OTC 23941-MS

Rigless Repair of Subsea Tubing Leaks Using Pressure Activated Sealant

D. Neil Cary, SPE, Seal-Tite International
Michael J. Chambers, SPE, BP
Kathryn J. Humphrey PE, SPE, BP
Ross M. Huebel, SPE, BP

This paper was prepared for presentation at the Offshore Technology Conference held in Houston, Texas, USA, 6–9 May 2013.

Abstract
BP policy specifies requirements for well barrier management throughout the life cycle of a well. Well barriers are specifically required to isolate energy sources within the earth from each other, the surface environment, and people. Annulus pressure management is fundamental to maintaining healthy well barriers and active monitoring assures the barriers are in place. In subsea wells, the only annulus that can be monitored in real time is between the tubing and production casing (aka A-annulus). When an anomaly is detected in the A-annulus, then a diagnostics and intervention program must be implemented to repair the suspected well integrity issue. In deepwater environments, repairing a well integrity issue with a rig can be costly and the traditional tools for well diagnostics and repair, such as wireline and coil tubing, are complex to deploy into subsea completions. Alternatives such as pressure-activated sealants have a proven track record repairing well integrity issues in dry tree wells. This technology is now being deployed to repair well integrity issues in subsea wells.

This paper presents two case studies where pressure-activated sealants were used to successfully repair tubing by A-annulus (T x A) communication in a subsea wells. BP had utilized this technology with great success in its Alaska fields (SPE Papers 10895 and 120978) and saw an opportunity to extend those learnings to subsea wells. These operations utilized innovative delivery techniques to enable sealant injection, placement, and activation downhole. Rigorous testing, simulation, and planning prior to starting the job increased confidence in the operational technique and reduced safety risks to the environment and the wells. Both efforts resulted in a successful repair of the well integrity issue.

There were several benefits for using a pressure-activated sealant for these two interventions. The less complex non-rig interventions presented fewer safety and environmental risks and were completed with no HSE incidents. The non-rig repairs were completed for a small fraction of the cost of a conventional rig repair and rig time was kept available for drilling and completing new wells. Given its effectiveness and these benefits, the application of this technology may be especially useful for subsea wells with marginal remaining reserves where the relatively lower cost may help to optimize productive life and ultimate recovery. The integrity of a sealant repair can be monitored during the life of the well just like a conventional rig repair and a sealant repair does not preclude the ability to perform a conventional rig repair in the future.

Introduction
Two case histories are discussed in this paper; the first well is an example where one-way annulus-to-tubing communication was repaired using pressure-activated sealant in 2009. The second well used a similar deployment method to repair two-way annulus-to-tubing communication with pressure-activated sealant in 2012.

Case Study – Well "A"
Well A has a subsea horizontal tree with a frac-pack completion for sand control. Pressures and temperatures are monitored in real time at the tree for both tubing and annulus and downhole in the tubing with bottomhole gauges. The well produces through a flowline to the production facility two miles away. Water depth is 6830 ft.

In September 2008, the production facility was evacuated for hurricanes Gustav and Ike and all wells were shut-in and safed out. After returning to the platform, the A-annulus pressures on all the wells were low, as expected, because of cooling due to the extended shut-in period and the low ambient temperature of seawater at great depth. As the wells were restarted, annulus pressures began to increase normally due to temperature rise. In Well A however, annulus pressure only increased for a short period of time before beginning to decrease although annulus temperature continued to rise as the tree warmed up. It quickly became apparent that the pressure behavior was due to a potential well integrity issue and was not related to thermal effects.

Issue Identification

The well barriers were quickly examined and tested. The well was shut-in and the SCSSV (surface controlled subsurface safety valve) and the USV (underwater safety valve) passed standard pressure tests. While shut-in, the annulus behavior was stable with only thermal pressure decline, indicating that the tubing and packer were holding pressure and the primary and secondary integrity barriers were in place.

The analysis pursued other potential flow paths, including the annulus methanol (MeOH) fill line, annulus bleed lines, and the potential for a production casing leak. These potential paths either tested fine or proved to be highly improbable. After diligent testing and multiple conversations with the GoM regulatory agency (MMS then, now BSEE), a one-way annulus-to-tubing leak was determined to be the most likely leak path.

