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Permanent plug and abandonment on Gyda field, challenges, solutions, and qualification of creeping formation to be used as a well barrier in Gyda

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Abstract

Well plugging and abandonment (P&A) presents a very substantial challenge to oil and gas operators, and this challenge will increase exponentially in the coming decades. P&A operation cost the operators billions of dollars without any return in investment.

Every well needs a unique program to plug it, that depends on the construction design, type of well and depth. Many challenges appear during the operation, as restricted access to the desired depth due to the scale deposits, casing collapse and other obstruction. In Gyda field many wells suffer from scale in the production tubing that required remedial operation to remove the scale and get access in order to set the deepest plug and cut the tubing.

P&A is divided into three phases: phase I (wireline phase) where it is conducted from the BOP deck to check well accessibility, cut the tubing and install a double well barrier to remove XMT and install BOP. Phase II is conducted from the drill floor using the rig, where the main and heavy operation is performed as pulling the production tubing and casing, install cement plugs, perform PWC or formation test. Phase III (decommissioning phase) is performed after phase II, which is conducted by cut and remove conductor and wellhead.

To permanently plug and abandon a well, a cross sectional barrier must be formed. In some wells, there is no cement behind the casing at the desired depth to install a barrier. In this case annular barrier must be established to get a cross sectional barrier. This means heavy and costly remedial operation is needed to establish the annular barrier as PWC or casing milling.

In some wells, logging showed good bonding between formation and casing above the theoretical top of cement, and formation communication pressure test verified it, the only justification behind that is the formation deformation where the formation moved toward the annular space and seal it off.

To qualify a formation as an annular barrier, two conditions must be fulfilled, the formation must have an enough strength to withstand the future reservoir pressure and the bonding between casing and formation must provide a hydraulic isolation. In Gyda field, the lower Hordaland formation (Creeping formation) was tested and qualified as an annular barrier.

Preface

This thesis has been executed as a final project of my two-year Master of Petroleum Engineering in Faculty of science and technology at the University of Stavanger.

The train has arrived at the final station in my education. Words and Vocabulary vanish to express the feeling right now, but it is a mixed feeling of happiness, success, and even crying. Finally, I did it and on the right way to get my master certificate.

In this part I should introduce my grateful to people helped me to accomplish it, but believe me, I cannot count you all and thanks-word is not enough to reward your help. I would thank Repsol for offering me an office space to write the thesis, a special thanks goes to 2 persons in Repsol, John Jacobsen as my manager during last summer internship and a friend at the same time, and Per Ove Staveland for his help and guidance during the thesis work and for introducing me this topic. The same thanks go to Espen Malde, Harald Blikra, Øystein Østerhus, Stian Dybvik, Yngve Frøyland and Knut Stanghelle as my small family during my summer internship and thesis in Repsol. The guiding and optimism they have provided has been invaluable.

I also want to send my gratitude to my supervising professor Eirik Kårstad who generously offered his time to provide me with insight and help during writing the thesis.

Thanks very much for Katherine Beltran Jimenez at NORCE and Helge Vindheim at Repsol for helping and checking Creeping shale part in the thesis.

Noura, Aous; my love and my little angel thank you for being patient and finally we have time to spend together.

Nomenclatures

XMT - Christmas tree

P&A - Plug and abandonment

TTOC - Theoretical top of cement

NORSOK - Norsk Sokkels Konkurranseposisjon

LOT - Leak-Off Test

VDL - Variable Density Log

CBL - Cement Bond Log

NCS - Norwegian Continental Shelf

WBE - Well Barrier Element

XLOT - Extended Leak-Off Test

Fig. - Figure

FAB - Formation as Barrier

TTA - Tubing to annulus communication

RKB - Rotary Kelly Bushing

PP&A - Permanent plug and abandonment

TVD - True vertical depth

MD - Measured depth

PWC - Perforate, Wash and cement

EZSV - Halliburton Bridge plug

HUD - Hold Up Depth

CS - Creeping Shale

DHSV - Downhole Safety Valve

HSE - Health, safety, and Environment

IS - Isolation Scanner

BOP - Blow Out Preventer

OBM - Oil Based Mud

MPC - Mechanical pipe cutter

MFC - Multi Finger Caliper

KWV - Kill Wing Valve

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Objectives of this master thesis:

This master thesis focuses on the following issues:

General Objective

Thesis will give a general overview about Gyda field after approximately 30 years of production. It will introduce P&A phases and describe procedures of each phase in details, lighting some tools used during P&A operation.

Objective 1

To understand the challenges to perform P&A operation, describing phases and new technologies and methods overcome.

Objective 2

To present the latest small-scale laboratory tests on creeping shale phenomena describing the effect of temperature, stresses, and chemical solution in the annular space to stimulate the formation to creep.

Objective 3

To explain the most thoughted mechanism of creeping formation and creeping process and try to find a general model of creeping shale.

Objective 4

To present the verification procedure of creeping formation to be used as qualified annular barrier using logging and pressure communication test.

Chapter 1

1. Gyda field overview, procedure, challenges, solutions during P&A

1.1 Gyda field history

Gyda field is located 280 km southwest of Stavanger in the North Sea block 2/1. The field started to produce in 1990, ten years after had been discovered in 1980. Talisman Energy Norge took over operation ship from BP in 2003, then Repsol (acquired Talisman in 2014) reaches an agreement with Talisman Energy to Acquire the Canadian company.

The Gyda field was planned with a water injection scheme, planned to start about a year into the field's production. The injection wells were planned to be drilled from new slots. The first production wells on Gyda came on with oil rates as expected or better than expected. Unfortunately, the wells declined more rapidly than expected and two producers were converted to injectors (A-3 and A-5).

The field was discovered by exploration well 2/1-3. This well is on the crest of the field. Later, 5 appraisal wells were drilled to define the field boundaries. 2 of the appraisal wells were drilled outside the field boundaries. 8 production wells were pre-drilled from Nov 1987 to July 1988, mainly targeting the crest (A-2 to A-8) and well A-1 to what is called the South-West. First oil was from the well A-4 on June 21, 1990.[1]

The Gyda reservoir is Upper Jurassic shallow marine sandstone at a depth of 4000 m TVD. The field consists of 32 wells and the oil was transported by pipeline to Teeside via Ekofisk, while the gas is piped to the Ekofisk Complex and on to Emden.

Repsol has submitted the decommissioning plan to the Norwegian Authorities and got approved in June 2017. The plan includes permanent plugging of 32 wells and the removal of platform as well as the removal of installations on the seabed.

Figure 1:Gyda Platform (Repsol)

License partner

• Repsol Norge AS (operator): 61%

• Ineos: 34%

• Kufpec: 5%

Figure 2: Gyda field location[2] (NPD)

1.2 Gyda Key Information

Table 1: Gyda key information (Repsol)

GYDA KEY INFORMATION	
Well Slots:	32
Water Depth:	65.5 m MSL
RKB Elevation:	56 m
PLATFORM LOCATION:	
Geographical Coordinates: (ED50)	Latitude: 56° 54´ 17.726" N Longitude: 3° 05´ 06.708" E
UTM Coordinates (ED50, Zone 31N)	UTM (ED 1950/Zone 31°N) 6 306 946.90 mN 505 188.97 mE
GYDA Field	
Gyda South Current Pressure:	238 bar
Gyda Main Current Pressure:	250 - 450 bar
Gyda Main Original Pressure:	600 bar – (virgin pressure)
Oil Specific Gravity (API)	40 - 45
Gyda South GOR (Sm3/Sm3)	507,8
Gyda South Bubble Point (bar)	340,7
Gyda Main GOR (Sm3/Sm3)	187
Gyda Main Bubble Point (bar)	221
H2S and CO2 content:	Co2 (1%-2%) , H2S (16 ppm-30 ppm)
Minimum temperature:	4 °C at sea bed
Maximum temperature:	158 °C -160°C at TD

1.2.1 Slot configuration and well status prior to permanent P&A

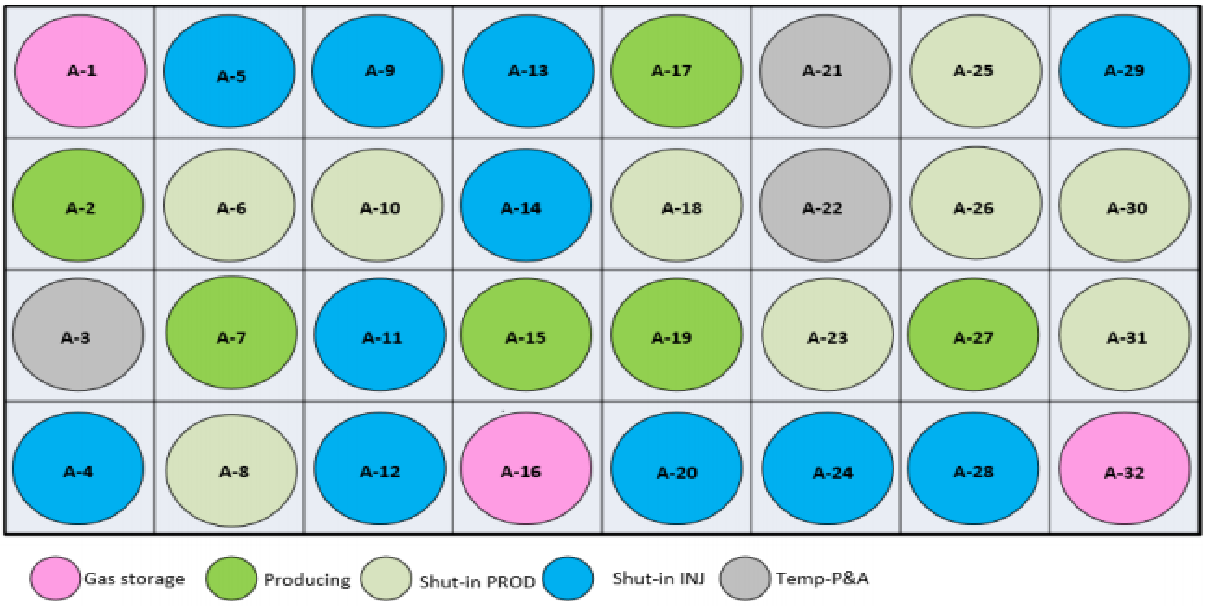


Figure 3: Slot configuration before P&A campaign (Repsol)

On Gyda platform there is 32 well slots. Eight wells (from 1-8) are subsea tie back wells that where pre-drilled prior to the arrival of Gyda platform. These wells were tied back to the platform.

1.3 Geology description

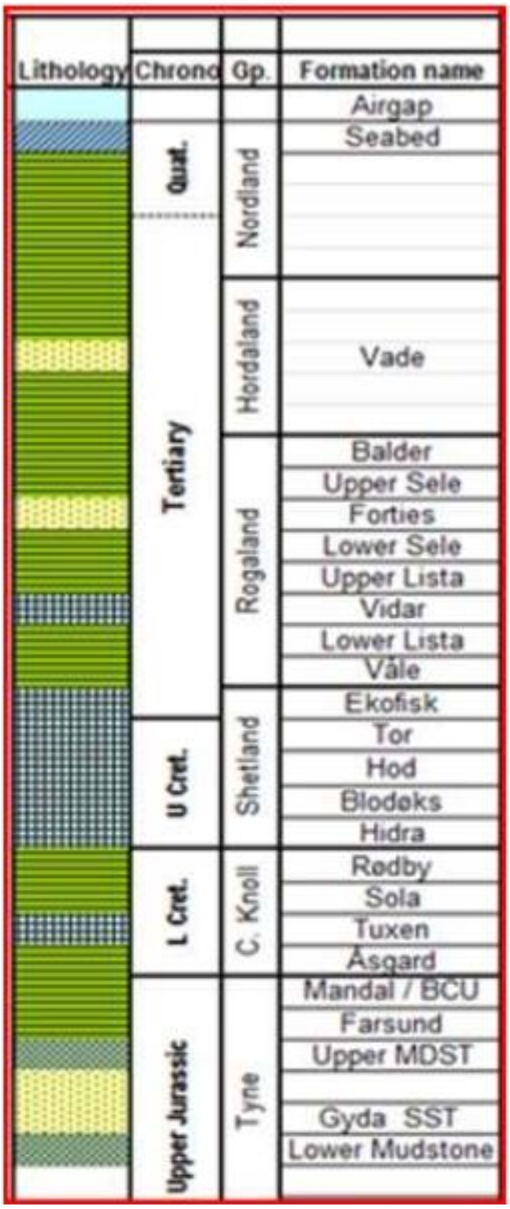


Figure 4: Lithology column and formation name in Gyda field

1.3.1 Formation Description

a. Nordland
b. Hordaland
c. Rogaland
d. Shetland group

e. Cromer Knoll Group
f. Tyne Group

Nordland Group: The upper part of the Nordland Group consists of clay/claystone with interbedded loose sand beds and stringers. All the wells are interpreted do have frequent beds of sand and/or coarser clastic sediments interbedded with clay from seabed and down to approximately 350m MDRKB or 294m TVDSS. These depths represent the average depth for the surface casing string. Further on the lithology is claystone with reduced frequency of sandstone interbeds and sand- and silt stringers and/or traces/disseminated silt and sand grains down to approximately 470m TVDSS, wherefrom present of sand is even more reduced. From 1000m TVDSS only occasional thin siltstone and limestone stringers are present. In some of the wells (2/1-A-5, 2/1-A-17, 2/1-A-20, 2/1-A-22, 2/1-A-23) sand or silt beds have been interpreted to be present deeper than 1000m TVDSS. In the case of well 2/1-A-17, a thin sand bed or stringer is present in the original wellbore but not seen in the sidetrack 2/1-A-17 A, 80m away. These beds are thus thought to be isolated sand bodies with limited influx potential.

No cores or sidewall cores have been taken in the Nordland Group. Permeability and porosity values will therefore be an educated guess. However, the Nordland interval down to approximately 1400mTVDSS is interpreted to be water wet with hydrostatic pressure which gives no influx potential. Creeping formation, which might act as a barrier for upwards migrating fluids, might be present based on drilling experience of tight hole, bit balling & swelling and thyropterid clay in parts of this formation.

Hordaland Group: This group comprises a thick sedimentary sequence of about 1100m TVD. In the production wells drilled by BP the change from the Nordland Group to the Hordaland Group was not identified. Neither has there for most wells been conducted any differentiation in formations within the Hordaland Group. However, the completion logs from the most recent wells have identified the Vade formation, also called Oligocene Sandstone Unit, and the Horde formation. The Vade formation is dividing the Hordaland Group into an Upper and a Lower part. The Hordaland Group above and below the Vade formation has in all wells been interpreted to consist mainly of claystone with stringers of limestone and/or dolomite. However, wells 2/1-A-14 B and 2/1-A-17 have seen sand stringers or beds in the Hordaland Group outside of Vade formation. In some wells the claystone is reported to be occasionally slightly silty, and in places traces of sand is interpreted present. There is an increase in dolomitic limestone stringers with depth.

The Vade formation is estimated to be 50m thick in average and top Vade is at approximately 2300m TVDSS where present. The formation has been identified with sand or silt beds and stringers in 18 well slots. In the rest of the wells the presence of sand and silt in this interval is uncertain. The assessment of the mobility inside Vade is also uncertain due to poor quality of the available data.

The start of the pressure ramp, transition from hydrostatic to overpressure, is interpreted to be at approximately 1400 m TVD, inside the Nordland Group, and the pressure is interpreted to increase gradually through the Nordland and the Hordaland Group. The pore pressure inside the Vade formation is uncertain. In the southern part of the Gyda field indications are that the sand and siltstone stringers may be in communication with hydrostatically pressured sandstone and siltstone beds to the east of the structure. Attempts of mapping the Vade formation on the main structure have not been able to show such continuity towards east, and since the pressure in the claystone above and below is higher than hydrostatic, the resulting interpretation of pressure in the Vade sand and silt beds is uncertain.

The Hordaland Group is interpreted as being water wet.

The Hordaland Group is interpreted to have a very low or non-existing probability for influx. Except for inside the sandy/silty Vade no zones with obvious permeability have been seen on logs and there are no reports of differential sticking from excessive overbalance in the Hordaland Formation. Some minor gas peaks experienced, including connection and trip gas, are thought to come from gas trapped in formations with very low permeability and released by the drilling process, most often because of unstable and tight hole. Creeping formations acting as barriers to flow are most probably present in the Hordaland Group, especially in the green claystone in the lower part. Several wells have experienced tight hole, bit balling, swelling- and thyropterid clay in this part of the formation.

Rogaland Group: The Rogaland Group represents the Paleocene succession and contributes with an average thickness of approximately 300m TVD. The subdivision into formations has changed with time and operator. In early wells the formation package from Sele to top Ekofisk was described as Ekofisk B formation. However, in some other wells the Lista, Vidar and Våle comprised the Ekofisk B formation. Also, the mud loggers sometimes described different formations and formation tops on the formation evaluation/pressure/gas logs compared to the operator's completion log. In this assessment the subdivisions used are Balder, Sele (including Forties), Lista (including Vidar, with upper Lista above and Lower Lista below) and Våle formations.

Sele and Forties: These formations are sometimes lumped together and sometimes split into separate formations. In some wellbores the Sele formation is described as overlaying the Forties formation while in other wellbores the section is divided into Upper and Lower Sele formation with Forties formation separating them. The Upper Sele formation consists of massive claystone with traces of limestone/dolomite, most often interpreted as thin stringers. In some wells traces of tuff are reported present in the upper part of the formation. In many wells the clay is partly described as moderately to slightly silty. Sandstone beds are reported to belong to Sele in some of the wellbores. The Forties formation is generally described as Sandstone and/or Siltstone beds. The Lower Sele formation is described as a continuation of Upper Sele. The thickness of Sele and Forties formation is on average 75 m TVD on the Gyda field.

The Sele formation on the Gyda field has been interpreted to have a formation pressure in the range of 1.50 to 1.55 sg EMW.

Mostly very low gas readings are experienced from this interval. The Siltstone and Sandstone beds are interpreted to be water wet.

The Sele formation is considered to have a very low permeability, potentially being totally tight, with a very low probability of influx. The Siltstone and Sandstone intervals are described as moderately to well sorted. This would normally indicate a good permeability in the Sandstone beds with a lower permeability in the Siltstone beds. No swelling tendencies are described in this interval.

Shetland Group: The Shetland Group represents the Cretaceous succession and contributes with an average thickness of approximately 540m TVD. It has been subdivided into Ekofisk, Tor, Hod, Blodøks and Hidra formations. Formation pressure is interpreted to go from approximately 1.51sg EMW at the top of the group and be reduced to approximately 1.45sg EMW at the bottom of the group. No cores are available from the Shetland Group in the Gyda field, but porosities are estimated to be around 10-20%. Petrophysical data from Ekofisk and Tor is limited, with relative high spread and significant uncertainties. In situ fractures in the limestone may contribute to permeability.

Cromer Knoll Group: The Cromer Knoll Group represents the lower part of the Cretaceous succession and contributes with an average thickness of 239m TVD. In the Gyda field it consists of Rødby, Sola, Tuxen and Åsgard formations. Rødby, Sola and Tuxen formations have been grouped into one section as subdivision of this interval has only been described in the newest wells. The formation pressure gradient in sg EMW is expected to increase in the Cromer Knoll Group. According to the latest estimate the pressure gradient is by Talisman interpreted to be between 1.48 and 1.55sg EMW. A couple of wells have indicated pressure anomalies in the Åsgard formation.

Tyne Group: The Tyne Group represents the upper Jurassic succession and contributes with a general average thickness of 42m TVD before entering the Gyda Sandstone formation. The group has been subdivided into the Mandal and Farsund formations before entering top reservoir. The formation pressure in the Tyne Group is estimated to be approximately 1.59sg EMW in the upper part. This group acts as a cap rock for the Gyda reservoir, and the lowermost part of Farsund might be depleted due to production from the reservoir.[3]

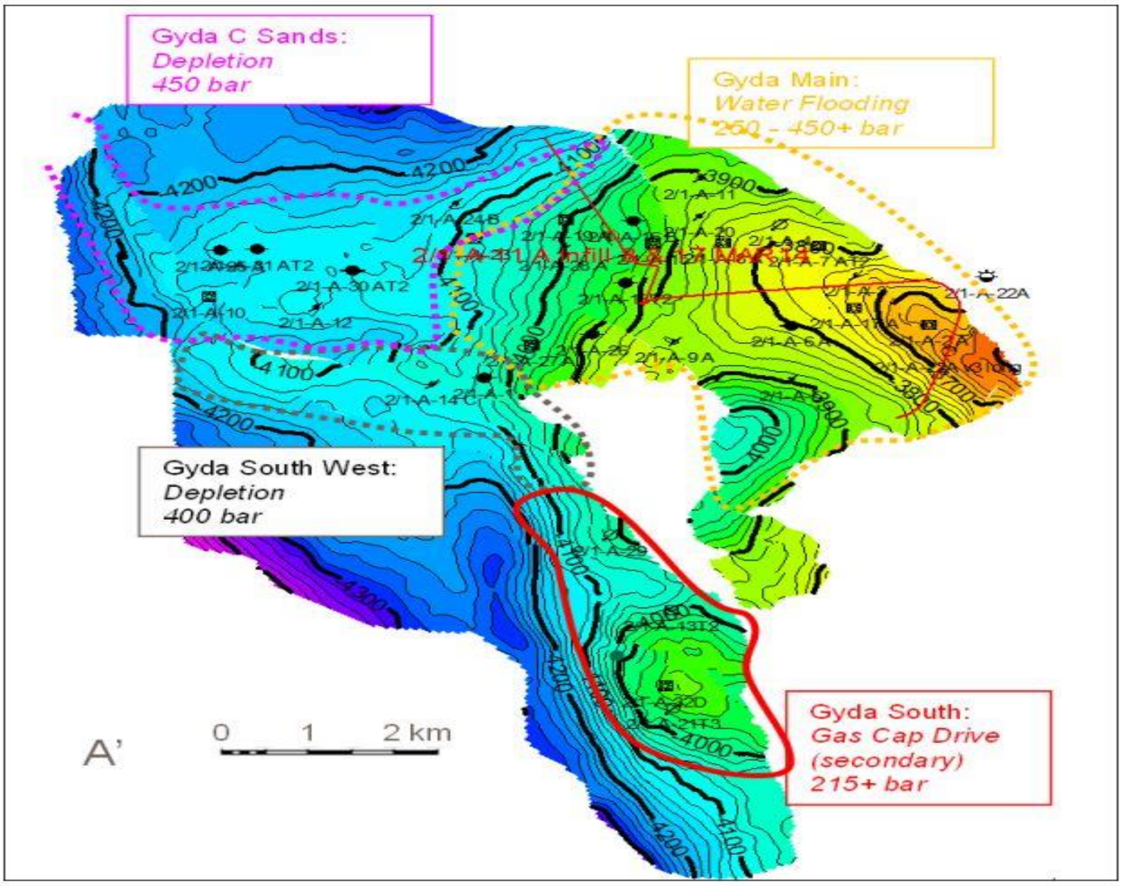


Figure 5: Gyda top reservoir depth map illustrating the main compartments identified by pressure and production data

1.4 Gyda Plug and abandonment concept

1.4.1 Abstract

Gyda has 32 wells which need to be permanently plugged and abandoned. NORSOK D-10 define the minimum requirements for P&A design. Two main inflow zones are identified for Gyda that require isolation and they are:

- Hydrocarbon bearing zones:
    - Gyda reservoir
    - Farsund
    - Lower Åsgard (in 7 wells)
- Water bearing zones with flow potential:
    - Sele/Forties/Lista

The following table shows which formation need to be isolated for every well where the risk of inflow is categorized into 3 groups:

- Low risk of Inflow → no need to be isolated
- Moderate risk → require isolation
- High risk (Gyda formation and Farsund in well A-2) → must be isolated

Where risk of influx is defined by the combination of probability of influx and consequences of influx. The table in next page shows risk of influx in Gyda wells per formation.[4]

1.4.2 Reservoir pressure

The following reservoir pressures have been provided by subsurface department as input to be used in the P&A design:

- Gyda Main:589 bar @datum 4112m TVD RKB.
- Gyda South:325 bar @ datum 3984,5 m TVD RKB.
- Forties:435 bar @ datum 2916m TVD RKB.

Table 2: Risk of Influx in Gyda wells per formation

Risk of Influx Well	Nordland Gp.	Deeper Nordland Gp.	Upper Hordaland Gp.	Vade Fm.	Lower Hordaland Gp.	Balder Formation	Sele Formation above sandy intervals	Sele incl Forties & *Sand in Upper Lista Fm	Vidar Fm.	Våle Fm.	Ekofisk.Fm.	Tor Fm.	Hod Fm.	Blodøks Fm.	Hidra Fm.	Rødby, Sola & Tuxen Fm.	Upper Åsgard Fm.	Lower Åsgard Fm	Mandal Fm.	Farsund Fm. Upper Mudstone Member	Gyda Fm.
2/1-A-1								*						NP?						NP	
2/1-A-2 A								*		ND											
2/1-A-3								NP?*						NP?						NP	
2/1-A-4								*												NP	
2/1-A-5								*												NP	
2/1-A-6 A																				NP	
2/1-A-7 AT2								*													
2/1-A-8 A				NP?				NP?												NP	
2/1-A-9 A								*													
2/1-A-10																					
2/1-A-11				NP?				*													
2/1-A-12				NP?				*													
2/1-A-13				NP?																	
2/1-A-14 C																				NP	
2/1-A-15																					
2/1-A-16 B																					
2/1-A-17 A																				NP	
2/1-A-18 T2				NP?																	
2/1-A-19 A				NP?																	
2/1-A-20				NP?																	
2/1-A-21 T3																					
2/1-A-22 A																					
2/1-A-23				NP?				NP?													
2/1-A-24 B																					
2/1-A-25 A																					
2/1-A-26								*		ND											
2/1-A-27 A																				NP	
2/1-A-28				NP?																	
2/1-A-29				NP?																NP	
2/1-A-30 AT2																					
2/1-A-31 AT2																					
2/1-A-32 D																					

Risk of influx: Low / Moderate / High

NP = Not Present
ND = Not differentiated

1.4.3 Number of barriers

References is made to NORSOK D-010 4.2.3.1 (function and number of well barriers) so the following number of barriers should be in place[5]:

Table 3: NORSOK, 4.2.4.1 Function and number of well barriers

Minimum number of well barriers	Source of inflow
One well barrier	a) Undesirable cross flow between formation zones b) Normally pressured formation with no hydrocarbon and no potential to flow to surface c) Abnormally pressured hydrocarbon formation with no potential to flow to surface (e.g. tar formation without hydrocarbon vapour)
Two well barriers	d) Hydrocarbon bearing formations e) Abnormally pressured formation with potential to flow to surface

According to NORSOK the well barrier should be designed with capability to:

- Withstand the maximum differential pressure and temperature it may become exposed to (considering depletion or injection regimes in adjacent wells).
- Be pressure tested, function tested or verified by other methods.
- Ensure that no single failure of a well barrier or WBE can lead to uncontrolled flow of wellbore fluids or gases to the external environment.
- Re-establish a lost well barrier or establish another alternative well barrier.
- operate competently and withstand the environment for which it may be exposed to over time.
- Always determine the physical position/location and integrity status when such monitoring is possible
- Be independent of each other and avoid having common WBEs to the extent possible.

Despite of the ability to combine both forties and Gyda formation in one well barrier(in some wells) located at the top of forties where we have a good cement or a creeping formation behind the casing that could hold the maximum anticipated pressure in the future and constitute a cross sectional barrier, the plan was to secure Gyda formation with a double barrier and secure forties with another two barriers. That would exceed the minimum requirements stated by NORSOK in the table above.

1.4.4 Crossflow evaluation

In Gyda field two inflow zones need to be secured with two barriers which are forties and main Gyda reservoir. Two main areas are distinguished on Gyda map:

- Gyda south: which has a reservoir pressure (325 bar) lower than forties (435) and in this case the crossflow would be downward toward Gyda
- Gyda main: which has a reservoir pressure higher than forties and in this case the follow would be upward.

The following conclusion has been made when evaluating if crossflow is undesirable:

1) It is acceptable for Forties water to flow down to Gyda reservoir (Gyda South Wells).

2) It is acceptable for Gyda water to flow up to Forties.

3) It is unacceptable for Gyda oil to flow up to Forties.

4) It is unacceptable for Forties water to flow up to Vade formation.

