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Casing Leak Investigation & Successful Repair by Application of Pressure Activated Liquid Sealant in a Newly Completed Well in Offshore Environment – A Case Study

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Abstract

Well XX-1 is a newly drilled Oil producer well in offshore east coast of India. Lower completion containing Formation Isolation Valve (FIV), Standalone Screens with integral SSD's & swell packers was run in 6" Open Hole & set on screen hanger packer. The FIV, packer & Production casing was then pressure tested to 3000 psi, during which pressure drop of ~15 psi/min & continuous return from secondary annulus ~1 litre/min was observed. The above indicated possible communication between 7" production casing & 9-5/8" surface casing.

The leak depth was investigated using a drillpipe conveyed single run multiple set mechanical packer & it was established that the bottom connection of Cross over below 7" casing hanger pup joint was leaking. Leak in production casing was a critical well integrity threat. Further, the well was designed to be operated on gas lift. There was no immediate remedy available to restore the production casing integrity. It was decided to complete the well and produce with adequate controls without gas lift till the casing leak was repaired. Meanwhile, extensive search and literature review was done & various options to repair the casing leak, both mechanical and chemical, were evaluated. Considering the expensive mechanical repair and associated high uncertainty, Pressure Activated Liquid Sealant was proposed as economical alternative.

The sealant works on the principle of polymerization and cross linking when subject to pressure drop. This sealant process has proven to be a successful long-term repair method for completion equipment. Utilizing a combination of fluid density control and packer fluid compressibility, the sealant was injected into the annulus casing valve then spotted & squeezed into the leak at 2500 psi and allowed to cure under pressure for 80 hrs. The production casing was then successfully pressure tested with both liquid and gas and the integrity was confirmed.

It not only prevented expensive work-over saving > 10 MMUSD, but the quick remedy also allowed the well to be brought online at a higher production rate ~ 1000 BOPD incremental. It has proved to be a reliable solution to well integrity problem.

Introduction:

A newly drilled deviated oil producer well was diagnosed with a casing leak at a very shallow depth. Leak in production casing is a critical well integrity threat. Further, it required specialized remedy to withstand gas lift pressures. Repairing the casing leak was a challenging issue. Mechanical option of repairing the casing leak using a workover rig was expensive, time consuming & had associated high uncertainty. Further, a mechanical repair of the kind of casing patch would have made future workovers and other well operations difficult and impractical. Moreover, since the leak was small (~1 litre/min @ 3000 psi), it was more practical to attempt to cure the leak through chemical means that was operationally much simpler and economical. Extensive search and literature review was done & pressure activated liquid sealant was proposed to cure the casing leak. This paper contains a case study detailing the diagnostic & remedial procedure of casing leak in the well.

Well Construction

Refer Figure 1 for well construction details. Well was drilled out of 26" conductor casing followed by 9-5/8" surface casing and 7" production casing. It was completed in 6" Open Hole with 3.5" Stand Alone Screens with SSD's. Lower completion comprised of, from bottom to top, Float shoe, Landing Nipple, Screens w/blank pipe and swell packers, Formation Isolation Valve & Screen Hanger packer. Upper completion was 3.5" that comprised of Tie back Seal assembly, Bottom No-Go Landing Nipple, Circulation SSD's, GLM's, TRSSSV & Tubing hanger.

Problem statement

After drilling 8-1/2" hole, 7" production casing was run and cemented. Pressure test of 7" production casing was carried out at 4000 psi as per SOP after cement plug bumping. The pressure test indicated an increasing trend of pressure, probably due to the exothermic nature of cement setting process. Refer Figure 2 for casing pressure test. Though casing leak did exist at that stage also, the pressure test chart was misinterpreted as successful casing pressure test and it was decided to proceed to next step of well completion operations. Lower completion was then run on 3-1/2" drillstring & screen hanger packer was set. Pickup & slack off test of 20k lbs was then successfully conducted. However, pressure test of packer attempted from annulus side failed. The packer running tool was then released & Shifting Tool was pulled through FIV to close it. The well was then displaced with filtered kill weight Packer Fluid.

The packer & FIV were again pressure tested against Production casing by closing Blind ram at different pressures of 300, 900, 2000 & 3000 psi in stages. Average pressure drops in the range of 1.5 psi/min, 6 psi/min, 11 psi/min & 15 psi/min were observed at respective pressures. B-Annulus (7" X 9 5/8") was monitored for returns – Observed continuous returns. Further, the returns stopped as soon as the pressure was bled off. The above investigation was repeated with same results. Please refer to Figure 3 for pressure test chart for the above event.

