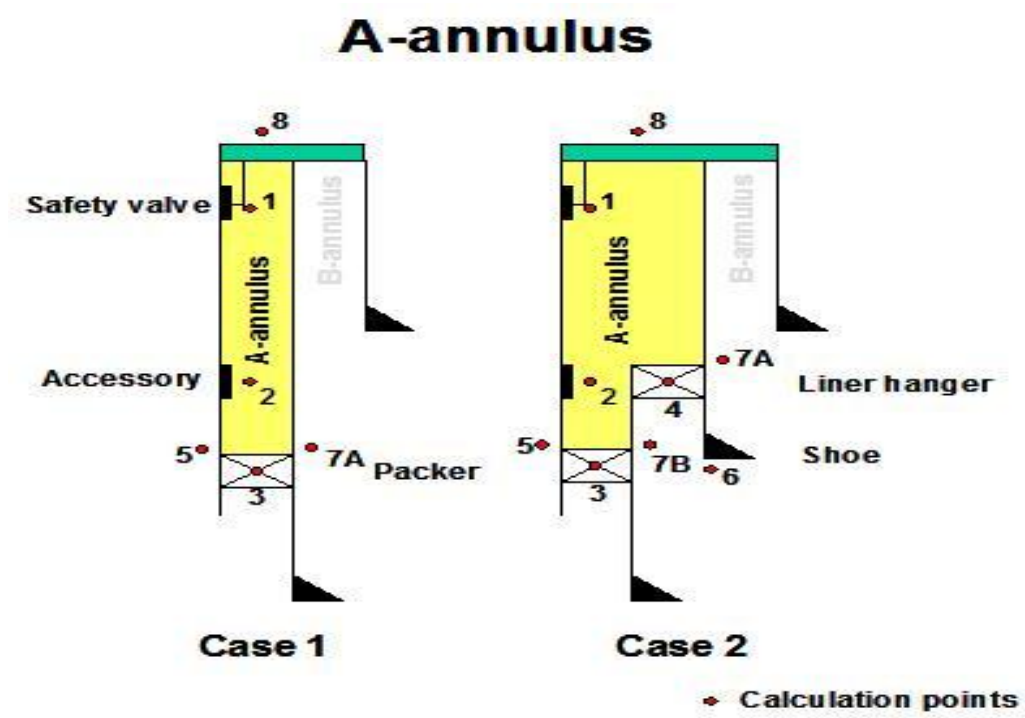
*Figure 63 Calculation points for A-annulus MAASP*

| Item | Formula | Assumptions |
|---|---|---|
| Tubing Collapse | Pc, tub-(Dpp*A_MGca)/1000 | Tubing evacuated, DF = 1.0 |
| Production Casing Burst | Pb, ca/1.1-(Dpp*(A_MGca-B_MGbf))/1000 | DF = 1.1, assume mud outside casing has degraded to base fluid |

*Table 8 Equations for calculation of MAASP*

| D | Depth in feet, TVD | Tub, ca | Tubing, casing |
|---|---|---|---|
| Pc, Pb | Collapse or burst pressure, psi | pp | Production packer |
| Pb | Burst pressure, psi | bf | Base fluid |
| A, B_MG | A, B, annulus mud/brine weight, pptf | DF | Design Factor |

*Table 9 Abbreviations used in the formulas above*

### 6.3.4. Setting of Maximum Operational Pressure (MOP)

In addition to an acceptance criteria for annulus pressure, MAASP, a maximum operational pressure (MOP) should also be defined for an annulus.

The MOP is a measure of how much pressure that can safely be applied to an annulus on a sustained basis. The MOP is measured relative to the ambient pressure at the wellhead for any particular annulus. It establishes a safety threshold when considering the ultimate integrity limit for a given annulus. In general, the MOP is not to exceed 80 % of MAASP.