For all Gyda South wells, crossflow will go from Forties and down into the Gyda South reservoir. This is regarded acceptable.

If enough fracture margin exists above Forties, only a double barrier above Forties is required to secure wells. Repsol has decided to place double barriers above each inflow zone and that is more than NORSOK- requirement.

For the Gyda Main wells, crossflow will go from reservoir and up to Forties. It is concluded that crossflow of water from Gyda Main up to Forties is acceptable, but crossflow of oil is not acceptable.

If there is enough fracture margin above Forties, only a single crossflow barrier is required when crossflow is regarded as undesirable. In the event crossflow is acceptable, no crossflow barrier is required. Main plugging strategy for these wells is still double barrier above reservoir and double barrier above Forties. This adds robustness to the P&A design

1.4.5 Placement and depth of the barriers

The placement of the primary and secondary well barriers for both Forties and Gyda will depend on two issues which are:

- Fracture margin: the formation must hold the maximum anticipated pressure

- The presence of cross-sectional barrier whereas the annular barrier can be qualified cement or formation.

If there is a presence of creeping formation, it would be logged, tested, and qualified as we will see in the next chapter that deeper Hordaland formation was qualified as a barrier.

Fracture margin means that the formation fracture pressure is higher than the reservoir pressure or the pressure from below, and that fracture margin should be positive to qualify the formation to place the primary and secondary barrier.

Table 4: The function and the depth position for all type of barriers (NORSOK).

Name	Function	Depth position
Primary well barrier	To isolate a source of inflow, formation with normal pressure or over-pressured/ impermeable formation from surface/seabed.	The base of the well barriers shall be positioned at a depth were formation integrity is higher than potential pressure below, see 4.2.3.6.7 Testing of formation.
Secondary well barrier	Back-up to the primary well barrier, against a source of inflow	As above
Crossflow well barrier	To prevent flow between formations (where crossflow is not acceptable). May also function as primary well barrier for the reservoir below.	As above
Open hole to surface well barrier	To permanently isolate flow conduits from exposed formation(s) to surface after casing(s) are cut and retrieved and contain environmentally harmful fluids. The exposed formation can be over-pressured with no source of inflow. No hydrocarbons present.	No depth requirement with respect to formation integrity

1.4.6 Fracture Margin

Fracture margin is calculated as following:

FM = P frac – (P res - P hyd)

FM: fracture margin

P frac: formation fracture gradient defined by Schlumberger[6]

P res: Gyda pressure after repressuring

P hyd: Hydrostatic pressure column above the reservoir until the barrier, either oil or water depends on the well.

There are no regulations stating what the fracture margin should be and in Gyda field it has been set 10 bars. Formation fracture gradient provided by Schlumberger are conservative, based on actual LOT`s.

1.4.7 Barrier verification

Both the annular barrier behind the casing and the cement barrier inside the casing must be verified to create a cross sectional barrier or what is called a rock to rock barrier. Annular barrier is being verified by logging and testing if necessary.

Annular cement is qualified as a barrier if interval length longer than 30m and bond bonding quality described as moderate to high or better.

Internal cement plug verified by the following concept:

- An EZSV will be installed and pressure tested and will act as the base for the internal barrier.
- After placing the cement, the top of the cement will be circulated out.
- The cement plugs will be tagged for the first 3 wells to confirm method and equipment reliability.

To avoid tagging TOC of an internal cement plug, it needs to satisfy the cement job performance matrix attached in Excel file.

1.5 Well configuration

The wells on Gyda are a mix of the ones drilled and completed by BP and the Talisman wells drilled between 2003-2014. The category that most wells fall into has been named Standard Wells. These wells were drilled from the platform, and the casing design typically consist of a 27” conductor, a shallow 13-3 / 8” surface casing, a deep 9-5 / 8” intermediate casing, 7” production liner and a 4- 1/2” liner across the reservoir. The early BP wells were often completed with a seal stem and no ASV. Talisman wells have production packer and ASV except from the injectors. Tubing is 5-1 / 2” or 5” to below DHSV and crossed over to 4-1 / 2” from this point and down.

1.6 Gyda P&A phases

The P&A phases have been divided into 3 phases:

1.6.1 Phase 1 (wireline phase)

This phase is performed from the BOP deck so it can be performed simultaneously with phase 2 which is performed from drilling rig.

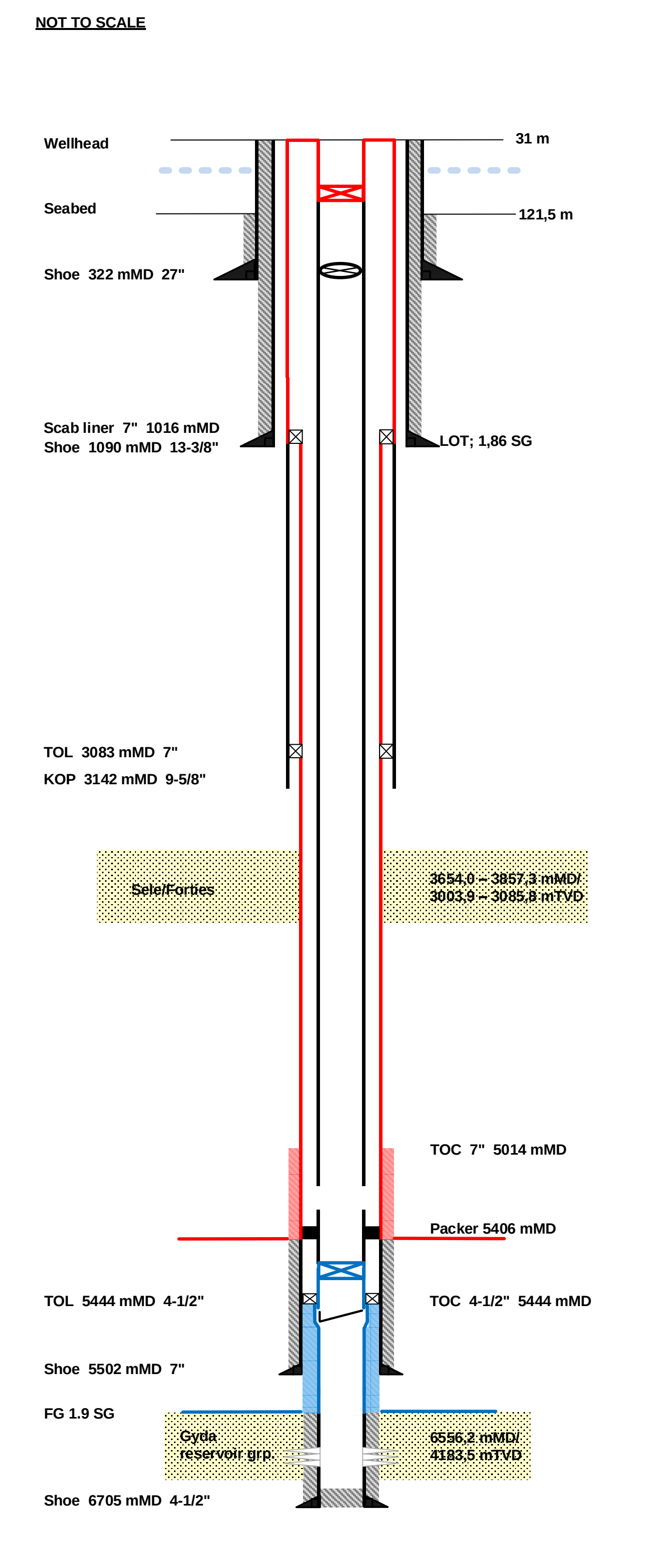
The main objective of phase 1 is to:

- Secure the well with 2 temporary barriers to remove the XMT and install the BOP (phase 2)
- This phase also involves release the annulus safety valve (if present) and cut the tubing
- Bull-heading (if possible) or circulate the HC to SW

The operational steps are:

- ➢ Rig up wireline, perform drift run
- ➢ Remove hydrocarbons by bull heading or circulating to seawater (if possible)
- ➢ Run in hole and install deep set mechanical bridge plug at required depth
- ➢ Pressure-test the mechanical plug
- ➢ Cut the tubing above the packer or seal stem
- ➢ Displace tubing and A-annulus to sea water
- ➢ Release ASV (if present)
- ➢ Set and test shallow tubing plug
- ➢ Rig down Wireline
- ➢ N/D XMT (Offline activity)

Well Barrier Diagram Gyda 2/1-A-31 AT2	Post Phase I P&A



Well information		
Field:	Gyda	
Well no.:	2/1-A-31 AT2	
Well type:	Shut in Oil Producer	
Validity:	N/D XMAS Tree & N/U Drilling BOP	
Revision:	2	October 2019
Prepared:	Øystein Østerhus	

Well barrier elements	Verification of barrier elements
PRIMARY BARRIER	
1. In-situ formation	51
2. Casing cement	22
3. Casing	2
4. Deep Set Mechanical plug	Pressure testet to 150 bar with SW
SECONDARY BARRIER	
1. In-situ formation	51
2. Casing cement	22
3. Casing	2
4. Shallow Set Mechanical plug	Pressure testet to 150 bar with SW
5. Tubing above plug	25
6. Tubing hanger	10
General Comments	

Figure 6: Well barrier diagram shows an example of wells post phase I, well A-31 (Repsol)

1.6.2 Phase 2

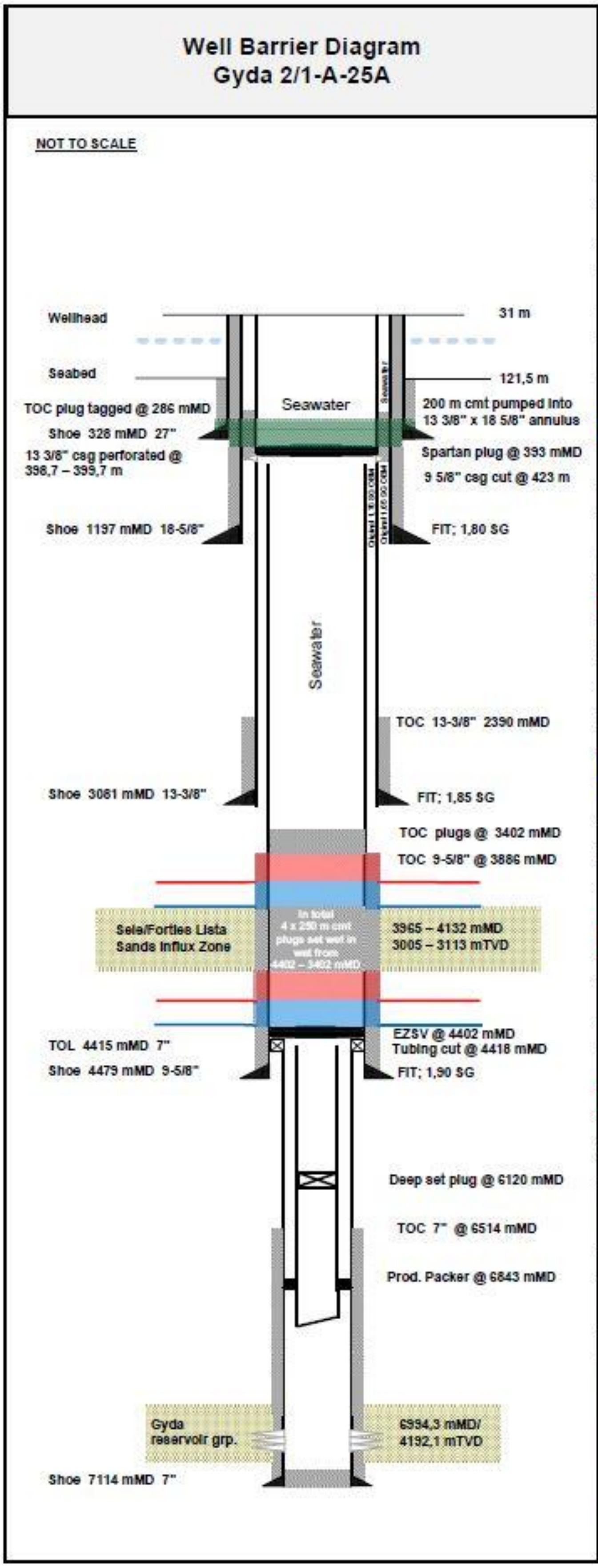
This phase is performed through the rig. The main objectives of this phase are:

- Pull the production tubing
- Log the well
- Permanently secure Gyda reservoir with primary and secondary barriers
- Permanently secure the inflow zones in the overburden (forties) with primary and secondary barriers
- Establishment of the environmental plug

The operational steps are:

- Nipple up the BOP
- Pump open shallow tubing plug
- Retrieve the tubing
- Perform scraper run and displace to weighted mud (if required)
- Run Bond Log to verify annulus barrier
- RIH, set and pressure test EZSV
- Place primary and secondary reservoir barriers on top of EZSV (cement plugs)
- RIH, set and pressure test EZSV
- Place primary and secondary overburden barriers on top of EZSV
- Cut and retrieve the 9 5/8" casing at ± 280 m
- Perform scraper run (Optional)
- RIH, set and pressure test EZSV
- Set 100 m environmental plug (surface plug) on top of EZSV
- Ensure no remaining annuli pressures remains in the wells for phase 3 work.
- Nipple down the BOP
- Skid to next well

Note: If distance between reservoir and forties barrier is less than 1500m, only an EZSV is set and x-nr of 250m cement plugs are set on top.



Phase II P&A

Well information		
Field:	Gyda	
Well no.:	2/1-A-25 A	
Well type:	Oil Producer	
Validity:	Post Phase II P&A	
Revision:	Final	February 2020
Prepared:	Stian Johnsen Dybvik	

Well barrier elements	Verification of barrier elements
PRIMARY BARRIER - RESERVOIR	
1. In-situ formation	Slb base frac strength at top of barrier: 2,05 sg EMW.
2. 9 5/8" casing cement	Barrier set inside qualified cement bond verified by SLB cement bond log
3. 9 5/8" casing	Pressure tested to 400 bar with 1,70 sg OBM
4. Cement plug	Job Performance. Set on pressure tested mechanical plug.
SECONDARY BARRIER - RESERVOIR	
1. In-situ formation	Slb base frac strength at top of barrier: 2,00 sg EMW.
2. 9 5/8" casing cement	Barrier set inside qualified cement bond verified by SLB cement bond log
3. 9 5/8" casing	Pressure tested to 400 bar with 1,70 sg OBM
4. Cement plug	Job Performance. Set on pressure tested mechanical plug.
PRIMARY BARRIER – SELE/FORTIES/LISTA SANDS	
1. In-situ formation	Slb base frac strength at top of barrier: 1,94 sg EMW.
2. 9 5/8" casing cement	Barrier set inside qualified cement bond verified by SLB cement bond log
3. 9 5/8" casing	Pressure tested to 400 bar with 1,70 sg OBM
4. Cement plug	Job Performance. Set on pressure tested mechanical plug.
SECONDARY BARRIER – SELE/FORTIES/LISTA SANDS	
1. In-situ formation	Slb base frac strength at top of barrier: 1,93 sg EMW.
2. 9 5/8" casing cement	Barrier set inside qualified cement bond verified by SLB cement bond log
3. 9 5/8" casing	Pressure tested to 400 bar with 1,70 sg OBM
4. Cement plug	Job Performance. Set wet in wet on top of transition plug.
OPEN HOLE TO SURFACE BARRIER	
1. 18 5/8" casing cement	TOC reported to be at surface. Visual verification.
2. 18 5/8" casing	Pressure tested to 90 bar with 1,30 sg WBM
3. 13 3/8" casing cement	13 3/8" csg perforated & cement pumped into the 13 3/8" x 18 5/8" annulus. Verified by job performance.
4. 13 3/8" casing	Pressure tested to 200 bar with 1,65 sg OBM
5. Cement plug	Cement barrier set on top of spartan plug pressure tested to 100 bar. Tagged at 286 mMD RKB.

General Comments

4 x 250 m cement barriers set "wet in wet" from 4402 to 3402 mMD RKB
Logging results:
Sele / Forties / Lista Sands Barrier
- 440 m Additional barrier formation (3930 – 3446m MD)
- 44 m Additional barrier cement (3930 – 3886m MD)
- 50 m Secondary barrier formation (3836 – 3786m MD
- 50 m Primary barrier formation (3886 – 3836m MD)

Reservoir Barrier
- 14 m Additional barrier cement (4306 – 4292m MD)
- 30 m Secondary barrier cement (4372 – 4306m MD)
- 30 m Primary barrier cement (4402 – 4372m MD)

Figure 7: Well barrier diagram post phase II, for example well A- 25 A

1.6.3 Phase 3 (wellhead and conductor removal)

The conductor and the wellhead are cut and will be retrieved from below the seabed.

- Cut 13 3/8” casing and 27” conductor below mudline.
- Retrieve 13 3/8” x 27” casing/conductor (performed by Allseas Group SA)

1.7 Environmental barrier

The main difference between the plug and abandonment activities and other operational activities like well construction in terms of well integrity is the environmental plug. While it is enough to use 2 well barriers during any well activities, we must install a supplementary plug to the previous 2 barriers which is the environmental barrier during the permanent plug and abandonment (the green plug in the upper well schematic)[7].

The principal function of the environmental plug is:

- Disconnect the open annuli after the casings are cut and retrieved where the OBM and slops left between the casing in B-annulus
- Prevent the slops and cutting which have been injected for many years in B-annulus from exposure to the environment

The environmental plug should be placed above the shallowest sands in each well. These sands range from 370 - 520 m TVD RKB.

1.8 Plug and abandonment challenges and solutions

In this section I will address one of the most challenging issues during the P&A campaign which is the presence of scale. I will pick up one of the 32 wells in Gyda which was the most challenging during the P&A phases. This is well 2/1-A-27 A, due to scale deposits.

What is scale?

Undesired mineral salt deposits on the inner wall of conduit, formation, or surface equipment.

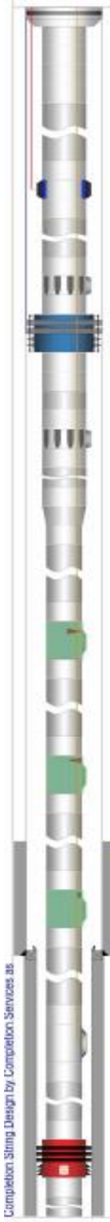
Scale problems exist through the lifetime of the well. This can occur from the time fluids begin to enter production well bore until the water is disposed of or injected into reservoir in injection wells.

Scale deposits are detrimental because they restrict flow of oil or prevent installing different oil tools in the well. Oilfield deposits can be classified into two general categories: organic and inorganic. Inorganic deposits are generally associated with water formed scales such as calcium carbonate, calcium sulphate and barium sulphate.[8]

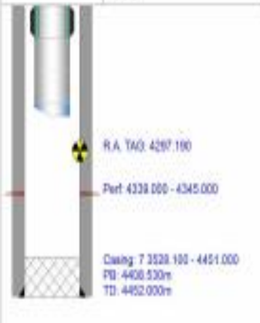
While organic deposits are usually soluble in oil or hydrocarbon-based solvents such as xylene, toluene, kerosene, etc. Many wells in Gyda suffer from scale and the worst case were observed in wells A-10 and A-27

1.8.1 A-27A well- Completion Schematic, Status and Sketch

Gyda 2/1-A-27 A (Main Wellbore)		Existing Gyda Well 2/1-A-27 A	Page: 1 / 4 Opr.Finish.Date: 24.12.2007	REPSOL
Version: 1.00	Tub.Inst.Date: 19.12.2007		Revision: 1.00	Prep. By: SKJELLEVOLL
Rig: Gyda	Status: Oil Producer		Last Update: 03.09.2014 08:14:32	
Comments: Heavily scaled up. HUD = 608m (2" sample bailer)				



Symbol	Symbol Extra Info	MD Top [RKB] [m]	Angle [Deg]	TVD Top [RKB] [m]	Length [m]	Min ID [inch]	Max OD [inch]	Description	Comments
		31.140	0.0	31.140	0.360	4.800	13.300	Tubing Hanger,13 5/8" x 5 1/2" - 3F-3T	
		31.500	0.0	31.500	1.550	4.778	6.100	Pup Anti Galvanic, 5 1/2" 20# 25Cr-125 VTHC PxP	
		33.050	0.0	33.050	3.050	4.715	6.071	Pup, 5 1/2" 20# 13Cr-80 VTHC	
		36.100	0.0	36.100	2.043	4.715	6.071	Pup, 5 1/2" 20# 13Cr-80 VTHC	
		38.143	0.0	38.143	1.108	4.715	6.071	Pup, 5 1/2" 20# 13Cr-80 VTHC	
		39.251	0.0	39.251	503.215	4.715	6.071	Tubing, 5 1/2" 20# 13Cr-80 VTHC	
		542.466	8.1	541.404	3.000	4.715	6.071	Pup, 5 1/2" 20# 13Cr-80 VTHC	
	Control Line: 2x1/4" dual Inc.625 TT400	545.466	8.4	544.373	1.730	4.562	8.187	DHSV-7.5K, 5.5" TRM-4P, 4.56" profile	
		547.196	8.5	546.084	1.860	4.715	6.071	Pup, 5 1/2" 20# 13Cr-80 VTHC	
		549.056	8.6	547.923	26.169	4.715	6.071	Tubing, 5 1/2" 20# 13Cr-80 VTHC	
		575.225	10.6	573.722	2.110	4.715	6.071	Pup, 5 1/2" 20# 13CrSSVM110 VTHC	
		577.335	10.7	575.796	0.660	4.695	8.260	5 1/2" Splice sub	
		577.995	10.7	576.445	0.660	4.715	6.071	Pup, 5 1/2" 20# 13CrSSVM110 VTHC	
		578.655	10.8	577.093	5.140	4.695	8.245	9 5/8" x 5 1/2" Annular Safety valve, AV3	
	Control Line: 2x1/4" dual Inc.625 TT400								
		583.795	11.1	582.140	0.960	4.715	6.071	Pup, 5 1/2" 20# 13CrSSVM110 VTHC	
		584.755	11.1	583.062	0.910	4.715	6.071	Pup, 5 1/2" 20# 13CrSSVM110 VTHC	
		585.665	11.2	583.975	1.230	4.625	8.258	Communication sub	
		586.895	11.3	585.181	0.650	4.715	6.071	Pup, 5 1/2" 20# 13CrSSVM110 VTHC	
		587.545	11.3	585.819	0.660	4.695	8.260	5 1/2" Splice sub	
		588.205	11.3	586.466	1.570	4.715	6.071	Pup, 5 1/2" 20# 13CrSSVM110 VTHC	
		589.775	11.4	588.005	13.082	4.715	6.071	Tubing, 5 1/2" 20# 13Cr-80 VTHC	
		602.857	12.2	600.809	5.030	4.715	6.071	Pup, 5 1/2" 20# 13Cr-80 VTHC	
		607.887	12.5	605.722	0.950	3.913	6.071	X-over, 5 1/2" 20# box x 4 1/2" 12.6# pin VTHC	
		608.837	12.5	606.650	4.050	3.958	4.937	PUP JT, 4 1/2" 12.6# 13Cr-80 VTHC	
		612.887	12.7	610.602	937.834	3.876	4.937	Tubing, 4 1/2" 12.6# 13Cr-80 VTHC	
		1550.721	23.0	1464.351	3.850	3.958	4.937	PUP JT, 4 1/2" 12.6# 13Cr-80 VTHC	
		1554.571	23.1	1467.894	2.800	3.855	7.250	GL Mandrel- MMRG, 1,5" pocket 4 1/2" 12,6# VTHC	
		1554.971			*0.530*		*1.500*	*1.5" R-20 Unloading Valve - 16/64"port*	
		1557.371	23.2	1470.469	2.030	3.958	4.937	PUP JT, 4 1/2" 12.6# 13Cr-80 VTHC	
		1559.401	23.3	1472.334	1183.000	3.876	4.937	Tubing, 4 1/2" 12.6# 13Cr-80 VTHC	
		2742.401	21.7	2561.655	4.030	3.958	4.937	PUP JT, 4 1/2" 12.6# 13Cr-80 VTHC	
		2746.431	21.7	2565.400	2.800	3.855	7.250	GL Mandrel- MMRG, 1,5" pocket 4 1/2" 12,6# VTHC	
		2746.431			*0.530*		*1.500*	*1.5" 02-30 R Orifice Valve*	*16/64" orifice*
		2749.231	21.7	2568.003	2.020	3.958	4.937	PUP JT, 4 1/2" 12.6# 13Cr-80 VTHC	
		2751.251	21.7	2569.880	731.219	3.876	4.937	Tubing, 4 1/2" 12.6# 13Cr-80 VTHC	
	Cement: 3110.000 - 3592.000								
		3482.470	22.8	3248.233	4.050	3.958	4.937	PUP JT, 4 1/2" 12.6# 13Cr-80 VTHC	
		3486.520	22.9	3251.965	2.800	3.855	7.250	GL Mandrel- MMRG, 1,5" pocket 4 1/2" 12,6# VTHC	
		3486.520			*0.200*		*1.500*	*Dummy, 1.5" RD*	
	Casing: 9 5/8 31.000 - 3591.818	3489.320	22.9	3254.545	2.060	3.958	4.937	PUP JT, 4 1/2" 12.6# 13Cr-80 VTHC	
	Cement: 3520.000 - 4451.000	3491.380	22.9	3256.443	694.121	3.876	4.937	Tubing, 4 1/2" 12.6# 13Cr-80 VTHC	
		4185.501	19.4	3897.062	7.640	3.958	4.937	PUP JT, 4 1/2" 12.6# 13Cr-80 VTHC	
		4193.141	19.2	3904.270	1.200	3.833	5.998	Gauge, Roxar - single gauge 4 1/2"	
	Control Line: E-line 1/4"x0.035"WT-825 Inc FEP								
		4194.341	19.2	3905.403	4.040	3.958	4.937	PUP JT, 4 1/2" 12.6# 13Cr-80 VTHC	
		4198.381	19.1	3909.220	36.404	3.876	4.937	Tubing, 4 1/2" 12.6# 13Cr-80 VTHC	
		4234.785	18.0	3943.732	4.380	3.958	4.937	PUP JT, 4 1/2" 12.6# 13Cr-80 VTHC	
		4239.165	17.9	3947.899	2.150	3.855	5.906	Packer, Premier Size 591-387 for 7" 29-32# casing	
		4241.315	17.8	3949.946	4.060	3.958	4.937	PUP JT, 4 1/2" 12.6# 13Cr-80 VTHC	
		4245.375	17.7	3953.812	21.539	3.958	4.937	Tubing, 4 1/2" 12.6# P110 VTHC	



Gyda 2/1-A-27 A (Main Wellbore)	Existing Gyda Well 2/1-A-27 A	Page: 2 / 4 Opr.Finish.Date: 24.12.2007	REPSOL
Version: 1.00 / Tub.Inst.Date: 19.12.2007		Revision: 1.00	Prep. By: SKJELLEVOLL
Rig: Gyda / Status: Oil Producer		Last Update: 03.09.2014 08:14:32	

Symbol	Symbol Extra Info	MD Top [RKB] [m]	Angle [Deg]	TVD Top [RKB] [m]	Length [m]	Min ID [inch]	Max OD [inch]	Description	Comments
		4270.964	17.2	3978.227	1.530	3.958	5.870	Glassplugg, TDP 4 1/2" 12.6# VTHC box x pin	
		4272.494	17.1	3979.689	4.050	3.958	4.937	PUP JT, 4 1/2" 12.6# 13Cr-80 VTHC	
		4276.544	17.0	3983.561	3.580	3.958	4.937	PUP JT, 4 1/2" 12.6# 13Cr-80 VTHC	
		4280.124	16.9	3986.986	0.300	3.856	4.920	4 1/2" 12.6# Half Muleshoe	

Figure 8: Completion schematic before P&A for well A-27A (Repsol)

1.8.2 A-27A status

Here is the status of the well before starting the P&A activities:

