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Public abstract

This report is part of the research project MiReCOL (Mitigation and Remediation of CO_2 leakage) funded by the EU FP7 programme. Research activities aim at developing a handbook of corrective measures that can be considered in the event of undesired migration of CO_2 in the deep subsurface reservoirs. MiReCOL results support CO_2 storage project operators in assessing the value of specific corrective measures if the CO_2 in the storage reservoir does not behave as expected. MiReCOL focuses on corrective measures that can be taken while the CO_2 is in the deep subsurface. The general scenarios considered in MiReCOL are 1) loss of conformance in the reservoir (undesired migration of CO_2 within the reservoir), 2) natural barrier breach (CO_2 migration through faults or fractures), and 3) well barrier breach (CO_2 migration along the well bore).

The objective of this report is to review remediation measures for well leakage in the oil and gas industry best practice portfolio as well as emerging technologies. The approach is to review the technologies with respect to well barrier element failure. Squeeze cementing methods, as the most commonly used for well leakage remediation, are described in detail for different applications. Squeeze cementing can be applied for annular cement failure or casing/liner failure. A variety of sealants that can be used for squeeze cementing, well abandonment, or possibly during well construction as a prevention measure, are described in this report. Other remediation measures include repairs to or replacement of specific well barrier elements that have failed. These operations can be more or less complicated depending on the type and location of the failure. Repair/replacement operations are thus described in a general manner. Well plugging and abandonment can be considered as a last remedy, if all other options failed or are not economically viable. Plugging & abandonment is not a remediation strategy as such and is not covered in this report.

Public introduction (*)

This report is part of the research project MiReCOL (Mitigation and Remediation of CO_2 leakage) funded by the EU FP7 programme. Research activities aim at developing a handbook of corrective measures that can be considered in the event of undesired migration of CO_2 in deep subsurface reservoirs. MiReCOL results support CO_2 storage project operators in assessing the value of specific corrective measures if the CO_2 in the storage reservoir does not behave as expected. MiReCOL focuses on corrective measures that can be taken while the CO_2 is in the deep subsurface. The general scenarios considered in MiReCOL are 1) loss of conformance in the reservoir (undesired migration of CO_2 within the reservoir), 2) natural barrier breach (CO_2 migration through faults or fractures), and 3) well barrier breach (CO_2 migration along the well bore).

Life cycle well integrity is currently in the spotlight of the oil and gas industry, regulators and public. Failures of the well barriers may lead to leakage of downhole fluids with potentially catastrophic safety and environmental consequences. Causes and mechanisms of well integrity problems are important parts of present oil & gas research and the knowledge about well integrity failures has significantly improved within the last decades. Ageing issues like cement degradation, casing corrosion and thermal loads imposed on the well infrastructure are examples of potential failure modes. Many of the available oil & gas technologies and methods used for oil and gas leaks can also be applied to CO_2 storage operations. Some of the available remediation methods will require modification for application in CO_2 wells, due to the chemistry and the long-term effects associated with CO_2 storage operations. This report will review the available technologies, while in future work we will evaluate how these can be deployed to remediate in the most likely scenarios for CO_2 leakage related to operational or abandoned wells.

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1 INTRODUCTION

This report is part of the research project MiReCOL (Mitigation and Remediation of CO_2 leakage) funded by the EU FP7 programme. Research activities aim at developing a handbook of corrective measures that can be considered in the event of undesired migration of CO_2 in deep subsurface reservoirs. MiReCOL results support CO_2 storage project operators in assessing the value of specific corrective measures if the CO_2 in the storage reservoir does not behave as expected. MiReCOL focuses on corrective measures that can be taken while the CO2 is in the deep subsurface. The general scenarios considered in MiReCOL are 1) loss of conformance in the reservoir (undesired migration of CO_2 within the reservoir), 2) natural barrier breach (CO_2 migration through faults or fractures), and 3) well barrier breach (CO_2 migration along the well bore).

The long term safety of CO_2 storage sites is largely dependent on the integrity of wells penetrating the storage site. Loss of well integrity has been identified as a major failure factor in CO_2 storage [1, 2]. Thus prevention and remediation options for any potential leakage through wells, which has been assessed in a risk analysis, play a crucial role in large scale implementation of CO_2 storage. A remediation operation can be described as an attempt to repair a leak in a well barrier (element).

In a previous MiReCOL report [3], well leakage scenarios were described using well-barrier/element failure approach. In order to maintain well integrity two independent well barriers shall be present at all times – this is the essence of the "two-barrier principle" from the NORSOK D-010 standard [4]. In other words, each well barrier can be seen as a chain of connecting well barrier elements i.e. well components that constitute a well barrier envelope. There shall be at least two such independent well barrier envelopes in the well, the primary and secondary envelope respectively, and these should not have common well barrier elements.

The primary (blue) and secondary (red) envelope are illustrated in Fig.1. The main elements in the primary envelope are: (1) formation, (2) annular cement, (3) liner, (4) production packer, (5) tubing and (6) downhole safety valve. The secondary envelope contains: (1) formation, (2) annular cement, (3) liner, (4) liner packer, (5) production casing, (6) casing hanger, (7) tubing hanger and (8) wellhead/X-mas tree with valves. In addition, some possible leak pathways due to well barrier envelope failures in an active CO_2 well are indicated: internal – within the well, or external – which may reach the surface. There are a number of reports on the statistics of well integrity failures both in onshore and offshore wells around the world, for example references [5-7]. Ageing issues with cement degradation, casing corrosion and wear, and thermal loads imposed on the well infrastructure are examples of the most likely causes of well leakage. The tubing is the Well Barrier Element that is by far the most likely to fail, probably due to corrosion and/or connection failure. Also the casing and the cement have a significant chance of failure.