Diagnosis

The above indicated possible communication between 7" production casing & 9-5/8" surface casing.
Possible leak paths were identified as follows:

1) 7" Casing hanger pack-off may not be sealing
2) Packer may not be sealing
3) FIV may be leaking
4) 7" Casing pipe body may be damaged
5) Any of 7" Casing connection may be leaking

7" Casing hanger pack-off seals was successfully tested to 5000 psi and this eliminated any possibility of hanger being the leak path. Refer Figure 4 for integrity test of the casing hanger seals. Being newly drilled, any damage in the 7" casing pipe body was highly unlikely. CBL-VDL-USIT log was then conducted on E-line. Cement quality was good enough not to let any leak in packer or FIV communicate up through the 7" X 9 5/8" annulus.

Only likely possibility left was leak in one (or more) of 7” casing connections.

To further investigate the leak depth, a drillpipe conveyed single run multiple set mechanical packer was run. Surface lines were made up to test both from annulus side and drillstring side. Packer assembly was run on drillpipe & packer was set @ 142m for shallow test. Pipe ram was then closed & 3.5” DP X 7” casing annulus was pressure tested, that failed. No pressure response in drillstring was observed. Further, continuous return from B-annulus was also observed. The above was repeated with same result.
Pressure test was then conducted from drillstring side, which was successful. Further, no returns from flowline & no return from B-annulus were observed. The above indicated a shallow depth casing leak. To pin-point the exact leak depth, the above event was repeated at following depths – 199m, 110m, 62m, 31m, 20m, 21m & 22m. It was finally established that the bottom connection of Cross over below 7” casing hanger pup joint @ 21.9mMDBRT was leaking. Please refer to Figure 5a, 5b, 5c & 5d for pressure test charts attached for the above mentioned sequence of events.

Leak in production casing was a critical well integrity threat. Further, the well was designed to be operated on gas lift. As there was no immediate remedy available to repair the casing leak, it was decided to complete the well and identify suitable remedy later on. Meanwhile, extensive search and literature review was done & various options to repair the casing leak, both mechanical and chemical, were evaluated.

Remedy

The case was discussed for possible solution to the problem and following three steps were discussed.

1) Size and depth of the casing leak was required to be determined: The exact depth was already determined as illustrated in the previous section. For determining the size of leak, it was decided to pressurize the A-annulus in stages of 500 psi from 500 to 2600 psi and establish baseline leak rates.
2) It was required to see if the casing leak is a good candidate for repair with pressure activated sealant. Previous successful job histories provided an approximate upper leak rate range of 8 gal/min. The geometry of the leak was also important. Since it was a casing collar leak, it had a much higher chance of long term success due to the high surface area and low cross sectional area. Further, the well fluid was required to be replaced with heavier brine so that the lighter sealant could be circulated down and spotted across the leak depth for long curing time without the risk of gravity segregation & dilution. Compressibility of fluids in the well was equally important to be taken care of for accurate positioning of sealant slug. Further, it was required to be verified if the sealant plug post curing remains subjected to positive pressure differential during the lifecycle of the well. The sealant plug is not supposed to withstand much of back pressure from the opposite side of the seal.
3) Proper execution of the job was equally important. A job program was required to be prepared with all contingencies and hazards taken care of including pre-job well preparations. It was required to be precisely executed to place the sealant across the leak site, force it into the leak, activate the sealant & hold pressure for at least 3 days for proper sealant curing.

Execution

Leak was established at the bottom connection of Cross over below 7” casing hanger pup joint @

21.9mMDBRT. The leak point was 2.9 m below the casing hanger landing point. Diagnostics had indicated a leak rate of ~1 liter per minute which was well within the range of desired leak rates for successful repair job. Diagnostics were verified before pumping sealant. Cementing line was made up from Cement pump to A-annulus. B-annulus was kept topped up with sea water and opened to a catch tank. Refer Figure 6 for the surface set up made for job execution.

A-annulus was pressurized in stages of 500 psi from 500 to 2600 psi and the leak rates were measured. Following was the baseline leak rate established:

B-Annulus returns @ leak site pressure differential:

- 550 ml/minute @ 500 psi
- 725 ml/minute @ 1000 psi
- 870 ml/minute @ 1500 psi
- 1025 ml/minute @ 2000 psi
- 1150 ml/minute @ 2600 psi

The sealant selected for this application was water based and had a density which can be adjusted from 8.9 ppg to 17 ppg depending on project requirements. To allow control of the sealant location, 10.1 ppg brine was reverse circulated into the A-annulus taking returns from the tubing. This brine would serve as a foundation for the lighter (9.1 ppg) sealant. The well was isolated from formation by closing production screen SSD's. Entire annulus and tubing volume was displaced to 10.1 ppg packer fluid to ensure uniform fluid environment in the well.

