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Analysis of Factors Contributing to Long Term Shallow Gas Migration to Seabed in Surface Casing Annulus

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Abstract

A common observation is a low rate gas bubbling from the outside of the 20” surface casing on wells located in the Haltenbanken area on Norwegian Continental Shore. This phenomenon is known as long term shallow gas migration in surface casing annulus.

In this thesis it is demonstrated that cement radial shrinkage is a major factor contributing to long term annular gas migration. This is done by performing an analysis of data obtained from leak tests conducted in laboratory and case study of the wells located on Norwegian Continental Shelf that has experienced shallow gas migration.

Acknowledgement

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Nomenclature:

SGS – Static Gel Strength

API - American Petroleum Institute

RAS - Right Angle Set

HT – High Temperature

SHC - Self-Healing Cement Concept

NCS - Norwegian Continental Shelf

RMR - Riserless Mud Recovery

MW - Mud Weight

SMO - Suction Module

GL – Ground Level

MSL – Mean Sea Level

TVD – True Vertical Depth

MD – Measured Depth

WBM – Water Based Mud

SG – Specific Gravity

1 Introduction

A key aim of cementing is to achieve zonal isolation between different formations and surface. Being that cement is a primary well barrier element, it is important that it is designed and implemented successfully to ensure the integrity of the well.

In the last years, advancements in technologies associated with well cementing have ensured high success rate of achieving good zonal isolation during primary cementation.

Despite the efforts, shallow gas migration in annulus to seabed is still a common observation on wells drilled on Norwegian Continental Shelf as well as in other areas of the world. Gas annular migration is defined as the invasion of formation gas into the annulus owing to a pressure imbalance at the formation face where gas may migrate to a lower pressure zone or to the surface. It is recognized as a major problem due to consequences that can be hazardous to human personnel and drill rig safety in case of blowout or environment due to contamination of ground water.

Gas migration phenomena is believed to be caused by various factors or combination of them that can take place at different periods as cement slurry evolves with time. Common factors include fluid density control, mud removal, cement-slurry properties, cement hydration and interactions between the cement, casing, and formation.

Short term or immediate gas migration can generally be controlled if the potential is predicted so that a suitable job design can be applied. This is therefore in general not a big or unsolved problem.

One unsolved problem though, is the long term low rate gas percolation to seabed from wells in the Haltenbanken area. This flow is observed as bubbles coming out by the wellhead from the outside of the 20” surface casing.

This thesis work is aimed to study factors contributing to annular gas migration and magnitude of their impact on wells with various cement types and formulations.

2 Theory

Gas migration is one of the most troublesome problems is petroleum industry. It is defined as the invasion of formation fluids into the annulus owing to a pressure imbalance at the formation face where fluids may migrate to a lower pressure zone or possibly to the surface (Nelson & Guillot, 2006).

Problems troublesome is topped by its complexity as many various factors influence the process, such as fluid density control, mud removal, cement-slurry properties, cement hydration, and interactions between the cement, casing, and formation. As no other well is the same, reasons that caused the gas migration can differ from one to another well.

Extensive research has been done to understand this phenomenon, resulting in various theories that explain the physical processes that can lead gas migration. This theory part concentrates on gas migration after primary cementing and focuses on conditions, types and factors that contribute to gas migration.

2.1 Conditions for gas migration

For annular gas migration to occur three conditions must be satisfied (Figure 2.1). If one of conditions is not satisfied or is not anymore present, then gas migration will not occur or will stop.

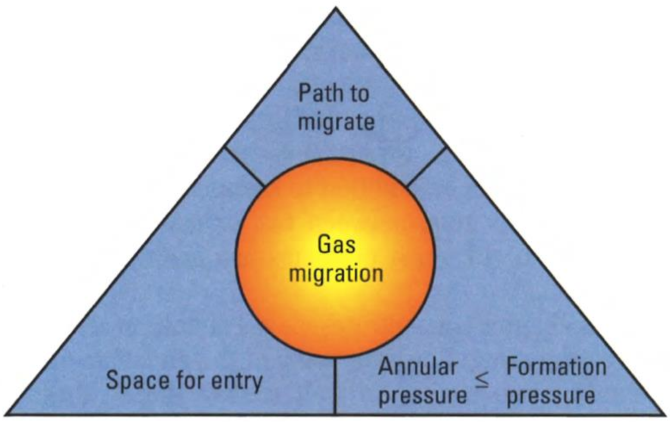

Figure 2.1: Conditions for annular gas migration (Nelson & Guillot, 2006, p. 290)

Conditions for annular gas migration are (Nelson & Guillot, 2006, p. 290):

1. The hydrostatic pressure in the annulus falls to a level that is less than or equal to the pore pressure of a gas bearing zone.
2. Space in the annulus allows gas entry.
3. A path is present in the annulus through which the gas can migrate.

In order to prevent the gas migration, it is sufficient to eliminate only one of the conditions. Most of the preventing strategies are aimed to do exactly that.

2.2 Types of gas migration

As gas migration can occur at any point of well lifecycle it is convenient separate types by time when migration occurs. Commonly, in literature, three types of gas migration are defined:

1. Immediate gas migration
2. Short-term gas migration
3. Long-term gas migration

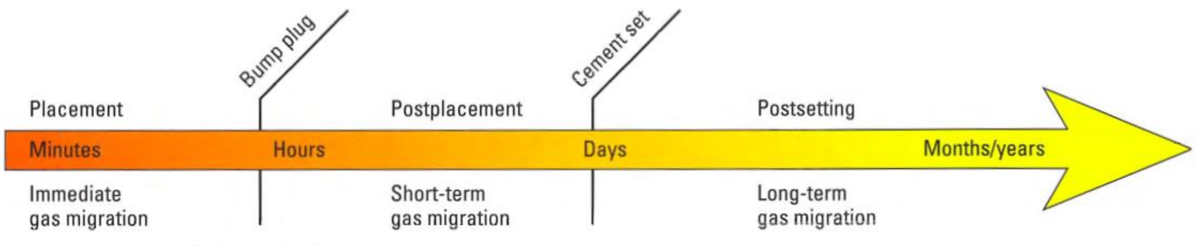

Figure 2.2: Types of gas migration (Nelson & Guillot, 2006, p. 291)

Further all three types will be described closely with focus on key factors for gas migration.

2.2.1 Immediate gas migration

Immediate gas migration occurs during placement of cement, between the start of the cementing operation and the end of cement placement, which is normally marked when the top wiper plug lands (Nelson & Guillot, 2006, p. 291).

In this time period, gas migration occurs due to poor well control or cement job planning. The most efficient way to deal with problem before it occurred – preventive action. During cement job planning, it is important to perform a free-fall/U-tubing computer simulation to ensure that the hydrostatic pressure against critical zones is maintained at all times above the pore pressure to avoid fluid influx and below fracturing pressure not to damage the formation and cause lost circulation (Drecq & Parcevaux, 1988). It is important to stress out "at all times" part, as the hydrostatic pressure on a single point is not constant during the job and comes from differences in densities of the mud, preflushes, spacer and cement slurry (Smith, 1987). If at any time of a job hydrostatic pressure falls below pore pressure, a gas influx will occur, further reducing hydrostatic head above a single point of the well, further worsening situation.

During the job, good job routines are important, such as proper density control during continuous mix of cement to avoid density fluctuations and ensure a uniformity of cement column (Granberry, Grant, & Clarke, 1989) and casing reciprocation that can cause drop in annular pressure due to swab effect.

If an influx occurs, one solution is by well control measures, to increase the density of the fluid in the annulus.

2.2.2 Short-term gas migration

Short-term gas migration, also called postplacement gas migration, occurs between the end of the primary cementing operation (normally marked by the landing of the top wiper plug) and the setting of the cement. (Nelson & Guillot, 2006, p. 292).

The timeframe is anytime between a few minutes to a few days after the end of the cementing operation.

This type of migration is the most complex and still not completely understood. Industry has studied it for more than 40 years with no clear answer to the problem, although it is believed that the process that causes migration is annular pressure decay. A wide array of factors is contributing to pressure decay in different extents according to different theories.

2.2.3 Long-term gas migration

Long-term gas migration occurs after the cement has set, which may occur within a few hours after the end of the cement job. There is no usual timeframe as migration can occur anytime in a few days, months, or even years.

Migration of this type is getting more attention now due to increasing number of Plug and Abandonment operations (P&A) as old wells get to the end of their life cycles. According to industry standards, such as NORSOK and API, one must provide long term integrity (eternal perspective) of well (Norway, 2013), which includes integrity of cement bonding, impermeability and ability to stop gas migration.

Due to increasing amount of wells that have already or will be soon plugged and abandoned industries interest in understanding, predicting and preventing of long-term gas migration has increased.

2.3 Factors affecting gas migration

There are several studies conducted on each of the factors, which therefore resulted in different theories. Study results and conclusions that were done regarding each of factors will be presented to give the reader the better understanding of complexity of gas migration phenomenon.

2.3.1 Fluid loss

Fluid loss is considered to be one of the main contributing factors to gas migration. Fluid loss from the cement slurry into formation is a simple process that leads to quite complex consequences that can be linked to all three conditions of gas migration.

Firstly, if we look on the first condition – the fall in hydrostatic pressure in annulus, fluid loss consequences that affect it are:

- Decrease in the height of the hydrostatic column due to a slurry-volume decrease
- Increased slurry gelation effects due to reduced water content in the slurry
- Annular bridging
- Friction-pressure losses during the compaction due to slurry volume decrease.

Secondly, fluid loss provides space for entry (second condition) within cement matrix, as well as the volume loss itself can lead to a significant pressure drop in an enclosed space.

Thirdly, fluid loss can be related to formation of filtercake and its properties, which consequently can provide a migration path.

Consequence of fluid loss that contributes the most to the gas migration is believed to be annular gelation as it can restrict the transmission of hydrostatic pressure in the annulus. Few researchers have tried to measure fluid loss rate that could prevent annular bridging. One of the first studies was conducted by Christian *et al.* in 1976, who derived a method for calculating the fluid loss rate and came to conclusion that reduction of the American Petroleum Institute (API) fluid loss rate to less than 50 mL/30 min would reduce the risk of gas invasion. This value is as an industry standard for slurry composition and testing.

Further studies built on that theory, but approached calculations in rather different way, basing them on Darcy flow equations. Baret (1988) got to a conclusion based on his calculations that sometimes API fluid-loss rates as low as 10 mL/30 min are needed to prevent annular bridging (Nelson & Guillot, 2006, p. 294).

2.3.2 Gel Strength Development

Another main contributing factor solicited by many in the industry is the gel strength development. After cement is pumped into wellbore and left static before it sets, it starts to develop gel strength. At some point in time, gel structure develops enough strength to resist the force load above it. This leads to decrease in hydrostatic pressure.

As during this transition time cement is most exposed to invasion, this time should be kept to a minimum.

To be able to calculate this transition time on any cement, a quantifying system was developed.

The term zero gel strength time is defined as the time it takes the cement to achieve the static gel strength (SGS) of 100 lbf/100ft^2. This value equals the viscosity of 30Bc.

Through testing a Static Gel Strength (SGS) value equal to 500 lbf/100ft^2 for gelled cement was found to be resistant against fluid invasion. The time it takes the SGS to reach 500 lbf/100ft^2 from 100 lbf/100ft^2 is called the transition time (Keeling, 2011).

Above statement is true but, a gas influx will occur only when cement gel strength is sufficient to prevent full hydrostatical pressure transmission, but at the same time not sufficient to resist gas invasion.

Therefore, to better reflect the statement above, a new parameter was introduced – critical gel strength (CGS). This parameter states that when the hydrostatic pressure in the well at interested point drops below the formation pore pressure, only then will it be acceptable to fluid invasion.

Taking in account all of the previous factors, the transition time now becomes the time cement develops static gel strength value of 500 lbf/100ft^2 from the CGS (API RP-65 part 2).

2.3.3 Cement shrinkage

Cement hydration shrinkage acts in two different mechanisms, which come into effect after the cement has gone through the gelation phase, by reducing annular pressure and by providing space for gas to enter a well.

Cement shrinkage comes from process of cement hydration, also known as cement chemical contraction, and is proportional to the degree of hydration of the cement. The volumetric change occurs because volume of the hydrated phases is less than that of the initial reactants.

Total chemical shrinkage can be measured by placing cement slurry in a reservoir under free access to water and it corresponds with the amount of water absorbed by the cement under the hydration process. The total chemical shrinkage is split between a matrix internal contraction (increase in porosity), which varies around 2%, and a bulk shrinkage representing from 4% to 6% by volume of cement slurry, depending upon the cement composition (Parcevaux & Sault, 1984). It is important to differentiate between the two types of contraction, but in most cases, data will be reported as a single number, which is referred to total chemical contraction.

Different theories discuss to which degree cement shrinkage contributes to hydrostatic pressure drop in the well.

One of the most recent studies were conducted by Nishikawa and Wojtanowicz, who came to conclusion that chemical shrinkage does not contribute to annular pressure reduction. They conducted a series of experiments they fabricated apparatus shown on Figure 2.3.

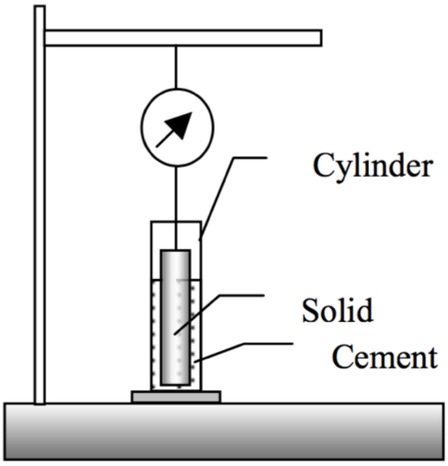

Figure 2.3: Apparatus for testing cement shrinkage and shear drag (Nishikawa & Wojtanowicz, 2002)

Apparatus consists of solid steel rod placed in cylindrical contained filled with Class H cement. Steel rod is connected to scales, that continuously measure weight of the rod.

The reasoning made by Nishikawa and Wojtanowicz was that chemical shrinkage would cause downward movement of cement slurry while gelation (SGS) would increase friction at the rod surface. If the two phenomena happened concurrently, the rod would be pulled down by friction force that would add to the measured weight. Experiment was designed to simulate a potential relationship between chemical shrinkage and pressure transmission in the well annulus and was conducted with two rods of different sizes (Nishikawa & Wojtanowicz, 2002).

