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MASTER'S THESIS

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SUMMARY

An increased frequency of minor gas leakages from seals in the wellhead (WH) area have been detected and recently given an increased focus among companies on the Norwegian continental shelf. Among others have Statoil and Shell reported concerns regarding this problem and are working simultaneously to identify and solve the problem.

There is however uncertainties in the industry related to how the problem regarding leakages in the WH can be solved, how critical the leakages actually are, the extend of the problem, and whether test of the seals actually can trigger a leakage itself or not. Questions regarding whether the seals should be tested on a general basis and regarding specific maintenance plans for the seals have been raised.

It has not been a common practice over the last years to test the seals in the WH after installation. It is therefore difficult to evaluate the extent of this problem as very limited test data exist. In addition, integrity issues in connection to the small cavities in the WH do often show unambiguous test results.

Three case studies of three wells at the Oseberg East installation (Statoil) will be presented in this thesis. The case studies have been carried out with the use of the exclusion methods, analysis of pressure and trends, tests results, and simulations of hypothetic scenarios. The main discoveries follow below:

It is indicated that the leakages in the seal assemblies in the WH are caused by:

- Design capabilities exceeded in operation
- Unsuccessful conversion of producers with an inactive A-annulus to producers with gas lift.
- Dirt and residual hydraulic oil from installation.
- Problems related to vibration
- Pressure tests of the DHSV
- Faulty design of WH

A review of the barriers on the wells concludes that the wells have in the first place two independent barriers that are possible to test. An additional third barrier gives increased safety against leakages to the atmosphere if seals fail. It is not possible to test the seal in the third barrier without introducing a risk to damage a unidirectional seal in the secondary barrier.

It is considered that the frequency of the leakages to the atmosphere is expected to increase with time. It is in particular expected that the total number of leakages will increase through the test ports.

The consequences of these leakage rates are considered to be negligible compared with the rates of leakages that are considered to give high risk of explosion and/or fire.

The leakages might however be of significant enough size to be detected by the gas-detector and thereby cause the production at the installation to be shut down.

The test ports should be monitored and an increased focus on maintenance should be initiated. With these initiatives, leaks to the environment are considered to represent a negligible risk.

It is a severe escalation of the leakage to cavities in the wellhead, if the consequence is that the unidirectional seal in the secondary barrier becomes weakened. This danger is reduced by being able to monitor the pressure between the elastomer seal and the unidirectional seal.

Examples of recommended compensating measures that will be discussed are:

- Pressure monitoring
- Use of foam around test plugs
- Use of chemical sealant
- Evaluate injection of nitrogen to cavities

It is recommended to bleed of pressure in the WH cavities before performing test on DHSV or commencement of other well activities.

New recommended accept criteria's in the WH follows:

- Operate the well with a 35 bar limit in the cavities
- AC. for leakages :
    - 35 bar/24hr for internal leakages
    - 0,1 kg/s for leakages to the atmosphere

The case studies that have been carried out are related to gas lift wells. There is however indication that minor gas leakages in the WH might exist on other types of wells as well.

Innhold

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3. ACKNOWLEDGEMENT

First I would like to thank Statoil and in special Line Hoff Nilsen for giving me an interesting topic for my thesis. I would also like to thank Frode Berentsen for sharing his expertise on wellhead systems and the valuable feedback during the work of this thesis. In addition I would like to thank for the assistance from Therese Sønstabø, Sally Serenyi and the rest of the Well Integrity team in Stavanger and Bergen.

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Last but not least, I would like to thank Professor Bernt Sigve Aadnøy at UIS for his advice and guidance.

4. BACKGROUND:

The wellheads that are installed on the Norwegian continental shelf have a designed lifetime of approximately 20-30 years. Beyond this lifetime a reliability analysis has to be performed in order to be allowed to continue to produce from the well.

During the designed lifetime of the wellhead, it is expected to fulfill the design requirements. Hence no leakages from the seals are expected. As of today, it is not common in the industry to test all the seals in the wellhead periodically after initial testing. Despite the fact that the wellhead is designed to prevent any leakages during its designed lifetime, there have been observed leakages.

An increased frequency on detected minor gas leakages from seals in the wellhead area led to an increased focus on this topic. Among others has Statoil internally established a requirement to verify the integrity of the now possible wakened well barrier elements in the wellhead area.

«R- 27189»:

"There shall be no leakage through seals that are defined as barrier elements or through fire resistant seals"

The requirement for periodic leak testing of seals only applies for seals in the wellhead tree available for testing from platform or onshore.

"R-27189" is also the background for this master thesis.

There is however uncertainties in the industry related to how the problem can be solved, how critical the leakages actually are, the extend of the problem and whether test of the seals actually can trigger a leakage itself or not. Questions regarding whether the seals should be tested on a general basis and regarding a specific maintenance plans for the seals, have been raised.

These are some of the issues that will be discussed in this thesis.

5. DESCRIPTION OF THE SITUATION

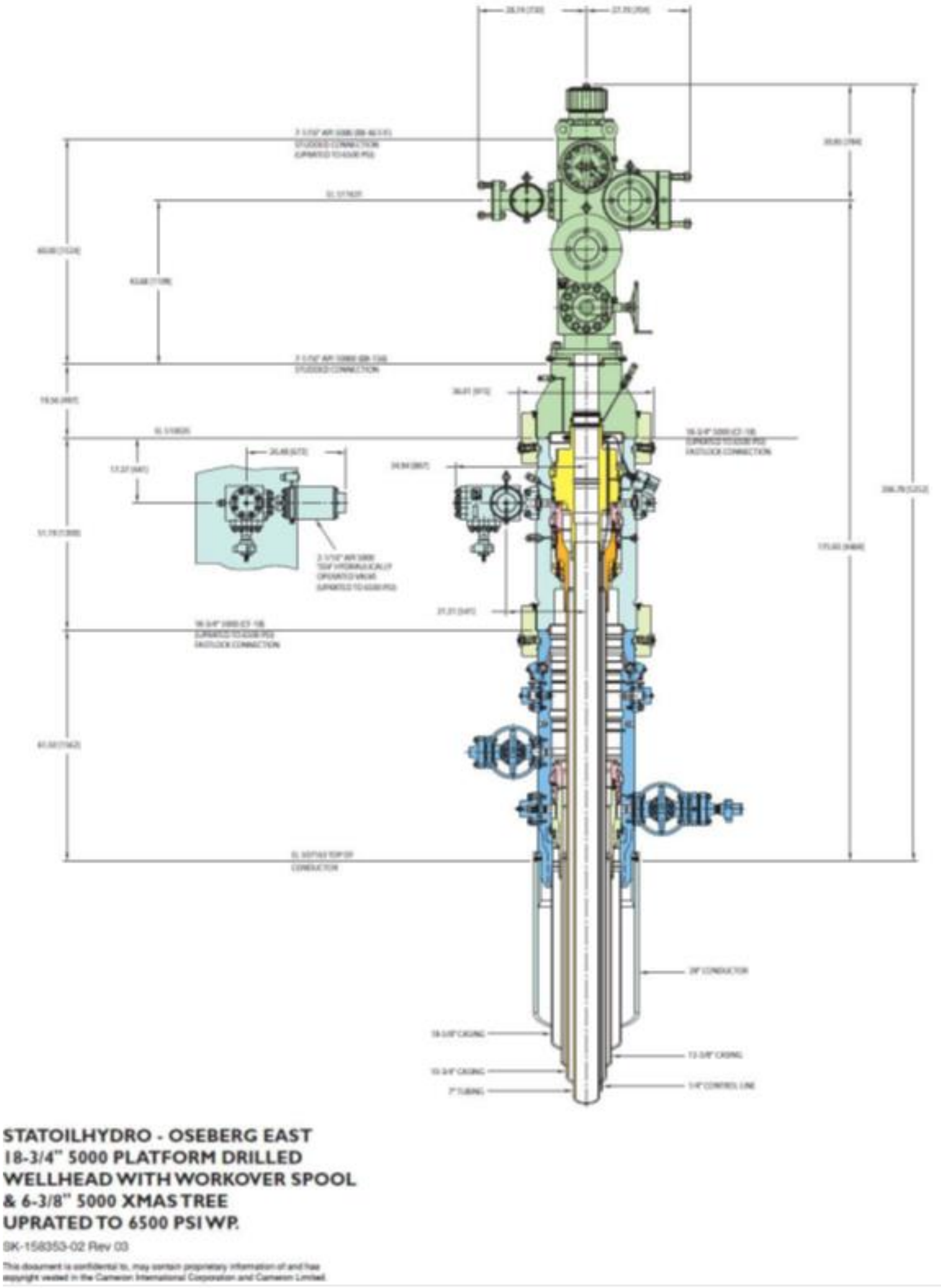


Figure 1 Wellhead and christmas tree (Camreron)

Figure 1 illustrates the wellhead (WH) and christmas tree (XT) system that this thesis revolves around.

There are currently a lot of issues related to leakages to cavity C1 (Figure 2). It is indicated that the seals related to C1 are a weaknesses of the secondary barrier.

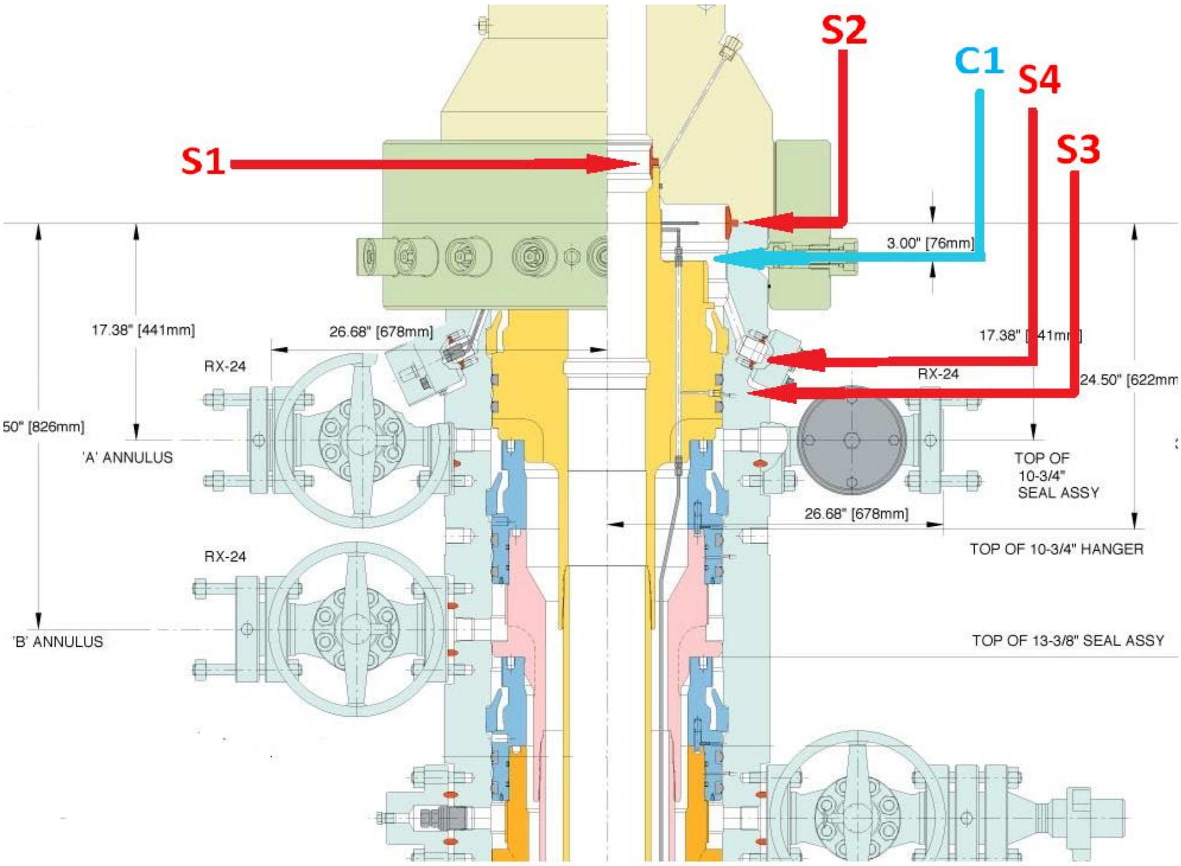


Figure 2 WH Oseberg East (Cameron)

The pressure in the cavity can due to an unknown leakage/reason start to increase. To solve the pressure increase there is a practice at Oseberg East to bleed off the pressure when it reaches a predefined pressure. This temporary risk reducing measures is only an opportunity for the wells which have pressure monitoring equipment located in connection to the cavity C1.

It is indicated that the leakages in the seal assemblies in the WH are caused by:

- Poor cleanliness during installation, which may have led to scratches and traces in the sealing surfaces.
- Dirt and residual hydraulic oil from installation. The residual oil will then suffer from thermal expansion during production of the well and the pressure might exceed the design capacity of the seal or system.
- Pressure tests of the DHSV might worsen the situation, as the seal then will suffer from an increased differential pressure across the seal. (The thermal expansion of the hydraulic oil can cause collapse of the seal)
- The properties of the elastomer seals has a tendency to deteriorate over time and thereby reduce its sealing capacity
- Problems related to vibration
- Wrong applied test pressure

- Design capabilities exceeded in operation
- Unsuccessful conversion of producers with an inactive A-annulus to producers with gas lift.
- Faulty design of WH

There exist different practices on how to deal with this situation in the industry. At some installations the seals in connection to the cavity are already being tested on a regular basis in order to verify the integrity of the barrier. The design on WH/XT may vary from installation to installations. This implies different accessibilities to test the seals and monitor the pressure in the annular cavity. Some wells have also been recompleted in order to solve problems related to leakages.

There is however uncertainties in the industry regarding testing of these seals. The limited access possibilities imply that unidirectional seals might have to be tested in the opposite direction of their design capacity. Worst case scenario of applied test pressure from the wrong side of the seal is to actually waken the seal and thereby cause a leakage.

There exist several possible solutions to the problem, but their arguments are often contradictory. Examples of this are shown in the table below

Table 1 Possible solution wekanesses

Possible solution	Weakness of solution
Plug test port in connection to the leaking system	Removes the possibility for further pressure and or temperature monitoring
Use of sealant	Removes the possibility for further pressure and or temperature monitoring
Use pressure/ temperatures transmitters or indicators	Weakens the fire integrity of the fire jacket
Alarm automated pressure bleed off	Demanding for the personnel in the, in the control room on the installations
Manual pressure bleed off	Time consuming
Use of tandem seals	Requires an extra venting system to deal with the temperature induced pressure between the seals

6. THEORY

6.1. Well integrity

Well integrity is defined as an application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well. (Birgt Vignes, 2001)

Primary well barrier if the first object that prevents flow from a source, and the secondary well barrier is the second object that prevents flow from a source. Well barriers (WB) are an envelope of one or several dependent well-barrier elements (WBEs) preventing fluid and gasses from flowing unintentionally from a formation into another formation, or to the surface.

The WB is defined before commencement of an activity by description of the required WBEs to be in place and specific acceptance criteria. Well barrier acceptance criteria are technical and operational requirements that need to be fulfilled in order to qualify the WB for its intended use.

In general the number of well barriers shall apply as follows:

Drilling and well activities	Formation
Two barriers	Formation with overpressure or reservoir exposed (potential source of inflow)
One barrier	Formation with normal pressure or less (no potential source of inflow)
One barrier	Between formation zones with a pressure differential that may cause undesirable cross flow

Figure 3 NORSOK barrier requirements

The well barriers shall be designed, selected and/or constructed such that:

- it can withstand the maximum loads and environment it may become exposed to
- it can be leak tested and function tested or verified by other methods
- no single failure of barrier or barrier element, whether caused by operational error or equipment failure, shall lead to uncontrolled release of wellbore fluids or gases to the external environment
- re-establishment of a lost well barrier or another alternative well barrier shall be possible, also in a situation where the ordinary power source has failed
- it shall function as intended in the environment (pressure, temperature, fluids) that may be encountered during the period it was intended for
- physical position/location and integrity status of the well barrier is known at all times when such monitoring is possible.

When the well barrier has been constructed, its integrity and function shall be verified by means of:

- leak testing by application of a differential pressure
- function testing of WBEs that require activation
- verification by other specified methods

Re-verification shall be performed when;

- the condition of the barrier element could have been changed since the initial/previous testing and/or
- change in worst case loads/well design pressure for the remaining life cycle of the well (drilling, completion and production phase)

Leak testing of well barriers or WBEs shall be performed:

- before it can become exposed to pressure differentials,
- after replacement of pressure confining components of the well barrier
- when there is a suspicion of a leak,
- when an element will become exposed to different pressure/load than it originally was designed for,
- routine tests during operation. (Hans-Emil Bensnes Torbergsen, 2012)

The pressure during testing shall as far as possible be applied in the direction of flow. If this is impractical, the pressure can be applied against the direction of flow, providing that the WBE is constructed to seal in both directions.

In general the acceptance criteria are zero for leak tests. (through seals that are defined as barrier elements) However should activity specific leak testing requirements apply:

Low pressure test: 5% deviation is accepted to account for temperature effect, air entrapment, media compressibility, but a decreasing trend – which approaches zero for minimum 5 min

High pressure test: 2% deviation is accepted to account for temperature effect, air entrapment, media compressibility, but a decreasing trend - which approaches zero for minimum 10 min - shall be documented on the test curve

Inflow test: Less than 3 bar/10 min deviation is accepted to account for temperature effect, air entrapment, media compressibility, but a decreasing trend (which approaches zero for minimum 10 min) shall be documented on the test curve.

Test pressure shall not exceed the test pressure the exposed elements have previously been tested to or working pressure/well design pressure/section design pressure. Degradation due to corrosion, wear, erosion etc. shall be accounted for. (Statoil, TR3507)

The accept critearias mentioned above applies for drilling and well activities.

Examples of how the application of requirement should be interpreted follows:

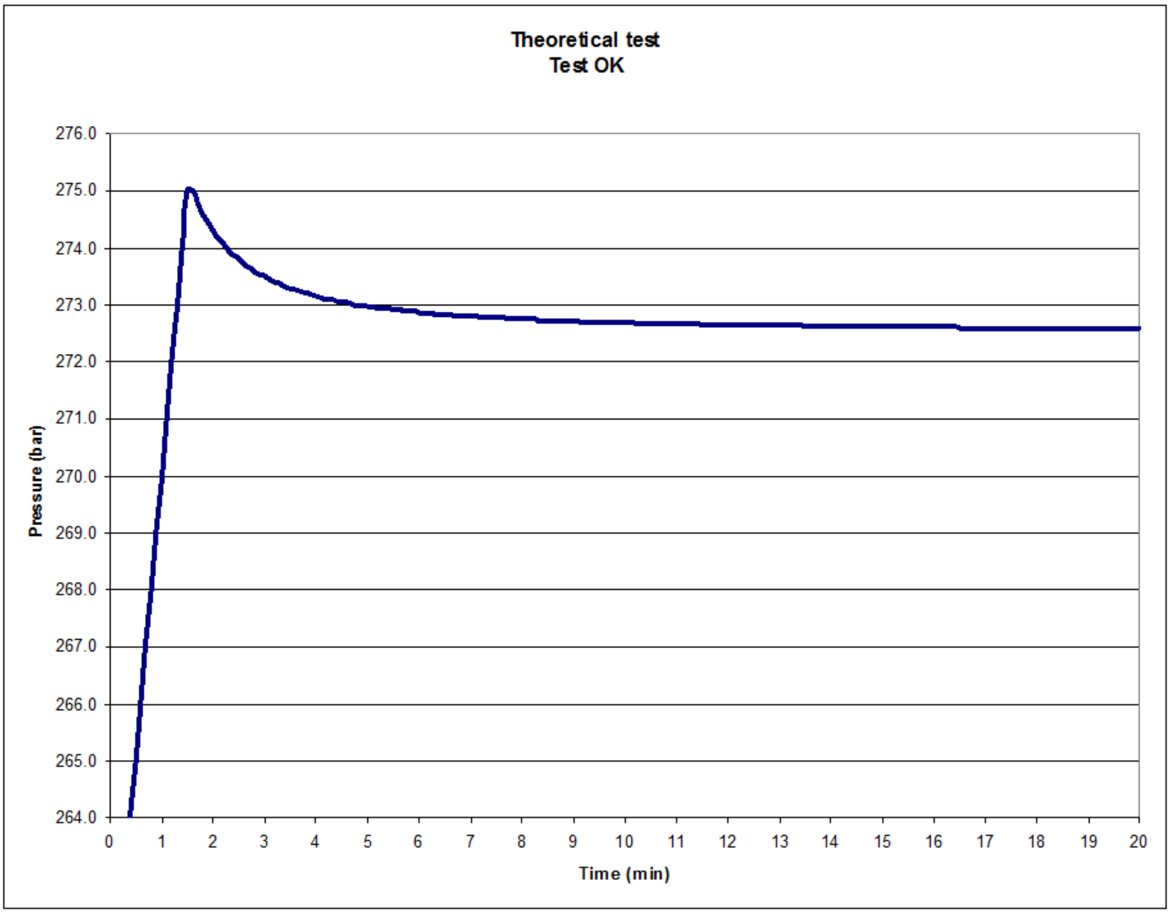


Figure 4 Theoretical test, approved

Figure 4 illustrates a high pressure test that was cleared ok. The pressure drops less than 2% for a minimum of 10 min and the slope of the curve has a decreasing trend, which approaches zero.

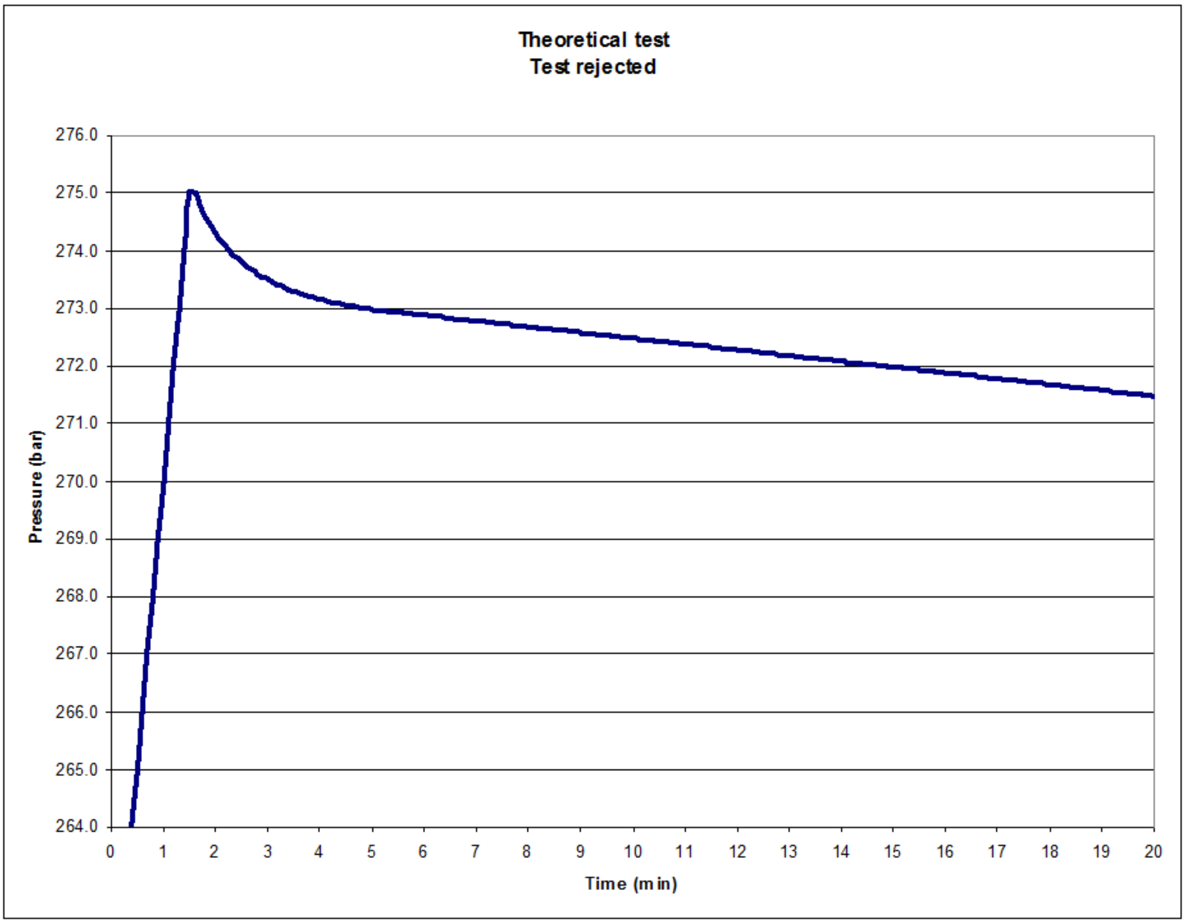


Figure 5 High pressure test, rejected

Figure 5 illustrates a high pressure test that was not cleared ok. The pressure drops less than 2% for a minimum of 10 min but the slope of the curve does not have a decreasing trend. Further investigations of the tested barrier element in this particular case, did however not show a leakage.

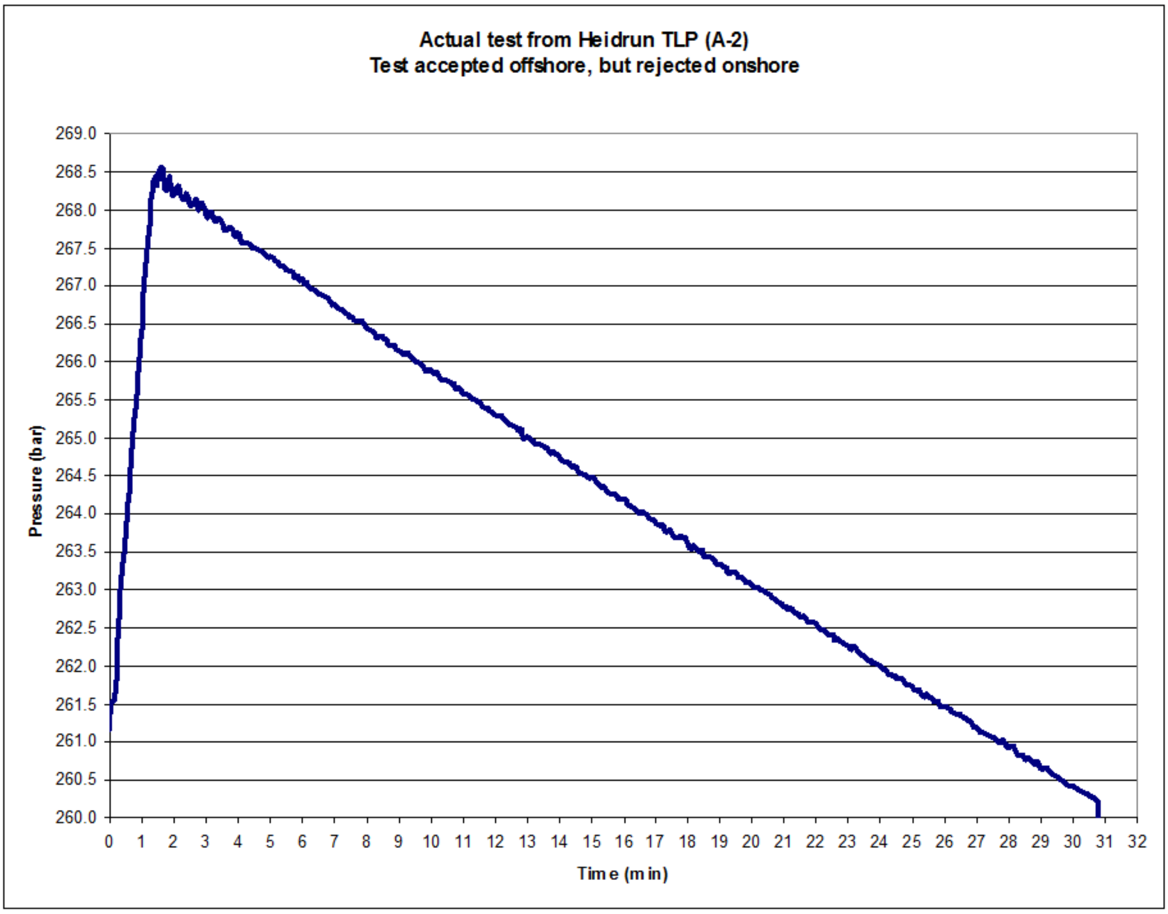


Figure 6 High pressure test. Approved offshore, but rejected onshore

Figure 6 illustrates a high pressure test that was not cleared ok. The pressure drops less than 2% for a minimum of 10 min but the slope of the curve does not have a decreasing trend. Further investigations of the barrier element confirmed that the element was leaking.

The commonly accepted way of determining leak rates 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.

Loss of well integrity is either caused by mechanical, hydraulic or electric failure related to the well components, or by wrongful application of a device. To reduce risk of failure it is important to control the risk factors and to detect leakages at an early stage (before failure).

The obvious consequences of loss of well integrity 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.

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.

6.2. Operational

6.2.1. General

The status of well barriers is to be known by monitoring the individual WBE of the well barrier envelopes during the production life of the well. This is commonly done by monitoring of annulus pressure and frequent leak testing of well barrier elements.

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

.1. Downhole safety valves, production tree valves and annulus valves shall be regularly leak tested. Leak test acceptance criteria shall be established and be available.
.2. The pressure in all accessible annuli (A and/or B) shall be monitored
.3. Registered abnormalities shall be investigated to determine the source of abnormalities and if relevant, quantify any leak rate across the well barrier.
.4. 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 functioning 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 should also be function tested regularly.

6.2.2. Annulus Pressure Surveillance Principles

The 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. Norsok D-010 states that 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.

There are three main types of annular pressures encountered in wells:

- Thermal Pressures
- Applied Pressures
- Sustained Casing Pressures. (Hans-Emil Bensnes Torbergsen, 2012)

When the temperature and flow rate are stable the annuli pressures should also be stable. Abnormal pressure changes may indicate a failure in the barrier envelope, such as a leakage. Assessments of parameter trends over longer periods are required to make it possible to identify slow pressure build ups over time. Operating wells with positive annuli pressures and differences in tubing and annuli wellhead pressures will facilitate detection of abnormal pressures.

6.3. Seal Design

6.3.1.Definitions

A seal is basically a device for closing a gap or making a joint fluid tight. Seals can broadly be categorized into two categories:

- *Static seal* where sealing takes place between surfaces which do not move relative to one another. The primary application requirements for the static seals involve keeping liquid, gas or dirt out. A typical static seal is the O-ring.
- *Dynamic seal* where the sealing takes placed between surfaces which have relative movement such as rotating shafts and pistons rings. (Borwn, 1995)

A number of dynamic seals may however equally well be employed for static type seals. There are also static seals (by function) which are designed to accommodate limited movement of the surface being sealed. These are sometimes called *semi-static seals*, but are more often described by purpose or application.

There are also types of seals designed specially to prevent access of dirt, dust or other harmful contaminants into a system. These are called *exclusion seals*.

6.3.2.Seal categories and types

Static seals are normally described by type. (Such as gasket, ring seals, etc.) They may further be categorized by material or by construction.

Sealants are regarded as a separate category.

Dynamic seals fall into two main categories:

- *Contact seals* where the seal bears against its mating surface under positive pressure
- *Clearance seals* which operate without rubbing contact

The majority of dynamic seals that are contact seals operating with rubbing and only separated and lubricated by a thin oil film. Contact seals may further be categorized by:

- *Compression seals*
- *Pressure-energized seals* (Borwn, 1995)

Dynamic seals are not part of the scope of this thesis, but sealing mechanism for the dynamic seals are often used in the static seals as well and will therefore further be explained.

Compression seals generate radial pressure for sealing by squeeze imparted to a soft gland material radially. Compression of this type may be employed for both dynamic and static application. They are also suited for sealing in both directions of motion and are thus double-acting seals. Their particular application is for heavy duty rod seals or rotary shaft seals. (Borwn, 1995)

Pressure-energized dynamic seals fall into two categories. The first comprise solid elastomeric rings which are assembled in grooves with an interference fit. This imparts a squeeze or preload pressure, providing sealing in a static condition. Under fluid pressure acting on one side of the seal through the clearance gap, the elastomeric section is deformed, increasing the interface pressure by an amount equal to the fluid pressure. Thus if the preload pressure is p and the fluid pressure is P, the effective pressure under working conditions is P+p. See Figure 7. Because P+p is grates than the actual sealing fluid pressure p, sealing is maintained. Seals of this type may be double-acting.

