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A Return to Production: Subsea Packer Leak Remediation with Pressure-Activated Sealant

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Abstract

The subject well was a subsea producer in the Gulf of Mexico exhibiting pressure loss from its production annulus. An approximately 40 mL/minute (15 psi/hour) leak was identified via logging techniques during a riser-based intervention campaign. This leak was then determined to be past the production packer element set. The well was isolated and the data was reviewed to identify forward options. Though considered, a riser-based intervention was eliminated as an option to restore integrity and return it to production due to technical, scheduling, and economic considerations. Based on these constraints, the operator opted for a sealant remediation approach.

The operator considered multiple sealant products, ultimately working with an engineered sealing solution provider to analyze all available data to evaluate leak characteristics while still progressing other contingencies. From these parameters, a subsea sealant blend tailored to the application was prepared and successfully tested to confirm its suitability for this application. A remediation procedure was then developed to fill subsea bladders with sealant, which were then spotted on the sea floor to inject the sealant into the annulus through a Well Stimulation Tool, Bass Adapter, and Tree Running Tool utilizing an engineered lubricate and bleed volumetric injection technique. Because the annulus was fluid packed, a series of four lube and bleed cycles were performed to compress annular fluid with sealant and bleed back completion fluid to a host platform via the flowline. The selected blend of sealant was approximately 240 kg/m^3 heavier than the packer fluid to facilitate its fall and allow for fluid swap in between cycles. This ensured only annular fluid was being bled off, rather than the injected sealant. After the final cycle, annular pressure was maintained at the maximum threshold for a cure period before testing the repair.

Within one day following the final lube and bleed cycle, the sealant had successfully accumulated on top of the packer as designed. The applied pressure maintained during the cure period had activated the sealant and the annular pressure remained steady over the operator's monitoring period. Given these positive indications, the operator tested the repair with no pressure loss over the test interval. All internal and regulatory requirements had been satisfied, allowing the well to be returned to production.

This sealant was designed to polymerize at the packer elements, which provided the needed pressure differential. This differential triggered a chemical reaction, thereby creating a flexible, solid seal only at the

leak site. This newly formed and tested seal was designed to furnish a seal for the forecasted production profile and excess sealant would remain liquid above the packer. In the event that the leak was to return, the operator would have the capability to perform an annular pressure manipulation sequence from the host platform to activate residual sealant, thus re-establishing integrity.

Introduction

The emergence of subsea exploration and production techniques have provided distinct advantages over dry tree completion systems in the appropriate applications. Identified reserves subject to technical constraints, water depth limitations, production infrastructure, or economic development concerns can become feasibly recoverable by employing subsea completion methodologies. This expanded capability, however, comes at the cost of increased complexity and expense from the initial well development, throughout the productive life of the well, and all the way through to its decommissioning. Due to the nature of subsea completions and the lack of topside infrastructure, well intervention methods have been steadily adapted to suit the operating environment. This paper will present a case study in which one such subsea completion, in 7569 foot water depth, developed a downhole leak, ultimately compromising its barrier integrity and forcing it to cease production under regulatory guidelines.

The subject well was initially drilled and completed in 2004 as a gas/condensate producer, but eventually transitioned to produce mainly oil. The well depleted over time, until in March 2017, the productivity index fell below the acceptable threshold for the operator, and was shut-in to preserve injectivity. In the following months, the operator performed an acid stimulation which initially improved production, but after a few days, the productivity index of the well had fallen back to pre-stimulation levels. In 2018, the target zone was abandoned and the well was recompleted to access a new reservoir.

The newly recompleted well (See Figure 1 below for completion drawing) stayed on production for approximately two years before the operator identified a leak through observed annular pressure loss. The liquid leak rate was estimated to be approximately 58 L/day. This triggered an investigation into the potential leak locations and failure mechanisms, which included eight leak path possibilities:

1. Annular tree valves
2. A-annulus to environment at mudline
3. A-annulus to tubing above SCSSV
4. A-annulus to tubing below SCSSV
5. A-annulus to BS49N reservoir
6. A-annulus to sands behind pipe
7. A-annulus to chemical injection line
8. A-annulus to B-annulus

The leak path from the A-annulus to tubing was initially expected to be near the SCSSV. During diagnostics, when A-annulus pressure was bled down to below tubing pressure, annulus pressure began to build, indicating an influx of tubing fluids. Without gathering additional diagnostic data, there was uncertainty around the depth of the leak. The leak was estimated to be close to the SCSSV, based on A-annulus/ tubing gradient intersection and the assumption that the system was in hydraulic equilibrium. An extended flow test diagnostic was performed from 2/26/2020 to 3/23/2020 to assess the leak rate under varying production rates of ~10, ~20, and ~30 mmscfd. The test concluded that the leak rate was operationally manageable while flowing at all rates. A-annulus pressure was managed by topping up with methanol as needed to maintain the pressure between 2900 psi and 4500 psi.