Table 5: well status for A-27A before P&A campaign

Well Type	Gas lifted oil producer
Well Depth	4408 m MD / 4119 m TVD
Reservoir Pressure	322 bar (EMW = 0.80 SG)
Reservoir Temperature	147 °C
Estimated SIWHP	13 bar
9-5/8" Csg Shoe	3592 m MD
Max. deviation	34° @ 1030 mMD
Top of 4-½" Reservoir Liner	3528 m MD
4-½" Liner Shoe	4451 m MD
HUD	Nothing reported
Top Perforation	4339 mMD / 4037 mTVD
Minimum ID	1.858"@ 609 mMD (scale below x-over)
Tubing fluid	Gas/oil/water
Annulus fluid	1.03 SG treated seawater
Annulus pressure	139 bar
Comments to XMT valve status	NA
Tree cap size	9"
Number of turns to operate swab	27 1/2 turns
RKB - SV depth	26.84 m
Injectivity	10-20 $Sm^3/d/bar$

1.8.3 Well data

General;	- **Year drilled;** 1992 - **Current completion installed;** 2007 - **Type;** Producer
Completion;	- **Size;** 5-1/2” x 4-1/2”, x-over @ 608 m MD - **Threads;** VTHC - **Min ID;** 3.833” @ 4193 mMD (Roxar Gauge) - **Max inclination;** 34® @ 1030 m MD - **Tubing hanger;** Kvaerner 13-5/8” x 5-1/2” - **DHSV;** Schlumberger TRM-4P @ 545 m MD - **Packer;** Baker Premier packer @ 4239 m MD - **DHPG;** Roxar single gauge @ 4193 m MD
Intervention;	- **HUD / OD / year;** 1.75” / 4280 m MD / 2017 - **Caliper min ID / year;** 1.889” at 610 m / 2017 (Logged interval 31-605 m. 2.922” @ 587 m / 2013) - **Debris;** Heavily scaled up - **Latest intervention;** Diagnostics campaign 2017 - **Plug/gauge-hanger/insert/fish depth;** NA
Integrity;	- **Green/yellow/red;** Green - **Tubing to annulus communication;** NA - **Annulus to annulus communication;** NA - **DHSV, CTRL status;** ok
Reservoir;	- **Top perf;** 4339 m MD / 4043 m TVD - **Reservoir pressure;** 322 bar at 4280 m (wireline 2017) - **Temperature at gauge;** 153®C (152C at 4280 m wireline 2017) - **Injectivity;** See scale squeeze in 2011 - **PI;** 10-20 Sm3/d/bar - **Scale squeezed / or injection rate and pressure;** 214 m3 / 3 bpm in 2011

1.8.4 Completion Sketch before P&A

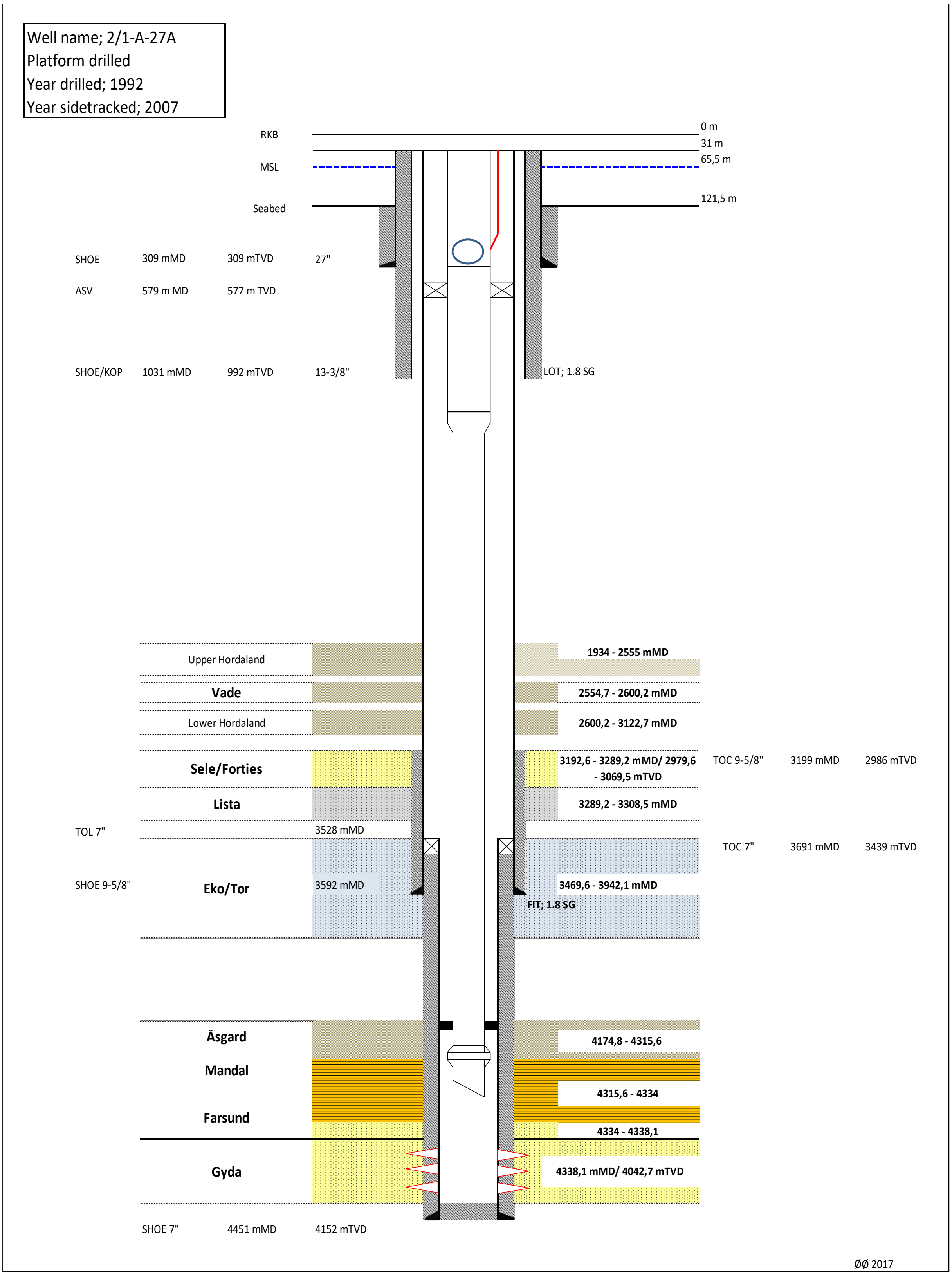


Figure 9: Sketch of well A-27A before P&A (Repsol)

A-27A well is an oil producer well and has two production tubing sizes 5.5” down to 608m MD and then 4.5” to 4280m MD. The top of perforation at 4339m MD. The packer is situated at 4239 m MD. DHSV at 545m MD and ASV at 578m MD. The well is shut in and handed over the P&A operation from the production department with DHSV and HMV closed, tested and pressure bleed off.

1.9 Phase I for A-27 Procedure, Challenges, Solution

A-27 well was the most challenging well during the phase I in Gyda P&A and had incredible amount of problems during the operation. I could point out that the main challenge was the restricted access due to the high amount of scale deposited on the inner wall of the tubing.

- It was not possible to make a hole inside the tubing to establish a circulation between the tubing and the annulus and in this way, thus it was not possible to mill out the scale inside the tubing and get the scale debris through the annulus.
- It was very difficult to fish the dropped and stuck tool string inside the tubing due to the small inner diameter
- Due to the inability to run ASV punch tool (has large OD), it was necessary to shoot string-shots in ASV to remove scale and use Baker Mechanical pipe cutter and cut ASV.
- Based on these challenges, changes had to be made to the planned program to solve the challenges faced during the operation.

In the next pages I will address how phase I in A-27 performed, describing the problems and solutions to overcome it, but before that I would show you the result of MFC survey conducted in 2017 before commencing the P&A operation.

1.9.1 Multi Finger Caliper survey (MFC)

Before starting to introduce MFC result I want to familiarize you with MFC tool.

Multi Finger Caliper provide measurements of the internal radii of tubing and casing used to evaluate well performance. Spring loaded caliper fingers contact the inner surface of the wellbore and move independently to track any variation in downhole geometry.

The MFC can be used to detect casing deformation, holes, scale deposition, paraffin build-up, and inner wall corrosion. The position of each finger and its relative orientation in the well are digitized to provide a complete 360° map of the wellbore profile.[9]

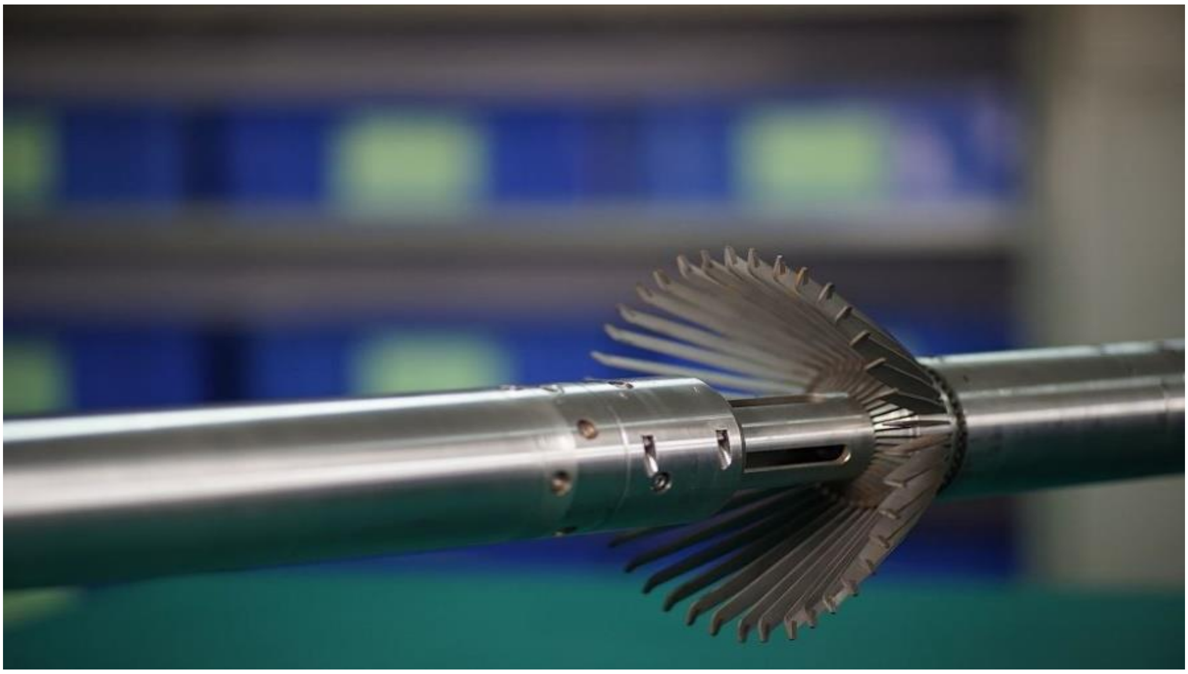


Figure 10: Multi Finger Caliper Tool (Baker Hughes)

In April 2017(before P&A camping which started in January 2020), drifted well with 1.75" dummy cutter to 4280 m (end of tail pipe - No HUD). Changed over to 5/16" e-line. Ran 24 arms MFC survey from 4273 m to surface.

At 4273 m (HUD) Temperature: 152 deg C. Pressure: 322bar. Tubing down to 4273 is affected by scale deposits. From 1700 m and below there is evidence of heavier scale deposits. The minimum cross well ID is 1.889 in at 609.9m immediately below the cross over between 5.5” and 4.5” and falls below 2 inches at several locations between 608.5m and 614.1m.

There are few indications of loose debris indicating that the scale is attached to the pipe wall. The short interval of 5.5in tubing above 39m also appears to be free from significant scale deposition.

The interval between 3490m and 3600m is particularly clean, showing almost no scale. The completion hardware components are affected by scale except for the DHSV and pup joints either side which appear to be relatively free from scale.

Here is some data got during 2017 MFC:

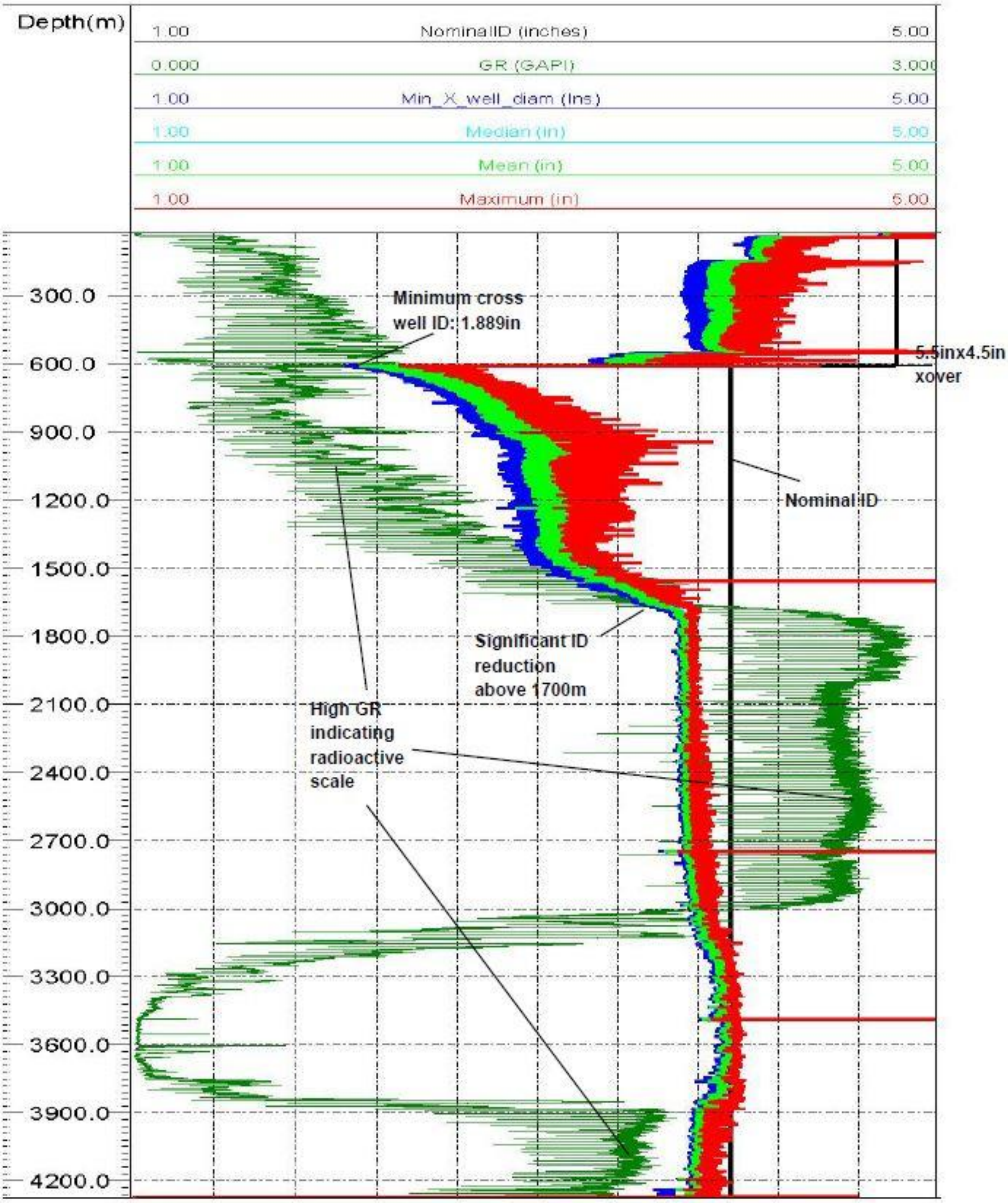


Figure 11: MFC chart for A-27 A conducted in 2017 before P&A (Archer)

In May 2019, another 24-finger caliper was run in well 2/1-A-27 A with the following objectives[10]:

- Compare data with that acquired in 2017 over the same interval to assess scale accumulation
- Identify suitable 4.20in OD plug setting areas between hanger and 150m MD

- Overview of general tubing condition with respect to deposits: determine minimum ID and max penetration
- Assess DHSV for scale-Determine minimum ID between DHSV and hanger
- Determine minimum ID at hanger

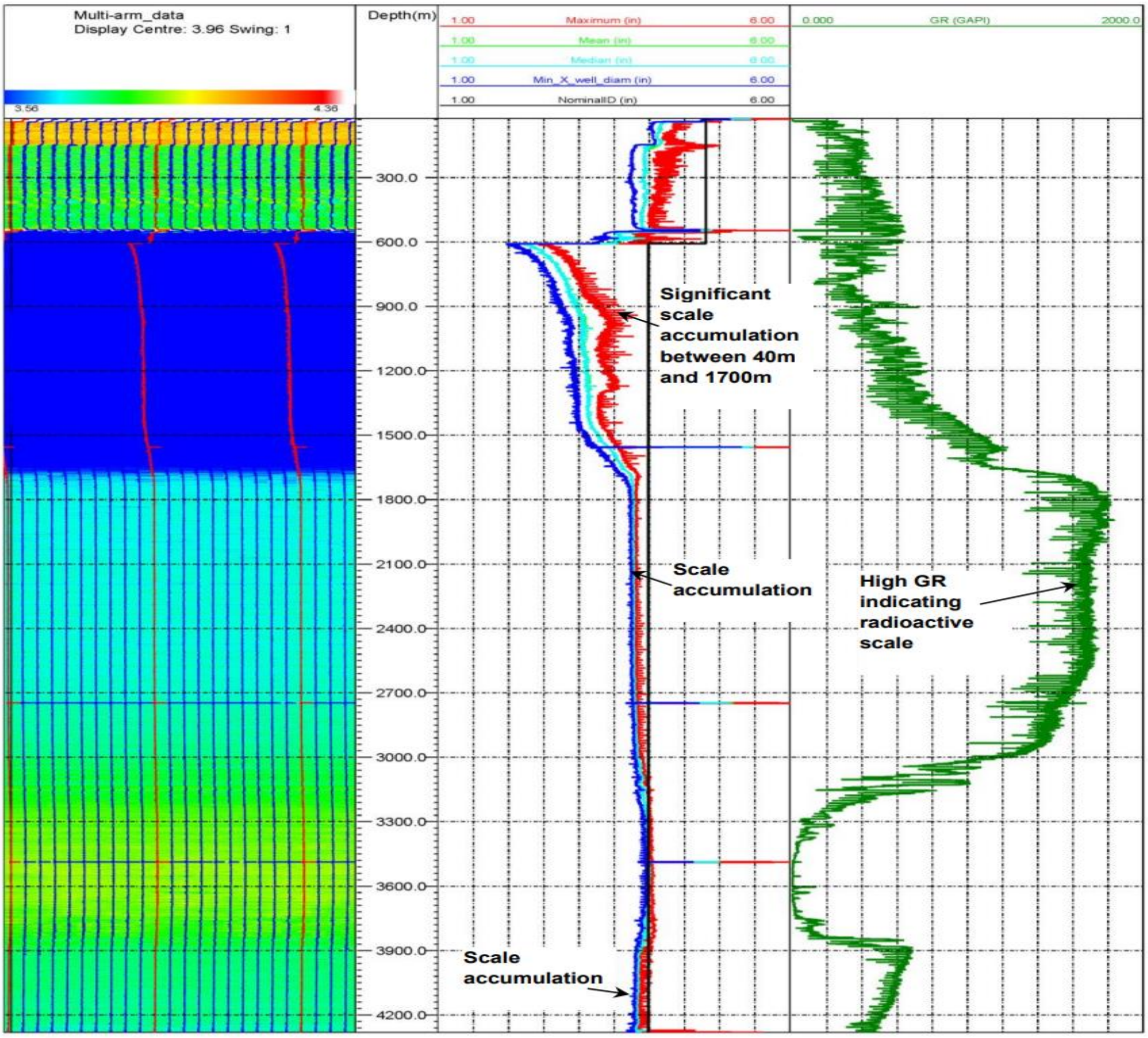


Figure 12: MFC chart result for A-27 A in 2019 provided by Archer

The result shows that:

1. The tubing is significantly affected by the radioactive scale which is more than 1.5 mm thick in the intervals 39.5- 3288 m and 3720-4280m.
2. Between 3288-3750 m MD seems to be unaffected by scale and the tubing has the origin ID
3. The higher scale deposition is between 39m and 1700m MD which is thicker than 10 mm.

4. The worst scale deposition presence at the crossover between 5.5” and 4.5” tubing where ID is about 1.858 at 609.1[11]

Relating these results with the results obtained in 2017, there is no considerable difference in terms of the scale thickness where the mean ID curves for both surveys do not show a noticeable change.

To evaluate the shallow plug setting depth, below 39.5m the tubing is affected by significant scale deposits and from surface down to 150m, the minimum ID is 3.869in at 75.2m. Between the tubing hanger and 39.5m the tubing appears to be clean with scale thickness <1.5mm. DHSV appears to be unaffected by scale and keep the nominal ID.

Comparing between the two MFC charts (in 2017 and 2019), there is no significant difference in terms of scale thickness as it appears in the following charts.

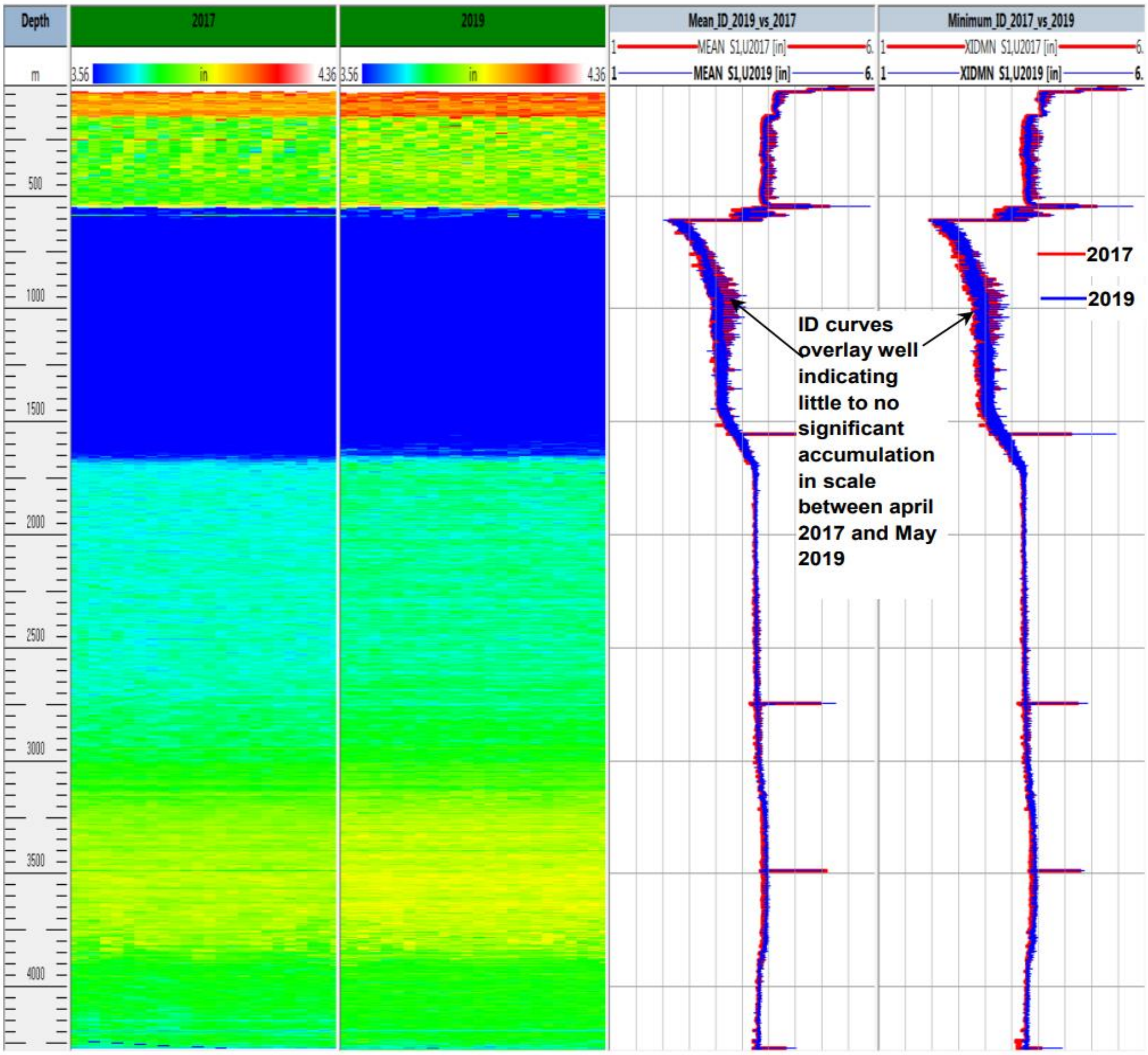


Figure 13: MFC comparison between 2017 and 2019 for well A-27A (Archer)

1.9.2 Problems faced and solutions during performing phase I in well A-27

The objective of phase 1 is to secure the well temporarily with two barriers to remove the XMT and install the BOP, one deep plug (mechanical or cement) and a shallow plug. Cut the tubing and displace the well to seawater to remove HC.

The procedure for phase I as follows[12]:

1. **Bullhead Seawater**

The well was bull-headed with 2m3 MEG/SW to check the injectivity of the formation, which was very low, and clean the well from HC.

2. **Punch tubing at 3804 m MD, with 1.75” plasma puncher**

During RIH with BHA, BHA got stuck two times at 120m and 54m. After measuring cable OD, it found that the cable was varied in OD, the cable cut and made a new cable head, RIH again and punch at 3804m.

3. **Circulate and bullhead tubing and A-Annulus to SW.**

Well status

- The well is open to the reservoir
- Tubing punched/cut at 3804m MD
- Annulus/completion content is 1.03 SG seawater and lift gas

Objective

- Circulate tubing and A-annulus to seawater.
- Establish injectivity and circulation rates after punching.
- Monitor and record annulus pressure during operation.

4. **Cement plug through the tubing:**

In this phase a cement plug pumped into the reservoir to make the first barrier to disconnect the XMT. I will not go into detail in the cement program since it is out of the scope here.

Well status

- Tubing punched @ 3804 m MD, above packer.
- Tubing and A-annulus displaced to seawater.

Objective

- Bullhead cement through tubing into reservoir.

The cement job was performed as per program and no challenges were faced. Due to the restricted diameter of the scale, brushing XMT down to DHSW was not possible.

5. **Drift run on slickline and leak test cement plug:**

The cement plug is waited until get its hardness, then it needs to be tagged and tested. A 1.8" drift RIH to find HUD of the cement plug which was at 4017 m. After that cement plug is tested to 100 bar and the test was ok.

6. **Cut the tubing challenges**

The tubing needs to be cut above the packer to enable pulling it out of the well in phase II. In this phase many obstructions where faced when lowering the BHA in the hole and all these problems related to the scale deposits.

Well status

- Tubing cut/punched with split shot at 3804m MD
- Tubing and A-annulus circulated to seawater
- Cement plug at 4017 m MD tagged and tested

a. RIH with Split-shot, correlated and fired split-shot, misfired after several attempts. POOH

b. RIH with plasma cutter stopped at 612 m (severe tubing restriction area), not able to pass through the scale, worked with tool string to pass, lined up from cement unit and pressured up well to 100bar, kept annulus side open to closed drain, Pressured up and bled off well head pressure and attempted to pass restriction with BHA, all these attempts does not work to pass the restriction. POOH

c. A new BHA with split shot 1,375" RIH, passed the restriction and made a shoot at 3800 m MD, attempted to circulate with cement pump. Pumped in total 290L and pressure on tubing increased to 150 bar and A-annulus pressure 2 bar, no indication for communication between tubing and A-annulus. POOH

Before continuing, I mentioned that plasma cutter and split shot tools, what are they?

Plasma cutter or Perforating Torch Cutter (PTC) provides a reliable pipe punching alternative to explosives. Perforating Torch Cutter tool perforate tubing without the use of explosives or hazardous chemicals. [13]

Figure 15: Plasma cutter tool used to make a hole in TBG (Repsol)

Figure 14: Result of PTC (Halliburton)

While Split Shot Cutter was designed for use where traditional jet cutters were not effective or could not be used. The Split Shot Cutter is run in a linear configuration adjacent to any collar or connection. After detonation, the collar or connection is split vertically allowing the pipe to be freed for easy removal. [14]

The adjacent image shows that the hole is vertically, and, in this case, it will be easier to free the tubing and make a connection between the tubing and the annulus.

Figure 16: Split shot result on tubing (Halliburton)

d. RIH a new BHA with plasma puncher 1.75”, but also a circulation not obtained between TBG and A- annulus.

It is the time now to check if the ASV is closed or open, maybe it was closed and prevented the circulation.

