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Microannulus Leaks Repaired with Pressure-Activated Sealant

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Abstract

Sustained casing pressure is a serious problem that is prevalent in most of the oil producing regions of the world. Annular pressure can be a significant safety hazard and, on a number of occasions, has resulted in blowouts. Sustained casing pressure results from the migration of fluids in the annulus. The most common path for migration of fluids is through channels in the annular cement. To safely and economically eliminate sustained casing pressure on a well in the Gulf of Mexico, W& T Offshore, Inc. utilized an injectable pressure-activated sealant technology to seal channels in the annular cement of their well and eliminate the casing pressure. The mechanical integrity of the well was restored, saving over $1,000,000 compared to a conventional rig workover.

Introduction

Migration of fluids through the annuli of wellbores can result in a condition known as “sustained casing pressure” or “SCP”. SCP is pressure that rebuilds in the annulus after being bled down.[1]

With age, the integrity of all wellbores deteriorate. Cracks and fissures develop in the annular cement due to a number of factors related to cement composition, thermal stress, hydraulic stress, compaction, wellbore tubulars, and the downhole environment. The most significant cause of sustained casing pressure in the outer casing strings is a poor cement bond that results in the development of cracks and annular channels.[2] The cracks and microannulus channels through the cement provide a path for high-pressure fluids to migrate from deeper strata to low-pressure strata or to the surface.

If left uncontrolled, SCP represents an ongoing safety hazard and can cause serious or immediate harm or damage to human life, the marine and coastal environment, and property.[3] A significant flow of high-pressure fluids to a low-pressure strata results in an underground blowout. A significant flow of high-pressure fluids to the surface results in an irreducible casing pressure at the wellhead and the potential for catastrophic failure of wellbore integrity.

SCP is a pervasive problem for the oil and gas industry. According to the records of the Minerals Management Service (“MMS”) of the United States Department of the Interior, SCP affects over 8,000 wells in the Gulf of Mexico.[4]

Conventional Remediation Risks

The conventional remedy for outer casing SCP is to perform an expensive and risky workover of the well using a rig. In the past, the industry has been reluctant to cure SCP problems on most wells based on a cost/benefit analysis of the relative risks. A conventional rig workover is a dangerous operation. Personnel can be injured or killed. Equipment can be damaged or destroyed. Blowouts or spills pose a significant environmental risk. The costs and risks of the conventional rig workover solution exceed the costs and risks associated with the current sustained casing pressure practices.[5]

The rig workover procedure requires removal of the tubing and injection or squeezing cement in an attempt to block the cracks and channels through the annular cement. Depending on the location, porosity and permeability of the cracks and channels, the cement squeeze may or may not be successful in sealing the paths for the migration of the fluid through the annulus. A cement squeeze is a costly procedure with a questionable probability of success.

Cost-Effective Alternative

As an alternative to a rig workover, a safe, cost-effective sealant process has been developed that eliminates the SCP by sealing the annular channels that provide the paths for the migration of the fluid through the annulus. Tests and actual job histories have shown that this sealant can be injected into the annular channels even after attempted injection with normal mud / cement mixtures have failed.

Pressure Activated Sealant.

As background, a critical element of the described repair method is a unique pressure activated sealant that is specifically designed to seal leaks in wells and severe environment hydraulic systems. The sealant is unique in that a pressure drop through a leak site causes the sealant fluid to polymerize into a flexible solid seal only at the leak site. Leak sealant operations have been performed on the following systems: subsurface safety valves; wellhead pack-off and hanger seals; casing and tubing packers, sleeves and connections; wellhead valves; riser connectors; umbilical lines, pipelines; and pressure due to annular cement leaks.

Pressure Activated.