A high pressure alarm with a trigger may be used to assist in controlling the operating pressure boundary and this is usually the MOP. When the pressure reaches this level, then action should be taken. The intention of the MOP is to reduce the probability of exceeding the MAASP and providing appropriate response time to manage pressures which approach these acceptance criteria.

Most wells are designed for operation with zero annulus pressure and even some vacuum in annuli. However, for some well designs it may be required to define a minimum operational pressure to reduce the risk of failure. This can be e.g. subsea wells where annulus pressures outside the A-Annulus cannot be monitored or vented, which may make it necessary to implement a minimum A-Annulus operating pressure to avoid collapsing the production casing.

When determining minimum operational pressures the same failure modes as examined for determination of MAASP should be considered, and similar assumptions should be applied.

In general, operating wells with modest positive annulus pressures are preferable.

### 6.3.5. 'A' Annulus MINAP (gas lifted wells)

Gas lifted wells that do not have a full liquid column inside the 'A' annulus and are allowed to bleed down the gas lift pressure, may be exposed to the risk of production casing collapse or tubing burst with insufficient applied pressure on the 'A' annulus. In such cases setting of a Minimum Annular Pressure (MINAP) for the 'A' annulus is advised. Gas lifted wells will therefore have to be designed to allow bleeding-off the gas lift pressure.

*Impact of a gas cap on the MAASP and MOP calculation*

In the event that the sustained casing pressure is supported by gas influx into the annulus, this may require adjustment of the MAASP (to account for the presence of a variable gas column), which would subsequently impact upon the MOP.

Some of the considerations that will come into play in this context include the consequences of a breach of annulus containment at surface, in particular:

- The potential for continuous hydrocarbon flow, and
- The risk associated with the release of the hydrocarbon inventory in the gas cap.

### 6.3.6. Management and Control

*Reaching High Pressure Alarm (HPA) values*

Timely alarm in case of pressure build up should ensure that pressures are bled-off in time. The High Pressure Alarm (HPA) should be set at the MOP but can be set lower. When the annulus pressure reaches the HPA, an assessment should be made as to whether the pressure is thermally induced or sustained from a leak or influx. The pressure is then to be bled down to below the MOP.

It is not advisable to bleed down the pressure to zero. The rationale for this is to limit bleed-offs to a minimum and comes from the fact that bleeding-off annular pressures may exacerbate the problem.

In the event of sustained annular pressure, operating the well at less than 50 % of MOP is considered good practice (i.e. in the lower half pressure band but above zero – see the figure below). The MAASP of the outer annuli will also have to be considered.

If an annular pressure is bled down, the following parameters are to be recorded:

- Pressure before / after
- Type and estimate of volume of fluid (gas/brine/oil/condensate)
- Density of fluid in case of liquid.
- Fluid chemical analysis to identify source

