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Subsea Well Annular Integrity Repair Using Coiled Tubing and Pressure Activated Sealant

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Abstract

Production from a subsea well was halted due to hurricane activity in the Gulf of Mexico. When the well was returned to production, the annulus experienced a loss of pressure integrity. To achieve regulatory compliance and return the well to production, annular integrity had to be restored in a safe, expeditious manner. This paper will describe the process of operations undertaken to cure this well integrity issue utilizing pressure activated sealant deployed via coiled tubing.

Pressure activated sealants have been utilized for a number of years to efficiently cure leaks in a wide variety of applications. One of the first challenges to be addressed when considering a sealant repair is the method of getting the material to the leak site. For the purpose of the subsea well in question, coiled tubing was used to convey the sealant to the sea floor from a service vessel. An ROV then connected the coil to an external tree cap via a flying lead after which the sealant was introduced to the annulus by lube and bleed pressure cycles.

The annular integrity issue was analyzed in an effort to determine leak severity and location. Pressure trends noted at annular pressures of 4000 psi indicated a leak ranging from 0.15 – 1.5 lit/min. Gradient analysis indicated that the leak was deep in the completion potentially at a liner lap or the packer. Based on this information a sealant blend approximately 2 ppg heavier than the completion fluid was developed for the purpose of curing the leak. An external tree cap was installed on the well in order to provide access to the annulus of the well via a hot stab connection. About eleven cubic meters of sealant was transferred to the annulus through 2" coiled tubing extended to the sea floor connected to the well via a flying lead. A series of lubricate and bleed cycles were performed to accomplish this without exceeding predetermined pressure limits. After allowing the sealant to settle on the packer, annular pressure was maintained to allow the sealant to cure at the leak site. The pressure differential at the leak caused the liquid sealant to form an elastomeric seal. A positive pressure test was obtained shortly after the process and the well was returned to production.

An example of how using pressure activated sealants designed to polymerize only at a leak site affords options to expensive workovers on subsea wells will be provided herein. The use of this technology in concert with coiled tubing deployment represents an expeditious, economic approach to solving complex well integrity issues.

Introduction

Under federal regulation per reference 30 CFR Part 250 Subpart E, governing well operations in the Gulf of Mexico, the pressure in 'A' annuli of subsea wells must be monitored on a daily basis to assure integrity is maintained. When a pressure event is noted which demonstrates communication between barriers, an operator is required to take action to mitigate the well integrity issues prior to returning the well to production. The operation required to correct the issue can vary wildly depending upon the nature of the failure. In the case of an annular barrier failure, it is often a certainty that rig workover or recompletion operations would need to be undertaken to address the issue and restore production. As the complexity of the subsea completions has evolved over the years, so too has the remediation methodology and execution. These operations introduce a substantial time and cost element to the company along with a considerable amount of risk.

When faced with the above referenced challenges, it is prudent to weigh all options available when considering a remediation technique. The curing of annular integrity failures has been accomplished in the past using a pressure activated sealant that forms a high strength, flexible elastomeric seal only at the leak site when it experiences a differential pressure drop. The material may be deployed in a wide array of methods which do not require the use of MODU or even light riser-less intervention vessels. Outlined below is a case history describing the diagnosis of a subsea wells' annular integrity failure and subsequent repair using this method deployed on coiled tubing.

The Subject Well

The asset in discussion is a subsea well completed in 2015 in 6,131' of water. This vertical well completion consists of a 9-7/8 liner string set to 18,108' MD. The liner is tied back to the subsea tree from a liner top packer assembly at 15,918' MD. The well is a gravel-pack completion with 4-1/2" tubing down to a production packer set at a depth of 16,986' MD. (Figure 1) The completion fluid is 12.7 ppg calcium bromide. Prior to experiencing the annular pressure event, the well was producing 8000 bopd and 16 MMscfd.

As a prudent precautionary measure, production operations on the subject well were ceased prior to hurricane Ida in September of 2021. The well was brought back on production on September 20th and as the well begin to warm, the annular pressure began to build as is typical with the increase in temperature. Over the course of the next day, the annular pressure asymptotically approached the typical annular operating pressure of around 6,000 psi. At 5:39 on September 22nd, an annular pressure loss event occurred wherein the pressure suddenly dropped from about 5,900 psi to 4,100 psi. (Figure 2.) The pressure in the annulus recovered to about 4,800 psi but then experienced a decline over the next few days.