- For a potential production casing leak path, pressure versus depth graphs were developed for all possible scenarios of annular fluid density, initial pressures, and leak location to determine if a crossover of pressure envelopes existed. It became impossible to match pressures at any depth between the A and B annuli, eliminating a B-annulus leak as a flow path.
- For potential leak paths to the subsea system (i.e. in the subsea tree, tubing hangar, crown plugs, etc.), a series of subsea pressure tests were conducted and no anomalies were observed. In addition, at the water depth of this well, there is no pressure anywhere in the subsea system as low as the pressure seen in the A-annulus and this leak path was consequently ruled out.
- For a potential production tubing leak, pressures were plotted vs. depth for all observed conditions in both the A-annulus and the tubing and it became apparent that the likely pathway was a one-way leak from the annulus to the tubing. The plot indicated that the leak was deep, possibly right at the packer, but uncertainty existed about how much differential pressure was required to initiate the leak. By testing the SCSSV with higher annulus pressures, it was possible to rule out the possibility of a leak above that point. Therefore, it was concluded that a one-way annulus-to-tubing leak was present above the production packer and below the SCSSV.

Repair Options

At this point, the Well A primary and secondary well barriers were proven to have integrity in the direction of normal reservoir fluids flow. No hydrocarbons were leaking from containment and the well was in compliance with all regulatory standards which address tubing-to-annulus leaks, but not the reverse. After discussions with the regulatory authority, the well was returned to production.

While repair options were developed, the well was managed closely. One-way leaks can become two-way leaks that 1) are usually harder to repair and 2) require the well to be shut-in until the repair is performed. In this case, production was curtailed so that the delta-pressure across the leak point was balanced and therefore minimized the potential for the development of a two-way leak due to erosion. Estimates were made and fine tuned by surveillance of the well behavior until a balance point was found by curtailing approximately 40% of total rate down to ~10 mbod.

The standard approach to these issues is a rig-based repair to pull the production tubing and packer and re-run the upper completion. In this case, BP decided to evaluate the possibility of utilizing a Pressure-Activated Sealant to repair the leak in a non-rig remediation mode. The Vendor evaluated multiple blends of sealant to accommodate the observed leak rate, pressure, temperature and deployment method parameters of this application. Several deployment methods were evaluated, including deployment from the PQ platform through an umbilical, ROV (remote operated vehicle) pumping, subsea bladder, and pumping through a thermoplastic hose from a nearby vessel.

The first option to deliver sealant subsea was through a standard umbilical. The benefit of this method would be that the operation of pumping would be relatively simple as it could be done from the existing production facility with a minimum of additional equipment. Unfortunately, the hydraulic limitations of pumping through a 3 mile, ½” OD umbilical required a less aggressive blend of sealant and increased the risk to plugging the existing subsea production equipment. Delivery of the sealant by ROV was quickly discarded because of the incompatibility of the sealant with ROV intensifiers and centrifugal pumps. The third option to be discarded was trying to tie in to the well with a thermoplastic hose from the MODU (mobile offshore drilling unit) present in the field. Unfortunately, while this thermoplastic ‘downline’ has high burst resistance it is very vulnerable to collapse. The low annulus pressures and high subsea hydrostatic pressures at that depth would have caused the hose to quickly fail.

Stepping back and looking at the physics of the problem, what was ideal was to deploy a heavy sealant into a sub-hydrostatic annulus. The selected method of delivery was to piggyback an umbilical onto the outside of the onsite MODU drilling riser and make a custom fabricated skid to use ambient ocean pressure to deploy sealant into the annulus. Accumulators in the skid with displacement pistons moved the sealant, as opposed to a more conventional pumping system that might have caused the sealant to set. Seawater pressure provided the driving force on the pistons which eliminated the need for a high-volume ROV pump. Sealant would be injected using a "Lube and Bleed" process, utilizing the compression of the large annulus volume to inject approximately 2.5 bbls of sealant for every 2500 psi cycle.

Subsea Skid Development

The subsea delivery system (Figure 1) was designed as a system of eight manifolded accumulators mounted on a typical subsea mud mat. A piston installed in each cylinder allowed filling with sealant on one side and then a power fluid applied on the other side of the piston to force sealant into the well. The skid was configured to allow injection of power fluid by the ROV or by utilizing ambient seawater hydrostatic pressure to drive the piston. Since the well annulus pressure was substantially below ambient hydrostatic, the seawater option was selected as the primary drive for this application.