The sealant reaction is analogous to blood coagulating at a cut. The sealants remain fluid until the sealant is released through a leak site. Only at the point of differential pressure, through the leak site, will the sealant reaction occur. The monomers and polymers in the formula are cross-linked by the polymerizing chemicals. As the reaction proceeds, the polymerized sealant plates out on the edges of the leak site and, simultaneously links across the leak site to seal the leak. The resulting seal is a flexible bond across the leak. The remainder of the sealant will remain fluid and will not clog the hydraulic systems or well.

Microannulus Sealant.

As an extension of the prior success using the pressure-activated sealant concept on hardware leaks, a new sealant formula and injection process were developed to seal the cracks and microchannels that often develop in the annular cement. Due to the fact that the sealant is a solution, the sealant is able to penetrate deep into the tight pore spaces in the cement. Penetration into micron size pore spaces is possible.

The concept was to slowly inject sealant into the annulus so as to penetrate the channels and cracks in the cement to as great a depth as possible without activating the polymerization process of the sealant. The injection would continue until the injection pressure equalizes with the pressure of the gases and fluids rising through the damaged cement. Then, the pressure would be released from the annulus to allow the injected sealant solution to be subjected to a pressure drop in the direction of the leak, so as to activate the polymerization process, causing the sealant to solidify and seal the cracks and channels.

Laboratory Testing

To test the annulus leak sealing concept, Cementing Solutions, Inc. ("CSI") developed a series of appropriate simulations of annulus leaks.

Test Fixture.

At their facility in Houston, Texas, CSI constructed a test fixture of two concentric casing strings—eight and five-eights and four inches in diameter—welded together with base and top plates, and tested to a 5000 psi pressure rating.

Figure 1: Microannulus Test Fixture

Cement was pumped into the annular space of the test fixture between the inner and outer casing strings. While the cement was curing, pressure was maintained in the inner string. Once the cement is cured, the inner casing pressure was released, creating an annular void space between the inner casing and the cement sheath. The release of pressure resulted in the creation of cracks and fissures in the cement.

Figure 2: Annular Cross-Section – Test Fixture

Microannulus Permeability.

The permeability of the damaged cement was verified by pumping nitrogen through the test fixture. The permeability of the 4-foot test fixture was calculated by using the generalized Darcy flow equation for Linear Flow in a gas regime as follows:

$$q_g = \frac{1.127Ak\,(P_1^2 - P_2^2)}{T\ z\,\mu\,L}$$

q_g = Gas Flow
A = Cross Sectional Area
k = Permeability
$P_1^2 - P_2^2$ = Pressure drop across sample
T = Sample Temperature
z = Compressibility Factor
= Viscosity
L = Sample Length

This formula rearranged to calculate the permeability is as follows:

$$k = \frac{q_g\ \ T\ z\ \mu\ L}{A\ (P_1 - P_2^2)}$$

Test Procedure.

The procedure used to seal the microannular cracks and fissures in the simulated annulus was as follows:

1. A leak rate from the bottom of the test fixture to the top of the test fixture was established at a pressure of 2000 psi. The initial permeability was calculated as 605 md.
2. Nitrogen was then pumped into the top of the test fixture to displace any gas or fluid from the microannulus cracks and fissures. Pressure was bled through bottom of test fixture at 0 psi.
3. Liquid sealant was atomized into nitrogen gas stream and the foamed sealant was injected into top of test fixture at increasing pressures.
4. Pressure was increased to 5000 psi while venting the the bottom of the test fixture. (Increasing back-pressure through the test fixture indicated that sealant was polymerizing and sealing channels through the cement.
5. Maintained 5000 psi on top of test fixture while venting bottom of the test fixture.
6. When injection of nitrogen/sealant mixture effectively ceased, pressure was maintained at 5000 psi and monitored for 24 hours.
7. After monitoring for 24 hours with minimal additional injection, pressure on top of test fixture was released and pressure increased on the bottom of the test fixture to 5000 psi (to simulate production reservoir pressure).
8. Calculated permeability through the treated annulus from bottom to top.
9. Verified no flow through annulus from bottom to top of test fixture.

Post-Test Permeability.