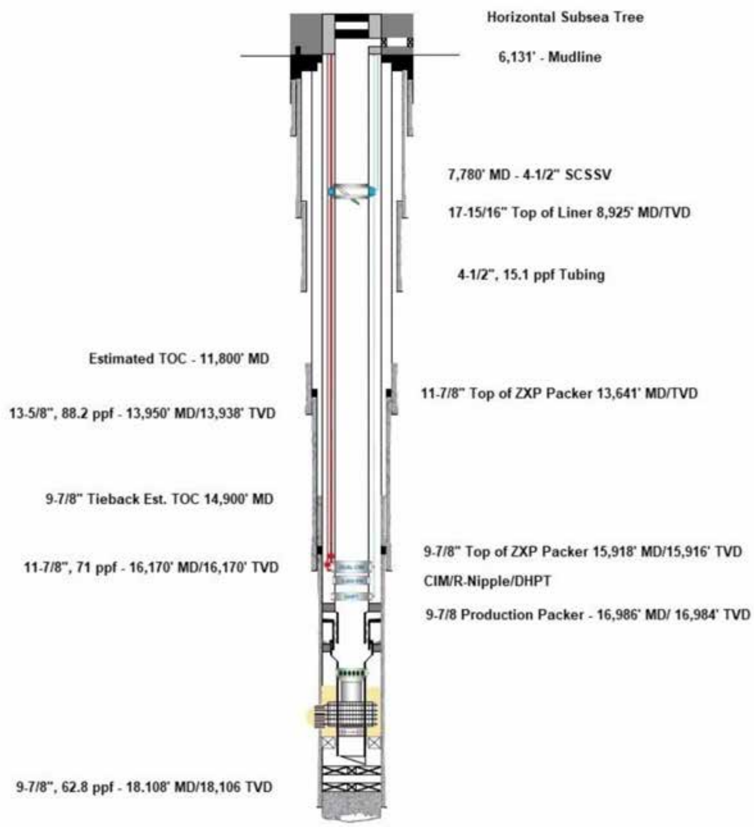

Figure 1—Subsea Wellbore Completion Schematic

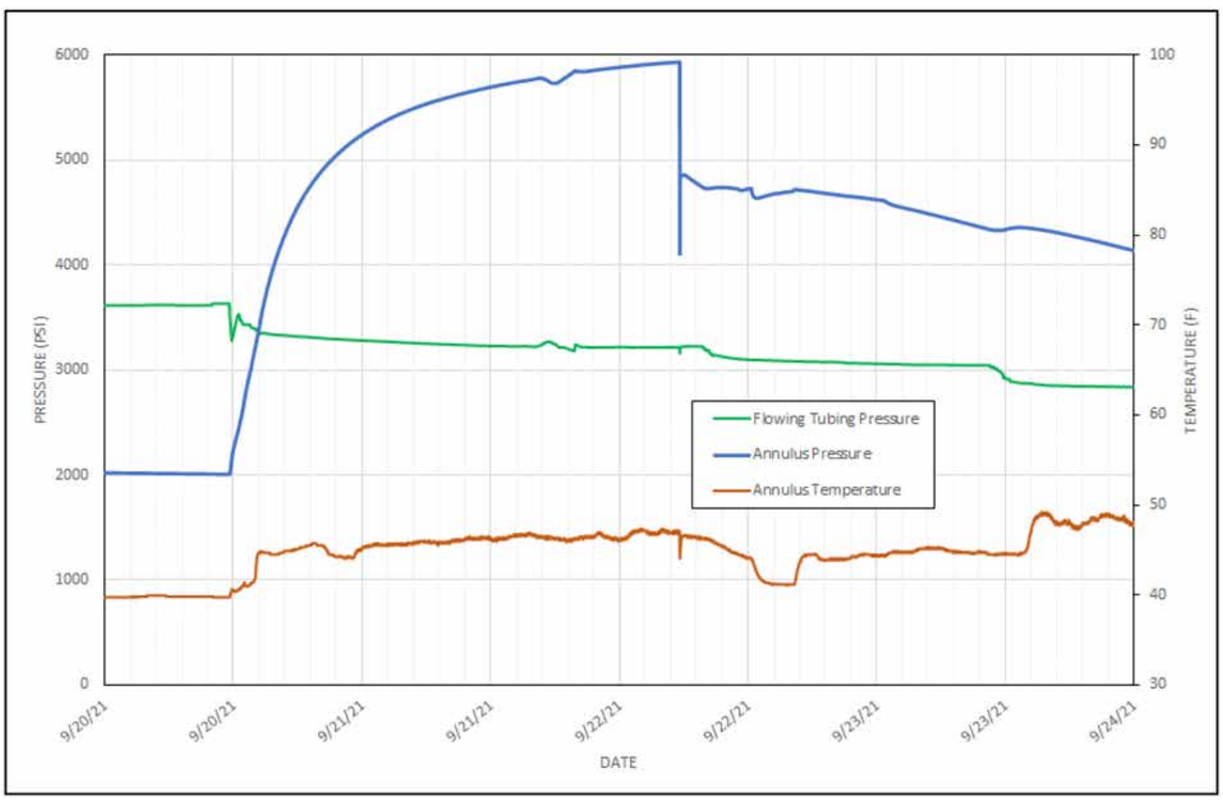

Figure 2—Well Start-Up Leak Event Following

In order to diagnose the pressure anomaly, the well was shut in and a series of pressure tests were performed on the annulus. This was done by pressuring the annulus using methanol to about 4,800 psi and monitoring the results. Four pressure cycles were performed, each with a resulting higher leak off rate than the previous. (Figure 3) The first leak off rate was 180 psi/hr and the final leak off rate was about 375 psi/hr. Based upon the pressure behavior in the annulus and taking into account the compressibility of the liquid therein, the leak rate was calculated to range from 0.15 l/m to 1.5 l/m.