Since the leak was only 2.9 m below the casing valve, the A-annulus fluid compressibility was used to enable placement and controlled squeeze of the sealant pill. Compressibility of annular volume of packer fluid at 1000 psi was 0.52 bbls (7m equivalent) & at 2600 psi was 1.36 bbls (17m equivalent). A 9.1 ppg pressure-activated sealant pill was designed to float on top of the 10.1 ppg packer fluid in the A-annulus. A 3 bbls sealant pill was blended in a cement slurry tank. Please refer to Figure 7 for the picture of sealant before & after blending.
It is recommended to use a triplex pump with a minimum 3" plunger size. The sealant was then pumped using the triplex pump at minimal rate till sealant was spotted at the flow-tee installed just upstream of A-annulus valve. This was done to ensure that line volume doesn't affect compressibility based sealant spotting calculations. Sealant was chased with packer fluid. The sealant pill was then injected into the A-annulus until the leading edge of the sealant contacted the leak location. During sealant displacement the B-Annulus returns were closely monitored to evaluate sealant progress. The A-annulus was pressurized to 1000 psi to activate the sealant in the leak site. The sealant when squeezed through the leak site converts into a ~90 durometer elastomer through polymerization. The sealant is unique in that it only activates when subjected to the shearing action of a significant pressure differential. The end result is something similar to blood coagulating in a cut. The sealant activated instantaneously at the applied pressure differential. At the same time returns through B-Annulus ceased indicating sealant activation. The seal was allowed to cure at 1000 psi pressure for 30 minutes.

The A-annulus pressure was increased at intervals of 500 psi every 30 minutes until 2600 psi (A-annulus test pressure) was reached. Refer Figure 7 for the pressure trend while selant placement and curing. The sealant is designed to break at its weakest point as pressure differential is increased. New sealant that is squeezed through this breakage activates becoming a stronger elastomer bond in the leak site. The sealant was allowed to cure with an A-annulus pressure around 2000 psi for 3.5 days. This cure period allows the sealant to increase in durometer but remaining a flexible solid in the leak site. Tubing, A and B Annulus pressures were continuously monitored during the entire duration of the curing time. Refer

Figure 8. No pressure drop in A-annulus and No pressure build up in B-annulus was observed.

The pressure was then gradually bled down back into the cementing line to zero in stages of 200 psi. Bleeding pressure back into the cementing line ensured that residual amount of sealant remained in the cementing line that will be utilized to be pumped during seal test with gas.

This well was designed to be operated on gas-lift in the future requiring a gas test at 1600 psi. Available gas injection pressure at platform (~1000 psi) was applied into A-annulus. The pressure test was successful with no leak from B-casing. Keeping the gas pressure trapped, sealant was pumped through the cementing line to further compress the gas & build up the pressure to 1600 psi. The pressure of 1600 psi was then locked in A-Annulus and monitored for 1 hr. Compressibility calculations done suggest the gas-liquid contact at 7m & 4.6m at 1000psi & 1600 psi respectively in A-annulus, both deeper that the repaired leak depth at 2.9m. Thus, the liquid level remained below the leak location and repaired area remained exposed to 1000 psi & 1600 psi gas pressure. After 1 hour successful test was obtained the A-annulus was bled to zero. Refer Figure 9 containing the pressure chart for the above mentioned event.
Sealant was then circulated out of the well through forward circulation by pumping base oil down the tubing till SSD depth & production screens SSD's were opened in preparation for a return to normal production.
Post casing leak repair job, the well was brought online on self at 5000 BLPD. The well was later brought on gas lift and has been flowing well since the job.

Conclusions

1. Using pressure-activated sealant to repair casing leaks resulted in significant cost savings – prevented expensive workover saving > 10 MMUSD.
2. Possibly avoided well abandonment – leak in production casing was a critical well integrity issue.
3. Returned well to production sooner – quick remedy enabled immediate production protection from the well.
4. Proved to be reliable solution to well integrity problem – leak has been successfully cured and well is on gas lifted production for last 6 months.