The following diagram outlines the relationship between MAASP, MOP, trigger (HPA) and working pressures:
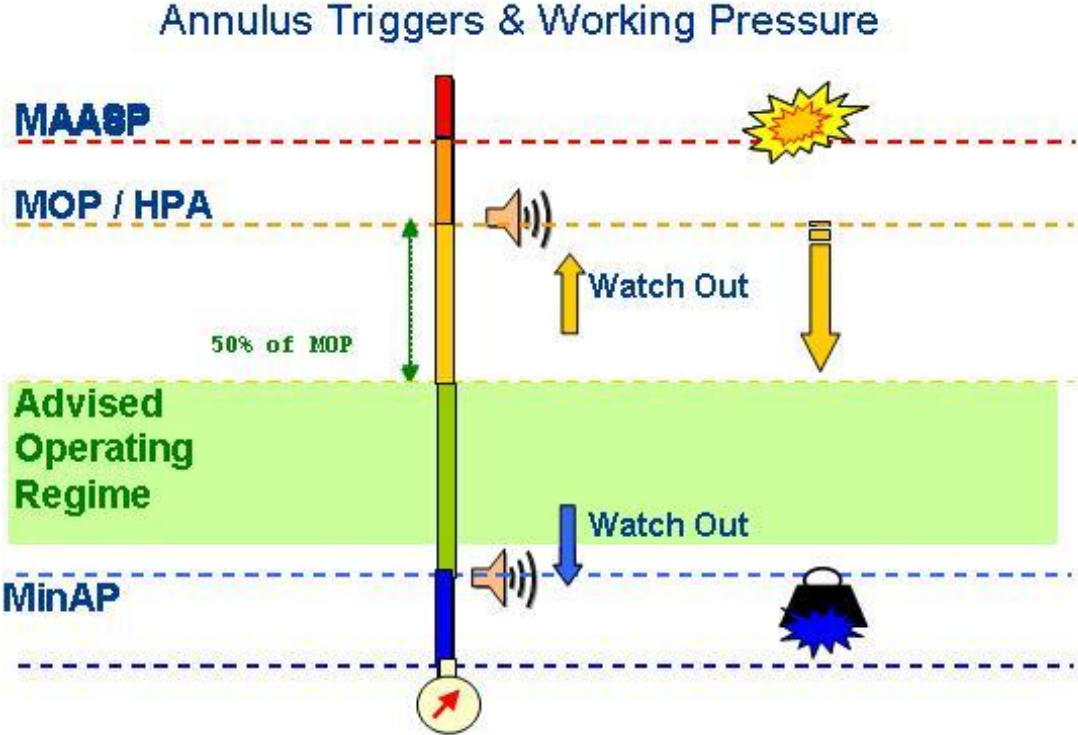


*Figure 64 Annular Triggers & Working Pressures*

# 7. Organizational

## 7.1. Roles and responsibilities

In a license we have an operator and usually one or several partners; this is outlined in the Petroleum Act. Both the operator and the partners have an obligation to ensure that the regulations are followed and that the work being done is in accordance with the regulations. The operator has the sole responsible for the day-to-day activities and the one that has the overall responsibility for the facility and operations undertaken. With that responsibility the operator has the duty to ensure that the sub-contractors are performing the work correctly and that they are following the relevant regulations and standards. The partners on the other hand have a duty to follow up the work of the operator and make sure that the regulations and license agreements are followed. This is done through various license committees and through audits of the operator. These duties are clearly defined in the regulations. Poor follow up by partners may lead to cost escalations and delays in projects and operations, and high risk of failures or accidents. PSA is also following up the operators and their activities to see if they are in line with the current regulations and standards.

All companies operating on the Norwegian Continental Shelf (NCS) are obliged by the regulations to have a management system and a system for controlling the HSE level of their operations. This management system is to reflect how the company operates and how the activities are carried out. Within the system there are to be clearly defined roles, responsibilities, interactions between departments and governmental organizations, governing documents, applicable standards and reporting routes. Management systems can be divided into two main categories of systems; one for oil companies that are operators and one for those who are only partners. The latter requires a different organization than the operator that will manage all activities required for field development including offshore operations. Partner reporting to the authorities is not as significant as for the operating company.

For the operators on the NCS it is a requirement that they have a system in place for managing the well integrity for the life cycle of all their wells. The intention with this system is to control and reduce the risk of incidents related to the wells. A description of elements required in a well integrity management system can be found in Norsk Olje og Gass guideline 117.

## 7.2. Competence and training

In the regulations and NORSOK D-010 there are specified requirements for competence and training for personnel involved in drilling and well operations. These requirements are not only limited to well integrity, but also well control and various other operations taking place on a rig/platform. The reason for this is that one wants to ensure that the personnel participating in these operations have adequate competence and are up to the job. Among all the positions on the rig there is a varying requirement for competence in accordance with what position they have in the organization. Personnel working hands-on on the drill floor have different competence requirements than the drilling supervisor, who is supposed to have an overview of the entire operation. It is also worth noting that people working with wells in production have a need for a different type of competence as the situation is different from drilling a well and they have to function in the rest of the production facility.