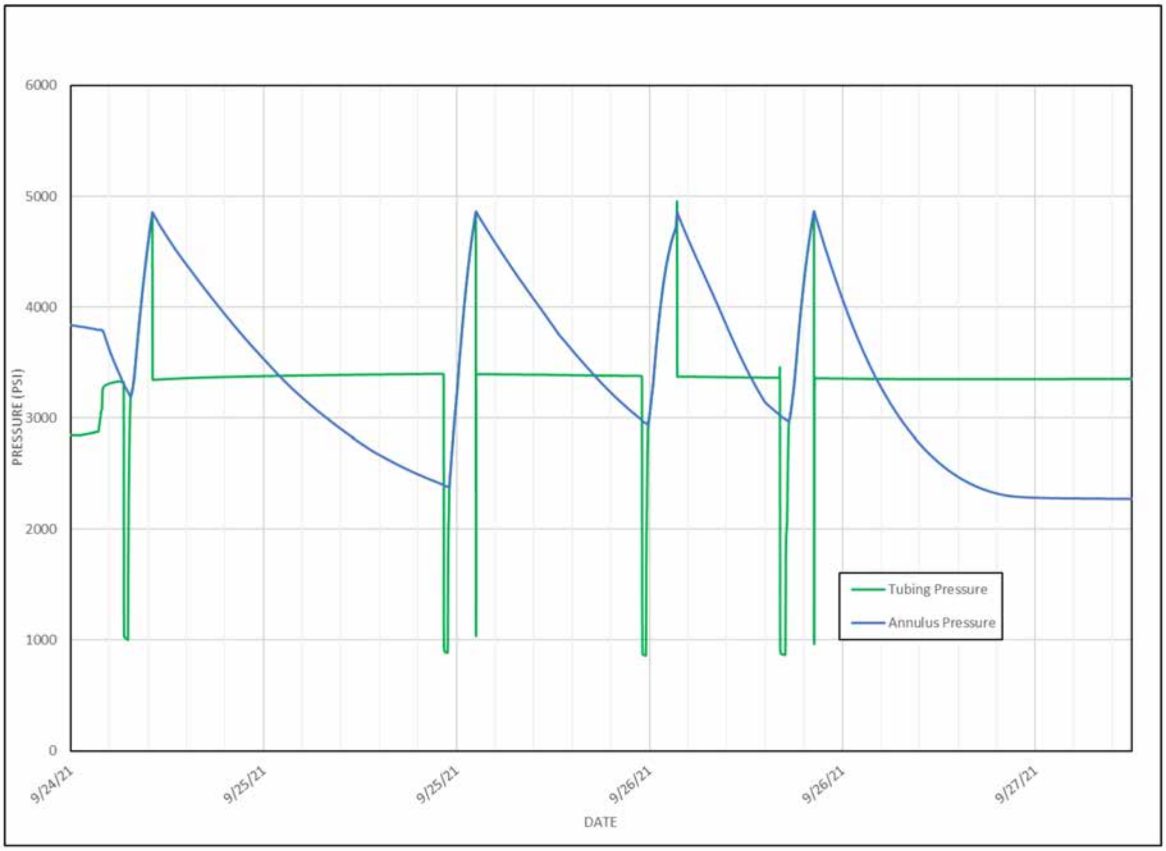

Figure 3—Well Start-Up Leak Event – Follow Up Pressure Tests

Potential Failure Point

After concluding the pressure testing, the well conditions and well history were thoroughly analyzed to determine potential failure points causing the issue. Armed with this information a suitable path forward toward remediation could be formulated. Figure 4 shows an expanded view of the suspected failure point at the 9-7/8 production tie back seals. The following discusses supporting information leading to this supposition.

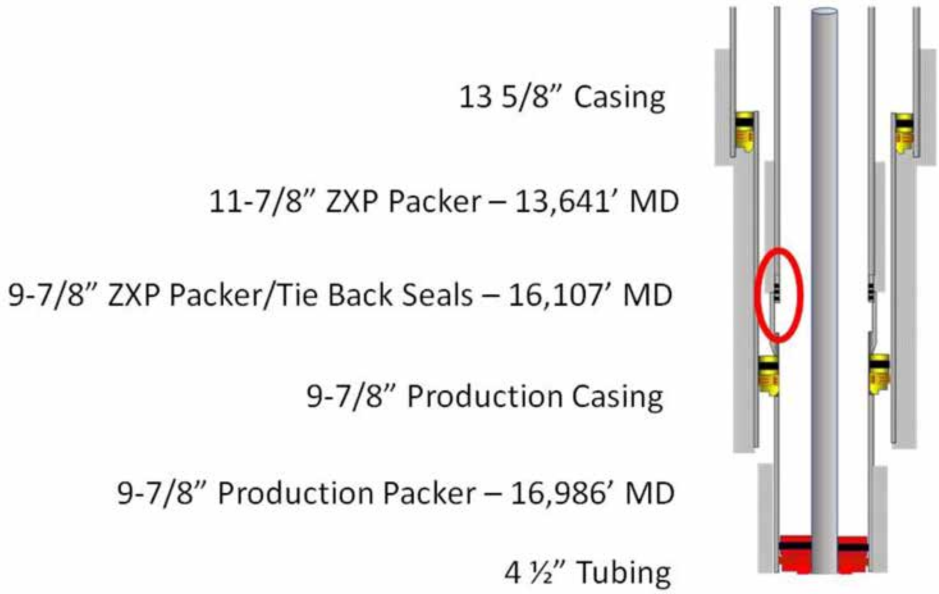

Figure 4—Suspected Failure Point

The shut-in tubing pressure of the well is on the order of 3,600 psi. Referring again to Figure 3, it is noted that the annular pressure reaches equilibrium at approximately 2,200 psi. The 'A' annulus contains 12.7 ppg fluid and the 'B' annulus contains 12.9 ppg fluid. The hydrostatic head of the 'A' annulus fluid (12.7 ppg) column compared to that of the tubing pressures suggest that the tubing pressure integrity is not compromised. However, this pressure equilibrium corresponds roughly with the hydrostatic differentials between the B and A annuli. In addition, the equilibrium pressure is comparable to the pore pressure at the 11 7/8" liner shoe. This suggests that there is a flow path into the B annulus and some communication to the formation outside that volume to the formation. Additionally, a cement bond log taken at the tie back assembly and 9-7/8" liner indicates the cement is poor in this area which would facilitate potential communication.