Acknowledgements

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Nomenclature

FIV = Formation Isolation Valve
SSD = Sliding Side Door
psi = Pounds per Square Inch
MMUSD = million United States Dollars
BOPD = Barrels of Oil Per Day
GLM = Gaslift Mandrel
TRSSSV = Tubing Retrievable Sub Surface Safety Valve
A-annulus = 3-1/2" Tubing x 7" Production casing annulus
B-annulus = 7" Production casing x 9-5/8" Surface Casing annulus
CBL-VDL-USIT = Cement Bond Log – Variable Density Log – Ultra Sonic Imaging Tool
E-line = Electric Line

MDBRT = Measured Depth Below Rotary Table
ppg = Pounds Per Gallon

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2. Humphrey, Kathryn J, BP, Chambers, Michael J, BP America Inc., Huebel, Ross M, BP, Cary, D. Neil, Seal-Tite International; Rigless Repair of Subsea Tubing Leaks Using Pressure-Activated Sealant. Paper SPE- 23941 presented at the 2013 Offshore Technology Conference held in Houston, Texas, USA, 6–9 May 2013.

Figures

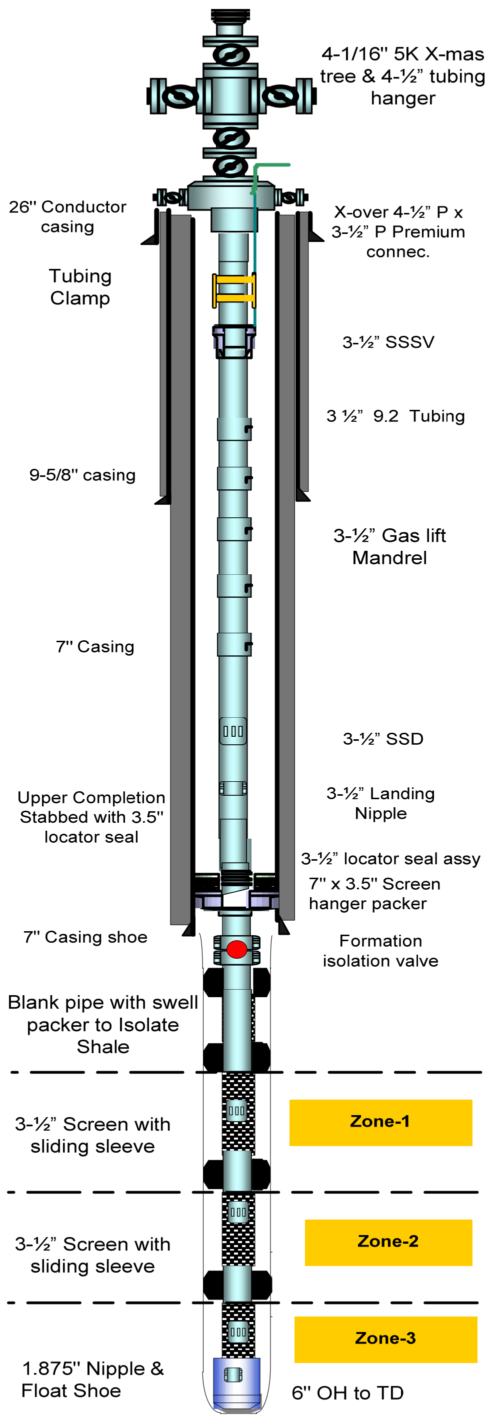

Figure 1: Well Construction

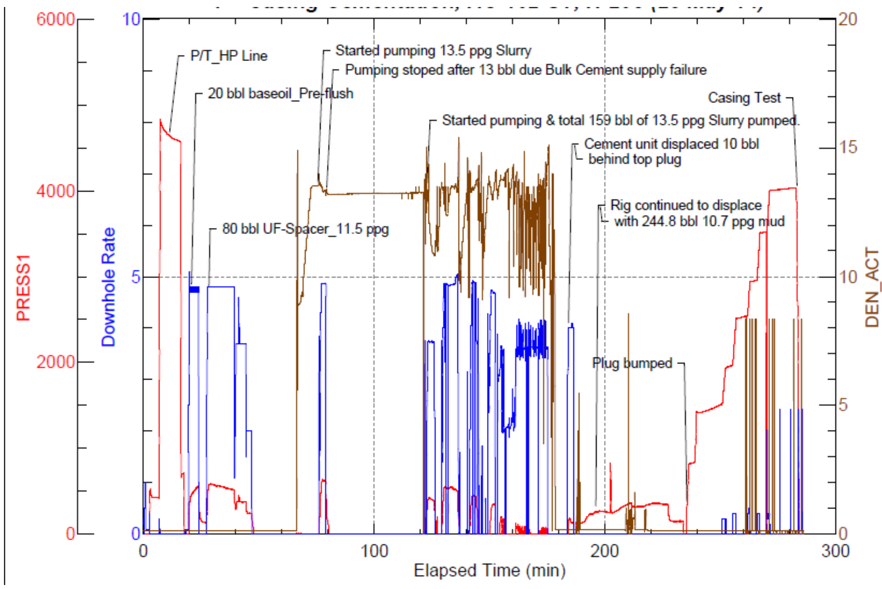

Figure 2: Pressure test of 7" production casing @4000 psi after cement plug bumping