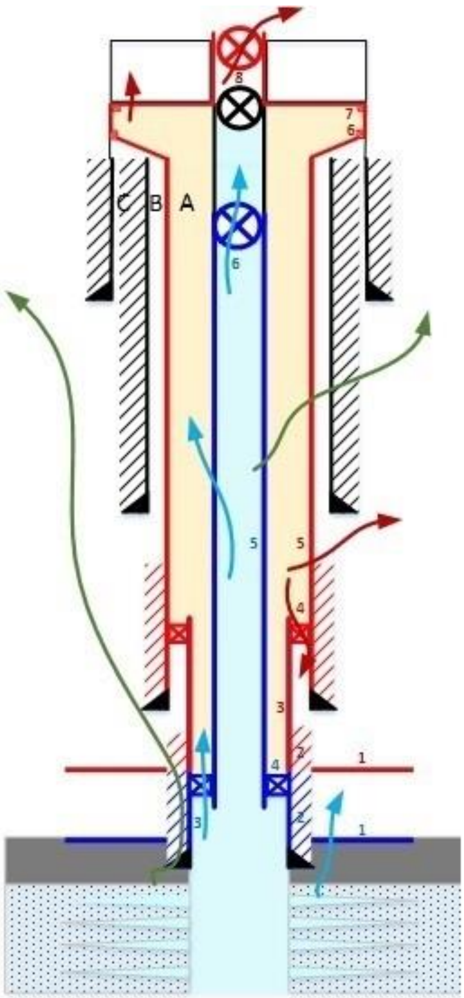

Figure 1: Schematic illustration of some possible leak pathways due to Well Barrier Element failures in an active CO_2 well. Blue arrows show failure of primary well barrier envelope, red arrows show failure of secondary well barrier envelope, and green arrows show failure of multiple Well Barrier Elements. (Acknowledgment to Jafar Abdollahi and Inge Manfred Carlsen, Weatherford Norge).

The objective of this report is to review remediation measures for oil and gas well leakage presently used by the oil & gas industry. We will review both established best practice methods and novel technologies. Remediation technologies used for oil and gas well leakages can be applied to a great extent to CO_2 wells. Squeeze cementing, as the most commonly used strategy to solve a variety of well problems, is thoroughly described in this report. This includes a review of different squeeze methods, tools and materials for squeezing jobs. In addition, standard casing repair methods are described, including casing patches and expandable casing/liner. Apart from the standard strategies to repair cement and/or casing leaks, there are larger remediation operations such as well-workovers. Cases where it is necessary to remove and replace failed well elements are described in a general way. Novel materials, tools and technologies are presented and their potential for leakage remediation is discussed. Well plugging and abandonment is not a remediation strategy as such and is therefore not considered in this report. A plugging & abandonment operation can be considered as the last remedy which ends the life cycle of a well.

The application of existing and novel oil & gas remediation technologies to CO_2 well leakage will be assessed in the future work. We will discuss strategies for leakage remediation for both active wells and inactive wells. The well barrier breach approach and selected performance criteria will be used to assess and classify the remediation technologies. Risk assessment for various types of leaks and subsequent remediation cost assessment and best practice recommendations will be presented. The next and final report will represent a summary of the work done and the previous report [3].

As future work, a number of laboratory tests are planned to examine the merits of new materials for remediation of well leakage. These materials include CO_2-reactive suspensions, polymer-based gels, smart cements with a latex-based component and a polymer resin for squeezing. If feasible, the efficiency of a designed sealant will be investigated in a field test at the Serbian Bečej natural CO_2 field.

2 SQUEEZE CEMENTING

Squeeze cementing is typically used to repair the annular cement or the casing/liner, or to stop migration of fluids within a well. This operation is usually performed at the time of running the casing. However, it can be used for remediation of leakage later on in the life of a well. General applications of squeeze cementing are:

- Repairing the primary cement job (mud channels, voids, debonding, cement degradation)
- Repairing casing/liner leaks (corrosion, split pipe)
- Sealing lost circulation zones (during drilling)
- Plugging one or more zones in a multi-zone injection well
- Water shut-off
- Isolation of gas or water zones
- Well abandonment

Squeeze cementing operations can be expensive since well workover and wellbore preparation are required. Before squeeze operations are initiated, problem identification, risk and economic analysis need to be performed in order to optimize the success of the operation.

Squeeze cementing is the process of pumping cement slurry through perforations, holes or fractures in the casing or the wellbore annular space into an isolated target interval, behind the casing or into the formation [8, 9]. Squeeze cementing operations start with wellbore preparation. If the slurry needs to be injected bottom-off, a plug must be installed below the squeeze interval to prevent slurry from flowing further downhole. The slurry is pumped through drillpipe or coiled tubing until the wellbore pressure reaches the predetermined value. In most cases the tubing is pulled out of the cement slurry during the setting period. The next step is removal of excess cement which is usually performed by reverse circulation.

Squeeze cementing is a dehydration process. The solid particles in cement slurry are in most cases too large to enter the formation. In case of a permeable formation, the solid particles filter out onto the fracture interface or formation wall, while only a liquid filtrate passes into the formation. This results in a cement filter-cake filling in the perforations, as illustrated in Fig.2. After the accumulation of the filter-cake, cement nodes protrude into the wellbore. Although the filter-cake is not yet set cement, it is impermeable and able to withstand the increased wellbore pressure.