Lined up cement unit and applied pressure to TBG 130 bar, no pressure increases in A-annulus (3,0 bar A-annulus). Decided to pressure up A-annulus, lined up cement unit and pumped in A-annulus up to 70 Bar, TBG pressure followed up to 70 Bar. Bled down A-annulus to 1,5 bar and TBG pressure dropped down to 0,5 Bar. Now a confirmation that ASV is open is obtained.

The next plots show a pressure build up graph for both circulation from the tubing to annulus and vice versa.

e. After checking that ASV is open, a new MFC survey RIH to confirm the existing of the holes made in the tubing wall.
f. Several new BHA with split shot and plasma puncher RIH to establish a communication between the TBG and annulus. The status of the well now as follow:
   - 1.75’’ puncher at 3804 m, 4-1/2’’ tubing inside 7’’. (caliper confirms hole)
   - 1-3/8’’ split shot at 3800 m, 4-1/2’’ tubing inside 7’’. (no hole/cut on caliper)

Moving up to avoid any potential settlements outside the tubing.

- 1.75’’ puncher at 3755 m, 4-1/2’’ tubing inside 7’’. (caliper confirms hole)
- Caliper to check perforation status.
- 1-3/8’’ split shot at 3740 m, 4-1/2’’ tubing inside 7’’.

Moving further up and out of 7’’ liner to avoid any potential settlements outside the tubing.

- 1.75’’ puncher at 3522 m, 5-1/2’’ tubing inside 9-5/8’’. (misfired)
- 1.75’’ puncher at 3522 m, 5-1/2’’ tubing inside 9-5/8’’.

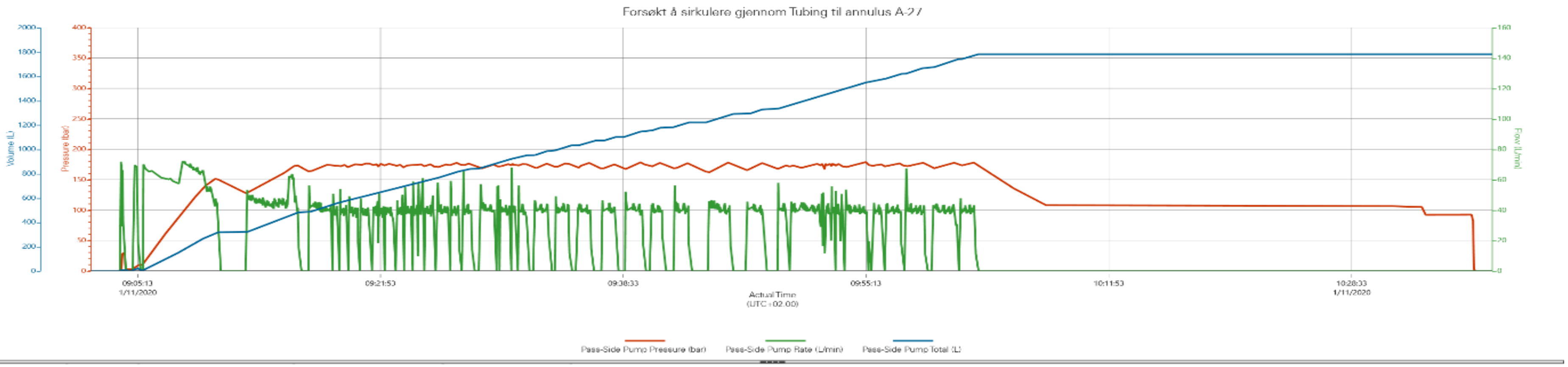
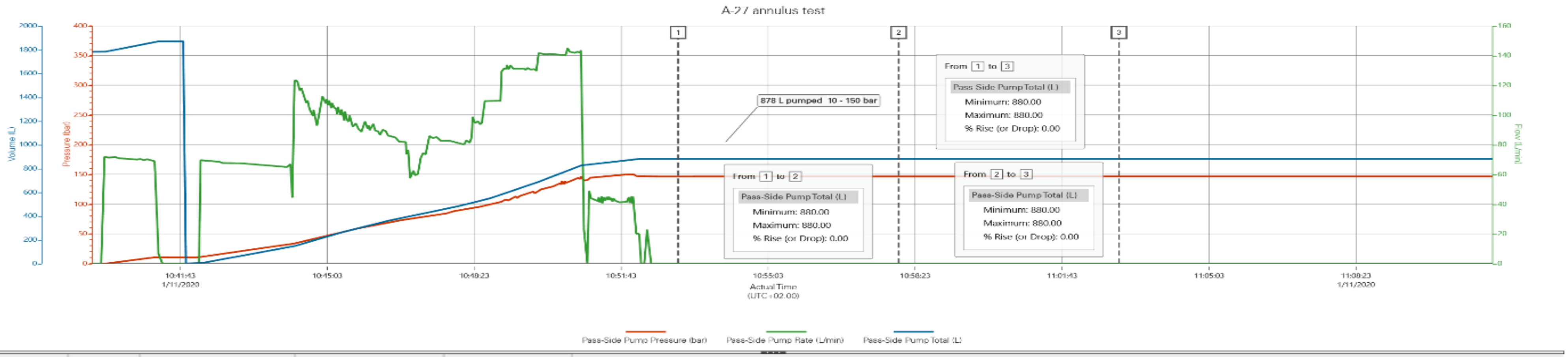


Figure 17: Circulation pressure plot from tubing to A-annulus for A-27A



Description	Actual Time (UTC+02:00)	Pass-Side Pump Pressure (bar)	Pass-Side Pump Rate (L/min)	Pass-Side Pump Total (L)
1 Pressure Test	10:53:01	146.32	0.00	880.00
2 Pressure Test	10:58:01	146.32	0.00	880.00
3 Pressure Test	11:03:01	146.17	0.00	880.00

Figure 18: Circulation pressure plot from A-annulus to the tubing for A-27A

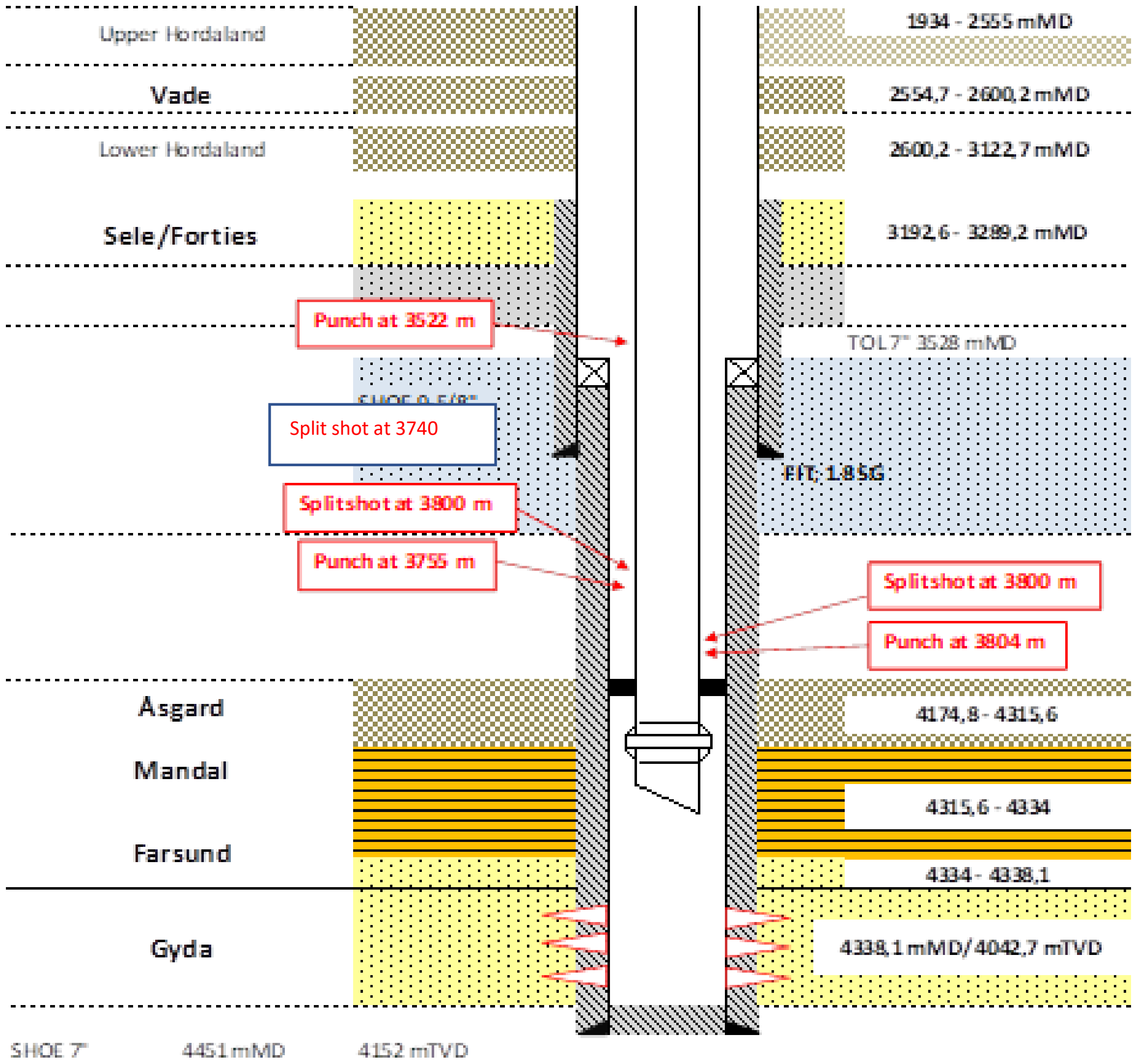


Figure 19: well schematic for A-27A shows places for holes in TBG

After all these punches, TBG and A-annulus are pressure tested to find out whether there is a communication or not and got the following results:

- Pressured up TBG from 10 to 150 bar, while the A-annulus was just 3.6 bar
- Continued pressuring up to 175 bar and maintained pressure by pumping then the A-annulus raised to 80 bar and increasing slowly.
- Lined over to test the whole well volume by pumping in annulus and into tubing at the same time through GLV to see if any solids settlement of any kind or casing collapse prevented circulation.
- Pressured up annulus and tubing (through GLV) from 10 to 150 bar (which is also perfect to test the cement plug again), the volume pumped was 878 liters, where the theoretical volume is 855 liters.

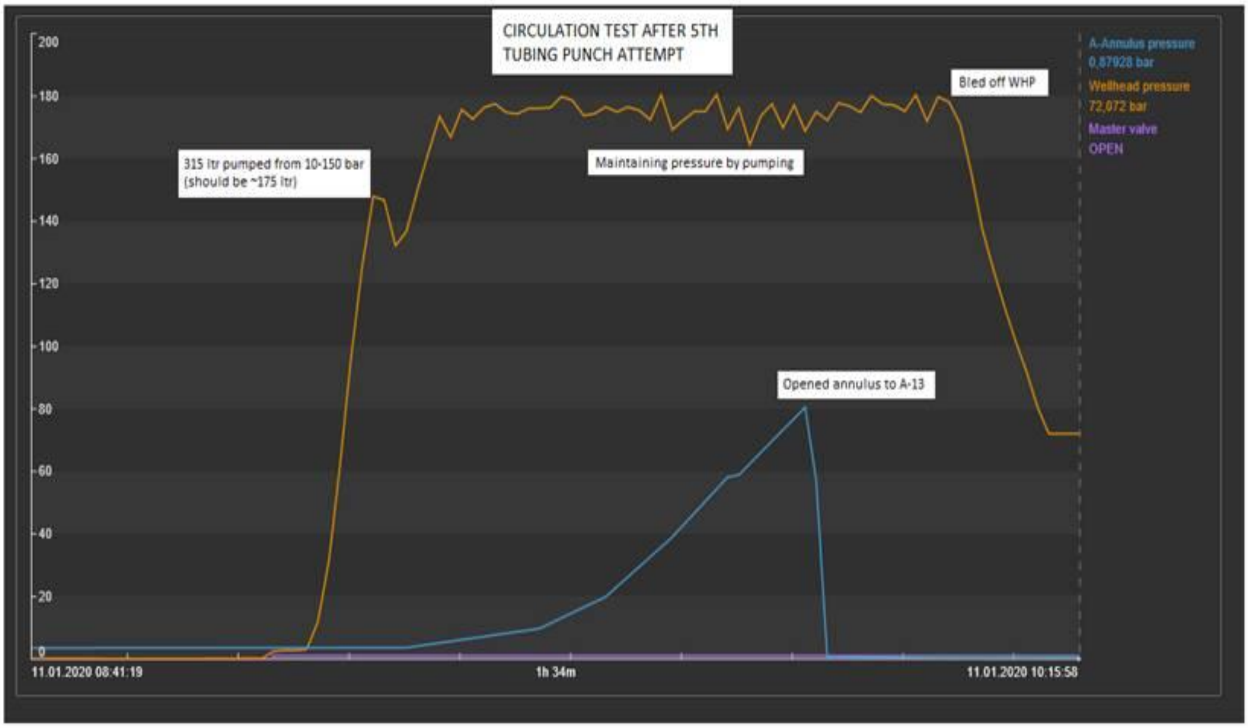


Figure 20: Plot shows a circulation test done after the 5th punch attempt (including split shots, minus misfired plasma).

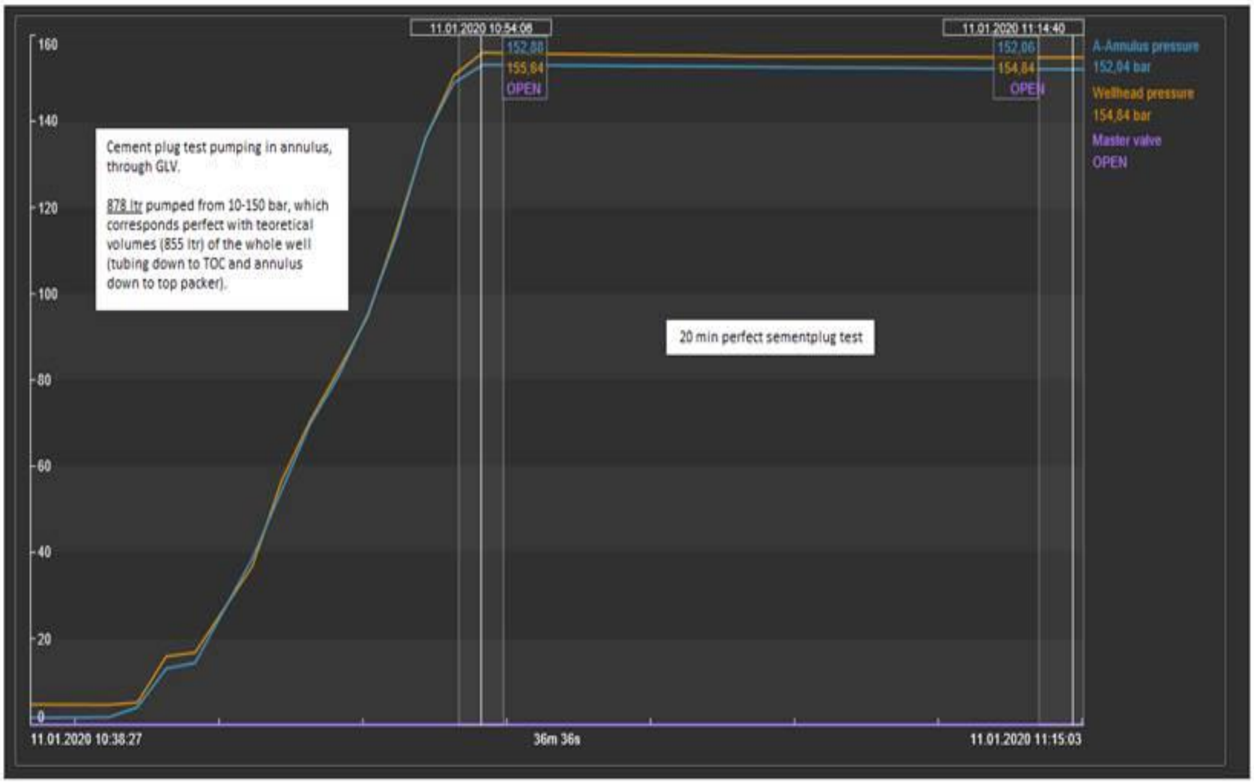


Figure 21: Testing the Cement plug by pumping in annulus, through GLV, 878liter pumped from 10-150 bar, which corresponds perfect with theoretical volumes (855liter) of the whole well.

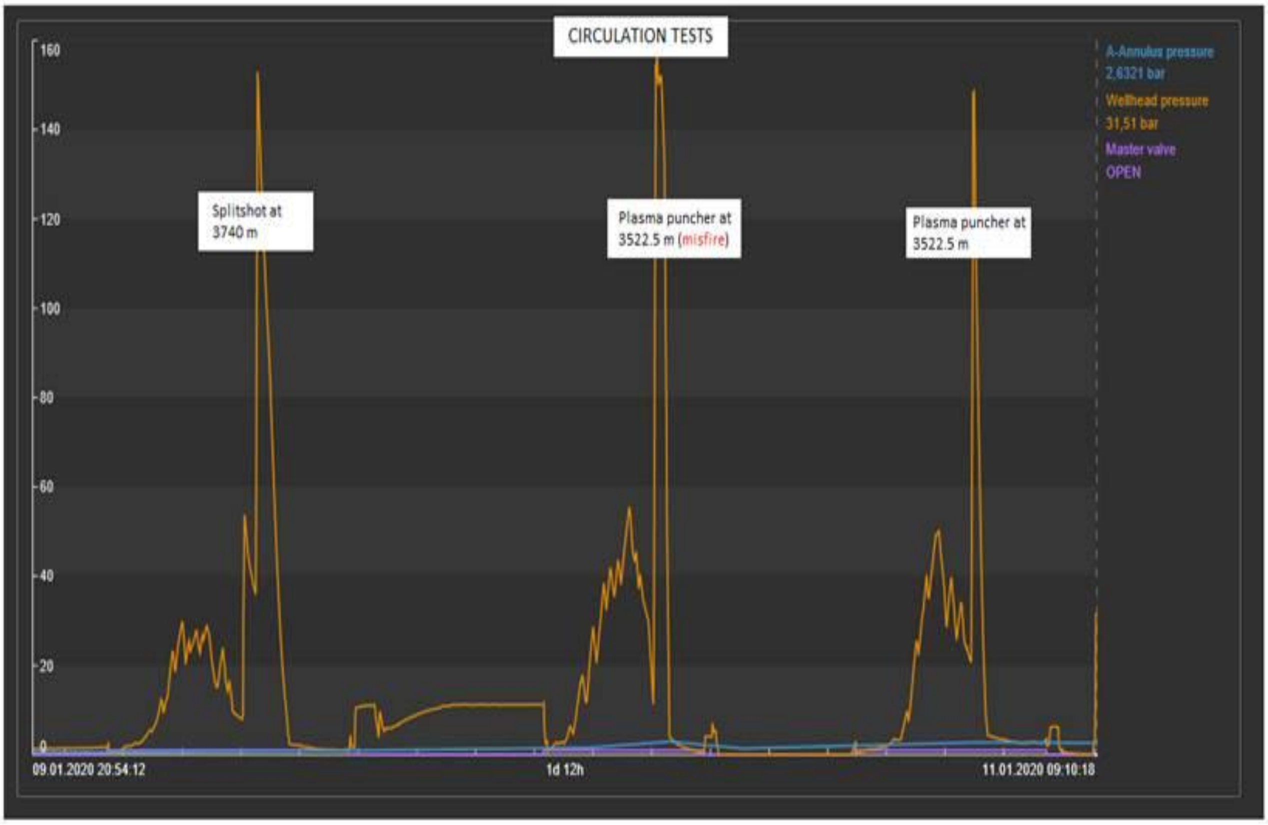


Figure 22: Comparison of failed circulation tests (by pressuring up tubing) after the 3 last attempts to punch the tubing, where A- annulus pressure does not change.

Conclusion:

The full volume of tubing (down to TOC) and annulus (down to packer) is reached when pumping in through GLV from annulus side. Hence, no solids like baryte or cement in tubing annulus. I believe that we do not have proper holes in tubing after punching. Why?

What I can't explain is that the caliper says that the two deep punches are through (but from the pictures they look like the hole is narrowing towards the outer part of the tubing wall, this could of course just be an art-affect in the program but if its truth it could explain why we can't get an open hole).

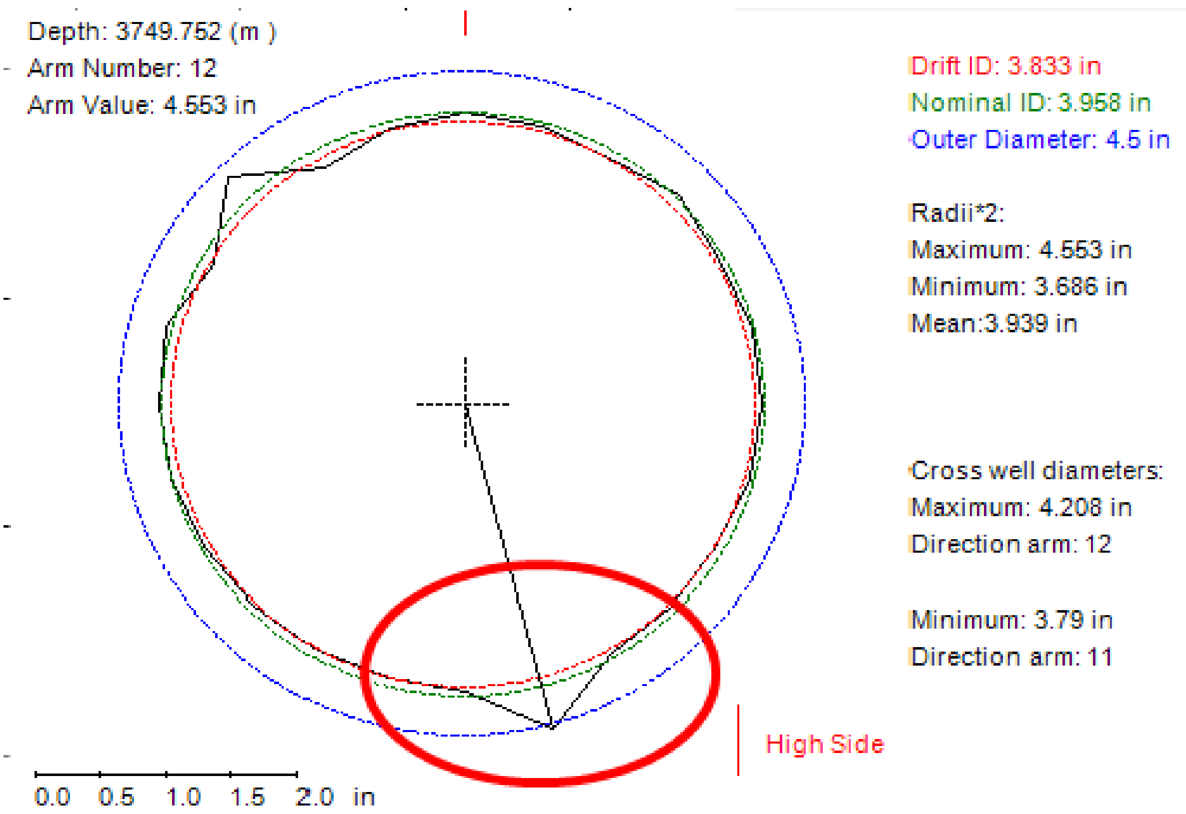


Figure 23: Sketch shows cross sectional MFC result at 3749m in A-27A (Archer oiltools).

So why haven't the split shots worked?

I see that there is some P110 tubing reported at the top and bottom of the completion. Could there be more, and if so, this could this explain why the split-shot could not break the tubing.

The first blinks of success….

After all these punches, establishment of circulation not obtained. The plan forward is to make a new try in shallower depth where MFC confirms that there is no scale inside the tubing and the probability of outer deposit is low, so it decided to make a punch at 3370 with 40 mm Dyna puncher. Punch depth is out of the 7" casing and inside the 9 5/8" casing.

After punching the tubing at this depth, finally a circulation established between the tubing and the annulus and in this way, it is possible to mill inside the tubing and get the return through the annulus**, but what is the reason to mill inside the tubing?**

To remove the scale inside the tubing and enlarge the hole to give an access for the tubing cutter and ASV-cutter in the hole, the type of the cutter will depend on the achievement during milling operation. A 3.5-inch mill bit with SLB tractor was used for milling operation, starting from 558m RKB.


Figure 24: Milling bit 3.5" used to mill the scale

As said earlier, type of cutters will be choosen depending on the achievement in milling. The plan forward was to continue milling with new target depths to accommodate both access for deep tubing cut and shallow cutting with Baker MPC.

- Target 1: If 610 meters reached, cut 4-1/2’’ tubing below XO with Baker MPC or 2.69’’ explosive cutter.
- Target 2: If (616-620) meters reached, make access for Baker MPC and deeper explosive cutter and open the worst restriction at 608-620 m to allow for running 1.75’’ cutter deep in tubing.[15]

Depending on the progress following two scenarios were set:

- If target 2 is achieved, then run 1.75’’ plasma cutter with anchor to 3501 meter and cut tubing 2 meter above coupling.
- If only target 1 is achieved, then Run broach in open hole and open restriction at 608 m and make access for 1.75’’ plasma cutter, and 2.69’’ explosive in 4-1/2’’ tubing below x-over at 608 m.


Figure 25: Types of broach used in A-27A (Repsol)

Roughly after 3 days of milling operation, milling bit reached at 616.6 meters after changing the bit several times due to wear as well as poor progress due to bad grip between the tractor wheels and the tubing.

To open the restriction below 616.6 meter a new method used by means of the broach, started with 2,1 "I-Broach and moved to tapered 2,2” I- Broach, which was the largest ID tool that could be use after trying many BHA in the ID between 2.1 and 2.2 “.

Broach reached at 1000 meter using Tapered I-Broach 2,16" to 2,19", but when using a 2.2" to broach the well the holdup depth was at 615.6 meter. Now it is the time to cut the tubing.

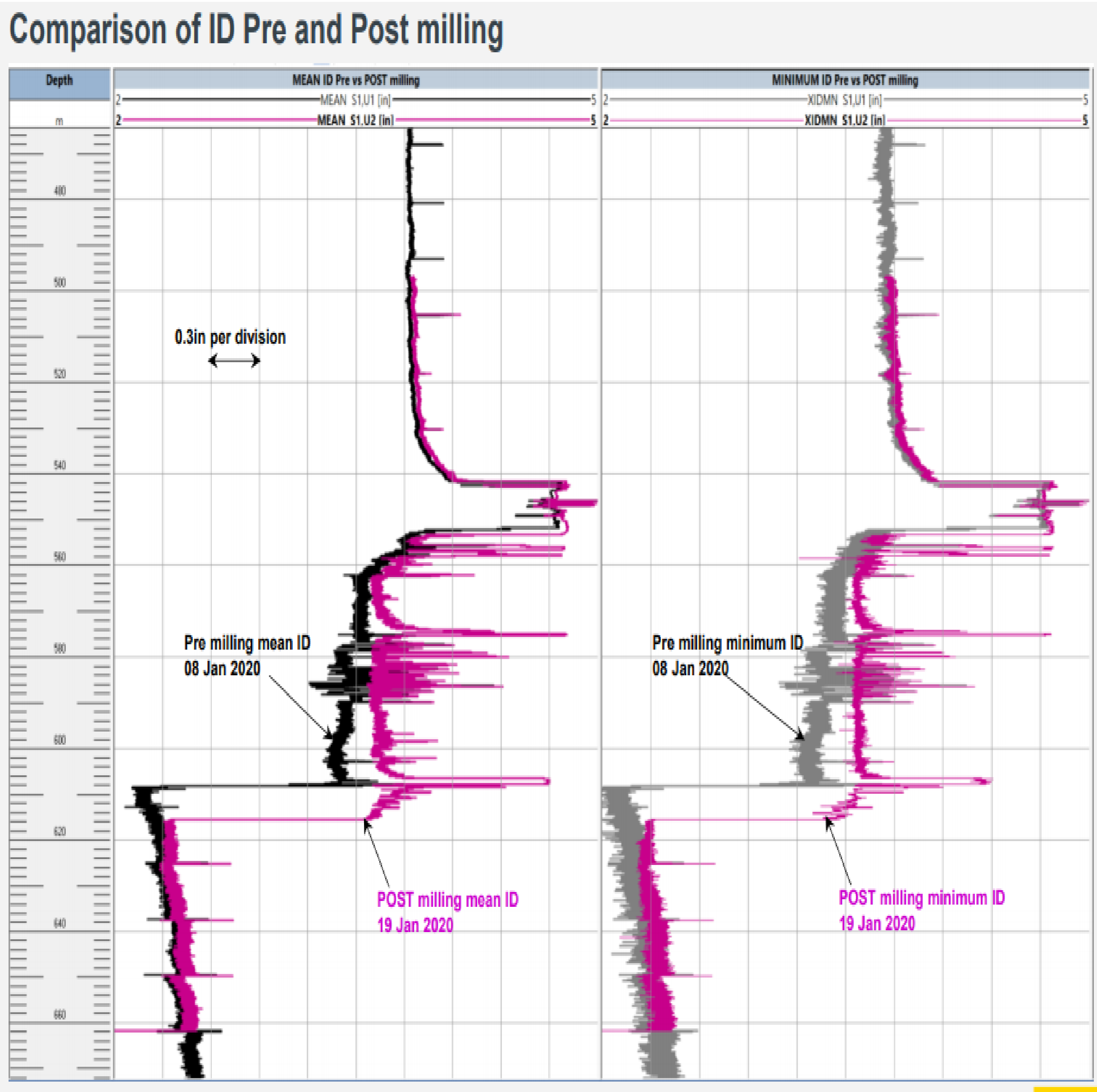


Figure 26: Plot shows a comparison between tubing ID pre and post milling operation in well A-27A (archer)

7. **Cut the tubing**

The scale was very hard to remove at the restriction and it was decided to run a tubing cutter to see if it will pass. RIH a new BHA with a plasma cutter 1.75" but this also stopped at 615 meters, tried several attempts to pull out for approximately 50 meter and run again with different speeds but with no success, and max speed reached was 70 m/min.