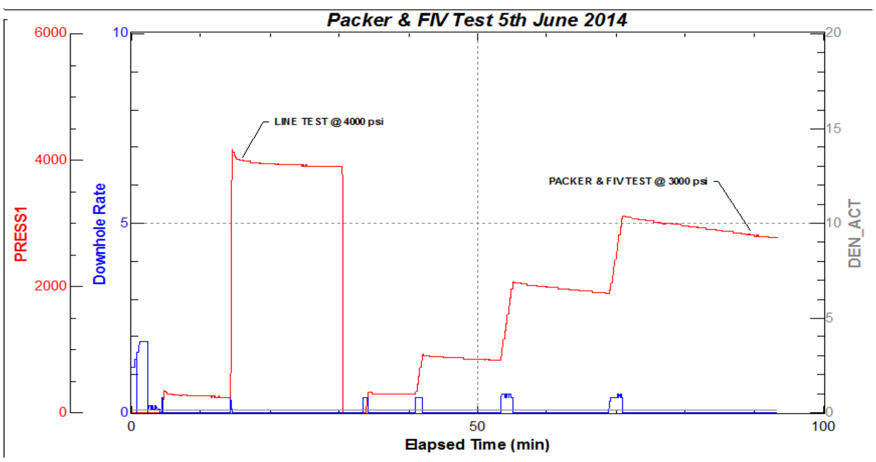

Figure 3: Leak observed while testing Packer & FIV

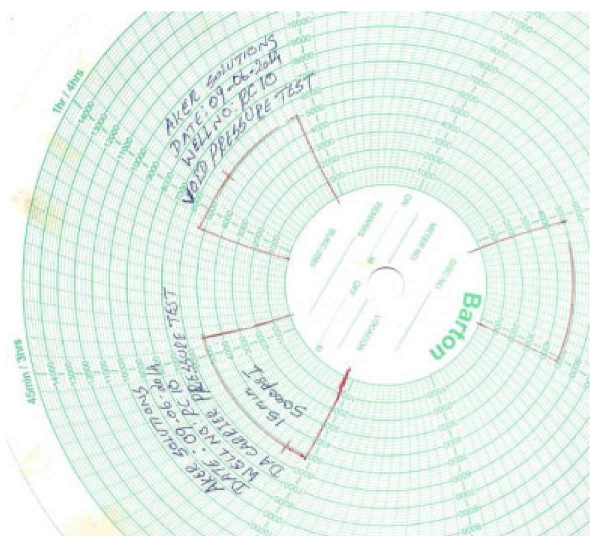

Figure 4: Integrity test of 7" casing hanger pack-off.