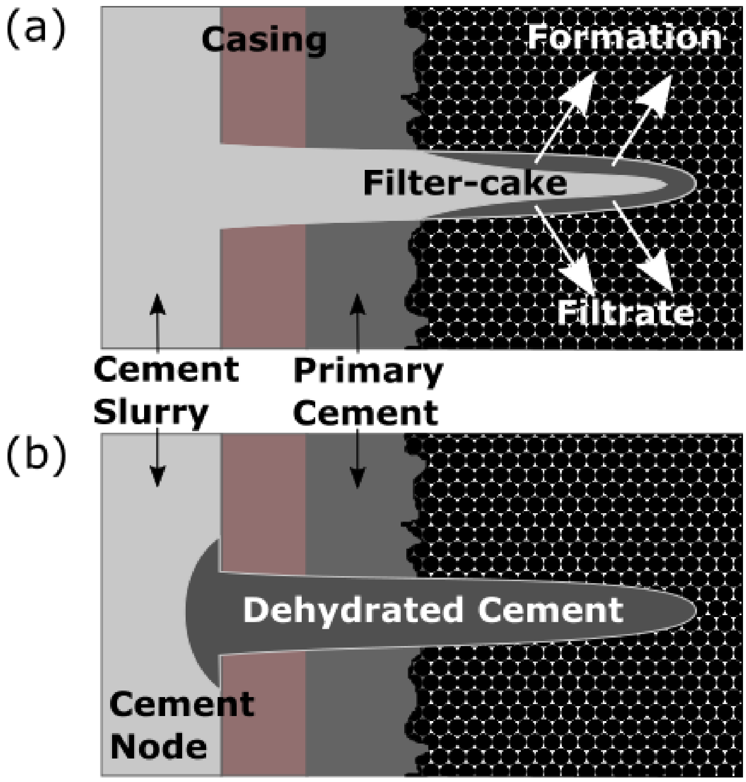

Figure 2: (a) Filter-cake buildup into a perforation channel. (b) Perforation channel filled with dehydrated cement and a cement node is protruding from the perforation.

Squeeze jobs are traditionally classified according to the bottomhole treating pressure into a) low-pressure squeeze (below the formation fracturing pressure) and b) high-pressure squeeze (above the formation fracturing pressure). There are two pumping methods: the running squeeze or the hesitation squeeze which can be applied at low or high pressure. The Bradenhead squeeze is a basic technique which can be applied in different pumping regimes and is usually combined with different squeeze tools. These basic techniques, methods and squeeze tools are described in the following sections.

2.1 Low-Pressure Squeeze

Low-pressure squeeze is the best option for remediation operations in the production zone. This technique avoids fracturing the formation by precise pressure control of the pump pressure and the hydrostatic pressure of the cement slurry [8]. Since no cement slurry is pumped into the formation, the slurry volume used is small. For successful application, it is essential to have the perforations and channels/interconnected voids cleared from mud and solids. If the slurry is properly designed, only a small node of cement filter-cake will remain inside the casing. Since there are many sensitive parameters, low-pressure squeeze requires careful design and execution. This technique is applied in multiple zones, long intervals and wells with low bottomhole pressure.

2.1.1 Circulating Squeeze

Circulating squeeze is a low-pressure method. This procedure involves circulating cement slurry between two sets of perforations, isolated by a packer or cement retainer. A cement retainer is preferable because it is easier to remove after the squeezing operation. Initially water or acid are pumped to achieve circulation, followed by a washer fluid. The cement slurry is pumped last. The exact required volume of cement slurry is unknown, so large amounts are pumped into the annulus. Thus there is a risk of cement slurry bypassing the packer/cement retainer and entering tubing, drillpipe, casing or annulus above the retainer. This may lead to stuck drillpipe or tubing if the excess cement sets. To minimize this risk, the cement retainer is placed as close as possible to the upper perforations and the stinger assembly is removed after cement placement. The excess cement slurry can be reverse circulated out of the well.

2.2 High-pressure Squeeze

When there are small cracks or micro-annuli, or disconnected channels in the annular cement, or when it is impossible to remove wellbore fluids and debris at low pumping pressures, then low-pressure squeeze is not appropriate remediation option [8]. In such cases fractures need to be induced in the formation at or near-by the perforated interval to allow the placement of cement slurry. Further application of pressure initiates slurry dehydration and filter-cake builds up against the formation walls and in all channels and fractures.

Since a high-pressure squeeze induces fractures in the formation, larger cement slurry volumes are needed to fill the additional voids created. This technique is applied when wellbore fluids or mud must be displaced to allow placement of cement slurry into the voids. High-pressure is also used for shoe squeeze, block squeeze and cementing liner top. One drawback is that the location and orientation of created fractures cannot be controlled. Other challenges are that the required squeeze pressure and build-up of filter cake may be difficult to attain. It is useful to wash the target interval with water or acid solution before the squeezing operation, to clean the perforations and open smaller fractures. This reduces the pressure required to initiate the fracture and the necessary slurry volume.

2.2.1 Block Squeeze

Block cementing is a high-pressure method, used to prevent leakage either above or below a producing zone which has poor zonal isolation. For this purpose the sections above and below the target formation are perforated and squeezed. This requires isolation of the permeable zone with a packer or retainer. The permeable interval below the producing zone is perforated and squeezed first, then the permeable interval above. The two residual cement plugs are drilled out after squeezing. Then the production zone is ready for perforation.

2.3 Pumping Methods

2.3.1 Running Squeeze Method

The running squeeze method is continuous pumping of the cement slurry until the final desired squeeze pressure is obtained [8]. If the pressure drops after the pumping stops, more cement slurry is injected until the pressure stabilizes without further pumping. The pumping rate should be low to avoid fracturing the formation and to fill narrow microannuli. Thus, fluid-loss control is not necessary and cement slurry design is simple. However, large volumes of cement slurry need to be injected.

This pumping method is applied only when:

- The wellbore fluids are clean.
- The formation has no fractures and no interconnected voids.
- The operation can be performed below formation fracturing pressure.

Design and application of running squeeze operation is simple, but the operation itself is difficult to control, because it is difficult to determine the rate of pressure increase and final squeeze pressure. Thus the pump rate should be reduced as the pressure builds up. There is a good chance to obtain the final squeeze pressure, but this is not a certain indicator of success. Another disadvantage is that it cannot be expected that all voids will be filled.

2.3.2 Hesitation Squeeze Method

The hesitation squeeze involves periodic pumping of cement slurry while monitoring the pressure on the surface [8]. In most cases during squeeze cementing, the formation absorbs the cement filtrate slower than the minimum pumping rate applied. Maintaining a constant differential pressure while not exceeding formation fracture pressure is therefore challenging, and the hesitation squeeze pumping method provides a solution.