The results of this experiment are plotted on Figure 2.4:

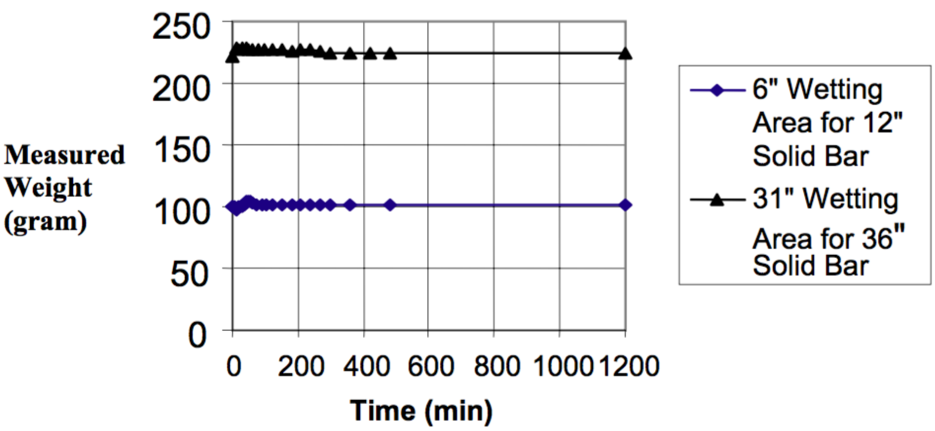

Figure 2.4: Results of Nishikawa and Wojtanowicz experiments on chemical shrinkage (Nishikawa & Wojtanowicz, 2002)

Cement top has dropped by ¼” for 12” rod and ¾” for 36” rod, which indicates that chemical shrinkage has occurred, however throughout the whole experiment, weight measurements has not changed. Nishikawa and Wojtanowicz has concluded that chemical shrinkage has occurred before SGS increase, and therefore it does not contribute to the mechanism of hydrostatic pressure loss.

Research conducted by Levine points on otherwise.

2.3.4 Permeability

During placement, cement in its gelled state and even during setting time is a permeable medium with matrix permeability measured to be as high as 300 mD.

Cheung and Beirute were first who proposed a gas migration mechanism, by conducting several laboratory studies, that gas first invades cement pores and eventually penetrates the whole cement matrix, successfully preventing hydration process in these pores, and establishing a migration path.

Later Parcevaux (1984) has built on that theory by conducting a study of pore-size distribution of cement slurries during thickening and setting times. His findings included a phenomenon of free porosity – well connected pores that begin to appear at the initiation of the setting period. After an initial gas invasion, pores enlarge and develop communication between each other, entering a pseudo-steady state when these connected gas pores form gas channels that reach a stable size.

In the industry, various admixtures are available that either block this internal pore space or makes gas absorb to the surface to prevent gas influx based on this theory; or a combination of these.

2.3.5 Mud removal

It is important to mention that poor mud removal or mud contamination was a serious problem before for service companies as it is one of the key factors for achieving a solid zonal isolation and good well-to-cement-to-casing bond after cement job is done. This problem is merely solved nowadays with introduction of modern well cleaning routines with implementation of spacers and flushers that are intended to displace drilling mud from the annulus, leaving the casing and formation water-wet and separate drilling fluids from the cement slurry. Cement design with mindset of right composition for right conditions will promote displacement efficiency. Software to model this is available and widely used in the industry.

The mechanism for gas migration is this case is fairly simple. First cement sets with no gas flow, with plastic state shrinkage of mud occurring later providing a space for entry and forming a gas channel. Flow volume is slight to moderate at this stage. Gas flowing through mud channels successfully widens them due to dry-shrinkage, increasing gas flow volumes with time. A visual representation of poor mud removal with formed gas channels can be seen on Figure 2.5.

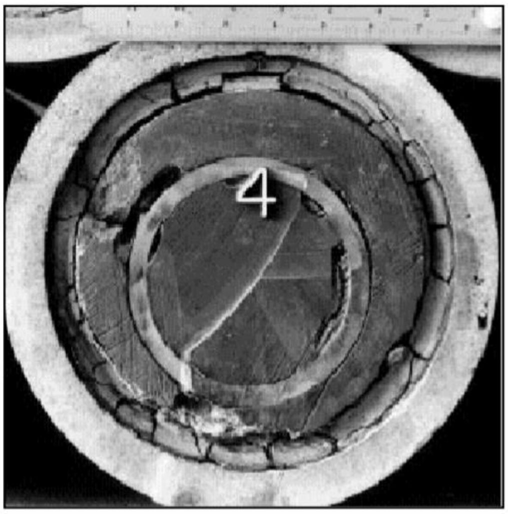

Figure 2.5: Gas flow through mud channels due to improper mud removal (Halliburton Annular Gas Migration Presentation, 2016)

Importance of a solid well cleaning job before cement placement cannot be underestimated as improper hole cleaning leads to formation of mud channels that gas flows within and providing both a space for entry and a path for gas migration.

2.3.6 Micro annulus

Gas migration can also occur in micro annulus – a small gap that may form between the casing or liner and the surrounding cement sheath, as well as between cement sheath and formation post setting. Outer micro annulus can in many cases close by formation collapse or creep short or long term.

Variations of pressure and/or temperature during or after cementing process cause steel casing to expand or contract both in length and diameter. These small movement cycles can break cement to casing bond, leading to the formation of a micro annulus. Typically, it is only a partial debonding, but in some severe cases the micro annulus may encircle the entire casing circumference leading to severe well integrity problems.

2.3.7 Mechanical failure of cement sheath

A gas migration path can be formed due to mechanical failure of cement. During change of temperature and pressure in the wellbore, tensile and/or compressional stresses will arise in the annular sealant. If tensile and/or compressional stresses exceed maximum values that cement is designed for micro cracks or local near casing crushing (shear failure) can form , creating both space for entry and a migration path for gas.

Tectonic stresses, subsidence and formation creep can also lead to loading of cement. These loads are often large and impossible to prevent, although with it is possible retard the effects by carefully planning completion.

It is important to implement relative strength of formation in calculations as hard formations with high Young's modulus will confine cement sheath and will make it less susceptible to cracking. On the other hand soft formations with low Young's modulus will not provide good enough confinement to prevent cracking (Nelson & Guillot, 2006, pp. 287, 299). The opposite effect is typically seen for the near casing shear deterioration.

The summary of the factors affecting gas migration is presented in Table 2.1.

Table 2.1: Factors affecting annular gas migration (Nelson & Guillot, 2006, p. 293)

	Annular Pressure ≤ Pore Pressure	Space for Entry	Path for Migration
Immediate	Hydrostatic underbalance	Fluid displaced from wellbore	Fluid displaced from wellbore
Short term	Fluid loss	Fluid loss	Slurry permeability
	Gel strength development	Free fluid	Slurry permeability
	Chemical shrinkage of cement	Chemical shrinkage of cement	Filtercake permeability
	Annular bridging	Slurry porosity	Filtercake permeability
	Annular packers	Slurry porosity	Filtercake permeability
Long term	Chemical shrinkage of cement	Chemical shrinkage of cement	Microannulus
		Mud channel	Mud channel
		Free fluid	Free-fluid channel
	Strength development of cement	Dehydrated filtercake	Dehydrated filtercake
		Bulk shrinkage of cement	Bulk shrinkage of cement
			Low cement tops
			Cement sheath mechanical failure

2.4 Strategies and solutions for prevention and combating of gas migration

All of the strategies for minimizing the risk of gas migration are simply based on targeting one or multiple conditions for gas migration - managing the annular pressure decline, reducing the space for entry or minimizing the path for migration.

Therefore, strategies and solutions can be arranged in three groups by the conditions they are targeting within the timeframe of three gas migration types as visible in Table 2.2.

Table 2.2: Solutions for prevention of gas migration(Nelson & Guillot, 2006, p. 306)

	Root Causes of Gas Migration		
	Annular Pressure ≤ Pore Pressure	**Space for Entry**	**Path for Migration**
Immediate	Fluid density	na[†]	na
Short term	Right-angle-set cements	Low-porosity cements	Packers
	Sandwich squeeze	Low-porosity cements	Sandwich squeeze
	Compressible cement	Compressible cement	Low-permeability cements
	Fluid density	Compressible cement	Surfactants
	Thixotropic cements	Low-fluid-loss cements	Thixotropic cements
	Low-fluid-loss cements	Low-fluid-loss cements	Thixotropic cements
	Back pressure	Zero-free-water cements	Low-permeability filtercake
	Annular pressure pulses	Zero-free-water cements	Low-permeability filtercake
Long Term	na	na	Packers
	na	na	Compressible cements
	na	na	Expansive cements
	na	na	Flexible cements
	na	na	Mud removal

[†] na = not applicable

2.4.1 Low Permeability cement slurries

This strategy is based on reducing the matrix permeability of a cement system during the liquid-to-solid transition time and targets the third condition. Low permeability is achieved by introduction of additives into cement slurry.

2.4.1.1 Microsilica

Silica fume known as Microsilica is an amorphous polymorph of silicon dioxide (85-98%), and is an ultrafine powder, is collected as a byproduct of the production of silicon and ferrosilicon. It consists of spherical particles ranging in 0-2 μm diameter size with an average particle size of 1.5 μm which is more that 100 times smaller than the average size of cement particle.

Introducing Microsilica additive to cement slurry is related to the following factors:

- Microsilica is a very reactive pozzolan due to large surface area and high content on silicon dioxide.
- Microsilica due to very fine particle size allows packing in between cement grains.

As the result, addition of Microsilica to fresh slurry will aid in gas migration prevention by immobilizing the pore water within cement matrix and packing pore spaces between cement grains that translates in to reduced permeability. Microsilica also reduces free water, fluid loss, improves stability and enhances slurry rheology.

As cement hardens, Microsilica will give better bonding capabilities, moderately increase strength of cement and less strength retrogression (Bjordal, Harris, & Olaussen, 1993; Grinrod, Vassoy, & Dingsoyr, 1988)

2.4.1.2 GasCon

GasCon is an additive consisting of colloidal silica. Colloidal silica is a pure form of amorphous silica containing only silicon dioxide and traces of sodium hydroxide. It was developed as an improvement on microsilica, eliminating drawbacks such as cost, bulk handling in offshore operations and continuous maintenance due to settling of particles. Like microsilica, colloidal silica particles are spherical, but considerably smaller, ranging from 5-9 nm thereby dramatically increasing specific surface area (500 m^2/g vs 15-25 m^2/g), as result eliminating particle settling and space drawbacks.

GasCon possesses same gas migration prevention qualities as Microsilica, but further improving them (Bjordal et al., 1993).

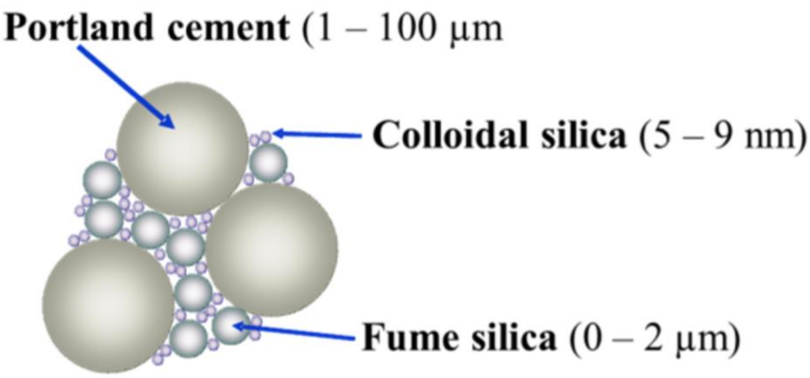

Figure 2.6: Microsilica and Colloidal silica particles in cement matrix (Gunnar Lende, 2016)

2.4.2 Right Angle Set Cements

Right Angle Set (RAS) cements slurries can be defined as slurries that does not show progressive gelation tendency during slurry placement followed by very quick increase in slurry viscosity at the end of the designed pump time. Viscosity development profile can be seen on Figure 2.7. This delayed gel approach ensures systems capability of maintaining full hydrostatic pressure transmission to gas bearing zone until the cement begins to set as it rapidly develops low permeable gel after full placement that prevents any significant gas intrusion. By designing RAS slurry, one is targeting the first condition for gas migration, minimizing critical time for when the cement is most accessible to fluid invasion by reaching static gel strength that can resist against fluid invasion fast as possible.

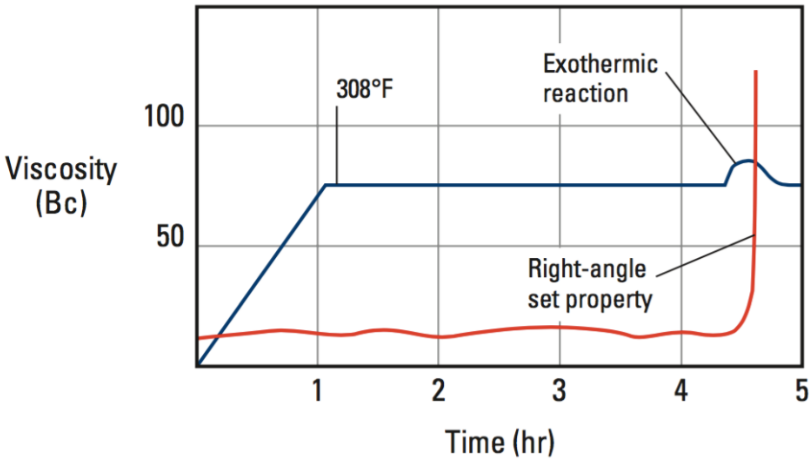

Figure 2.7: RAS cement system viscosity development profile (Nelson & Guillot, 2006, p. 310)

It is important to point out that it is difficult to design RAS cement slurries for temperatures below 120°C as process of rapid gel development is temperature dependent. Therefore this type of approach is typically seen on high temperature (HT) wells and is not really applicable for 20” casing cementing program (Keeling, 2011; Nelson & Guillot, 2006).

2.4.3 Expanding cements

This strategy targets the third condition for gas migration by mitigating micro annulus formation in long term perspective. The concept is that the cement expansion will fill any gap and ensure good bonding either between the formation and the cement or between the casing and the cement.

Cement expansion is an increase in bulk volume of the initial cement volume, which is achieved by the addition of cement expanding agents to base cement slurry.

There are two principal techniques that are used to bulk expand: crystal growth and gas generation.