After the sealant procedure was implemented and the microannulus channels were sealed, the permeability through the treated annulus was calculated. The summary of results is as follows:

Table 1

Pre-treatment permeability (4-foot test annulus):	605.0 md
Post-treatment permeability (4-foot test annulus):	1.6 md
Permeability-Competent cement:	1.8 md
Actual Flow Reduction (4-foot test annulus):	99.70%
Estimated Flow Reduction (100 foot actual annulus):	99.90%
Estimated Flow Reduction (200 foot actual annulus):	99.96%

As shown by the summary of results, the treated annulus had integrity equal to or better than competent cement.

Test Conclusions.

As shown by the permeability calculations, once treated with the sealant process, the annulus has the same integrity as a just-completed properly implemented cement job on a new wellbore. The test results show that the sealant process sealed the annular cracks and fissures and the only post-treatment communications was through the cement matrix.

W&T's Microannulus Leak Repair

A good example of the benefits of the pressure-activated sealant solution over a traditional rig repair of a sustained casing pressure problem can be seen in an operation performed in the Gulf of Mexico for W&T Offshore.

Well Background.

The South Timbalier 203 B-2 well was originally drilled by a large independent oil company. The prior operator completed the well in November, 1991 with a total depth of 14,310'. The casing program consisted of 30" drive pipe, 20" surface, 13 3/8" & 9 5/8" intermediate, and 7" production casing. The casing string characteristics are listed on Table 2. The ST 203 B-2 well had experienced a sustained casing pressure ("SCP") problem for several years in the 13 3/8" x 7 5/8" annulus.

Well Restoration.

During 2002, W&T negotiated the purchase of the ST 203 B-2 as part of a package of wells. W&T needed to evaluate which of the purchased wells to permanently abandon. The cost and timing of abandoning certain wells in the package greatly affected the value of the package. By eliminating the SCP problem and restoring the well to a "no risk" condition, W&T could defer the abandonment of the B-2 well pending review of all wells. By grouping a number of abandonments into one continuous operation, W&T could save $150,000+ in mobe/demobe costs per well.

SCP Remediation Alternatives.

Reducing the abandonment mobe costs would be of little consolation if the only means of curing the SCP was a rig workover. A conventional workover solution to eliminating the SCP would have cost $1,000,000 plus a $200,000+ mobe cost. As an alternative, in August, 2002, W&T contacted Seal-Tite to evaluate and possibly repair the microannulus leaks so as to eliminate the SCP problem and restore the well to a "no risk" condition.

Leak Analysis.

Diagnostics indicated that the pressure source was most likely a zone at the 13 3/8" casing shoe, traveling to the surface via annular channels. When bled to zero, the pressure would increase to 1015 psi within ten (10) minutes. A sustained flow through the annular channels of approximately 1.6 gallons per hour was recorded.

The diagnostics indicated a stabilized fluid feed-in rate of 100 ml/min, and the ability to pump into the microannulus at 2 liters/hour at 1200 psi, increasing to 17 liters/hour at 2500 psi. Analysis of the pressure diagnostics for all strings indicates that the pressure source for the subject annulus was most likely a reservoir close to the 13 3/8" shoe, traveling up the annulus via "microannulus channels". The observed pressure is very similar to the pressure expected in a reservoir at that depth.

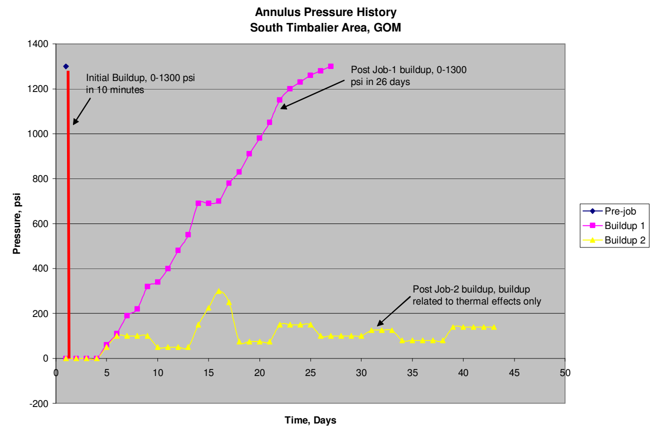
Work Summary.