Cement slurry must be carefully designed and shutdown periods between pumping cycles estimated accordingly. For example, a cycle can be 20 min pumping at ¼ - ½ bbl/min, followed by 10-20 min shutdown. The initial hesitation period depends on the formation and will be longer for loose formations. During the shutdowns the pressure drops due to filtrate loss to the formation. In the first pumping cycles, leak-off to the formation is quick. As the filter-cake builds up, the pressure increases, shutdown periods become longer and the difference between pumping and shutdown pressure diminishes. A nearly unchanged pressure during a shutdown indicates the end of the squeeze job.

This pumping method is used for all types of wellbore problems. The hesitation squeeze is more efficient in filling all the voids than the running squeeze, and in this case obtaining the final squeeze pressure is a sign of success. This technique requires much smaller slurry volumes than the running squeeze but the procedure is much more complex. The hesitation squeeze may be characterized as follows:

- Longer cement placement time and increased waiting-on-cement time.
- Squeeze tool placement is critical.

- Pumping rate, cement volume and hesitation time need to be carefully estimated.
- Cement slurry design is complex (fluid loss control, low gel strength).

2.4 Bradenhead Squeeze

The bradenhead squeeze technique is a low-pressure squeeze applied when it has been ensured that casing can withstand the squeeze pressure [8]. This technique owes its popularity to the simplicity of the squeeze procedure (no special tools involved) and a good success rate. As illustrated in Fig.3, an open-end tubing is run to the bottom of the perforated interval. A bridge plug may be used below the perforated interval to isolate the lower part of the wellbore. No squeeze fluid ahead of cement is needed, since the cement slurry is injected directly into the perforated interval. After the slurry is set in place, the tubing is pulled above the cement top and pressure is applied through the tubing with the blowout preventer rams closed. After waiting-on-cement time interval, a reverse circulation of the excess cement is performed through the tubing, providing an easy clean-up procedure.

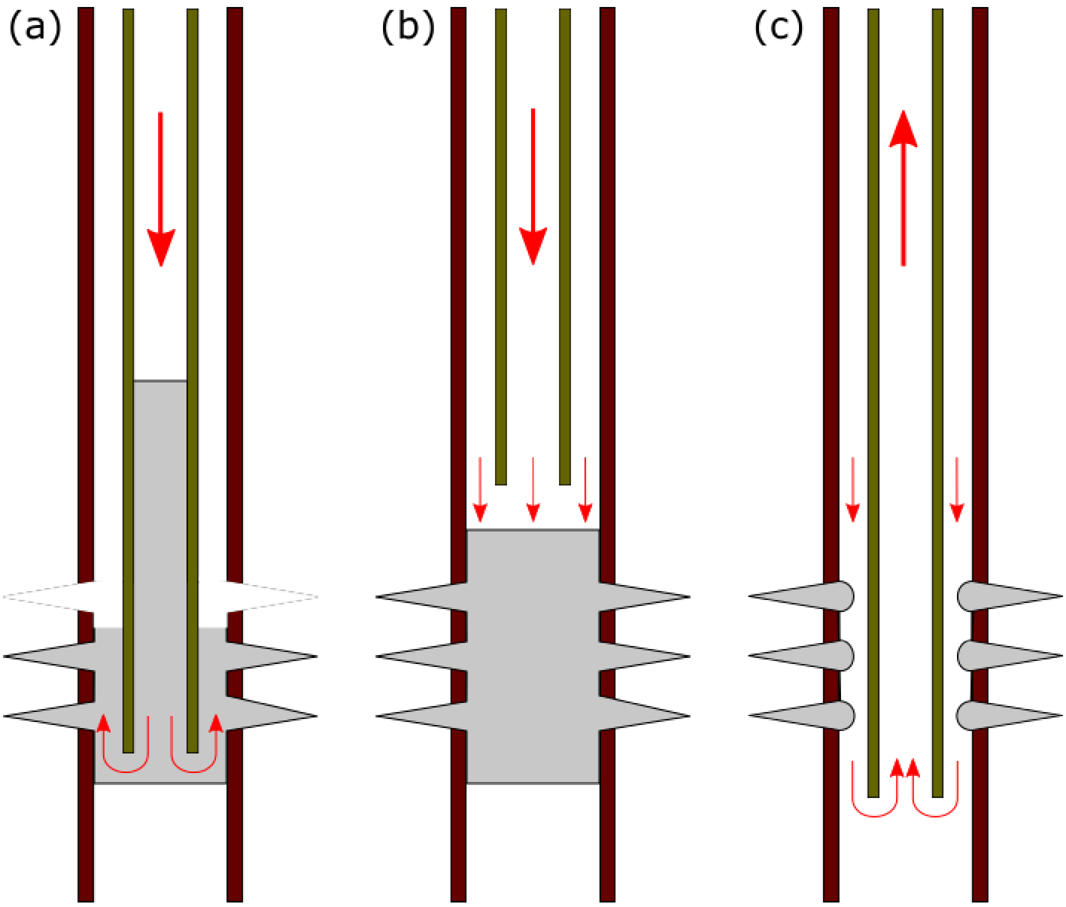

Figure 3: Bradenhead squeeze technique.(a) Cement slurry injection into the perforated interval. (b) The tubing is pulled out of the cement slurry and pressure is applied through the tubing. (c) Reverse circulation of the excess cement slurry.

This technique is often applied when lost circulation occurs during drilling or soon after primary cementing to fix a weak casing shoe. A hesitation squeeze pumping method is often used to force the cement slurry more effectively into the voids. Most coil-tubing squeeze applications are performed using a Bradenhead squeeze.

Drawbacks of the bradenhead squeeze include:

- The whole casing is exposed to the pressure during waiting-on-cement time. Casing integrity must be guaranteed (no corrosion, fatigue, splits).
- During the squeeze, the casing expands and restricts the flow of cement slurry through the microannuli/channels in the annular cement. These channels may not be completely filled with the slurry and will reopen after pressurizing is stopped.

2.5 Squeeze Tools

The main of objective of using squeeze tools is to isolate the squeeze target or the wellhead and the casing from high pressures applied downhole. Squeeze tools increase control over the cement slurry volume and the squeeze pressures and more accurately locate the target interval.