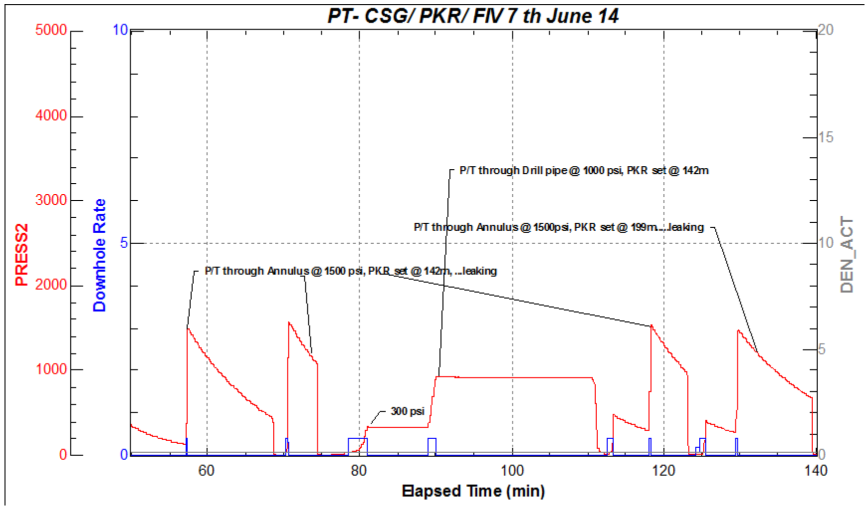

Figure 5a: Pressure test with packer set @ 142m

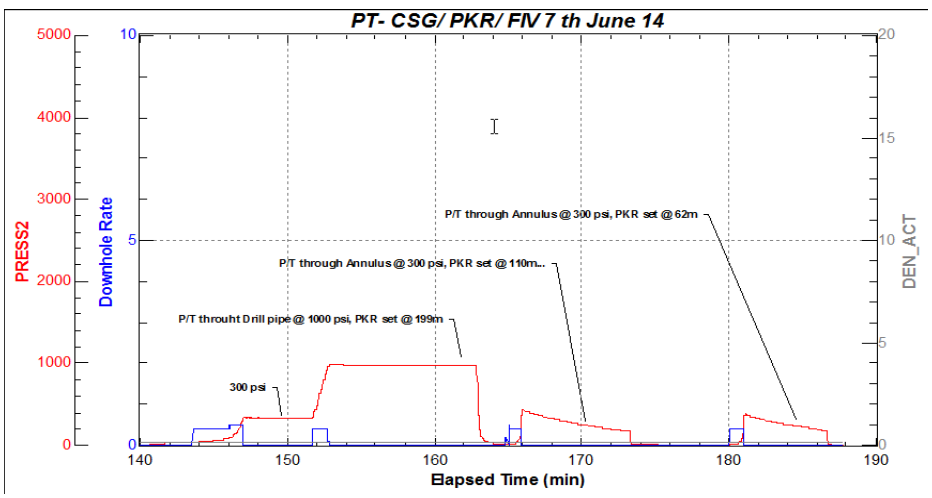

Figure 5b: Pressure test with packer set @ 199m, 110m & 62m

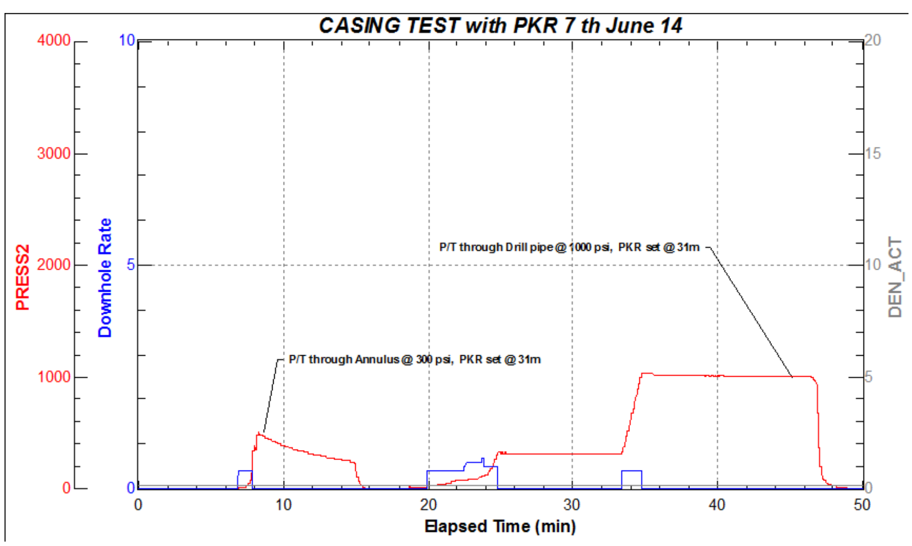

Figure 5c: Pressure test with packer set @ 31m

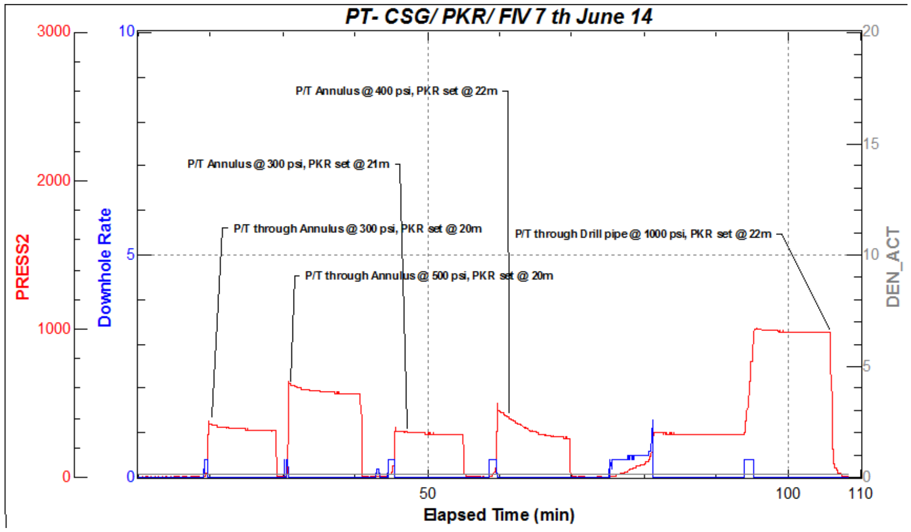