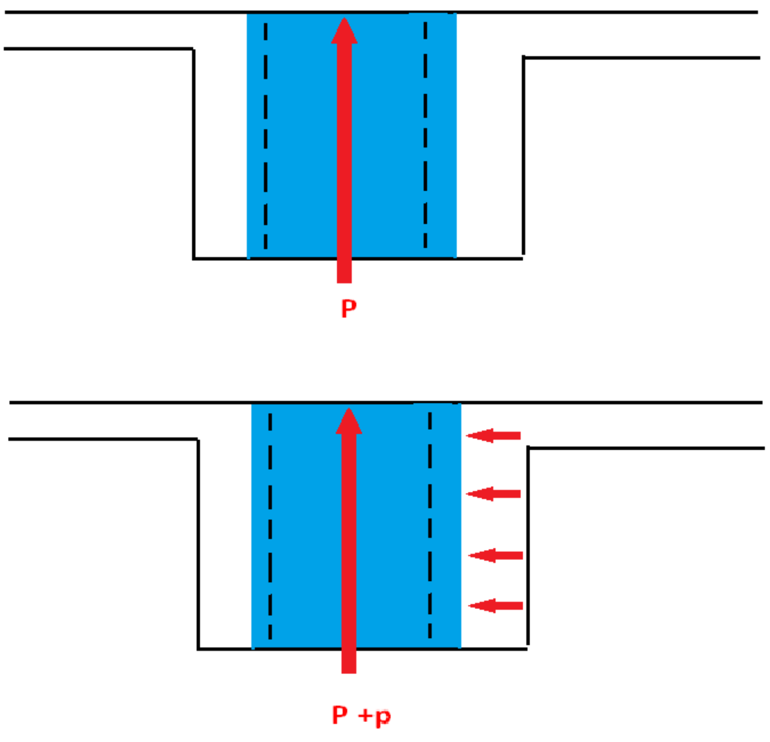


Figure 7 Pressure energized seals

The other category of pressure-energized seals employs a hollow section with a flexible lip or lips. Again it is assembled with an interference fit giving a preload pressure p. Fluid pressure P acting on the section then further increases the interface pressure to p+P. Typical seal sections in this category are the u-ring and the v-ring. Seal of this type are single acting, which means that by pressure energization is effective in one direction only. Single acting seals might also be referred to as unidirectional seals.

There are further types of ring seals which combine both modes of working. They incorporate a flexible lip section fitted with a solid elastomer ring. Some of these may also incorporate back-to-back configuration to produce double acting seals.

6.3.3.Mechanism of sealing

Static seal aim to provide a complete physical barrier in a potential leakage path to which they are applied. They are zero leakage seals. To achieve this, the seal must be resilient enough to flow into and fill any irregularities in the surface being sealed and at the same time remain rigid enough to resist extrusion into the clearance gap. Both requirements must be long term. Resilient flow is produced by closure loading, stressing the seal in compression. Contact pressure pressure is then maintained by stored elastic energy in the complete seal system. Performance will be degraded by any stress relaxation which may occur in the system. This may be caused by:

- Stress relaxation in the seal material itself (which may also be associated with creep into the clearance space)
- Differential thermal expansion
- Flange deflection or bolt stretch

In the theory the greater the stored elastic strained energy of the seal and thus the greater margin available to resist any relaxation effects in service. This is largely true up to the point where the seal material itself is damaged by excessive compression and suffers a permanent loss of properties.

6.3.4.Wear and seal life

Because of their different designs, and because they are produced from different materials, sealing systems have varying behavior patterns at increasing operating pressures. When a hard material is used, the danger of damage by compression is being reduced. On the other hand a hard material does not have such good sealing characteristics as a soft material, particularly at low pressures. For the best sealing system that are effective at high and low operating pressures, a seal constructed from several types of material with different properties is needed.

Seals lose their ability to function because of normal wear of the seal material. The first indication of leakage is seen at low pressures. This is because of wear and the seal is no longer capable of maintaining the required contact with the sealing surface. At high pressures, because the deformation is greater, sealing may continue to be adequate so long as the pressure is maintained.

Elastomer seal

Definition: a material capable of 100% elongation (Borwn, 1995)

$$E = \frac{tensile\ stress}{tensile\ strain} = \frac{FL}{A\Delta L}$$

Where

E is the Young's modulus (modulus of elasticity)

F is the force exerted on an object under tension;

A is the original cross-sectional area through which the force is applied;

ΔL is the amount by which the length of the object changes

L is the original length of the object.

All rubber components deteriorate over a period at high temperatures, especially in air. They become brittle and lose their elastic property. See Figure 8. This effect is time dependent, irreversible and varies considerably from one elastomer to another.

At temperatures below 0°C rubber compounds progressively stiffen and loser their resilience as the temperature falls, until brittleness occur. The brittleness is reversible when the temperature rises again, as long as cracks not already have appeared in the rubber component. Additives to the elastomer may be added to provide a greater resistance to stiffening at low temperatures.

It is known that when the rubber becomes immersed in certain fluids, the tolerance of the rubber compound to significantly higher temperatures can be much lower compared to its operating pressure in dry heated air.

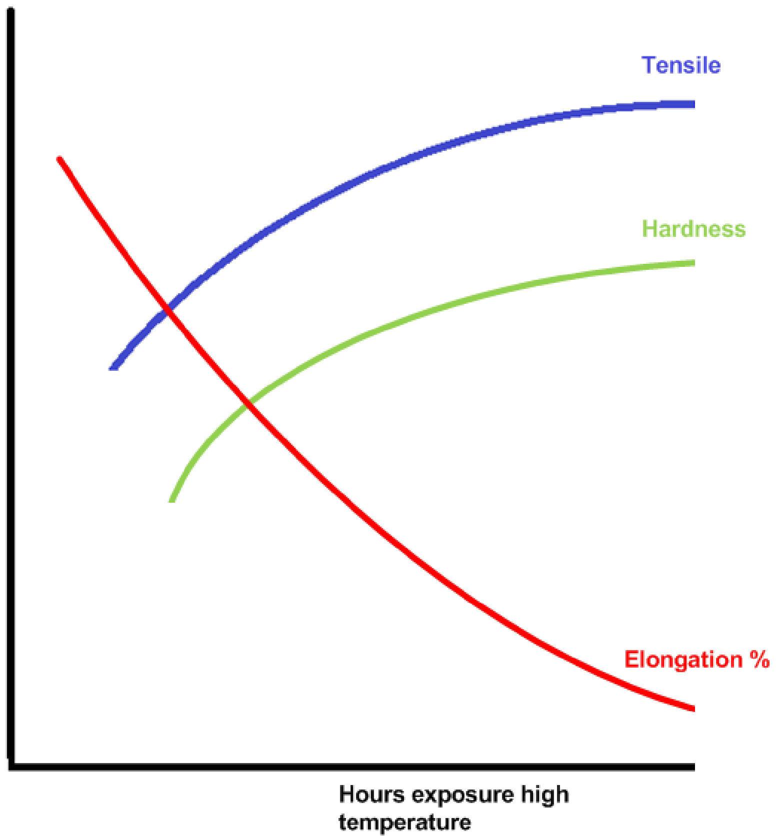


Figure 8 Ageing effects on rubber

An elastomer in contact with a fluid will tend to absorb a certain amount of the fluid and the elastomer will swell as a consequence of this. This will tend to modify the properties of the elastomer such as hardness, strength, resilience and abrasion resistance. Such changes are usually acceptable and inevitable, but an excessive swell may indicate lack of compatibility.

6.3.4.1. Joule Effect

Joule effect- when a stretched rubber is heated it does not elongate, but tries to contract. (Borwn, 1995). The modulus of elasticity increases with a rise in temperature. Joule effect does not occur if the rubber is not stretched when heated.

6.3.5. Safety and environmental health

Environmental health works both ways, as far as the seals are concerned. The environment itself has a considerable influence on seal selection. At the same time, the purpose of a seal is to protect the environment from contamination. The meaning of contamination in this context may range simply from avoiding messiness and product loss to the elimination of contamination of nauseous, toxic or hazardous fluids by fully containing them to the surface.

From either aspect, the basic problem involved is the same and starts with the selection of the most suitable seal for the job. This must take into account all the environmental factors involved.

External environmental problems are far more likely to arise where the atmosphere is contaminated or incompatible with simple materials. Contaminated air may in cases not injurious to health, but can cause metallic corrosion.

Internal factors are primarily concerned with the sealed fluid, the operating parameters and the installation design. Some of these factors may need consideration:

- Fluid pressure
- Fluid temperature
- Fluid viscosity
- Fluid nature (lubricator or not)
- Cleanliness
- Chemical activity of product
- Toxicity
- Vapour pressure, which may dictate degree of temperature control required
- Entrained air, which can cause accelerated wear at faces of mechanical seals

These factors are essential in the process of determine the seal type, material and design.

- Other design and operating parameters are:
- Available space, which may restrict the type of seal
- Motion
- Quality control
- Eccentricity, which can seriously influence seal performance. Particularly in the case of lip seals.
- Vibration

6.3.5.1. *Vapour emission*

Direct vapour emission from "zero-leakage" or "dry" seals is possible. This can cause unexpected danger where the product is hazardous. Especially as the vapour emission may be invisible.

A common problem is that single seals emit vapour even where there is no visible leakage of fluid.

Factors most likely to lead to increased vapour emission:

- Increased fluid pressure
- Higher fluid volatility
- Pump stop or start of intermitted duty

6.3.5.2. *Environmental control*

There are basically three types of environmental control:

- Temperature controls
- Controls for dirty or incompatible environment
- Safety controls

The temperature at which the seal works is a vital operating parameter. It governs seal wear and life and also it's resistant to chemical attack. It also affects the behavior of the fluid being contained, as well as the behavior of the seal itself. Available temperature controls are:

- Jacket cooling or heating
- Bypass flush
- Heat exchanger
- Air cooler

6.3.5.3. Safety controls

There are two basic approaches to controlling leakage in the event of seal failure. One is use of tandem seals which will prevent leakage of the process fluid to the atmosphere. Tandem seals are two seals set in the opposite direction of each other, sealing the same gap

The other is to use single seal but make provision for restraining and collecting leakage.

6.4. Calculation methods

6.4.1. Temperature induced B-annulus pressure

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

The following demonstrates the temperature induced pressure with an example.

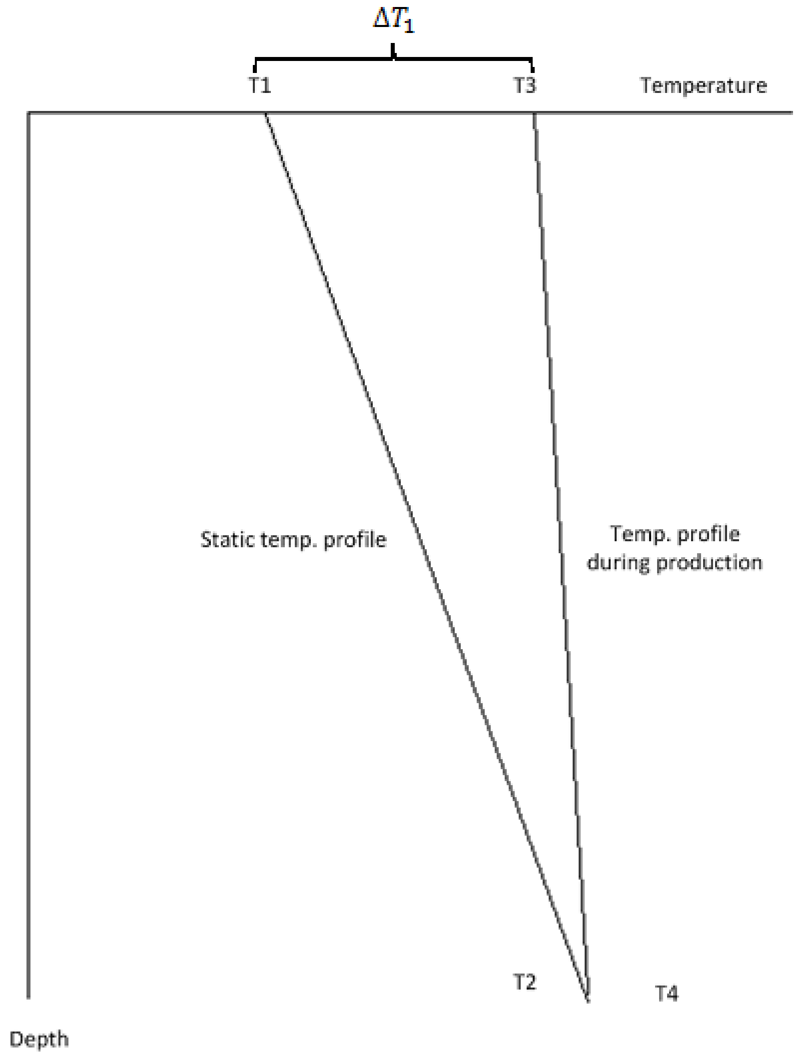


Figure 9 Simplified temperature profiles in a well during various phases

Figure 9 shows a fictive temperature profiles during production of the well and the static temperature profile for a closed in well. These are considered the two extreme cases. Assuming a linear temperature profile, the changes in temperatures can be expressed as:

At wellhead:

$$\Delta T_1 = T_3 - T_1$$

Eq.1

At the bottom of the well/DHSV:

$$\Delta T_2 = T_4 - T_2$$

Having a total volume V in the cavity or annulus, free expansion of this volume subjected to the temperature change of equation 1, we obtain:

$$\frac{\Delta V}{V} = \frac{1}{2} \propto (\Delta T_1 + \Delta T_2)$$

Or if we insert the actual temperatures from equation 1, we obtain:

$$\frac{\Delta V}{V} = \propto (\frac{T_3 + T_4}{2} - \frac{T_1 + T_2}{2})$$

Eq.2

(Aadnøy, 2010)

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

During production, from Figure 9, $T_2=T_4$. Hence

$$\Delta T_2 = 0$$

In the case of pressure evaluations in the wellhead, we do also only consider the temperature change in the wellhead area.

Eq. 2 becomes:

$$\frac{\Delta V}{V} = \propto (T_3 - T_1)$$

Eq.3

To consider the pressure element, first imagine that the fluid is allowed to expand freely according to equation 3. Then the fluid is compressed back to its initial volume. The pressure required is:

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

Or by inserting equation 3

$$\Delta P = \left(\frac{-\propto}{c}\right)(T_3 - T_1)$$

Eq.4

Where: c= compressibility of the fluid

$\propto$= heat expansion coefficient

Equation 4 gives an estimate for the temperature-induced pressure in a closed cavity, assuming that the mass of the fluid remains constant.

In the derivation above only fluid behavior is studied. The casing and the rock compressibility is assumed negligible.

6.4.2. Equation of state

For ideal gas

$$PV = nRT$$

Van der Waal's equation for real gases

$$\left(P + \frac{n^2 a}{V^2}\right)(V - nb) = nRT$$

(Lide, 2007)

6.4.3. Pressure drop calculations

In this section an equation for calculating the rate of leakage through a leaking sealing section will be derived.

In general there exist two flow regimes in this setting, laminar and turbulent flow. For a pressure drop over a leaking sealing section the flow regime will in worst case scenario be turbulent. For a relation between pressure drop and flow rate for Newtonian fluids the following relation exist:

$$P \sim \rho f q^2$$

Eq. 5

Where:

P= pressure drop

q= flow rate

ρ= fluid density

f= friction factor

The flow rate through the sealing section is given by the continuity equation:

$$q = v_a A_a = v_b A_b = constant$$

or

$$v_a = \frac{q}{A_a}, \quad v_b = \frac{q}{A_b}$$

Eq.6

Where:

v= velocity

A= area

(The subscript a refers to cavity C1 and b to sealing section)

Using the conservation of principle, and assuming an incompressible an frictionless system, the pressure drop across the sealing section is:

$$\frac{v_a^2}{2} + \frac{P_a}{\rho} = \frac{v_b^2}{2} + \frac{P_b}{\rho}$$

Eq.7

Pressure drop over sealing section can be defined by:

$$P = P_a - P_b$$

Eq.8

Combining eq. 7 and eq.8:

$$P = \frac{\rho}{2}\left(v_b^2 - v_b^2\right)$$

Eq.9

From experimental measurements, it is found that the flows is not ideal and somehow lower than prediction by the equation above. A discharge coefficient of 0,95 is often used. Introducing these elements and the continuity relation, the above equation can be expressed as: (Aadnøy, 2010)

$$v_0 = 0{,}95\sqrt{\frac{2P}{\rho}}$$

Eq. 10

Or

$$P = \frac{\rho q^2}{2A^2\,0{,}95^2}$$

Eq. 11

(Aadnøy, 2010)

This equation can be used to determine the flow rate of leakage.

7. SYSTEM DESCRIPTION

7.1. Surface Completions

7.1.1. Christmas tree (with XT valves and exit blocks)

The XT 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 XT 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.

The XT 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. (Hans-Emil Bensnes Torbergsen, 2012)

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.

The XT is placed on top of the WH. Figure 10 illustrates different types of dry XT.

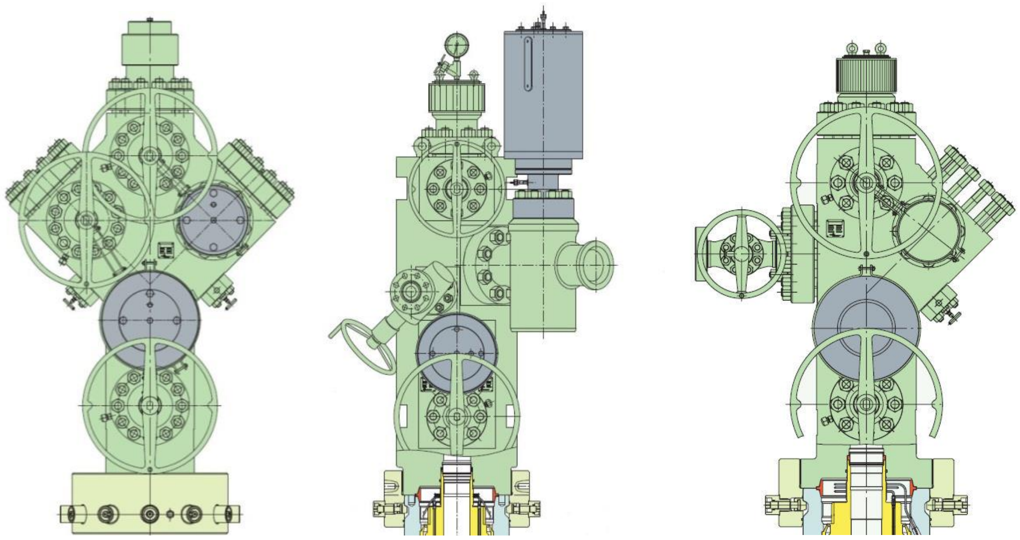


Figure 10 Different types of dry X-mas trees (Cameron)

7.1.2. Wellhead

The primary purpose of a WH is to provide the suspension point and pressure seals for the casing strings that run from the bottom of the hole section to the surface pressure control equipment (XT or BOP). The WH seals are usually part of the secondary well barrier envelope in the wells.

Figure 11 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.

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.

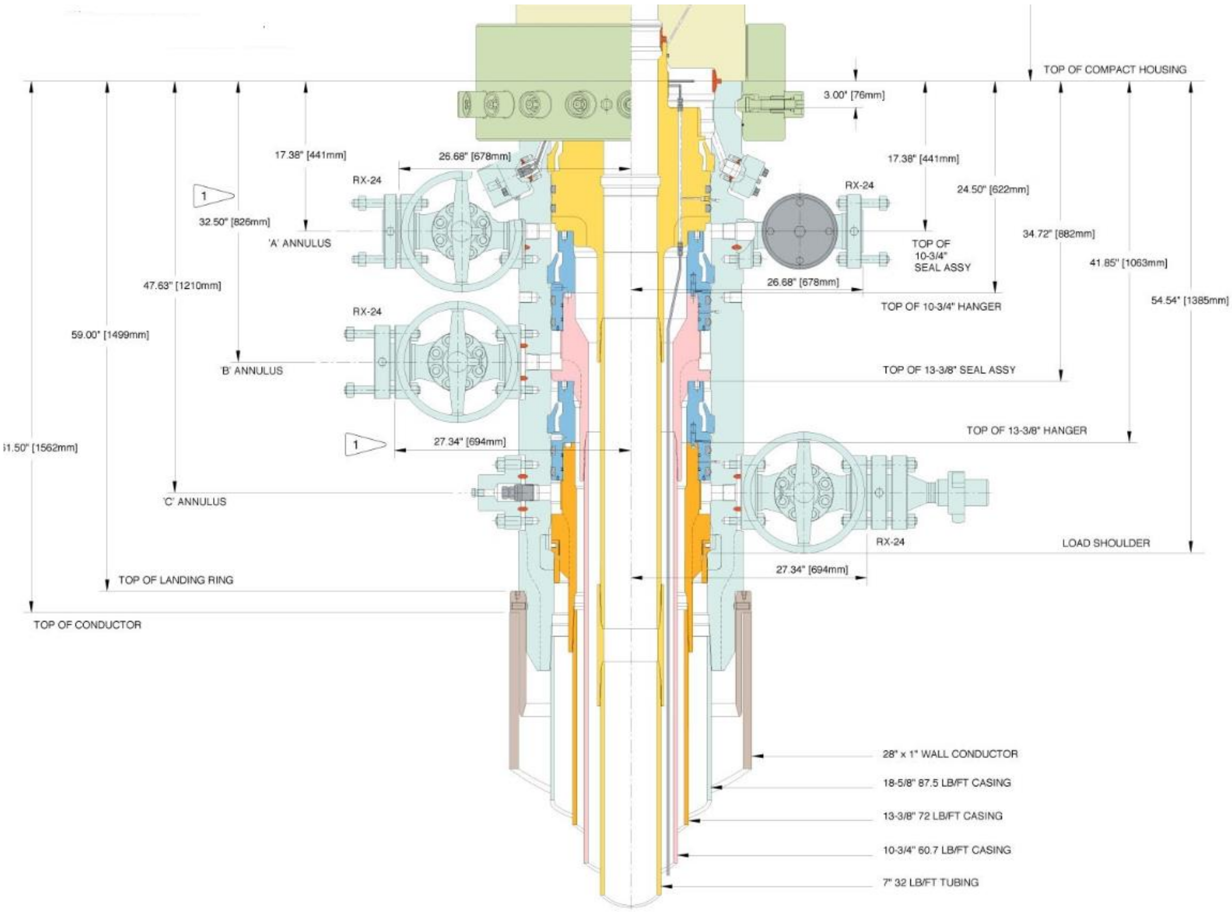


Figure 11 Wellhead system (Cameron)

7.1.3.XT-connection

The XT connection is the connection between the XT and the WH 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 12 illustrates a XT connection.

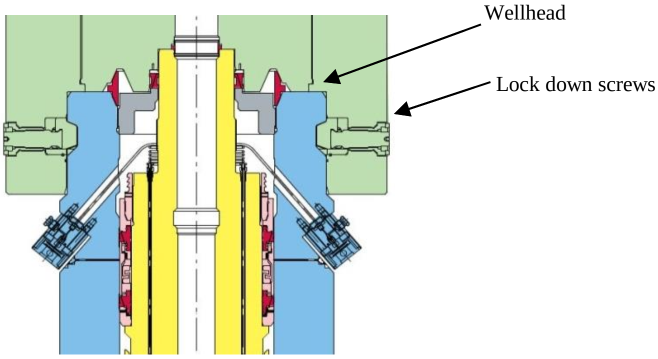


Figure 12 Illustration of XT locked to the WH by lock down screws (Cameron)

7.1.4.Casing hanger seal

The casing hanger is the portion of a WH assembly which provides support for the individual casing strings when it is lowered into the wellbore. It is usually welded or screwed to the top of the surface casing string and serves to ensure that the casing is properly located. When the casing string has been run into the wellbore, it is hung off by a casing hanger, which rests on a landing shoulder inside the casing spool. Casing hangers (Figure 13) provide a seal between the casing hanger and the spool and are usually part of the secondary well barrier envelope in production wells.

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.

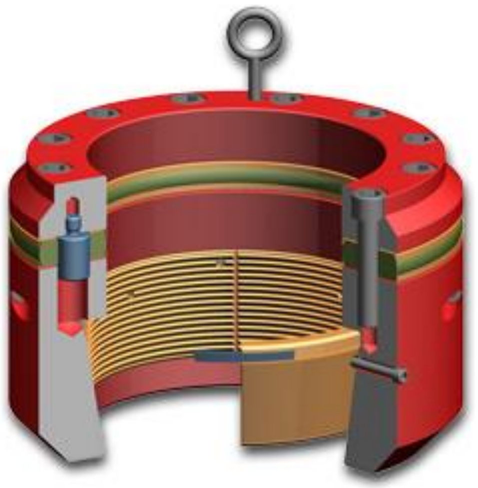


Figure 13 Example of a casing hanger with sealing elements (Hans-Emil Bensnes Torbergsen, 2012)

7.1.5.Annulus valves

For a dry WH 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 WH 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. The valves are also used to increase or reduce the pressure in the annuli and if needed also top up the fluid level.

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. (Hans-Emil Bensnes Torbergsen, 2012)

7.1.6.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 has often 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:
  .1. Production tubing and wellhead

.2. 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.

Figure 14 illustrates an example for a tubing hanger with control lines.

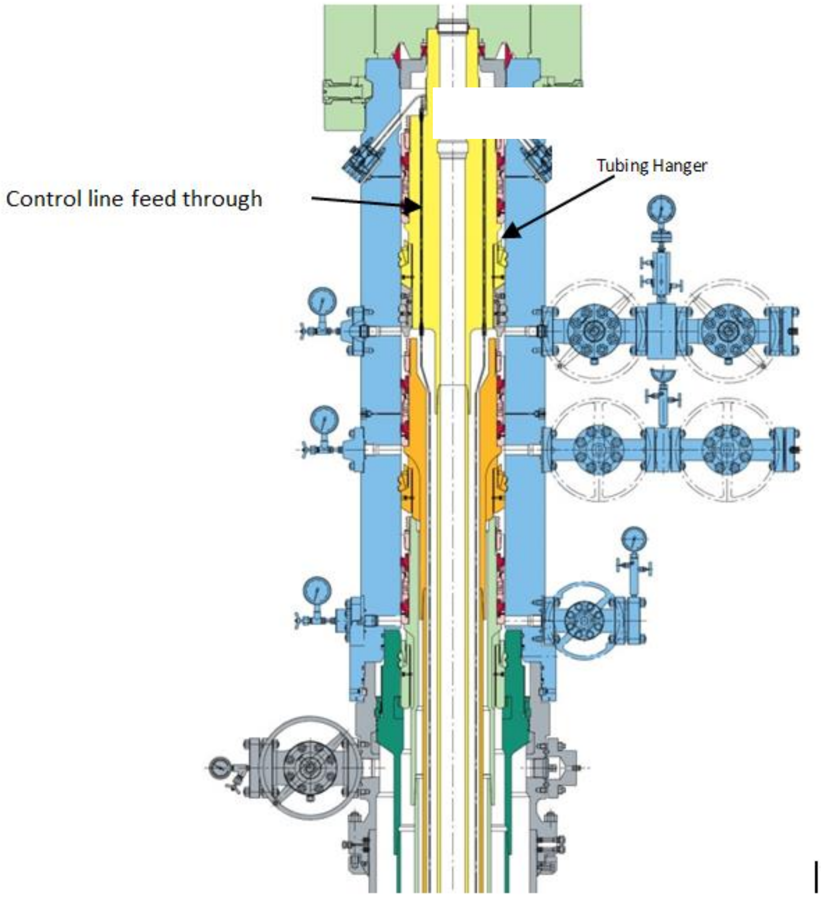


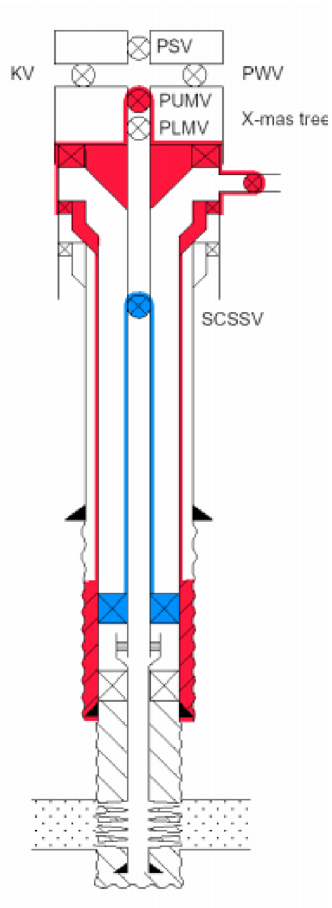
Figure 14 Tubing hanger installed in dry wellhead with control line feed through (Cameron)

7.2. The barrier envelopes

Figure 15 and Figure 16 illustrates the WB envelopes and the WBE of a producing well, without and with gas lift. The blue elements are part of the primary barrier and the red elements are part of the red barrier.

8.8 Well barrier schematic illustrations

8.8.1 Typical well capable of flowing - Shut-in



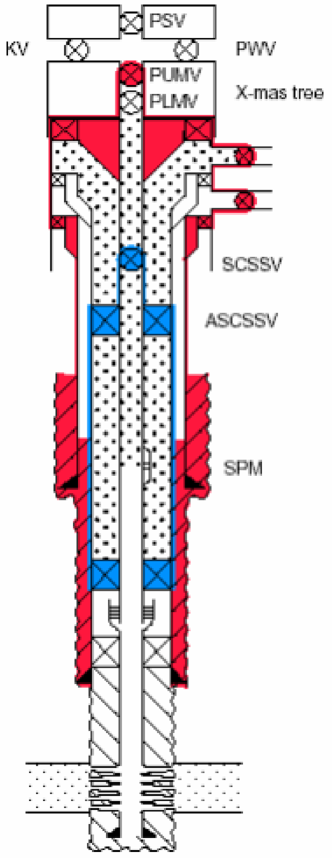
Well barrier elements	See Table	Comments
Primary well barrier		
1. Production packer	7	
2. Completion string	25	Tubing between SCSSV and production packer.
3. SCSSV	8	
Secondary well barrier		
1. Casing cement	22	
2. Casing	2	
3. Wellhead	5	Casing hanger, tubing head with connectors.
4. Tubing hanger	10	
5. Annulus access line and valve	12	
6. Production tree	33	Body and master valve.

Note
None

Figure 15 WB envelopes for a well, shut in, but in production (D-010)

NORSOK standard D-010 Rev. 3, August 2004

8.8.2 Typical gaslift platform production well



Well barrier elements	See Table	Comments
Primary well barrier		
1. Production packer	7	
2. Casing	2	Between ASCSSV packer and production packer.
3. ASCSSV	9	
4. Completion string	25	Between ASCSSV and SCSSV.
5. SCSSV	8	
Secondary well barrier		
1. Casing cement	22	Production casing cement.
2. Casing	2	Production casing and casing into intermediate casing.
3. Casing cement	22	Intermediate casing cement.
4. Casing	2	Intermediate casing.
5. Wellhead	5	Intermediate casing hanger w/seals.
6. Tubing hanger	10	
7. Annulus access line and valve	12	Tubing head w/annulus gas injection line w/valve.
8. Surface production tree	33	W/master valve.
9. Annulus access line and valve	12	B-annulus access line w/valve.

Note
None

Figure 16 WB envelopes of a gas lift well, shut in, but in production (D-010)

7.3. Fire resistant envelope

Normally the following equipment shall be covered by the fire resistant envelope (Figure 17):

- Wellhead / Christmas tree connector
- Upper actuated master valve
- Lower manual master valve
- Inner valve at A - Annulus (production annulus)
- Control line exit block in wellhead / christmas tree
- Tubing head
- Tubing hanger and seal assembly / packoff
- Casing hanger and seal assembly / packoff from A - Annulus (production annulus) and up

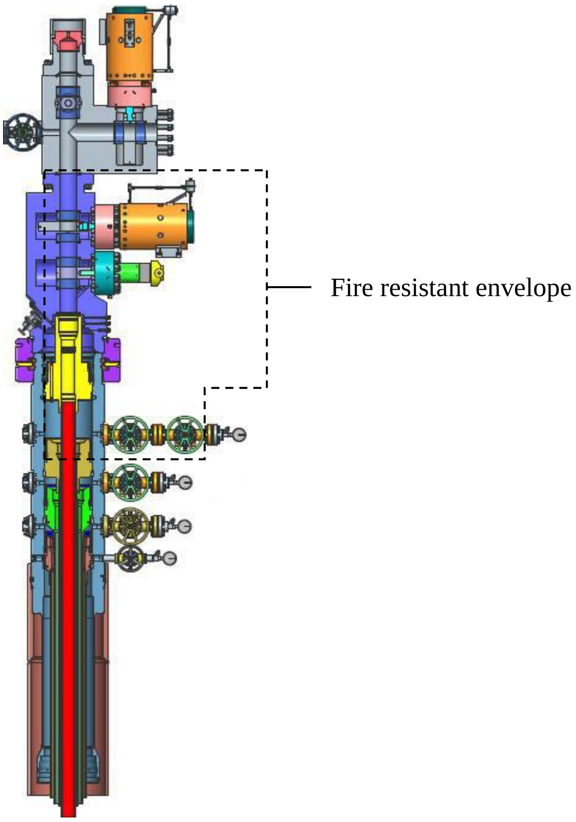


Figure 17 Fire resistant envelope (Statoil, TR3540)

For wellhead systems with active gas lift or production through the A-annulus, the equipment that shall be covered by the fire resistant envelope is the same with the exception of

- Casing hanger and seal assembly / packoff from B - Annulus and up

And an extra element

- Inner valve at B – Annulus

is included in the envelope. See Figure 18.