2.5.1 Retrievable Squeeze Packer

Compression or tension-set packers are used for squeezing. The packer can be set above/below the target interval or between two intervals. The packer allows circulation of the wellbore before the cement slurry is pumped and seals off the annulus during the squeezing. Retrievable packers have a bypass valve which allows fluid flow while running into the wellbore and after the packer is set. The valve is closed during cement squeezing. After the cement job, the valve allows reverse circulation to clean excess slurry. The main advantage over the drillable retainer is that the packer can be recovered and reused. Some possible disadvantages of using a packer are:

- Backflow cannot be prevented.
- Reversing excess slurry may damage the squeezed cement.
- Mechanical problems during running/placement.
- Contamination of the cement slurry is possible during placement.
- Build-up of cement on the packer/string.
- Valve opening during squeeze job.

2.5.2 Drillable Cement Retainer

Cement retainers are drillable packers with a controllable valve. Cement retainers or bridge plugs are used to create a false bottom and isolate the wellbore below the squeeze target. Cement retainers are used to prevent backflow or when there is a high negative differential pressure which disturbs filter-cake build-up. A cement retainer has an advantage that it can be placed more precisely than a packer, close to formation or between perforations. Disadvantages of the retainer are that it takes an additional trip to set it, can be used only once and drilling-through takes time.

2.5.3 Coiled-Tubing Squeeze

Coiled-tubing squeeze is a popular technique that has been in use since the 1980s [8]. This method dramatically reduces workover costs and enables accurate placement of small volumes of cement slurry. A tubing with a packer is used to guide the smaller coiled-tubing with a nozzle down the wellbore to the squeeze interval. The subsequent procedure is as follows:

- Viscous mud is injected into the well until its level is just below the perforations, which acts as a supporting column for the squeeze job. The mud contaminated with wellbore fluids is circulated via the coiled-tubing, and then water or diesel is injected above the mud column.
- The coiled-tubing nozzle is placed just above mud-water interface and cement slurry is pumped in until the perforations are covered. Then the squeeze pressure is applied with the nozzle located below the water-cement interface.
- When the squeeze pressure is reached, a contaminant fluid is injected to dilute the excess slurry and the wellbore is reverse-circulated.

Drawbacks of this technique are:

- Poor depth control.
- The coiled-tubing volume should be directly measured to enable placement of small slurry volumes.
- Fluid contamination can be prevented with use of additional plugs.

2.6 Cement Slurry Design for Squeeze Cementing

Certain factors have to be taken into account for optimal cement slurry design for each squeezing operation [8]:

- Rheology and sedimentation. Low viscosity allows pumping through coiled-tubing and penetration into small cracks and voids. Too low viscosity may result in free water and sedimentation. On the other hand, thick slurries are useful for cementing large voids.
- Low gel-strength during placement is important since gelation restricts slurry flow and increases surface pressure.
- The choice of cement particle size depends on the type of leak and the formation. Engineered micro-cement can be used for small casing leaks or low-permeability formations. For fixing leaks in unconsolidated formations, gravel/grain size, permeability and pore size of the formation are used to determine the appropriate cement particle size.
- Absence of free water is desirable.
- Appropriate fluid-loss control ensures optimal filter-cake build-up within cracks and perforations. The fluid-loss rate can be adjusted from low (<50-100 mL/30 min) for small cracks or to match formation permeability, to high (300-500 mL/30 min) for large cracks/voids behind the casing.
- The thickening time for squeeze job is designed in a way that squeezing and placement is possible as well as subsequent well cleanout. Thickening time generally depends on pressure and temperature. The temperature during squeeze cementing is usually higher than during primary cementing, which should be taken into account when designing the slurry.

- Higher slurry density results in better quality of the set cement but it causes higher hydrostatic pressure during placement. By engineering the particle size in the slurry it is possible to achieve low-density slurry with good mechanical properties or high-density slurry with relatively low viscosity.
- Chemical resistance: the usual requirement is resistance to acidic environment (HF/HCl/H_2S).
- Economic cement slurry design: the cement itself usually costs less than 10% of the total squeeze operation costs. Choosing the cement system that increases chance of squeeze job success is thus recommended.

2.7 Squeeze Cementing Summary

Examples of squeeze cementing techniques and possible applications focusing on failure of the cement sheath as a Well Barrier Element are given in Table 1. Squeeze cementing is used both during drilling and completion, and after primary cementing during the production or injection phase. In case of annular cement failure it is challenging or sometimes impossible to determine the nature of the failure (mud channels, fractures, debonding from the casing or formation, cement degradation). But detecting the location of the leak and its severity are some of the essential factors for planning the squeeze operation.

Squeeze Technique	**Application**
Low-pressure squeeze	Loss of well integrity in production zone
Circulating squeeze at low pressure with cement retainer/packer	Annular cement failure; casing/liner leak
High-pressure squeeze	Mud channels, cracks, micro-annuli in cement; casing shoe or liner top cementing
Block squeeze at high pressure with cement retainer/packer	Zonal isolation of a permeable zone – leakage prevention
Bradenhead squeeze with coiled-tubing and retainer/packer; hesitation pumping	Loss of circulation during drilling; cementing casing shoe; annular cement failure; casing/liner leak

Table 1: Examples of squeeze cementing techniques and possible applications.

3 OTHER SEALANT TECHNOLOGIES

3.1 Pressure Activated Sealants

Pressure-activated sealant technology was at first developed to remediate leaks in hydraulic control lines and surface controlled subsurface safety valves (SCSSV) [10, 11]. Since its development, this technology was expanded to various applications:

- Surface leaks - valves, pinholes, weld defects, etc.
- Wellhead leaks – pack-offs, bradenheads, casing/tubing hangers
- Casing/tubing leaks
- Cement leaks - microannuli, plugs, cavern casing shoe
- Downhole leaks – SCSSVs, umbilical lines, subsea well control systems, packers, pressure and temperature gauge mandrels, etc.