It seems that the lowering speed does not help in passing the restriction, the cement unit lined up to KWV and started to increase the pressure above the BHA while lowering with speed 40 m/min. with help of pump pressure finally BHA managed to pass the restriction when the pump pressure reached to 40 bar.

The cutter was placed at 3506.5 meter and fired, giving good indication on the firing panel.

The cutting is verified by running MFC at the cutting depth, inspected 20 meter above the proposed cutting depth and 20 meters below at the interval (3480- 3520) m.

The interpretation of FMC logging showed that the cutting is incomplete and that means the tubing need to be cut again with new BHA, but before running this the well was circulated to biocide treated seawater. RIH a new BHA with plasma cutter 1.75” and cut the tubing at 3502.9 meters. The cut was verified.

It is good to notice that the indication of cutting on the panel and losing some weigh on the winch is not enough to verify a complete cut.

Figure 27:The pictures show a tubing cut for well A-32D at 4405 meters. There are no pictures for well A-27 lower cutting since the phase 2 was suspended due to corona virus.

8. Run mechanical pipe cutter to below ASV

RIH with 2.69" Dyna cutter and make a cut at 610 meters. This cut is below ASV which is at 579 m. The objective is to release the ASV. Before that scale deposits need to be removed and allow for Baker Mechanical pipe cutter to be installed.

Run 2 BHA with string-shots (one double and one quadruple primary cord), they were fired to clear the mandrel from scale in the cutting zone of the ASV.

The string shot fired was verified by running a new MFC. The caliper showed completely scale free mandrel in the cutting zone after the string-shots.

What is a string shot?

One to four strands of explosive detonating cord suspended by wireline in a well and exploded to "rattle" the pipe and drop scale and debris from the sides of the pipe.[16]

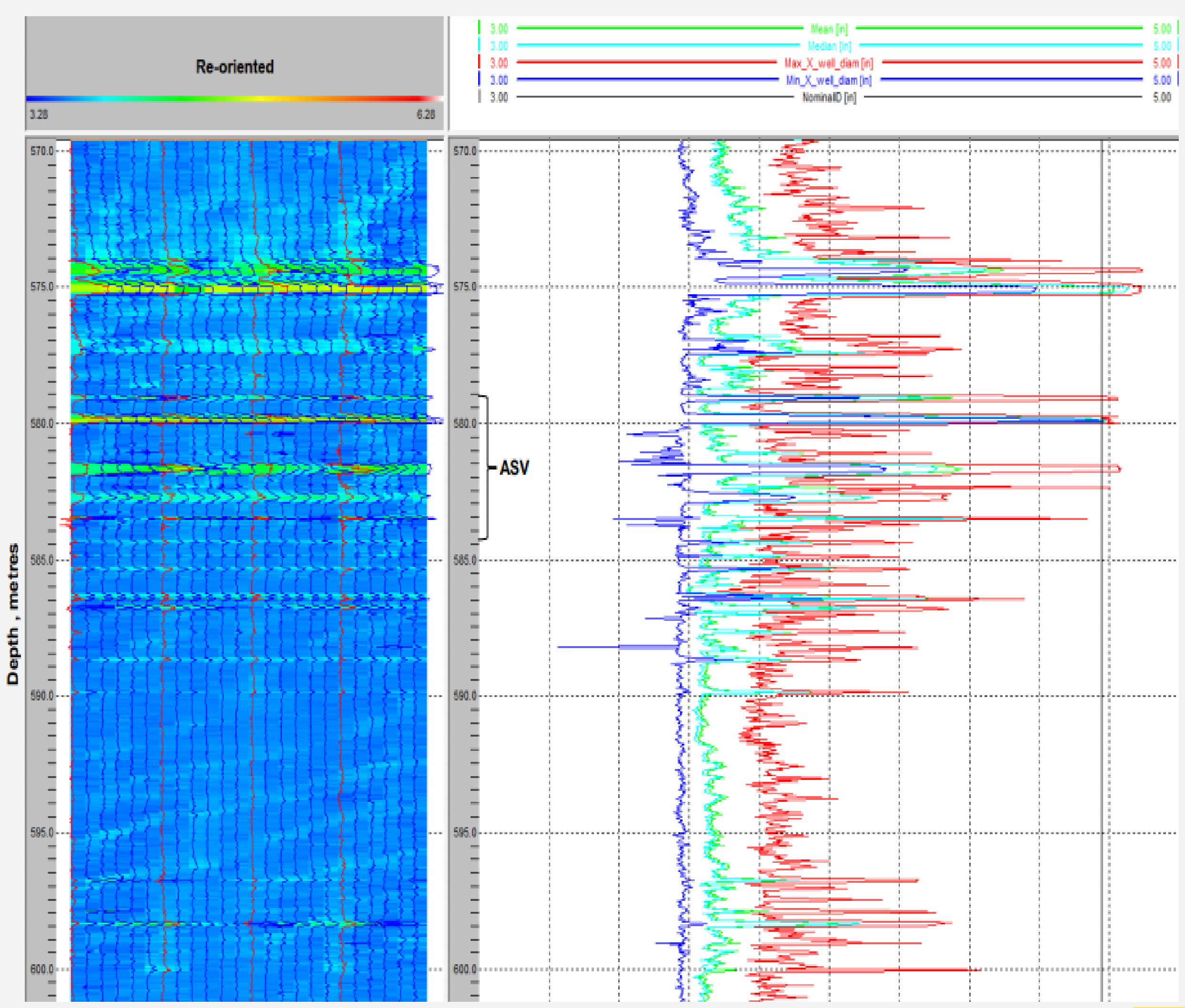


Figure 28: The graph shows ASV interval (on MFC chart) post string shot (Archer).

Figure 29: Evaluate the effectiveness of running the string shot in removing the scale in the pipe. Left: pre string shot. Right: post string shot

The Baker MPC was run and cutting was initiated at 581.7 meter which was optimum target in the cut-zone. During the cut the blade stalled out and lost 60 kg weight on wireline unit.

- Center ASV cut zone is 3.01 meters from top of ASV.
- Cut window is 50 cm long, position cutter in center of this.

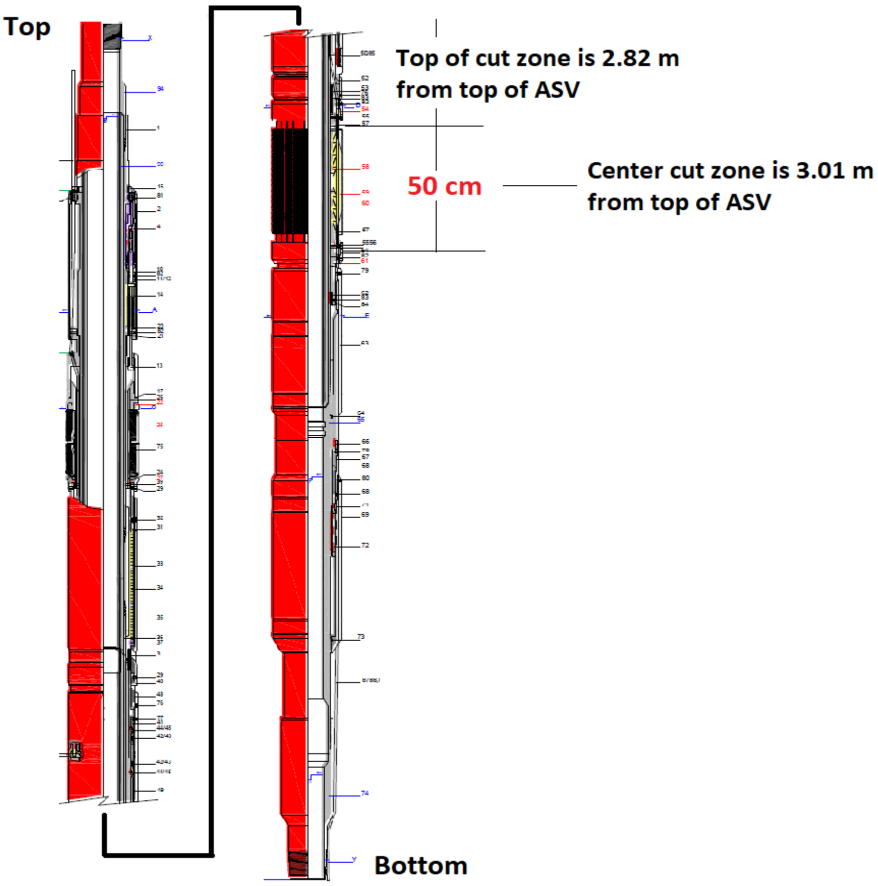


Figure 30: ASV drawing for well A-27

Cutter initiated cutting at 4.698" and continued cutting to OD = 5.594" when the blade suddenly was broken off. ID/OD of the mandrel was listed as 4.716"/5.523" in the technical manual and from that it can conclude that the cutter was well centralized and that the blade has gone all the way through.

What is Baker MPC?

According to Baker Hughes The MPC tool achieve precise downhole pipe cutting without damaging external tubulars. The cutting penetration is continuously measured and controlled.[17]

Figure 31: pictures shows Baker Mechanical pipe cutter MPC

9. Setting the shallow plug

Well status

- Tubing cut at 3804 m MD with split shot.
- Cement plug installed in liner at 4017 m MD.
- Tubing cut at 3502.9 m MD with slim plasma cutter.
- Tubing and A-annulus displaced to biocide treated seawater.
- Tubing cut below ASV at 610 m.
- ASV mandrel cut for release at 581.7 m MD.

Objectives

- Set shallow mechanical plug at 34m and pressure test same from below.
- Rig down wireline equipment.

RIH the last BHA for phase I for well A-27 with (420-550 ME bridge plug). The plug was set at 34 meters. The plug was leak tested from below to 100 bar for 15 min.

Phase I is completed after installing the shallower plug where two barriers were set, a cement plug deep in the hole and a shallow plug at 34 meters. After installing two barriers Now it is possible to rig down the XMT and install the BOP to start phase II.

The tubing was cut deep in the well and would be retrieved during the phase II which is suspended due to outbreak of Corona virus.

The pressure control equipment rigged down of the well, announcing that phase I is accomplished. The schematic of the well after completing phase I is shown below:

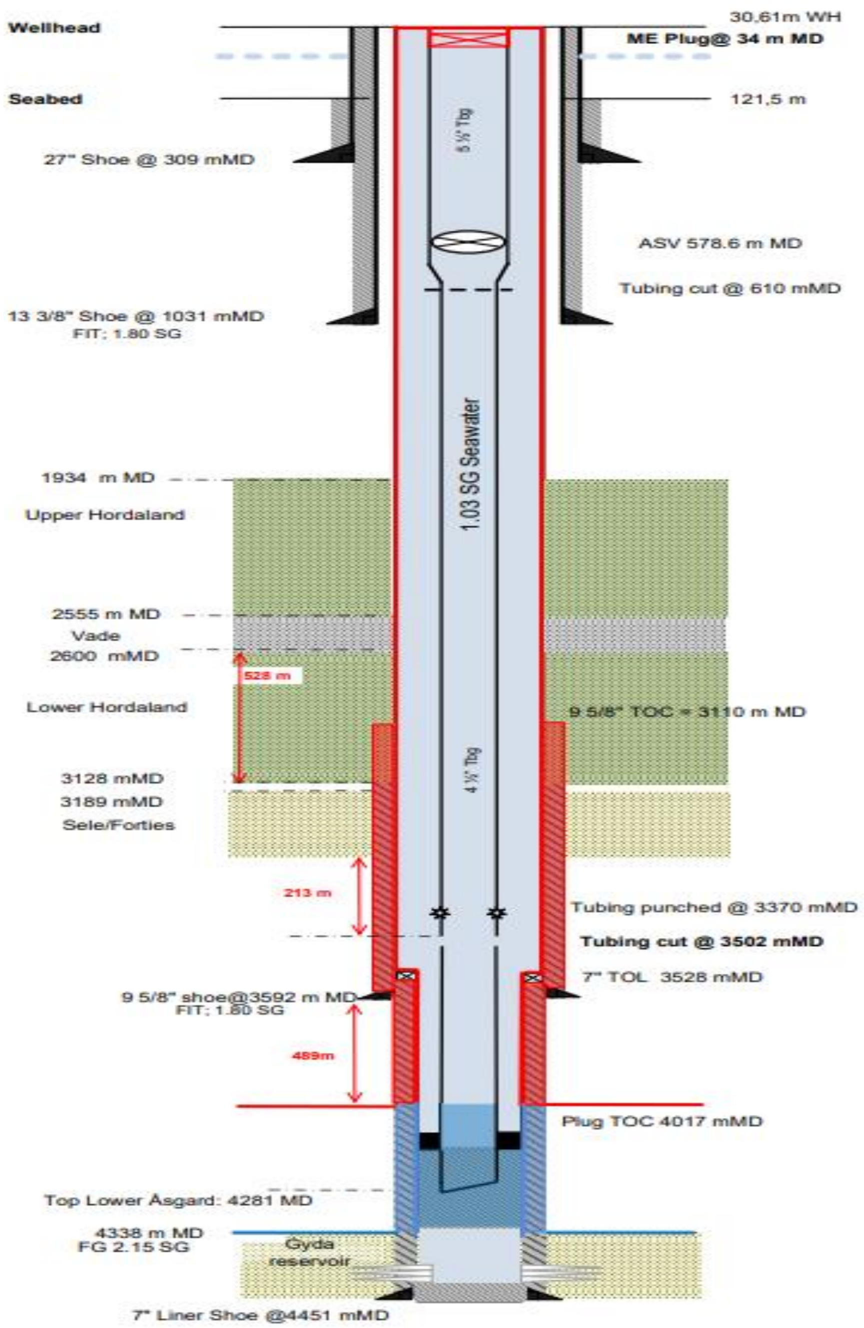


Figure 32: A-27A well schematic shows status after completing phase I (Repsol).

The questions that may arise in your mind now, **Why the plug and abandonment operation has been divided into three phases?**

a. **Cost efficient**

Plug and abandonment operation form around 15-25% of the cost comparing to well construction and in some complicated wells the cost of P&A increases significantly. Since the P&A operation is a non-profit operation for the petroleum companies, all the effort is made to reduce the cost of P&A but at the same time achieving the aim of the operation and satisfy the local requirements (NORSOK).

The aim of P&A is to minimize the use of the rig as much as possible which has a very high day rate compared to wireline operation, so Wireline is implemented in the operation to do the activities which can be performed rig-less.

b. **Time efficient**

The other reason for having three phases is the ability to perform the Phases simultaneously, where in Gyda platform phase I is performed from the BOP deck while phase II is performed through the rig deck and phase III (decommissioning) can be done after completing phase II.

And why the tubing needs to be retrieved while it is possible to leave them in the well since the well will be permanently abandoned?

The tubing must be retrieved to get an access for logging and due to the presence of control line latched to the tubing. These control lines prevent forming a cross sectional barrier:

a. Flow potential from the reservoir to the surface through the channel
b. The poor quality of bonding between the control lines surfaces and cement and that create a micro annuli channel around the control line.

Chapter 2

2. Creeping shale mechanism, process, and effect of chemicals

2.1 Introduction

When the gas and oil wells reach to the end of its life cycle, they require permanently plug and abandonment. An estimation of 3000 wells need to be plugged on the Norwegian Continental shelf according to NPD.

An estimation and minimizing of the P&A cost are a target for many of the operators in Norway, due to the high day rate of renting rig and personnel involved in operation, and without any financial return on investment. The Norwegian oil and gas association has derived what is called "conservative estimate "for calculating the total cost of plug and abandonment in Norway.

The estimation proposes if we have 3000 wells need to be plugged and an average of 35 rig-days per well then, the cost will be around 420 billion NOK, based on the average of a rig day-rate of 4 million NOK.[18]

NORSOK requires the presence of two barriers for each source with flow potential to prevent escape of formation fluids from the hydrocarbon bearing formations and from abnormally pressured formations with potential to flow to surface.

2.2 Cross sectional barrier

The principle for creating a barrier is based on what is called "rock to rock barrier "or a cross sectional barrier. According to NORSOK D-010 "extend across the full cross section of the well, include all annuli and seal both vertically and horizontally. Hence, a WBE set inside a casing, as part of a permanent well barrier, shall be at a depth interval where there is a WBE with verified quality in all annuli."

Some of the barriers are easy to establish if cement behind the casing is founded and is verified to be in good condition in terms of bonding and quality to grant-isolation, its condition is normally verified through logging and complemented using the cement reports registered during well construction, and production reports proving the absence of integrity problems as Sustaining Casing Pressure (SCP).

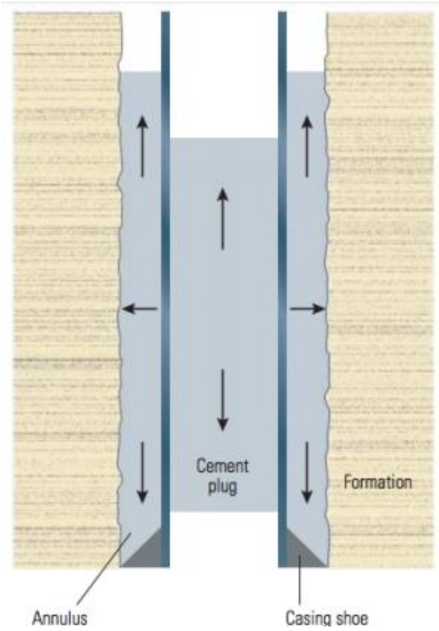


Figure 33: Cross sectional barrier in case we have a cement in the annulus

The problem comes when there is no cement behind the casing to create a barrier, then a remedial operation must be used. The traditional solution is to mill the casing at the required depth and place the cement in the section. The milling operation is very costly and time-consuming operation where you should mill at least 50 meters along the casing to create one barrier interval accompanied with HSE issue if you must circulate the swarf to the surface.

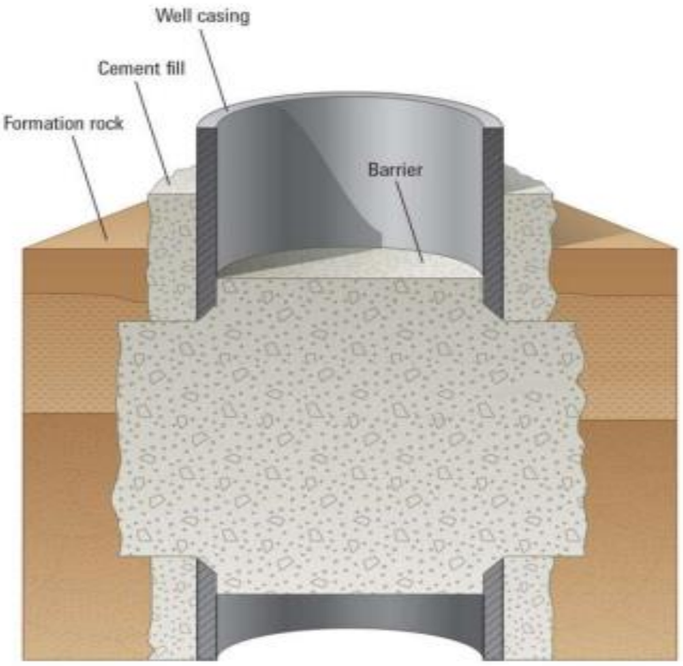


Figure 34: Cross sectional barrier in case we milled the casing

A new technology has been used in the recent years which is called PWC (perforate- wash-cement). The idea behind PWC technics is to perforate internally across the casing at the required depth and then wash behind the casing through the perforation. Finally, cement is pumped in the annulus through the perforation and inside the casing. The whole process could be performed in one run[19].

Figure 35: PWC (Perforate, Wash, Cement) sequences according to Archer oil tools.

2.3 Description

It has been observed in some wells at depths above the top of cement, that logs showed a good bonding between the casing and the material behind the casing. This is surprising because no cement job has been performed on those depths and the pressure communication test has verified the sealing. The reason for that is that certain formations, such as mobile salts and shales, could creep into uncemented annular spaces and form competent annular barrier to close and seal off the annulus. The existence of such shale barriers facilitates plug and abandonment P&A operations, which gives significant cost reductions.

Creep has been identified on sonic and ultrasonic bond logs and verified using pressure testing in different oil fields. Shale has all the needed characteristics which NORSOK requires to form a good barrier:

- Impermeable: it is well known that the permeability of shale in the range of micro Darcy, 21 nano Darcy to 6.6 micro Darcy for North Sea field (Kristiansen, 1998)
- Non-shrinking: unlike cement the shale does not exhibit any shrinking properties
- Ductile (not brittle): under differential stresses the shale flow and bend and does not break (low young modules)
- Resistant to different chemicals/substances
- Wetting to ensure bonding to steel
- Long-term integrity: this is, of course, not surprising, because shales are well-known to act as excellent cap rocks on top of hydrocarbon-bearing zones for thousands of years.

2.4 Definition and Function of creeping formation

NORSOK defined the creeping formation as formation that plastically has been extruded into the wellbore and located in the annulus between the casing/liner and the bore hole wall.

The purpose of the creeping formation is to provide a continuous, permanent, and impermeable hydraulic seal along the casing annulus to prevent flow of formation fluids and to resist pressures from above and below.

To classify the crept formation as a barrier element, it should have the following requirements:

- The formation shall be capable of providing an eternal hydraulic pressure seal.
- The minimum cumulative formation interval shall be **50** m MD.
- The minimum formation stress at the base of the element shall be enough to withstand the maximum pressure that could be applied.

- The formation shall be able to withstand maximum differential pressure.

It has been verified that the differential stress is the underlying cause of formation creepiness and the two types of formation that have the tendency to flow is salt and shale. In Gyda, only shale formation has been tested and verified as a creeping formation, so it is worthy here to know some shale properties.

2.5 Shale properties

Any group of fine-grained, laminated sedimentary rocks consisting of silt- and clay-sized particles is called shale.

Shales typically are form in environments where muds, silts, and other sediments were deposited by gentle transporting currents and became compacted, as, for example, the deep-ocean floor, basins of shallow seas, river floodplains, and beaches.

Shales characteristically consist of at least 30 percent clay minerals and substantial amounts of quartz. They also contain smaller quantities of carbonates, feldspars, iron oxides, fossils, and organic matter

Shales play a major role in petroleum exploration and production because they are commonly considered to be both source rocks and seals. Their ability to exhibit good sealing characteristics arises from their small and water-wet pores.

- Argillaceous (clay-rich) rocks are the most abundant sediment on the earth
- Shale is a fine-grained rock made of compressed mud and clay.
- shale is easily divided into thin layers.
- Black and Gray shales are common, but the rock can appear in any colour.
- Roughly 55% of all sedimentary rocks are shale. [20]

Figure 36: gray shale

2.6 Creep process

Creep is a well-known phenomenon in material engineering and there is a theory says that all material on the earth flow when it is subjected to stress, even a plate of window glass is thicker at the lower part than upper part.

It is difficult to recognize creeping phenomena due to the interacting with other physical and chemical process, but in general the creep process undergoes three stages[21]:

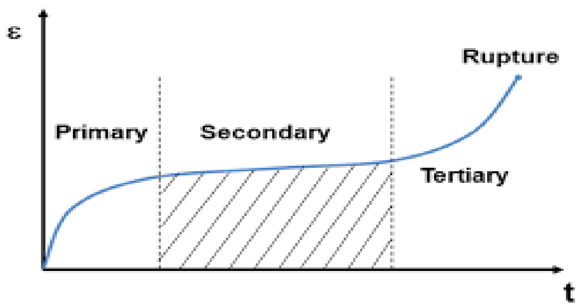


Figure 37: plot shows creeping stages during creeping process (Fjær et al).

a. **Primary or transient mode** before drilling a hole, we have a stress equilibrium through the formation, but after drilling we create a stress disequilibrium on the wellbore where it is typically the overburden stresses is higher than annulus pressure. When the production starts then the wellbore temperature will increase as the oil flow, here we have the most two common factors that initiate the creeping process.
   This phase is caused by thermally activated grain boundary slip. If the applied stress is removed, the rock acts elastically and will go back to its initial size. The deformation will be reversed and approach zero (Fjær et al. 2008).
   This is an interesting result where we can see that the most effective factor in the creeping process is the differential stress.
b. **Secondary or Steady state creep:** over time if the stress and temperature continue to be relatively high, the transient creep stage will be followed by the second stage called steady state creep, where the deformation rate will stabilize.
   Steady state creep is defined as increasing deformation with constant strain rate as you can notice on the plot above. For the P&A purposes when we talk about the time, so we are talking about years and decades.
   Upon the removal of the stresses in this stage, the deformation is irreversible (plastic deformation).

c. **Tertiary or accelerating creep**: if the stress is sustained for enough period and the stress and temperature is enough, the deformation will proceed into the third and final stage called tertiary stage.

We notice that the deformation rate increases exponentially with time.

Depending on the stress level and deformation rate we have two consequences of creeping, either the formation will contact the casing and achieve a new stress equilibrium, or in some cases where the stresses is higher than the casing strength then we end up with casing collapse.

2.7 Shale deformation mechanism

1. Elastic deformation:

According to (Fjær et al., 2008), elastic deformation is not enough to close an annulus around a casing. This type of deformation outcomes from distortion of the equilibrium state through the formation.

Elastic deformation is:

a. proportional to the difference between the horizontal stresses trying to close the wellbore and the wellbore pressure trying to support the wellbore wall.

b. inverse proportional to the shear modules (G) of the rock

$$G = E/(2(1+v)) = \tau/\gamma$$

Where:

E: young's module

v: Poisson's ratio

γ : shear strain

τ : shear stress

2. Elastic-plastic deformation

This type of deformation occurs when the shale formation under stress behaves in a ductile manner and reduce its stiffness by a factor of 5 to 10, then create a plastic deformation. In the extreme case of a perfect plastic deformation process the rock will deform infinitely for a very small increase in stress. Since rocks very rarely behave as perfect plastic materials, due to the circular geometry and rocks typically showing strain hardening, elastic-plastic deformation will seldom be enough to close the annulus.

3. **Consolidation**

   In shale formation it is difficult to differentiate between creeping and consolidation. Consolidation is time dependent deformation which is related to the low permeability of the shale. As the rock is exposed to an altered stress state the deformation in the shale matrix will increase the pore pressure in the water saturated shale and the shale will deform in a time dependent fashion until the excessive pore pressure induced by the increased load has dissipated. The consolidation time is therefore very dependent on the permeability of the shale[22].