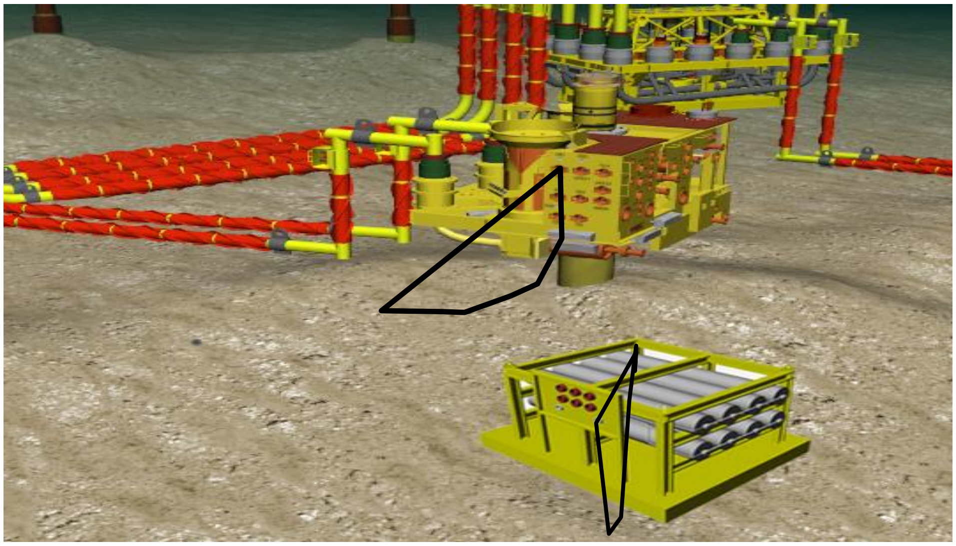

Figure 1. Subsea Delivery Skid

During field development, the project team had the foresight to include a hot stab port providing direct access for fluid injection into the A-annulus. See Figure 2.

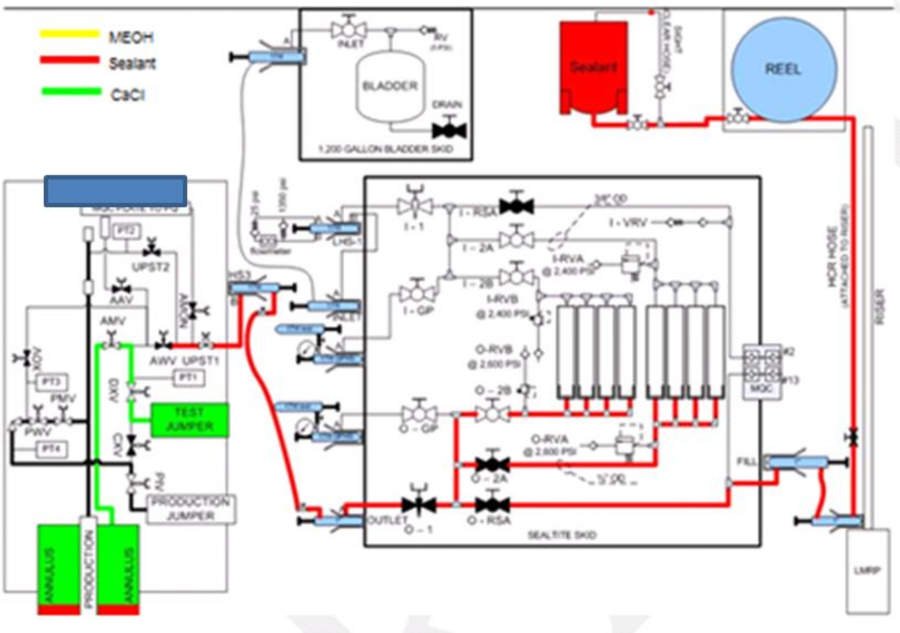

Figure 2. Injection Schematic

This provided the sealant with a flow path that minimized restrictions that could have caused unintentional pressure drops and unwanted sealant activation. The total volume of the eight cylinders was 11 bbls. Since the planned injection volume was 75 bbls, provisions for refill of the cylinders was necessary. It was already known that a MODU would be stationed on the same well template performing drilling operations on an adjacent well. This would allow the MODU to be used as the work platform for sealant blending and storage. A 1” line would be strapped to the drilling riser and serve as the flow conduit from surface to the subsea skid for sealant refill.