An example of this technology which is presently in use is Seal-Tite®. The pressure-activated sealant formula consists of a super-saturated mixture of short-chain polymers, monomers and other components [10]. High differential pressure at the leak site causes polymerization of the sealant into a flexible solid, as illustrated in Fig.4. The sealant polymerizes first at the edges of the leak site and gradually bridges across the leak site and closes it. The reaction stops when the pressure drops. The resulting plug is flexible and fills in holes/cracks at the leak site. At first the plug is fragile, but it develops strength over time while it retains its flexibility. The plug withstands the pressures up to pressure that activated its polymerization. The remaining injected sealant remains liquid – it will not clog nor plug the hydraulic system. The efficiency of sealing mechanism is not affected by pressure, temperature and time needed to reach the leak site, since each sealant formula is developed for that particular problem.

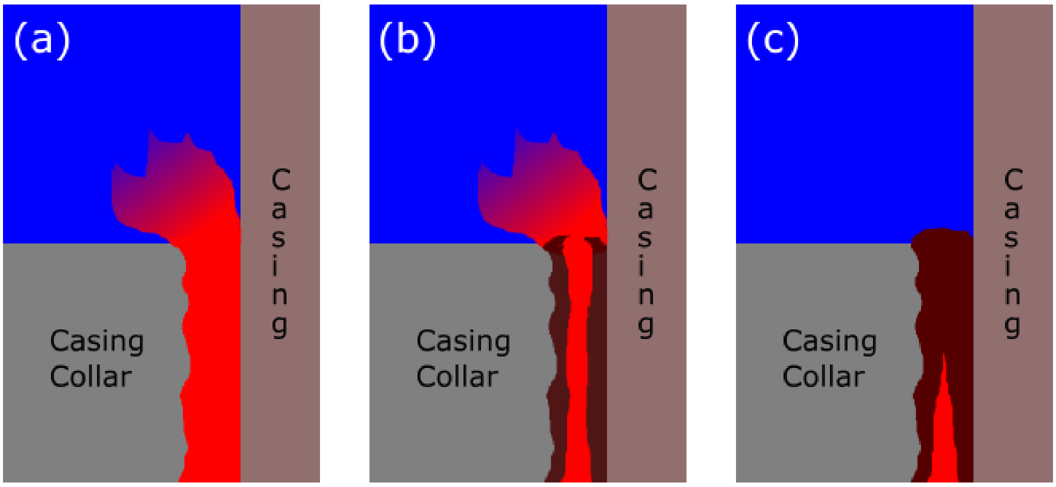

Figure 4. Illustration of pressure-activated sealant mechanism: (a) Sealant (red) forced through the leak site under pressure. (b) Pressure drop causes polymerization along sides of the sides of the leak. (c) The leak is plugged and the remaining sealant is liquid.

The advantage of pressure-activated sealant remediation is that there is no need for workover which dramatically reduces the costs. So, this technology has become popular in subsea applications, offshore and in arctic/remote locations. It has been used worldwide and a high success rate of 80% is claimed for the period of 2005-2012 [10, 11].

The majority of repairs concern wellhead pack-offs. However the development of ultrasonic leak detection has enabled the use of this sealant technology for the repair of small casing/tubing leaks without pulling the tubulars.

3.2 Temperature Activated Sealants

Temperature activated sealants are polymer resin systems designed to cure at a specific temperature. This allows placement, pumping or squeezing while in the liquid state into a desired interval in a well and subsequent curing when the resin reaches the appropriate temperature. Curing temperature, density, viscosity and curing time can be accurately designed for a particular application. In general, polymer resins tolerate some degree of contamination and are compatible with most wellbore fluids and cements. Treatments with polymer resin systems can be reversible (milling, acid treatment). A couple of examples of commercially available temperature activated sealants are described in the following.

ThermaSet® (WellCem) is a polymer resin system that is developed for solving problems such as loss of circulation [12], consolidation of loose formations, channels behind the casing, casing leaks and plugging in general [13], but can be used for many other well integrity issues. Some properties of Thermaset® are:

- Penetrates into permeable formation and narrow channels.
- Cures into a strong and flexible plug that withstands thermal expansion.
- Good bonding to steel and rock.

Thermatek® (Halliburton) is a temperature-activated rigid-setting fluid with a controlled right angle set that quickly develops high compressive strength. Some of the applications are consolidation of loose formations, plugging in general, annular seals behind or between casing/liner sections and fixing casing or packer leaks. Exothermic reaction when mixed initiates the setting process. Additional heat of formation as the fluid is pumped downhole speeds up the setting process. Setting time can be controlled by the addition of a retarder. Some properties of Thermatek® are:

- Controllable right angle set.
- Rapid build-up of compressive strength.
- No shrinkage.
- Zero static gel generation.
- Will not invade formation.

Temperature-activated sealants can in principle be used for squeeze-cementing and remediation of casing and annular cement integrity loss.

3.3 Silicate-based Sealants

Silicate-based methods, although not as widely used as polymers, have a potential for treating many production/injection problems as well as well for leakage remediation [14]. Silicate/polymer methods have been extensively used in Hungarian fields within last decades for water shut-off, profile correction in water injection wells, stabilization of reservoir rocks, etc. Silicate-based treatment was also deployed in the Bečej field (Serbia) in 2007 for mitigation of vertical CO_2 migration as a consequence of the CO_2 blowout in 1968 [15], as described in Report D8.1 [3].

Some advantages of silicate systems are low viscosity, good placement, can be gelled by a variety of inorganic and organic compounds and environmental friendliness [14]. Disadvantages are for example gel rigidity, shrinkage, short setting time and precipitation instead of gelling.

Development of polymer/silicate methods started at the end of the 1970s. The polymer/silicate technique is based on simultaneous cross-linking of hydrolized polyacrylamide and polymerization of sodium ortho-silicate [15]. In this method two solutions are used, with the following main components:

- Partially hydrolyzed polyacrylamide and Na or K ortho-silicate
- Potassium aluminum sulfate, calcium chloride, hydrochloric acid.