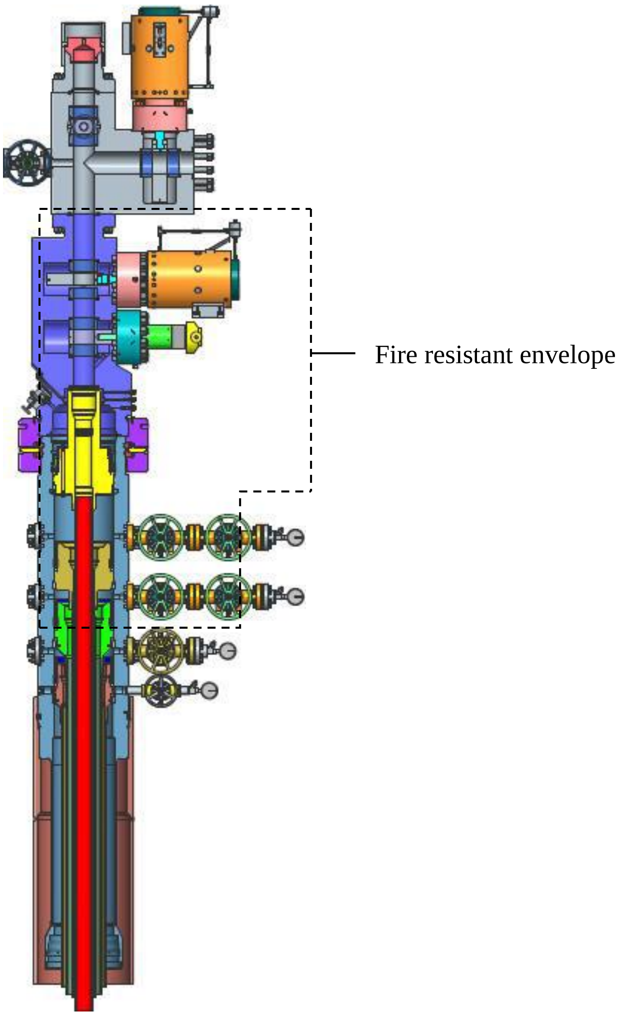


Figure 18 fire resistant envelope for wells with an active A-annulus (Statoil, TR3540)

The same qualification requirements are valid for casing / tubing hanger packoff's and/or seal assemblies, but not including the bend test. (Statoil, TR3540)

8. REQUIREMENTS

8.1. NORSOK D-010 rev 3

8.1.1. Table 33 – Surface production tree

Norsok D-010 rev.3 defines the surface production tree to be an element that consists of a housing with bores that are fitted with swab -, production master, kill- and flow valves.

8.1.1.1. Design, construction and selection

The following is specified in NORSOK D-010 with respect to design, construction and selection of seals in surface production tree:

- All primary seals shall be of metal-to-metal type.
- All connections, exit blocks etc. that lies within a predefined envelope shall be fire-resistant.

8.1.1.2. Test requirements

There are not stated any specific requirements regarding testing of seals.

8.1.2. Table 5 Wellhead

Norsok D-010 rev.3 defines the wellhead to be an element which consists of the wellhead body with annulus access ports and valves, seals and casing/tubing hangers with seal assemblies.

The following is specified in NORSOK D-010 with respect to the seals.

8.1.2.1. Initial test and verification

The wellhead bodies and seals, annulus ports with valves and the casing or tubing seal assemblies shall be leak rested to maximum expected shut in pressure for the specific hole section or operation.

8.1.2.2. Use

A wear bushing should be installed in the wellhead whenever movement of tools/work- strings can inflict damage to seal areas.

8.1.2.3. Failure modes

Failure of the stated requirements will lead to:

- Leaking seals or valves

5.1.3. Table 10 Tubing hanger

Norsok D-010 rev.3 defines the tubing hanger to an element which consists of body, seals and a bore which may have a tubing hanger plug profile.

8.1.2.4. Initial test and verification

The primary seal shall be tested in the flow direction.

The hanger seal can be tested against the flow direction.

If only single seals are used in the tubing hanger, annulus is to be tested. In the case of double seal, an in-between seal test might be performed.

8.1.2.5. Failure modes

Failure of the stated requirements will lead to:

- Leaking seals or valves

8.1.3.Table 12-Well head/ Annulus access valve

Norsok D-010 rev.3 defines the wellhead / annulus access valve to be an element which consists of the wellhead housing and an isolation valve.

8.1.3.1. Monitoring

Sealing performance shall normally be monitored through continuous recording of the annulus pressure measured at the wellhead level.

8.1.3.2. Failure modes

Failure of the stated requirements will lead to:

- Inability to maintain a pressure seal
- Seaping or sweating valve surface

8.2. NORSOK D-010 rev 4 draft

(A draft of the new version of NORSOK D-010 (rev 4) was published during the work of this thesis. A NORSOK D-010 rev. 3 and the draft of rev. 4 has therefore compared in order to detect possible new requirements regarding seals in WH)

5.2.1 Table 32- Surface production tree

NORSOK D-010 rev. 4 defines the surface production tree in the same manner as NORSOK D-010 rev. 3.

NORSOK D-010 rev. 4 sets the same requirements to design and construction for the surface production tree equally, as Norsok D-010 rev. 3.

There are not stated any new requirements regarding testing of seals.

8.2.1. Table 5 Wellhead

NORSOK D-010 rev. 4 defines the wellhead in the same manner as NORSOK D-010 rev. 3.

8.2.1.1. New requirements

Monitoring:

Accessible seals shall be periodically leak tested, first time within 1 year then at a maximum frequency of two years.

8.2.2. Table 9 Tubing hanger

NORSOK D-010 rev. 4 defines the tubing hanger in the same manner as NORSOK D-010 rev. 3.

8.2.2.1. New requirements

Initial test and verification:

- All seals shall be tested in the direction it is designed to hold pressure.

Monitoring:

- Accessible seals shall be periodically leak tested, first time within 1 year then at a maximum frequency of two years.

8.2.3. Table 11-Well head/ Annulus access valve

Norsok D-010 rev. 4 defines the the wellhead / annulus access valve to be an element which consists of the wellhead housing, the XT/wellhead connection and an annulus isolation valve.

8.2.3.1. New requirements

New requirement regarding monitoring, but not directly related to the seals.

8.3. API

8.3.1. Valve Test Criteria

According to API 14B, 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. 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.

8.4. TR 3504 Surface wellhead and Christmas tree system

8.5. General design requirements

All bolt-on valve connections towards the WH housing and XT block within the fire resistant envelope shall have dual metal-to-metal seals with the possibility to pressure test both seals individually. The control line block towards the WH connection is a secondary seal and hence a single metal-to-metal seal is acceptable.

The chemical injection block terminations towards the cross in the XT tree block shall in addition have a metal-to-metal check valve installed in the XT tree block, to ensure two metal-to-metal seals towards the production medium. Optional a chemical injection block connection with dual metal-to-metal seals shall be used.

All permanently installed non-metallic seals (primary and secondary/test seal) shall be resistant to the rapid gas decompression requirements and compatible with each individual fluid environment. See section under Abbreviations

The WH to XT interface design shall provide a minimum of two independent sealing surfaces between the tubing hanger bore and the atmosphere, one located in WH/XT connection and one located between the tubing hanger neck and the XT bore.

The WH and XT instrumentation shall be performed by utilizing anti-vibration type compression fittings (e.g. Autoclave® or Butech® type fitting).

Autoclave® and Butech® are high pressure coned-and-threaded connections.

8.5.1. General qualification requirements

8.5.1.1. Seals

Metallic seals shall be qualified in accordance with ISO 10423 F.1.11.

Non-metallic materials and manufactures shall be qualified in accordance with ST076 and qualified in accordance with ISO 10423 F.1.11 and F.1.13.

Non-metallic primary seals such as stem seals, and all non-metallic secondary sealing exposed to production fluids or gas, shall be of the rapid gas decompression resistance type in accordance with ST076 (NORSOK M-710). All seals and back up components shall be compatible with the individual fluid environment.

Primary seals in contact with hydrocarbons or part of the well barrier system, shall be of metal-to-metal design or minimum fire resistant design and tested using Nitrogen.

Installation of the seals for the test fixture shall simulate actual installation conditions and the test fixture shall simulate real behaviour including thermal effects and axial movements.

The seal design shall be qualified for intended use, e.g. leak tightness from both directions where applicable. Each individual seal, including its application, individually or as part of a seal arrangement / seal stack, shall be fully qualified.

Both primary and secondary sealing functions shall be qualified.

No visible indications of welds in the sealing area are allowed.

The seals should be protected during transportation to avoid damage on the sealing surface. Damage on the sealing surface is a common reason for leakages through the seals.

8.5.2. Technical specifications wellhead

The wellhead should be of a compact type, and one of two options:

- A starting head and one piece multibowl housing comprising the casing and tubing hangers as shown by the principles of Figure 19.
- A starting head, a casing head housing comprising the casing hangers, and a drill through tubing head comprising the tubing hanger as shown by the principles of Figure 20.

Complete assemblies shall be qualification tested. Individual seals, as well as complete seal assemblies including locking mechanism, shall be qualified. Qualification testing performed on individual parts, shall only be considered complete upon retesting with the component parts fully assembled, tested and qualified as a complete assembly. Preferably the component shall be functioned and run using field installation tools during the qualification test.

If metal-to-metal lip seals are used in the wellhead they shall be installed in by utilizing an appropriate tool.

The wellhead shall be equipped with test ports for integrity testing of all system seals from the exterior of the wellhead. All test ports shall be in doublets for effective testing, set 180° apart. Test port fittings to wear a protective pressure sealing cap, with integrated vent function, to detect and enable a controlled release of any trapped pressure behind the sealing cap. All threaded test / vent ports within the fire resistant envelope shall be of an Autoclave® or Butech® type connection.

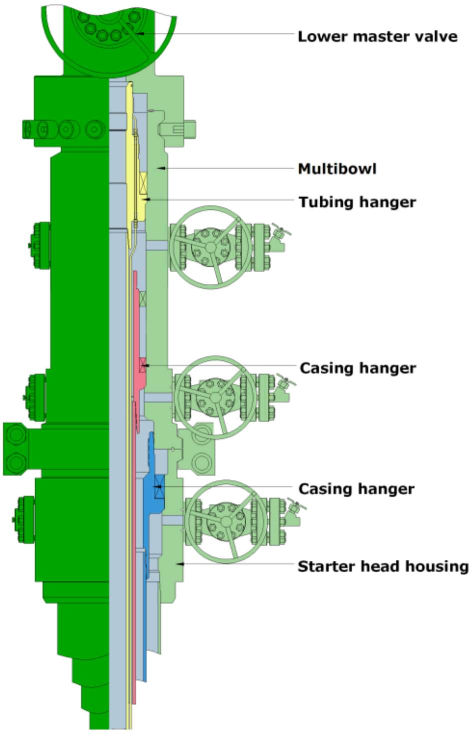


Figure 19 Typical compact wellhead / mulitbowl assembly nomenclature (Statoil, TR3540)

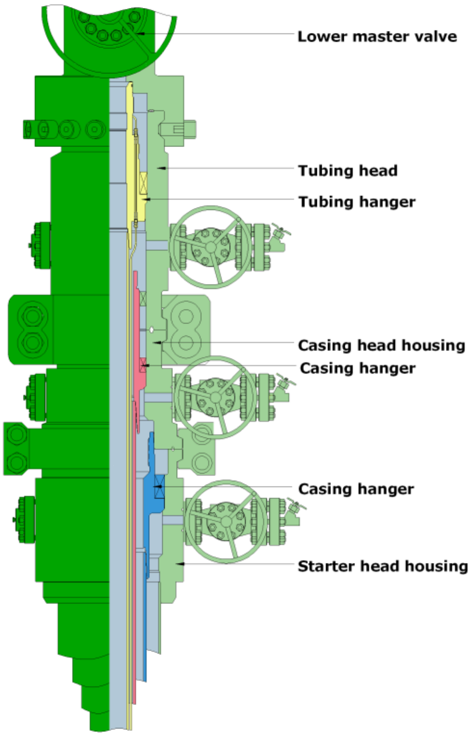


Figure 20 Typical split drill through type wellhead assembly nomenclature (Statoil, TR3540)

8.5.2.1. Annulus Pack-off and Seal assembly

The annulus pack-off and seal assemblies are barrier elements and pressure controlling components, and shall be designed according to the principles of ISO 10423.

Casing and tubing hanger annulus seals shall be of a bi-directional metal-to-metal design, retrievable without having to pull the casing or tubing hanger and certified for the life of the field.

As a minimum, the seal assembly for the production casing and tubing hanger shall be of a fire resistant design.

See also section "

Fire resistant envelope" for further details.

For standardization purposes same pack-off or seal assembly shall be used throughout in multi-bowl systems. Use of tie-down bolts shall be avoided. Pack-off and seal assembly shall be run through a drained rise

8.6. Conclusion/ the minimum accepted requirements

All equipment used in WH and XT shall be designed for and entirely suitable for twenty years in continuous operations at specified duty, unless specifies otherwise in project specific requirements.

When equipment is to be modified or otherwise altered, latest editions of the standards shall apply.

The equipment shall be designed to comply with Statoil's barrier philosophy for the overall system. The system shall provide fail-safe features such that any single failure will not result in an unsafe system condition. There should always be two independent barriers and in cases where this is not feasible, risk reducing measures should be implemented.

Normally the following equipment shall be covered by the fire resistant envelope:

- Wellhead / Christmas tree connector
- Upper actuated master valve
- Lower manual master valve
- Inner valve at A - Annulus (production annulus)
- Control line exit block in wellhead / christmas tree
- Tubing head
- Tubing hanger and seal assembly / packoff
- Casing hanger and seal assembly / packoff from A - Annulus (production annulus) and up

For WH systems with active gas lift or production through the A-annulus, the inner valve at B-Annulus is also part of the fire resistant envelope.

All bolt-on valve connections towards the WH housing and XT block within the fire resistant envelope shall have dual metal-to-metal seals with the possibility to pressure test both seals individually. The control line block towards the wellhead connection is a secondary seal and hence a single metal-to-metal seal is acceptable.

The chemical injection block terminations towards the cross in the XT block shall in addition have a metal-to-metal check valve installed in the XT block, to ensure two metal-to-metal seals towards the production medium. Optional a chemical injection block connection with dual metal-to-metal seals shall be used.

All permanently installed non-metallic seals (primary and secondary/test seal) shall be resistant to the rapid gas decompression requirements and compatible with each individual fluid environment.

The WH and XT instrumentation shall be performed by utilizing anti-vibration type compression fittings.

The seal design shall be qualified for intended use, e.g. leak tightness from both directions where applicable. Complete seal assemblies shall be qualification tested. Testing performed on individual parts, shall only be considered complete upon retesting with the component parts fully assembled, tested and qualified as a complete assembly.

The WH and XT should be equipped with test ports for integrity testing of all system seals from the exterior part. All test ports, bleed ports or other valve body penetrations shall be equipped with fittings, Autoclave® type or plugs with metal-to-metal sealing.

Valves leaking above allowable criteria, or other leaking components in the barrier envelope, require a commitment to repair within a certain time-frame .

9. CASE STUDY OF WELL A-1, A-2 AND A-3 AT OSEBERG EAST

In the following chapters case studies regarding leakages through seals in connection to cavity C1 will be presented. See Figure 21.The full case study of a well named A-1 will be presented, as well as the major topics from the case study of well A-2 and A-3. All of these three wells are located at the Oseberg East installation.

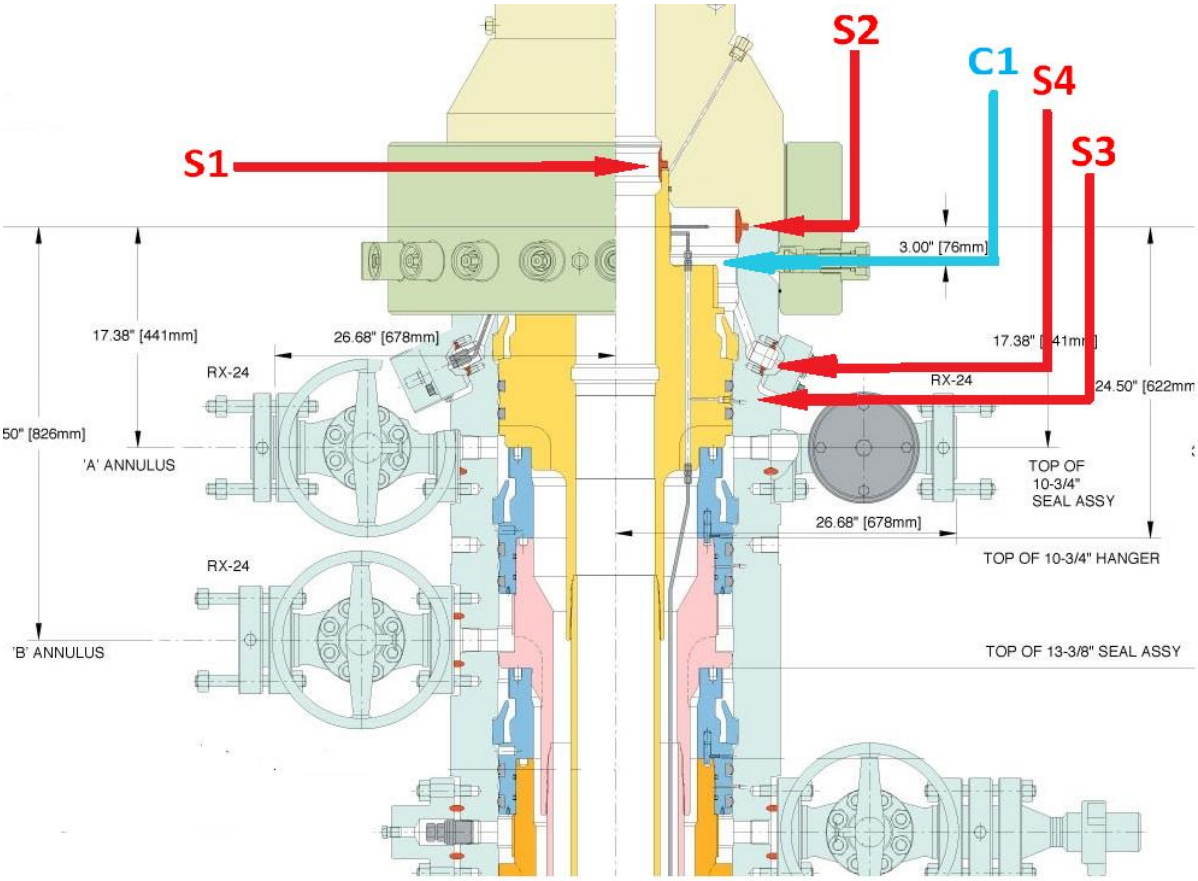


Figure 21 WH Oseberg East (Cameron)

9.1. Wellhead configuration of well A-1, A-2 and A-3

All wellheads at the Osberg East installation have Cameron wellheads. The specific WH configuration, which is relevant for this particular case study, for the wells A-1, A-2 and A-3 are described in the following chapters. (There is installed an add-on wellhead on A-1, but this will not affect the system boundaries of the system that will be discussed in this case evaluation)

9.1.1.Standard Snap Ring Modular Compact Wellhead System

Cameron's standard snap ring modular compact (SSMC™) wellhead system (see Figure 22), has been developed as a total system to cater for the different requirements of working pressure and casing programs that may be encountered, but utilizing a minimum number of components that are interchangeable within the system. This approach for the various components allows flexibility and considerably reduces inventory, particularly since seal assemblies are identical for each stage and interchangeable between elastomeric and metal/metal. (Cameron sealing technology)

Elastomeric and metal seal assemblies are interchangeable.

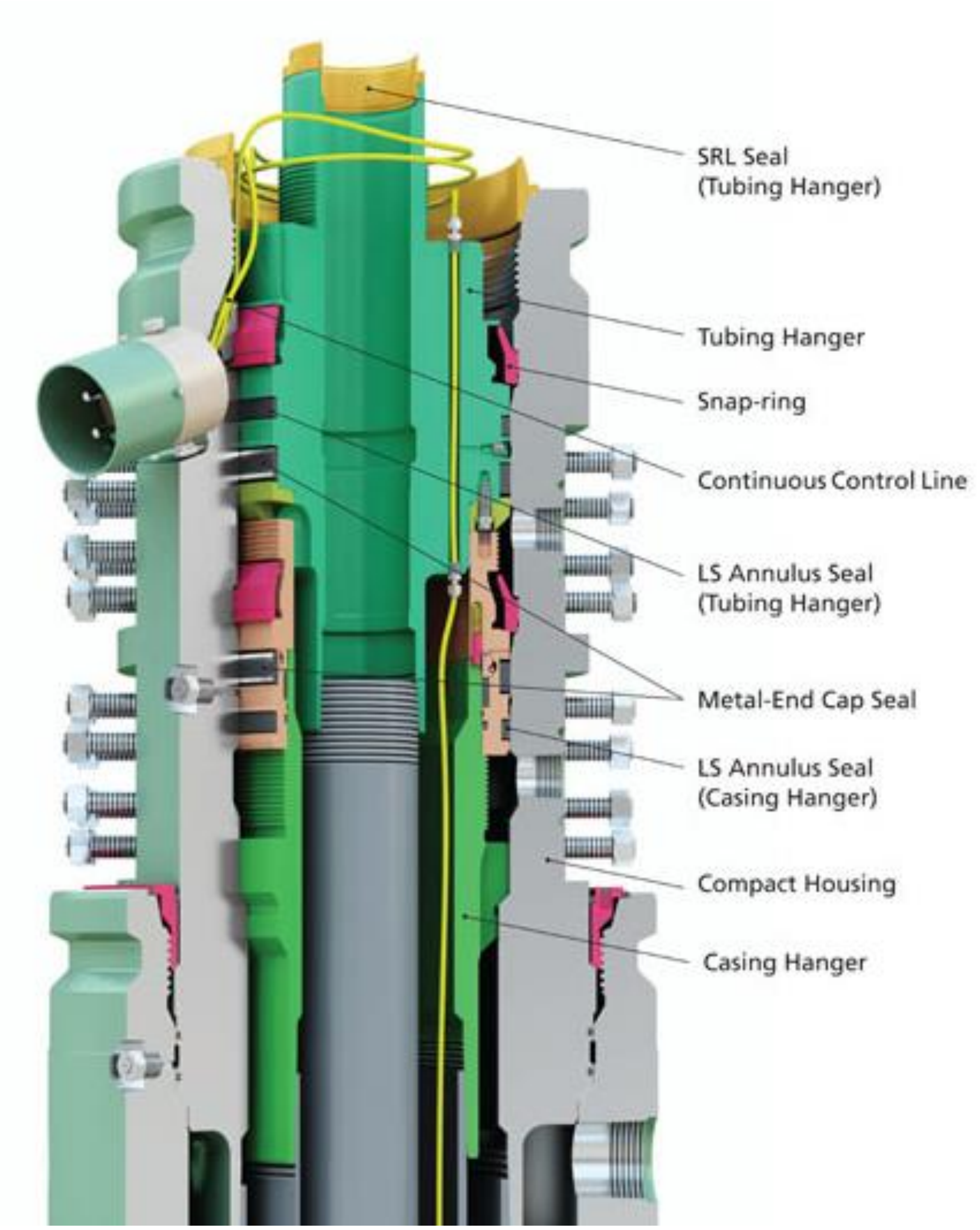


Figure 22 SSMC™ wellhead system (Cameron)

9.1.2.Straight Bore Radial Lip Metal Seal- SRL

The 'SRL' seal (Figure 23) is a pressure energized unidirectional, straight bore seal. An initial sealing interface is created by radial interference of each seal lip when installed into the mating seal bore. Pressure acts on the unbalanced portion of each lip to produce the contact forces necessary for high pressure sealing, and limits the bearing stresses to prevent damage to the mating seal surfaces. The 'SRL' seal sub is used in tubing hanger necks for an internal flush radial seal provides a center hub region that is sized to support the pressure loading. This seal may be installed into a pocket without reliance on radial support from the mating housing. The 'SRL' flange or bonnet gasket provides for a minimally sized center hub and must be installed into a mating counterbore with close tolerance fits to carry the radial pressure loads, while providing a more compact design. (Cameron sealing technology)

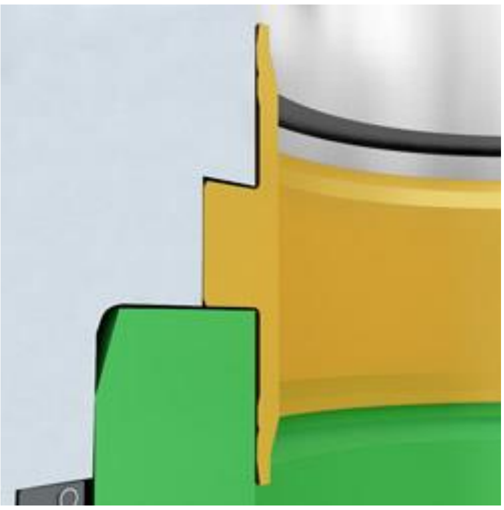


Figure 23 SRL seal (Cameron)

9.1.3.Metal End Cap Seal (MEC)

MEC seals (Figure 24) are radially squeezed, pressure energized elastomeric annulus seals. Metal shells provide a zero gap extrusion barrier that eliminates exposing the elastomer material to the corrosive well bore environment. MEC seals can tolerate surface imperfections such as those caused by casing centralizers.

The MEC assembly is a seal that offers the advantages of metal-to-metal seals and elastomeric seals. The MEC seal itself consists of a robust elastomeric seal that is encapsulated by 316 stainless steel metal end caps. The metal end caps have interference fits with the wellhead body and casing hanger body. Tests have proved that the end caps isolate the elastomer from fluid in the annulus. The elastomer however permits the seal to seal on scratches and mechanical damage in the wellhead bore. (Cameron sealing technology)

Figure 24 MEC seal (Cameron)

9.1.4.LS Elastomer Seal

LS-seal is an elastomer seal with the following features:

- Cost-effective
- Radiused seal face protects during installation. Large cross section for better sealing.
- Application: Non-metal-to-metal rated for 10,000 psi and below.
- Method to Energize Seal: Radial interference using stainless steel garter springs to prevent extrusion. (Cameron sealing technology)

Figure 25 LS seal (Cameron)

9.2. Case Study, Oseberg East well A-1

The case study of the well A-1 at the Oseberg East follows.

9.2.1. History of the well A-1

- Drilled in 2001
- WO 2007 due to A to B annulus communication below the annulus safety valve
- WO 2010 due to:
  - A to B annulus communication, caused by a leak in the 10 3/4” x 7 5/8” tie back
  - Additionally, two small leaks have been identified in the wellhead, one from the A annulus to the tubing hanger cavity, and the other across the SRL seal to the tubing hanger cavity.
- Additional leaks in connection to C1 was seen in February 2011
- Cameron performed tests in August 2012 that confirmed the leaks

The A-1 well was originally drilled and completed in 2001, with a simplified casing plan. The well had a 28” conductor, 13 3/8” intermediate casing, and 10 ¾” x 9 5/8” production casing. The reservoir section was cased with 7” liner, and perforated. The original completion was a 7” x 5 ½” gas lift design, with a dual FLX annulus safety valve.

The 10 ¾” x 9 5/8” (NSCC) production casing developed A to B annulus communication below the annulus safety valve, and the well was suspended.

The well was worked over, and recompleted in 2007. An HX-4 plug was set in the 5 ½” tubing below the SABL production packer, the tubing was then cut and retrieved above the packer. In order to provide a more robust gas lift solution, the production casing was cut above the 13 3/8” shoe. A Read Hydraulic Expandable Tubular System (HETS) patch was run, and connected to the top of the 9 5/8” casing stub. The 9 5/8” casing was then tied back to the 13 3/8” casing with an FLX liner hanger packer. This allowed a new 10 ¾” x 7 5/8” tie back string to be run, creating an additional annulus, and therefore giving a more robust design for a gas lifted well.

At this point the HX-4 plug was to be retrieved, as it would not be possible to retrieve it through the new completion. However, it was not possible to retrieve the plug, and it was eventually pushed to bottom (4659m mD).The well was recompleted with 5 ½” x 4 ½”production tubing, utilising a 10 3/4” x 5 ½” dual FLXannulus safety valve (ASV), gas lift, four mandrels, a downhole pressure and temperature gauge, and a chemical injection valve for scale inhibition.

In 2009 the well suffered loss of casing integrity, with A to B annulus communication, caused by a leak in the 10 3/4” x 7 5/8” tie back. Additionally, two small leaks have been identified in the wellhead, one from the A annulus to the tubing hanger cavity, and the other across the SRL seal to the tubing hanger cavity.

A Well Leak Detector (WLD) tool was run in September 2009, but the operation was unsuccessful in determining the point of the leak due to several difficulties experienced during the operation. The main problem was the inability to initiate and maintain a consistent leak across the casing, at sufficient rate for the WLD to identify. (Macrae, 2010)

The well was suspended in October 2009 and recompleted in 2010.

A schematic of the completion is shown in Figure 26 below. The monitoring well barrier schematic of the well is shown in Figure 27.

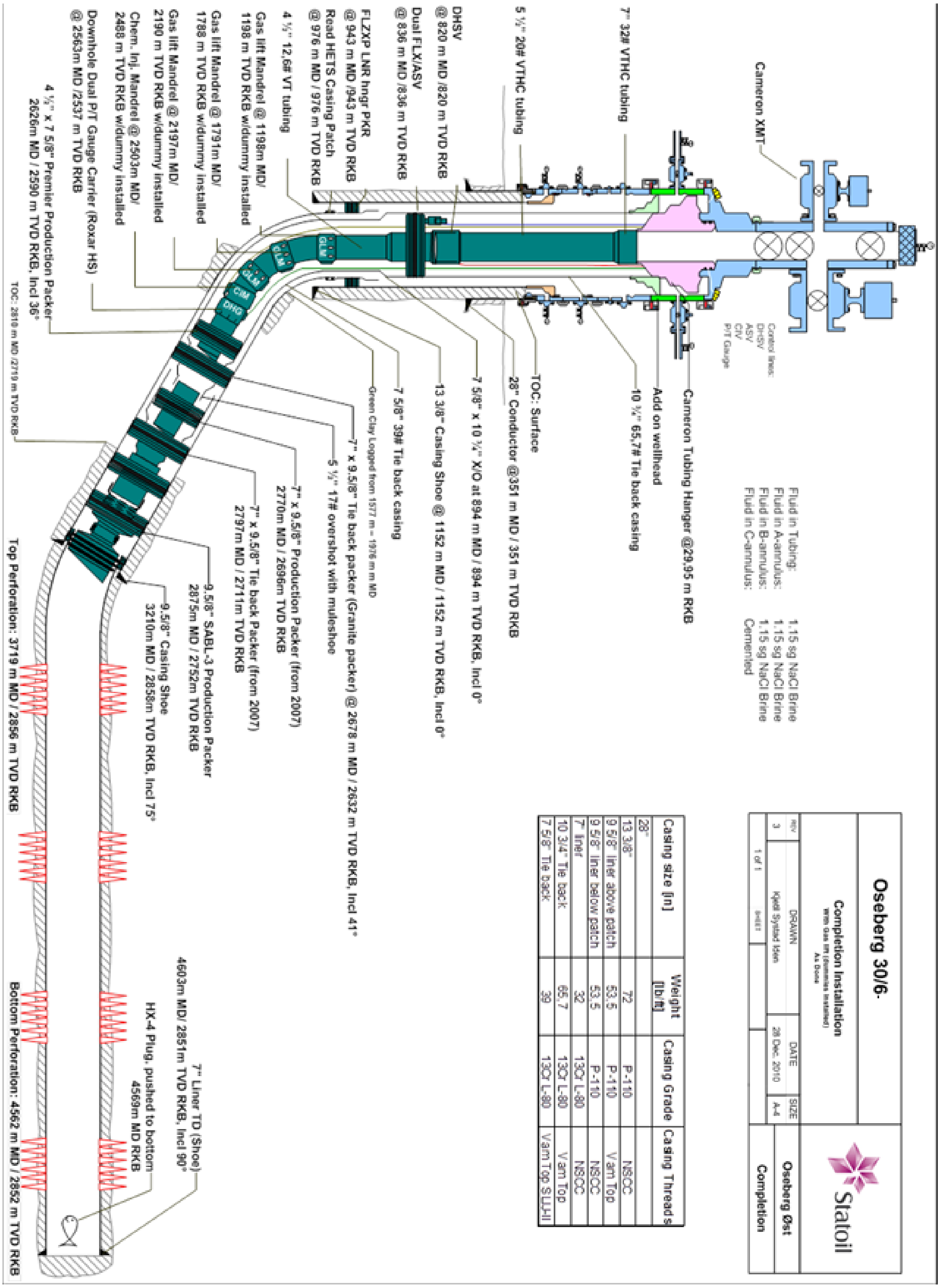
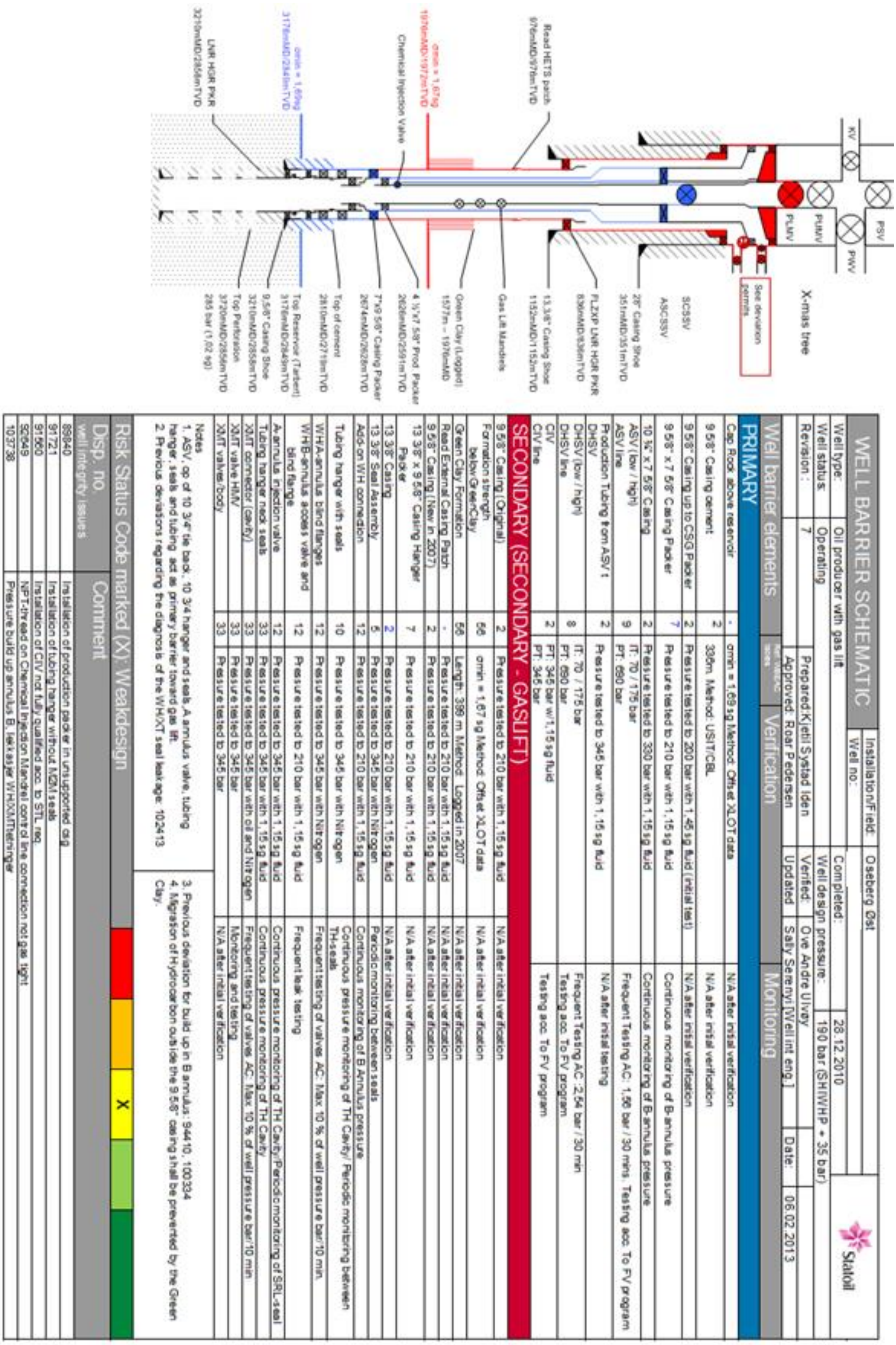