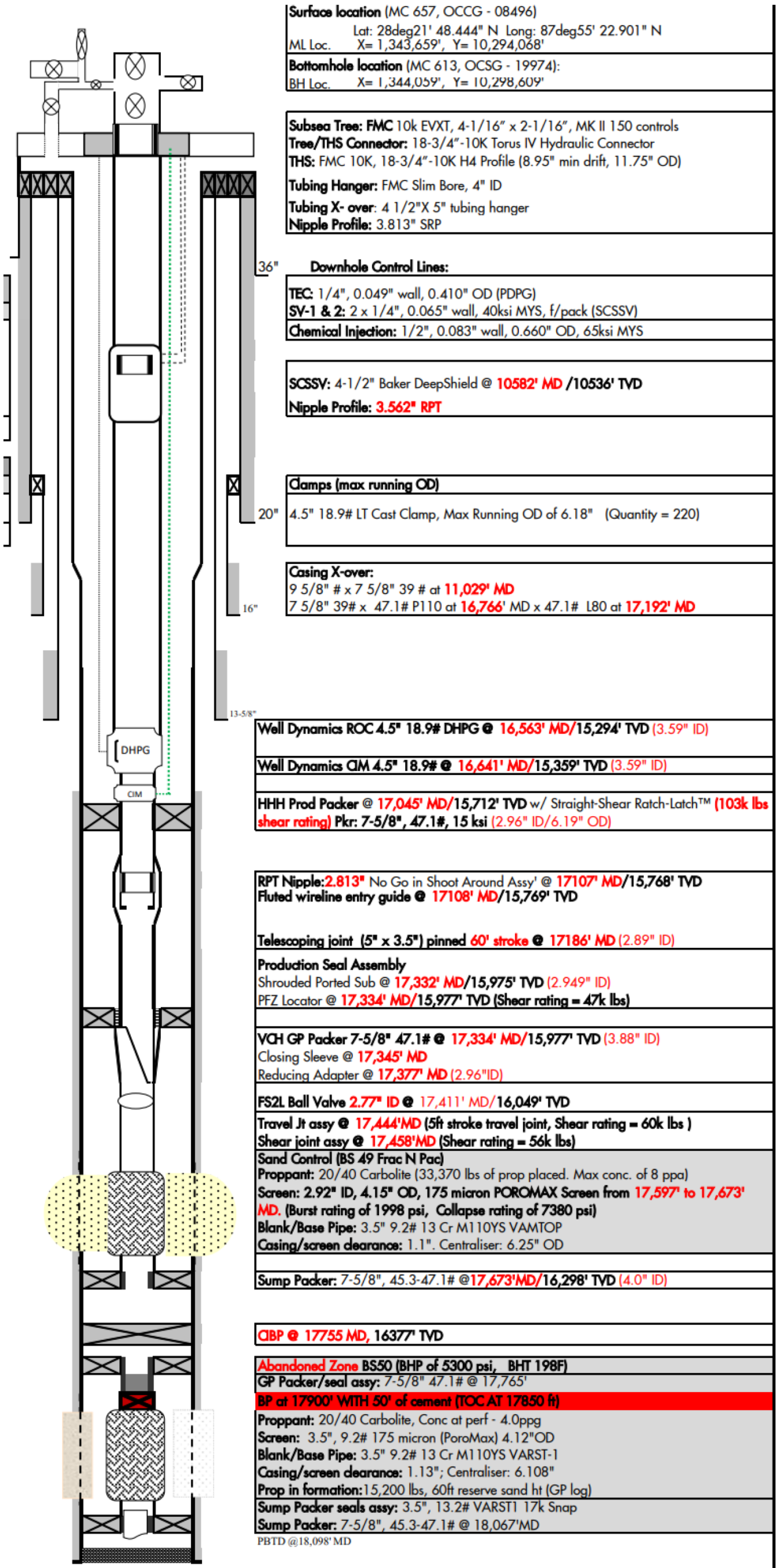


Figure 1—Subject Well Completion Schematic

A riser-based intervention to locate the leak point was performed on July 12, 2020. It was determined from the logging data obtained from the acoustic sensing and analysis platform (included in Figure 1 below), that the leak tubing to annulus was located near the production packer instead of the SCSSV, as initially expected. Review of the available data suggested a leak at the production packer, set at 9400 ft MD. This leak location was confirmed through acoustic logging and specified to be caused by a compromised element set.

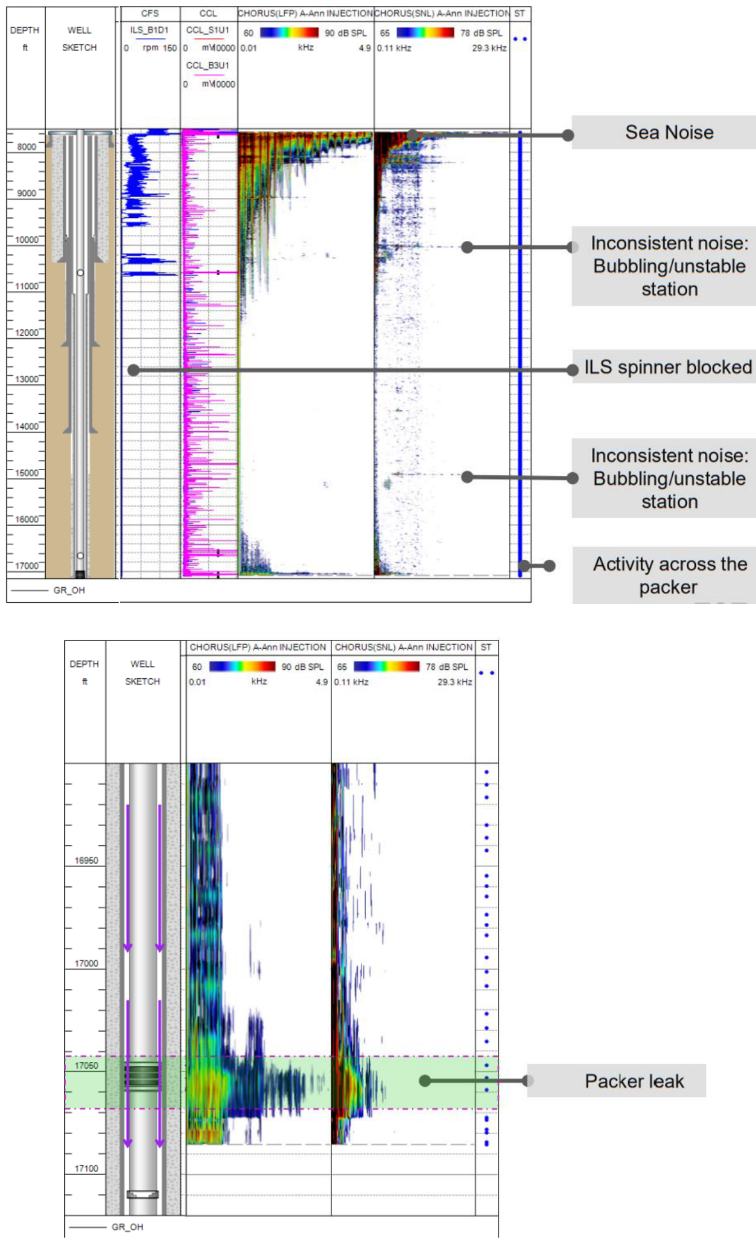


Figure 2—Acoustic Logging Data Indicating Leakage Across Packer Elements

Considering this information, the operator appropriately shut-in and plugged the well at the gravel pack assembly below the packer. Faced with the prospect of a mechanical intervention, and the associated risks, costs, and non-productive time, the operator elected to perform a riserless intervention to apply pressure-activated sealant to restore integrity to this well.

Statement of Theory and Definitions

When considering how to best restore integrity to this well, the operator considered a number of conventional/ mechanical options, along with another less conventional approach:

Rig Intervention/ Riser Based Upper Recompletion

Considering this primary option, the well would need to be killed by bullheading heavy brine to the formation. Following this, wireline would need to be run to set a retrievable bridge plug, and all production and annular barriers would be tested for integrity. Once proven, the subsea tree could be removed and replaced with a subsea blowout preventer stack, which would then allow for removal and replacement of the tubing hanger and production tubing above the production packer. Once complete, the wireline would remove the retrievable bridge plug and SSBOPs would be pulled to allow for re-installation of the SSXT. A more detailed, step-wise procedure example considered by the operator is included in Appendix A.