   Near the wellbore one will have both consolidation and creep ongoing and it can be difficult to separate the two. As the shale consolidate it will also deform laterally, but seldom enough to close the annulus.

2.8 Creeping shale simulation

The model used in this section was developed by SINTEF, and is based on the discrete element method [23]. The assumption is considered that the shale grain is bonded initially and the creep deformation result from grain distortion and not change in the grain volume. The influences of the three common factors of creep shale are consider:

a. Stresses: the effective in situ horizontal stresses were set randomly at 30 MPa
b. Temperature
c. Time

The model is constructed of many circular discs where the large disc representing the casing and the other small discs represent the grain in the formation.

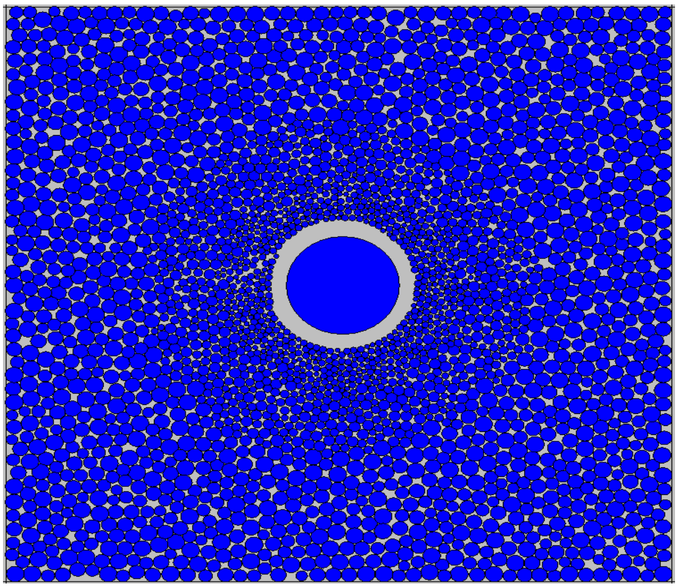


Figure 38: The model immediately after starting the simulation, the casing radius is reduced by 23%

If the total displacements between two elements unchanged, creep induces an increase in the plastic deformation while the elastic part reduced. Over the time as the plastic deformation will be dominant, the interaction forces between the particles will reduce and the particles tend to relax, that is called a stress relaxation. Consider the following:

τ: the average shear stress at a contact between two small circles (discrete elements)

τ': the average shear stress after a time Δt where we allowed the stress relaxation

τ_0: threshold for creep

(τ') is less than(τ) since the average stress will reduce at the expense of plastic deformation $\Delta\varepsilon p$ over the period Δt

$$\tau' = \tau - M\,\Delta\varepsilon_p$$

where M is a Module

The ratio of the stresses after and before relaxation α

$$\alpha = \frac{\tau'}{\tau} = 1 - \frac{M\Delta\varepsilon_p}{\tau}$$

The creep strain in time Δt can be assumed as (following Jaeger et al., 2007):

$$\Delta\varepsilon_p = V_0 e^{-(\beta/T)} \left(\frac{\tau}{\tau_m}\right)^n \Delta t$$

Where (V_0, β, τ_m, n) are constants, T is the temperature

These constants should be determined from the experimental work. Data for Haynesville shale (Sone and Zoback, 2014) were used for calibration of strain rate, giving V0 = 0.00028. The parameter controlling temperature (β) was set to 500 K (Folstad, 2015). Thus, the equation become

$$\alpha = 1 - \frac{MV_0 e^{-(\beta/T)}}{\tau_m^n} \tau^{n-1} \Delta t$$

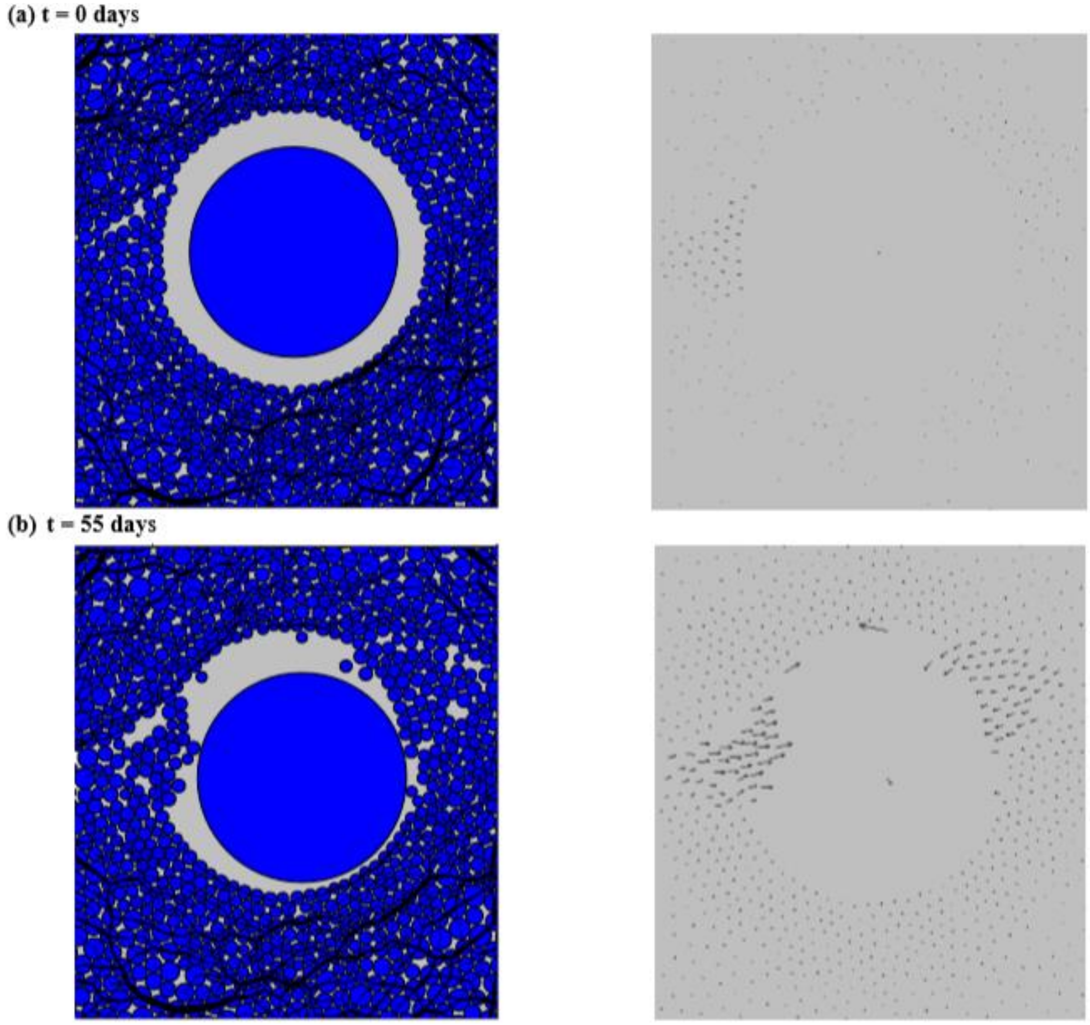
This equation is used to calculate the creep rate induced stress relaxation (contact force reduction). In the pre-simulation phase, the casing radius is set equal to the borehole radius where it represents the case before drilling and stress distribution through the formation is equal. The simulation starts by reducing the casing radius to 23.6% of the borehole radius.

The number 23.6% is not a random number, but where does it come from?

In the drilling program we traditionally drill a 17 ½” hole and install a 13 3/8” casing, or 9 5/8” casing inside a 12 ½” hole. In the first setup it is easy to calculate that casing radius is reduced from the borehole by 24% and in the second one by 23%.

This gap which is around 1.4” represents the amount of deformation the rock needs to suffer to fill it.

30 MPa horizontal in situ stresses are also applied to the external boundary of the model. In this case the casing would not be subjected to any stress due to the gap, and the stresses will be distributed through the small discs which represent the formation grains. The results of the simulation are presented on the following figures:



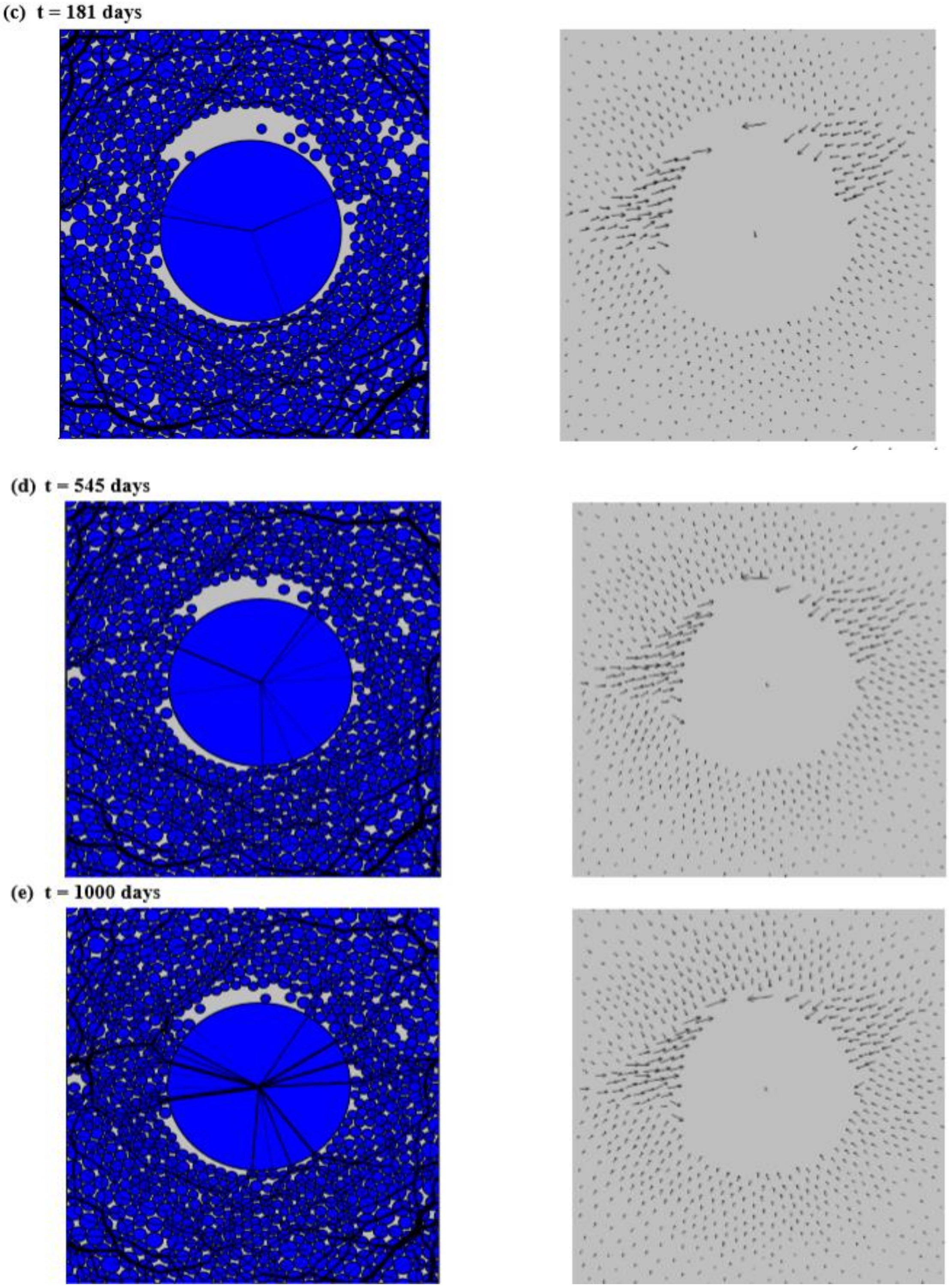


Figure 39: These are the results after 1000 days of simulation where: Left column shows particles and contact forces, the thickness of the black lines is proportional to magnitude of contact forces. Just keep in mind that the thicker lines the higher contact forces

The below chart shows how the gap has developed after 1000 days:

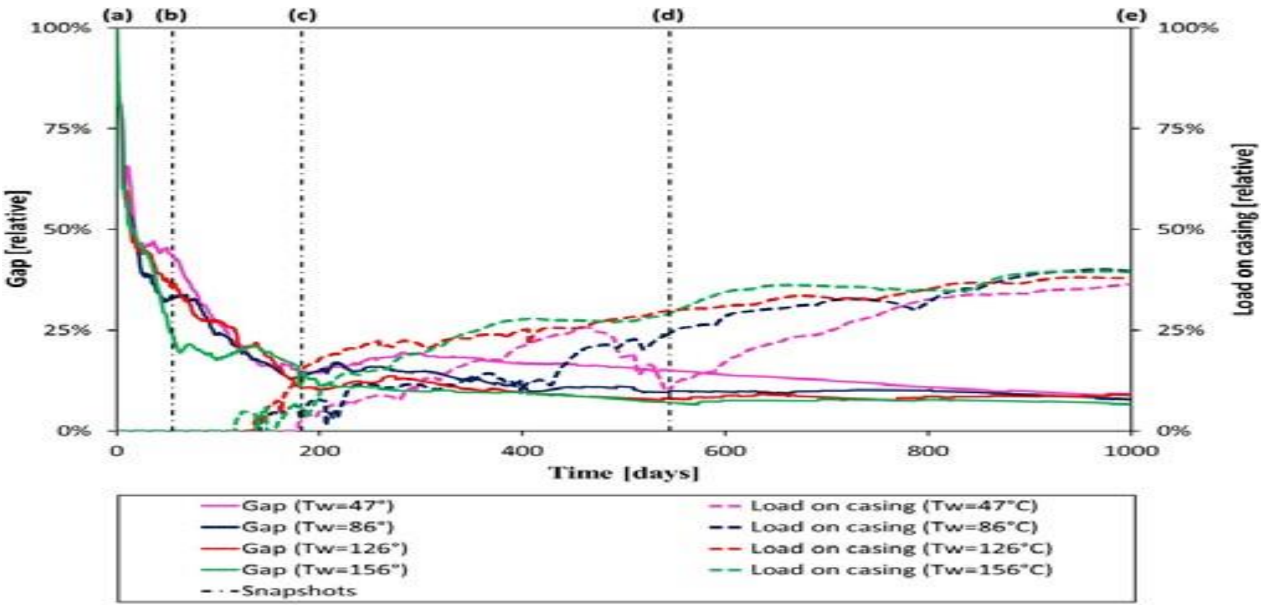


Figure 40: Plot shows gap between casing and formation, relative to the gap at the start of the simulation. Load on casing, relative to the external stress

The continuous lines show the gap reduction over the time, while the dashed lines show the load on the casing at four different borehole temperature (47, 86,126,156℃). 47℃ is the base case where the formation temperature is equal to the borehole temperature, while the others is a borehole temperature mimicking the production phase.

We notice that after around 200 days that parts of the formation reach to the casing and start to apply force on the casing and casing load increases over the time. The load on the casing is defined as the sum of all contact forces acting on the casing divided by the total circumference of the casing.

2.8.1 Conclusion of the simulation

1. The model is valuable for illustrating the creeping process, but it does not reflect the reality since the circular discs differ from the shale spherical once.
2. Higher temperature may speed up the creep process slightly, but the gap closure versus time seems to be reduced after the formation has established contact with the casing.
3. The gap is quickly reduced in the beginning of simulation, but the closure rate is further reduced considerably. This is probably due to arching effects, which reduce the driving force for the gap closure process.
4. By plotting the distribution of the radial and tangential stresses, the formation can be divided into two zones:

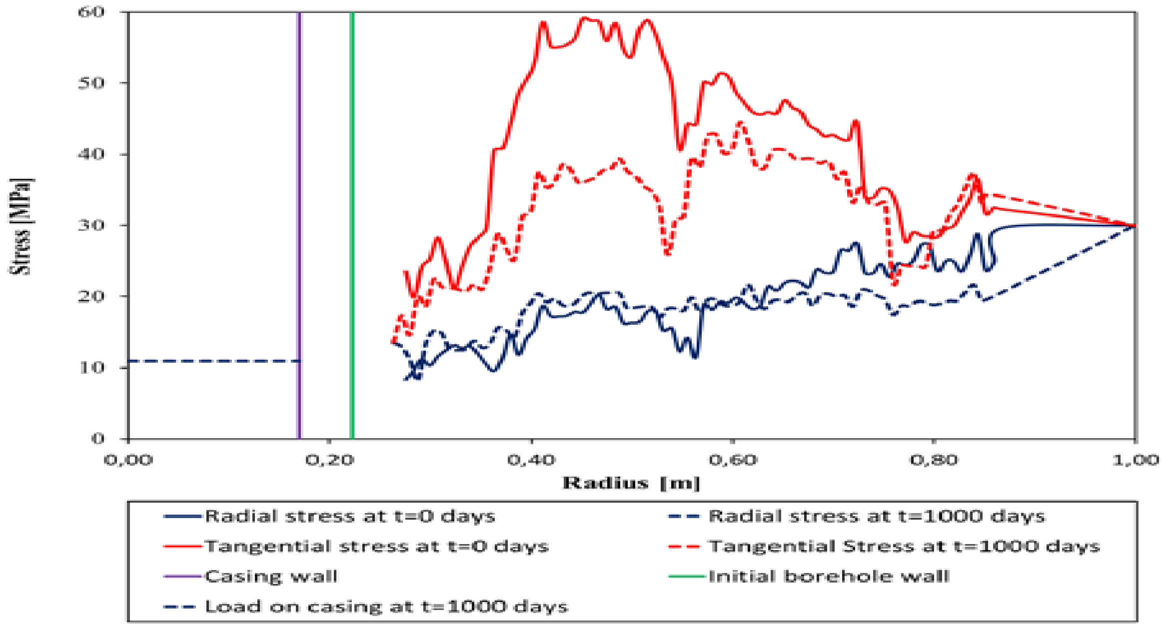


Figure 41: Distribution of radial and tangential stresses at 47°C

a. Plasticized zone near the borehole, where the tangential stress falls rapidly towards the borehole wall.
b. Elastic zone where the tangential stress is reduced as we move far from the hole.

This behaviour matches nicely the predictions of Elastic-plastic models for stress distributions introduced earlier by (Fjær et al., 2008). The initial reduction in the gap closure rate is probably due to the stress relaxation in the plasticized zone.

5. Clearly appear that the best creep candidates are shales with a low threshold for plastic flow and a high ability to maintain large plastic deformations.
6. The higher compressive stress would be able to push the rock closer to the casing, but it might also create some small gaps, thus preventing the establishment of hydraulically sealing barrier.
7. If the formation has a low threshold to deform and the compressive stress was high enough, then the whole stresses will be subjected to the casing and if that was higher than the strength yield of the casing we will end up of casing collapse.

2.9 Creeping shale test

After checking the analytical creeping shale model and the associated simulation result, it is time to move more closer to the reality by examining the small-scale laboratory test of creeping shale. The simulation model has some drawbacks like disability to represent the actual shale grain and the interaction forces between them.

The test is quite new and was presented at the IADC/SPE International Drilling Conference and Exhibition held in Galveston, Texas, 3–5 March 2020[24].

The test studies the effective of pressure and temperature, but particularly interested in type of fluid in the annular space that stimulate the near bore shale to creep.

The effect of temperature of shale creeping is verified and well- known as it affects the visco-plastic behaviour of the rock and accelerate the creeping process, but using the temperature to motivate the downhole formation is unpractical where heaters should be used down in the hole for many days and maybe weeks for at least 50 meter (NORSOK requirements).

Shale formation can be stimulated to creep by reducing the annular pressure and in this way the differential stress (= overburden stress - annular pressure) will increase, but also the reduction of the pressure in the annular space is unpractical and has harmful sequences:

1. A large pressure drop may cause shale shear failure rather than accelerated creep, filling the annulus with caves rather than stimulate the shale to creep.
2. Reduction of the annular pressure may cause a well control incident

The last factor to play with is to circulate different chemical in the annulus behind the casing and that is more practical.

2.9.1 Experimental- Shale specimen properties

The specimen core was taken at 1407 m TVD in the B-annulus of North Sea Lark-Horda shale; the chemical and physical properties of the core was as follow:

- Non-clay mineralogy: 19 – 21% Quartz, 5 – 9 % Pyrite, 1-2 % Carbonates (Calcite and Dolomite), Trace minerals – 1% K-Feldspar, Plagioclase, Apatite
- Clay content: 70-73% total clay (3-4 % Smectite, 9-12% Illite / Smectite, 37-40% Illite / Mica, 18 – 21% Kaolinite, 1% Chlorite)
- CEC (cation exchange capacity) value: in the range of 55 – 80 MEG/100g
- Rock stiffness and Mohr-Coulomb failure parameters: Young's Modulus 120,000 psi (827.4 MPa), Poisson's Ratio 0.27, cohesion 857 psi (5.7 MPa), friction angle 4.3 degrees, dilation angle not determined

Obviously, the sample has a very high clay content and that give it a high tendency to creep.

2.9.2 Test structure

The cylindrical shale sample was placed inside a core holder. A solid steel cylindrical rod was mounted at the centre of the cylindrical shale sample, leaving an annular gap between the casing and the shale rock.

The upper and lower part of the sample was fixed to two plates allowing to apply an axial stress and providing a path of the upstream and downstream fluid to flow through the gap. The body of the core holder was also connected to a pipe to applying radial confining pressure.

Strain gauges and pressure lines were placed in a triaxial load frame, which allowed for the application of axial and radial confining pressures and the precise regulation of temperature up to 121°C.

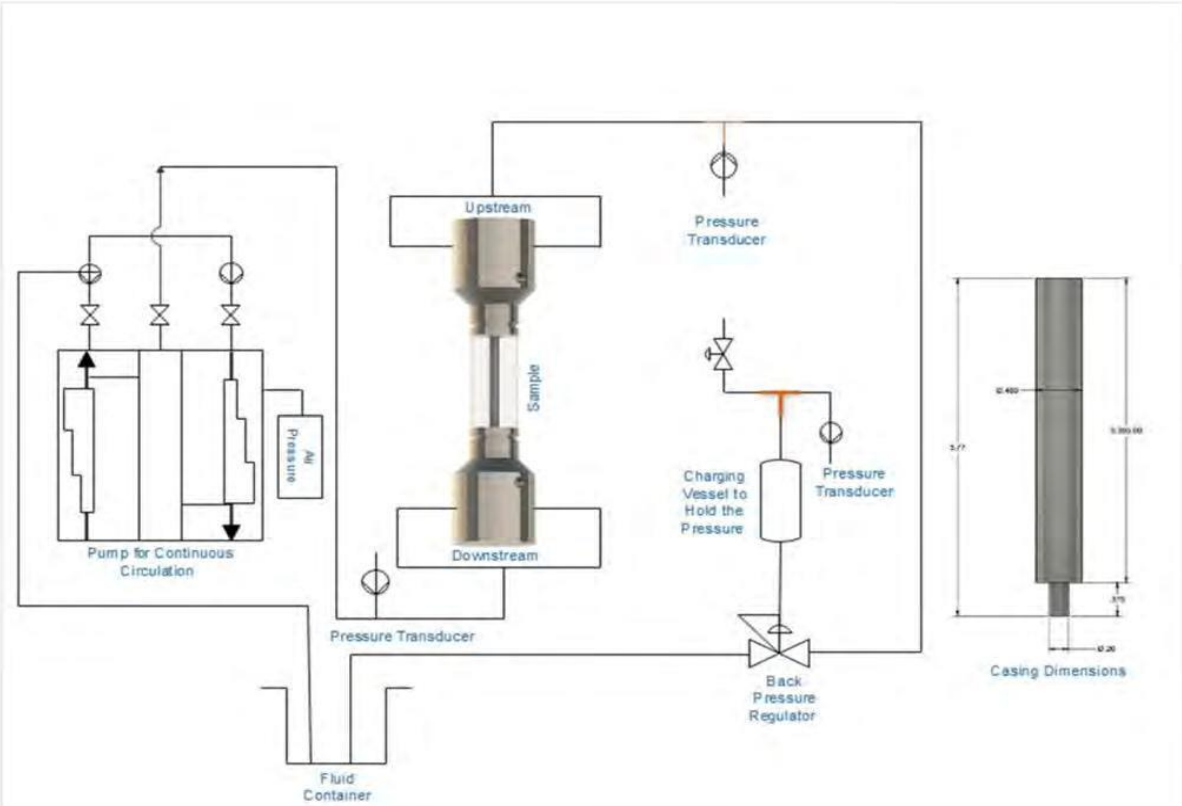


Figure 42: Schematic of the core holder and casing insert (shown enlarged on the right), with arrangement of upstream and downstream reservoirs, pressure transducers, displacement pumps and charging vessel.

Figure 43: Left: top view of cylindrical shale sample with concentric casing insert before testing; (right) mounted shale sample in the test cell with cantilever bridge for strain measurement and upstream and downstream reservoirs with their pressure lines.

2.9.3 The test procedures

In the first experiment the field in-situ stresses were applied but the shale sample collapsed. This was attributed to the fact that pore pressure reacts much slower to applied values than applied stress, therefor the test performed at reduced pore pressure value while maintaining the field effective stress values as in the table below:

Parameter	**In-situ Value (at 1,407m / 4,618 ft)**	**Experimental Test Value**
Vertical (axial) Stress	27.9 MPa (4,050 psi)	12.4 MPa (1,800 psi)
Horizontal (confining) Stress	26.5 MPa (3,850 psi)	11.0 MPa (1,600 psi)
Pore Pressure	17.2 MPa (2,500 psi)	1.7 MPa (250 psi)
Annular Pressure	17.2 MPa (2,500 psi)	1.7 MPa (250 psi)

Vertical Effective Stress	10.7 MPa (1,550 psi)	10.7 MPa (1,550 psi)
Horizontal Effective Stress	9.3 MPa (1,350 psi)	9.3 MPa (1,350 psi)
Differential Effective Stress	1.4 MPa (200 psi)	1.4 MPa (200 psi)
Temperature	54°C (130°F)	54°C (130°F)

Table 6: Stress and temperature information for Lark-Horda shale under in-situ conditions and as used in the laboratory experiments

Then the test was conducted by

1. apply axial stress through the upper and lower plates and radial stress through the flank pipe
2. increase the cell temperature and wait until stabilization
3. fill the annular space with the artificial fluid (5 types of fluid were used)
4. Measure radial and axial strain values as sample equilibrates to stresses, pore pressure and temperature.

It was used five different types of annular fluid for 5 tests to check the efficiency of chemicals in creeping activation

1. Base test: conducted with artificial pore fluid consists of 50.28 mg/l NaCl, 17.48 mg/l $MgCl_2.6H_2O$, 7.81 mg/l $CaCl_2.2H_2O$ and 0.35 mg/l K_2SO_4
2. Sodium hydroxide test, with a highly alkaline (pH = 12) 2M NaOH fluid as annular fluid
3. Elevated temperature test, conducted with artificial pore fluid as annular fluid and experimental temperature raised from 54°C (130°F) to 85°C (185°F)
4. Sodium silicate test, with 10% v/v sodium silicate fluid as annular fluid
5. Lithium silicate test, with 10% v/v lithium silicate fluid as annular fluid

All tests showed the characteristic behaviour of traditional creeping process of fast primary creep followed by slower secondary creep as in the graph below:

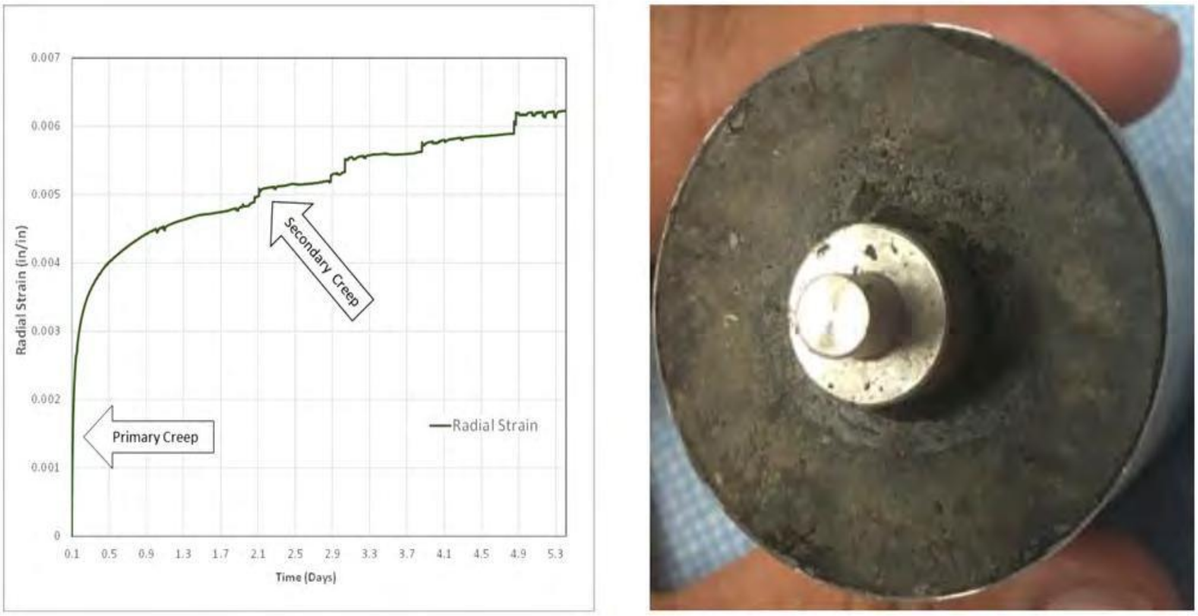


Figure 45: Typical shale radial strain behaviour observed during tests, with fast primary creep followed by slower secondary creep; (right) the ultimate result of creep, with an annulus around the central casing rod insert that has become completely blocked off with shale material

Creep behaviour by itself is insufficient to indicate if the annular space was totally sealed or not. To verify if the seal was created a pressure pulse decay method was used. A pressure pulse was created in the upstream line and monitoring the response in the downstream reservoir.