Figure 26 Well sketch A-1



WELL BARRIER SCHEMATIC		Installation/Field:	Oseberg Øst		Statoil
		Well no:			
Well type:	Oil producer with gas lift		Completed:	28.12.2010	
Well status:	Operating		Well design pressure:	190 bar (SHIWHP + 35 bar)	
Revision:	7	Prepared: Kjetil Systad Iden	Verified:	Ove Andre Ulvøy	
		Approved: Roar Pedersen	Updated	Sally Serenyi [Well int eng.]	Date: 06.02.2013

Well barrier elements	Ref. NORSOK tables	Verification	Monitoring
PRIMARY			
Cap Rock above reservoir	-	σmin = 1,69 sg Method: Offset XLOT data	N/A after initial verification
9 5/8" Casing cement	2	336m. Method: USIT/CBL	N/A after initial verification
9 5/8" Casing up to CSG Packer	2	Pressure tested to 200 bar with 1,45 sg fluid (initial test)	N/A after initial verification
9 5/8" x 7 5/8" Casing Packer	7	Pressure tested to 210 bar with 1,15 sg fluid	Continuous monitoring of B-annulus pressure
10 ¾" x 7 5/8" Casing	2	Pressure tested to 330 bar with 1,15 sg fluid	Continuous monitoring of B-annulus pressure
ASV (low / high) ASV line	9	IT: 70 / 175 bar PT: 690 bar	Frequent Testing AC: 1,56 bar / 30 mins. Testing acc. To FV program
Production Tubing from ASV t DHSV	2	Pressure tested to 345 bar with 1,15 sg fluid	N/A after initial testing
DHSV (low / high) DHSV line	8	IT: 70 / 175 bar PT: 690 bar	Frequent Testing AC :2,54 bar / 30 min Testing acc. To FV program
CIV CIV line	2	PT: 345 bar w/1,15 sg fluid PT: 345 bar	Testing acc. To FV program
SECONDARY (SECONDARY - GASLIFT)			
9 5/8" Casing (Original)	2	Pressure tested to 210 bar with 1,15 sg fluid	N/A after initial verification
Formation strength below GreenClay	56	σmin = 1,67 sg Method: Offset XLOT data	N/A after initial verification
Green Clay Formation	56	Length: 399 m Method: Logged in 2007	N/A after initial verification
Read External Casing Patch	-	Pressure tested to 210 bar with 1,15 sg fluid	N/A after initial verification
9 5/8" Casing (New in 2007)	2	Pressure tested to 210 bar with 1,15 sg fluid	N/A after initial verification
13 3/8" x 9 5/8" Casing Hanger Packer	7	Pressure tested to 210 bar with 1,15 sg fluid	N/A after initial verification
13 3/8" Casing	2	Pressure tested to 210 bar with 1,15 sg fluid	N/A after initial verification
13 3/8" Seal Assembly	5	Pressure tested to 345 bar with Nitrogen	Periodic monitoring between seals
Add-on WH connection	12	Pressure tested to 210 bar with 1,15 sg fluid	Continuous monitoring of B Annulus pressure
Tubing hanger with seals	10	Pressure tested to 345 bar with Nitrogen	Continuous pressure monitoring of TH Cavity/ Periodic monitoring between TH-seals
WH/A-annulus blind flanges	12	Pressure tested to 345 bar with Nitrogen	Frequent testing of valves AC: Max 10 % of well pressure bar/10 min.
WH/B-annulus access valve and blind flange	12	Pressure tested to 210 bar with 1,15 sg fluid	Frequent leak testing
A-annulus injection valve	12	Pressure tested to 345 bar with 1,15 sg fluid	Continuous pressure monitoring of TH Cavity/Periodic monitoring of SRL-seal
Tubing hanger neck seals	33	Pressure tested to 345 bar with 1,15 sg fluid	Continuous pressure monitoring of TH Cavity
XMT connector (cavity)	33	Pressure tested to 345 bar with oil and Nitrogen	Frequent testing of valves AC: Max 10 % of well pressure bar/10 min
XMT valve HMV	33	Pressure tested to 345 bar	Monitoring and testing
XMT valves/body	33	Pressure tested to 345 bar	N/A after initial verification

Notes
1. ASV, op of 10 3/4" tie back, 10 3/4 hanger and seals, A annulus valve, tubing hanger, seals and tubing act as primary barrier toward gas lift.
2. Previous deviations regarding the diagnosis of the WH/XT seal leakage: 102413
3. Previous deviation for build up in B annulus: 94410, 100334
4. Migration of Hydrocarbon outside the 9 5/8" casing shall be prevented by the Green Clay.

Risk Status Code marked (X): Weakdesign — X

Disp. no. well integrity issues	Comment
89840	Installation of production packer in unsupported csg
91721	Installation of tubing hanger without M2M seals
91560	Installation of CIV not fully qualified acc. to STL req.
92649	NPT-thread on Chemical Injection Mandrel control line connection not gas tight
103738	Pressure build up annulus B, lekkasjer WH/XMTtetninger

Figure 27 WBS A-1

9.2.2.Deviation history

According to the Statoil deviation system, the following deviations have been registered for the well A-1 (Synergy numbers)

- 94410 Diagnosis for pressure build up in B annulus, gas bled off 10 ¾» seal and leakage seen past SRL seal (April 2011)
- 100334 Diagnosis for pressure build up in B annulus (3/12-12/12). Mentions SRL leak.
    - Actions: fill B annulus
- 102413 Diagnosis for internal leakages XT/WH (7/12-9/12)
    - Actions: - Leakage rate to SRL seal, leakage rate to XT cavity. Limit SRL seal to 35bar diff pressure
- 103738 To produce the well with current issues:
    - XT/WH internal leakages
    - Historic build leak in B annulus via 10 ¾» seal (very slow increase in B annulus)

Risk Status Code marked (X): Weakdesign				X		
Disp. no. well integrity issues	Comment					
89840	Installation of production packer in unsupported csg					
91721	Installation of tubing hanger without M2M seals					
91560	Installation of CIV not fully qualified acc. to STL req.					
92649	NPT-thread on Chemical Injection Mandrel control line connection not gas tight					
103738	Pressure build up annulus B, lekkasjer WH/XMTtetninger					

Figure 28 Risk status Code, A-1

Based on the exclusion method, analysis of pressure trends (Figure 29 and Figure 30) as well as the tests performed by Cameron in August 2012 diagnosis of the wellhead leakages over the last years has been made. The main discoveries will be presented below.

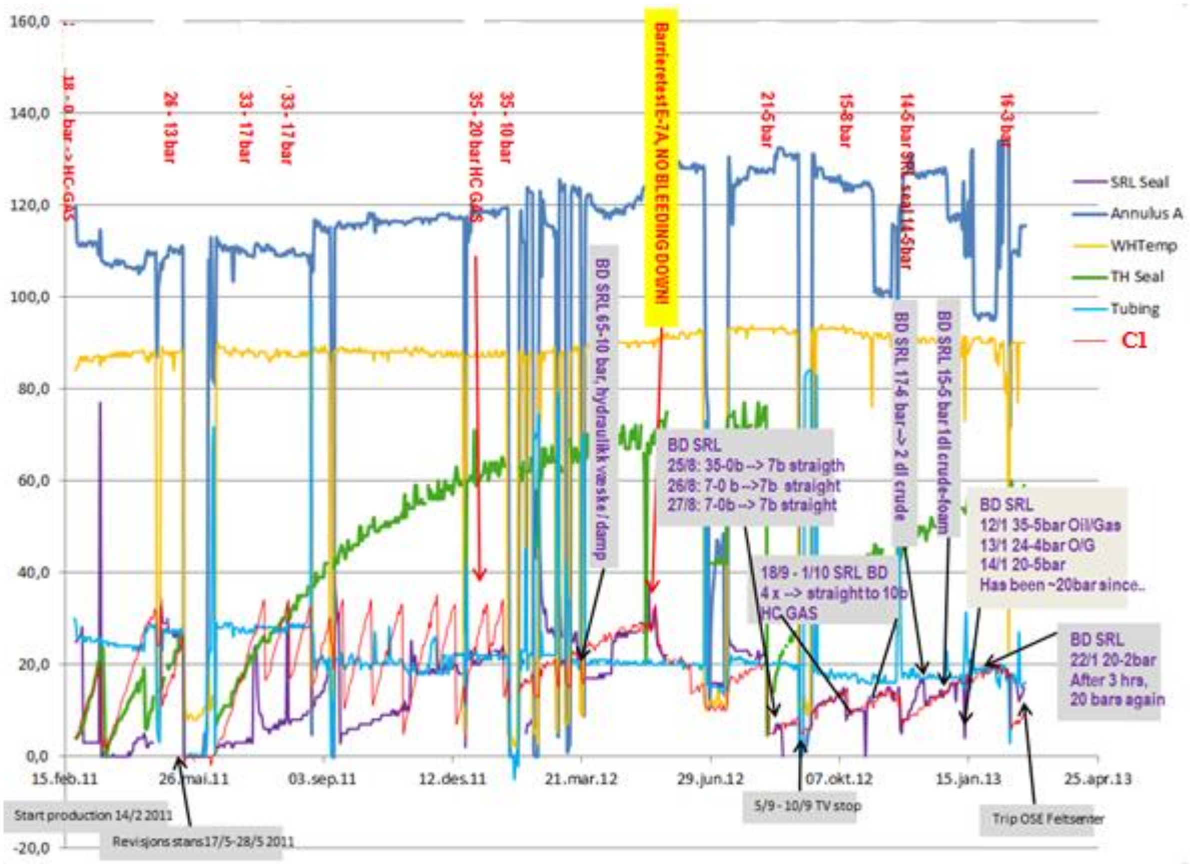


Figure 29 Temperature and pressure trends in WH/XT A-anulus, A-1 (Sally Serenyi)

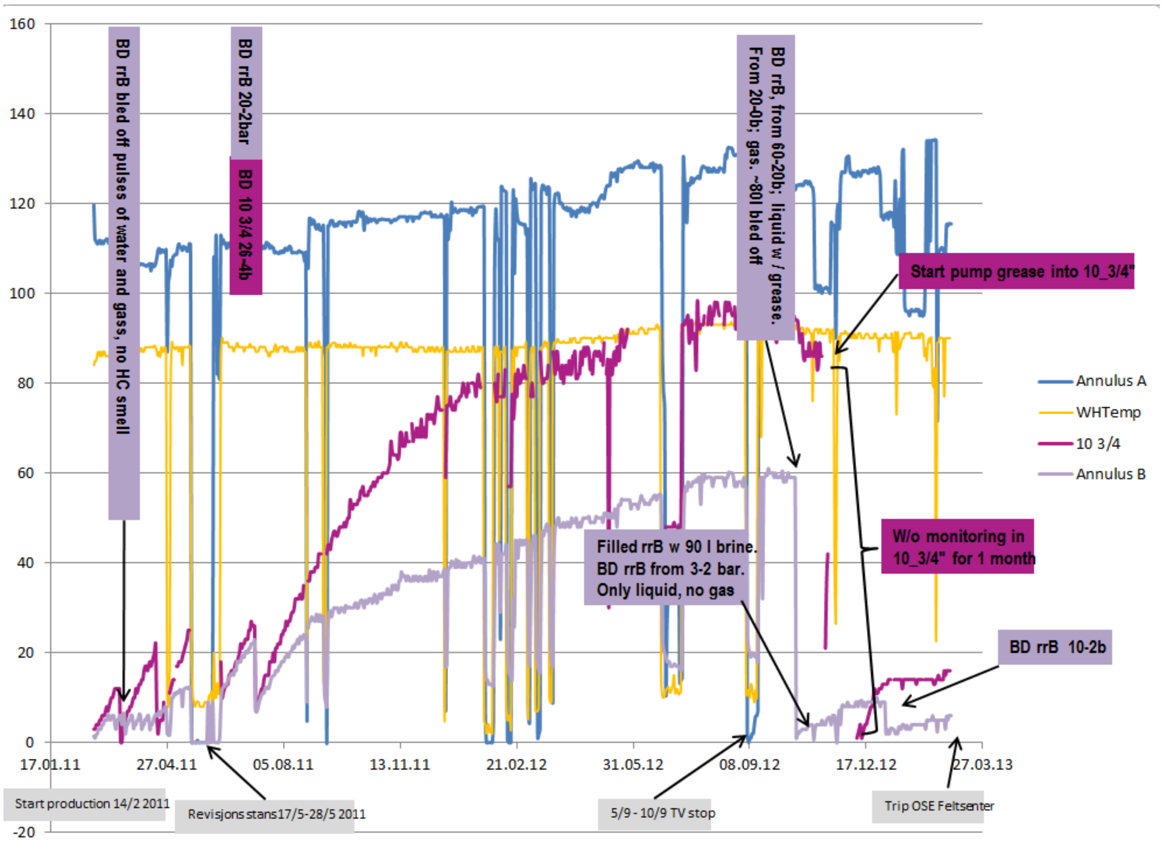


Figure 30 Temperature and pressure trends in WH/XT B-anulus, A-1 (Sally Sereny)

9.2.2.1. Historic pressure build up in C1

- Pressure build up to tubing pressure in tubing hanger neck seal (SRL) seal monitor port. See Figure 31.
  - Leak rate 0,00003 l/hr
  - Actions: bleed off pressure at 35 bar
  - Crude oil seen during bleed off

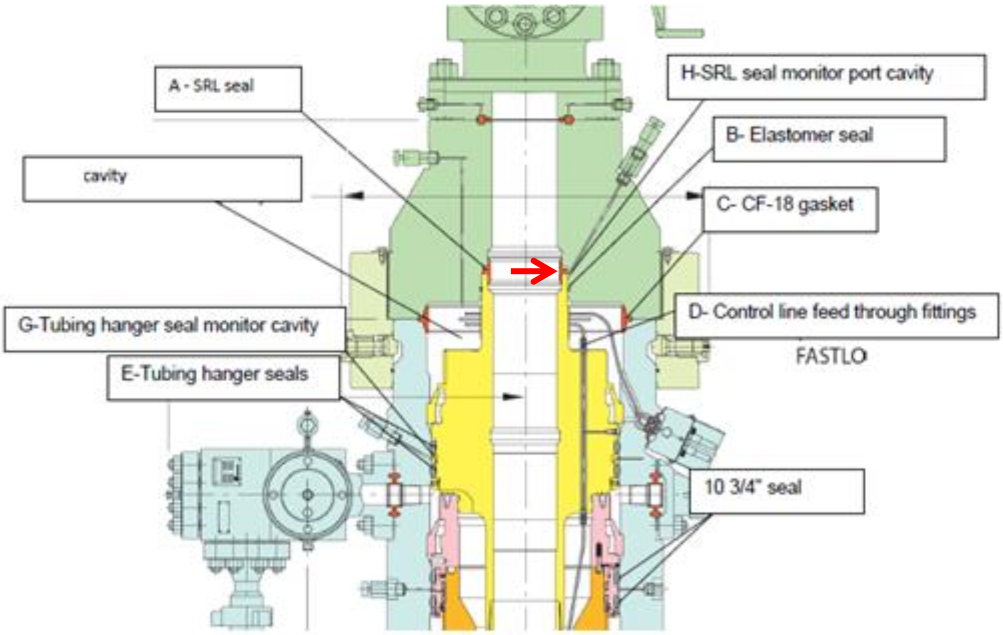


Figure 31 WH illustration of pressure build up in SRL cavity

- Historic (2012) pressure build up in C1. See Figure 32
  - Higher than tubing pressure
  - Leak rate 0,08 l/hr
- Current build up seen in C1. Figure 32.
  - Not higher than tubing pressure
  - Leak rate 0,12 l/hr

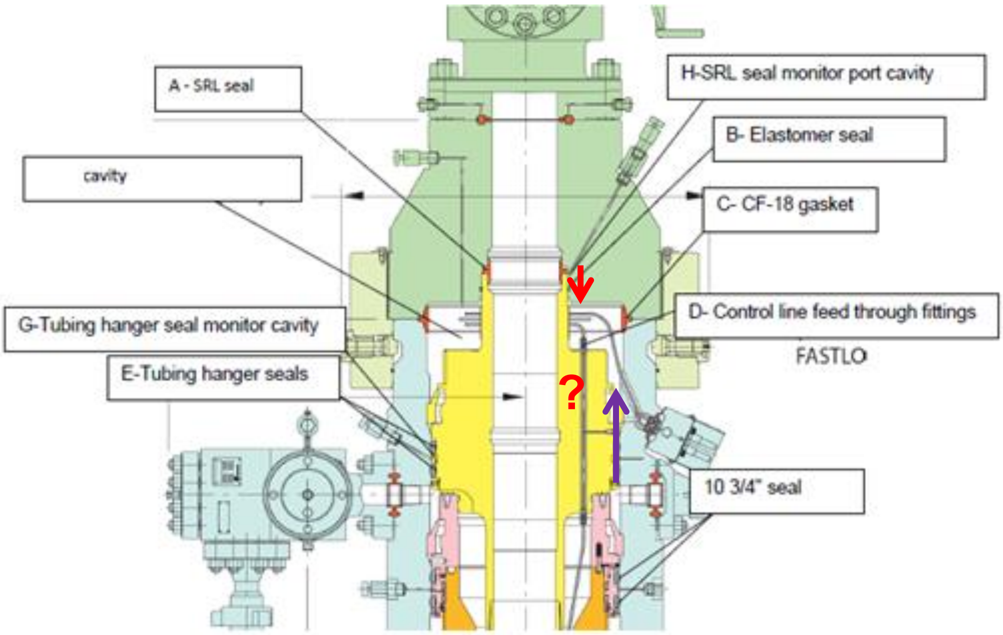


Figure 32 WH illustration of pressure build up in C1

This case does give unambiguously indications of the origin of the leakage, but by evaluating the Cameron test results as well as the pressure history of the well, it is possible to conclude that the integrity between A-annulus and C1 is intact. (Due to the low leak rate/ pressure build up) However the pressure at the tubing hanger monitor port is slowly rising.

9.2.2.2. Historic build up in B-annulus and 10 ¾" seals

A small pressure build up has been detected, but no gas where sampled under the last pressure bleed off. See Figure 33

- B-annulus pressure increased by 3bar in 2 months
- 10 ¾" casing hanger seal pressure increased by 15 bar in 2,5 months

Actions:

- Gas bled off, but not sampled
- B-annulus filled with treated brine

- VAL-TEX 80 pumped inside, excess grease removed with hydraulic oil and pressure tested to 150 bar nitrogen. The test was cleared ok.

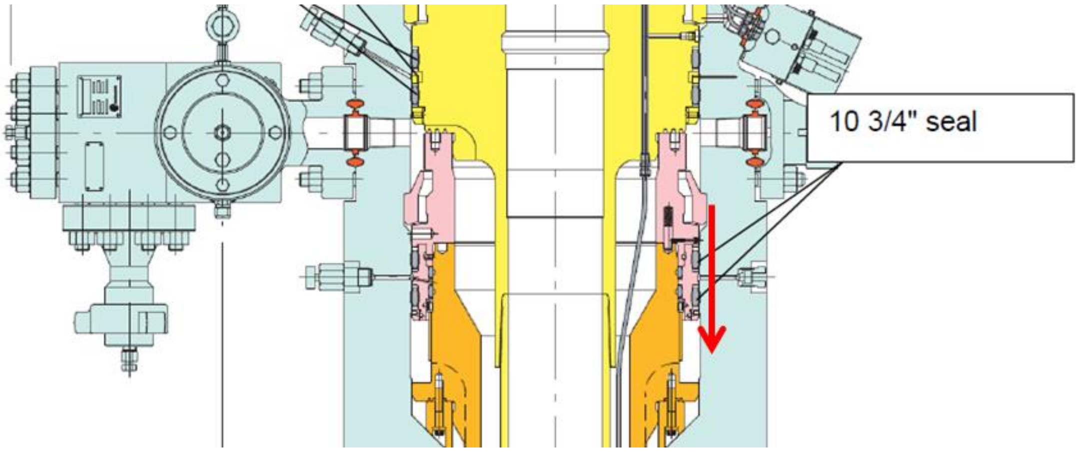


Figure 33 B-annulus and 10 3/4" seals leakages

9.2.2.3. *Cameron test August 2012*

Table 2 shows a summary of the tests performed by Cameron in August 2012 on the well A-1. Further details of the tests are shown in the appendix.

Table 2 Summary Camreon test August 2012

	Seals	Integrity	Reference
SRL seal monitor port cavity	SRL seal	YES	Test nr 3-Some crude oil where detected during pressure bleed off Test (6)- Stable pressure ~24 bar
	Elastomer seal	Inconclusive	Need more info – the SRL seal test
C1	Elastomer seal		
	CF-18 gasket	YES	Daily «sniffing round». No indications of leakages
	Exit block	YES	Daily «sniffing round». No indications of leakages
	Control line feed thru fittings	NO	Tester (1) & (2)- show pressure build up in C1but a stable pressure in TH-seal. By us of the exclusion method- leakages through control line fittings Plott (6) shows a long term pressure increase in C1. Test (7) shows that gas is bled off from cavity
	TH seal-upper	YES	Test (2) indicates that integrity of the upper seal is ok with 120 bar. 12 bar in C1 and 126 bar in A-annulus
Tubing hanger seal monitor port cavity	TH seal -upper		
	TH seal lower	YES	Plot (6) shows that the pressure increases from 6- bar in two months. The pressure in C1 has during that time frame reached 35 bar several times
10 ¾" seal monitor port cavity	10 ¾" seal - upper	YES	Plot (5) Stable pressure ~95 bar +/- 5 bar for 1,5 months Stable A-annulus pressure ~130bar +/- 5 bar
	10 ¾" seal - lower	YES	Plot (5) Stable pressure ~95 bar +/- 5 bar for 1,5 months Stable B annulus pressure ~45 bar +/- 2 bar
13 3/8" seal monitor port cavity	13 3/8" seal- upper	YES	Plot (5) shows a pressure increase from 14-16 bar in 1,5 months Stable B annulus pressure ~45 bar +/- 2 bar
	13 3/8" seal- lower	YES	Plot (5) shows a pressure increase from 14-16 bar in 1,5 months No functional C annulus

Comments to the tests:

- Hydraulic oil were bled off in test nr 7, otherwise the fluid that was bled off was either crude oil or gas

9.3. Case Study, well A-2

The case study of the well A-2 at the Oseberg East follows.

9.3.1. History of the well A-2

- A-2 is an oil producer with gas lift
- The well was originally drilled and completed in 2000
- Recompleted Jan 2012
- Internal WH/XT leaks was first observed in Jan 2012
- There has also been documented pressure build up on C annulus
- Cameron performed seals tests Aug 2012

A schematic of the completion is shown in Figure 34 below. The monitoring well barrier schematic of the well is shown in Figure 35.

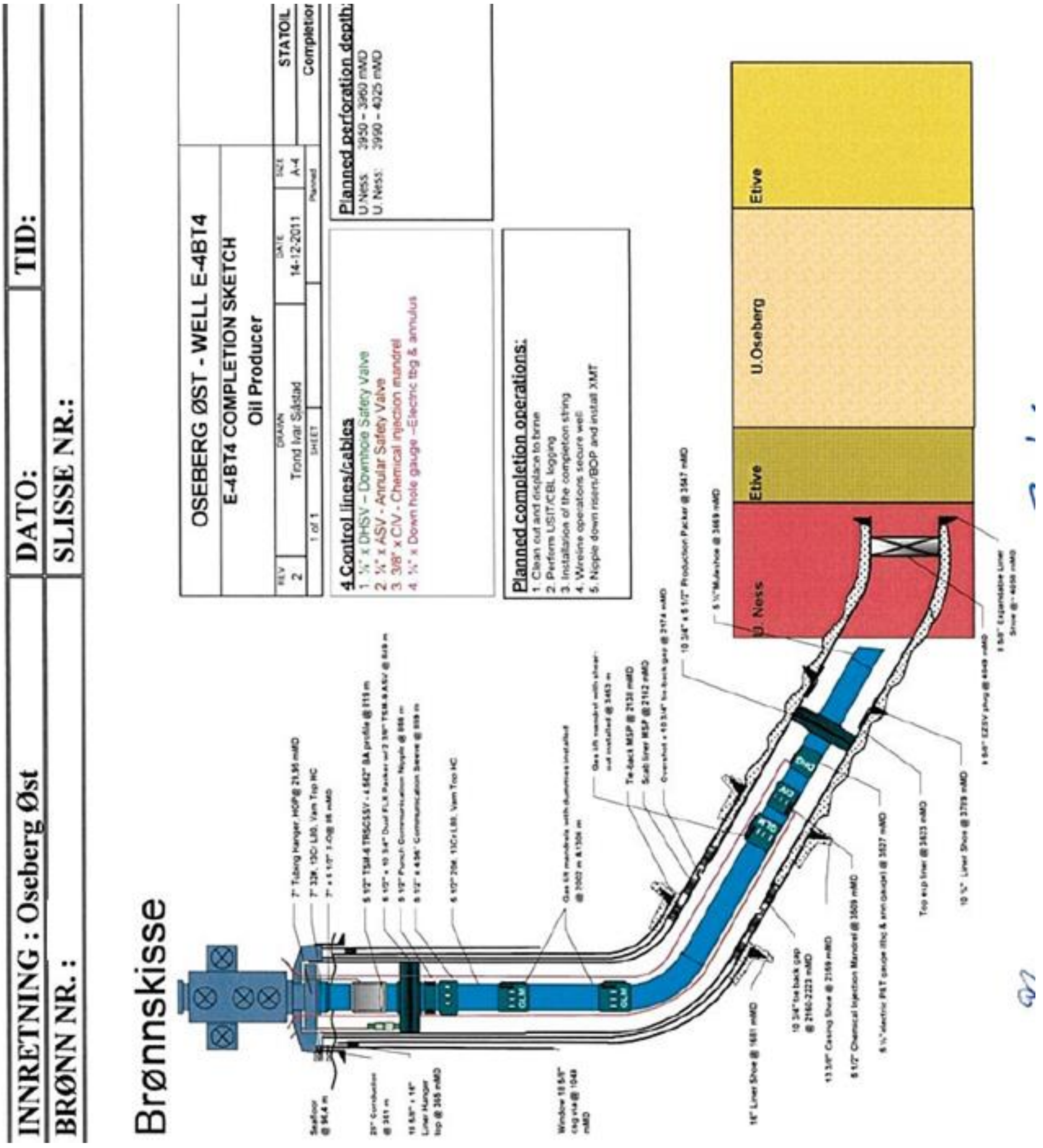


Figure 34 Well scetch A-2

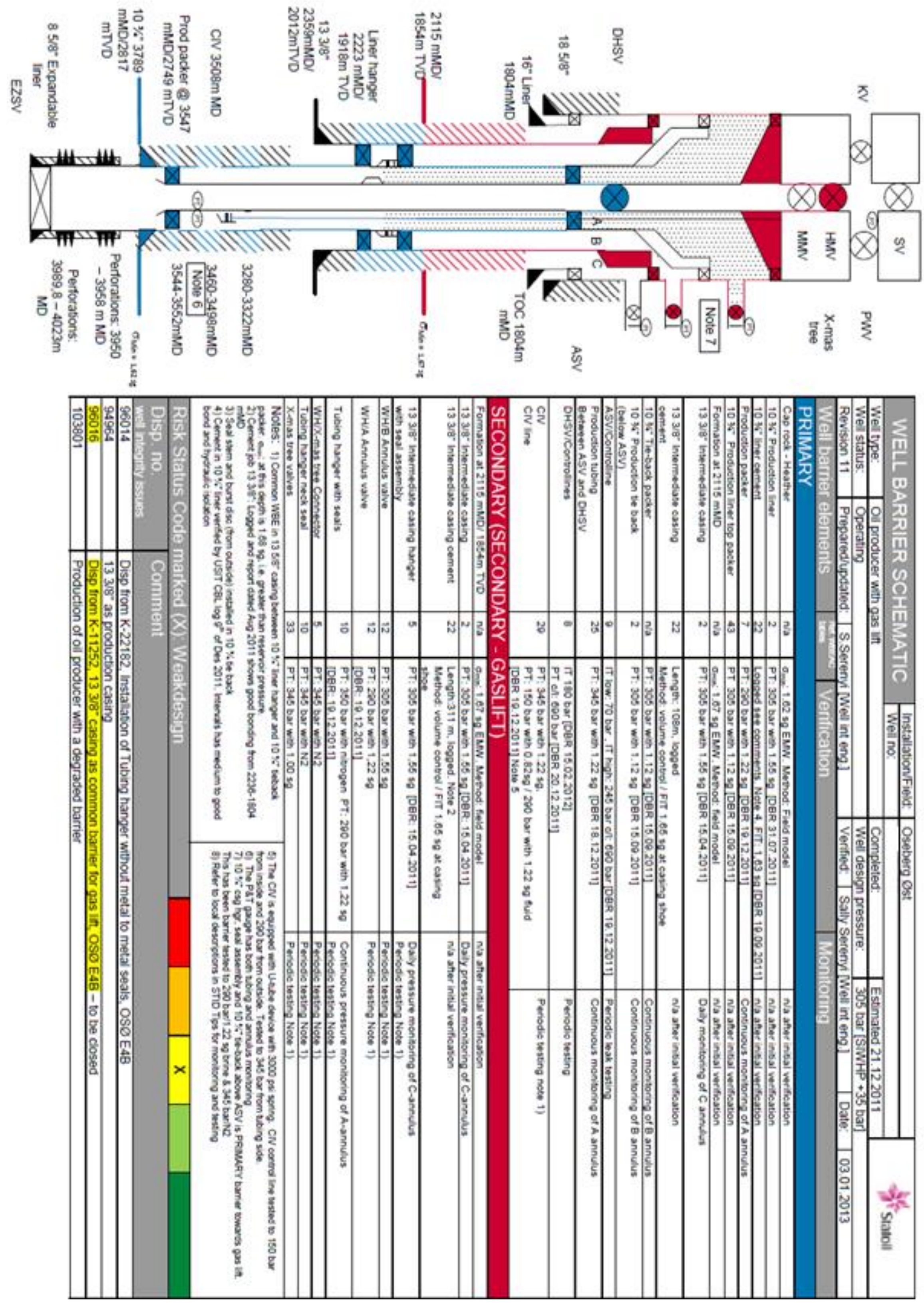


Figure 35 WBS E-4B

9.3.2. Deviation history

According to the Statoil system for deviations the following deviations have been registered for the well A-2 (Synergy numbers)

Table 3 Risk status code, A-2

Risk Status Code marked (X): Weakdesign				X		
Disp. no. well integrity issues	Comment					
96014	Disp from K-22182, Installation of Tubing hanger without metal to metal seals, OSØ E4B					
94964	13 3/8" as production casing					
96016	Disp from K-11252, 13 3/8" casing as common barrier for gas lift, OSØ E4B – to be closed					
103801	Production of oil producer with a degraded barrier					

Based on the exclusion method, analysis of pressure trends (Figure 36 and Figure 37) as well as the tests performed by Cameron in August 2012, diagnosis of the wellhead leakages over the last years has been made. The main discovery will be presented