The expansion related to crystal growth relies on nucleation and growth of certain mineral species within the set-cement matrix. The magnitude of expansion depends on the amount of expanding agent, cement powder, slurry design and curing conditions (pressure, temperature) but is usually controlled to be less than 1% (bulk volumetric expansion). It is important to note that although the cement expands, it does not eliminate total chemical shrinkage and only acts to increase bulk volume of cement (Baumgarte, Thiercelin, & Klaus, 1999; Nelson & Guillot, 2006). Although testing shows that permeability is not significantly affected (Gunnar Lende, 2016).

The expansion related to gas generation is achieved by addition of gas-generating material such as aluminum powder and others that produce hydrogen gas. Process is controlled by same conditions as in crystal growth design.

Experimental work found that expanding cements perform poorly in soft formations as the expansion moves radial outwards in the direction of the least resistance thus creating a micro annulus between casing and cement. Therefore, it is suggested to use expanding cements only in relatively hard formations (Baumgarte et al., 1999).

2.4.4 Foam cement

Foam cement is a cement system consisting from base cement slurry, a foaming agent and a gas, usually nitrogen. These ingredients are mixed to form a stable, lightweight foamed cement slurry containing microscopic bubbles that do not coalesce or migrate. Cement density is varied by amount of nitrogen that is introduced into the mix. Although foam cement was introduced as a lightweight cementing solution, in the last decade foaming has been used to alter cement mechanical properties even if lightweight is not required (Halliburton, 2008).

As foam cementing is not simply a slurry additive, but is a technology that possesses a variety of benefits over conventional cement, it does not target one specific condition for gas migration, but all three of them, eliminating few factors that contribute to increased possibility of gas migration.

The main benefits of foam cementing over conventional solution that can be applicable to reduced possibility of gas migration are (Halliburton, 2015):

- Improved displacement efficiency
- Improved elasticity, impact resistance and toughness
- Ability to mitigate loss circulation, energized
- Gas and water influx control due to significant compressibility
- Reduced shrinkage

2.4.4.1 Improved displacement efficiency

Foamed cement shows better hole cleaning with lower displacement rate as it possesses improved solids lifting abilities with decreased channeling tendencies. As seen on Figure 2.8, foamed cement job at lower displacement rate provides better hole cleaning that conventional systems.

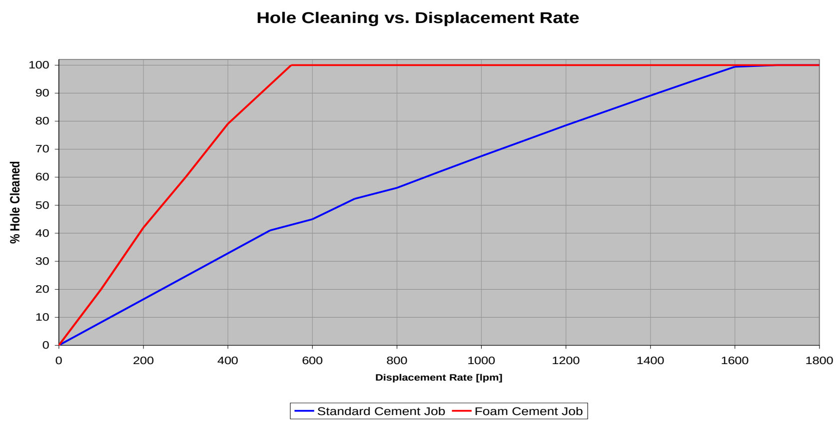

Figure 2.8: Hole Cleaning vs Displacement rate comparison between conventional cement job and foamed cement job (Halliburton, 2015)

2.4.4.2 Improved elasticity, impact resistance and toughness

Elasticity and mechanical strength are one of the most crucial properties for long-term well integrity. Foam cement exhibit improved ductility over conventional cements. This allows the foam cement to withstand higher hoop stresses from casing pressure and temperature cycling (Kjøstvedt, 2011). During loading if cement collapses, it collapses locally instead of initiating cracks as bubbles act as fracture stoppers through stress relief.

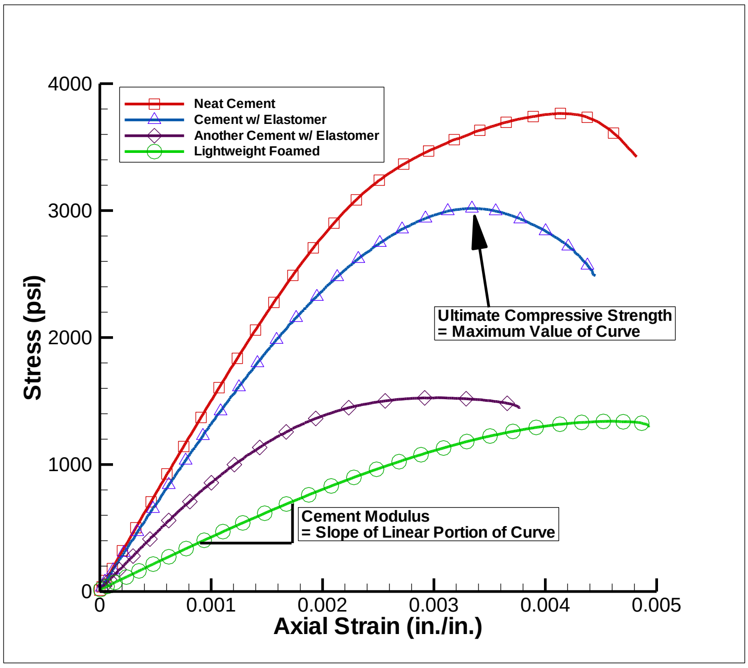

Figure 2.9: Axial Strain vs Stress plot for Foam Cement and Conventional Cement Systems (Halliburton, 2015)

Figure 2.9 plots testing results of axial strain versus stress for foam cement and conventional cement systems. Foam cement curve shows superior elasticity compared to other cement systems.

2.4.4.3 Ability to mitigate loss circulation, energized

Foam cement is a thixotropic system. If a low pressure zone or washout occurs, nitrogen gas bubbles expand and agglomerate, increasing viscosity and successfully blocking flow channels.

2.4.4.4 Gas and water influx control

Foam cement is highly compressible. Nitrogen bubbles in cement expand if pressure is relieved. This prevents or minimizes pressure loss until cement has gelled up, keeping gas in formation.

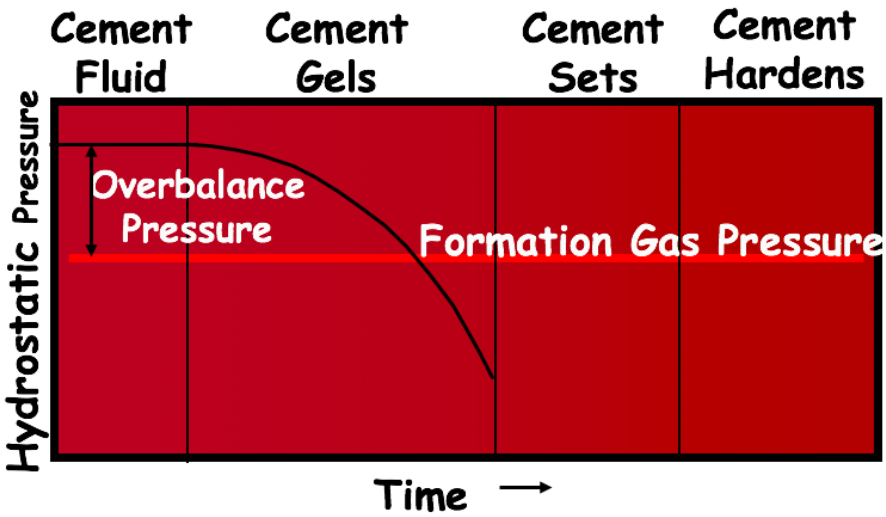

Figure 2.10: Hydrostatic Pressure Changes of Foam Cement vs Time (Halliburton, 2015)

2.4.4.5 Reduced shrinkage

Finely dispersed nitrogen bubbles help in compensating for hydration chemical shrinkage. Figure 2.11 shows test data of shrinkage of foam cement and conventional cement plotted versus time. Foam cement is plotted in red and conventional cement is plotted in blue. As visible from Figure 2.11, bulk shrinkage for conventional design can be significant as for foam cement systems, bulk shrinkage is reduced.

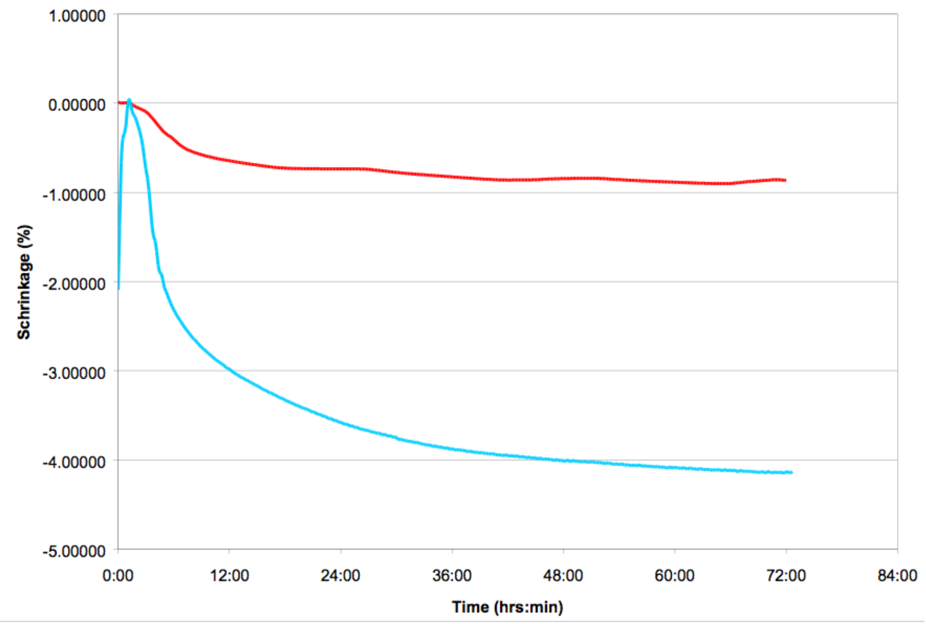

Figure 2.11: Bulk Shrinkage chart of Foam Cement and Conventional Cement plotted vs Time (Halliburton, 2015)

2.4.5 Self-healing cements

One of the latest developments is self-healing cement (SHC) concept and is targeting third condition for gas migration. The SHC is a cement concept that enhances long term zonal isolation with a material that has self-repairing ability within the set cement. If a set cement sheath is cracked, material enables automatic repair of the crack and it thus prevent the flow of fluids through the path.

This is achieved by addition of swelling material to cement slurry, that is activated upon contact with hydrocarbon fluid. Although the concept seems to be a perfect solution against gas migration, it has a major fall through - the slurry design and self-healing material needs to be optimized for type and composition of hydrocarbons that are targeted. As the exact composition of shallow gas is not always known before cementing, it is hard to design an effective cement formula.

3 Tests

To deeper understand the fluid annular migration process Halliburton has conducted a series of tests.

The target of the tests was to determine factors that contribute to gas migration phenomena and compare magnitude of their impact on wells with various cement types and formulations.

Total of three test were conducted using both conventional and foam cement formulations.

3.1 Test 1: Water injection during conventional cement gelation and hydration periods

The purpose of the Test 1 was to simulate the scenario of fluid influx during cement postplacement early stages – during gel period and cement setting. This test is done in order to determine if cement shrinkage leading to development of micro annulus is one of the major factors contributing to annular gas migration.

3.1.1 Model set-up

A large scale test model was constructed to conduct the tests. System schematics for this test are shown on Figure 3.1:

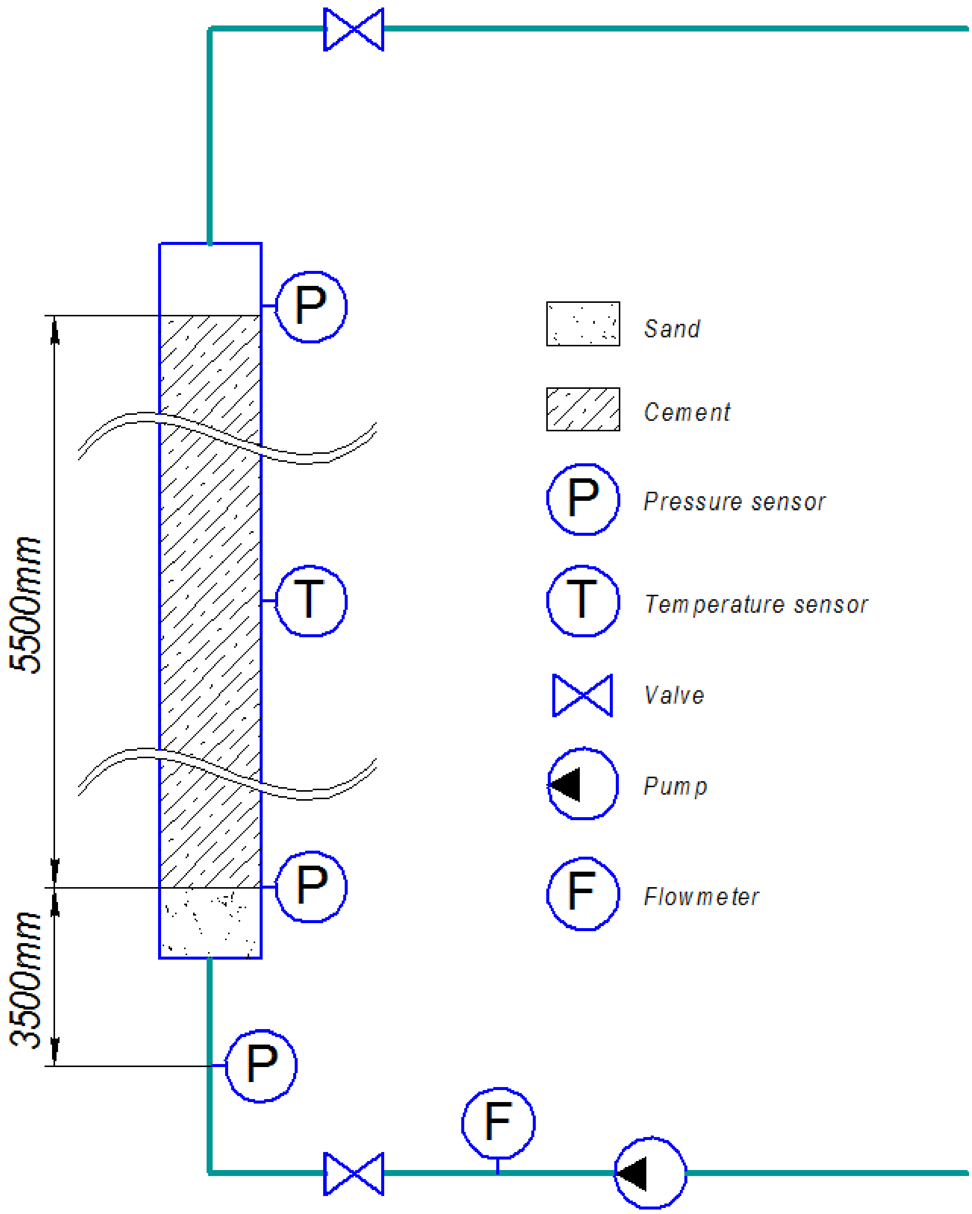

Figure 3.1: Model schematics used for the Test 1

Model consisted of a vertically placed steel tube. On lower part of tube, a permeable sand pack was placed to provide support for placed cement. On top of the sand pack a pressure sensor was installed to monitor cement bottom pressure. Steel tube had mechanisms on the ends that allowed to seal the ends of the test tube. Each end had a flow lines with pressure sensors installed in them as well as sealing valves. A temperature gauge was installed to monitor the temperature of cement during hydration period.