For this option, the scope of a upcoming MODU intervention would be to set a deep plug only due to scheduling constraints. The tubing replacement would then be done by a MODU rig at a later date, and a follow up MODU intervention would be required after that to recover the deep plug. The downsides to this option are time and cost. Because of the need for a rig intervention and a follow up MODU intervention, the earliest production could be restored would have been nearly 2 years from the initial action, considering a very accelerated timeframe for operational planning and a break-in to the rig schedule that would push other production back. During the initial planning stages for remediation of this integrity issue, there was concern that a break-in to the rig schedule would not be attainable for this intervention. Additionally, the cost of this option would be significantly more expensive than a MODU intervention alone; total expected cost would have been an order of magnitude larger. Another risk of a full workover is recovery of the deep set plug following the job; due to issues with debris it can be difficult to recover a deep set plug and there is risk of significant cost associated with attempting to fish it. In the worst case scenario it may not be possible to recover the plug at all and the well would have to be sidetracked.

Due to the significant time and cost factors it was recommended that a through-tubing fix be attempted first before making the decision to perform a full rig workover.

Tubing Straddle Installation

A second option could be to place a straddle with the risk that there is more than one leak not being addressed with the straddle mobilized. To install the straddle, A riser based vessel would need to be mobilized to allow for the setting of a retrievable bridge plug, followed by tubing leak detection logging to identify the possible leak site(s). From this point the tubing straddle could be run, bridging off the leak discovered leak site.

Although the advantages of the straddle option made it palatable during planning, there were some limitations and risks identified which would ultimately remove this option from consideration. The first issue was a potential production rate limitation due to the reduced ID of the staddle. Although, this limitation would not likely change the ultimate recovery over time, it would cause an undesired extension in operating life of the asset. Additionally, straddle packers often seal to the ID of the tubing with elastomeric elements. These elements are generally not compatible with common solvents (xylene, toluene, etc), limiting options should the well develop asphaltene deposition issues. Finally, a large concern was increased difficulty in abandoning the well with a straddle installed. Under the worst case, the straddle would need to be burnt over with coiled tubing, and in the best case, there is still the possibility of improper retrieval. In any case, if difficulties were encountered during decommissioning, additional rig time, and cost would be necessary.

Tubing Patch Installation

A tubing patch option would involve installation of a sealing element that expands against the ID of the tubing, rather than being held in place by packers as is the case with a straddle. The advantage of a patch is that it would be less likely to have some of the issues associated with the straddle (potential reduced max rate, abandonment issues, solvent compatibility). There are two significant hurdles to a patch option, however. One major issue is availability at this size; most patches tend to be designed for casing and the selection for through-tubing applications is limited. It is possible there are patches on the market in this size but the options in terms of lead time, materials, specs, etc will likely be limited. It would also take some time to locate and identify a patch solution, which does not work with the accelerated timeline that the equipment needs to be delivered in to meet the target execution date. The other issue with a patch is pressure differential; because they do not seal with slips/elements like a straddle system most patches have low differential limits. This would likely prevent use for this application as the annulus/tubing differential will vary significantly during production based on well conditions and would be very difficult to manage to maintain a consistent low differential

Pressure-Activated Sealant Approach

This leak could be addressed through the application of pressure-activated sealant technology. This proprietary solution is applied in a liquid state, but once subjected to pressure differential at the leak site, penetrates into and through the leaking component, polymerizing into a flexible solid only at the point of differential. Varying formulations and additives are used to optimize the sealant for the particular application and associated in-situ dynamics. Blends are selected to ensure compatibility with oil or water-based fluid systems in a wide variety of surface and downhole equipment. Any residual sealant remaining within the treated system remains in the liquid state, available to re-seal the leak, should the initial seal yield due to extraneous stresses. Alternatively, if operational parameters dictate, remaining liquid sealant can be flushed out of the system without compromising the resultant seal. Additionally, the polymerized seal does not "cement" any well components into place, eliminating any concern in regard to future interventions or end of life decommissioning.

A potential risk of this approach is uncertainty in regard to the leak characteristics inherent to its downhole location. As a result, any treatment plan devised is on the basis of the limited information obtained via diagnostics and hypotheses inferred as a result. Due to this, effective determination of a mechanical chance of success of a potential repair is largely tied to the quality and veracity of the initial leak investigation. Because this approach is a repair to a damaged piece of equipment, there is the possibility that a successful repair can yield due to further degradation of the leaking components or continuation of factors that produced the leak. As such, a definitive and permanent remediation is not guaranteed. In line with these risks, the operator would need to schedule a MODU intervention shortly after the treatment as a mitigation for a potentially unsuccessful repair. Additionally, should the repair prove to be initially successful, but fail at some point in the near term during production, intervention schedules would yield difficulties in mounting a timely response.

Based on the above options and their implications, a pressure-activated sealant repair approach was selected for this use case. This repair methodology held advantages in regards to total cost, tooling, manpower, and intervention duration. Using a Light Weight Intervention Vessel (LWIV) suited for this work, the sealant application was completed over a span just over two days from beginning to end, using only 2 sealant technicians to cover 24 hour operations during the treatment. Further leveraging the low-footprint and minimal duration, the operator was able to use the LWIV on the heels of the repair to work on an adjacent subsea well, providing further value at a lower cost basis.

Description and Application of Equipment and Processes

To confirm and optimize the anticipated sealant injection method, the operator performed SIT testing in conjunction with the sealant and subsea service providers. In the initial planning stages, subsea bladders were selected to be filled on the deck of the vessel, and be deployed to the sea floor. The sealant would then be displaced into the production annulus via a Hydrate Remediation Skid (HRS), or ROV mounted duplex pump, through a Subsea Safety Module (SSM), composed of a Well Stimulation Tool, Bass Adapter, and Tree Running Tool (Routing pictured in Figure 3 Below). Coiled Tubing was considered to relay the sealant directly to the well or to fill a subsea accumulator system, but ultimately the use of bladders and subsea injection schemes proved to be a better fit for this application.