For personnel working on the drill floor an Norsk Olje og Gass guideline has been issued, Norsk Olje og Gass guideline no. 24. For well integrity Norsk Olje og Gass guideline 117 applies, this also deals more with the production phase of a well and not only drilling. In addition NORSOK D-010 sets forth some requirements about competence for personnel involved in drilling and well operations.

# 8. Appendix A - Homework problems

## 8.1. Exercise 1

Oil production is planned on a platform. Top reservoir at 2827 mTVD. The maximum expected reservoir pressure is 350 bar at 3100 mTVD. The gas gradient is 0.15s.g.EMW. The wellhead depth is 6 m.

### a) Calculate Maximum expected SIWHP

The maximum expected kill margin for this well is 70 bar.

### b) What is the MWDP for this well?

The well is planned to be constructed with a 30"conductor, 20"" surface casing, 13 3/8" intermediate casing, 9 5/8" production casing, and a 7" liner set through the reservoir. Perforations are planned at the interval 2898 – 3050 mTVD. The planned setting depths and mud weights are indicated on the wellbore stability plot. The maximum control line pressure is 520 bar.

### c) Plan the well barriers, required and planned cement heights, required test pressures, as well as monitoring methods for the operational phase. Describe through setting up planned well barrier schematics. Calculate the maximum allowable pressure build up above the DHSV, as part of the monitoring. The volume above DHSV is set to 1.88 m³, Δz-factor: 0.90 and middle temperature: 90⁰C.
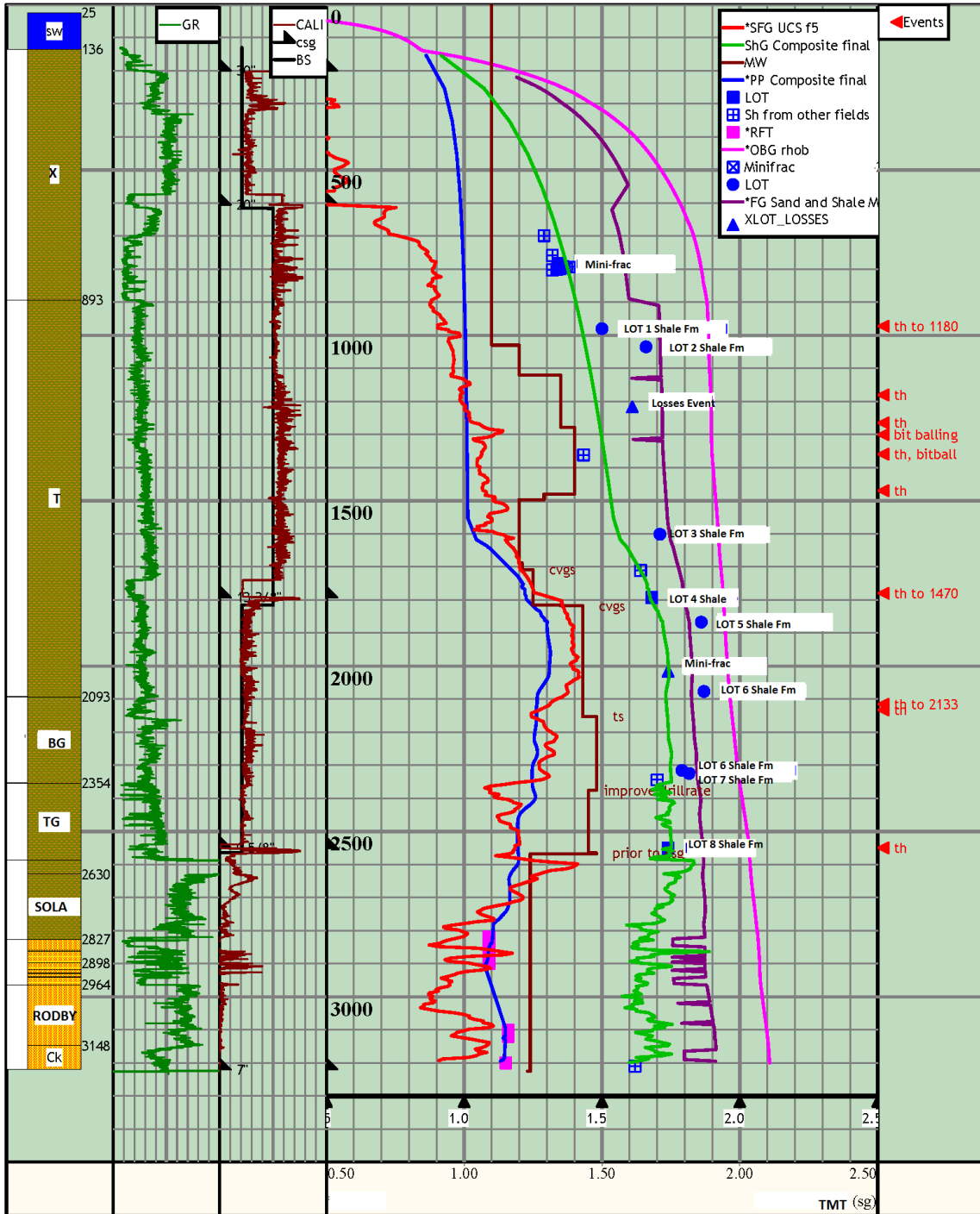
### d) Also describe how you will permanent plug the same well by setting up a well barrier schematic. Define cement lengths and test pressures.