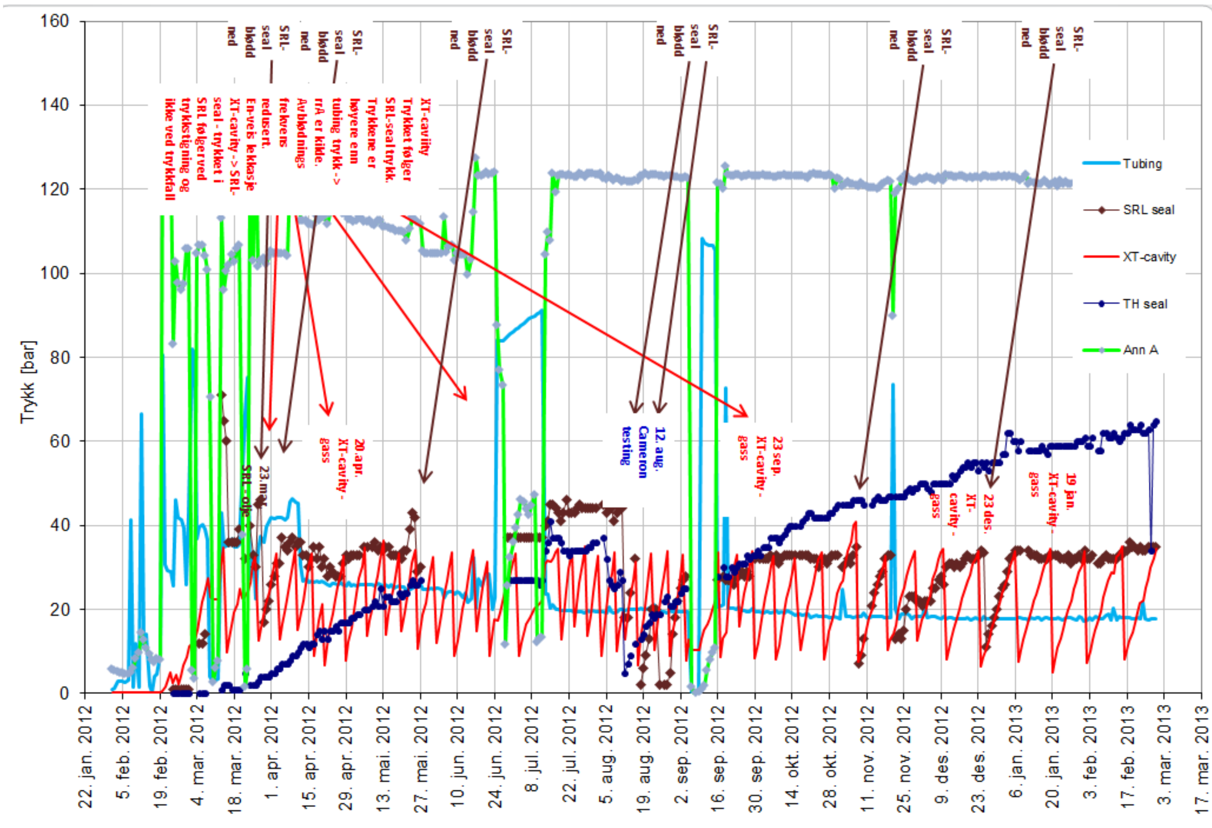


Figure 36 Pressure trends in WH/XT, 1, A-2

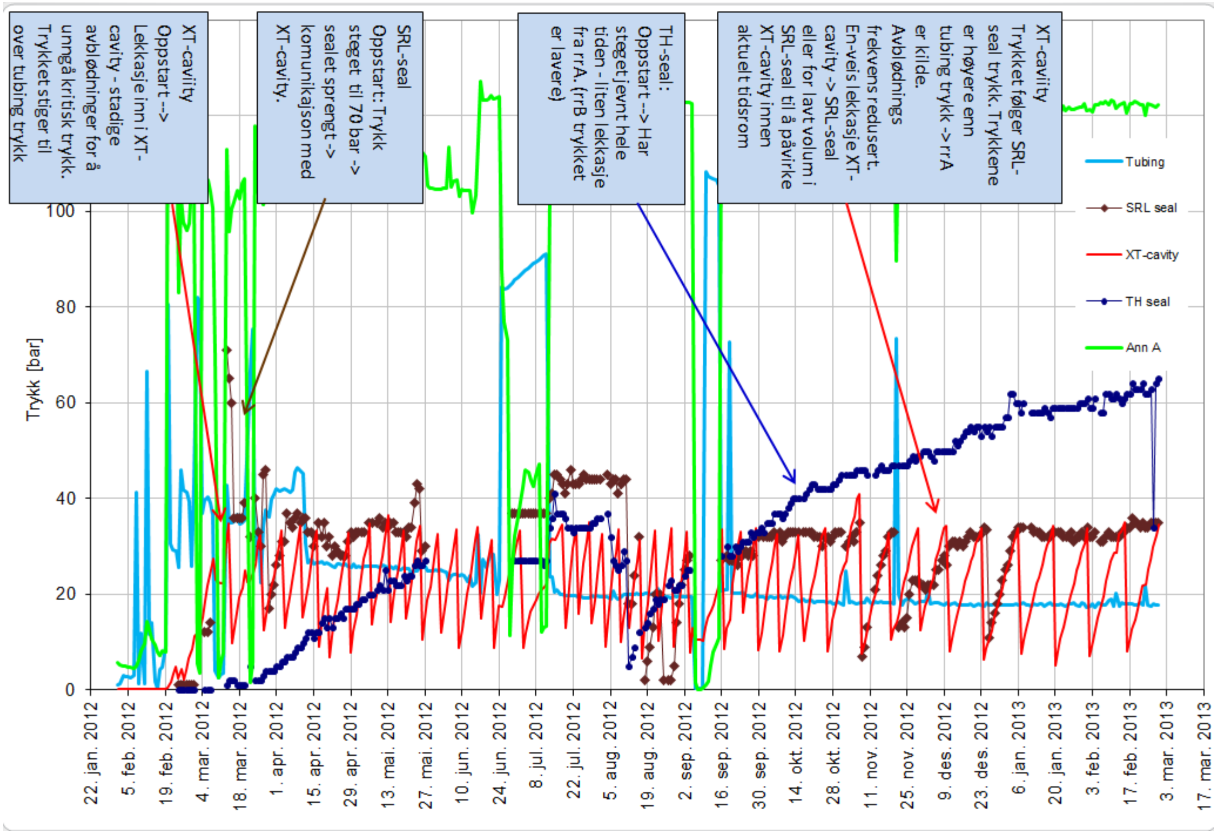


Figure 37 Pressure trends in WH/XT, 2, A-2

Comments to Figure 36 and Figure 37

- The pressure in C1 follows the pressure in SRL-cavity. The pressure is higher than the tubing pressure. Hence, the source of the pressure increase must be the A-annulus.
    - The frequency of the manual pressure reliefs are reduced
    - This is a one-way leakage from C1 to the SRL-C as the pressure in the SRL-cavity follows the pressure at increases from C1 but not reductions from C1. The volume of the SRL-cavity (less than 100ml) is not sufficient to affect the pressure in C1 (25l)
- The pressure at the tubing hanger (S3) is slowly rising after production starts. It is indicated as small leakage from the A-annulus. (The pressure of the B-annulus is lower)
- At production start the pressure in SRL-cavity increases to 70 bar. Hence the SRL seal must have been deformed and communication between C1 should be the consequence.

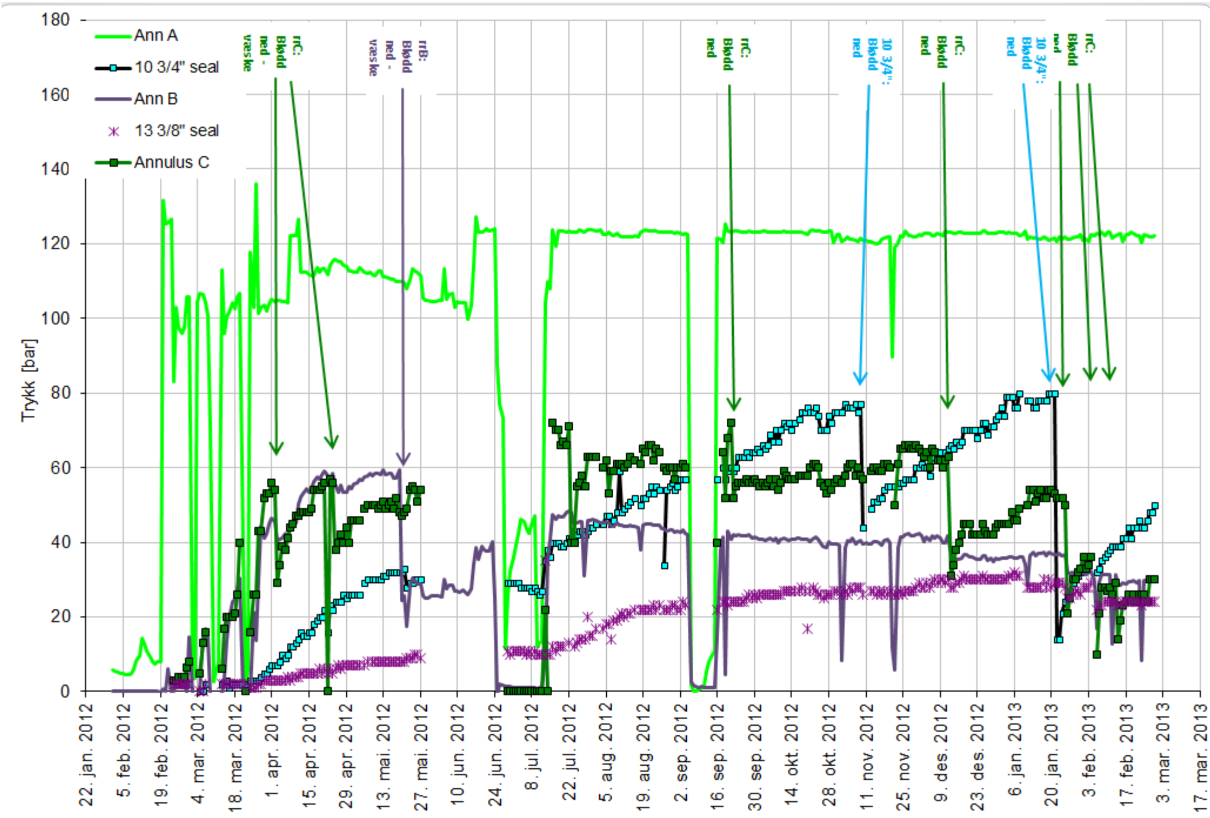


Figure 38 Annuli trend, 1, A-2 (Sally Sereny)

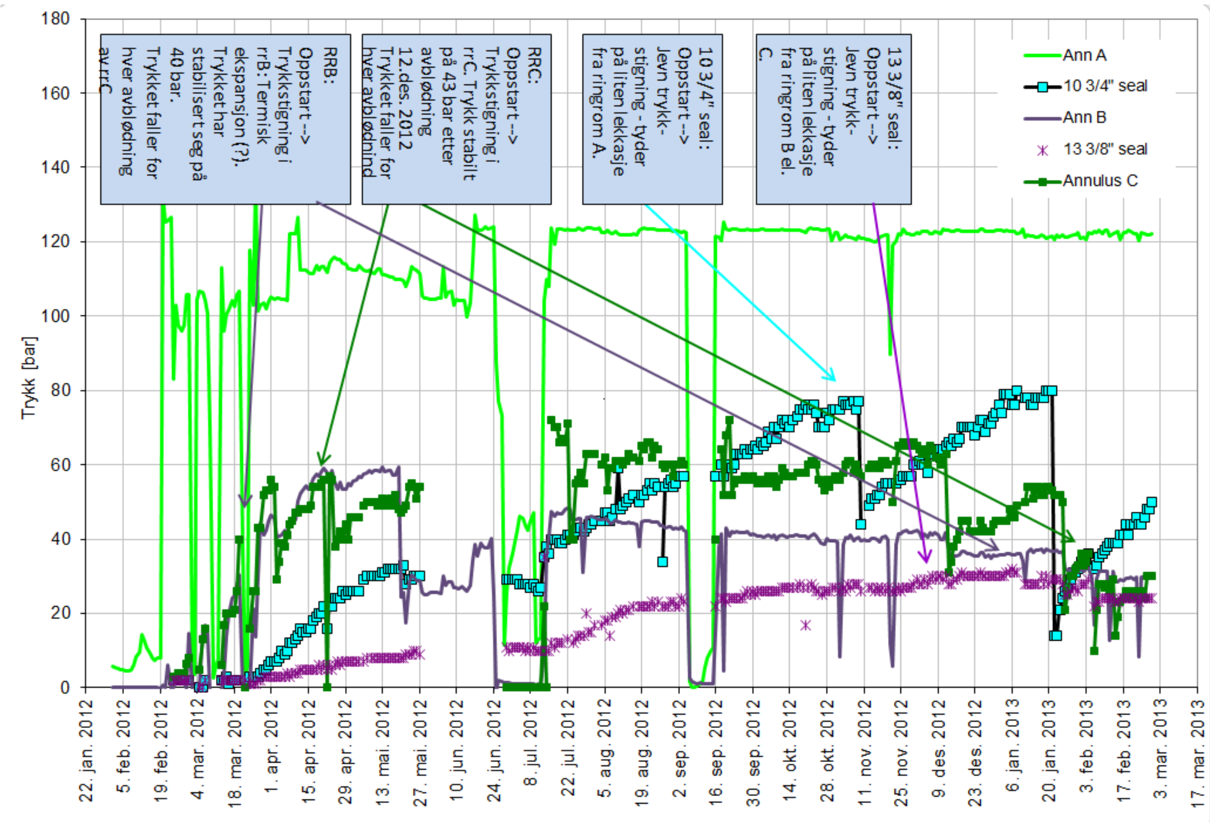


Figure 39 Annuli trend, 1, A-2 (Sally Sereny)

Comments:

- The B-annulus pressure increases after the first production start. This might be temperature induced pressure.
- At production start an even pressure increase at the 10 ¾” seal is observed. Might indicate at small leakage from B-annulus or C-annulus

9.3.2.1. Historic pressure build up in C1

- Pressure in SRL-cavity higher than tubing pressure. See
- Pressure in C1 is rising
    - Leakrate 1.9 l/hr
- Leak path: from C1 to SRL, not from SRL to C1. Hence the pressure build up must come from the A-annulus
- Cameron test Aug 2012 proved that the leakage did not come from the tubing hanger itself
- Conclusion: Leakage from A-annulus to C1 goes via the control line fittings. See Figure 40.

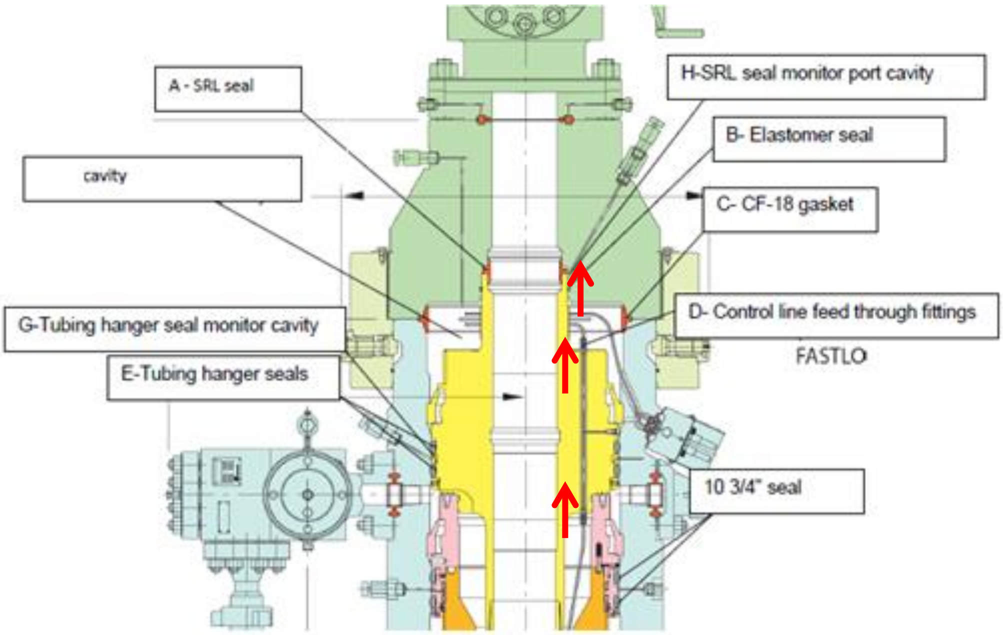


Figure 40 WH illustration of pressure build up in C1 A-2

9.4. Case Study well A-3

The case study of the well A-3 at the Oseberg East follows.

9.4.1. History of the well A-3

- Well A-3 is an oil producer with gas lift
- The wall was drilled and completed Aug-2000
- Internal WH/XT leaks first observed sept ’10
- In Aug 2012, leak into C1 escalated
- Approved deviation in place to produce the well
- Recompleted in april 2013

Since the well was recompleted during the work of this thesis the analysis has been performed based on the status of the well in February 2013.

A schematic of the completion is shown in Figure 41 below. The monitoring well barrier schematic of the well is shown in Figure 42.

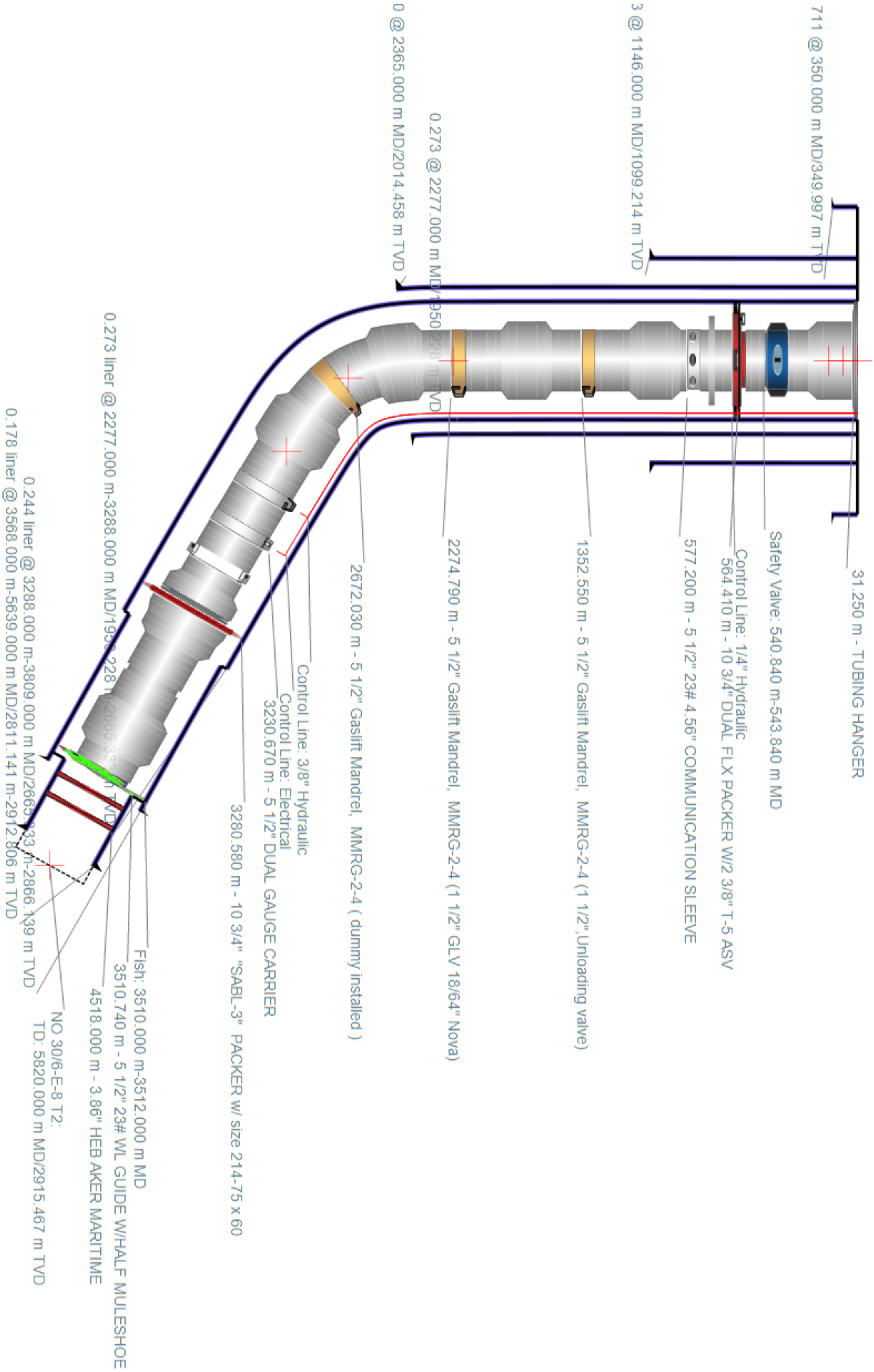
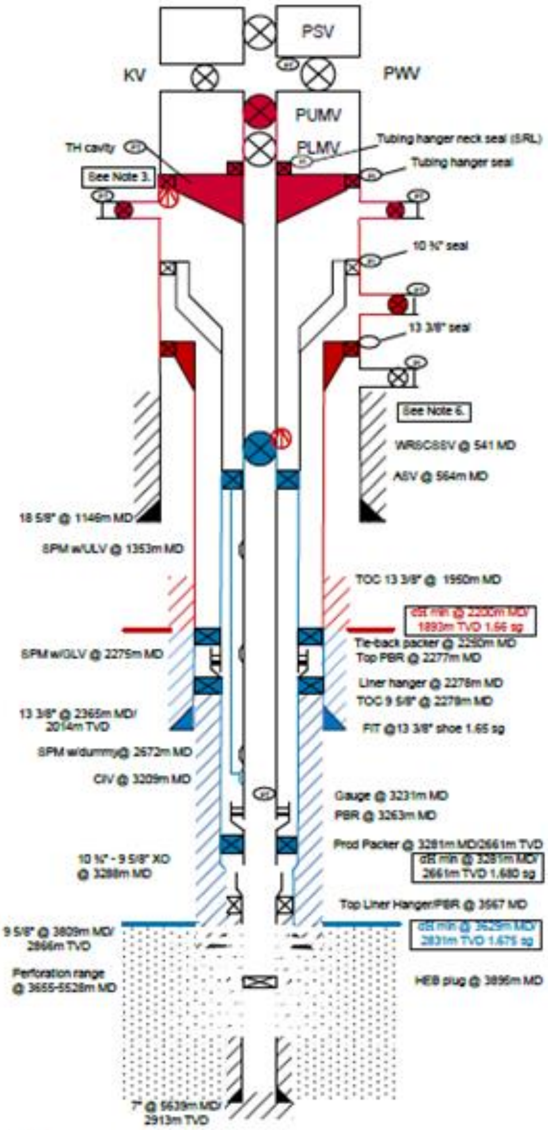


Figure 41 Compleation A-3

WELL BARRIER SCHEMATIC

Monitoring



Notes:

1. 10 ¾" x 9 5/8" TOC: Volume control, ref old WBS & FWR drawing.
2. 13 3/8" TOC: Volume control, ref old WBS. FWR: cement job ok.
3. Leakages in WH/XT, see Disp.
4. CSD Rev 1.06: CIV line confirmed plugged Sept 2008.
5. Sh_min Oseberg Øst (XLOT, minifrac, mudloss) table Sept 2010.
6. Leakage in DHSV control line, se deviation permit.
7. 10 3/4" csg hgr, seal assembly and 10 3/4" tie-back above ASV is primary barrier towards gas lift. This is monitored by continuous pressure monitoring of B -annulus and periodic monitoring of seals.

Well data			
Installation/Field:		Oseberg Øst	
Well no:		Completed date:	02.08.2000
Well type:		Oil producer with gas lift	
Well design pressure:		345 bar	
Revision no:	9	Date	20.12.2012
Well status:		Operating	
Prepared/ Verified:		ExproSoft/H.P.Jenssen	
Approved:		Ove A. Ulvøy	
Updated:		S.Serenyi (well integrity eng) 20.12.2012	

Well barrier elements	Ref. WBEAC tables	Monitoring of barrier elements
PRIMARY (Primary barrier toward gas lift)		
Formation at Cap rock	n/a	n/a after initial verification
10 ¾" x 9 5/8" Production liner cement	22	n/a after initial verification
10 ¾" x 9 5/8" Prod. liner	2	n/a after initial verification
10 ¾" Liner hanger packer	43	n/a after initial verification
13 3/8" Casing and cement upto 10 ¾" Tie-back packer	2	n/a after initial verification
10 ¾" Tie-back casing packer	43	Continuous pressure monitoring of B -annulus
10 ¾" Tie-back casing below ASV	2	Continuous pressure monitoring of B -annulus
CIV	29	Periodic leak testing AC: See local work description
ASV	9	Periodic leak testing AC: Max 1.20 bar/30 min.
Production packer	7	n/a after initial verification
Production tubing between ASV and DHSV	25	Continuous pressure monitoring of A -annulus
DHSV (WRSCSSV)	8	Periodic leak testing: AC: Max 1,59 bar/30 min.
SECONDARY (Secondary barrier toward gas lift)		
Formation at 2200m MD/1983m TVD	n/a	n/a after initial verification
13 3/8" Intermediate casing cement	22	n/a after initial verification
13 3/8" Intermediate casing	2	Daily pressure monitoring of C-annulus
13 3/8" Casing hanger with seal assembly	5	Periodic testing/monitoring of seals:
Tubing hanger with seals	10	Continuous pressure monitoring of TH cavity
WH/A- and B-annulus access valves	12	Periodic leak testing AC: See local work description
WH/Annulus injection valve	12	Periodic leak testing AC: See local work description
Tubing hanger neck seals	33	Continuous pressure monitoring of TH cavity
X-mas tree connector	33	Continuous pressure monitoring of TH cavity
X-mas tree valve PMV	33	Periodic leak testing AC: See local work description
X-mas tree valves/body	33	Periodic leak testing AC: See local work description

Risk Status Code:				
		X		

Disp. no. well integrity issues	Comment
103723	Leakages in WH/XT
85328	Injection of scale inhibitor in A-annulus
99960	Leakage in DHSV hydraulic control line

Statoil

Figure 42 WBS A-3

9.4.2.Deviation history

According to the Statoil system for deviations the following deviations have been registered for the well A-3 (Synergy numbers)

Table 4 Risk status code, A-3

Risk Status Code:				
		x		

Disp. no. well integrity issues	Comment
103723	Leakages in WH/XT
85328	Injection of scale inhibitor in A-annulus
99960	Leakage in DHSV hydraulic control line

Based on the exclusion method, analysis of pressure trends (Figure 43 and Figure 44) as diagnosis of the wellhead leakages over the last years has been made. The main discovery will be presented

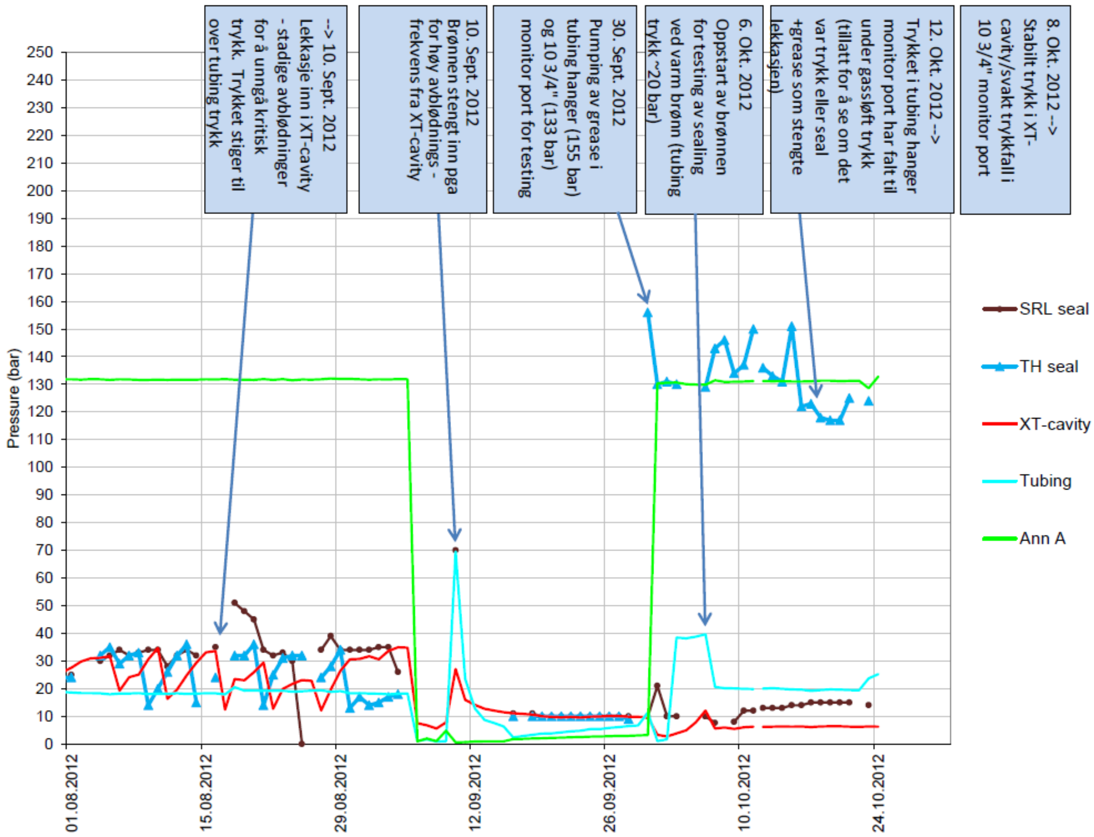


Figure 43 WH trend A-3

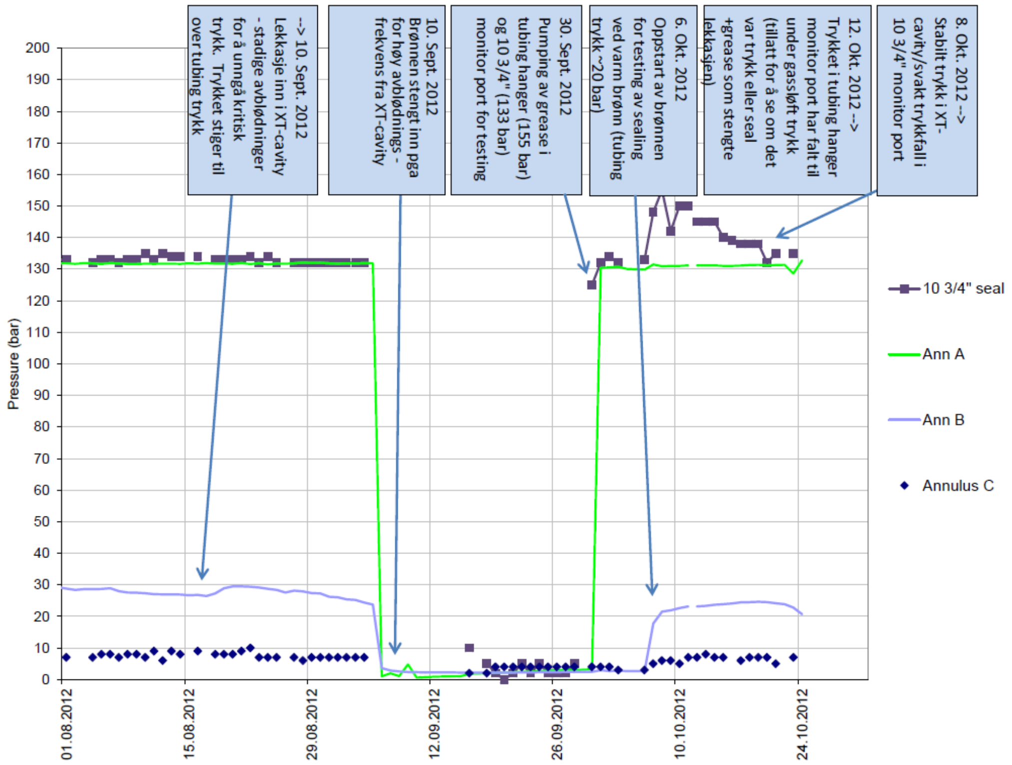


Figure 44 Annuli trend A-3

9.4.2.1. *Historic pressure build up in C1*

See Figure 45.