In October, 2002 a sealant technician was mobilized to the platform. The procedure involved bleeding the annulus to zero and then slowly atomizing a customized blend of sealant into the annulus. Injection continued over the space of six days, interspersed by bleed-off periods to begin sealant activation. A total of 30 gallons of sealant was successfully injected into the annular area, at a maximum injection pressure of 2500 psi. Nitrogen pressure was left on the annulus to allow the sealant to cure.

After 3 days the pressure was released and the casing vented for one hour. A 7-day chart was placed on the casing to monitor the pressure increase. Over the course of 27 days the casing pressure slowly built back up to 1300 psi. This corresponds to the initial buildup rate of 3 hours, for a reduction of 99.5%.

In November 2002 a technician was mobilized to perform a second sealant application. The annulus pressure was again bled to zero. Additional sealant was then injected into the annulus and allowed to cure. The pressure was bled off and monitored. After 43 days the casing pressure of 75-300 psi has been observed to fluctuate according to thermal effects, which is expected due to a fluid packed annulus. No sustained feed-in has been recorded.

Figure 3: Annulus Pressure History



Conclusion-W&T Well.

The pressure-activated sealant procedures have effectively sealed the annular channels in the South Timbalier 203 B-2 well. By curing the SCP problem using Seal-Tite, W&T realized a cost savings of $1,000,000 for the actual rig operation plus the $200,000+ mobe/demobe cost per well.

Similar Case Histories

Annular Gas Leak.

A Gulf of Mexico well hadexperienced a sustained casing pressure ("SCP") problem for several years in the 10 3/4"" x 7 5/8" annulus. Diagnostics indicated that the pressure source was most likely a zone at the 10 3/4" casing shoe, traveling to the surface via microannulus channels. When bled to zero, the pressure would increase to 1300 psi within 45 minutes, for an equivalent calculated rate of 7.6 MCF/day.

A conventional workover solution to eliminating the SCP would have cost $750,000. Instead, the operator elected to repair the annular leaks and eliminate the SCP problem using a pressure-activated sealant solution. Using procedures similar to those described for the W&T well, the channels through the annular cement were sealed by the sealant process. After the first operation, the initial feed in rate was calculated to be only 0.042 MCF/Day, a reduction of 99.4%. A second sealant treatment of 20 gallons was then applied and the casing again bled to zero. After 69 days the annulus pressure had built up to 825 psi. This corresponds to a calculated inflow rate of 0.023 MCF/day, a 99.9% reduction in the original inflow rate.

Producing Well with Pressure on Annulus

On a gas-lifted producing well in Angola, a pressure of 520 psi was observed in the annulus between the tubing and 7" and a pressure of 205 psi was observed in the annulus between the 7" and the 9 5/8". The flow up the annuli resulted in a compbined annular fluid flow of 5.5 liters per hour.

To cure the flow, sealant was atomized into both annuli at a pressure of 1000 psi. Once the injection pressure stabilized at 1000 psi, the annulus was vented to atomosphere to activate (polymerize) the sealant. After the sealant procedure was completed, no further pressure was seen on either annulus.

Pressure Experienced During P&A

An onshore Louisiana well was in the plug and abandonment process. After perforating and circulating cement into all strings and monitoring the well for 9 days, the operator found a 130 psi built up in the 7 5/8" and a 220 psi built up in the 13 3/8". The tubing work string and 9 5/8" remained at 0 psi. The pressure buildup in the 7 5/8" and 13 3/8" exhibited the classic signs of a microannulus-type leak.

Diagnostics were performed and an injection rate of 200 ml/min at 3000 psi was established into the 7 5/8", and 400 ml/min at 2700 psi into the 13 3/8".