The pump was attached to bottom flow line. The pump that was used is a high pressure pump that was limited to output pressure of 50 psi as the steel pipe had a limited pressure rating. Injection rate was monitored on inflow line.

Test was conducted with water as injection fluid due to low compressibility and ease of use as well as due to safety precautions. Shallow water annular migration is a common problem that theoretically occurs due to same mechanics as shallow gas annular migration, therefore this experiment results can be applied to study of annular gas migration.

Test was conducted in room temperature.

3.1.2 Testing Procedure

Conventional cement slurry was mixed and placed into vertical pipe. It has accounted for total height of 5.5 m on top of the sand pack. Then tube was sealed. Top of the tube had an air gap that later was filled with nitrogen.

During the test, fluid (water) was injected applying pressure from the bottom.

System was pressured up by injection fluid (water) from the bottom and then balanced. During cementation, slurry in fluid and gel states cannot withstand big differential pressure. Therefore, it was decided to let cement go through gelation period underbalanced. Theoretical bottom of cement column pressure was determined by calculating hydrostatic head pressure of 1.60 SG cement in liquid state with length of 5.5 m that turned out to equal to 12.52

psi and adding to it back pressure (top cell pressure) that was 5.6 psi. This value was used to program the injection pump. Pump was programmed to keep the system underbalanced with maximum differential pressure of 2.5 psi between injection system cell (sand pack) and theoretical bottom of cement column pressure.

Test lasted for 15 hours and was stopped when the hydraulic isolation failed and communication between zones was identified.

Data measurements - pressure from three sensors, injection rate and temperature – were logged each 20th second. Data was saved and stored on PC files and further processing.

3.1.3 Cement slurry used

In the Test 1, the conventional gas tight cement slurry was used. List of slurry additives is presented in Table 3.1:

Table 3.1: Additives list for cement slurry used in the Test 1

Conventional cement slurry for the Test 1	
Component	**Comment**
Norcem API Class G Portland cement	-
SCR-100 L	Retarder
GasCon III	Colloidal silica, gas migration control
NF-6	Defoamer
Total cement slurry density is **1.60 SG**	

3.1.4 Results

Data acquired during test was processed and plotted resulting in Figure 3.2:

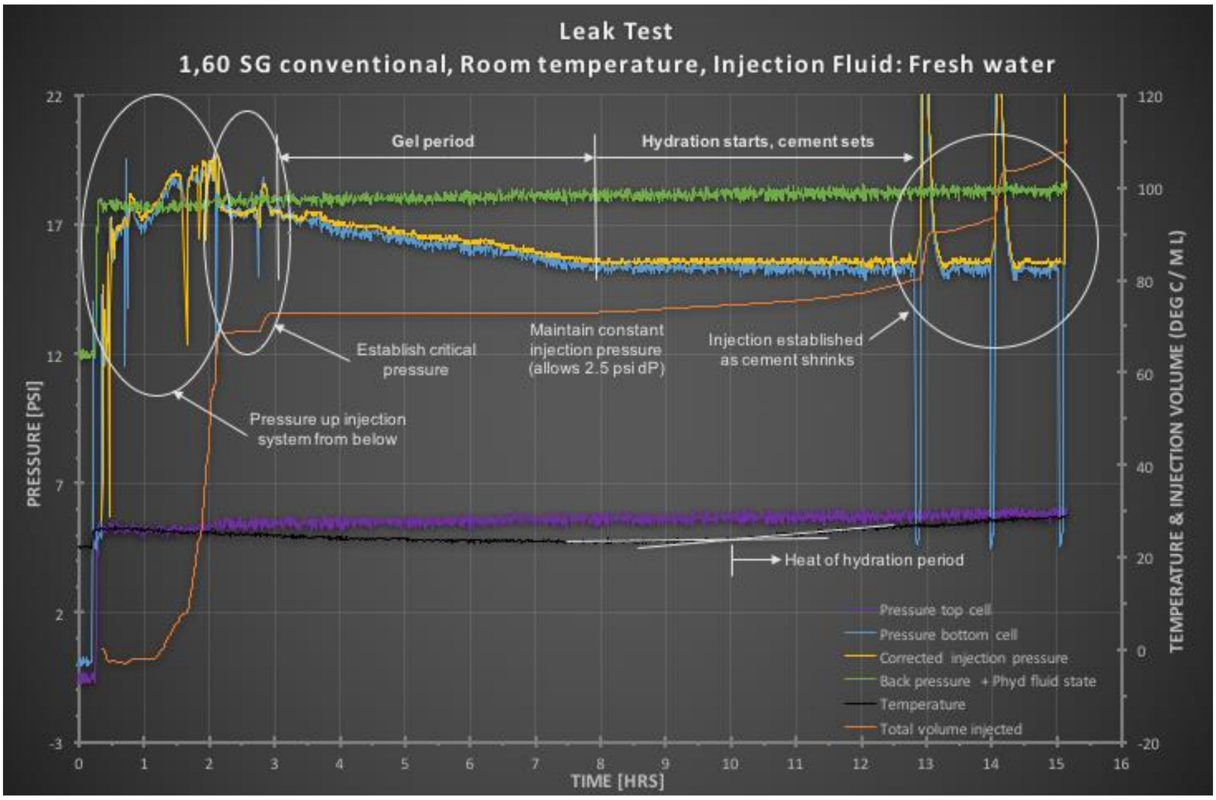

Figure 3.2: Test 1 plot of conventional cement. Micro annulus establishment during hydration period.

3.1.4.1 Description and calculation of curves:

Pressure top cell – measured data collected by the pressure sensor located above the top of the cement column. Values are the same as back pressure. Values represent the pressure in top cell above cement at given time.

Pressure bottom cell - measured data collected by the pressure sensor located on the bottom of the cement column. Values represent the pressure in bottom of the cement column at given time.

Corrected injection pressure – calculated fluid injection pressure data. Pressure measurement data was collected from the pressure sensor located in injection system cell 3.5 m below the cement column. These values were corrected with added hydrostatic pressure of injection fluid column equal to 4.98 psi. Values represent the pressure in injection fluid at level of cement and injection fluid boundary at given time.

Back pressure + P_{hyd} fluid state – calculated pressure data. Theoretical hydrostatic pressure of 1.60 SG cement with height of 5.5 m which is equal to 12.52 psi is added to the measured back pressure (top cell pressure). Values represent the pressure exerted on the pressure sensor located on the bottom of the cement column while cement is in fluid state at given time.

Temperature – measured data obtained from the temperature sensor in cement column. Values represent the temperature of cement at given time.

Total volume injected – calculated volume data of injected fluid. Fluid injection rate data was measured by the flowmeter located in pump outlet. Injection rate data multiplied with time data gave volume data of injected fluid. Values represent the total amount of injected fluid in the system at given time.

All of the data was plotted against time.

3.1.4.2 Plot analysis

During the first 3 hours after cement placement the system was being pressurized and stabilized. When critical pressure for injection cell was determined and reached, pump was programmed to keep the system underbalanced considering the gel strength of the cement with maximum differential pressure of 2.5 psi.

System stabilization was followed by development of cement gel structure. As cement was underbalanced during gel structure establishment, no fluid got into cement column as total volume injected curve shows constant value in this period.

As cement entered hydration phase, temperature measurement values increased (heat of hydration). As cement hydration reaction begins, cement starts to set and it starts to shrink. Radial shrinkage of cement column leads to establishment of micro annulus in the model. Shrinkage leads to establishment of space for fluid entry. As pump was programmed to maintain constant pressure, space for entry created by cement shrinkage lead to small drop of pressure, therefore pump has injected more fluid into the system to maintain the pressure. The change of injected volume can be visible from the total volume injected curve.

As cement continues to shrink, the volume of injected fluid continues to rise. At 12 hours and 42 minutes into the test, isolation fails and communication between zones is established. This can be seen from corresponding drop in bottom pressure to back pressure level.

From the results of this test, it can be concluded cement shrinkage is a major factor contributing to long term annular fluid migration. It should be noted that this particular test was done as a plug in pipe setup, for an annulus setup the impact of shrinkage will be less due to smaller dimensions (thickness of cement between casing and formation).

3.2 Test 2: Water injection into conventional cement post setting

Test 1 has showed that conventional cement has failed to stop fluid migration due to cement radial shrinkage and establishment of micro annulus.

As foam cement is believed to possess superior gas migration prevention qualities over conventional cement, a logical thought would be to test foam cement in the same model as used in the Test 1. This task proved to be quite difficult as foamed cement could not be stable under such conditions.

Therefore, it was decided to conduct 2 additional tests that consisted of injecting fluid in already fully set cements and compare conventional and foam cements in that way.

The purpose of the Test 2 was to leak test the fully set conventional cement column in steel tube.

3.2.1 Model set-up

The model schematics for this test are shown on Figure 3.3:

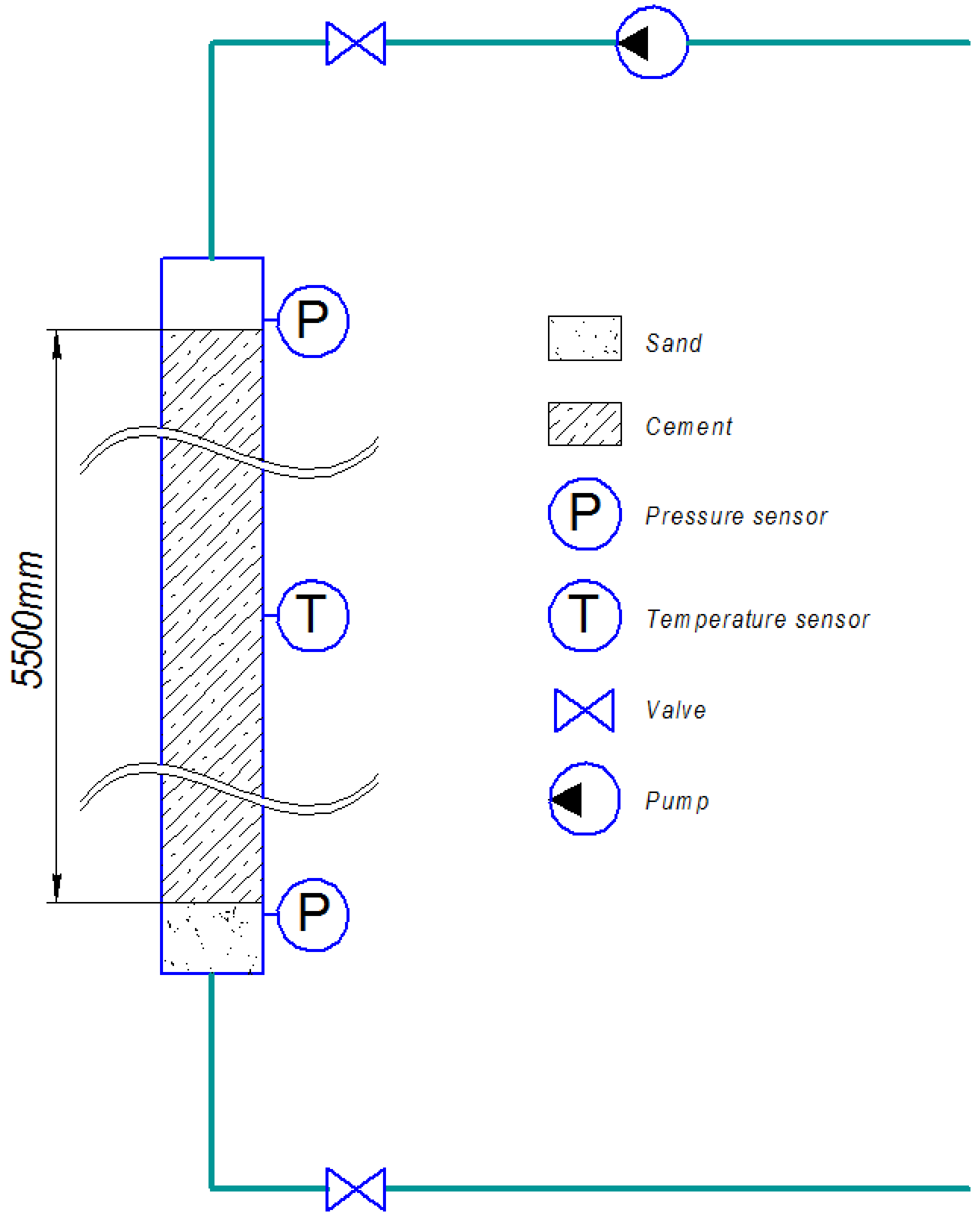

Figure 3.3: Model schematics used for the Test 2

Model consisted of a vertically placed steel tube. On lower part of tube, a permeable sand pack was placed to provide support for placed cement. Steel tube had mechanisms on the ends that allowed to seal the ends of the test tube. Each end had a flow lines with pressure sensors installed in them as well as sealing valves. A temperature gauge was installed to monitor the temperature of cement.

In this test pump was attached to the top of the tube due to technical reasons. Pump that was used is a high pressure pump that was limited to output pressure of 50 psi as steel pipe had a limited pressure rating.

Test was conducted with water as injection fluid due to low compressibility and ease of use as well as due to safety precautions.