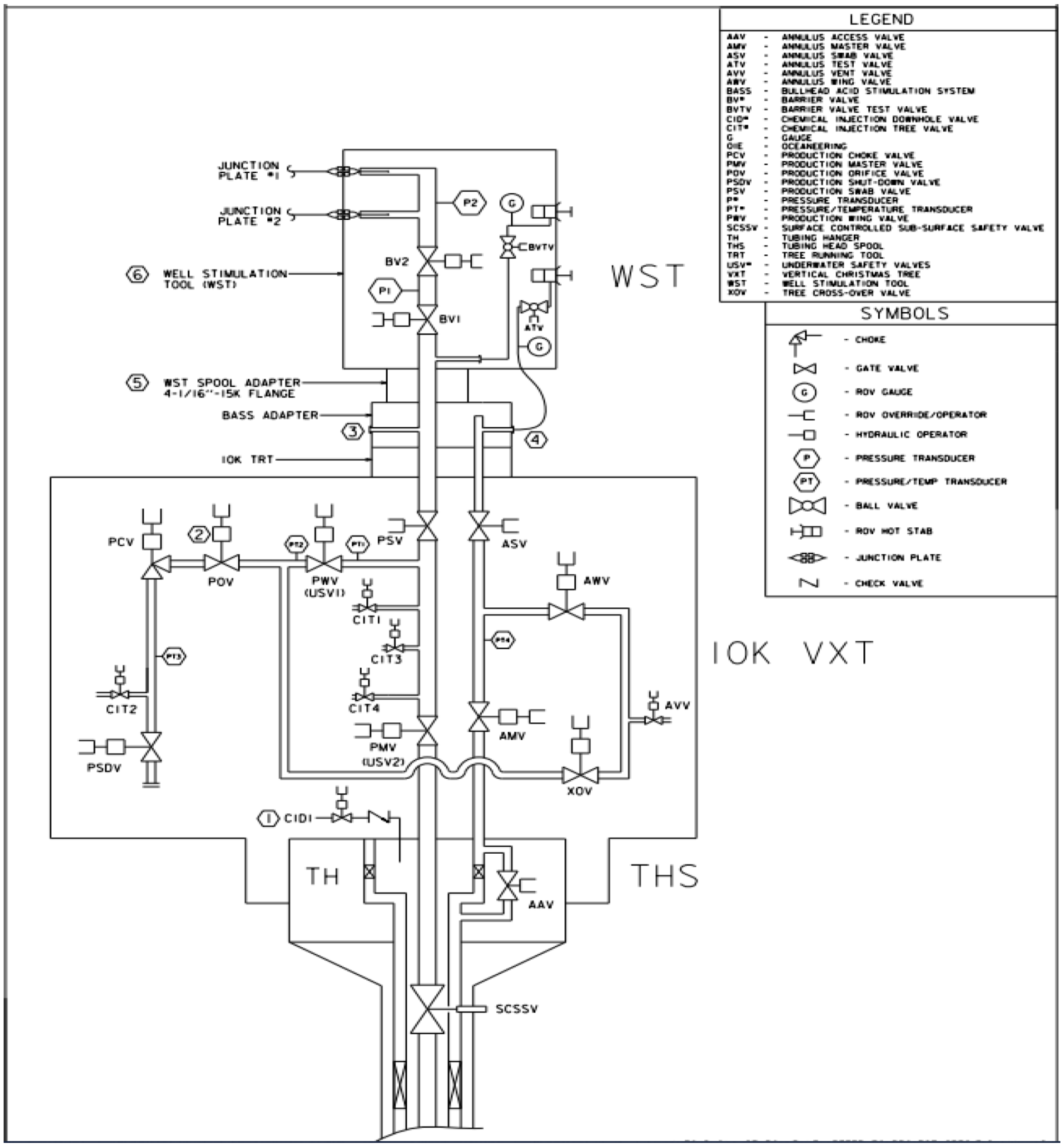


Figure 3—Subsea Sealant Injection Annulus Routing

During the SIT, the major focus was identifying key constraints that could hamper sealant injection during the execution of the repair. To simulate seawater hydrostatic pressure acting upon the bladders, sealant was placed within a pressure pot, from which a suction line was initially rigged up to the HRS, then discharged through an analog hydraulic flying lead to the WST/TRT. Returns were then captured from this system to quantify the injection rate that could be achieved using various injection configurations. During initial tests using the HRS as an intermediary from bladder to SSM, the rheological properties of the sealant proved to drastically slow the achievable sealant injection rate due to small ID plumbing within. To remove this constraint, a standalone duplex pump was used to bypass the HRS, and a number of different suction and discharge hose dimensions were tested, along with varying HPU settings to improve the sealant injection rate. Following these trials, the optimal HPU settings had been identified, and larger suction/ discharge hose dimensions were noted to provide better injection rates through reduction of friction pressure losses.

The blend of sealant for the application was tailored to the subsea deployment and was weighted to 12.5 ppg to facilitate its fall through the 10.5 ppg $CaCl_2$ annular fluid. In total, 15 bbls (630 gal, 2385 L) of sealant was prepared, 10 bbls of which was designed to be injected, with 5 bbls to maintain on deck as a contingency against unforeseen volume loss. The above 10 bbl volume would equate to approximately 500 ft of residual sealant, which would provide more than adequate annular coverage above the packer.

Once all the operational details had been sufficiently ironed out, the mobilization began to load out the vessel for the operation. The SSM was stump tested at the dock per applicable guidelines and the vessel began sailing to location. Upon arrival at the well, an ROV and the SSM were deployed, the Tree Cap was removed, and the SSM was installed in its place. Using the ROV, the system was tested beyond the operational threshold to ensure integrity for the operation.

At the conclusion of the testing, the subsea injection system was then put in place. Two of the selected 1200 gal (4542 L, 28.6 bbl) bladders were filled with an initial 7.5 bbl (315 gal, 1192 L) of sealant and MEG, respectively, and overboarded to be spotted near the well in the safe work zone. Additionally, a 2.9 bbl (120 gal, 454 L) bladder basket was filled with sealant and sent over to provide contingency volume. To facilitate fluid transfer, three, 30.5m (100 ft) hydraulic flying leads were rigged up with 17H hot stabs on either end. A drawing of the injection system is included in Figure 4 below.