Sealant Development

The Pressure-Activated Sealant service company custom blends sealants for each particular application. Based on the well data provided, a low shear, low friction, low dilution, Pressure-Activated Sealant would be required for remediation of this particular leak and delivery procedure. Two possible options for sealant delivery were presented.

Option 1 - Pump the sealant from the platform through 4.4 miles of ½” umbilical. This option was rejected due to the high friction pressures predicted by simulation.

Option 2 - Inject sealant using a remote skid of hydraulic accumulators that would be initially loaded with sealant then lowered to the sea floor. Subsequent refills of the skid would be accomplished by injection through a ~ 7000’ umbilical strapped to the drilling riser. Therefore the focus was to develop a pressure-activated sealant which had the following parameters:

- Able to pump through 7000’ of 1” umbilical with acceptable friction losses,
- Able to fall through approximately 10,000 feet of 10.8 ppg completion ‘packer’ fluid with no significant dilution or separation,
- Maintain acceptable rheology characteristics with subsea temperatures of approximately 38° F,
- Able to pass through two hydraulic couplers and a hot stab with 0.200” ports without creating significant pressure differential and potentially sealing the ports,
- Once reaching the estimated leak location, able to seal an assumed connection leak of approximately 100 ml/min to a 2000 psi pressure differential.

The base sealant selected for further development is a water-based, pressure-activated sealant routinely used for relatively large casing and tubing leaks under similar conditions. After a series of lab modifications, a blend was created suitable for qualification tests.

Fall Tests – To simulate the wellbore, one liter of 12.1 ppg sealant was poured into a 4” x 10’ column of 10.8 ppg $CaCl_2$ brine. See Figure 3. The sealant fell through the brine (upper clear layer) at an average rate of 1 ft/sec and consolidated at the bottom of the column. Sealant integrity was satisfactory with volume loss less than 1%. The Flo-Seal SS is seen at the bottom of the column (the yellow layer). The next tan layer is a gel pad which was originally at the bottom of the tube. The sealant blend displaced this gel pad and pushed to the bottom, indicating the ability to move heavy fluids by gravity settlement.

Flow Loop Tests – To achieve injection into the subsea wellhead, standard hot stab assemblies and subsea hydraulic couplers would be encountered. Flow loops simulating these obstructions were constructed and sealant was pumped through the devices at various rates and pressures to determine plugging behavior. Sealant blends were adjusted until a 200 gallon circulation volume could be achieved with no signs of sealant breakdown or plugging.

Figure 3. Sealant Test Column

Friction Pressure Loss – A second flow loop consisting of 450’ of ½” nylon-lined umbilical was prepared. Sealant was circulated at various rates under subsea temperature conditions (38 F). The sealant exhibited pseudoplastic flow performance with unit friction pressure loss decreasing with increasing pump rate. See Figure 4. This data was used to predict the expected pumping requirements during the repair.