Test was conducted in room temperature.

3.2.2 Testing Procedure

Conventional cement was placed in the tube and was let to set during period of 60 days. Height of cement column was 5.5 m. After curing time tube was set up with measuring equipment to proceed with testing.

During the test, fluid (water) was injected applying pressure from the top. Maximum pump output was limited to 50 psi and maximum pressure was applied with once. Pressures on top and bottom of tube were monitored and logged once every 10^{th} second. Temperature measurements were taken as well, but as cement has already passed the hydration phase, temperature reading remained the same throughout the test which these measurements not relevant for this exact test.

As the hydraulic isolation failed and communication between top and bottom zones was established, water started to come from bottom of the tube, equalizing the pressure between top and bottom.

Test was ended after 1 hour when full communication between zones was identified.

Data was logged and saved for further processing.

3.2.3 Cement slurry used

In the Test 2, the conventional gas tight cement slurry was used. List of slurry additives is presented in Table 3.2:

Table 3.2: Additives list for cement slurry used in the Test 2

Conventional cement slurry for the Test 2	
Component	**Comment**
Norcem API Class G Portland cement	-
SCR-100 L	Retarder
GasCon III	Colloidal silica, gas migration control
NF-6	Defoamer
Total cement slurry density is **1.60 SG**	

3.2.4 Results

Data acquired during test was processed and plotted against time, resulting in Figure 3.4.

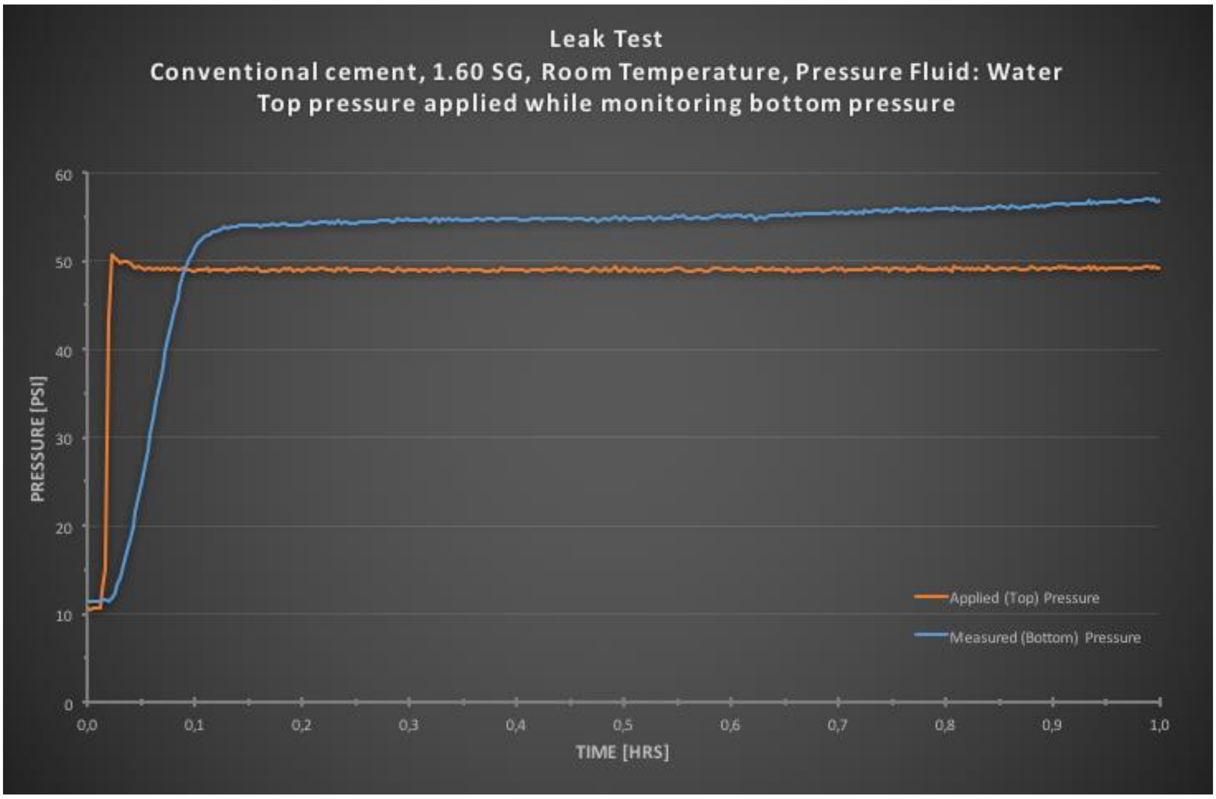

Figure 3.4: Test 2 plot of conventional cement. Top and bottom pressures plotted versus time. Top pressure applied while monitoring bottom pressure.

Test was running for 1 hour after pressure was applied from the top. From plot above it is visible that connection between top and bottom was established shortly after beginning of the test.

Figure 3.5 shows close-up of breakthrough on Test 2.

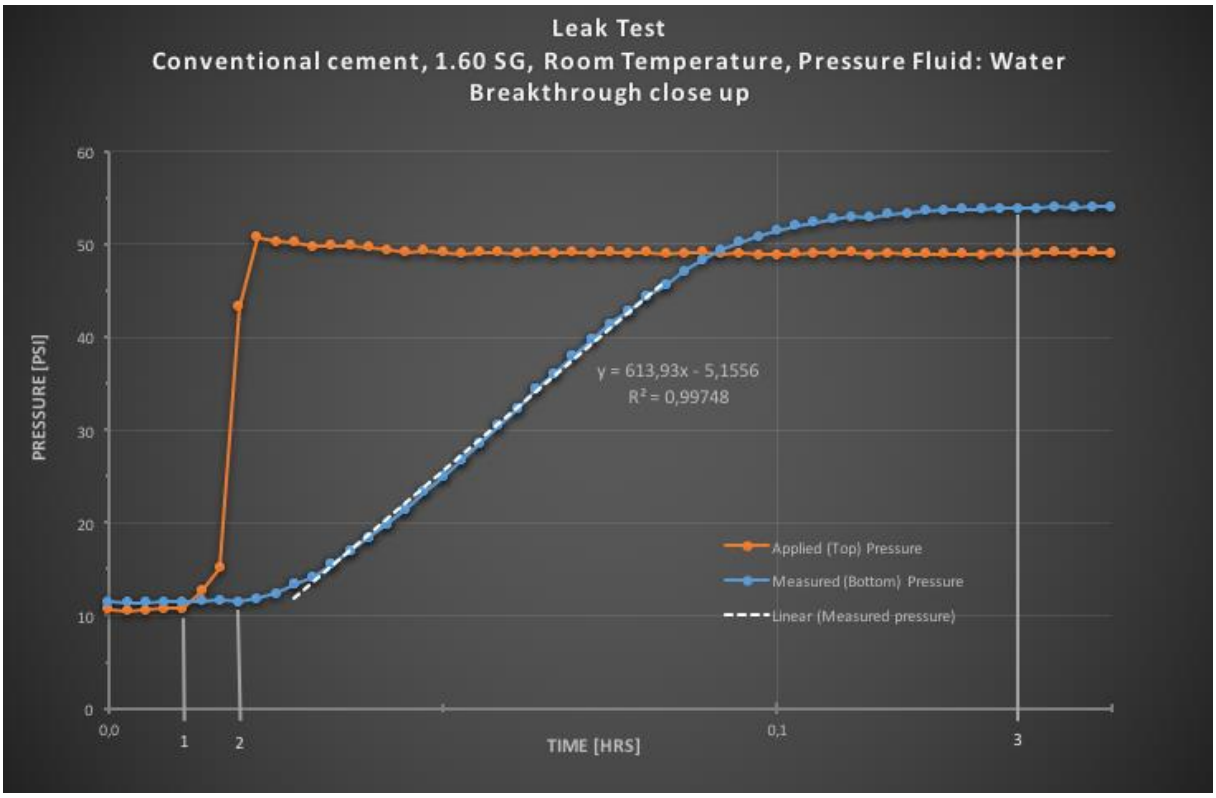

Figure 3.5: Close-up of breakthrough of Test 2 plot for conventional cement.

Vertical gridline 1 marks the beginning of pressure application, vertical gridline 2 marks establishment of connection between the top and the bottom and vertical gridline 3 marks pressure equalization between the top and the bottom. Difference between the top and the bottom pressures at gridline 3 is the hydrostatic pressure of water column.

The distance on x-axis between gridline 1 and 2 represents time that it takes to establish connection between top and bottom. It takes 40 seconds for connection to establish, including the time it takes to build up top pressure. The connection is established before the top pressure reaches a maximum level of 50 psi. For pressures to reach equilibrium it takes 8 minutes from the pressure application.

The trend line is very linear with an R^2 value of 0.99748. The rate of change can be obtained from the slope of trend line and is equal to 613.93.

3.3 Test 3: Water injection into foam cement post setting

The purpose of the Test 3 was to leak test the fully set foam cement column placed in steel tube.

3.3.1 Model set-up

The model schematics for this test are shown on Figure 3.6:

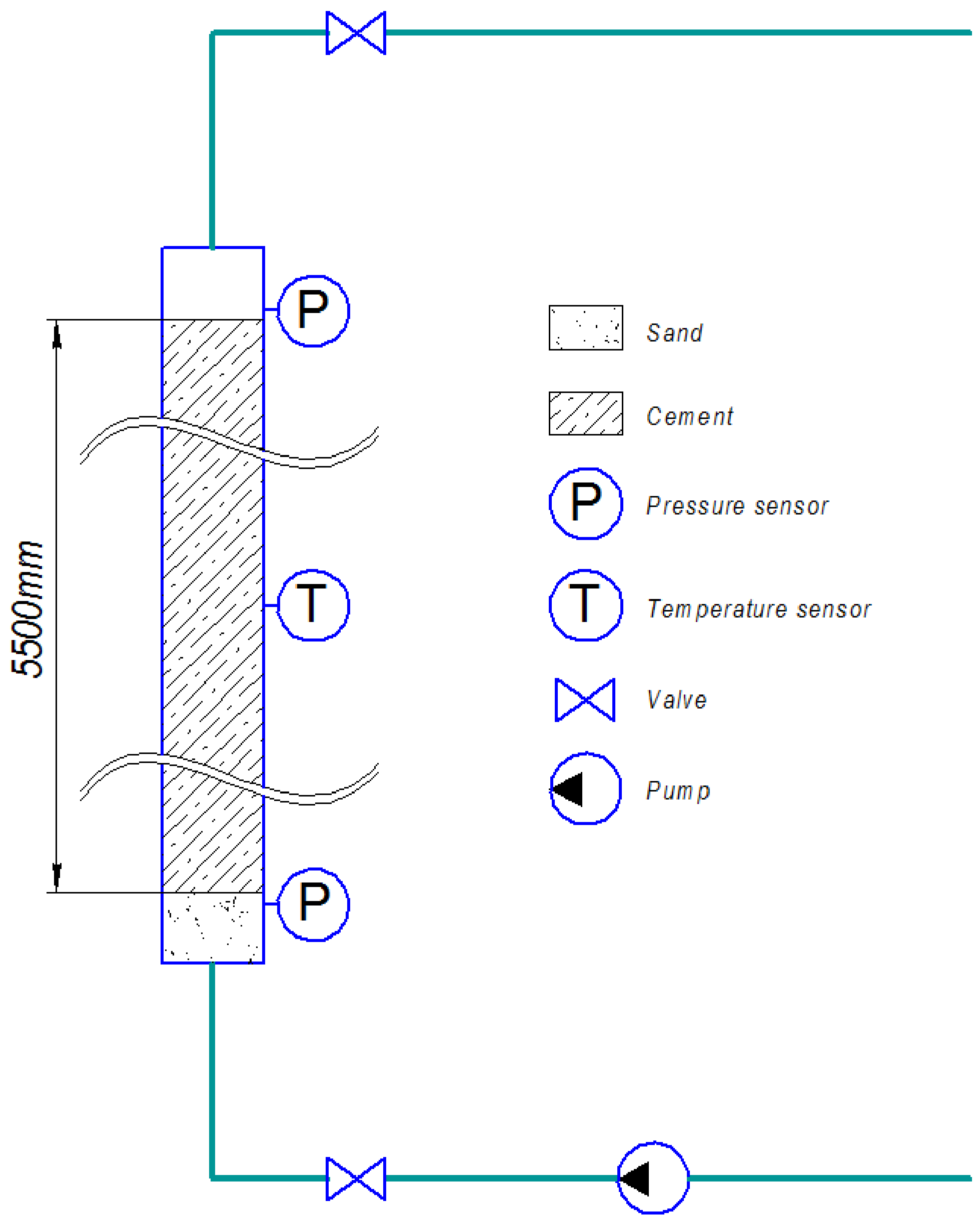

Figure 3.6: Model schematics used for the Test 3

Model set-up used for the Test 3 was similar to set-up used for the Test 2 with one difference - during the test, fluid (water) was injected applying pressure from the bottom.

3.3.2 Testing Procedure

Foam cement was placed in the tube and was let to set during period of 60 days. Height of cement column was 5.5 m. After curing time tube was set up with measuring equipment to proceed with testing. In this test pump was attached to the bottom of the tube.

During the test, fluid (water) was injected applying pressure from the bottom. Maximum pump output was limited to 50 psi and maximum pressure was applied in 2 steps. During the first step pressure was increased to 15 psi and during second step pressure was increased to 50 psi. Pressures on top and bottom of tube were monitored and logged once a second.

As cement sheet failed and communication between top and bottom zones established, water started to come from top of the tube, equalizing the pressure between top and bottom.

At this point it was decided to try to increase pressure further up to 100 psi. Due to pipe low pressure rating, it was decided to abort the test without waiting on top and bottom pressures to equalize.

Total test duration was 4 hours.

Data was logged and saved for further processing.