These solutions can be injected sequentially or mixed depending on the desired penetration depth. In the example of Bečej 5 well remediation, a sequential injection procedure was applied to avoid premature plugging effect. In the mixing zone, the following chemical reactions take place:

- Cross linking of polymers
- Gelation (polymerization) of silicates
- Precipitation of polymers, silicates and aluminum hydroxides.

If these solutions are injected into in porous formations, absorption of chemicals and entrapment of microgels, clusters, or hydroxides occur at the interfaces with the porous medium. The gelation process is terminated when viscosity reaches 8000-12000 mPa s [15]. The penetration efficiency mostly depends on the viscosity of both solutions. The cross-linking solution has similar viscosity to water and poses no issue. The content of polymer affects the viscosity more dramatically than silicates, increasing with polymer concentration. After curing, the permeability of the treated region is reduced by 4-5 orders of magnitude, the gel strength exceeds 10 bar/m and the barrier is stable up to 150 C.

The limitation of this technique is that it was primarily developed to treat the formation in the vicinity of the wells and as such it is not focused on well integrity issues, but on formation related problems.

4 CASING REPAIR

Leakage through the casing (or tubing) is usually caused by mechanical erosion, wear and/or corrosion. In oil & gas production wells such leaks may result in loss of production, crossflow, production of unwanted fluids, etc. CO_2 injection wells face the same risks with casing/tubing leaks, especially if a well was originally designed as production well and has been already in operation for many years.

Casing leaks can be repaired by squeeze cementing, but this is an expensive and not a very successful technique. The squeeze operation may damage the casing further due to pressure applied during squeezing. Another option is to set a cement plug within the damaged casing which is more successful than squeezing [8], but this solution is part of the plugging & abandonment phase. The focus of this section is on alternative methods, involving casing manipulation, which allow continued operation of the wellbore. Some these methods are also used to repair cement leaks behind the casing.

4.1 Patching Casing

This method is an alternative to squeeze cementing for repairing casing/liner leaks when squeeze cementing has failed or is not applicable. A casing patch can be placed over or completely replace the damaged/corroded/weakened interval of the existing casing [9]. In the latter case, the inner well diameter is preserved.

Casing patch can be coated with epoxy resin on the outer surface prior to placement across the desired interval. Expander assembly is used to expand the patch against the casing. A simplified example of casing patch installation is illustrated in Fig.5. The expanded casing patch is anchored to the casing wall by the friction caused by compressive hoop stress. During the expanding, the epoxy resin fills the voids in the casing and becomes an additional sealant. This technique creates a hydraulic and gas-tight connection between the old and the new casing. Patching casing operation normally takes less than a week. This technique proved to be successful in many cases.

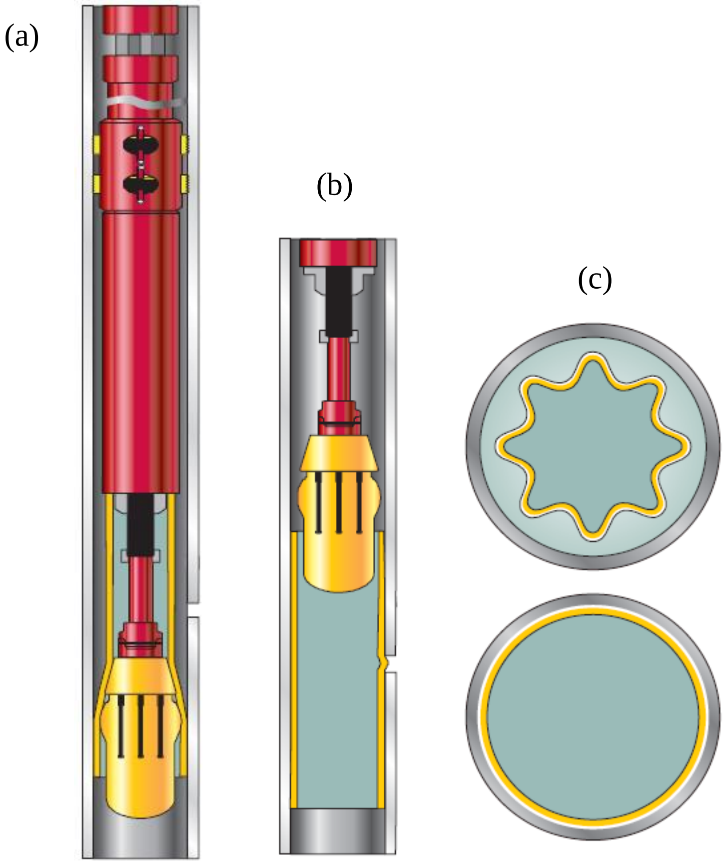

Figure 5: HOMCO® Internal Steel Liner Casing Patch short installation procedure: (a) After placing over desired interval, the patch is expanded, (b) fully expanded patch covering the leak site, (c) top view of the casing patch before and after expanding. Illustration taken from Weatherford.

4.2 Expandable Casing/Liner

Use of expandable casing has become a standard technique in the oil & gas industry over the past 10-15 years. Expandable casing technology is commonly used in extended reach drilling but can also be applied for remediation of leakage in the existing wells. It is especially used for casing-off perforations and damaged casing sections. After installation of the expandable casing, perforation can be repeated.

Wellbore cleaning is essential before the expandable casing/liner is installed, to ensure free expansion and proper sealing of the elastomers. The expandable liner is run downhole together with the expander assembly which contains a solid cone. When the expandable liner is set in place, the cone is driven through the liner bottom-up using mechanical force or hydraulic pressure. During the expansion process, the liner diameter increases causing shortening of the overall liner length, but at the same time the wall thickness decreases only slightly. The expansion is completed when the anchor hanger seals the expandable liner against the original casing. The expandable liner can comprise many joints to create necessary length.

The expandable liner technology can be used during drilling and primary cementing as well, this being an open-hole liner expansion operation. In this case, drilling is performed with the expandable liner run down-hole together with the drill bit. The expansion of the liner hanger is performed after cement slurry placement in the annulus. Such an operation drastically reduces the rig time during well completion by avoiding unnecessary trips.