Case 1: if the upstream pressure pulse was registered without any delay in the downstream reservoir, it indicated that the annulus is not sealed

Case 2: if a time-delay was registered between the upstream pulse and downstream response, it indicated that the annulus had closed and sealed.

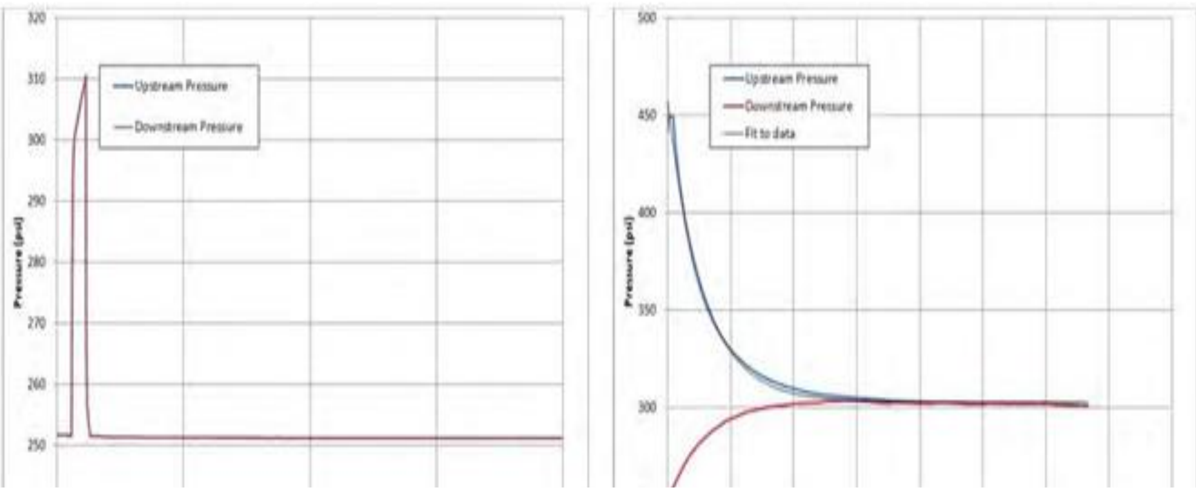


Figure 46: (left) pressure pulse experiment with an annulus that is still open: downstream pressure responds immediately to the upstream pressure pulse, and the two curves overlay perfectly; (right) pressure pulse behaviour when annulus is closed, showing delayed response of downstream pressure to upstream pressure pulse.

In the last part of the test with an intact barrier formed, a leak-off test was performed, the pressure was increased until a communication was established between the upstream and downstream reservoir, this is the highest pressure value that the shale sample can withstand before fracturing.

2.9.4 Post-test analysis

A visual inspection was performed on the sample where a computed tomography (CT) conducted before and after the test, the photos is just for the base case where artificial fluid was used:

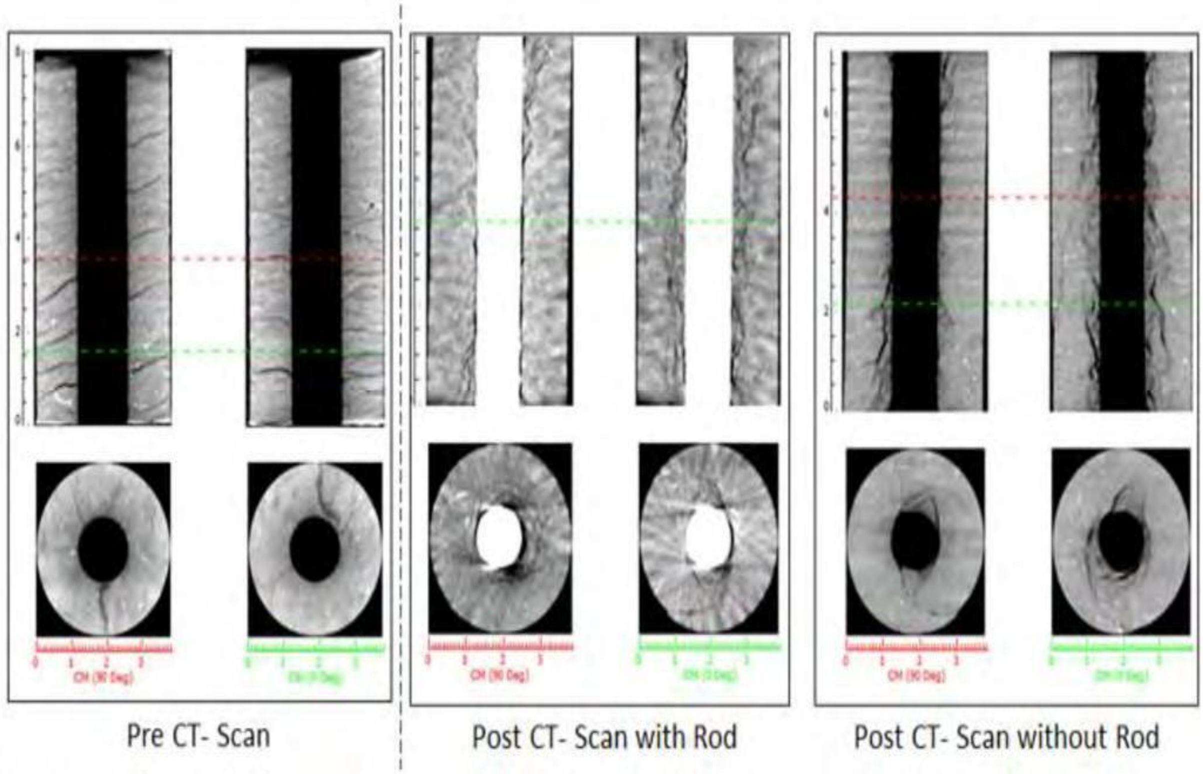


Figure 47: CT scans of cylindrical shale sample (left) prior to testing; (middle) right after testing with casing rod insert still mounted; (right) after testing with casing rod insert removed. Images were obtained for the base test, as discussed in the Results

2.9.5 Test results

The result for the 5 samples is presented below where it is valuable to notice the efficiency of using different fluid chemicals in the annular space for shale activation. Result shown that using lithium silicate gives better result in terms of creep acceleration, permeability and seal-ability comparing to the elevated temperature. The general observations are:

Table 7: Results of the tests, indicating observed annular closure time (= barrier formation time), permeability of the barrier at the time the last pressure pulse decay tests was carried out during the experiment, and the breakthrough pressure observed during the leak off test at the end of the test

Experiment	Annular Closure / Barrier Formation Time	Permeability of shale barrier	Breakthrough pressure during leak-off test
Base Test	18.2 days	10.1 µD @ 10.5 days	Not tested
NaOH Test	Annular barrier not formed		
Elevated Temperature Test	11.5 days	2.3 µD @ 13.2 days	724 psi (4.99 MPa) @ 19.5 days
Sodium Silicate Test	5.1 days	12.3 µD @ 5.3 days	1,054 psi (7.27 MPa) @ 5.9 days
Lithium Silicate Test	2.9 days	1.7 µD @ 6.3 days	943 psi (6.50 MPa) @ 6.9 days

1. The annular fluid chemistry change has a key impact on shale creep and annular barrier formation, and the process seems to be relatively fast.
2. Using chemicals in the annulus gives faster and stronger results than increasing temperature
3. For field deployment, pumping chemicals in the annulus is practically easier and safer than increasing temperature or reducing annular pressure like (PWC - method)
4. It is quite remarkable that a small shale lab sample of only 3 in. in length can hold on the order of 1,000 psi of differential pressure at the end of the test. This provides confidence that actual shale barriers in the field that satisfy regulatory minimum requirements are going to be very good barriers indeed.
5. The tests showed considerable acceleration of barrier activation by sodium and lithium silicate solutions, with the fastest annular closure time observed for lithium silicate. The cause for this may be:
   a. silicate solutions are highly alkaline (pH ~ 11) which can cause shale weakening and dispersion
   b. clay swelling can also be caused by unfavourable cation exchange at clay sites, such as the replacement of potassium ions by sodium or lithium ions, which can lead to increased intermolecular hydration forces and double-layer repulsion in the clay fabric
6. The barrier permeability values at the end of the tests were in the range of 1 – 12.5 µD, which is 3 times higher than the permeability value of the natural shale (3.5 µD), but this value will decrease if the sample tested for longer time.

Chapter 3

3. Qualification of the creeping formation barrier

3.1 Abstract

The previous chapter discussed the creeping mechanism and the different factors that affect the creeping activation. It was obviously that in situ stress is the main driving forces for creeping, while the annular pressure acts oppositely. The process is also affected by the formation content of clay and quartz (the higher clay content the higher tendency to creep and create a plastic deformation) temperature, and fluid chemistry in the annular space where the small scale test revealed astonishing result to accelerate the creeping process using lithium silicate.

Permanent P&A requires cross sectional barrier where the barrier must be extended from the formation rock to the annular space behind the casing, casing, cement plug inside the casing. Standard well construction leave uncemented casing intervals, if the barrier needs to be established adjacent to these intervals, remedial work is needed to establish annular barrier as:

- Section milling of at least 50 meters to establish one barrier and place cement plug in the open hole - milled section.
- Cut and Pull of casing
- The advanced technology (PWC)

But these solutions are complex, time consuming and costly.
The sonic (CBL and VDL) and ultra-sonic logging showed a good formation bonding to the casing in depths where there is no cement has been placed. This phenomenon was observed at depths where shale formation is located downhole. The shale layers have a high trend to interact and deform upon stress applying causing many problems during well construction as swell and collapse, but this response can be used as an advantage in the P&A phase.

3.2 Creeping requirements

If the formation has been displaced onto the outside of the casing in a uniform manner around the circumference and over a sufficient interval along the casing, then this formation could provide an annular barrier to reservoir fluids, eliminating the costly remedial solution.

To qualify the crept formation as annular barrier, the following characteristics need to be satisfied[22]:

1. The formation strength must be high enough to withstand the expected reservoir pressure (pressure from below)
2. The formation permeability must be extremely low to provide a hydraulic seal off
3. The displacement mechanism of the shale must be suitable to preserve the well barrier properties.

NORSOK stated the practical procedure on how the formation can be verified as annular barrier:

1) Position and length of the element shall be verified by bond logs:
    a) Two (2) independent logging measurements/tools shall be applied. Logging measurements shall provide azimuthal data.
    b) Logging data shall be interpreted and verified by qualified personnel and documented.
    c) The log response criteria shall be established prior to the logging operation.
    d) The minimum contact length shall be 50m MD with 360 degrees of qualified bonding.
2) The pressure integrity shall be verified by application of a pressure differential across the interval.
3) Formation integrity shall be verified by a LOT at the base of the interval. The results should be in accordance with the expected formation stress from the field.
4) If the element has been qualified by logging, pressure and formation integrity testing, logging is considered sufficient for subsequent wells.

Apparently logging and formation communication test is the main key to qualify the displaced formation as annular barrier.

3.3 Displaced formation in Gyda field

The only formation that has been tested for creeping purposes is lower Hordaland. The formation has been logged and tested in 3 wells (A-22 A, A-28 A and A-06 A).

The formation was an appropriate candidate to creep as the formation consists mainly of clay stone, creeping was expected in Hordaland formation especially in the green claystone in the lower part. Several wells have experienced tight hole, bit balling & swelling and hygroturgid clay in parts of this formation.

The first well that has been plugged and abandoned in P&A campaign was A-22A, creeping formation was also tested in this well. In the first chapter phase I of P&A was discussed. I will use the well A-22A as a case to describe the phase II and present how to carry out the formation verification procedure to prove creeping.

3.3.1 2/1-A-22 A History

A-22A is a dry exploration well. The well was named 2/1-14 S when drilled. It was side-tracked from 2/1-A 22**. No completion or liner was installed.**

- 2009: XMT installed 6 months after the well was plugged and abandoned due to flow from well
- The well was temporary plugged and abandoned in 2009:
  - Primary reservoir barrier set in open hole from TD to above the reservoir (6130 – 5880 m MD).
  - Secondary cement barrier is placed in transition from OH and into the bottom of the 9 5/8" casing shoe (5140 – 4929 m MD).
  - A shallow cement barrier is set from 1200 – 990 m MD RT. No annulus cement at this depth. Cement plug was set to optimize for setting of a whip stock for a potential side-track.

3.3.2 Well Information

Well Name	2/1-A-22 A (2/1-14 S) – Temporary P&A
Rig	Gyda
RKB – MSL	56 m
Water depth	65,5 m
RKB - Seabed	121,5 m
RKB – WH Datum	30,87 m
Minimum ID through well	9 5/8", 53,5# casing with ID of 8,535"
Maximum inclination	65° @ 2000 - 4929 m MD
Well fluid (inside 9 5/8" casing)	Seawater down to top secondary reservoir barrier at 4929 m MD (SW may be contaminated by OBM). 1,64 SG OBM below secondary reservoir cement barrier (secondary barrier will not be drilled out)
9 5/8" x 13 3/8" fluid	OBM

13 3/8" casing shoe (KOP)	925 / 924 m MD/TVD RKB
TOC behind 13 3/8" casing	Cemented to surface
9 5/8" casing shoe	4992 / 3082 m MD/TVD RKB
TOC behind 9-5/8" casing	4585 m MD RKB – (Theoretical – to be verified by log)
Top Sele/Forties Sands formation	4415 / 2837 m MD/TVD RKB
Reservoir pressure	P&A in 2009 – TOC plug #1@ 5880 m MD
Estimated pressure in Forties formation	1.54 sg @ ±2837mTVD (±427 bar)
Estimated frac gradient in Forties formation	1.95 sg formation strength (Base frac from SLB)
Top Gyda formation	6022 / 3721 m MD/TVD RKB
Current estimated reservoir pressure	582 bar @ 3721 m TVD RKB (Plugged back)

3.3.3 Well schematic prior to phase II

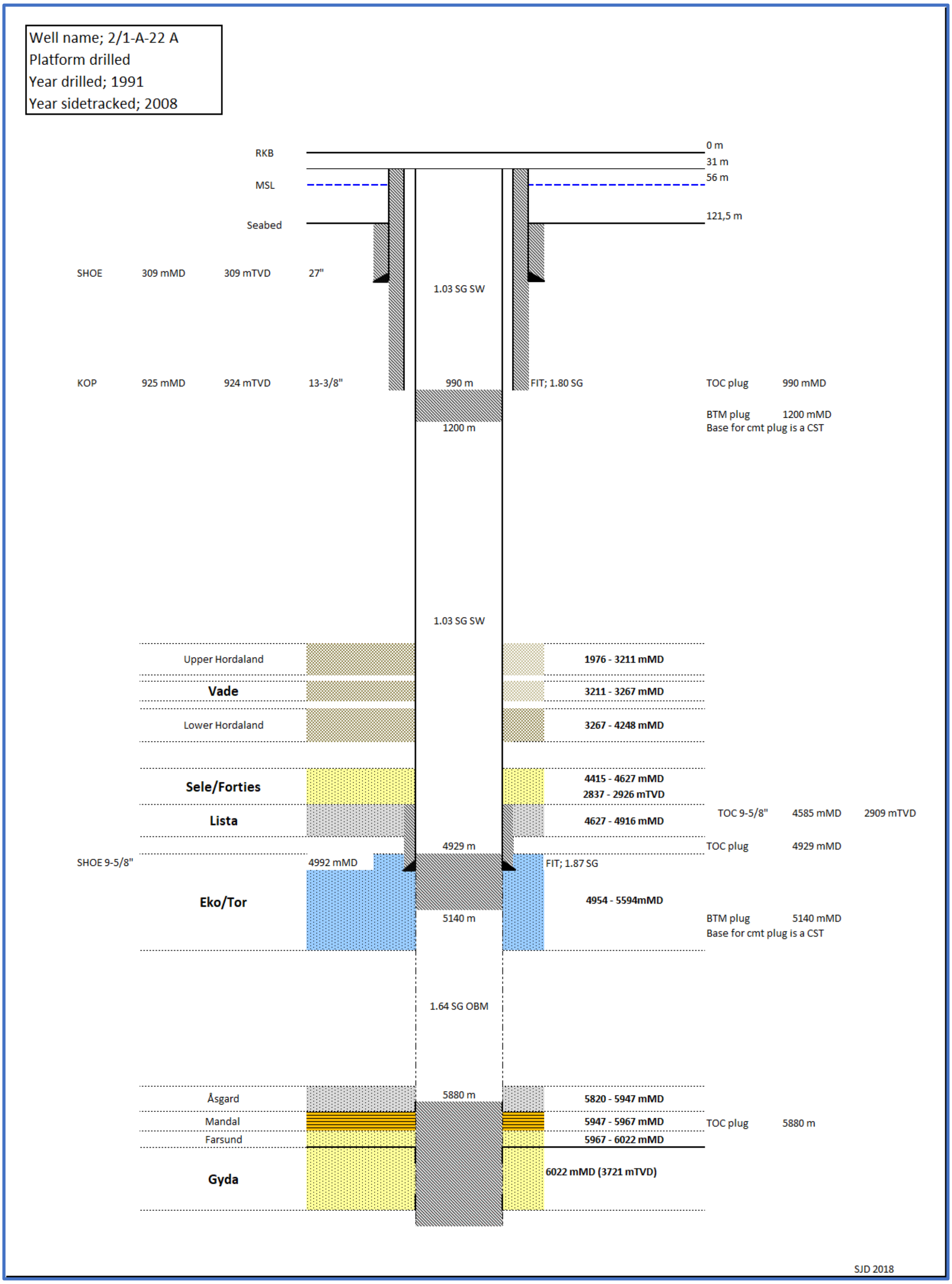


Figure 48: A-22 well schematic prior to phase II (Repsol)

3.4 Plugging design

There was no need to perform phase I in this well since the well has not been completed. Plugging design is based on the Influx and formation evaluation survey to identify influx zones.

Survey outcomes refer that Sele /Forties formation in the overburden has a high probability of influx.

The Sele formation (4415- 4627 m MD) is divided into Upper and Lower Sele with Forties formation in between. The formation has been described as a massive claystone formation.

The Forties formation has a high risk of inflow potential, but only water is expected. It is clearly permeable and has good porosity

Lithology of Forties: Based on cuttings descriptions, formation has an interbedded sandstone, siltstone, and claystone intervals.

This implies that Sele formation and Forties and shallower part of Upper Lista formation have a high probability influx. This layer defined as Tertiary Inflow Zone (4392-4590 m MD)[25].

Balder Fm	4253
Sele Fm	4392
Tertiary Inflow Zone	4392 – 4590
Forties	4415
Upper Lista Fm	4568
Vidar Fm	4640

Table 8: Upper depth of A-22 formation

Based on this evaluation the design is:

- Reservoir must be secured with double reservoir barrier in the place between the reservoir and tertiary influx zone.
- Tertiary influx zone must be secured with double barrier in the place between the zone and not shallower than 4000 m MD to sustain positive fracture margin. These two barriers prevent cross flow to Vade formation and further to the surface
- Cross flow barrier between reservoir and Tertiary influx zone
- Environmental plug

2/1-A-22, 2/1-14 S

Formation	Depth mMD	Depth mTVDSS	«Reservoir quality»?	Water or Gas	Mobility?	Overpressure?	Probability of influx	Consequence of Influx	RiskofInflux	Comment
Nordland Gp. to ±1100m Claystone with sandstone stringers & beds	12	66	Yes	Water	Yes	No	Very Low	Low (bulkvolumesofwater)	Very Low	? Well plugged, top cement plug @990mMD in 9 5/8" csg.? Well is 2/1-14S from 931mMD to TD
Deeper Nordland Gp. Claystone with thin limest. stringers	93	875	No	Water	Uncertain	Yes	Lo	Low (confined volumes)	Low	Sandston estringers 1470-1570mMDindonorwell A-22
U. Hor aland Gp. Claystone with occ. limest. stringers	1962	1735	No	Water	No/Uncertain	Yes	Lo	Low (confined volumes)	Low	
Vade Fm. Interbe ded Sandstone, Siltstone and Claystone	3211	2270	Yes	Water	Yes	Uncertain	Uncer ain	Medium (bulkvolumesofwater)	Medium	Not present in donor well A-22
L. Hordaland Gp. Claystone with thin limest. stringers	3267	2294	No	Water	No/Uncertain	Yes	Lo	Low (confined volumes)	Low	
Balder Fm. Claystone and Tuff	4253	2712	No	Water	No/Uncertain	Yes	Very Low	Low (confined volumes)	Very Low	
Sele F incl Forties Claystone, Siltstone and Sandstone in Forties	4392	2771	Yes	Water	Yes	Yes	Yes	Medium (bulkvolumesofwater)	Medium	Forties Fm.; Sandstone described
Lista, Vidar Fm. Marl, Limestone and Claystone beds	4568	2845	No	Water	No/Uncertain	Yes	Very Low	Low (confined volumes)	Very Low	Well cut by fault
Våle Fm. Claystone w/ limestone stringers	4916	2993	No	Water	No/Uncertain	Yes	Very Low	Low (confined volumes)	Very Low	
Ekofisk Fm Chalky Limestone	4955	3010	No	Water	Uncertain	Yes	Yes	Medium (bulkvolumesofwater)	Medium	EkofiskFmpossiblyporous/fractured,goodROPin places.
Tor Fm Chalky Limestone	5180	3105	Uncertain	Water	Yes	Yes	Yes	Medium (bulkvolumesofwater)	Medium	TorFm. appearsporousandfracturedinlowerpart
Hod F Limestone, argillaceous	5598	3328	No	Water	Uncertain	Yes	Uncer ain	Low (minor volumes)	Low	Well cut by fault
Blodøks Fm Limestone and Marl	5719	3416	No	Water	No/Uncertain	Yes	Very Low	Low (minor volumes)	Very Low	
Hidra Fm Limestone	5729	3424	No	Water	No/Uncertain	Yes	Very Low	Low (minor volumes)	Very Low	
Rødby, Sola & Tuxen Fm Claystone with Limestone stringers and beds	5739	3432	No	Water	No/Uncertain	Yes	Lo	Low (minor volumes)	Low	Well cut by fault
Åsgard Fm. Claystone with Limestone stringers	5820	3496	No	Gas? /Oil?	No/Uncertain	Yes	Very Low	Low (minor volumes)	Very Low	
Mandal Fm. Organic rich Claystone	5947	3602	No	Gas?	No/Uncertain	Yes	Very Low	Low (minor volumes)	Very Low	
Farsund Fm. Upper Mudstone Mbr Claysto e tr Sandstone at base	5967	3619	No	Gas/Oil	Uncertain	Yes	Uncer ain	Medium (Limited HC volumes)	Medium	Drilled ith high overbalance
Gyda Fm. Reservoir sandstone	6022	3665	Yes	Gas/Oil	Yes	Yes	Yes	High Large HC volumes	High	Expected to return to virgin reservoir pressure

Table 9; probability of influx for A-22 formations (Repsol)

3.5 Phase II procedure

After rig skidded to A-22 and XMT removal:

- Nipple up HP riser, BOP, LP riser
- Make up the Clean out BHA and run it to 990 meters (top of shallow cement plug)
- Displace well to 1.60 sg WBM
- Drill out cement plug from 990 – 1200 m MD
- After drilling the shallower cement plug, continue RIH with clean out assembly down to top of cement plug at ± 4929 m MD
- The cement plug was tagged at 4929 m MD, the last 5 meter above the cement reamed due to the mud deposits.
- The whole well circulated to 1.6 sg WBM and BHA pulled out of the well.

Clean out BHA that is used to drill the cement plug consists of 8 1/2" Rock bit with 6 3/4" mud motor, 9 5/8" casing scraper and stabilizers

Reference Photo: 8-1/2 in. (215.9mm) RC137

Figure 49: Milling bit that was used to drill the cement plug

3.5.1 Logging

Well status

- 9 5/8" casing has been scraped & cleaned down to 4929 m MD.
- The well is filled with 1.60 sg WBM.
- Fracture strength at 9 5/8" casing shoe: 2,04 SG EMW
- Top Sele / Forties sands at 4415 m MD / 2837 m TVD (top of sand interval which will have to be isolated: 4392 m MD / 2827 m TVD)
- TTOC outside 9-5/8" casing reported to be at 4585 m MD
- 13-3/8" casing window / shoe at 925 m MD / 924 m TVD.
- 9-5/8" shoe at 4992 m MD / 3082 m TVD.

Objective:

- Identify potential presence of a hydraulic isolation barriers, either cement or formation bonding, located inside the annulus on the outside of the 9-5/8'' casing in the interval from 4918m MD and up to approximately 1900m MD. If present, these potential hydraulic sealing barriers were planned to be used as primary and secondary well barriers to isolate potential source of inflow from the reservoir to surface and for preventing undesired crossflow between formations.
- If possible, qualify intervals with cement in the annulus as hydraulic sealing barriers.
- Advice with regards to optimal perforation intervals for pressure testing/verification of barrier.
- Pressure test and if possible, verify creeping formation and cement intervals as hydraulic sealing
- If possible, qualify annulus barrier intervals as hydraulic sealing based on the pressure test result.
- Advice with regards to optimal perforation intervals for a potential cement squeeze job.
- Advice with regards to presence of barite between the 9-5/8'' and 13-3/8'' casings.

- Better understand the mechanism responsible for the formation bonding development.

The tool string was comprised of:

- Isolation Scanner (IS)
- Cement Bond Log/Variable Density Log (CBL/VDL)

Logging was carried out in one run through the 9-5/8'' section from 4918m MD to 1900 m MD.