### e) Do you have suggestions for another casing program to make the well barriers more robust?

# WELLBORE STABILITY PLOT

## Field : Offshore Continental
## Well: ABC  Airgap: 25 m   Water Depth: 114 m

### 8.2. Exercise 2

Well 1 a) above (in Exercise 1) has a leak through the production packer. The leak rate is 0.03 kg/min with HC gas. Is this an acceptable situation? What risk factors do you need to evaluate? What do you recommend to do? (Use Norsk Olje og Gass 117 and understand the different risk factors to evaluate)

### 8.3. Exercise 3:

A gas lift well was completed with well barriers as defined on the well barrier schematic below. The MWDP was set to 345 bar based on the maximum kill pressure of the reservoir.

1. Calculate the minimum formation stress required for the production packer depth. Use a gas gradient of 0.15 s.g. EMW

2. Calculate the minimum formation stress required for the shoe of 9 5/8" casing.

3. The maximum possible gas lift pressure is set as 180 bar wellhead pressure with equivalent maximum gas lift pressure at 13 3/8" window of 200 bar. Calculate the minimum required formation stress at the 13 3/8" window. Note that C-annulus is not designed for the gas lift pressure.

4. Is this well qualified for gas lift? Give the reasoning for your answer by stating the requirements.

KV    SV    PWV

HMV
MMV
X-mas tree

PT

DHSV nipple @ 283m MD
ASV @ 305m MD

20" @ 778m MD
SPM @ 810m MD
13 3/8" – window @ 1228m MD/ 1158m TVD
SPM @ 1454m MD
SPM @ 1952m MD

TOC 13 3/8" window not identified

SPM @ 2415m MD
CIV @ 2446m MD

TOC 9 5/8" @ 2000m MD

Dual Gauge carrier @ 2479m MD

PT

Prod Packer @ 2498m MD/2288m TVD
PBR @ 2526m MD
Packer @ 2539m MD

Liner hanger packer/PBR @ 2560m MD

9 5/8" @ 2601m MD/ 2395m TVD

Top reservoir @ 2657m MD / 2447m TVD

Open hole completion, gravel pack, screen @ 2600– 2751m MD

TD @ 2751m MD

A  B  C

### 8.4. Exercise 4
Based on Exercise no 3:

1. Categorize the well according to Norsk Olje og Gass 117, if the well was decided for gas lift

2. What would be the potential risks if this well was gas lifted and a large leak from the A to B-annulus occurred?

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