- Historic build up in 10 ¾" and TH seal monitor port ~ 130 bar
    - Build up seen in C1 Leakrate ~17,8 litres/hr
    - Actions: greased both 10 ¾" and TH seal
- Currently ~130bar seen in 10 ¾" and TH seal monitor ports
- Slow build up seen in XTC today leakrate ~0,2 litres/hr

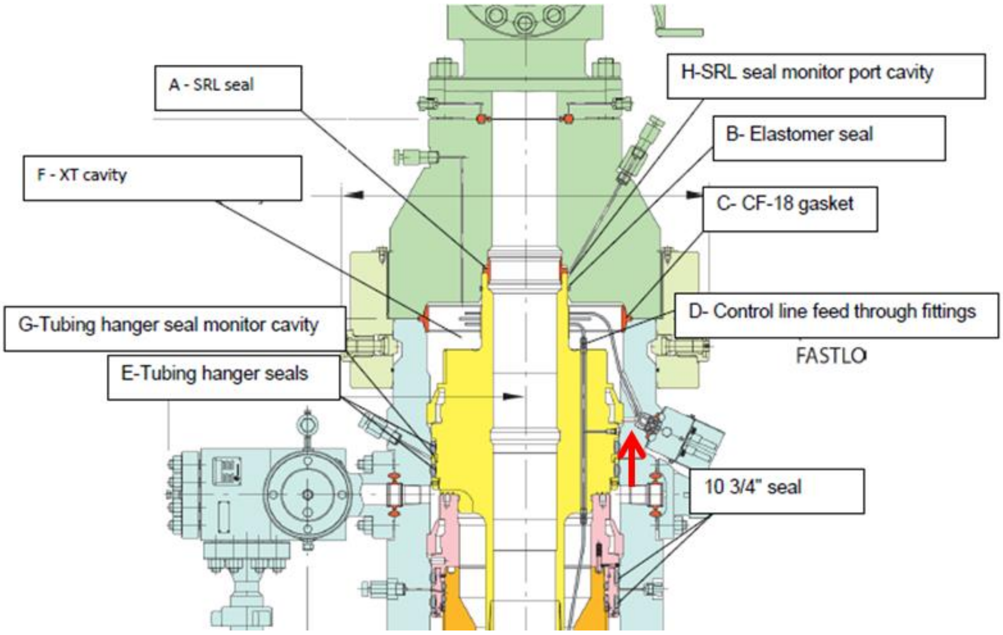


Figure 45 WH illustration of pressure build up in 10 3/4" seal and TH seal monitor port, A-3

See Figure 46

- Historic pressure-build up seen in SRL seal monitor port.
- Currently SRL seal monitor port is following tubing pressure. It is a one way leak since it builds up when WH pressure is high, but does not bleed off when WH pressure is lower

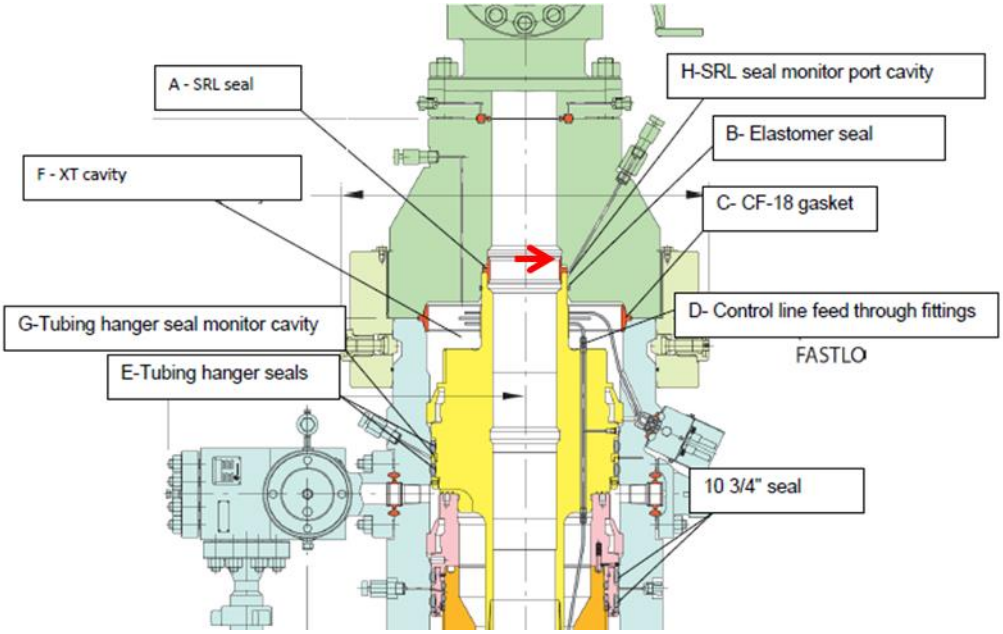


Figure 46 WH illustration of pressure build up in C1, A-3

9.5. The well barriers

The well barrier elements on well A-1, A-2, A-3 in connection to C1 are identical for all three wells and will now be discussed.

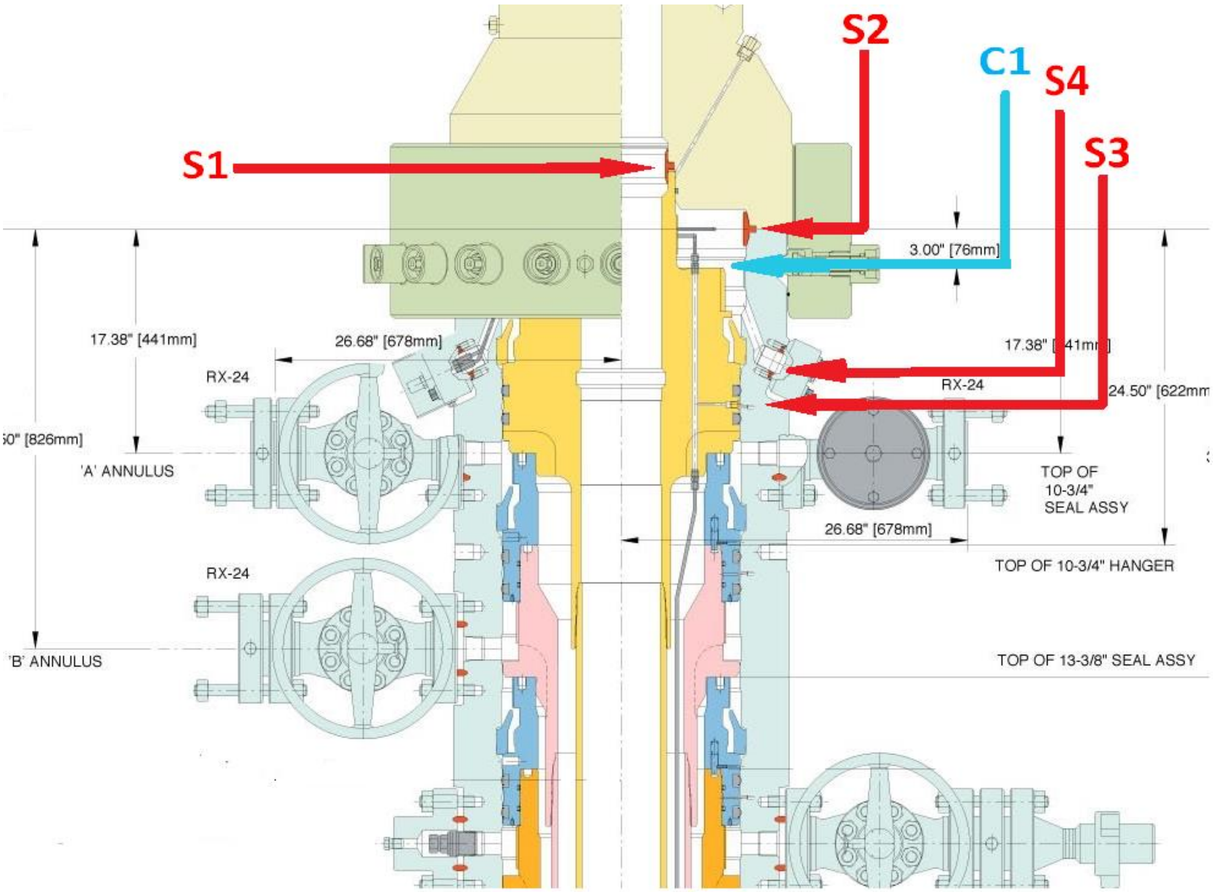


Figure 47 WH Oseberg East (Cameron)

It is required to have two independent and tested barriers. This is fulfilled by:

Barrier 1 (annulus): ASV is a valve located in A- annulus. It is held open by hydraulic pressure and it is possible to leak test it by bleeding off the pressure above the valve.

Barrier 1 (tubing): DHSV is a hydraulic operated valve, located in the tubing. It is held open by the hydraulic pressure, and it is possible to test the valve by closing it, and then bleed of the pressure on top of it.

Barrier 2 (annulus, S3): This is a metal seal assembly which is designed like a reverse "V" and has increasing sealing capacity along with increasing annulus pressure. The sealing capacity of the assembly can be measured by monitoring the pressure of cavity (C1).

Barrier 2 (tubing, S1): This is a SRL-seal which seals between tubing head and XT. It is possible to monitor the integrity of S1 by monitoring the pressure between S1 and an elastomer seal located between S1 and C1.

Barrier 3 (S2 & S4): Both S2 and S4 are metal to metal seals. It is an extra barrier between the reservoir and the atmosphere and can be tested by pressuring up the cavity. This test is however associated with a risk to damage S1.

Barrier	Annulus	Test possibilities	Tubing	Test possibilities
Primary	ASV	Pressure tested by closing the valve and bleed of the P	DHSV	Pressure tested by closing the valve and bleed of the P
Secondary	Metal sealassembly between tubing head and tubing hanger (S3)	Monitoring possibility, but a P test will not give an unambiguously result	Metal sealassembly between tubing head and XT (S1)	Monitoring possibility, but a P test will not give an unambiguously result
Third	Metal seal assembly between tubing hanger and XT (S2) Metal seal assembly, exit block (S4)	Pressurizing C1. (introducing risk of damaging S1)	Metal seal assembly between tubing hanger and XT (S2) Metal seal assembly, exit block (S4)	Pressurizing C1. (introducing risk of damaging S1)

Table 5 Barrier elements and test possibilities

A sketch of the system boundaries shown on Figure 48

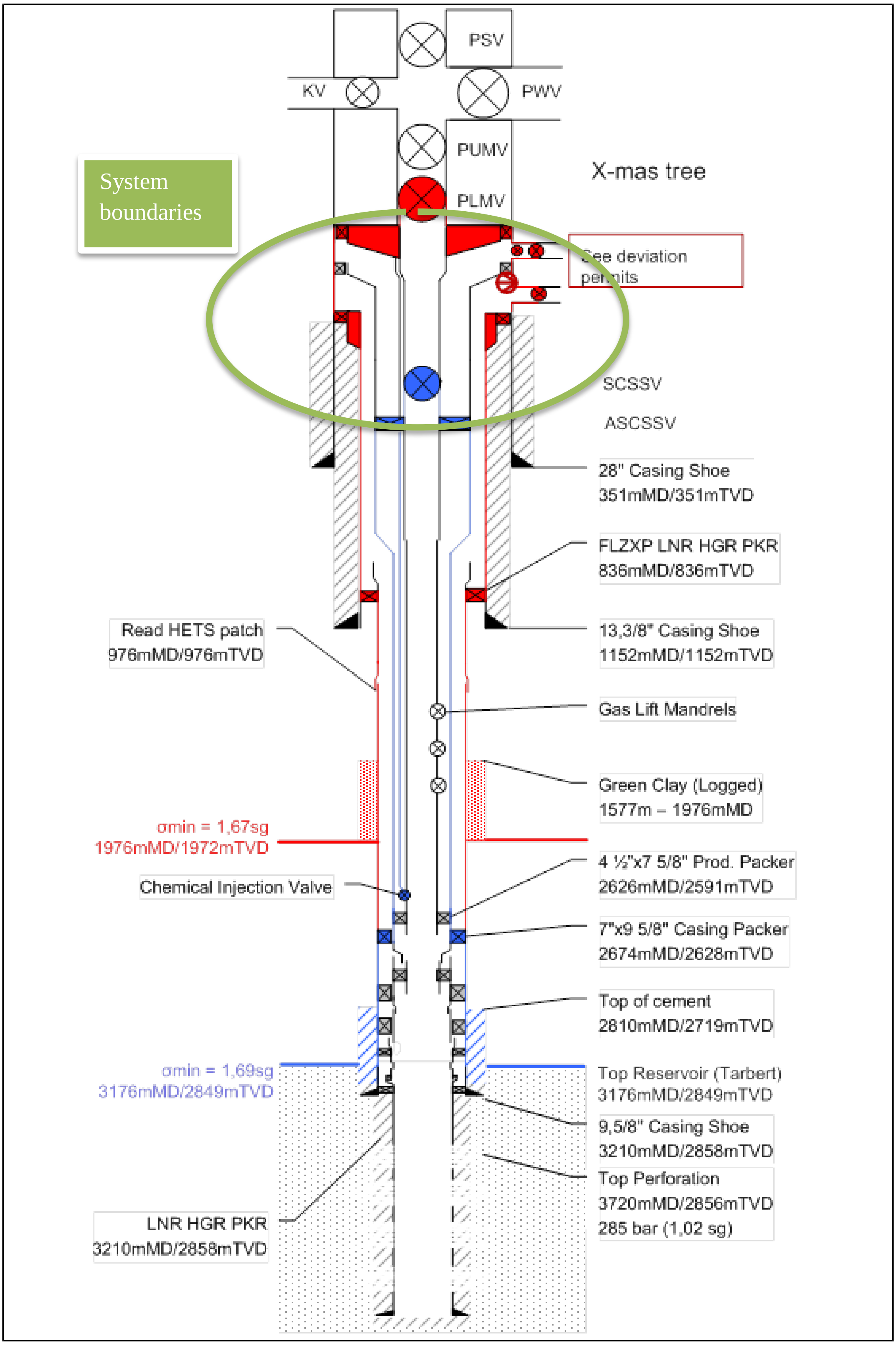


Figure 48 Barriers of A-1

9.5.1.Discussion of the barriers

Barrier 1, the ASV and the DHSV, are independent and gives clear indications of errors when testing.

Barrier 2 in tubing (S1) and annulus (S3) are independent, separate seal assemblies. In case of a leakage through these seals, both of them will pressurize the cavity (C1). In order to determine whether it is S1 or S3 that is leaking, additional pressure bleed offs in annulus or tubing have to be performed.

Barrier 3 (S2 and S4) will normally not be exposed for hydrocarbons, unless S1 or S3 is leaking. The sealing functionality of S2 and S3can be tested by pressurizing the cavity. This test is however considered to be a possible risk factor of damaging S1. S1 are rated to 345bar from the tubing side. Cameron does not guarantee for pressure sealing in the opposite direction (from C1). A maximum pressure limit of 10 % of the WH design pressure (345bar) is however used as a common limit for the pressure on S1 from the C1 side. (Based on recommendations from FMC on other similar Statoil installations)

There exist an elastomer seal behind S1 on the cavity side which has full rating (345bar) from both directions. The elastomer seal is however not considered to have the same reliability as the metal seal assembly. There exists therefore a monitor port to measure the pressure between the SRL-seal and the elastomer seal in S1. As long as the elastomer seal is functioning it will however protect S1 from the high pressure introduced from pressure testing of S2 or S4.

9.5.1.1. Conclusion, discussion of the barriers

A review of the barriers on the gaslift wells A-1, A-2, A-3 concludes that the well has in the first place two independent barriers that are possible to test. S2 and S4 give an additional third barrier and increased safety against leakages to the atmosphere in case S1 or S3 fails. It is not possible to test S2 and S4 with an unambiguous result, without introducing a risk to damage S1.

9.6. Evaluation of the barriers with a leakage in the SRL seal (S1)

Leakages in S1 have among other been detected on the wells A-1 and A-2.

A leakage between the tubing hanger and wellhead will weaken the secondary barrier and in worst case result in failure of the secondary barrier. In this case the secondary barrier element, S1, is not intact and not possible to test directly. (With reference to Figure 47 and Table 5) A leakage to the atmosphere is prevented by S2 and S4 being intact. The same applies for all test ports in connection to C1.

It is possible to continuously monitor the situation by monitoring the pressure in C1and SRL-test port and bleed of the pressure when it reaches a predefined limit.

The remedy for such leakages might be to inject VAL-TEX80 over the seal assembly S1. This is however only a temporary solution, as the results of the treatment are not unambiguous and it is common to eventually see that the pressure increases in cavities again. Another negative effect of using VAL-TEX80 or other grease sealants is that the grease blocks for further use of pressure monitoring in the specific area.

The status of wells with a leakage in S1 can be summarized:

- Two independent barriers in the tubing are still intact.
- It is possible to test them both

In the case of a leakage through S1, C1 could be exposed to the following pressure (See Table 6):

- Well flowing pressure

Table 6 Seals exposed to the following pressures

Barrier	Failure of barrier in A-annulus	Exspected introduced pressure to C1, due to barrier element failure	Failure on barrier in tubing	Exspected introduced pressure to C1, due to barrier element failure
1	ASV	P from injection gas	DHSV	Well flowing P
2	Metal sealassembly between tubing head and tubing hanger (S3)	1. P from injection gas 2. Controlline P	Metal sealassembly between tubing head and XT (S1)	Well flowing P
3	Metal sealassembly between tubing hanger and XT (S2) Metal seal assembly, exit block (S4)	1. P from injection gas 2. Well flowing P 3. Controlline P	Metal sealassembly between tubing hanger and XT (S2) Metal seal assembly, exit block (S4)	1. P from injection gas 2. Well flowing P 3. Controlline P

9.7. Evaluation of the barriers with a leakage in the tubing hanger seal and through control line fittings (S3)

Leakages in S3 have among other been detected on the wells A-1, A-2 and A-3.

A leakage between the tubing hanger and wellhead will weaken the secondary barrier and in worst case result in failure of the secondary barrier. In this case the secondary barrier element, S3, is not intact. (With reference to Figure 47 and Table 5) A leakage to the atmosphere is prevented by S2 and S4 being intact. The same applies for all test ports in connection to C1.

It is possible to continuously monitor the situation by monitoring the pressure in C1 and bleed of the pressure when it reaches a predefined limit. In order to define whether it is the tubing hanger seal, control line fittings or the control line fittings that are leaking, additional pressure bleed offs and build ups through tubing hanger test port has to be performed.

The remedy for such leakages can be to inject VAL-TEX80 over the seal assembly S3 if it is the tubing hanger seal that is leaking.

The status of wells with a leakage in S3 can be summarized:

- Two independent barriers in the tubing are still intact.
- It is possible to test them both, but the test on S3 is however considered to be a possible risk factor for introducing damage on S1.

In the case of a leakage through S3, C1 could be exposed to the following pressures (See Table 6):

- Pressure from the injection gas
- Control line pressures

9.8. Evaluation of the barriers with temperature induced pressure in C1

In addition the leakages that are diagnosed on well A-1, A-2 and A-3 it is evaluated that the temperature induced pressure in cavities may cause damages on the seals and WH.

A temperature increase in the wellhead, due to for example production start, will result in a pressure increase in C1. Assumed that the temperature in C1 follows the temperature of the WH. Simulations of this scenario have been performed and an extract of the calculations are shown in the tables below. (For further details, see appendix).

It is assumed that the cavity is either filled by:

a. Oil or water (Table 7)
b. Air or gas (Table 8)

The method of “Temperature induced B-annulus pressure” has been used in the simulation of Table 7.

From the method of “Temperature induced B-annulus pressure”, Eq 4:

$$P = \left(\frac{-\propto}{c}\right)(T_3 - T_1)$$

Where: c= compressibility of the fluid

$\propto$= heat expansion coefficient

In the simulation it is assumed that the relation between the compressibility of the fluid and the heat expansion coefficient are the same for oil and water.

$$\left(\frac{-\propto}{c}\right)_{water} \approx \left(\frac{-\propto}{c}\right)_{oil}$$

The method of ideal gas has been used for simulations of Table 8 and thereby it is assumed that the gas is ideal.

For both of the simulation methods it is assumed that C1 has fixed system boundaries and hence, no fluid will escape from C1 during the temperature/pressure increase.

Table 7 Temperature induced pressure in C1 (oil or water filled).

New pressure in C1 due to wellhead temperature increase (bara)	951	751	501	401	351	341	301	151	51
Initial temperature in C1 (°C)	0	0	0	0	0	0	0	0	0
Wellhead temperature (°C), increase from 0°C	95	75	50	40	35	34	30	15	5
New pressure in C1 due to wellhead temperature increase (bara)	901	701	451	351	301	291	251	101	1
Initial pressure in C1	5	5	5	5	5	5	5	5	5
Wellhead temperature (°C), increase from 0°C	95	75	50	40	35	34	30	15	5
New pressure in C1 due to wellhead temperature increase (bara)	801	601	351	251	201	191	151	1	-99
Initial pressure in C1	15	15	15	15	15	15	15	15	15
Wellhead temperature (°C), increase from 0°C	95	75	50	40	35	34	30	15	5

Table 7 shows that at only a temperature increase of 35°C will give a pressure of 351bar which is higher than the design rating of 345 bar of the WH. Hence a larger temperature increases then 34°C will cause the pressure to increase sufficiently to damage the seals and/or the entire WH.

The simulation did also show that a temperature increase of only 3,5°C will cause the pressure in cavity (when it is completely filled with oil or gas) to increase sufficiently to overcome the predefined rating of 35 bar for unidirectional seals (S1). (S1 is designed to see 345bar from the tubing side, but not from side of C1)

Table 8 Temperature induced pressure in C1 (gas/air filled or with a mixture of gas/air and water/oil).

Start production 14.02.2011						
New pressure in C1 due to wellhead temperature increase (bara)	5,15	4,92	4,70	4,47	4,25	4,13
Initial pressure in C1 (bar)	4	4	4	4	4	4
Initial temperature in C1 (°C)	82	82	82	82	82	82
Wellhead temperature (°C), increase from 0°C	95	75	55	35	15	5
Revisjonsstans 17.05.2011						
New pressure in C1 due to wellhead temperature increase (bara)	2,30	2,23	2,16	2,09	2,02	1,99
Initial pressure in C1 (bar)	1	1	1	1	1	1
Initial temperature in C1 (°C)	9	9	9	9	9	9
Wellhead temperature (°C), increase from 0°C	95	75	55	35	15	5
12.12.2011						
New pressure in C1 due to wellhead temperature increase (bara)	10,25	9,75	9,25	8,74	8,24	7,99
Initial pressure in C1 (bar)	9	9	9	9	9	9
Initial temperature in C1 (°C)	85	85	85	85	85	85
Wellhead temperature (°C), increase from 0°C	95	75	55	35	15	5
29.06.2012						
New pressure in C1 due to wellhead temperature increase (bara)	17,78	16,87	15,96	15,05	14,14	13,68
Initial pressure in C1 (bar)	13	13	13	13	13	13
Initial temperature in C1 (°C)	12	12	12	12	12	12
Wellhead temperature (°C), increase from 0°C	95	75	55	35	15	5

Table 8 shows a more realistic case as it is more likely that C1 will either be filled with air/ gas or with a mixture of air/gas and oil/water. In the case where C1 might be filled with a mixture of liquid and gas, the gas will contribute as the controlling force in pressure calculations since it is more compressible than water or oil. Hence the method of “ideal gas” can also be used for the simulation of C1 filled with a mixture of air/gas and oil/water.

A pressure increase of 5 bar is the highest simulated value for temperature induced pressure increase

In the case of pressure increase above 34,5 bar the following may occur:

- Leakage out through the test ports to the atmosphere
- Leakage out exit block
- Leakage through SRL-test port
- Leakage through SRL seal to tubing
- Leakage through tubing hanger seal to A-annulus
- Leakage through control line fittings

In addition to C1, there exists smaller cavities in the WH, which may suffer from temperature induced pressures.

- SRL-cavity, less than 100ml
- TH-seal cavity, less than 200ml
- 10 ¾”-seal cavity, less than 200ml

Due to the small volumes, the pressure in those cavities will increase more rapidly and thereby may cause damage on the connecting seals.

9.9. Fire integrity on the wellheads at Oseberg East

As a consequence of the requirements from NORSOK and API, S1, S2, S3 and S4 should be fire-resistant. The seal assemblies should withstand an external fire and have a minimum of leakages after the exposure of the fire. This requirement is under normal circumstances met by the metal seal assemblies.

The fire resistant requirement is however not met on wells with leakages from S1, S3 or CL. The treatment with VAL-TEX80 cannot be considered to satisfy this requirement.

The test ports in connection to C1 are not fire resistant. To compensate for this, a fire-jacket around the wellheads is used.

9.10. Danger indications under normal operations

9.10.1. Escalation of the leakage to the atmosphere

The cavity C1 fills up with gas due to the leakage in S1, S3or CL. The size of the leakage through S1, S3 or CL determines how fast the pressure increases in C1. The total volume of C1 is 15 liters and the pressure build up could take anywhere from a few hours to several days.

The gas in C1 will pressurize and be exposed to a number of possible leak paths towards the atmosphere:

- Test ports
- S2
- S4

S2 and S3 are reliable metal seal assemblies which under normal operation of the well should have a low probability for leakages. (Wellmaster)

The plugs in the test ports are on the other hand evaluated to have a higher probability for leakages. It has been found that the plugs turn themself out of the ports due to vibration. It has also been found that “lock tight” is not a reliable method to lock the plugs.

The leakage area will be very small as long as the plugs are still tightened to the test port. 1mm^2 hole opening has been used as the smallest area of leakage. The rates of leakage at different pressures in C1 are shown in the table below: (The values of the pressures are picked from the calculated values under "Evaluation of the barriers with temperature induced pressure in C1"

Table 9 Leak rates at different pressures in C1 gas filled. Several calculations in appendix

Pressure (pa)	Density methan (kg/m3)	Leak rate (m3/s)	Leak rate (kg/s)
514642	2,4	0,004	0,0011
230480	2,4	0,003	0,0007
1025129	2,4	0,006	0,0015
1778397	2,4	0,008	0,0020

Table 10 Leak rates at different pressures in C1 oil/water filled. Several calculations in appendix

Pressure (pa)	Density oil (kg/m3)	Leak rate (m3/s)	Leak rate (kg/s)
95100000	0,9	0,100191483	0,0090
90100000	0,9	0,097522077	0,0088
80100000	0,9	0,091951074	0,0083

The results from Table 9 and Table 10 show that the leakages will be less than what normally is being considered in a risk evaluation. 0,1 kg/s are in "NORSOK Z-013" being used as cut-off for how small leakages that are being considered.

In the case where the plug is cut loose from the test port, the result will be a spontaneous emission of 25 liters of gas. The size of the equivalent stoichiometric cloud is in" Brage risiko og beredskapsanalyse" determined to be:

Table 11 Size of gas cloud due to a spontaneous emission (Scandpower A/S, 1998)

Pressure in cavity, C1	Gas cloud sixe (m^3)
34 bar	**2,4**
80 bar	**5,6**
160 bar	**10,8**

The data in Table 11are based on calculations for a similar case at the Brage installation. The main difference is that C1 in the WH on the Brage installation are only 15l. (Compared to 25l on Oseberg East).The calculated stoichiometric clouds can there for not directly be applied for the WHs on Oseberg East. In addition the geometry in the WH area as well as assumptions regarding wind may also differ. It does however give an indication regarding the expected size of the cloud and the potential risk related to the emission.

The calculations of the gas cloud size are based on the assumption that 50% of the gas that was released contributes to equivalent stoichiometric cloud.

All of the calculated gas clouds were significant less than the gas clouds that are evaluated to give a high enough pressure to create an explosion at the wellhead area. (Scandpower A/S, 1998)

9.10.1.1. Conclusion, leakages to the atmosphere

It is evaluated that the frequency of the leakages to the atmosphere is expected to increase. It is in particular expected that the total number of leakages will increase trough the test ports.

The consequences of these leakages are evaluated to be negligible, as the actual leakages are small compared to the rates of leakages that are considered to contribute to risk of explosion in "NORSOK Z-013".

It should however be pointed out the leakages could be of significant enough to be detected be the gas-detector and thereby cause the production at the Oseberg East installation to be shut down.

All of the calculated gas clouds for the Brage installation are significant less than the gas clouds that are evaluated to give a high enough pressure to create an explosion at the wellhead area.

The test ports should be monitored and an increased focus on maintenance should be initiated. With this initiative, leaks to the environment are considered to represent a negligible risk.

9.10.2. Escalation of leakages to tubing

It is expected that it is possible to get a higher pressure in C1, than what S1 is dimensioned for.

As mentioned earlier S1 is rated to 345 bar from the tubing side, but Cameron does not guarantee for any pressure in the opposite direction (from C1). S1 will under normal conditions not see any pressure from the C1 direction due to the elastomer seal that is located between S1 and C1. The elastomer seal is rated to 345 bar. As mentioned earlier the elastomer seal is however considered to be a less reliable seal. (Wellmaster). The integrity of the elastomer seal is monitored by the monitor port between the elastomer seal and S1.

In the case of a weakened elastomer seal, and a pressure build up in C1, S1 could be exposed to the following pressures:

- Pressure from the injection gas
- Control line pressure

Table 12 Seals exposed to the following pressures

Barrier	Failure of barrier in A-annulus	Exspected introduced pressure to C1, due to barrier element failure	Failure on barrier in tubing	Exspected introduced pressure to C1, due to barrier element failure
1	ASV	P from injection gas	DHSV	Well flowing P
2	Metal sealassembly between tubing head and tubing hanger (S3)	1. P from injection gas 2. Controlline P	Metal sealassembly between tubing head and XT (S1)	Well flowing P
3	Metal sealassembly between tubing hanger and XT (S2) Metal seal assembly, exit block (S4)	1. P from injection gas 2. Well flowing P 3. Controlline P	Metal sealassembly between tubing hanger and XT (S2) Metal seal assembly, exit block (S4)	1. P from injection gas 2. Well flowing P 3. Controlline P

All of these pressures will be higher than what S1 is rated for. Hence it follows that gas from C1 will blow into the flow in the tubing. The amount of gas blowing into the tubing is very limited and it is not expected to be noticed in other ways than a pressure decrease in C1.

The problem related to this situation is that S1 might get permanent deformation, which in turn causes S1 to lose its integrity. This is considered to be a significant weakening of the secondary barrier.

9.10.3. Conclusion, leakage to tubing

It is a severe escalation of the leakage to C1, if the consequence is that S1 becomes weakened due to the pressure build up in C1.

This danger is reduced by being able to monitor the pressure between the elastomer seal and S1.

9.10.4. Escalation of other leak paths

There exist possibilities to get leakages from the control lines. The pressure in the control lines are less than 600 bar. It is therefore not possible that the gas can leak from C1 to the control lines and further. It is on the other hand possible to get leakages from the control lines to C1.

9.11. Danger indications in case of fire

9.11.1. Loss of integrity due to pressure increase

In case of fire where the WH becomes exposed to the fire, a significant pressure increase in C1 will occur. The pressure increase in C1 is illustrated in the table below. The calculations are based upon two different gas temperatures as a result of the fire and 9 different initial pressures in C1. The calculations are also based upon the case the fluid will be trapped in C1 and does not have the possibility to escape from its origin. The gas temperature before heating is set at 85°C. The calculations in Table 13 and Table 14 are also base on the case that the gas will be trapped in C1, and does not have the possibility to escape back from its origin.

Table 13 Pressure in C1 under different loads due to fire oil/water filled cavity

Fire load (temp in gas) °C	New pressure in C1 due to wellhead temperature increase (bara)								
	1	5	10	35	55	80	90	110	120
1000	9991	9951	9901	9651	9451	9201	9101	8901	8801
650	6491	6451	6401	6151	5951	5701	5601	5401	5301

Table 14 Pressure in C1 under different loads due to fire gas filled cavity

Fire load (temp in gas) °C	Initial pressure in C1 (bara)								
	1	5	10	35	55	80	90	100	110	120
1000	3,6	17,8	35,5	124,4	195,5	284,4	319,9	355,5	391,0	426,6
650	2,6	12,9	25,8	90,2	141,8	206,2	232,0	257,8	283,5	309,3

One of the consequences of fire is that elastomer seal will melt. The elastomer seal is not rated for such high temperatures that a fire will cause. Only the metal seals will be able to maintain its functionality under the temperatures of a fire.

In the case where the pressure in C1 increases to 110-120bar, which is the injection pressure, it is possible that the pressure will exceed the WH and XT design pressure at 345bar. This may cause damages which in worst case scenario may cause the WH and XT to lose its integrity.

It is on the other hand more likely that the seals will open when the pressure from C1 increases. This will result in a pressure relief from C1 to the tubing, but more severe: a permanent deformation of the seals and consequently a loss of the barrier elements integrity.

9.11.1.1. Conclusion, pressure build up due to fire

The consequence of the melting elastomer seal is that S1 becomes exposed to pressure from C1. If the initial pressure in C1 is greater than 10 bar it is likely that S1 will be exposed to a pressure above 34,5 bar, and thereby introducing a risk of damaging S1.

9.11.2. Escalation of fire due to leakages

It has been identified several leak paths associated with C1 earlier in this theses.

In the case of a fire, the test ports with “lock tight” plugs will start to leak. The leakages will be small and the amount of gas that will be fed to an ongoing fire will be very small. The problem related to this is however the increased difficulty to extinguish the fire. The leakages from the test ports will also increase the duration of the fire. The duration of the fire has to be evaluated based on the information from **Error! Reference source not found.**” and the fact that S1 and S3 are connected to a bigger olume of hydrocarbons, the A-annulus volume down to the ASV and the tubing volume down to the DHSV respectively. The volumes are 9,85 m^3 and 32,85m^3 respectively.

Since there has been found leakages at several numbers of wells at Oseberg East , it is likely that the subsequent fire scenario will involve several wells.

In the report “Fareanalyse av lekkasjer i tubinghanger på brage”, it is evaluated that probability for the plugs tighten with “lock-tight to start to leak is high. There are reasons to believe that the same applies for the situation at Oseberg East. It is therefore recommended an to increase the focus on check-rounds to ensure the plugs are tightened and in the long run replace “lock-tight” with “Autoclave” or “Butech”.

The deluge at Oseberg East will make the subsequent fire scenario controllable.

9.11.3. Escalation to uncontrolled blow out

An uncontrolled blow out is a leakage where all the barriers against the reservoir has failed.