For the repair operations, sealant was displaced into the 7 5/8" casing using 1/4" control line to spot sealant at the top of cement at 77' below the wellhead. Calculated sealant penetration depth was 3100'. Also, sealant was displaced into the 13 3/8" microannulus leak (TOC at surface) for a calculated sealant penetration depth of 4400'.

After the sealant treatments, the casing pressures in both subject annuli remained at zero, passing the regulatory requirements for a safe and proper P&A.

P&A Well with Pressure on Annulus

A well in the Netherlands had been previously plugged and abandoned. The tubing was cut and capped with cement at 80 m. The 7", 9 5/8" and 13 3/8" casing strings were perforated and cement was circulated to surface. After cement cured, pressure buildup in the 7" x 9 5/8" annulus was observed. The pressure buildup and bleed-off exhibited the classic signs of a microannulus-type leak.

Diagnostics were performed which indicated the ability to inject 10 liters per hour into the problem annulus. Sealant was displaced into the annulus and pressured to 1600 psi. Subsequently pressure was observed on the 9 5/8" x 13 3/8" annulus. Sealant was injected into this annulus as pressurized to 1000 psi. Both annuli were then allowed to cure.

After the sealant treatment, the casing pressure in both the A and the B annuli remained at zero, passing the regulatory requirements for a safe and proper P & A.

Casing Leak

A lead patch on the casing of a gas lifted producing well in Australia was leaking. A leak path had developed from the casing patch to the outside of the casing strings resulting in gas bubbling to the surface around the platform. Using the pressure-activated sealant atomized into gas lift gas, it was possible to create a differential pressure through the leak site, activate the sealant mechanism and cure the leak. A cost saving in excess of US$500,000 was realized by curing the casing leak using the pressure-activated sealant rather than working over the well.

Tubing Leak

On a Gulf of Mexico well, annulus pressure increased to 6000 psi within two days after bleed off. H_2S and CO_2 were in the annulus gas. Diagnostics indicated a connection leak at a depth of 16, 000 feet in the well. Due to the importance of production from the well, the operator did not want to shut-in the well to cure the problem..

The sealant solution was to inject a polymer pill followed by a sealant pill into the annulus. The pills were displaced down the annulus with sodium bromide. The sealant was extruded through the tubing leak into the production gas stream. A differential pressure was maintained across the leak until the leak was sealed.

The tubing leak was repaired without interrupting production. The alternative solution would have been to shut-in the well and conduct a $1,000,000 tubing replacement workover.

Wellhead Hanger Leaks

A large number of old wellheads in Kazakhstan were experiencing wellhead hanger leaks due to the associated H_2S and CO_2 found in the production stream. Leaks were evident in both the primary and secondary hanger seals.

The leaks were cured using a two-step process. First, a two-part resin material was pumped into the hanger voids to re-establish the basic integrity of the seals. Then, to fill in potential leak paths through the resin seals, the pressure-activated sealant was pumped in and polymerized by differential pressure through the void area.

P&Aed Well with Pressure on Annulus

A Gulf of Mexico well was plugged and abandoned with a bridge plug and cement in each (7", 9 5/8", 11 ¾", and 16"). A dry hole tree was installed on the 16" casing. A year after the well was plugged and abandoned, pressure build up was discovered below the tree. The pressure increased with time to the point that remedial action was required to cure the leak. The leak rate calculated from pressure build up data was 8 ml/hour.

Diagnostics were performed on the leak and the technicians were able to establish a fluid injection rate of 30 ml/min @ 1500 psi and 130 ml/min @ 2000 psi through the microannulus channels in the 200 feet of cement in the 16" casing. Control line (1/4" 0.035" WT) was run to the top of cement at 300 ft and a custom blended sealant (brine based) was pump down the control line and injected into the microannulus channels until sufficient sealant was injected to cure the leak. Max allowable casing pressure of 2500 psi was applied to polymerize the sealant. The pressure stabilized at 1850 psi and was held for four days to allow the sealant to cure. The casing pressure was then bled to zero several times to remove the remaining gas from the well until no pressure build up was observed.