Figure 5d: Pressure test with packer set @ 20m, 21m & 22m

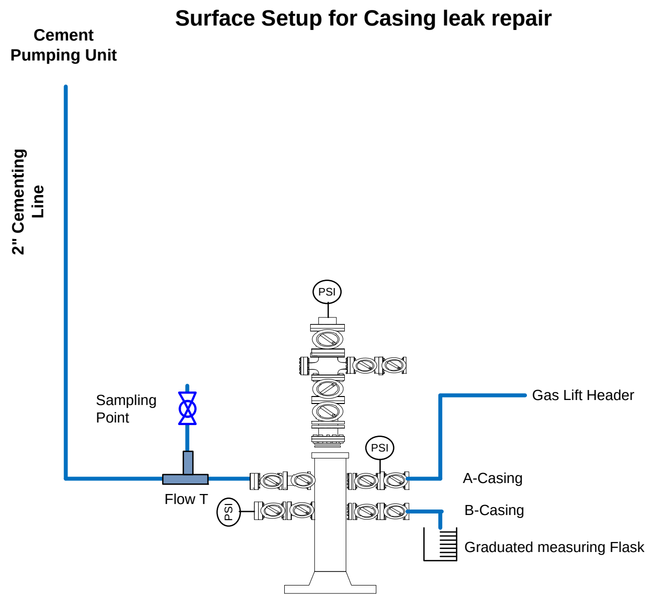

Figure 6: Surface setup for casing leak repair treatment.

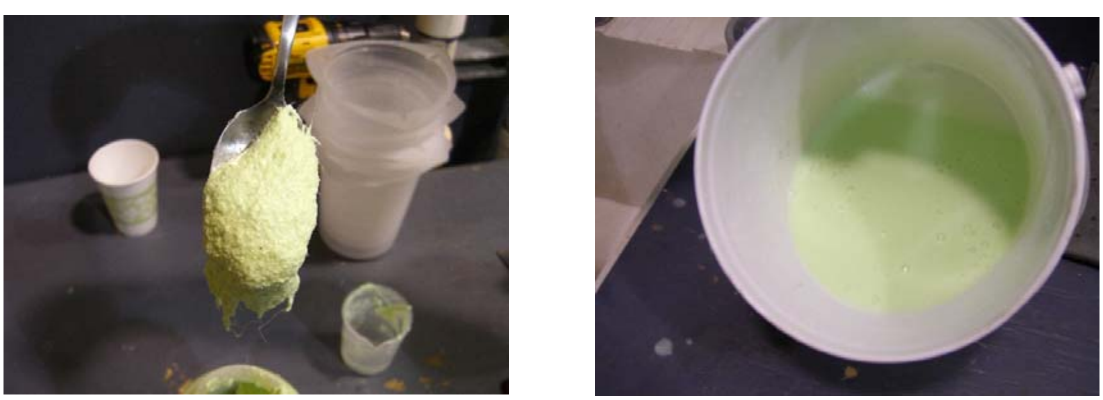

Figure 7: Sealant concentrate before blended with seawater (left) and the blended product (right)