An uncontrolled blow out is unlikely for a scenario where the seals in the WH are degraded or completely damaged. If however such an unlikely event occurs the kill pressure for bull heading should be reevaluated as the design rating of the seals in the WH are degraded.

9.12. Operational risks related to monitoring and maintenance of C1

When the pressure reaches 34,5 bar, it is a common practice to bleed off the pressure. This is a manual operation and there exists procedures for the execution of the work. The operation is however time consuming due to the access difficulties to the nipples/test ports.

It is common to bleed of the pressure directly to the atmosphere, where the operator executing the work is located.

There are reasons to believe that the maintenance frequency related to this operation will have to be performed more frequently in the future. In that case, automatic pressure relief in connection to the high pressure flare is recommended.

9.13. Danger indications of multiple leakages

From the previous case studies of leakages in connection to C1, it appears that it is a possible scenario that leakages from different seals might occur simultaneously. In the case of simultaneous leakage (damaged S1, S3 and communication through control lines) the pressure in C1 could increase to a critical value in a shorter time period. The volume of C1 is in connection to S2 which again is connected to the atmosphere, is however still the same (25liter). The case has to be evaluated again as a small volume (C1), in connection to a bigger volume (the volume of the tubing down to DHSV (9,58m^3) and/or the volume of A-annulus down to ASV (32,95 m^3)and the volume of the control lines). The connected volume to C1 will cause an eventually fire to last longer or create a bigger stoichiometric cloud.

10.DISCUSSION

Minor gas leakages in the WH area do not only exist at the Oseberg East installation. Other Statoil installations such as Brage has reported similar cases. In addition, other companies such as Shell and ConocoPhillips have also reported similar concerns and are working simultaneously to solve the problem.

Since it has not been a common practice over the last years to test the relevant seals after installation, it is difficult to evaluate the extent of this problem as very limited test data exist. In addition, integrity issues in connection to the small cavities related to C1 do often not affect the A- and/or B-annulus pressure. They are therefore difficult to detect. It should be mentioned that the first detected leakage in connection to C1 was detected by an operator performing a "sniff test" during the daily check round in the WH area.

The information reviewed in this thesis as well as general information from other companies on the NCS show that:

- The problems related to leakages in WH often occurs typically within 2-3 years after the wells have been put on gaslift
- Seals are not optimized, designed and properly tested for long term gas integrity

The test results, as well as statistics from the pressure monitoring do not always give unambiguously results and conclusions. This may indicate that the potential leakages not always are actual leakages caused by a mechanical failure of the seal. Dirt and residual hydraulic oil from installation may cause pressure disturbances which may lead to an erroneous conclusion. Vibrations in the wellhead may cause small drops of fluid to penetrate the seal and thereby cause the pressure in the cavity to rise slowly, without an existing mechanical failure of the seal.

The problems related to vibration are reduced on more recent completed wells, where Autoclave or Butech fittings in test ports are being used. On older wells were NPT fittings are in use, it is recommended to increase focus on maintenance of the fittings.

In addition a campaign to drain out excessive hydraulic oil from test ports on all wells should be initiated. The practice to always drain out the fluids after tests, installations and maintenance should also be included in the "best practice" manual.

A common remedy to deal with leakages from seals has been to treat the leakage with a sealant (Val-Tex 80). The procedure for treatment with a sealant is to inject the grease through a test port, but the treatment shows variations in results. It is recommended to inject the sealant from two different test ports in the opposite direction of one other, in order to ensure an optimal sealing effect through the cavity. (To ensure that the sealant flows into and covers the whole area). The use of sealants should however always be evaluated carefully as injection of the grease through a test port removes the possibility for further pressure and or temperature monitoring through that port. In addition treatment with sealants does not satisfy the requirement regarding fire integrity.

In order to monitor the pressure in the cavity, pressure transmitters or indicators has to be installed at the wellhead. Not many wells on the Norwegian continental shelf have this type of pressure monitoring. On Oseberg East the well A-1, A-2 and A-3 have the following equipment:

Table 15 Pressure monitoring equipment

Cavity	A-1	A-2	A-3
Tubing	Transmitter	Transmitter	Transmitter
C1	Transmitter	Transmitter	Transmitter
SRL-cavity	Indicator	Indicator	Indicator
10 3/4" hanger cavity	Indicator	Indicator	Indicator
13 3/8" hanger cavity	Indicator	Indicator	None
A-annulus	Transmitter	Transmitter	Transmitter
B-Annulus	Transmitter	Transmitter	Transmitter

It is recommended that such pressure monitoring should be installed on other wellheads where there exist indications of leakages. However, installation of pressure transmitters or indicators at test ports should also be evaluated considering the negative effect on the fire integrity. The fittings in the test ports are in principle not fire resistant but the fire jacket normally installed around the WH is a compensating measure. The integrity and functionality of the fire jacket becomes weakened by using transmitters or indicators on the wellhead.

C1 should not see pressure under normal conditions. Since the trends shows that this is not always the case, it is therefore recommended to avoid installations of unidirectional seals, such as the SRL-seal, on any further future wells until design other general improvements have been made. It is recommended to use seals such as Cameron's CAHN or a general double tandem seal. The use of tandem seal requires the pressure between the two seals to be lower than the pressure between the two seals. It is therefore crucial to choose a solution with venting of the disposed heat from temperature induced pressure between the seals.

In general it is recommended that unidirectional seals should not be used in WH-configurations where there is a probability for the production well to be put on gas lift. History shows that the elastomer seals originally installed on the WHs on Oseberg East are not suitable to be used for sealing in gas lift wells. There is therefore a risk that C1will be exposed to pressure and thereby also the SRL seal from the opposite direction of what it is designed for.

If it is desired to put producers on gas lift, the design criteria on every element should always be thoroughly checked and it is recommended that Cameron's design criteria should be met. If the specifications of the seals are only met by dry gas, a conversion to gas lift wells is not recommended.

There exists examples on the NCS were the test ports in connection to C1 have permanently been plugged after WH installation. This solution is not recommended, as this will result in losing the monitoring possibility of the cavities. Thereby the leakages might in worst case scenario only be detected after reaching the atmosphere.

All of the three wells that have been evaluated in this thesis are gas lift wells. Examples of similar cases are from Shell are also from gas lift wells. Since there is such limited test data, it is difficult to draw a conclusion regarding whether the leakages are only a problem related to gas lift wells or whether the problem might exist on other types of wells as well. To be able to conclude, further tests on all types of wells has to be performed.

An indication of that the problem might not only be linked to gas lift wells are worries regarding test of DHSV. During a DHSV the SRL seal will see a significant higher differential pressure towards the tubing, as the pressure in the tubing above the DHSV will be bled off before commencement of the test. If there is already pressure behind the SRL seal which is higher than the atmospheric pressure, there might be risk for the differential pressure to increase above design limits. Such scenario, are as likely for gas lift wells, as well as for any other types of wells. It is therefore recommended to always bleed of the pressure in C1 and the SRL-test port before commencement of a DHSV test.

A summary of the calculation performed related to the cases presented are shown in table below:

Table 16 Summary, expected pressure in C1 & leak rates

	Expected pressure in C1 and/or test ports		Comments
Tubing P (Leak through S1)	≈75	°C	
Injection P (Leak through S3)	≈120	Bar	
Control line P (Leak through S3)	<600	Bar	
Temp induced P water/oil filled C1 (WCS)	751	Bar	
Temp induced P air/gas filled C1 (WCS)	Δ 5	Bar	
Fire induced P water/oil filled C1	> 345 (WH design P)	Bar	
Fire induced P air/gas filled C1	> 345 (WH design P)	Bar	This applies for the cases where C originally sees either injection P or CL P
Leak rate to the atm with 1 mm² hole opening	< 0,1	kg/s	

It should be noted that the leak rates are based on 1mm^2 hole opening which is evaluated as the most likely scenario. In cases of a bigger hole openings or in the case of a completely damaged seal to the atmosphere it is evaluated that there exist a risks for the gas detectors to detect the leakages. When the gas detector detects gas in the WH, an automatic shutdown of the production occurs. A shutdown of the production will lead to economic losses. On the other hand, this has not yet proven to be a problem.

The calculations for the stociometric clouds in chapter "9.10.1Escalation of the leakage to the atmosphere" are based on the WH configuration at Brage. The calculated gas cloud sizes do give an indication regarding the possible cloud size at Oseberg East. It is however recommended to carry out a new risk evaluation for Oseberg East in order to be able to evaluate the explosion and fire case more precisely.

Injection of nitrogen gas in cavities

The main risks related to leakages in the seals are driven be the case of fire and/or explosion. To mitigate this risk it is proposed to replace the fluid in the WH cavities with nitrogen gas. Nitrogen gas and air are a stable composition and will not cause auto-ignited chemical explosion explosions. (firesandexplosion)

A stoichiometric cloud of a mixture of nitrogen, hydrocarbons and air will also be less flammable compared to stoichiometric cloud of only air and hydrocarbons.

In addition the thermal heat expansion coefficient for nitrogen gas is less than for air. Hence the effects of thermal induced pressure will also be less.

There is however HSE issues regarding use nitrogen gases in high consecration that must be taken into consideration.

Exceeded design capacities

Due to unambiguous test results it is difficult to point out on clear conclusion regarding the cause of the leakages. Several aspects have been mentioned already. In addition there are reasons to believe that design capacities for the wells A-1, A-2 and A-3 have been exceeded and therefore might have caused damage on the seals.

All of the three wells were designed as gas lift wells with following specifications:

- Design temperature 29°C- 82°C
- The gas in connection with the WH should also be of dry quality (no fluids or injected chemicals)

After the wells were put on gas lift, there have been instances where the design capacities of the WH have been exceeded. The gas that has been injected has held a higher temperature than what the elastomer seals installed in the WH are designed to meet. In addition the injection gas has not been of dry quality. This may have led to leakages through the elastomer seals/fitting as they are neither designed to see such high temperatures nor to see the wet gas.

It has also been reported from Cameron that there has been injected corrosion inhibitor into the well which are corrosive against black steel. (Used in WHs in other wells at the Oseberg East installation)

10.1. Acceptance criteria for leakages

10.1.1. Internal WH leakages

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*

This requirement can be used providing the observation volume is adequately large to give meaningful tests and the valves or seals are connected to a closed system. In the case related to C1 the volumes that are being evaluated are too small in order to successfully meet the API requirement. See Figure 49Hence, more conservative acceptance criteria for the leakages in connection to the wellhead should be defined.

Comparisons	E-7 (0,12l/hr)	E-4 (1,9l/hr)	E-8 (0,2l/hr)
API (25,5 Sm3/hr)	~ 200,000 smaller	~ 13000 smaller	~ 130,000 smaller
Matrix (0.1kg/sec)	~3,000,000 smaller	~ 190,000 smaller	~1,800,000 smaller

Approved deviation

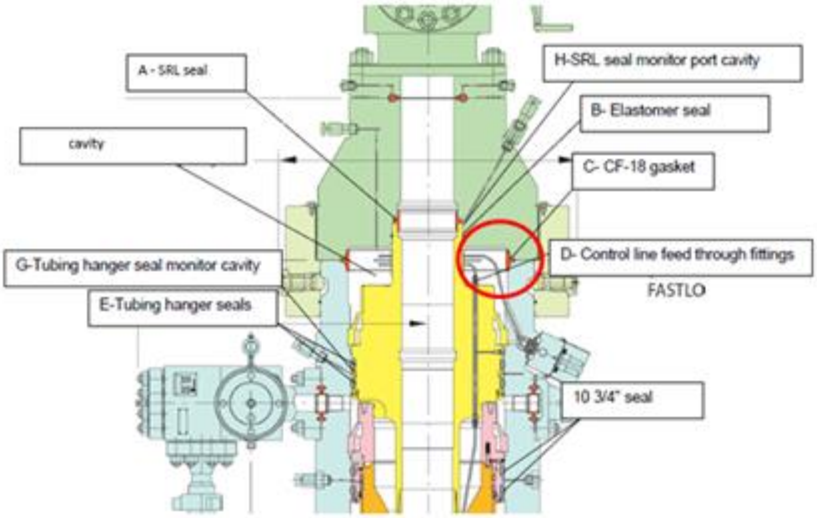


Figure 49 API & OLF comparison of leak rates (Sally Serenyi)

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

Since it has been evaluated internally in Statoil that the unidirectional seals does tolerate more than 10 % of the design rate from the opposite direction, it is evaluated that the unidirectional seal should not see higher pressure than 34,5 bar from the opposite direction of what the seal is designed for. Before the pressure in C1 reaches 34,5 bar the pressure should then manually be bled off to approximately the atmospheric pressure. It is therefore evaluated that the acceptance criteria should be 35bar/24h.

It is recommended that leak testing should be performed as a minimum the first time after 12 months. If the test is satisfactory, the test interval can be increased to maximum 24-monthly.

For barrier seals that could be exposed to gas, nitrogen is the recommended preferred test medium. Remaining seals are to be tested with water / hydraulic oil. This is to ensure that the test is as realistic as possible.

The test shall last for a sufficient time period so that any leakage can be detected. It is therefore e recommended that the test duration should be minimum 10 min. In the case of unambiguous test results, it is recommended d to extend the variation of the test.

10.1.2. Leakages to the atmosphere

Norsok D-010 states that there should be zero leakages to the atmosphere.

Norsok Z-013 states that leakages with a leak rate below 0,1kg/s will not contribute to risk for explosion.

Based on the calculation from this thesis as well as the two requirements above, it is recommended to consider a accept criteria of less than 0,1 kg/s to the atmosphere under deviation. It is indicated that this leak rate will not contribute explosion risk. However, a leak rate below 0,1kg/s might contribute to minor environmental consequences. Compensatory measures such as an increased focus on cleanliness around the WH should than be initiated.

11.CONCLUSION

Conclusion, leakages to the atmosphere

A review of the barriers on the gaslift wells A-1, A-2, A-3 concludes that the well has in the first place two independent barriers that are possible to test. S2 and S4 give an additional third barrier and increased safety against leakages to the atmosphere in case S1 or S3 fails. It is not possible to test S2 and S4 with an unambiguous result, without introducing a risk to damage S1.

It is evaluated that the frequency of the leakages to the atmosphere is expected to increase. It is in particular expected that the total number of leakages will increase trough the test ports.

The consequences of these leakages are evaluated to be negligible relative to the rates of leakages that are considered to contribute to risk of explosion and/or fire.

It should however be pointed out the leakages could be significant enough to be detected be the gas-detector and thereby cause the production at the installation to be shut down. On the other hand, this has not yet proven to be a problem.

The test ports should be monitored and an increased focus on maintenance should be initiated. With this initiative, leaks to the environment are considered to represent a negligible risk.

It is a severe escalation of the leakage to C1, if the consequence is that S1 in addition becomes weakened. This danger is reduced by being able to monitor the pressure between the elastomer seal and S1.

Proposed actions:

The recommendations after performed test of seal in WH follow:

If the test was cleared ok:

- The barrier and the well is in accordance with:
  - Norsok D-010
  - Statoil well integrity policy
- The well can then be put back on production again

If the test was not cleared ok:

- The seal/element failed the function of being a well barrier element
- Raise a deviation to flow the well under compensating measures in anticipation of a work over to be carried out.

It is recommended that the compensating measures should be evaluated in accordance to a similar table as the one below

Table 17 Likelihood, consequece, risk and compesating measures

Scenario	Likelihood	Consequence	Risk	Compesating measures
Leaking seal	Short term			
	Medium: Based in barrier element design and track record	**Medium:** Small leakages to atmosphere, unscrewing plugs at high back pressure	**Acceptable**: Acceptable with compensating measures	• Increased monitoring/surveillance • Spray foam around test plugs to be able to detect leaks more easily. • Install autoclave plugs (bleed and test plugs) with option to monitor pressure behind
	Long term			
	High: Based in barrier element design and track record	**High:** The leakage is not expected to escalate significantly	**Not acceptable**: The risk of having leakages to the atmosphere is significant	Workover

In addition other short term solutions that should be evaluated are:

- Seal repair with chemical sealant
- Monitor and always log the bleed off medium to more easily be able to identify the source of the leakage

The long term solution compensating measures:

- Evaluate injection of nitrogen to cavities
- Pressure alarms on transmitters to ensure that the pressure do not exceed the predefined limit
- Improvements in maintenance of the WH
- Develop, test and qualify new design for seal assemblies/wellheads/tubing hangers
- Workover of XT/WH

During the daily visualization round there should be a focus on visual inspection

- Plug movement
- Seeping fluid and/ or foam from plugs

Campaign:

- Drain out the hydraulic oil left after installation, on all wells
- Tighten fittings in all test ports

Best practice:

- Always drain out the hydraulic oil used during installation or tests
- Increase focus on cleanliness during installation of the seals to avoid residual dirt and scratches on the seal surfaces
- Increased focus on training to be able to use the stinger tool and proper execution of the maintenance and test of seal
- Bleed of pressure in C1 and SRL-testport cavity before performing test on DHSV, CT-operations or permanent abandonment of the well

Recommendation to operations:

- Operate the well with limits on C1 pressure
- Suggested :
    - 35 bar/24hr for internal leakages
    - 0,1 kg/s for leakages to the atmosphere

Recommendation for further work

- Select data to create statics of the leakages, with data regarding frequency
- Evaluate the effect of injection of nitrogen gas into cavities.
- Evaluate the need for a new risk evaluation for Oseberg East in order to be able to estimate the explosion and fire risk more precisely.

12.Key terms and definitions

Fail safe close:

This means that the valves will automatically close if the signal or hydraulic control pressure is lost.

Gas decompression requirement/ explosive decompression:

Rapid pressure drop in a gas containing system causes the gas trapped inside an elastomer (polymer) to expand. The pressure drop rate must be faster than the diffusion rate of the gas inside the polymer (standard, 1994)

Soap/ foam test:

A test performed to check for leakages to the atmosphere. A gas leakage can then be difficult to detect. To facilitate the detection of gas a fluid like “soap” is greased on the interface that is under investigation. I the case of a leakage, the soap will develop bubbles which are easy to detect.

Tandem seals:

Two seals set in the opposite direction of each other, sealing the same gap.

Unidirectional seals:

Seal of this type are single acting, which means that by pressure energization is effective in one direction only.

13. Abbreviations

C1- XT cavity

Csg- casing

MD-measured depth

M2M- Metal to metal

P-pressure

S1- SRL seal

S2- metal seal

S3- Tubing hanger seal assembly

S-3- metal seal

WH- Wellhead

WB- Well barrier

WBEs- Well barrier elements

WCS- Worst Case Scenario

XT- Christmas Tree

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15.APPENDIX

15.1. Basic calculation examples

15.1.1. Pressure increase in C1, oil/water filled cavity

From the method of temperature induced B-annulus pressure

$$\Delta P = \left(\frac{-\propto}{c}\right)(T_3 - T_1)$$

Eq.4

Ex:

$$T_3 = 95\,°C$$

$$T_1 = 0°C$$

In the simulation it is assumed that the relation between the compressibility of the fluid and the heat expansion coefficient are the same for oil and water.

$$\left(\frac{-\propto}{c}\right)_{water} \approx \left(\frac{-\propto}{c}\right)_{oil} \approx \left(\frac{3 * 10^{-4/°C}}{3 * 10^{-5/bar}}\right)$$

Hence:

$$\Delta P = \left(\frac{3 * 10^{-4/°C}}{3 * 10^{-5/bar}} \frac{-\propto}{c}\right)(95 - 0)°C = 950\ bar = 951 bara$$

The same method is used for pressure increase due to fire.

15.1.2. Pressure increase in C1, gas/air filled cavity

From the method of ideal gas

$$PV = nRT$$

V, n, R –assumed constant

$$\left(\frac{P}{T}\right)_3 \approx \left(\frac{P}{T}\right)_1$$

Ex:

$$T_3 = 95\,°C = 368{,}15°K$$

$$T_1 = 82°C = 355{,}15°K$$

$$P_1 = 4bar = 400000\,pa$$

$$P_3 = \left(\frac{P}{T}\right)_1 * T_3$$

$$P_3 = \left(\frac{400000}{355{,}15}\right)_1 * 368{,}15 = 414641{,}17\,pa = 4{,}15bar = 5{,}15bara$$

The same method is used for pressure increase due to fire.

15.1.3. Rate of leakage

$$P = \frac{\rho q^2}{2A^2\,0{,}95^2}$$

Eq. 11

This equation can be used to determine the rate of leakage.

$$q = \sqrt{\frac{P2A^2 0{,}95^2}{\rho}}$$

Ex:

$$A = 1mm^2$$

ρ_{methan} =2,437802151

$$P_3 = 5{,}15bara = 514642pa$$

$$q = \sqrt{\frac{514642 * 2 * 0{,}000001^2 0{,}95^2}{2{,}437802151}} = 0{,}001kg/s$$

15.2. Additional simulations

Table 18 P increas in C1, oil/water filled

New pressure in C1 due to wellhead temperature increase (bara)	951	901	851	801	751	701	651	601	551	501	451	401	351	341	331	321	311	301	251	201	151	101	51	41	31	21	11
Initial temperature in C1 (°C)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wellhead temperature (°C), increase from 0°C	95	90	85	80	75	70	65	60	55	50	45	40	35	34	33	32	31	30	25	20	15	10	5	4	3	2	1
New pressure in C1 due to wellhead temperature increase (bara)	901	851	801	751	701	651	601	551	501	451	401	351	301	291	281	271	261	251	201	151	101	51	1	-9	-19	-29	-39
Initial pressure in C1	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Wellhead temperature (°C), increase from 0°C	95	90	85	80	75	70	65	60	55	50	45	40	35	34	33	32	31	30	25	20	15	10	5	4	3	2	1
New pressure in C1 due to wellhead temperature increase (bara)	801	751	701	651	601	551	501	451	401	351	301	251	201	191	181	171	161	151	101	51	1	-49	-99	-109	-119	-129	-139
Initial pressure in C1	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Wellhead temperature (°C), increase from 0°C	95	90	85	80	75	70	65	60	55	50	45	40	35	34	33	32	31	30	25	20	15	10	5	4	3	2	1

Table 19 P increase in C1, air/gas filled

Start production 14.02.2011																			
New pressure in C1 due to wellhead temperature increase (bara)	5,15	5,09	5,03	4,98	4,92	4,86	4,81	4,75	4,70	4,64	4,58	4,53	4,47	4,41	4,36	4,30	4,25	4,19	4,13
New pressure in C1 due to wellhead temperature increase (pa)	414641,70	409010,28	403378,85	397747,43	392116,01	386484,58	380853,16	375221,74	369590,31	363958,89	358327,47	352696,04	347064,62	341433,20	335801,77	330170,35	324538,93	318907,50	313276,08
Initial pressure in C1 (bar)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Initial temperature in C1 (°C)	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82
Wellhead temperature (°C), increase from 0°C	95	90	85	80	75	70	65	60	55	50	45	40	35	30	25	20	15	10	5
Initial pressure in C1 (pa)	400000	400000	400000	400000	400000	400000	400000	400000	400000	400000	400000	400000	400000	400000	400000	400000	400000	400000	400000
Initial temperature in C1 (K)	355,15	355,15	355,15	355,15	355,15	355,15	355,15	355,15	355,15	355,15	355,15	355,15	355,15	355,15	355,15	355,15	355,15	355,15	355,15
Wellhead temperature (K), increase from -273,15 K	368,15	363,15	358,15	353,15	348,15	343,15	338,15	333,15	328,15	323,15	318,15	313,15	308,15	303,15	298,15	293,15	288,15	283,15	278,15
Revisjonsstans 17.05.2011																			
New pressure in C1 due to wellhead temperature increase (bara)	2,30	2,29	2,27	2,25	2,23	2,22	2,20	2,18	2,16	2,15	2,13	2,11	2,09	2,07	2,06	2,04	2,02	2,00	1,99
New pressure in C1 due to wellhead temperature increase (pa)	130480,24	128708,13	126936,03	125163,92	123391,81	121619,71	119847,60	118075,49	116303,38	114531,28	112759,17	110987,06	109214,96	107442,85	105670,74	103898,64	102126,53	100354,42	98582,31
Initial pressure in C1 (bar)	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Initial temperature in C1 (°C)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Wellhead temperature (°C), increase from 0°C	95	90	85	80	75	70	65	60	55	50	45	40	35	30	25	20	15	10	5
Initial pressure in C1 (pa)	100000	100000	100000	100000	100000	100000	100000	100000	100000	100000	100000	100000	100000	100000	100000	100000	100000	100000	100000
Initial temperature in C1 (K)	282,15	282,15	282,15	282,15	282,15	282,15	282,15	282,15	282,15	282,15	282,15	282,15	282,15	282,15	282,15	282,15	282,15	282,15	282,15
Wellhead temperature (K), increase from -273,15 K	368,15	363,15	358,15	353,15	348,15	343,15	338,15	333,15	328,15	323,15	318,15	313,15	308,15	303,15	298,15	293,15	288,15	283,15	278,15
12.12.2011																			
New pressure in C1 due to wellhead temperature increase (bara)	10,25	10,13	10,00	9,87	9,75	9,62	9,50	9,37	9,25	9,12	8,99	8,87	8,74	8,62	8,49	8,37	8,24	8,12	7,99
New pressure in C1 due to wellhead temperature increase (pa)	925129,14	912564,57	900000,00	887435,43	874870,86	862306,30	849741,73	837177,16	824612,59	812048,02	799483,46	786918,89	774354,32	761789,75	749225,18	736660,62	724096,05	711531,48	698966,91
Initial pressure in C1 (bar)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Initial temperature in C1 (°C)	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Wellhead temperature (°C), increase from 0°C	95	90	85	80	75	70	65	60	55	50	45	40	35	30	25	20	15	10	5
Initial pressure in C1 (pa)	900000	900000	900000	900000	900000	900000	900000	900000	900000	900000	900000	900000	900000	900000	900000	900000	900000	900000	900000
Initial temperature in C1 (K)	358,15	358,15	358,15	358,15	358,15	358,15	358,15	358,15	358,15	358,15	358,15	358,15	358,15	358,15	358,15	358,15	358,15	358,15	358,15
Wellhead temperature (K), increase from -273,15 K	368,15	363,15	358,15	353,15	348,15	343,15	338,15	333,15	328,15	323,15	318,15	313,15	308,15	303,15	298,15	293,15	288,15	283,15	278,15
29.06.2012																			
New pressure in C1 due to wellhead temperature increase (bara)	17,78	17,56	17,33	17,10	16,87	16,64	16,42	16,19	15,96	15,73	15,50	15,28	15,05	14,82	14,59	14,36	14,14	13,91	13,68
New pressure in C1 due to wellhead temperature increase (pa)	1678397,33	1655602,31	1632807,29	1610012,27	1587217,25	1564422,23	1541627,21	1518832,19	1496037,17	1473242,15	1450447,13	1427652,11	1404857,09	1382062,07	1359267,05	1336472,03	1313677,01	1290881,99	1268086,97
Initial pressure in C1 (bar)	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
Initial temperature in C1 (°C)	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Wellhead temperature (°C), increase from 0°C	95	90	85	80	75	70	65	60	55	50	45	40	35	30	25	20	15	10	5
Initial pressure in C1 (pa)	1300000	1300000	1300000	1300000	1300000	1300000	1300000	1300000	1300000	1300000	1300000	1300000	1300000	1300000	1300000	1300000	1300000	1300000	1300000
Initial temperature in C1 (K)	285,15	285,15	285,15	285,15	285,15	285,15	285,15	285,15	285,15	285,15	285,15	285,15	285,15	285,15	285,15	285,15	285,15	285,15	285,15
Wellhead temperature (K), increase from -273,15 K	368,15	363,15	358,15	353,15	348,15	343,15	338,15	333,15	328,15	323,15	318,15	313,15	308,15	303,15	298,15	293,15	288,15	283,15	278,15

Table 20 P increase in C1, air/gas filled

26.05.2011											
New pressure in C1 due to wellhead temperature increase (bara)	1	1	1	1	1	1	1	1	1	1	1
Initial pressure in C1 (bar)	0	0	0	0	0	0	0	0	0	0	0
Initial temperature in C1 (°C)	0	0	0	0	0	0	0	0	0	0	0
Wellhead temperature (°C), increase from 0°C	95	90	85	80	75	70	65	60	55	50	45
Initial pressure in C1 (pa)	0	0	0	0	0	0	0	0	0	0	0
Initial temperature in C1 (K)	273,15	273,15	273,15	273,15	273,15	273,15	273,15	273,15	273,15	273,15	273,15
Wellhead temperature (K), increase from -273,15 K	368,15	363,15	358,15	353,15	348,15	343,15	338,15	333,15	328,15	323,15	318,15
New pressure in C1 due to wellhead temperature increase (bara)	7,50	7,41	7,32	7,24	7,15	7,06	6,97	6,88	6,79	6,71	6,62
Initial pressure in C1 (bar)	5	5	5	5	5	5	5	5	5	5	5
Initial temperature in C1 (°C)	10	10	10	10	10	10	10	10	10	10	10
Wellhead temperature (°C), increase from 0°C	95	90	85	80	75	70	65	60	55	50	45
Initial pressure in C1 (pa)	500000	500000	500000	500000	500000	500000	500000	500000	500000	500000	500000
Initial temperature in C1 (K)	283,15	283,15	283,15	283,15	283,15	283,15	283,15	283,15	283,15	283,15	283,15
Wellhead temperature (K), increase from -273,15 K	368,15	363,15	358,15	353,15	348,15	343,15	338,15	333,15	328,15	323,15	318,15
New pressure in C1 due to wellhead temperature increase (bara)	21,00	20,73	20,45	20,18	19,91	19,64	19,37	19,10	18,82	18,55	18,28
Initial pressure in C1 (bar)	15	15	15	15	15	15	15	15	15	15	15
Initial temperature in C1 (°C)	3	3	3	3	3	3	3	3	3	3	3
Wellhead temperature (°C), increase from 0°C	95	90	85	80	75	70	65	60	55	50	45
Initial pressure in C1 (pa)	1500000	1500000	1500000	1500000	1500000	1500000	1500000	1500000	1500000	1500000	1500000
Initial temperature in C1 (K)	276,15	276,15	276,15	276,15	276,15	276,15	276,15	276,15	276,15	276,15	276,15
Wellhead temperature (K), increase from -273,15 K	368,15	363,15	358,15	353,15	348,15	343,15	338,15	333,15	328,15	323,15	318,15

Table 21 P increase in C1, gas/air filled

26.05.2011								
New pressure in C1 due to wellhead temperature increase (bara)	1	1	1	1	1	1	1	1
Initial pressure in C1 (bar)	0	0	0	0	0	0	0	0
Initial temperature in C1 (°C)	0	0	0	0	0	0	0	0
Wellhead temperature (°C), increase from 0°C	40	35	30	25	20	15	10	5
Initial pressure in C1 (pa)	0	0	0	0	0	0	0	0
Initial temperature in C1 (K)	273,15	273,15	273,15	273,15	273,15	273,15	273,15	273,15
Wellhead temperature (K), increase from -273,15 K	313,15	308,15	303,15	298,15	293,15	288,15	283,15	278,15
New pressure in C1 due to wellhead temperature increase (bara)	6,53	6,44	6,35	6,26	6,18	6,09	6,00	5,91
Initial pressure in C1 (bar)	5	5	5	5	5	5	5	5
Initial temperature in C1 (°C)	10	10	10	10	10	10	10	10
Wellhead temperature (°C), increase from 0°C	40	35	30	25	20	15	10	5
Initial pressure in C1 (pa)	500000	500000	500000	500000	500000	500000	500000	500000
Initial temperature in C1 (K)	283,15	283,15	283,15	283,15	283,15	283,15	283,15	283,15
Wellhead temperature (K), increase from -273,15 K	313,15	308,15	303,15	298,15	293,15	288,15	283,15	278,15
New pressure in C1 due to wellhead temperature increase (bara)	18,01	17,74	17,47	17,20	16,92	16,65	16,38	16,11
Initial pressure in C1 (bar)	15	15	15	15	15	15	15	15
Initial temperature in C1 (°C)	3	3	3	3	3	3	3	3
Wellhead temperature (°C), increase from 0°C	40	35	30	25	20	15	10	5
Initial pressure in C1 (pa)	1500000	1500000	1500000	1500000	1500000	1500000	1500000	1500000
Initial temperature in C1 (K)	276,15	276,15	276,15	276,15	276,15	276,15	276,15	276,15
Wellhead temperature (K), increase from -273,15 K	313,15	308,15	303,15	298,15	293,15	288,15	283,15	278,15