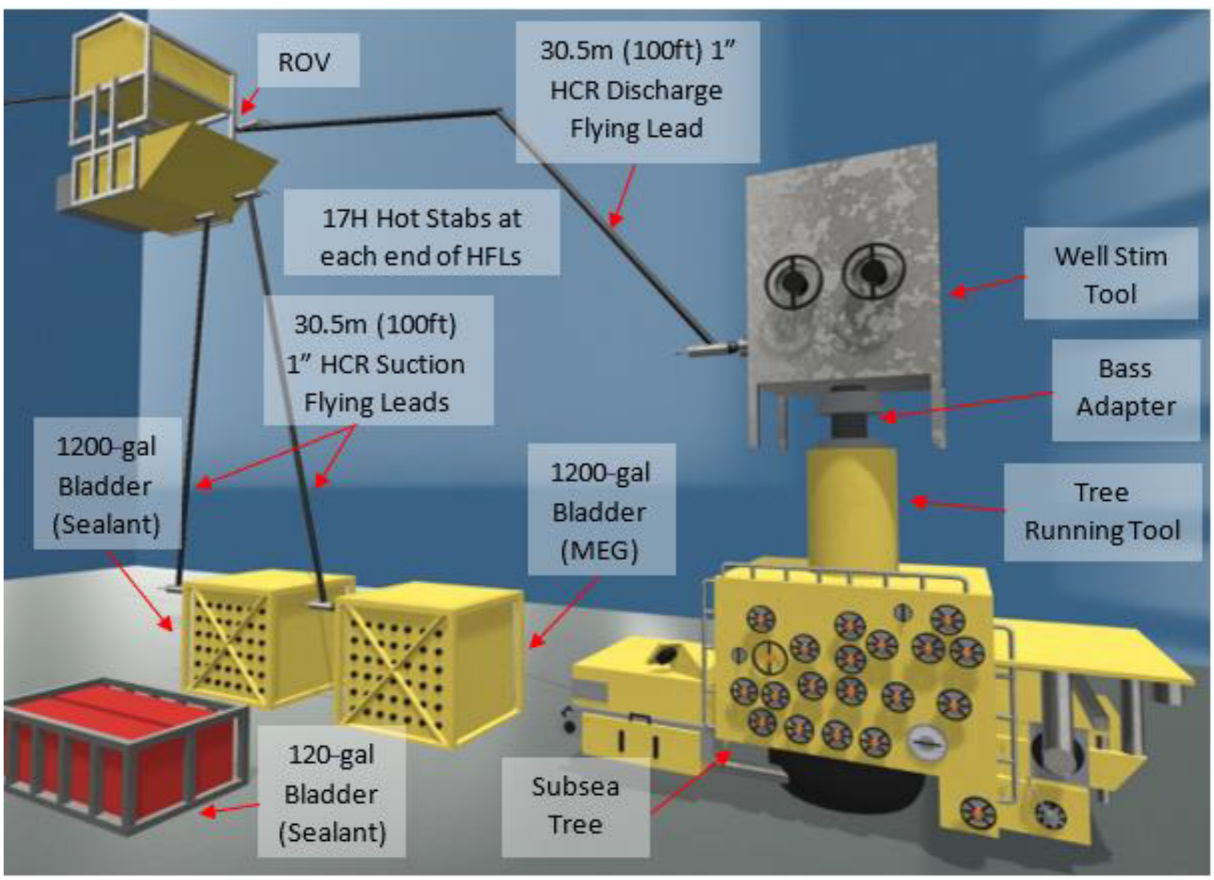
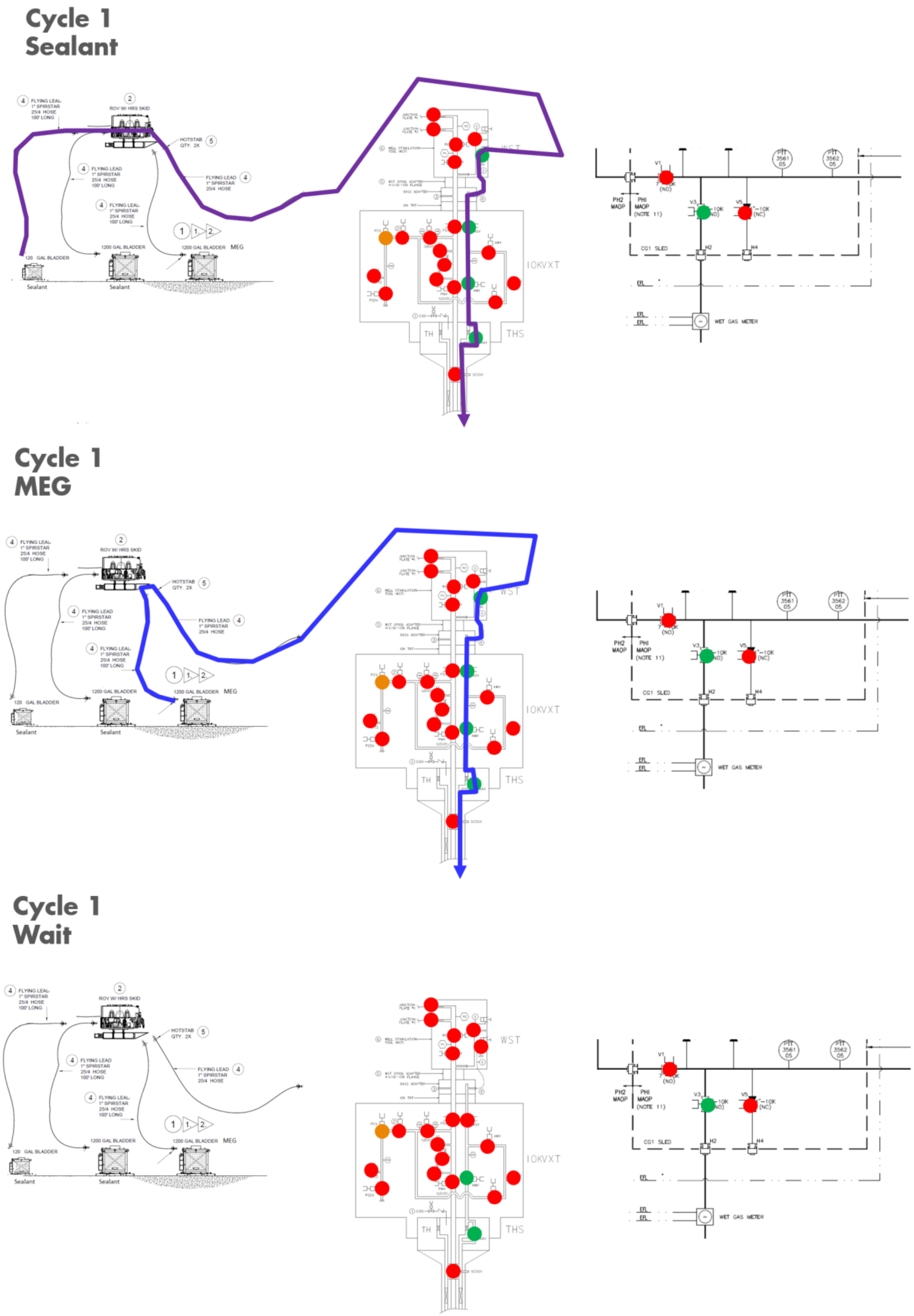


Figure 4—Subsea Injection System Rendering

Because this annulus was completely fluid-packed, in order to inject the sealant, four lube and bleed cycles were performed whereby sealant was injected to pressurize the annulus to a determined upper threshold. Once reaching target pressure, the injection was shut-off and time was allowed for the sealant to fall through the completion fluid. This waiting period was designed to ensure that little to no sealant volume would be lost during the subsequent bleed cycle. After this waiting period, annular fluid was then bled off through the Crossover Valve (XOV) via the flowline to the host platform. A pictorial representation of the process is included in Figure 5 below.