3.3.3 Cement slurry used

In the Test 3 foam cement slurry was used. List of slurry additives is presented in Table 3.3:

Table 3.3: Additives list for cement slurry used in the Test 3

Foam cement slurry for the Test 2	
Component	**Comment**
Norcem API Class G Portland cement	-
CGM-1	Gel accelerator
SCR-100 L	Retarder
ZoneSeal 4000 L	Foamer
Total cement slurry density before foaming is **2.05 SG**	
Total cement slurry density after foaming is **1.56 SG**	
Foam quality **24%**	

3.3.4 Results

Data acquired during test was processed and plotted resulting in Figure 3.7:

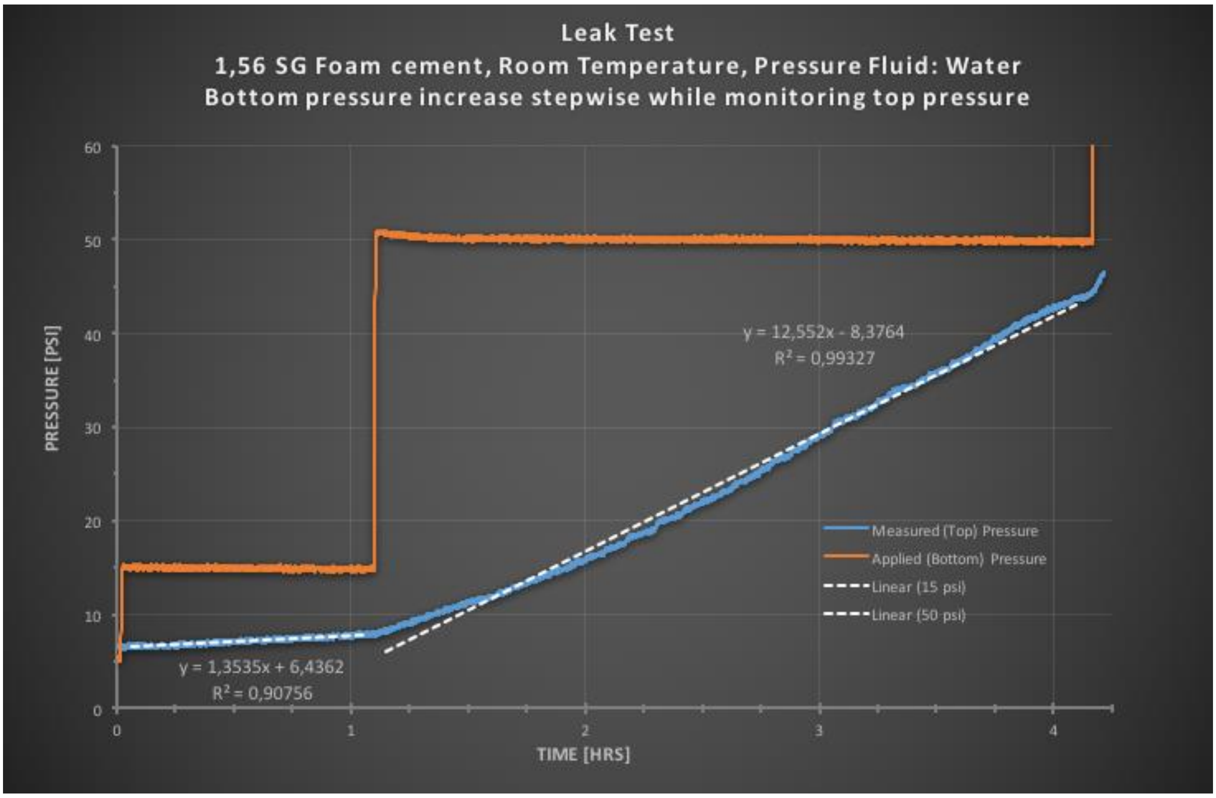

Figure 3.7: Test 3 plot of foam cement. Top and bottom pressures plotted versus time. Bottom pressure applied and increased stepwise while monitoring top pressure.

Test was running for 4 hours and 12 minutes after pressure was applied from the bottom. From plot above it is visible that connection between top and bottom was established shortly after beginning of the test. The trend lines for both pressure application stages are linear and are visible on the plot above. The trend lines for 50 psi applied pressure is very linear with an R^2 value of 0.99327. The rate of change obtained from the slope of trend line and is equal to 12.552.

The trend line for 15 psi applied pressure is less linear, with R^2 value of 0.90756 and rate of change equal to 1.3535.

4 Discussion

4.1 Comparison and discussion of the Test 2 and the Test 3

As data from both tests was measured against time, it is possible to plot both leak test data for conventional and foam cements on one plot and compare. Results are presented on Figure 4.1, where leak test data form conventional and foam cements is plotted against time for any pressure applied.

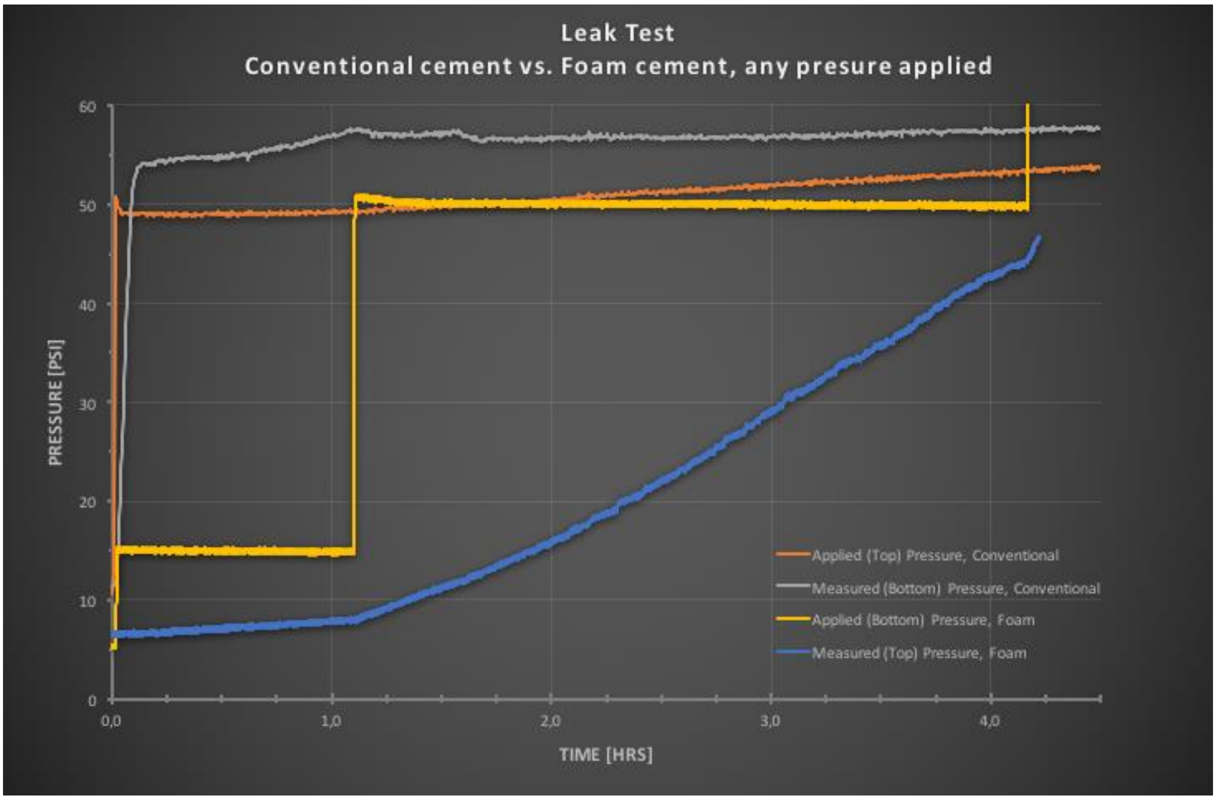

Figure 4.1: Leak test data for Conventional and Foam cements, any pressure applied

For both tests same pump was used with the same restrictions. As no flowrate data was measured and logged during the course of both experiments, it is not possible to set up Darcy flow equation, which puts some boundaries on what can be concluded from this comparison.

The only way that the plots can be compared to each other is to compare the rate of pressure change and time it takes for the pressure to equalize.

As Darcy flow equations cannot be set, it is not possible to determine whether the pressure change during application of 15 psi pressure on foam cement column can be interpreted as natural permeability of this particular cement column as rate of pressure change is rather small.

Therefore, it is more correct to compare the curves with the same pressure applied. The results of comparison are plotted on Figure 4.2, where leak test data form conventional and foam cements is plotted against time for any 50 psi pressure applied.

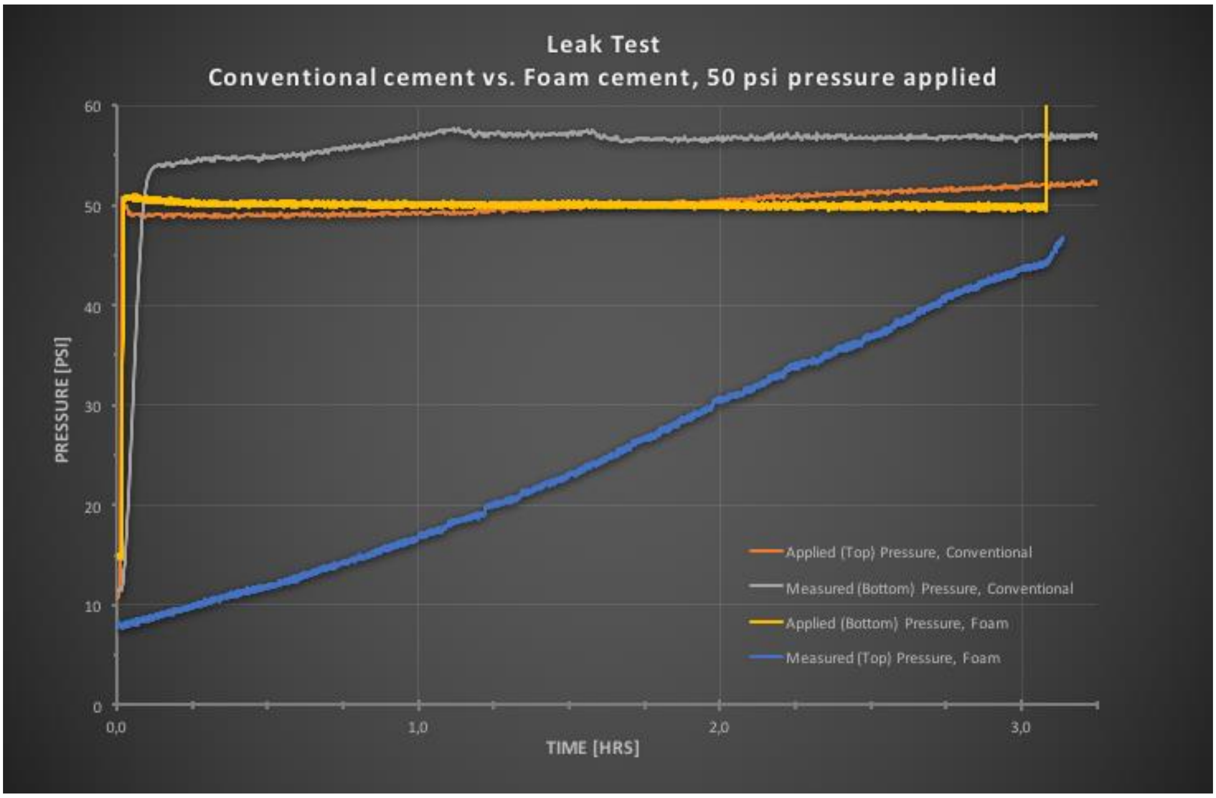

Figure 4.2: Leak test data for Conventional and Foam cements, 50 psi pressure applied

As seen from figure above, in foam cement column pressure takes much longer time to equalize than in conventional cement column. Pressure in foam cement column takes 3 hours and 4 minutes to equalize compared to 8 minutes in case of conventional cement.

Rate of change for foam cement is equal to 12.552 compared to 613.93 for conventional cement.

It is possible to deduct from the Test 2 and the Test 3 that foam cement possesses superior pressure retaining capabilities to conventional cement. It should be noted that permeability of the two cement systems was not tested, so the contribution from flow into and through the cement core itself could not be calculated.

4.2 Possible test improvements

Based on the above discussion there seems to be a need for improvement both with respect to the test procedure itself as well as supporting the results with additional tests in order to improve the understanding of observed phenomena's.

Through the study it was found that additional parameters are of importance when comparing 2 different cement slurry types.

Tests 2 and 3 were conducted without logging the flow rate. Conducting the same tests with continuous measuring of flow rate would enable possibility to set up the Darcy flow equation for each cement type. Darcy flow equation would provide size of micro-annulus and flow potential.

Development of model that could be used for testing of foam cement could provide valuable insight in cements behavior.

Tests 2 and 3 were conducted with cement-steel interface. Model that would simulate bonding to different types formation types both dry and treated with drilling mud would provide more accurate results on pressure retention capabilities.

5 Field examples

5.1 Objectives

As gas annular migration is a complex problem, a study of existing wells on various fields on Norwegian Continental Shelf (NCS) was conducted.

The main objectives were:

- Conduct a review of wells that have experienced shallow gas annular migration
- If data amount was sufficient, conduct a statistical study of data
- Compare performance of conventional cement to foam cement with regard to shallow gas migration
- Outline a common pattern that could have led to annular migration of shallow gas
- If common patters were found and established, provide a possible solution for problem solving

5.2 Methodology

To fulfill the objectives of this project part, during the course of writing of this report, all of the major operator companies conducting their work on NCS were contacted with inquiry of cooperation and data sharing.

Wells that were targeted were wells on NCS that has experienced shallow gas annular migration in interface of surface casing during or post conducting a cement job.

Two of the operators – Lundin Norge AS and Wintershall Norge AS have agreed to participate in data sharing and provided assistance on this study. Few other companies have showed interest in study but did not provide any data.

Companies were asked to share information and documentation on wells that has experienced or are still experiencing shallow gas annular migration problems.

Documentation that was used consisted of:

- Well design reports
- Well drilling programs

- Daily activity reports
- Well drilling reports
- Post cementing reports
- End of well reports
- Final well reports

Wells from the same template or drilled in the same reservoir with close proximity were used as a reference. If the well that experienced gas migration was an exploration well and was the only well drilled to provide insight on targeted formation, wells from the adjoining fields in 100 km radius distance that had same geological setting were used as references.

5.3 Scope of study

During the course of this study, operators have shared and allowed use in total of:

- 6 fields of which 2 fields have experienced shallow gas migration
- 3 wells that experienced gas leaking to surface
- 7 reference wells

This lead to conducting a study of 2 cases that were separated by field criteria. Reference wells were used to provide a better insight on surrounding area, identify possible shallow gas hazards and compare drilling and cementing procedures.

5.4 Sensitivity of information

All of the well documentation is property of operator companies that has operating right for the fields. Due to sensitivity of some of the well data, all of the actual well and field names were substituted with numbers. No data that can be used to directly link the described fields and well to actual fields and wells was provided here.