The well was taken off the operator's rig schedule after the successful sealant operation.

Risk / Economic Benefits

In the final analysis, what actions should be taken to address the problem of sustained casing pressure are a function of the benefits of maintaining a well in a condition with pressure on the casing versus the costs and risks of attempting to eliminate the casing pressure.

Risk Benefits.

A major impediment to addressing the sustained casing pressure problem is that the risks associated with curing the problem may be greater than the risks of ignoring the problem. A conventional rig workover is a risky operation. In contrast, the described sealant process can be performed using only two technicians and very little equipment. No rig is needed. Thus, sustained casing pressure can be eliminated and the risks of injury to personnel or damage to equipment and the environment are reduced.

Economic Benefits.

Typical expenditures for annular leak workovers on similar wells have been in the range of $500,000 to $1,500,000. Using the described pressure-activated sealant technology, the total cost is approximately $75,000 - roughly a 90% reduction.

Proposed API Recommended Practices.

The question is: "When is pressure on the casing an unacceptable risk?" This question was posed in comments included in a letter dated March 5, 2002 from the Offshore Operators Committee ("OOC") to the Minerals Management Service ("MMS").[6] The OOC was commenting on proposed rule to amend regulations in Subpart E dealing with sustained casing pressure in oil and gas wells on the outercontinental shelf.[7] Among the comments by the OOC to the MMS, the OOC proposed a technical and risk based analysis of the risk and cost of addressing the SCP issue. As a result of discussions between the MMS and the OOC, the API is conducting a study of the issue and will be proposing Recommended Practices ("RP") on casing pressure. Issuance of the new regulations has been postponed pending the outcome of the API study.

Further information on assessing the risks associated with sustained casing pressure can be found in a report prepared for the MMS in October, 2000, addressing the risks of temporarily abandoned or shut-in wells.[8]

Conclusions

Based on the described laboratory testing and field sealant operations, the use of a pressure-activated sealant technology to seal microannulus channels and eliminate the casing pressure is a safe and cost-effective alternative to a conventional rig workover. The benefits of the sealant technology significantly lower the cost/benefit threshold to remediating the pervasive SCP problem.

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SPE Metric Conversions

psi x 6.894 757	E+00 = kPa
in x 2.54*	E-02 = m
ft x 3.048*	E-01 = m
mi x 1.609344	E+00 = km

All SI Metric Conversion Factors can be found at:
www.spe.org/spe/jsp/basic/0,,1104_1732,00.html

Acronyms and Abbreviations

A = Cross Sectional Area
CO_2 = Carbon Dioxide
CSI = Cementing Solutions. Inc.
H_2S = Hydrogen Sulfide
" = inches
k = Permeability
L = Sample Length
md = millidarcies
MMS = Minerals Management Service, United P_1^2-
P_2^2 = Pressure drop across sample
q_g = Gas Flow
SCP = Sustained Casing Pressure
States Department of Interior
T = Sample Temperature
z = Compressibility Factor
µ = Viscosity

Table 2

Casing String	Shoe Depth	Burst	Collapse	Cement Info
30"	254 ft	-		Drive Pipe
20"	1010'			Details unknown – reported to surface
13 3/8"", 68#/ft N80	4499'	5020 psi	1950 psi	Details unknown – reported to surface
9 5/8"", 47 #/ft S95	11,371'	8150 psi	5080 psi	Details unknown – reported to surface
7" 32#/ft P-110 LT&C	14,200'	11640 psi	10760 psi	Details unknown – reported to surface

References

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8 Nichol, J.R. and Kariyawasam, S.N.; Risk Assessment of Termorarily Abandoned or Shut-in Wells, a Final Report prepared for the MMS pursuant to Contract No. 1435-01-99-RP-3995