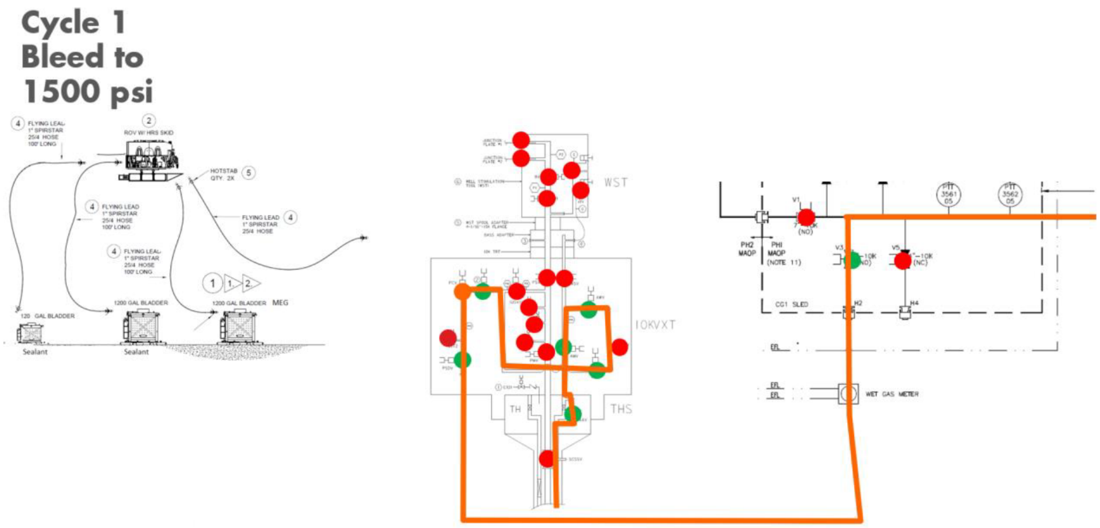


Figure 5—Lube and Bleed Cycle Valve Manipulations and Injection Path

The first of these lube and bleed cycles pulled sealant from the 120 gallon bladders and was only able to increase annulus pressure to equalize with the 3380 psi hydrostatic pressure at the mudline. It was later determined that the second bladder within subsea basket had been unable to be emptied due to a collapsed internal suction line within the bladder. This first cycle had injected approximately 1.2 bbls. For the next two cycles, suction was switched to the larger 1200 gallon bladder and pressure was able to be increased from 1500 psi to 6100 psi. Cycles 2 and 3 both injected roughly 3.5 bbls each. After the third cycle, the 1200 gallon bladder was recovered to deck and re-filled with the remaining 5.5 bbls of sealant available and was overboarded once again. For the fourth and final cycle, pumping from the 1200 gallon bladder, annulus pressure was increased from 1500 psi to 6300 psi, translating to 3.7 bbls of added volume.

In total, 11.9 bbls of sealant had been injected through the above lube and bleed cycles. In between each of the cycles, prior to the 30 minute allowed fall time, the pump suction HFL was stabbed into the MEG bladder and the system was flushed with 24 gallons to ensure all sealant for the respective cycle had been injected into the annulus. With the desired sealant volume having been injected, the annulus was shut in at 6992 psi, and monitored over a 24 hour cure period. At the conclusion of the cure, Annulus pressure was seen to be nearly stabilized, and after 29 hours, pressure had flatlined at 6980 psi. Although not necessitated due to observed stabilizing trend, additional lube and bleed cycles could have performed after injecting the sealant volume with MEG to speed the sealant pill's descent and minimize sealant stacking at the tight annular restriction at the SCSSV.

Presentation of Data and Results

Annulus pressure had stabilized after just over a day after the conclusion of the last cycle and 51 hours after sealant was first injected into the annulus. Pre-Treatment annular pressure trends can be seen below in Figures 6 and 7. Given the observed pressure at the mudline post-treatment and reservoir pressure below, an approximately 5500 psi differential from above was supported by the polymerized sealant and confirmed that the created seal could withstand the annular pressure conditions anticipated for the remainder of the productive life of the well. Following the cure and seeing integrity restored, the operator used the steady post cure-trend as indicated below in Figure 8 as a test demonstrating integrity for the well to be returned to production, now with all critical barriers intact. Figure 8 also illustrates the lube and bleed cycles performed as well as the cure period at full treatment pressure prior to the final test at normal operational pressure.

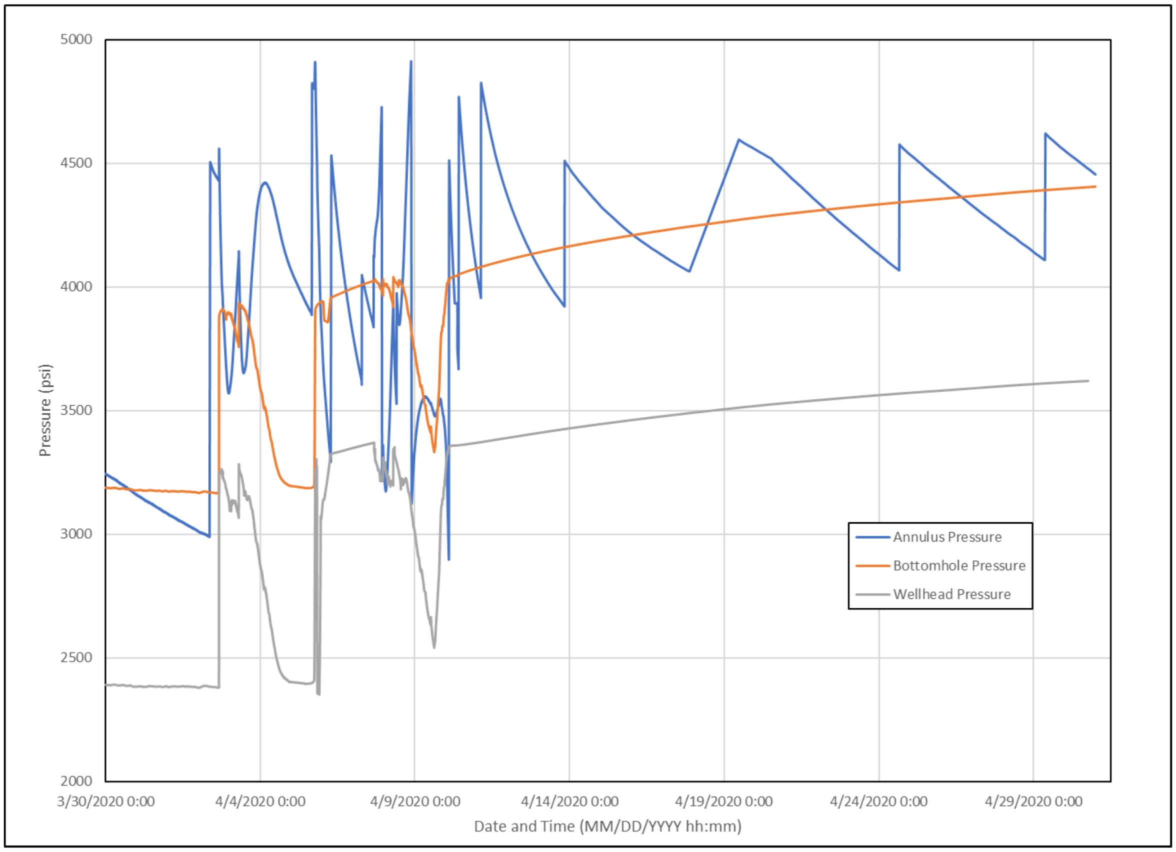


Figure 6—Annulus Pressure Trend Prior to Treatment (April)