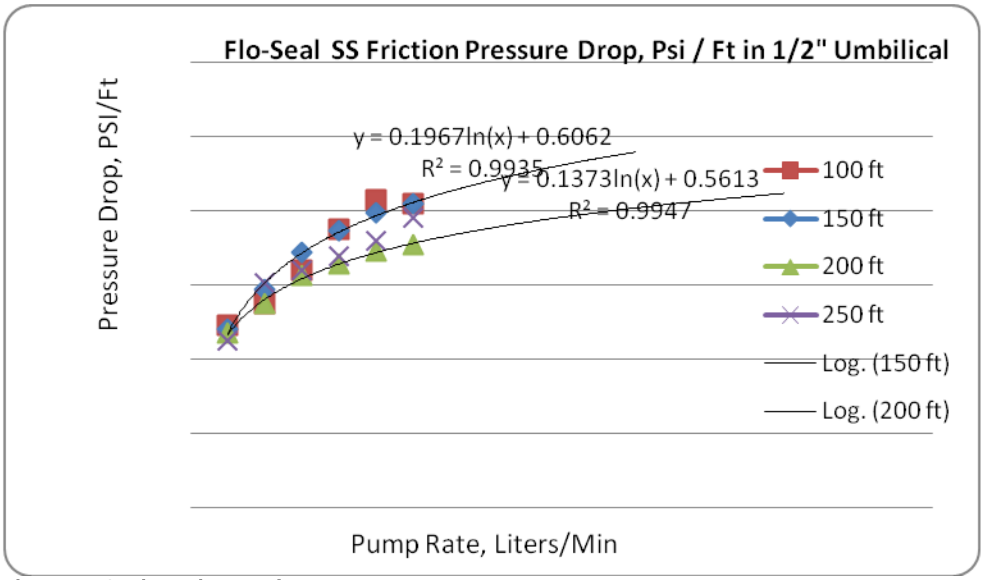

Figure 4. Sealant Flow Performance

Leak Testing – As a final test, a 2 7/8" 8-RD pup joint threaded connection was damaged until the leak conditions were similar to those observed in the target well. The final sealant blend was squeezed into the leak at various pressures and monitored. A successful repair to 3000 psi was achieved, qualifying the sealant for use.

Operation and Results

The job was conducted in 3Q 2009. A total of 32 bbls of pressure-activated sealant were pumped into the Well A annulus without incident. Monitoring of well pressures during the injection cycles indicated that the leak was plugged after the first batch of 10 bbls, however additional sealant was inserted to form an excess of sealant above the leak site in case the leak reactivated. Deviations to program expectations were observed, mainly in barrier testing and higher than expected friction pressures during the sealant skid refill process. These learnings provided valuable data for planning pressure-activated sealant repairs on future wells, for example the Well 2 case history below.

Total cost of the job was < 5% of a rig-based repair and resulted in a sustained rate increase over the integrity-curtailed rate. Well A is still on production more than three years later and the Pressure-Activated Sealant repair is considered a great success. The well is always carefully monitored to verify that the annulus operating envelope delivers a positive pressure from the annulus to the tubing across the former leak site at all flowing and shut-in conditions. This is accomplished by careful attention to procedures that manage annulus pressure by bleeding off or topping-up with MeOH.

Case Study – Well "B"

Well B is a gas well capable of producing approximately 50 mmscfd and 3500 bopd in a water depth of 6934 feet to a floating production facility moored 20 miles away. The well was completed in December 2003 as a dual zone, frac-packed, intelligent well with downhole flow control capped by a vertical subsea tree.

The well developed an integrity issue during a 2011 facility turn-around (TAR). Diagnostics determined the issue to be a two-way communication between the reservoir and A-annulus through a leak either at the production packer or a deep leak in the tubing at or near the packer (T x A communication). This would normally require the well to be shut-in until a rig-based completion repair could be made. Although planning for a rig-based repair was kicked off, the intervention team, based on the previous success repairing Well A in 2009 using pressure-activated sealant, determined that Well B could also be repaired by the application of pressure-activated sealant.

Repair Program

The Well B program was designed to repair the T x A communication by placing sufficient heavy sealant at the bottom of the A-annulus to more than cover the calculated leak location with spare sealant above it to reinstate the seal should it become dislodged. The design also included replacing a percentage the 11.6 ppg Calcium Chloride (CaCl) completion brine with 13.8 ppg Calcium Bromide (CaBr2) brine to allow the A-annulus operating surface pressure to achieve a 200 psi overbalance from annulus to tubing at the leak point to keep the sealant in place. It was especially critical to maintain the overbalance during shut-in periods when the well temperature cooled down, the A-annulus pressure dropped, and the tubing pressure increased. At the same time, the volume of CaBr2 brine was carefully calculated to limit the post-job flowing (well hot) pressure on the A-annulus to stay safely below the Maximum Allowable Wellhead Operating Pressure (MAWOP).

The team calculated how much the Annular Fluid Expansion (AFE) volume due to hot, well-flowing thermal effects would increase the A-annulus pressure with one zone flowing and with two zones flowing based on the historical A-annulus warm-up pressures seen in the well. The maximum Shut-In Tubing Head Pressure (SITHP) was also a critical input into the job design in order to be able to maintain overbalance from annulus to tubing at the leak point. To maintain the post-job A-annulus operating conditions, the plan was to pump 50 barrels of 14.2 ppg sealant to seal the leak at the packer area chased with 150 bbls of viscosified 13.8 ppg CaBr2 brine. The post-job A-annulus operating pressure range allows production operations without the need to bleed pressure when flowing (warm) or to top it up with Methanol (MeOH) when shut-in (cold).