Another option is to expand the existing casing/liner that is cemented in place. During casing expansion, the hydrated cement in the annular space behind the casing is compressed. In laboratory scale experiments [16], it was observed that the cement becomes softer and changes consistency after expansion. But after a certain rehydration period (in contact with water), the cement regains its compressive strength and solid structure.

4.3 Swaging

When casing becomes deformed or collapses into the well, a swaging technique is used to restore it to its correct form [9]. A swaging tool is used to force the tubing or casing walls out while it is driven through deformed/collapsed section. This tool can also be used to expand casing or liner.

4.4 Tubing replacement/repair

Tubing replacement requires a well workover, so the costs are comparable to packer replacement. This operation is applied when other simpler solutions cannot be used to remediate the leakage. When the tubing is pulled out, the leaking joint(s) are replaced and the whole tubing is inspected so that other repairs can be conducted.

5 OTHER REMEDIATION STRATEGIES

5.1 Wellhead and X-mas tree repair

Well head equipment can be easily inspected and repaired for onshore or platform wells. For subsea wells, well head/X-mas tree repair involves a well service vessel and remotely operated vehicle [9]. Depending on the type of the problem, it may be solved at the sea bottom or X-mas tree may be removed and repaired on-shore. The latter operation requires well killing.

5.2 Packer Replacement

A packer leak is detected through the drop in annular pressure when the casing and tubing are known to be intact [9]. The removal and replacement of a production or injection packer is a complicated operation. Such workover includes killing the well, X-mas tree removal, tubing retrieval and finally packer removal. The whole operation takes about two weeks.

A permanent packer is removed using a packer mill. After milling, the remaining packer parts are retrieved and the well is flushed to remove the debris. A retrievable packer is pulled out together with the tubing and then replaced.

6 NOVEL REMEDIATION TECHNOLOGIES

6.1 CannSeal™

CannSeal™ was developed within a DEMO 2000 Project with the support of Statoil, Eni, Total and Shell in the period of 2005-2009, and was launched by AGR CannSeal AS in 2010. This technology features epoxy-based annular zonal isolation and a specially developed tool for sealant placement, as illustrated in Fig.6. The tool is based on an extension to existing perforating/punching technology to create a channel through the tubing/casing into the annulus. A container device is also incorporated into this tool to deliver a sealant precisely into the perforated interval. This tool allows use of more environmentally friendly sealing materials.

The sealing material used is an epoxy resin with adjustable viscosity, setting temperature, elasticity, etc. An example of this epoxy resin cured in the annular space is shown in Fig.7. The epoxy properties can be tailored both prior to hardening (to optimize deployment) and after hardening (to enhance the durability of the seal) according to the needs of the application.

The sealant can be deployed either in an open annulus or in a gravel pack. The treatment effectively seals off unwanted fluid flow behind liners, tubing and screens by placing a solid external annular plug. Other annulus sealing/repair applications, such as placing a plug just above a leaking packer, are also achievable with the tool. This technology can be also used for plugging & abandonment or could replace the traditional cement squeezing in future.

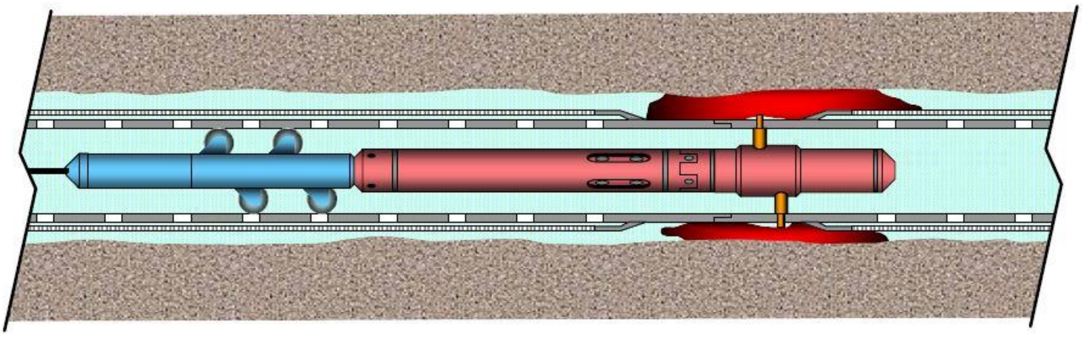

Figure 6: Illustration of Cannseal tool and remediation method.

Figure 7: Cured Cannseal epoxy-resin.

7 CONCLUSION

A wide range of technologies and methods from the oil & gas industry are available that can also be used for the remediation and mitigation of leakages from CO_2 wells. These include:-

- Squeeze cementing - pumping cement slurry into an isolated target interval through perforations in the casing/liner to repair the primary cement job or casing/liner leaks.
- Casing/liner repair by patching, expandable casing, welding, or replacement.
- Sealant technologies for zonal isolation, such as pressure- or temperature-activated sealants, polymer-based gels and different cement systems.
- Well workover and replacement of failed Well Barrier Element.

A summary of the main Well Barrier Elements (WBE) coupled with oil & gas remediation methods & technologies that have been described in this report is presented in Table 2. Note that recurring Well Barrier Elements in the primary and secondary barriers are not distinguished since the remediation methods are independent of which barrier the Well Barrier Element belongs to.

WBE\Method	Squeeze Cementing/ Other Sealants	Casing/Liner repair	Replacement	Cannseal
Formation	x			
Cement	x	x		x
Tubing		x	x	
Casing/Liner	x	x	x	x
Packers	x		x	
Valves	x		x	
Wellhead			x	

Table 2: Summary of the available remediation methods with respect to failed WBEs.

The existing technologies mainly focus on the repair of the annular cement and casing/liner/tubing. Valves, packers, wellhead are examples of Well Barrier Elements that can be replaced. Replacement of any Well Barrier Element in general is not a simple operation and it may involve long downtime and well workover. Some Well Barrier Elements may be difficult to access or even inaccessible, such as formation, or annular cement behind several casings/liners; such leaks may lead to sustained casing pressure and are challenging to repair without plugging the well.

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