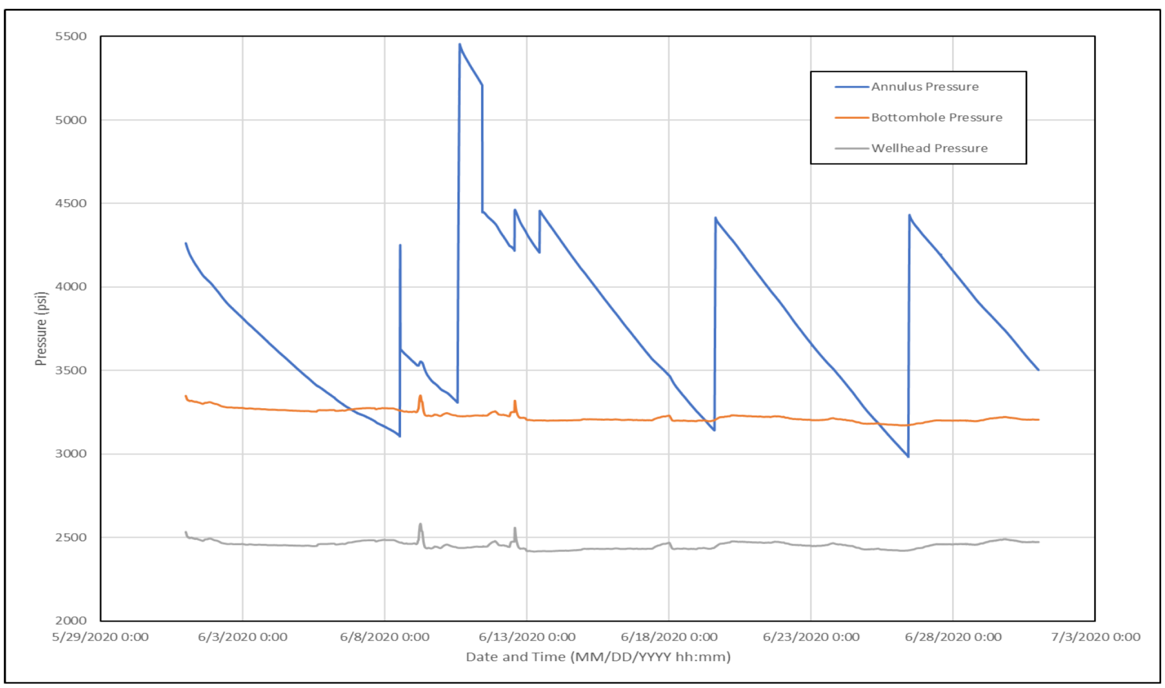


Figure 7—Annulus Pressure Trend Pre-Treatment (June)

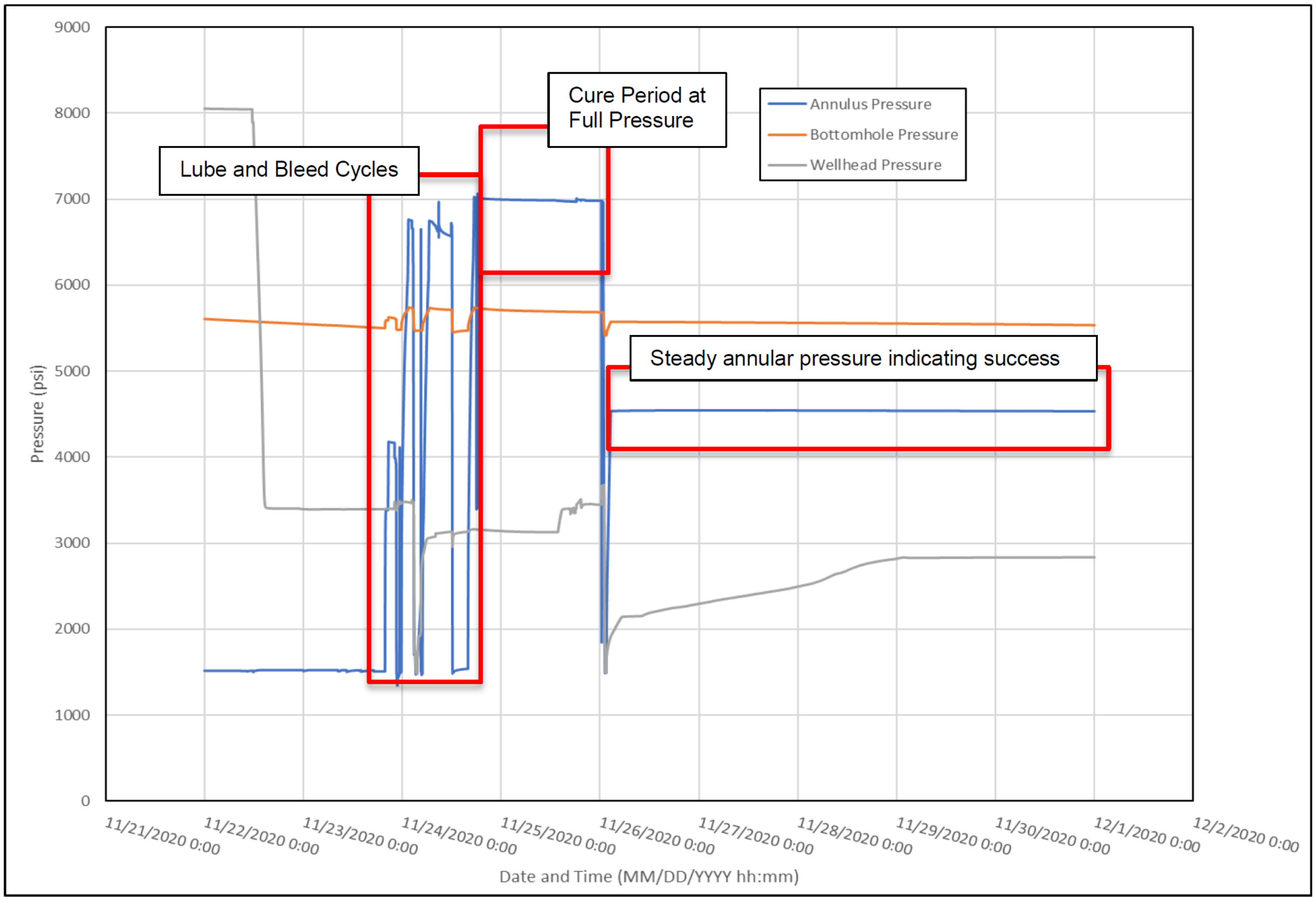


Figure 8—Annulus Pressure Trend During and After Sealant Treatment (November)

In defining the well's annulus pressure operating envelope post-treatment, the operator considered shut-in and flowing scenarios to establish the minimum and maximum allowable pressures to be read from the pressure transducer at the mudline used during treatment.