Data of sensitive character that was provided by service company, Halliburton, such as cement formulations and exact workflow cementing process was removed of simplified.

5.5 Structure

Two cases were formed by field criteria.

Each case consisted of wells that has experienced shallow gas migration and wells or information taken from reference wells that did show any shallow gas migration. Geological setting, shallow gas possibility study pre-drilling and design premises, drilling and cementing categories were described on each case. Well cementing data was provided for each well. Gas leakage analysis summarized and concluded all the data.

5.6 Case 1

5.6.1 Well 1

Well 1 is a wildcat well and is a part of the Field 1. Field 1 is located in the central North Sea. The primary objective was to test the hydrocarbon potential in the Field 1. The water depth at the location is 108 m MSL. Well was drilled by semi-submersible installation.

Well has experienced shallow gas migration.

5.6.1.1 Geological setting

Surface casing is cemented in Nordland Group.

The Nordland Group consists mainly of claystone with a few sandstone interbeds.

The upper part of the Nordland Group consists of undifferentiated sands and clays. The basal part is represented by the Utsira Formation.

The clays are medium dark grey to medium grey, soft and sticky, occasionally sub- blocky, massive to amorphous, non-calcareous, slightly silty, locally sandy, with occasional traces of black to brownish black carbonaceous material, locally micromicaceous, occasional micropyritic with traces of microfossils (foraminifera) and rare shell fragments.

The sand consists of loose clear quartz grains, very fine to fine, occasionally coarse, sub-angular to angular and is moderate to poorly sorted.

The siltstone is medium dark grey to medium grey brown, soft, blocky, amorphous, argillaceous, sandy, non calcareous and slightly glauconitic.

Lithostratigraphy (all depths are in meters from MSL)

111 – 117: Sand, medium dense to dense, slightly silty, contains very loose to medium dense intervals. Occasional layers of clay cannot be excluded. Scattered boulder can occur.

117 – 140: Clay, stiff to hard. Occasional layers of dense sand, gravel and scattered boulders may occur.

140 – 223: Interbedded sand and clay, silty, stiff to hard. Scattered boulders may occur.

223 – 357: Clay, silty, stiff to very hard, interbedded with thin sandy layers. Scattered boulders may occur in the unit.

357 – 752: Clay, very hard, with thin layers of silt and sand. Layer around depth of 620 m may contain loose sand.

Depositional environment is open marine with glacial.

An average formation temperature gradient of approximately 4 °C per 100 m TVD was estimated in the range where surface casing is placed.

Pore pressure gradient was estimated as seawater gradient in the range where surface casing is placed.

5.6.1.2 Shallow gas possibility study pre-drilling and design premises

Shallow gas possibility was addressed before drilling was conducted. Within the Well 1 site survey area there are three levels of anomalous amplitude horizons interpreted. Two of them are of our interest.

First anomaly was classified as high gas risks at a depth of 365 m +/- 18 m below MSL on reference wells. But it was concluded that this anomaly in not present the location of the Well 1.

The second was identified in intra Nordland Group at a depth of 605 m +/- 30 m below MSL. The detailed evaluation of the seismic data showed that the gas risk is not considered to be so high as Well 1 location is some distance from possible gas-filled closures and significant seismic anomalies that have been seen on close proximity well.

Due to second anomaly, a 20” casing was decided to be set well above a high gas risk zone to enable drilling the high gas zone with pressure control.

5.6.1.3 Drilling and cementing

The pilot hole was drilled down to 585 m RKB to check for shallow gas. No shallow gas observed in the pilot hole.

20” surface casing was installed at 394 m RKB. Cement job was conducted with conventional cement. No gas migration prevention additives were used as shallow gas study did not show any hazards in depth range of surface casing.

General surface casing data and cement formulation for the Well 1 is presented in Table 5.1 and Table 5.2:

Table 5.1: General data for surface casing cement used for Well 1

WELL DATA - 20" SURFACE CASING					
Casing Depth, MD	[m]	± 394	BHST	[°C]	20
Casing Depth, TVD	[m]	± 394	BHCT	[°C]	17
Casing Size	["]	20	WOC Time	[hrs]	13
Casing weight	[lb/ft]	133	Mud Type		WBM
Slurry Volume (lead/tail)	[m^3]	± 24/34	Mud Weight	[SG]	1.25
Preflush type		Sea Water	Volume preflush		1 csg volume
Hole Size	["]	26	TOC, Lead	[m]	Seabed @ 133
OH Excess (lead/tail)	[%]	100/20	TOC, Tail	[m]	194

Table 5.2: Cement composition used for cement job on surface casing for Well 1

CEMENT SLURRY DESIGN & DATA				
Slurry design	"G" class Cement	**Amount:**		**Units**
		Lead	Tail	
	Filler cement to increase volume and decrease density		-	Liter/100kg
	Liquid $CaCl_2$	-		Liter/100kg
	Defoamer			Liter/100kg
	Sea Water			Liter/100kg
	Density	**1.45**	**1.95**	**SG**
	Total Mix Fluid	133,05	43,11	Liter/100kg
	Yield	164,23	74.29	Liter/100kg
	Thickening Time at BHCT			Cement samples
Test results	Time to 30 BC	07:02	03:34	Hrs:Mins
	Time to 70 BC	**08:30**	**04:11**	Hrs:Mins
	Time to 100 BC	08:55	04:22	Hrs:Mins
	Fann readings at BHCT	27	80	300 RPM
		24	63	200 RPM
		20	48	100 RPM
		18	42	60 RPM
		17	36	30 RPM
		14	21	6 RPM
		11	16	3 RPM
	UCA compressive strength	-	05:17	50 psi
		-	12:19	500 psi
		-	24 hr	1150 psi

Prior to cementing, hole was circulated clean with sea water with no losses. Sea water was used as spacer. Cement slurry was mixed and displaced at 2300 lpm. Cement placement went as planned.

Casing was pressure tested and no backflow was observed. No short term gas migration was observed.

5.6.1.4 Gas leakage

Gas leakage was observed post well plugging and abandonment. Leakage was noticed during well surveys. The flow of gas is low.

5.6.2 Well 2

Well 2 is an appraisal well and is a part of the Field 1. The primary objective was to confirm the northern extent of the oil discovery in the Field 1. The water depth at the location is 110 m MSL. Well was drilled by semi-submersible installation.

Well has experienced shallow gas migration.

5.6.2.1 Geological setting

Well 2 is in close proximity of the Well 1. Therefore, the geological setting is the same as for the Well 1.

5.6.2.2 Shallow gas possibility study pre-drilling and design premises

Shallow gas possibility was addressed before drilling was conducted. Data from reference wells was used. Well 2 was designed to cater for shallow gas similar to the Well 1.

The 20” casing was decided to be set above a high gas risk zone to enable drilling the high gas zone with pressure control

5.6.2.3 Drilling and cementing

Pilot hole was drilled down to 400 m RKB to check for the potential shallow gas zones. No shallow gas was observed in the pilot hole.

20” surface casing was installed at 411 m RKB. Cement job was conducted with conventional cement. Cement job was performed with back-up slurry as main slurry became too viscous for pumping due to technical reasons.

No gas migration prevention additives were used as shallow gas study did not show any hazards in depth range of surface casing.

General surface casing data and cement formulation for the Well 2 is presented in Table 5.3 and Table 5.4:

Table 5.3: General data for surface casing cement used for Well 2

WELL DATA - 20" SURFACE CASING					
Casing Depth, MD	[m]	411	BHST	[°C]	20
Casing Depth, TVD	[m]	411	BHCT	[°C]	17
Casing Size	["]	20	WOC Time	[hrs]	+-15
Casing weight	[lb/ft]	133	Mud Type		WBM
Slurry Volume	[m^3]	80	Mud Weight	[SG]	1.25
Preflush type		Sea Water	Volume preflush		1 csg volume
Hole Size	["]	26	TOC	[m]	Seabed @ 135
OH Excess	[%]	100			

Table 5.4: Cement composition used for cement job on surface casing for Well 2

CEMENT SLURRY DESIGN & DATA			
Slurry design		**Amount:**	**Units**
	Light blend cement		
	Fresh Water		
	Defoamer		
	Density	**1.52**	**SG**
	Thickening Time at BHCT		Cement samples
Test results	Time to 30 BC	+/- 7 hours	Hrs:Mins
	Time to 70 BC		Hrs:Mins
	Time to 100 BC		Hrs:Mins
	Rheology	No data	
			300 RPM
			200 RPM
			100 RPM
			60 RPM
			30 RPM
			6 RPM
			3 RPM
	Gel strength (10 sec/10 min)	No data	

Prior to cementing, hole was circulated clean with sea water with no losses. Sea water was used as spacer. Cement slurry was mixed and displaced at 3000 lpm. Cement placement went as planned.

Casing did not pass the pressure testing.

Cement squeeze job was performed in the 20” casing shoe, but did not resolve the problem which pointed that leak was not in the casing shoe. No short term gas migration was reported.

5.6.2.4 Gas leakage

Gas leakage was observed post well plugging and abandonment. Leakage was noticed during well surveys. The flow of gas is low.

5.6.3 Reference Well 3

Well 3 is an appraisal well and is a part of the Field 1. The primary objective was to confirm the resource estimate in the Field 1. The water depth at the location is 109 m MSL. Well was drilled by semi-submersible installation.

Well has not experienced shallow gas migration.

5.6.3.1 Geological setting

Well 3 is in close proximity of the Well 1 and the Well 2. Therefore, the geological setting is the same as for the Well 1 and the Well 2.

5.6.3.2 Shallow gas possibility study pre-drilling and design premises

Shallow gas possibility was addressed before drilling was conducted. Data from reference wells was used. Well 3 was designed to cater for shallow gas similar to the Well 1, with exception of second gas zone located slightly deeper on depth of 630 m.

5.6.3.3 Drilling and cementing

Pilot hole was drilled down to 606 m MD RKB to check for the potential shallow gas zones. MWD logs in the pilot hole confirmed that all permeable formations were water bearing and shallow gas was not present. Minor gas sands were observed in the main bore at 631 and 726 m, but no gas flow occurred.

20” surface casing was installed at 600 m TVD. Cement job was conducted with conventional cement with gas migration prevention additives used.

General surface casing data and cement formulation for the Well 3 is presented in Table 5.5 and Table 5.6:

Table 5.5: General data for surface casing cement used for Well 3

WELL DATA - 20" SURFACE CASING					
Casing Depth, MD	[m]	600	BHST	[°C]	-
Casing Depth, TVD	[m]	600	BHCT	[°C]	-
Casing Size	["]	20	WOC Time	[hrs]	-
Casing weight	[lb/ft]	133	Mud Type		WBM
Slurry Volume (lead/tail)	[m^3]	118/20	Mud Weight	[SG]	1.40
Preflush type		Sea Water	Volume preflush		136 m^3
Hole Size	["]	26	TOC, Lead	[m]	
OH Excess (lead/tail)	[%]	100/20	TOC, Tail	[m]	

Table 5.6: Cement composition used for cement job on surface casing for Well 3

CEMENT SLURRY DESIGN & DATA					
Slurry design	"G" class Cement		**Amount:**		**Units**
			Lead	Tail	
	Defoamer				Liter/100kg
	Viscosifyer				Liter/100kg
	Colloidal silica - antigas migration additive				Liter/100kg
	Dispersant				Liter/100kg
	Fluid loss control additive				
	Fresh Water				
	Density		**1.56**	**1.92**	**SG**
					Liter/100kg
					Liter/100kg
	Thickening Time at BHCT				Cement samples
Test results	Time to	30 BC	06:52	03:27	Hrs:Mins
	Time to	70 BC	**08:21**	**04:14**	Hrs:Mins
	Time to	100 BC	08:55	04:43	Hrs:Mins
	Fann readings at BHCT		58	139	300 RPM
			48	104	200 RPM
			32	63	100 RPM
			19	43	60 RPM
			4	8	30 RPM
			4	5	6 RPM
			6	7	3 RPM

Prior to cementing, hole was circulated clean with sea water with no losses. Sea water with addition of fresh water was used as spacer. Cement slurry was mixed and displaced at 1200 lpm. Cement placement went as planned.

Casing was pressure tested and no backflow was observed.

5.6.4 Reference Well 4

Well 4 is an appraisal well and is a part of the Field 1. The primary objective was to test the area north of the Field 1. The water depth at the location is 111 m MSL. Well was drilled by semi-submersible installation.

Well has not experienced shallow gas migration.

5.6.4.1 Geological setting

Well 4 is in close proximity of the Well 1 and the Well 2 and the Well 3. Therefore, the geological setting is the same as for the previous wells.

5.6.4.2 Shallow gas possibility study pre-drilling and design premises

Shallow gas possibility was addressed before drilling was conducted. Data from reference wells was used. Well 4 was designed to cater for shallow gas similar to the Well 1. Lower gas filled sandstone was estimated to be on the depth of 382 m RKB.

5.6.4.3 Drilling and cementing

Pilot hole was drilled down to 585 m MD RKB to check for the potential shallow gas zones. MWD logs in the pilot hole confirmed that shallow gas was not present and only water filled sands were seen.

20” surface casing was installed at 585 m TVD. Cement job was conducted with foam cement.

General surface casing data and cement formulation for the Well 4 is presented in Table 5.7 and Table 5.8:

Table 5.7: General data for surface casing cement used for Well 4

WELL DATA FOR 20" CASING					
Casing Depth Measured	[m]	576	Casing OD	[inch]	20
Casing Depth TVD	[m]	576	Casing ID	[inch]	18.7
Depth to Top Cement	[m]	136	Hole Size	[inch]	26
Previous casing depth	[m^3]	214	Hole MD/TVD	[m]	585
Excess on OH	[%]	100	Mud Type		WBM
Volume foamed slurry	[m^3]	± 121	Mud Weight:	[SG]	1.30
Volume base slurry	[m^3]	± 93	BHST Temperature	[°C]	20
Density Cement	[SG]	1.73 / 1.35	BHCT Temperature	[°C]	16
Spacer Volume/ SG	[m^3]	20/1.30	Spacer Type		TSE +

Table 5.8: Cement composition used for cement job on surface casing for Well 4

CEMENT SLURRY DESIGN & DATA				
Slurry design	Foam cement	**Amount:**		**Units**
		Tail		
	Fluid loss control additive			
	Retarder			
	Stability and free water additive			
	Fresh Water			
	Density	**1.73**		**SG**
	Foamer			
	Nitrogen quality	**22**		**%**
	Downhole density	**1.35**		**SG**
	Thickening Time at BHCT			Cement samples
Test results	Time to 30 BC	4:13		Hrs:Mins
	Time to 70 BC	**6:11**		Hrs:Mins
	Time to 100 BC	7:36		Hrs:Mins
	Rheology	Mix	API	
		90	94	300 RPM
		79	86	200 RPM
		68	73	100 RPM
		62	66	60 RPM
		57	59	30 RPM
		27	31	6 RPM
		22	25	3 RPM
	Gel strength (10 sec/10 min)	20/39	23/41	

Prior to cementing, hole was circulated clean with sea water with no losses. Drill water with weighted barite of final density of 1.30 SG was used as spacer.