Subsea Skid Development

The lessons learned during the equipment development for the successful 2009 tubing repair project helped to shorten the review process. Since a rig would not be available as a work platform, all work would have to be performed from a Dive Support Vessel. The team selected a system utilizing subsea bladders for sealant storage and a subsea pump for sealant injection. See Figure 5. These would be connected and controlled with an ROV and jumpers. The jumper system made retrieval and replacement of the bladder systems a simple operation.

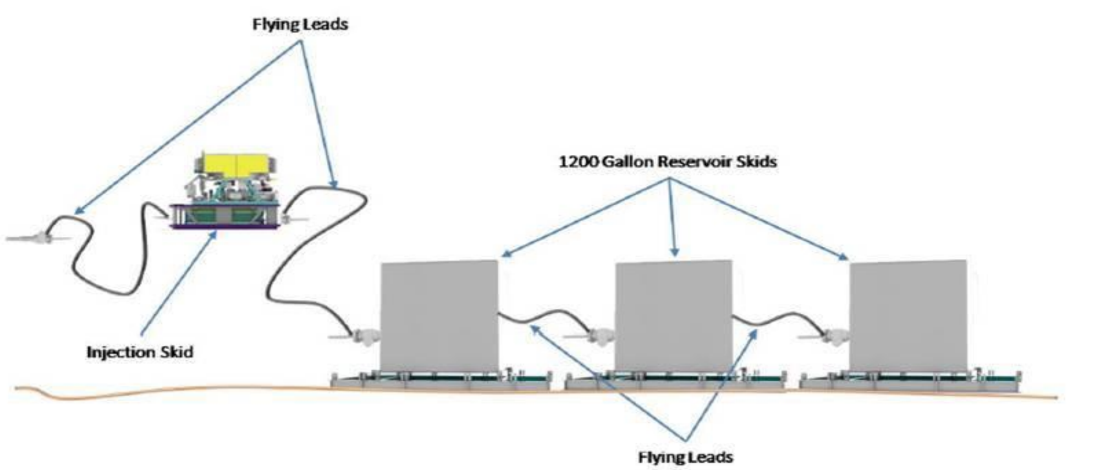

Figure 5. Sealant Injection System

The subsea bladders were standard kit and readily available. The subsea pump was a standard duplex 50 hp model rigged for subsea operation powered by the ROV. During the SIT (stack-up integrity test) with sealant injection, the pump rates were too low to support the project schedule. After upgrading the check valves and other skid internals, the pump rate was increased to a satisfactory level. Connection to the tree was accomplished with specialized subsea intervention equipment integrated with a Tree Running Tool Adapter purpose built for the tree. This provided all the barriers necessary for a safe operation as well as relatively large bore access into the A-annulus.

Sealant Development

The Pressure-Activated Sealant requirement for the Well B project was very similar to the Well A project with the exception of density – 14.2 ppg vs. 12.1 ppg respectively. The density increase was obtained in the lab with no significant change in sealant rheology. The major difference was the requirement for injection of ~ 150 bbls of 13.8 ppg CaBr2 brine to displace lighter brine and any hydrocarbons from the A-annulus. This heavy brine would provide the hydrostatic needed to maintain a reasonable operating envelope.

To be effective this brine would need to fall through the existing 11.7 ppg fluid column and accumulate on top of the sealant pill with no minimal dilution. Blending development and fall tests were performed in a manner similar to the Well A project. The tests qualified a viscosified 13.8 ppg CaBr2 brine with a fall rate of 2 seconds per foot and expected dilution of <1%.

Operation and Results

The operation was conducted in March 2012. Sealant was injected using a "Lube and Bleed" process similar to the Well A operation. The chart below shows the lube and bleed cycles associated with the work and illustrates the consistency of the repair procedure. See Figure 6. Once all injection fluids were in the well, the annulus pressure was increased to fully activate the sealant, then reduced for performance monitoring. The flat line observed on the chart demonstrates the successful repair of the two-way communication.