First, the MINAASP was established to adhere with the sealant provider's recommendation to maintain a minimum differential of 500 psi across the packer. As the packer differential decreases during well shut-in scenarios (as annulus pressure reduces and tubing pressure increases), the operator established a MINAASP of 1,737 psi to ensure the 500 psi differential was maintained against a realistic high pressure: the reservoir pressure. A 15% safety margin was considered in establishing a low alarm of 2,000 psi to alert the control room that annulus pressurization is required.

Second, the MAASP was established to ensure the pressure differential across the packer did not exceed the tested differential of the sealant at the time of the intervention (approximately ~5,500 psi). This ultimately translated to a MAASP of 5,300 psi when referencing the minimum flowing bottom hole pressure expected during future operations. Alarms were put in place to alert the control room that the MAASP was approached or exceeded, and that pressure must be bled or the well shut-in to avoid significant excursion.

After the sealant pumping intervention, the zonal isolation plug was pulled and the well returned to production.

Since the MINAASP and MAASP are established based on reference shut-in and flowing pressure assumptions, respectively, they are subject to renewal should wellbore conditions change over well life. During a well integrity review, the operator noticed that the well's flowing pressures were lower than previously assumed when the MAASP was originally set due to natural depletion and well ramp-up. When updating the MAASP value to ensure the tested differential was not exceeded over the short-term, the MINAASP was similarly reduced to account for the reservoir pressure loss due to depletion since the treatment. The operator has created a process for ensuring these values are revalidated throughout the well's life at a minimum frequency or if excursions occur. This process ensures that the key tenets of the sealant's operating envelope—maintaining a minimum 500 psi differential while not exceeding the tested differential of 5,500 psi—are adhered to.

Conclusions

In most cases, subsea well integrity issues are met with remediation offerings that are more complex, costly, and time intensive than dry-tree completions. As illustrated in this case study, given the right conditions, a pressure-activated sealant repair has the potential to restore integrity to a well allowing it to return to or continue production on an accelerated timeline, with lower associated costs and risks.

Given difficulties that could arise as a result of mechanical means of repair, and the necessary large-scale actions to address them, pressure-activated sealant can provide an effective first-line approach. Even if the repair were to prove unsuccessful, there are no hindrances to other means of intervention. In these cases, the cost implications of a sealant treatment are merely a "drop in the bucket" in comparison to the alternative means.

To determine the suitability for a repair of this type, care should be given to obtain as much detail as possible in regard to the leak location, likely geometry, and severity to optimize the potential for a successful repair. Consideration should also be given to the trajectory of the well's life cycle and the risk versus reward of opting for this strategy. In the case of the above described well, production has been online for nearly two years with no indication of seal degradation, illustrating that a sealant repair can be more than a temporary solution as a bridge to mechanical intervention.

Appendix A

Sample Procedure for Rig Intervention

Phase 1 – Preparation for Intervention

1. Deploy IRS to subsea tree elevation. R/U surface tree & wireline pressure control equipment. Pressure test surface equipment & riser string.
2. Displace riser to inhibited brine, land out IRS on subsea tree, & complete IRS barrier pressure test
3. Open tree valves; perform injection test & bullhead kill formation with inhibited brine.
   - ➢ If unable to bullhead workover fluid perform gauge ring run to determine Hold Up Depth (HUD) and if required perform coil tubing clean out and circulate out hydrocarbons.
4. RU Wire line unit and pressure control equipment and test lubricator. Perform wireline gauge ring/ GR/CCL run
5. MU retrievable bridge plug on wireline and test quick connect. RIH with retrievable bridge plug to below production packer
6. Test production tubing and bridge plug to 1,000 psi pump pressure for 10 minutes and inflow test plug.
7. MU wireline tubing cutting BHA and test quick connect. RIH to above production packer. Perform tubing cut and displace entire well to inhibited brine and inflow test production casing.
8. Close SCSSV.
9. Pressure test against SCSSV to 1,000 psi pump pressure for 10 minutes.
10. Close AAV and test for 10 minutes.
11. Displace riser to seawater recovering inhibited brine. Prepare Subsea Tree (SSXT) to be recovered.
12. Unlock subsea tree with IRS; pick up tree to verify release and set back down. Splash subsea crane to recover SSXT.
13. Unlock IRS from tree and recover to surface. Simultaneously recover SSXT on wire.

    BARRIERS in place:

    - Production bore barriers: Retrievable Bridge Plug, SCSSV
    - Annulus barriers: Production Packer, Tubing Hanger & AAV

Phase 2 – Pull & re-run production tubing via SSBOP

14. Run SSBOP, displace riser to inhibited brine, & latch to Tubing Head Spool (THS). Pressure test BSR & connector.
15. Perform initial on-bottom SSBOP testing per MODU.
16. Perform SSBOP pressure tests as per the table below.
17. Make up the Tubing Hanger Running Assembly (THRA) & RIH on landing string. Latch into Tubing Hanger (TH) & confirm with over pull.
18. Unlock tubing hanger & pull production tubing.
19. Run new production tubing with overshot, packer, control lines, and accessories. MU TH & THRA and RIH on landing string. Land & lock TH in THS. Test TH. Rig up Flowhead.
20. Displace well tubing by casing annulus to packer fluid down kill line and up through flow head.
21. Pressure up on the tubing to pressure to set production packer. Hold pressure for 15 minutes as tubing test.
22. Bleed off to achieve ~1,000 psi differential SCSSV test for 15 minutes.
23. Test production packer from below to ~1,000 psi surface pump pressure for 15 minutes.
24. Close & test AAV surface pressure for 10 minutes.

25. Unlatch THRA from the TH & recover to surface.
26. Displace riser to seawater.
27. Unlatch SSBOP
28. Install SSXT with SS crane and test connectors and SSXT with ROV.

BARRIERS in place:

- Production bore barriers: Retrievable Bridge Plug, SCSSV, tubing hanger, tested tree valves.
- Annulus barriers: Production Packer, Tubing Hanger & AAV

Phase 3 – Thru-tubing operations via IRS

29. Deploy IRS to subsea tree elevation. R/U surface tree and wireline pressure control equipment. Pressure test surface equipment & riser.
30. Displace riser to inhibited brine, land out IRS on subsea tree, & complete IRS barrier pressure test as per pressure test documentation.
31. Open tree valves and SCSSV.
32. RU slick line unit and pressure control equipment and test lubricator. MU retrieval pulling tool BHA and RIH to recover junk basket set above retrievable bridge plug. RD slick line.
33. RU electric line unit and pressure control equipment and test lubricator. MU electric line stroker retrieval BHA and test lubricator and quick connect. RIH to retrievable bridge plug and recover same. POOH and rig down.
34. Pressure test SSXT production master and swap valves to ~1,000 psi for 10 minutes.
35. Displace riser to seawater.
36. Unlatch from subsea tree, RD surface equipment & recover IRS .
37. Install and test tree pressure cap with ROV.
38. Perform site survey with ROV. Demobilize MODU.

BARRIERS in place:

- Production bore barriers: Tested Tree and SCSSV
- Annulus barriers: Production Packer, Tubing Hanger & AAV