Foam cement job was performed as planned, however during displacement of cement the top cement wiper plug was not released after applying sufficient pressure on the releasing mechanism. This resulted in not displacing out all of the slurry from the casing as planned.

Cement top was tagged inside 20" casing at 136.2 m. Cleanout assembly was run in the hole.

Cement was drilled down to 500 m MD.

Top of cement was found to be 7 meters below seabed on both funnels. 10 m3 of conventional 1.92 sg “G” class cement with addition of defoamer and $CaCl_2$ was pumped.

Casing was pressure tested and no backflow was observed.

5.6.5 Gas leakage analysis

Wells on Field 1 present an interesting case due to different cement formulation used in every well – Well 1 and 2 were cemented with conventional cement without any gas migration additives, Well 3 was cemented with conventional cement with addition of colloidal silica and Well 4 was cemented with foam cement.

Gas leakages were observed only in Well 1 and 2.

During pre-drilling shallow gas possibility study, few common anomalies were identified for all four wells. First anomaly located on depths ranging from 365 to 382 m TVD MSL was identified on reference wells, but was concluded as not present on the well locations. Second anomaly located on depths ranging from 605 to 630 m TVD MSL was also identified on reference wells and was concluded to be present on the well locations.

Pilot holes did not show any gas bearing formations, but none of the pilot holes have reached the depth of second anomaly. All of the surface casings were cemented in depth range of pilot holes. Only further drilling of 17 ½ main bores have confirmed shallow gas zones.

Wells 1 and 2 have experienced shallow gas migration only in long term period and no gas flow was reported immediately after cement job.

Jobs on leaking wells were finished without any problems as planned therefore possibility of poor hole cleaning and improper mud displacement that resulted in mud channeling is small.

Wells are not of production or injection type and were not exposed to pressure and temperature cycles, therefore possibility of casing debonding due to stress imposed on it is small.

Gas leakage is not severe which points on rather small size opening for gas migration. This type of leaking could be caused by formation of micro annulus due to shrinkage of cement or possibility of small migration channel or radial cracks through cement matrix.

Wells 3 and 4 have been cemented with possibility of gas migration in mind – Well 3 used colloidal silica additive that reduces slurry permeability and Well 4 has used foam cement that possesses various advantages over conventional cement both for short term gas migration control and mechanical properties / shrinkage.

Therefore, it is possible to conclude that use of proper gas migration preventive additives and more complex cement slurry composition could have prevented shallow gas flow on wells with similar conditions.

5.7 Case 2

5.7.1 Well 5

Well 5 is an appraisal well and is a part of the Field 2. Field 2 is located in the Norwegian Sea. The primary objective was to appraise the northern extension of the Field 2. The water depth at the location is 298 m MSL. Well was drilled by semi-submersible installation.

It is important to note that the well has experienced shallow gas migration from 2 shallow plugs that were set into 12 ¼" pilot hole and not from the surface casing.

5.7.1.1 Geological setting

Surface casing and pilot hole plugs are located in Nordland Group.

Compared to North Sea, in Norwegian Sea Nordland group consists of claystone, siltstone and sandstone. The clay is grey to greyish green, soft to firm, blocky, non-calcareous, and in parts silty. The basal part is represented by the Utsira Formation.

In the Norwegian Sea the Nordland Group was deposited in a marine environment in a rapidly subsiding basin characterized by major westerly prograding wedges. The upper part is of glacial to glacio-marine origin.

An average formation temperature gradient of approximately 4 °C per 100 m TVD was estimated in the range where surface casing is placed.

5.7.1.2 Shallow gas possibility study pre-drilling and design premises

Shallow gas possibility was addressed before drilling was conducted. Shallow gas was predicted based on offset wells.

Drilling with weighted mud and Riserless Mud Recovery (RMR) was a selected as mitigation. Planned Mud Weight (MW) in the program was 1.2-1.3 SG.

A 12 ¼" pilot hole was planned to be drilled from 398 m (setting depth of conductor) to 700 m TVD GL to investigate shallow gas possibility.

Due to anomaly observed on offset wells, a 20” casing was decided to be set well above a high gas risk zone that was predicted to be on depth of 565 m TVD GL.

5.7.1.3 Drilling and cementing

The 12 ¼” pilot hole was drilled from 398 m to 703 m TVD GL and shallow gas was indicated.

At 647 m gas bubbles were observed coming out of Suction Module (SMO) and 0.7% gas recorded during circulation.

At 703 m drilling was stopped due to boat handling. Flow check was conducted. Increase in bubble intensity during flow check with 1.2 sg MW, and measured 9.5% gas during bottoms up circulation. Crew had to increase to 1.35 SG in order to achieve stable well. It was decided to plug the 12 ¼” pilot hole and set 20" surface casing shallower than planned.

General pilot hole data and shallow gas plug cement formulation for the Well 5 is presented in Table 5.9 and Table 5.10:

Table 5.9: General data for pilot hole and cement used for Well 5

Well Data						
Hole Depth, MD	(m)	± 1000	B.H.S.T.	(°C)	29
Hole Depth, TVD	(m)	± 1000	B.H.C.T.	(°C)	22
Hole Size	(inch)	12 ¼	TOC, MD	(m)	± 750
Mud Type		WBM	Mud Weight	(S.G.)	1,25
Spacer volume	(m^3)	12 + xxx	Open hole excess	(%)	50 (tbc)
Preflush type		Spacer	Volume slurry	(m^3)	± 28,5

It is important to note that hole depth in Table 5.9 is measured in meters MD from MSL.

Table 5.10: Cement composition used for shallow gas plugs for Well 5

SHALLOW GAS PLUG CEMENT SLURRY DESIGN & DATA				
Slurry design	"G" class conventional cement	**Amount:**		**Units**
	Defoamer			
	Retarder			
	Cement friction reducer			
	Microsilica liquid			
	Fluid loss additive			
	Seawater			
	Density	**1.96**		**SG**
	Thickening Time at BHCT			Cement samples
Test results	Time to 30 BC	2:59		Hrs:Mins
	Time to 70 BC	**3:46**		Hrs:Mins
	Time to 100 BC	3:59		Hrs:Mins
	Rheology	Mix	BHCT	
		85	114	300 RPM
		61	82	200 RPM
		35	48	100 RPM
		23	32	60 RPM
		14	20	30 RPM
		5	6	6 RPM
		3	4	3 RPM
	Gel strength (10 sec/10 min)	5/24		

Shallow gas plug cement job was conducted with conventional cement. Prior to cementing, hole was circulated clean. 1.96 SG gas tight cement slurry was mixed and pumped followed by 1.65 SG spacer and displaced with 1.35 SG WBM. Full returns were observed during all phases of cement job. Crew has waited on cement and after 8.75 hours started to observe bubbles out of SMO. The top of shallow gas cement plug 1 was tagged at 588 m TVD GL. Shallow gas was suspected to bypass the cement plug from above 588m**,** thus a decision to set additional cement plug was made.

Crew has mixed and pumped 1.96 SG cement slurry followed by 1.70 SG spacer. Cement and spacer were displaced with 1.45 SG water based mud. Full returns were observed during all phases of cement job. The top of shallow gas cement plug 2 was tagged at 535 m TVD GL.

After waiting on cement, crew has displaced well to 1.25 SG and performed a 60 minutes flow check. After 11 minutes from the beginning of flow check, crew has started to observe bubbles out of SMO with a slight increase in intensity - from 20 seconds to 2 minute per bubble to a bubble every 10/30 seconds. Well was circulated bottoms up and observed a gas peak of 0.12 %.

Mud was weighted up in steps up to 1.7 SG. During this procedure gas peaks were dropping from initially 0.24% to finally 0.05%. Crew has flow checked well after every increase and observed bubbles, which only stopped with the 1.7 SG mud in hole.

Well was drilled further with 26” drilling assembly. 26” section was drilled down to depth of 562 m TVD GL. MW was raised to 1.70 SG and flow check was conducted for 60 min with no bubbles observed. Well was circulated bottoms up with no gas peak being observed.

20” casing was set at depth of 556 m TVD GL. Surface casing was cemented with foam cement.

General surface casing data and cement formulation for the Well 5 is presented in Table 5.11 and Table 5.12:

Table 5.11: General data for surface casing cement used for Well 5

WELL DATA – 20” CASING					
Casing Depth MD	[mtr]	±556	Casing OD	[inch]	20
Casing Depth TVD	[mtr]	±556	Hole Size	[inch]	26
Top Conductor Depth (RKB)	[mtr]	327	Previous Casing	[inch]	30
Previous Casing Depth MD	[mtr]	397	BHST Temperature	[°C]	20
Casing Weight	[ppf]	129.3	BHCT Temperature	[°C]	20
Depth to Top Cement	[mtr]	Seabed	Spacer Type		Tuned Spacer E+
Excess on OH	[%]	100	Spacer weight	[SG]	1.60
Target cement density	[SG]	1.55 – 1.60	Spacer Volume	[m3]	20
Foam Cement Base Volume	[m3]	55	Mud Type		Aquadrill WBM
Downhole Volume	[m3]	61	Mud Weight:	[SG]	??

Table 5.12: Cement composition used for cement job on surface casing for Well 5

CEMENT SLURRY DESIGN & DATA				
Slurry design	Foam cement	**Amount:**		**Units**
		Tail		
	Fluid loss control additive			
	Fresh Water			
	Density	**1.70**		**SG**
	Foamer			
	Nitrogen quality	**8**		**%**
	Downhole density	**1.55-1.60**		**SG**
	Thickening Time at BHCT			Cement samples
Test results	Time to 30 BC	2:32		Hrs:Mins
	Time to 70 BC	**4:56**		Hrs:Mins
	Time to 100 BC	5:16		Hrs:Mins
	Rheology	Mix	BHCT	
		112	81	300 RPM
		92	69	200 RPM
		76	56	100 RPM
		66	48	60 RPM
		54	39	30 RPM
		27	22	6 RPM
		20	16	3 RPM
	Gel strength (10 sec/10 min)	19/39		

All the stages of cement job went as planned with returns observed during all phases of the job. Casing was successfully pressure tested and no gas bubbles were observed.

5.7.2 Gas leakage analysis

Even though gas leakage did not occur from surface casing, Well 5 is an interesting case due to different cement formulation used in shallow gas cement plugs and in surface casing.

Gas leakages were observed on both of shallow gas plugs shortly after cementing. Cement that was used for the plugs is conventional gas tight cement with addition of liquid Microsilica.

Jobs were finished without any problems as planned therefore possibility of poor hole cleaning and improper mud displacement is small and will not be considered.

After cementing the plug 1, crew has waited on cement and after 8.75 hours started to observe bubbles. As gas migration has occurred after 8.75 hours, it points on that migration occurred during cement hydration process while cement sets. If gas migration would occur during gel period, gas bubbles would be observed sooner. Addition of Microsilica to the cement slurry aids in reduced permeability during fluid-to-solid state transition.

Therefore, it is possible to conclude that gas migration from the shallow gas plug 1 has occurred due to cement shrinkage and formation of micro annulus.

After cementing the plug 2, crew has waited on cement and did not observe any bubbles. Plug 2 was placed using 1.70 SG spacer and 1.45 SG WBM compared to 1.65 SG spacer and 1.35 SG WBM that were used to displace cement for plug 1. If possibility of gas migration occurring due to mud weight being insufficient to provide sufficient hydrostatic head during placement was considered, gas leakage would be visible on the plug 1 but would not be visible on plug 2 as hydrostatic head was increased on plug that was placed on shallower depth.

Gas leakage on plug 2 was observed only after conducting flow check with 1.25 SG mud. This points to the fact that hydrostatic head was sufficient to prevent gas migration during gel formation.

Increase in intensity of bubbling intensity - from 20 seconds to 2 minute per bubble to a bubble every 10/30 second point to progressive increase of micro annulus size throughout cement setting process on both plugs.

Top of shallow gas plug was tagged at depth of 535 m TVD GL. Surface 20” casing was set to depth of 556 m TVD GL which is lower that leaking shallow gas plug 2 and overlaps it with 21 meters. After casing string was cemented with foam cement, no gas annular migration was observed. This points to superior capabilities of foam cement on prevention of shallow gas migration.

It is important to point out that after full well completion, no gas migration was observed.

5.8 Challenges experienced while conducting research in Section 5

A smaller amount of data then planned was gathered due to some challenges. Data that had to be collected in order to conduct this study is an intellectual property and confidential information of various operator companies and cannot be used without a written consent of the owner. In order to access this data and be able to use it in this research, I had to make enquiries and go through legal process of screening and signing non-disclosure agreements. This process takes a long time and as enquiries are made to various operator companies with different routines. After the legal process is finished, operator companies need to assign a person with knowledge of topic that would help me in finding the cases that fit to criteria. Due to challenging situation in the oil and gas industry at the time of writing this thesis, companies had difficulties with finding time and resources that could have been allocated to support me at the same pace as project has progressed.

Me and my supervisor have struggled with response time from Halliburton customers and have also needed to find alternatives as some of companies most important sources of information have refused to participate due to current situation on the market.

6 Conclusion

The scope of this work was to analyze factors contributing to annular gas migration to seabed.

This was done by performing an analysis of data obtained from leak tests conducted in laboratory and case study of the wells located on Norwegian Continental Shelf that has experienced shallow gas migration.

Analysis of leak test data shows that cement shrinkage is a major factor contributing to long term annular gas migration.

Test data suggests that cement radial shrinkage contributes to gas migration by creating micro annulus which acts as space for gas entry and migration path. As cement shrinkage progresses with time, the size of micro annulus proportionally increases.

Comparison of leak test data for conventional and foam cement types shows that foam cement possesses superior pressure retaining capabilities to conventional cement due to reduced radial shrinkage.

Case study of the wells that has experienced shallow gas migration backs up the leak test data, showing the main factor that contributed to gas migration was cement shrinkage.

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