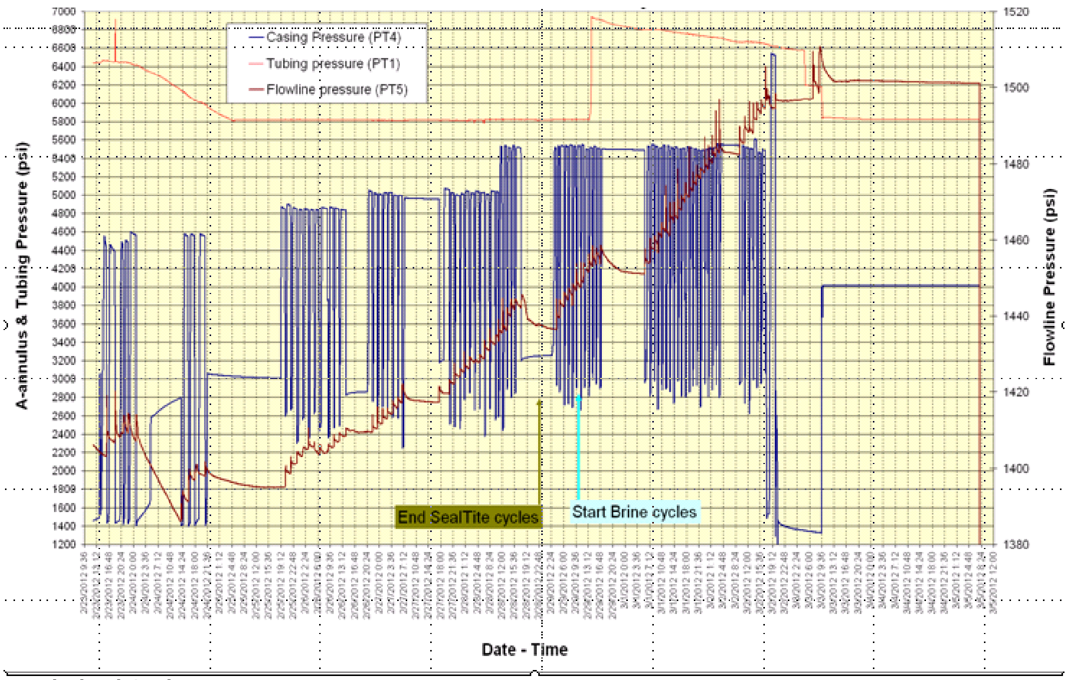

Figure 6. Lube and Bleed Cycles

Near the end of the operation, due to the impending bad weather, a decision was made to stop pumping operations to allow time for testing the well barriers, retrieval of the intervention connection/barrier equipment, and installation of the tree cap before the vessel and crew had to sail off location.

Due to the curtailed repair operation, volume reconciliation revealed that all of the planned 50 bbls of sealant, but only 124 bbls of the planned 150 bbls of viscosified brine had been pumped. As a result of the reduced volume of brine pumped, the cold A-annulus flowing start pressure was increased and the final warm A-annulus operating pressure had to be increased above the planned pressures.

As a result of the job, operation of the well requires a more complex set of instructions to the control room operators to maintain the A-annulus pressures within the temperature range that will maintain the sealant seal. In addition, it is necessary to maintain certain differential pressures across the subsea tree gate valves to prevent them from 'floating' off seat and allowing communication across the tree. The repair operation was a success because Well B is available for production and there is no longer T x A communication.

Conclusions

These two case histories demonstrate that there is now a non-rig option for well integrity repair of certain subsea wells. These successful operations illustrate that a repair to restore production can be performed using pressure-activated sealant deployed without a rig. Pressure-Activated Sealants have a distinct and valuable role to play in the subsea well intervention tool kit; and if carefully developed, tested, and deployed, can produce a cost-effective repair.

Acknowledgments

The authors thank the management of BP and the partners for permission to publish this work. The opinions stated here and the techniques and/or conclusions are those of the author(s) and are not necessarily shared by BP.

Special recognition is made to the team representatives from BP, Seal-Tite International, FMC and Oceaneering. Their input and evaluation of the various options and procedures helped make the pressure activated sealant program a success.

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