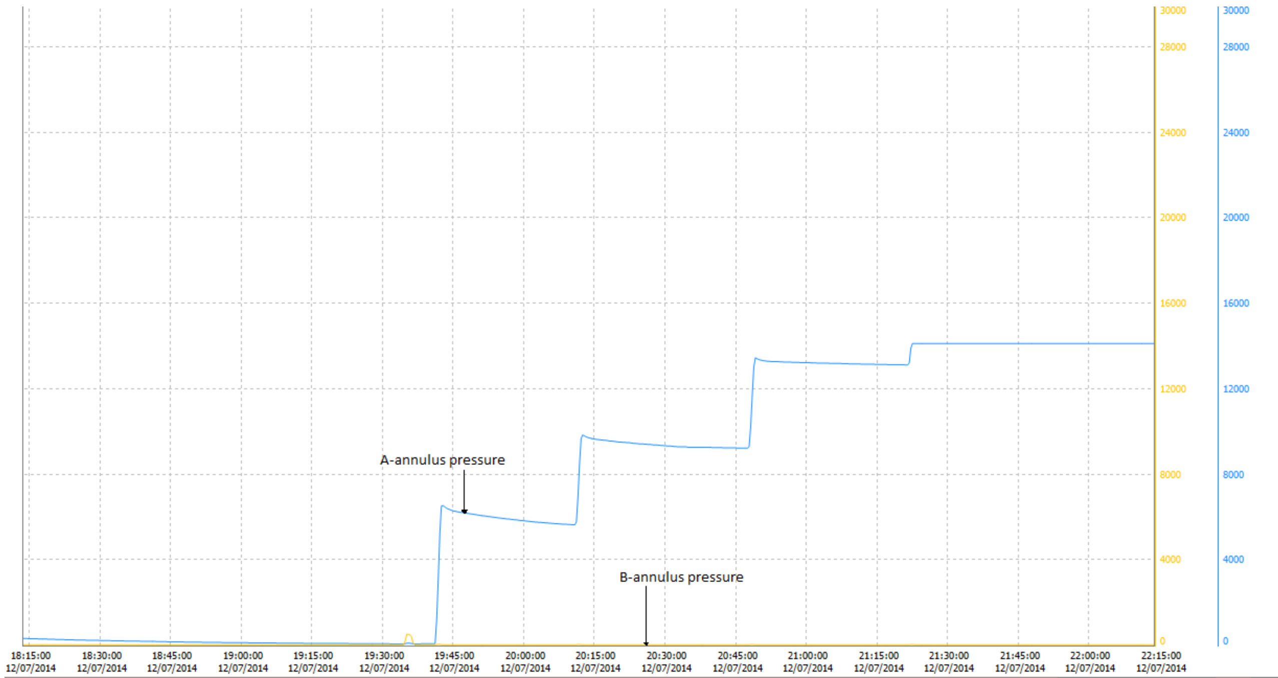

Figure 8: Sealant Placement & curing in pressure steps of 1000 psi till 2600 psi

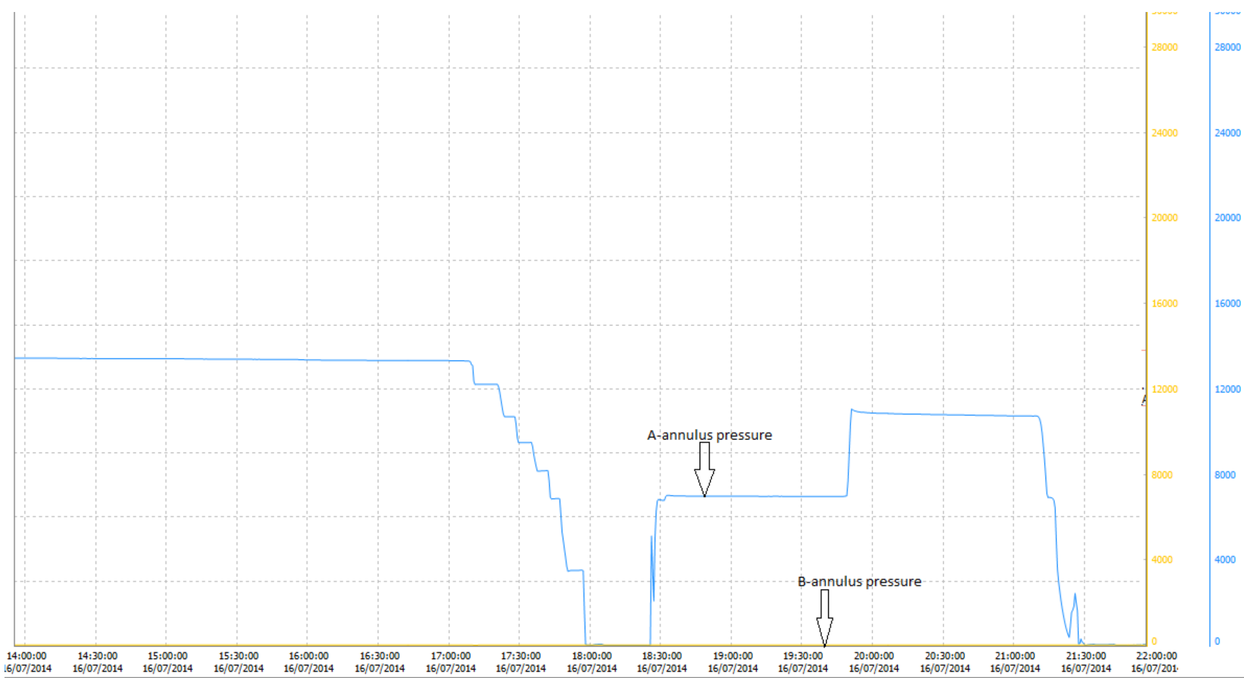

Figure 9: Pressure bled off after completion of curing time & subsequent Seal test with gas at 1000 psi & 1600 psi