3.5.2 Logging results

- TOC is defined at 4689m MD, while it was expected at 4585 m MD.
- TOC is as defined by Schlumberger and confirmed by Repsol. Annular content below the defined TOC is assessed as Cement. Annular content above the defined TOC is assessed as Formation, even when other materials, e.g. fluids, cement, barite, are present.
- Solids behind the casing observed all the way up to 848 m MD.
- Logging chart interpreted by both Repsol and Schlumberger with slightly difference. The differences mostly depending on the length of each interval interpreted
- Details of the High and Moderate to High Quality Bond intervals are given in the table below:

Below Tertiary Inflow Zone								
Total bond interval			**Below defined TOC**			**Above TOC**		
Total, m	**High / Moderate to High**		**Total**	**High / Moderate to High**		**Total**	**High / Moderate to High**	
347	66	19%	279	12	4.4%	68	54	79%
Above Tertiary Inflow Zone								
Total bond interval			**Below defined TOC**			**Above TOC**		
Total, m	**High / Moderate to High**		**Total**	**High / Moderate to High**		**Total**	**High / Moderate to High**	
1125	753	67%	–	–	–	1125	753	67%

Table 10: Interpretation of CBL, VDL, IS logging in well A-22 A to determine bonding quality length in meter

The Interpretation based on the following threshold matrix:

Bond quality assessment	VDL	CBL (mV)	AI average (MRayl)	AI map	FA average (dB/m)	FA map	Applied to:
Low	–	–	–	–	–	–	**Fluids**
High / Moderate – High	Weak / No casing arrivals + clear formation arrivals	<10	>3	Homogeneous	>70	Homogeneous	**Cement**
Moderate	Medium contract casing arrivals + Medium contract formation arrivals	10 – 20	2.6 – 3.0	Isolated pockets / channels / slightly heterogeneous	60 – 70	Isolated pockets / channels / slightly heterogeneous	
Low / Moderate – Low	Strong casing arrivals + weak / formation arrivals	>20	<2.6	Heterogeneous / connected pockets and channels	<60	Heterogeneous / connected pockets and channels	
High / Moderate – High	Weak / No casing arrivals + clear formation arrivals	<20	>3	Homogeneous	>70	Homogeneous	**All other annular contents**
Moderate	Medium contract casing arrivals + Medium contract formation arrivals	20 – 30	2.6 – 3.0	Isolated pockets / channels / slightly heterogeneous	60 – 70	Isolated pockets / channels / slightly heterogeneous	
Low / Moderate – Low	Strong casing arrivals + weak / formation arrivals	>30	<2.6	Heterogeneous / connected pockets and channels	<60	Heterogeneous / connected pockets and channels	

Table 11: Interpretation Matrix that is used by Repsol to identify bonding quality

The bond quality assessed for each formation by Repsol and Schlumberger interpreters for A-22 well in the interval (1900-4619) as follow:

Formation	Top (m)	Base (m)	Annulus			VDL	CBL (mV)	AI av. (MRayl)	AI Map	FA (dB/m)	FA map	TIE	Bond Quality Assessment	
			Content	Gross length (m)	Net length (m)								RENAS	Schlumberger
	1900	3040	Formation + Fluids	1140	500									
Upr Hordaland	3040	3200		160										
	3200	3211	Formation	11	11									
Vade	3211	3244	Formation + Fluids	33										
	3244	3252	Formation	8	8									
	3252	3267	Formation + Fluids	15										HIGH
Lwr Hordaland	3267	3319	Formation	52	40									
	3319	3487	Formation + Fluids	168										LOW TO MODERATE
	3487	3590	Formation	103	80									
	3590	3680	Formation	90	80									HIGH
	3680	3775	Formation	95	70									
	3775	3942	Formation + Fluids	167	150									LOW TO MODERATE
	3942	4067	Formation + Fluids	125	122									HIGH
	4067	4128	Formation + Fluids	61	48									MODERATE TO HIGH
Top Tested Interval														
Lwr Hordaland	4128	4228	Formation + Fluids	100	75									
Bottom Tested Interval														
Lwr Hordaland	4228	4228	Formation	25	18									
Balder	4253	4253	Formation	87	70								High/High – Mod	
	4340	4340	Formation + Fluids	52									Low/Mod – Low	POOR

Top Influx Zone	4392													
Sele	4392	4432	**Fluids**	40										
	4432	4553	**Fluids**	121										
Lwr Forties & Upr Lista	4553	4580	**Formation + Cement**	27	27								High/High – Mod	**MODERATE TO HIGH**
Upr Lista	4580	4590	**Formation + Cement**	10	8								High/High – Mod	
Base Influx Zone	4590													
Upr Lista	4590	4613	**Formation + Cement**	23	18								High/High – Mod	
	4613	4639	**Formation + Cement**	45	36								High/High – Mod	**LOW TO MODERATE**
TOC	4639													
Upr Lista	4639	4640	**Cement**	1									Moderate	
Vidar	4640	4660	**Cement**	20									Low/Mod – Low	
	4660	4664	**Cement**	4	3								High/High – Mod	
	4664	4715	**Cement**	51									Moderate	
	4715	4738	**Cement**	23									Low/Mod – Low	
	4738	4755	**Cement**	17	5								High/High – Mod	
	4755	4761	**Cement**	6	4								High/High – Mod	
	4761	4775	**Cement**	14									Low/Mod – Low	
	4775	4781	**Cement**	6									Low/Mod – Low	
	4781	4812	**Cement**	31									Low/Mod – Low	
	4812	4862	**Cement**	50									Low/Mod – Low	
	4862	4912	**Cement**	50									Low/Mod – Low	
	4912	4916	**Cement**	4										
Våle	4916	4918	**Cement**	2										
BASE OF LOG	**4918**													

Table 12: Table shows bond quality assessment for A-22A formations conducted by Repsol and Schlumberger in the interval (1900-4619)

3.5.3 Assessment of cement bond quality

(1) Below the Tertiary Inflow Zone

- The Tertiary Inflow Zone extends from 4392m MD to 4590m MD**.**
- The 9-5/8'' casing TOC is defined at 4639m MD.

Schlumberger did not qualify any intervals with cement in the annulus as hydraulic sealing. Hydraulic sealing cement is, by Schlumberger's definition, cement with bonding quality of ''Moderate to High'' and ''High''.

Repsol defined minor zones, with a total length of 12m as providing a potential barrier.

(2) Above the tertiary inflow zone

No cement above the Tertiary Inflow Zone.

3.5.4 Assessment of formation bond quality

(1) Below the Tertiary inflow zone

- The 9 5/8'' casing TOC is defined at 4639m MD.
- Above the TOC and below the Tertiary Inflow Zone is an interval 49m long displaying characteristics of Formation bond from 4639 – 4590m MD.

Schlumberger assessed this interval as being Low to Moderate quality Formation bond in the lower part (4639 – 4613 m MD) and Moderate to High in the upper part (4613 – 4590m MD). This gives a total bond length of 18m according to the Schlumberger interpretation.

Repsol assessed the interval above the defined TOC as containing "Formation + Cement" with Moderate to High quality bond. Repsol assesses a total of 54m Moderate to High quality Formation bond in the interval 4639 – 4590m MD.

On examination, the difference in assessed bond quality arises because of slight differences in the calculated average CBL and AI values. In both assessments these values are borderline between Moderate and Moderate to High. Given this interval will not be relied upon as a barrier, these differences are of minor importance.

(2) Above the tertiary inflow zone

Schlumberger assessed the bond quality above the Tertiary Inflow Zone as being "High" and "Moderate to High" quality "Formation" and "Formation + Fluids" bond in the annulus in the interval up to 3244m MD.

Within this interval Schlumberger picked 4392 – 4340m MD within the Balder formation as being of “Poor” quality, and from 3942 – 3772m MD and 3487 – 3319m MD as being “Low to Moderate” quality bond.

In the interval from 4392 – 3200m MD, Schlumberger assess 805m as being “High” and “High to Moderate” bond quality and it seems to be the best interval to check creeping formation.

The interval (4128- 4228 m MD) through Lower Hordaland formation selected to perform a pressure communication test to check seal-ability of creeping formation.

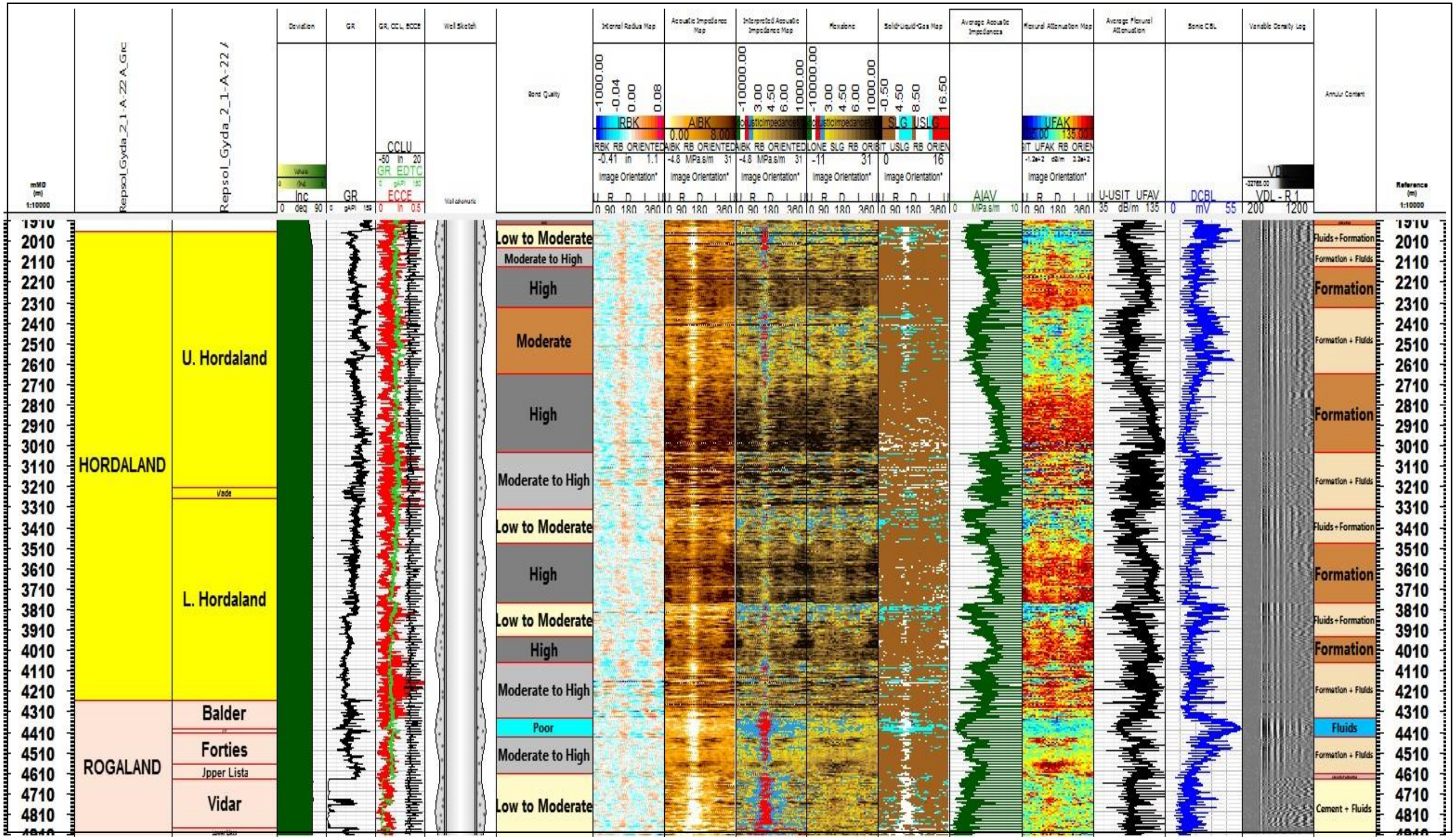


Figure 50: Annular conditions from Isolation Scanner /CBL within lower logged interval (4918m-1900m)

3.5.5 Formation test and cementing

Well status

- 9 5/8" casing has been scraped & cleaned down to 4929m MD
- 9 5/8" casing has been logged
- Results from logging:
  - No qualified casing cement from Cement bond Log
  - Creeping formation will be tested from 4228 to 4128 m MD
- Well filled with 1.60 sg WBM.
- Fracture strength at 9 5/8" casing shoe: 2.04 SG EMW

Objective:

- Qualify creeping formation for placement of Forties Barrier by perforating casing and pressure testing.
  - Zone to be tested is based on information from the Isolation Scanner log.
- In case the formation was qualified during pressure test to be used as annular barrier Set 4 cement plugs as one continuous cement plug wet in wet on top of the present barrier at 4929m MD.
  - Cement plug no 1 from 4904 to 4654 m
  - Cement plug no 2 from 4654 to 4404 m
  - Cement plug no 3 from 4404 to 4250 m
  - Cement plug no 4 from 4250 to 4000 m
- Dress off and pressure test cement barriers.

1. RIH with Archer TCP guns and Stronghold Defender System

Stronghold Defender system provided by Archer enables to perforate and test annular barrier.

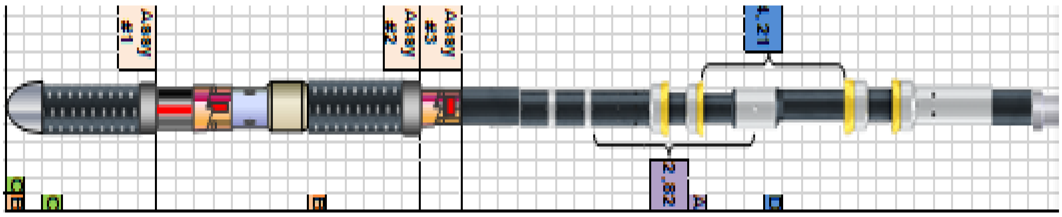


Figure 51BHA used for formation test and cementing for A-22A:

2. Continue RIH to place lower gun at upper perforation depth at 4128 m

3. Perforate casing at upper perforation depth at 4128 m MD
4. Continue RIH to place the upper gun at the lower perforation depth at 4228 m MD
5. Test integrity of Stronghold Defender System by placing Formation test tool against blank casing ± 5 m above the lower perforation and drop ball into string to divert the flow out between the swab cups.
6. Perform formation test to the interval between (4128-4228) by Position string so that the lower perforations at 4228m MD are between the swab cups. Pressure up against the lower perforation to 85bar and monitor the pressure for at least 2 hours. The criteria to verify if there is a pressure communication test behind the casing or not is:
   a. The test is successful if there are no returns to trip tank.
   b. The test is unsuccessful if there are fluid returns on surface combined with pressure drop in DP.

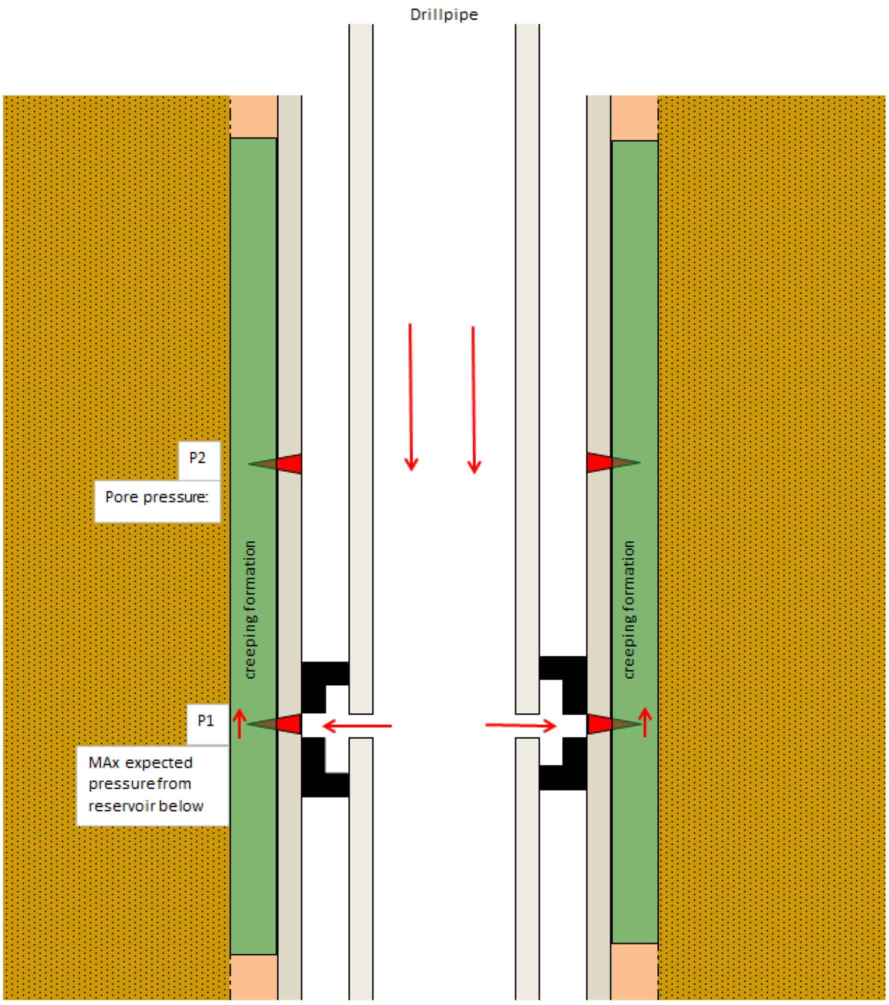
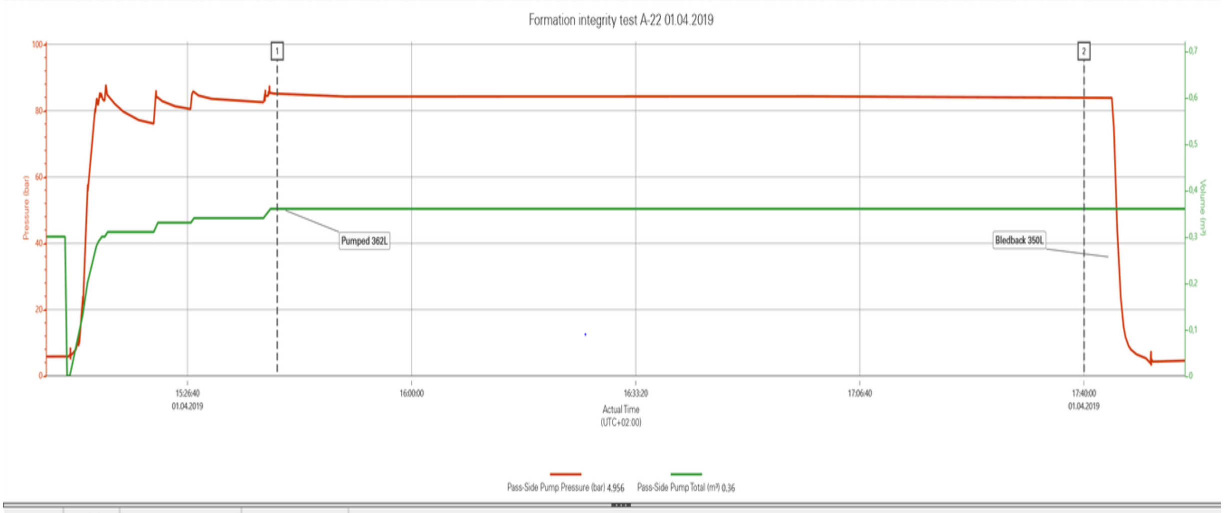


Figure 52: sketch of the well and formation test method using swap cup



Description	Actual Time (UTC+02:00)	Pass-Side Pump Pressure (bar)	Pass-Side Pump Total (m^3)
1 Cement At	15:40:01	84,99	0,36
2 Bump Plug	17:40:01	83,95	0,36

Figure 53: formation integrity test result for A-22A

This graph shows that the pressure was stable, and no volume increase in the trip tank was observed at surface. This is proving the presence of an annulus hydraulic seal being able to withstand the maximal future reservoir pressure. This means that the interval is qualified as an annular barrier based on logging and formation integrity test. The cross-sectional barrier in this case just requires a cement plug inside the casing to be qualified as barrier.

7. RIH with BHA to top of cement at 4929 m MD, then Drop a ball to activate the BHA release sub and drop BHA (length 22.8 m)
8. Circulate the well with 1.6 sg
9. Space out string 2 m above dropped BHA (top of BHA at 4906m MD)
10. Set balanced cement plug #1 (250 m from ± 4904 – 4654 m)
11. Set balanced cement plug #2 (250m from ± 4654 – 4404 m)
12. Set balanced cement plug #3 (154m from ±4404 – 4250 m)
13. Set balanced cement plug #4 (250m from ± 4250 – 4000 m)
14. POOH**:** once the cement stinger was in surface was noted the lower part of the BHA was not release as expected, the stronghold defender tool and perforation guns still attached to the string.
15. RIH 8 ½” cement dress off. Top of Cement Plug No.4 was tagged at 4013m MD and confirmed with 8 tons, cement was dressed off from (4013- 4016mMD) with 5-8 tons WOB

A total of 888m of cement plug was pumped down in 4 separate cement jobs, plugs set wet-in-wet. This represents a total qualified barrier interval of 599m of 888m.

Above the influx zone 192m “High” and “High to Moderate” bond quality in an interval 237m long within the Lower Hordaland constitute:

- Two barriers of 50m each
- Additional barrier of 92m

The cement plugs were tested to 160 bar, positive test.

3.5.6 CUT & RETRIEVE 9 5/8” CASING

Well status

- Top of barite sag in 9 5/8” x 13 3/8” annuli at 830 m MD
- TOC plugs inside 9 5/8” casing dressed off to 4016m MD
- 1.60 sg WBM in well above TOC.
- Cement plugs and 9 5/8” casing pressure tested to 160 bar.
- OBM in 9 5/8” x 13 3/8” annulus
- 13 3/8’’ casing shoe at 995 m MD
- FIT at 13 3/8” casing shoe: 1.80 sg EMW

Objective

- Cut 9 5/8” casing at ±278 m.
- Displace B-annulus to 1.60 sg WBM.
- Release and retrieve seal assembly.
- Retrieve 9 5/8” casing
- Scrape the 13 3/8” casing.

The casing cutter tool lowered at 278 m and cut the 9 5/8” casing, then the B- annulus displaced to 1.6 sg WBM and 9 5/8” seal assembly retrieved**.** The 9 5/8” casing spear was RIH, engaged and pulled the 9 5/8” casing.

Scraper assembly to above top of cut 9 5/8” casing at 276m MD was RIH, performed circulation and thick fluid was observed in returns over shakers.

3.5.7 Environmental plug

Well Status

- TOC plugs inside 9 5/8” casing at 4016 m MD
- 5/8” casing retrieved down to cut at 278 m MD
- Well filled with 1.60 sg WBM.
- 13 3/8” casing scraped down to top of 9 5/8” casing cut at 278 m.
- 13 3/8’’ casing shoe (window) at 995 m MD / 994 m TVD
- FIT at 13 3/8” casing shoe: 1,80 sg EMW

Objective

To install the environmental plug

Procedure

- RIH and install EZSV at ± 272m MD
- Displace well to seawater
- Set balanced cement plug on top of EZSV (100 m from ± 272 – 172 m)
- Pull to top of cement and circulate
- RIH and tag TOC at 172m

Now phase II is completed and well A-22 is permanently plugged and abandoned. During phase III, wellhead and conductor will be cut and removed[26].

In the next page, well barrier diagram for well A-22A post phase II.

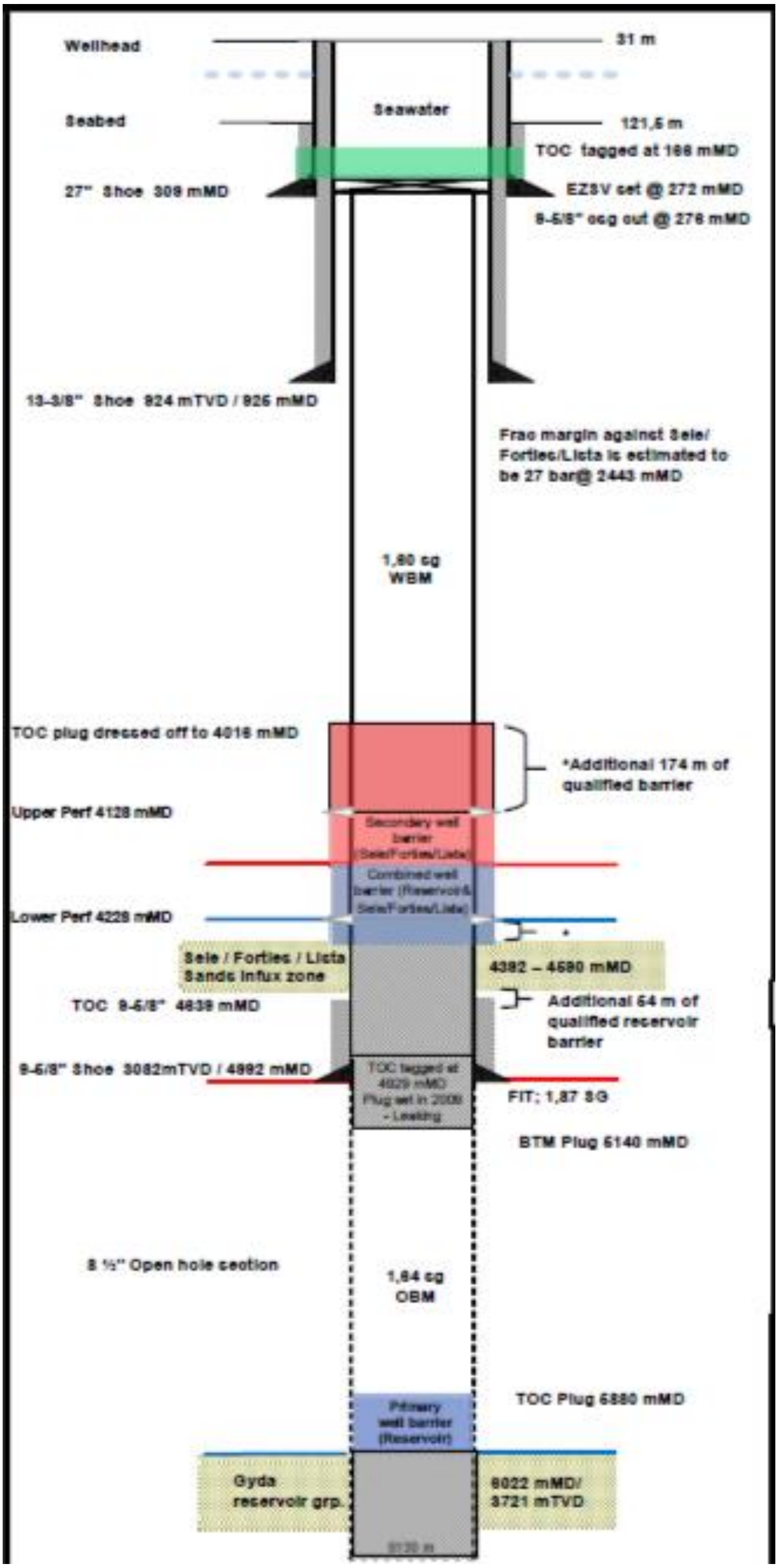


Figure 54: well barrier diagram for well A-22A post phase II

Conclusion

It appears that dividing P&A activities into 3 phases is beneficial in terms time and cost where the light activities are being performed using wireline while the heavy activities require rig intervention. The rig-day rate is very high comparing to wireline. Many companies aim to perform P&A rig-less, but currently it is not possible to perform P&A rig-less due to obstructions and challenges to get access deep in the well, and the need to perform heavy activities (pull casing and tubing, PWC, milling….etc) that is beyond wireline capability.

The presence of creeping shale has a high influence when performing P&A in terms of cost and time. It facilitates cross sectional barrier establishment. Not all types of shale creep, but it appears that best candidates are shales with a low threshold for plastic flow and a high ability to sustain large plastic deformations. There are three proven factors that stimulate and accelerate shale to creep which are temperature increasing, annular pressure reduction, and the presence of chemical solution in the annular space. Scientifics focus now on circulating chemical solution rather than increase temperature which seems to be difficult to perform or reduce annular pressure which brings well control concerns.

The preferred solutions are solutions that reduce near-wellbore stiffness of a shale formation, and such solutions are generally undesirable from a wellbore stability standpoint during drilling. This indicates that silicate solutions are prime candidates for testing barrier activation. The test introduced by Van Oort showed that lithium silicate gives an interesting result. This solution showed the fastest annular closure time of only 2.9 days, which is 6.3 times faster than the normal pore fluid.

Recommendation for future work

Lithium and sodium silicate showed a very good results for accelerating shale creep, but it is only tested on North sea Lark-Horda shale formation which already showed creeping properties, but what if these solution used for shale formation that does not show creeping behaviour or has low creeping tendency?

I recommend combining chemical solution (Lithium, sodium silicate) with other chemical solutions that heat up shales to activate shales formation that does not show creep behaviour. The reaction between shale and chemicals need a further study. The barrier formation process may induce large and possibly highly uneven load on the casing. Thus, collapse of the casing are possible consequences, that is why it is important to identify solution exposure time to shale formation to get the desired deformation.

There is no clear model for creeping formation until now, due to the large number of parameters and lack of intensive studying. The only model was presented by SINTEF and there is another model for salt formation presented in Brazil, but it is not relevant for NCS. To be closer to the reality, the model should consider smaller grain size and random shapes (not circular).

In general P&A operation is very costly for operators and has not any return on investments. The most cost-effective solutions for P&A are to consider the P&A scenarios during the well design phase. Proper primary cement jobs, depth of TOC, and identification of pressure sources in the overburden, scale depositions were the key factors during Gyda P&A.

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