15.3. Test of A-1 & A-2

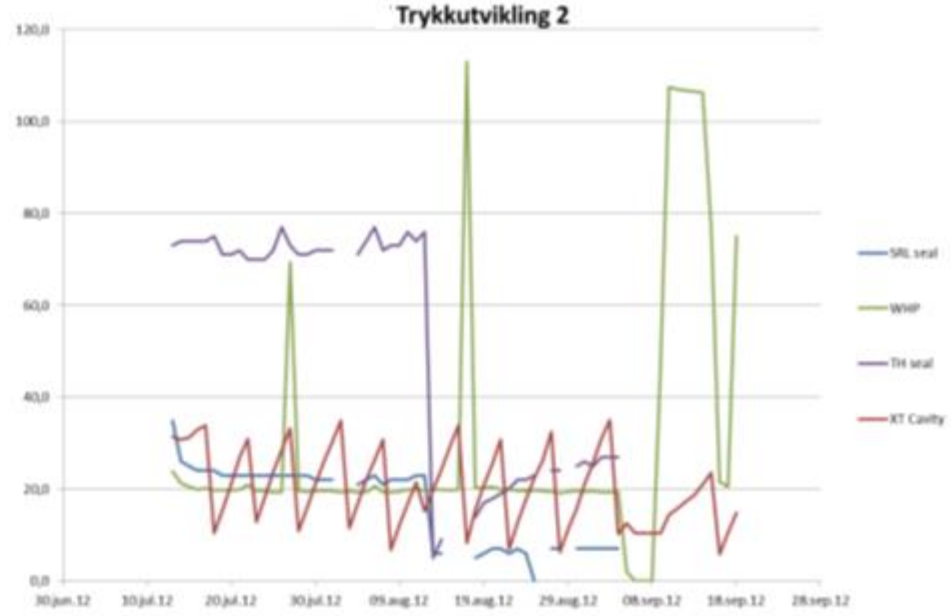
Test A-1

1. Summary - Test August 2012 / pressure trends /bleed off

Item no 1:	Information /
1: Test (1)	Blødde ned XT cavity (F) fra 40 til 12 bar. Blødde av XXXX ??? Blødde TH seal monitor port cavity (G) fra 20 til 11 bar. Blødde av XXXX ???? **~Trykk ved start av test:** - XT cavity (F) 12 bar - TH seal monitor port cavity (G) 11 bar - SRL seal monitor port cavity (H) - - Gass løft trykk/A annulus 126 bar (gass) - Tubing 18 bar (olje/gass/vann) **Trykk endring ~1 time monitoring:** - XT cavity (F) 12,1 bar til 13,4 bar + 1,3 bar - TH seal monitor port cavity (G) 10,6 bar til 12,0 bar + 1,4 bar
2: Test (2a)	Trykk op mellom TH seals (G) fra 13,5 til 150 bar med nitrogen. **Trykk ved start av test:** - XT cavity (F) 12 bar - TH seal monitor port cavity (G) 150 bar - Gas løft trykk/A annulus 126 bar (gass) - Tubing 18 bar (olje/gass/vann) **Trykk endring 1 time monitoring:** - XT cavity (F) 12,0 bar til 12,2 bar + 0,2 bar - TH seal monitor port cavity (G) 150,6 bar til 150,9 bar + 0,3 bar
2:Test 2b)	Blødde ned TH seal monitor port cavity (G) fra 151,2 bar til 7,0 bar**,** blødde av XXXX **Trykk ved start av test:** - XT cavity (F) 4,3 bar - TH seal monitor port cavity (G) 7,0 bar - Gas løft trykk/A annulus 126 bar (gass) - Tubing 18 bar (olje/gass/vann) **Trykk endring 3,5 time monitoring:** - XT cavity (F) 4,3 til 4,7 på 1 timer (TH seal 8,0 bar) 4,3 til 5,0 bar + 0,7 - TH seal monitor port cavity (G) 7,0 til 9,3 bar + 2,3

2:Test 2c)	Blødde ned TH seal monitor port cavity (G) fra 9,3 bar til 1.3 bar **Trykk ved start av test:** - XT cavity (F) 5,0 bar - TH seal monitor port cavity (G) 1,3 bar - Gas løft trykk/A annulus 126 bar (gass) - Tubing 18 bar (olje/gass/vann) **Trykk endring 14 time monitoring:** - XT cavity (F) 5,0 til 5,3 bar + 0,3 bar - TH seal monitor port cavity (G) 1,3 til 5,5 bar + 4,2 bar
3:Test (3)	Blødde ned SRL seal monitor port cavity (H) fra x til x. Lit crude oil observer ved av blødning. Seal holding after bleed off – need Plot of SRL seal holding??
4: Test (4) Ikke utført	Possible further work?? Blø ned SRL seal monitor port cavity til ~1 bar. Hvilken fluid? Blø ned A-annulus ~0 bar. Hvilken fluid? Blø ned XT cavity ~0 bar. Hvilken fluid? **Trykk ved start av test:** - XT cavity (F) ~0 bar - TH seal monitor port cavity (G) 20 bar - SRL seal monitor port cavity (H) ~ 1 bar - Tubing 18 bar (olje/gass/vann) - A-annulus ~0 bar (gass) **Trykk endring X time monitorering:** => XMT cavity (F) ? => SRL seal monitor port cavity (H) ? => Tubing ?
5: Pressure trends: - A, B, C annulus - 10 ¾" seal - 13 3/8" seal	

6/28/2013

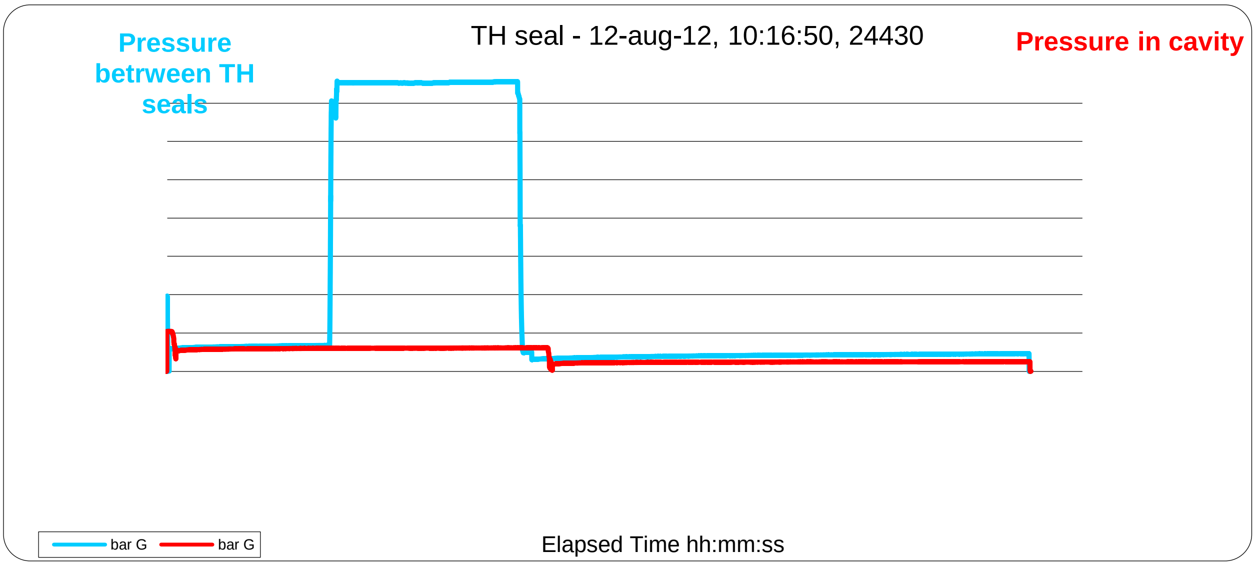
6: Pressure trends: - XT cavity - SRL seal cavity - Tubing - TH seal	
7: Bleed of from - SRL seal cavity - XT cavity - TH seal cavity	**From : 13-July-2012** **XT cavity (F):** **Blødde av ~31-35 til 6-13 bar hver 4-6 days** **Ikke er rapportert men ta fra plot over.** **Avblødd media: Gass** **SRL seal (H)*:** **SRL seal øker til 7 bar straks etter avblødning (25, 26 & 27 Aug)** **SRL seal øker til 10 bar straks etter avblødning (18 Sept)** **Avblødd media: Gass** **TH seal (G):** **Ikke er rapportert** ***SRL seal blødde av fra 65 til 10 bar (23-Mar-2012)** **Avblødd media: Hydraulikk væske/damp**

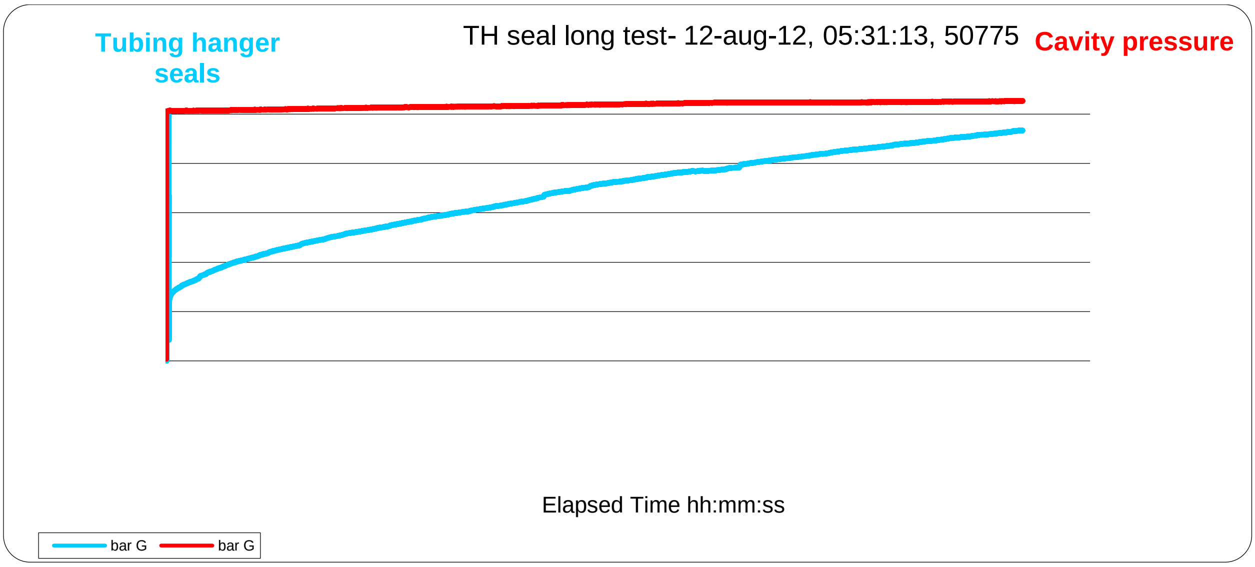
General			
Customer	Statoil.	**Well No**	
Company Rep	Tom Jensen	**Field**	Oseberg
Service Tech(s)	Einar Veim.	**Rig**	Øst
Activity	.		
Departure Date		**Release Date**	

Installation			
System Type	18 5/8" SMCC	**Flange/Connector Type**	18 5/8" Fastlock
Pressure Rating	6500 PSI	**Actual Pressure**	Tubing 18 bar. Gas lift 126 bar
CSG Size	N/A	**Tubing Connection**	
Interface Seal Type	18" CF	**Tree Cap Connection**	

Date	Time	Activity
12/8		Rigget opp Nvision test instrument på cavity test port og tubing hanger test port. Blødde av trykket I cavity til 10 bar. Trykk I tubing hanger test port 12 bar. Gass løft trykk 126 bar. Monitorerte trykket i mellom tubinghanger seals og i cavity i 1 time. Etter 1 time var cavity trykket 13 bar og trykket mellom tubinghanger seals 12 bar. Pumpet opp trykket mellom tubinghanger seals til 150 bar. Cavity trykk fremdeles 12 bar og gass løft trykk 126.bar. Etter en time var tubinghanger seals trykket 150 bar og cavity trykket på 12 bar. Blødde trykket mellom tubing hanger seals til 7,03 bar og cavity trykket til 4,35 bar.
	13:30	Startet logging og fikk følgende resultat:
	14:00	Tubing hanger seals 7,03 bar. Cavity 4.35 bar. Gass løft 126 bar.
	14:30	Tubing hanger seals 7,63 bar. Cavity 4.64 bar. Gass løft 126 bar.
	15:00	Tubing hanger seals 8,09 bar. Cavity 4.77 bar. Gass løft 126 bar.
	15:30	Tubing hanger seals 8,34 bar. Cavity 4.85 bar. Gass løft 126 bar.
	16:00	Tubing hanger seals 8,59 bar. Cavity 4.91 bar. Gass løft 126 bar.
	16:30	Tubing hanger seals 8,79 bar. Cavity 4.96 bar. Gass løft 126 bar.
	17:00	Tubing hanger seals 9,01 bar. Cavity 4.99 bar. Gass løft 126 bar.
	17:30	Tubing hanger seals 9,25 bar. Cavity 5.02 bar. Gass løft 126 bar. Avsluttet logg.
		Startet ny logge sekvens. Logge sekvensen vil stå å gå til I morgen tidlig. Trykk ved start test: Tubing hanger seals 1,32bar. Cavity 5.07 bar. Gass løft 126 bar

13/8	07:30	Avsluttet monitoring av trykk. Etter 14 timers logg var trykkene følgende: Tubing hanger seals 5,50bar. Cavity 5.34 bar. Gass løft 126 bar Dette indikerer veldig liten lekkasje fra annulus til cavity, om det i det hele tatt skal kalles lekkasje. SRL seal holder tett. Ved avblødning av trykk bak sealet kom det litt crude oil i retur, men når avblødning ble stengt igjen holdt sealet tett. Trykket ble observert i 14 timer uten trykkoppbygning bak.





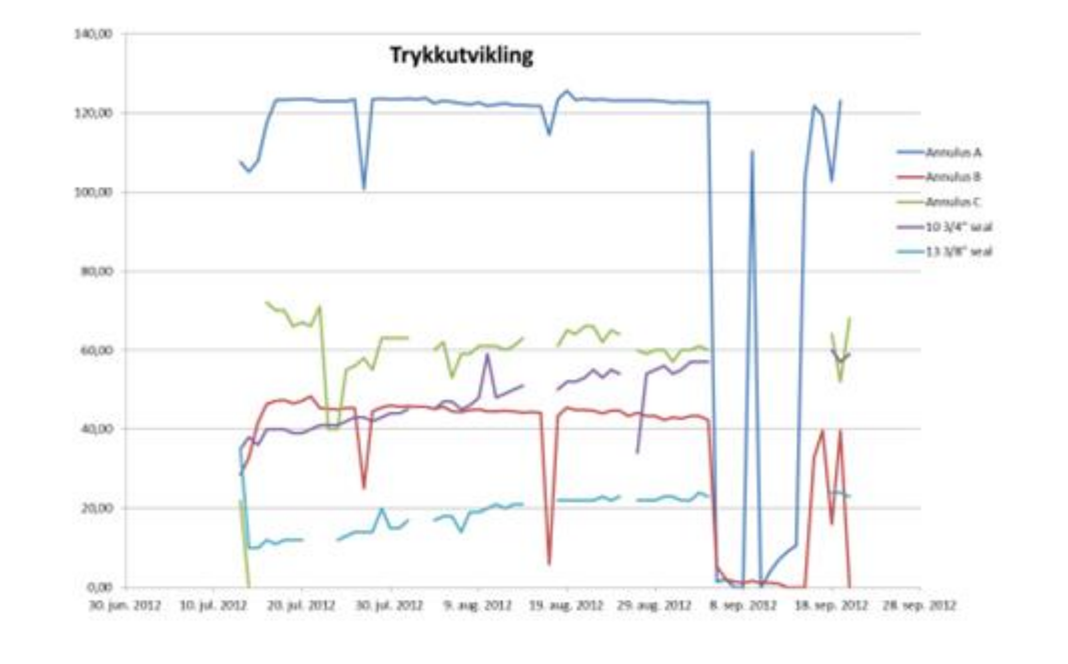
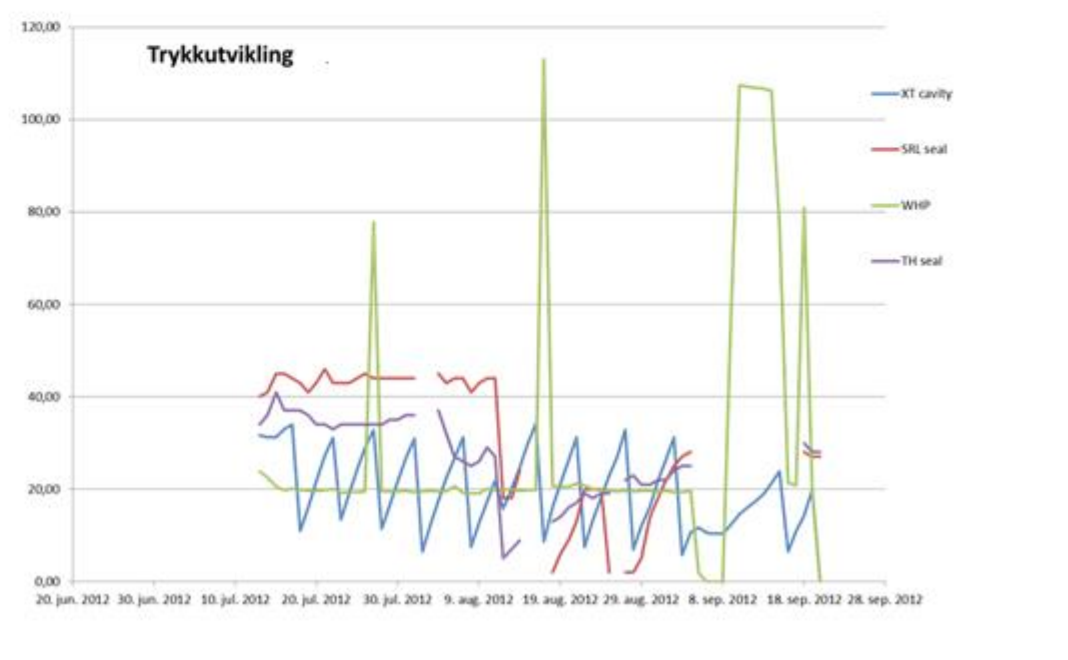
1. Summary – SEAL STATUS

	Seals	Integrity	Reference
SRL seal monitor port cavity	SRL seal (A)	JA!	(3) Lit crude oil observer ved av blødning (6) Stabilt trykkt ~24 bar (3 uke)
	Elastomer seal (B)	Inconclusive	Need more info – eg SRL seal test
XT Cavity	Elastomer seal (B)		
	CF-18 gasket (C)	JA	Daglig "sniffe runde", ingen indikasjoner på lekkasje.
	Exit block	JA	Daglig "sniffe runde", ingen indikasjoner på lekkasje.
	Control line feed thru fittings (D)	NEI	Tester (1) og (2) viser på trykkoppbygging i XT cavity men at TH seal holder tett. Då er gjennom utelukkingsmetoden lekkasje gjennom kontroll linjer gjennomføringer. Plotter (6) viser på langsiktige trykk oppbygning i XT cavity. Rapporter (7) viser at gass er avblødd fra XT cavity.
	TH seal (E)-upper	JA	(2) Test tyder på at øvre seal er ok med ~150 bar og 12 bar i XT cavity og 126 bar i A-annulus
Tubing hanger seal monitor port cavity	TH seal (E)-upper		
	TH seal (E)-lower	JA!	(6) Trend viser at trykk bygges opp 6 til 35 bar på 2 mån. under denne tid har det trykket oppnåtts flere ganger i XT cavity
10 ¾” seal monitor port cavity	10 ¾” seal - upper	JA!	(5) Stabilt ~95 bar +/- 5 bar (1,5 mån) A-annulus stabilt ~130bar +/- 5 bar
	10 ¾” seal - lower	JA!	(5) Stabilt ~95 bar +/- 5 bar (1,5 mån) Stabilt B annulus ~45 bar +/- 2 bar
13 3/8” seal monitor port cavity	13 3/8” seal-upper	JA!	(5) Trend viser trykk økning, 14-16 bar (1,5 mån. B annulus stabilt ~45 bar +/- 2 bar
	13 3/8” seal-lower	JA!	(5) Trend viser trykk økning, 14-16 bar (1,5 mån. C annulus - no functional C annulus

Test A-2

1. Summary - Test August 2012 / pressure trends /bleed off

Item no 1:	Information /		
1: Test (1)	Blødde ned XT cavity(F) fra X bar til 10 bar, blødde av XXXX.		
	~Trykk ved start av test:		
	- XT cavity (F)	10 bar	
	- TH seal monitor port cavity (G)	20 bar	
	- SRL seal monitor port cavity (H)	-	
	- Tubing	18 bar (olje/gass/vann)	
	- A-annulus	120 bar (gass)	
	Trykk endring ~1 time monitoring:		
	=> XMT cavity (F)	10,8 bar til 11,2 bar.	+ 0,4 bar
	=> TH seal monitor port cavity (G)	Stabilt 20,4 bar til 20,5 bar	+ 0,1 bar
2: Test (2)	Trykkte opp TH seal monitor port cavity (G) til 150 bar med nitrogen.		
	~Trykk ved start av test:		
	- XT cavity (F)	11 bar	
	- TH seal monitor port cavity (G)	20 bar	
	- SRL seal monitor port cavity (H)	-	
	- Tubing	18 bar (olje/gass/vann)	
	- A-annulus	120 bar (gass)	
	Trykk endring ~1 time monitorering:		
	=> XMT cavity (F)	11,2 bar til 11,4 bar.	+ 0,2 bar
	=> TH seal monitor port cavity (G)	Stabilt: 150,8 bar til 149,5 bar	- 1,3 bar
3: Test (3)	Blødde ned SRL seal monitor port cavity (H) fra X bar til 0 bar, blødde av XXXX.		
	~Trykk ved start av test:		
	- XT cavity (F)	12 bar	
	- TH seal monitor port cavity (G)	- bar	
	- SRL seal monitor port cavity (H)	0 bar	
	- Tubing	18 bar (olje/gass/vann)	
	- A-annulus	120 bar (gass)	
	Trykk endring ~ 2 timer monitorering:		
	=> XMT cavity (F)	11,7 bar til 12,0 bar.	+ 0,3 bar
	=> SRL seal monitor port cavity (H)	5,7 bar til 11,4 bar på 20 min (XT cavity 11,7)	
		5,7 bar til 11,9 bar	+ 6,2 bar
4: Test (4) - IKKE UTFØRT	Blø ned SRL seal monitor port cavity til ~1 bar. Hvilken fluid?		
	Blø ned A-annulus ~0 bar. Hvilken fluid?		
	Blø ned XT cavity ~0 bar. Hvilken fluid?		
	Trykk ved start av test:		
	- XT cavity (F)	~0 bar	
	- TH seal monitor port cavity (G)	20 bar	
	- SRL seal monitor port cavity (H)	~ 1 bar	
	- Tubing	18 bar (olje/gass/vann)	
	- A-annulus	~0 bar (gass)	
	Trykk endring X time monitorering:		
	=> XMT cavity (F)	?	
	=> SRL seal monitor port cavity (H)	?	
	=> Tubing	?	

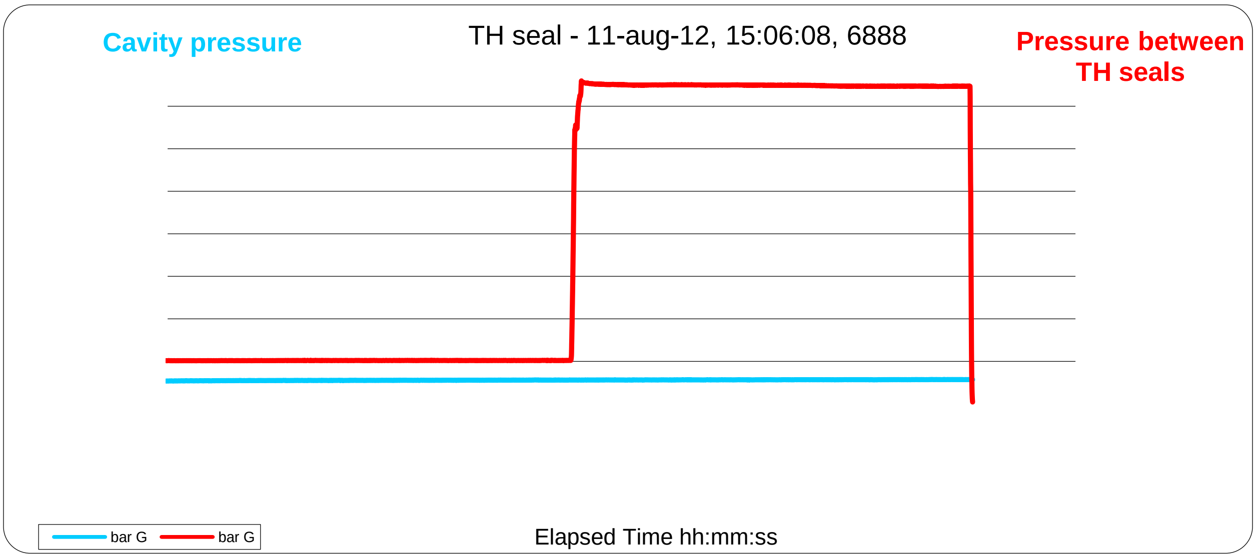
5: Pressure trends: - A, B, C annulus - 10 ¾" seal - 13 3/8" seal	
6: Pressure trends: - XT cavity - SRL seal cavity - Tubing - TH seal	
7: Bleed of from - SRL seal cavity - XT cavity - TH seal cavity	**From 13/7-2012:** **XT cavity (F):** **Blødd av ~35 - 10/5 bar hver 5-6 dag.** **Den siste avblødning i september frekvens på 2 uker.** **Avblødd media: gass (via mail, ikke i daglig oppfølging)** **SRL seal (H):** **Blødd av ~35/20 til 5/0 bar to (2) ganger under perioden (8 dager mellom)** **Avblødd media: gass (via mail, ikke i daglig oppfølging)** **TH seal (G):** **Inget er rapportert.**

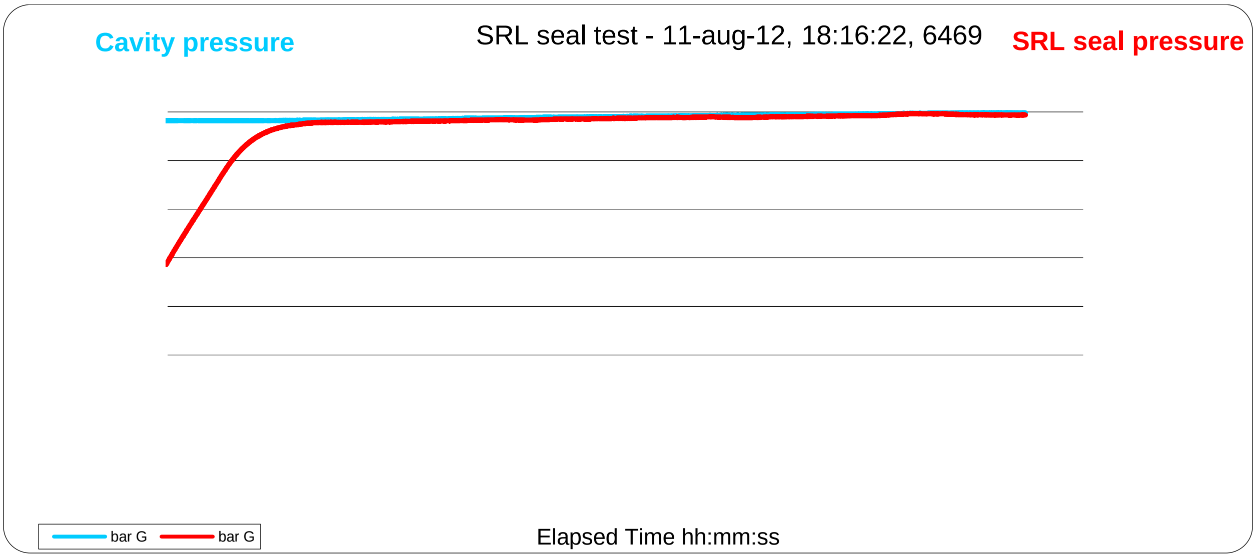
***CAMERON REPORT**

General			
Customer	Statoil.		
Company Rep	Tom Jensen	**Field**	Oseberg
Service Tech(s)	Einar Veim.	**Rig**	Øst
Activity	.		
Departure Date		**Release ate**	

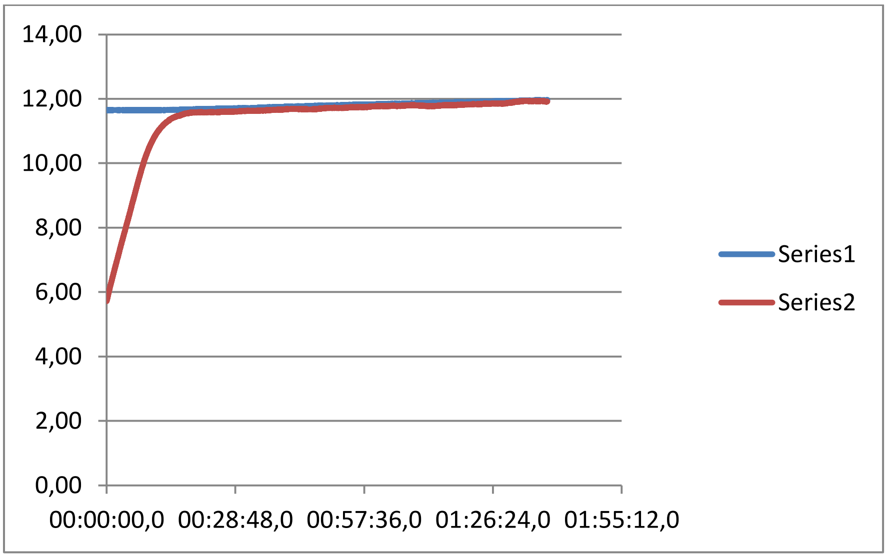
Installation			
System Type	18 5/8" SMCC	**Flange/Connector Type**	18 5/8" Fastlock
Pressure Rating	6500 PSI	**Actual Pressure**	Tubing 18 bar. Gas lift 120 bar
CSG Size	N/A	**Tubing Connection**	
Interface Seal Type	18" CF	**Tree Cap Connection**	

Date	Time	Activity
11/8	13:00 20:00	Avholdt pre jobb møte. Rigget opp Nvision test instrument på cavity test port og tubing hanger test port. Blødde av trykket I cavity til 10 bar. Trykk I tubing hanger test port 20 bar. Monitorerte trykket i mellom tubinghanger seals og i cavity i 1 time. Trykk mellom seals stabilt mens trykket i cavity er svakt stigende. Trykket opp til 150 bar mellom tubing hanger seal. Trykk i cavity 11 bar. Monitorerte trykket i en time. Trykk i cavity er svakt stigende. Trykk i mellom tubing hanger seal er stabilt. Disse testene indikerer at tubing hanger seals holder tett mot gassløft trykket. Trykket som bygger seg opp i cavity kommer mest sansynlig gjennom kontroll linje gjennomføringene i tubing hangeren. Koblet om Nvision til SRL seal monitor port og cavity test port. Blødde SRL seal til 0 bar å beholdt 12 bar i cavity. Trykket i SRL seal øker ganske raskt til samme trykk som cavity å flater ut. Monitorer trykkene i to timer. Trykket i SRL seal følger trykket i cavity. Mest sansynlig lekker gummi sealet mellom cavity og SRL seal. Vil monitorere trykkene i cavity og SRL seal videre fra kontrollrom for å verifisere lekkasje. Rigget ned alt test utstyr fra brønnen å plugget alle testporter.





CAMERON REPORT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Series1
Series2

2. Summary - STATUS TETNINGER

Cavity / Hullrom	Tetninger	Integrity	Referens
SRL seal monitor port cavity	SRL seal (A)	JA !	Test (3) flater ut på 12 bar og ikke på 18 bar som er tubing trykk. Rapporter (7) viser at gass er avblødd fra SRL seal monitor port (med et unntak i begynnelsen) og ikke olje som i tubing. Fra trykk plotter (5) er det rapportert høyere trykk i SRL seal monitor cavity port enn i tubing.
	Elastomer seal (B)	NEI (1 veis?)	Test (3) viser på kommunikasjon der SRL monitor port følger XT cavity trykk. Rapporter (7) viser at gass er avblødd fra SRL seal monitor port (med et unntak i begynnelsen) og ikke olje som i tubing. (6) Trend viser at SRL trykk følger XT cavity opp men ikke ned. (hvilket kan tyde på en veis lekkasje.)
XT cavity	Elastomer seal (B)		
	CF-18 gasket (C)	JA	Daglig "sniffe runde", ingen indikasjoner på lekkasje.
	Exit block	JA	Daglig sniffe runde ingen indikering på lekkasje.
	Control line feed through fittings (D)	NEI	Tester (1) og (2) viser på trykkoppbygging i XT cavity men at TH seal holder tett. Då er gjennom utelukkingsmetoden lekkasje gjennom kontroll linjer gjennomføringer. Plotter (6) viser på langsiktige trykk oppbygning i XT cavity. Rapporter (7) viser at gass er avblødd fra XT cavity.
	TH seal (E) - Upper	JA	(2) Test tyder på at øvre seal er ok med ~150 bar og 12 bar i XT cavity og 120 bar i A-annulus
Tubing hanger seal monitor port cavity	TH seal (E) - Upper		
	TH seal (E) - Lower	JA !	(6) Trend viser at trykk bygges opp 5 til 30 bar på 5 uker under denne tid har det trykket oppnåtts flere ganger i XT cavity.
10 ¾" seal monitor port cavity	10 3/4" seal () - upper	JA!	(5) Trend viser trykk økning fra 40 til 60 bar (2 måneder) Stabilt A-annulus trykk på ~120 bar.
	10 3/4" seal () - lower	JA	(5) Trend viser trykk i seal over B-annulus trykk og stabilt B annulus trykk tyder på at nedre seal er tett.
13 3/8" seal monitor port cavity	13 3/8" seal () - upper	JA !	(5) Trend viser trykk økning, 10 til 25 bar (2 mån.) B-annulus stabilt på ~45 bar.
	13 3/8" seal () - lower	JA !	(5) Trend viser trykk økning, 10 til 25 bar (2 mån.) C-annulus stabilt på ~ 60 bar +/- 10 bar