Another concern on this area arises from the operating envelope of the 9-7/8" tie back extension assembly. A bleed down of the applied pressure to the 'A' annulus pressure occurred on a number of occasions previous to the pressure event in discussion. The 'A' annulus applied pressure was bled to around 1,500 psi. When these pressure bleeds occurred, the differential pressure across tie back extension assembly potentially exceeded the collapse pressure of 2,460 psi. (Figure 5) Considering the hydrostatic pressure on the 'A' and 'B' annuli, and accounting for an estimated annular pressure buildup of 4,000 psi in the 'B' annulus due to warming of this fixed volume, the collapse was exceeded by about 2,000 psi. This certainly could have damaged or significantly weakened the tieback extension.

'B' Annulus Hydrostatic Pressure	'A' Annulus Hydrostatic Pressure	
12.9 PPG @ 11-7/8" Shoe	12.7 PPG @ TB	Differntial
10,733 PSI	8739 psi	2,004 psi
B Annulus Pressure Build Up	'A Annulus Applied Pressure	
4,000 psi	1,500 psi	2,500 psi
	Collapse Force=	4504 psi

Figure 5—Tie back Differential Pressure Analysis

A final consideration when reviewing the tie back extension as a possible failure point is the engagement of the seal itself. A review of this assembly stack up indicated that there was only partial (approximately four) feet of seal engagement. Due to piston and ballooning effects, this seal had a potential for substantial movement. Pipe stretch calculations indicated as much as three feet of movement was possible leaving potentially only one foot of seal engagement.

Remediation Operation

Given the well conditions and a highly likely failure mechanism, a remediation technique could then be considered. For this type of failure, wherein the secondary barrier has been compromised, access to the leak would need to be gained to undertake repair operations. First, it would be prudent to confirm the location of the leak by logging or other means before proceeding with repair. If the leak was to be confirmed at the9-7/8" tie back seals, the repair method selection would rest on the severity of the damage. For example, if only the tieback seals had failed only but the base pipe was intact, an expandable or patch might be used to secure the leak. However, as the collapse was potentially exceeded, more severe damage may be present that would require more drastic measures such as sidetrack and recompletion operations. In either case, the operation would require mobile offshore drilling unit (MODU) operations to accomplish.

When planning operations of this nature, the basic items for consideration are unit lead time, spread cost, equipment availability and the time required for the operation. The time required for the operation can be a moving target depending upon the complexity of the undertaking and if unforeseen issues occur as it progresses. While the risks of these operations are manageable for the most part, this is an important metric when deciding how to proceed. Of course, all of these metrics affect the time required to return the well to production.

After a thorough evaluation of the well parameters, the pressure activated sealant repair method was determined to be a viable option to attempt to seal the leak in question. This operation would greatly reduce spread cost by eliminating the need for a MODU and the associated risks and time elements as outlined above. Additionally, if unsuccessful, the sealant operation would not leave the asset in a condition as to hinder conventional work over operations.

Sealant Blend Design

For this case, the pressure activated sealant blend was designed to be aggressive to cover a range of leak rates. The worst-case scenario as indicated by the leak performance from the initial pressure event was taken into consideration. The sealant may be water or oil based and is compatible with most all completions fluids and is environmentally friendly. The ‘A’ annulus of this well was filled with 12.7 ppg CaBr with a methanol cap of at least 17 barrels. The sealant blend was designed be 14.3 ppg which would allow the sealant to fall through the completion fluid and settle on packer set at 16,986’ MD. The intent was to introduce enough sealant into the annulus to cover the suspect tie back assembly with ample excess to allow for sealant activation. Additionally, the excess amount would provide contingency for any accumulation of sealant shallower in the well that may not reach total depth. In all, it was planned to install 75 barrels of sealant in the annulus to cover to 550 feet above the tie back seals. (Figure 6) The total sealant column was planned to cover 16,986’ to 15,560’ MD.

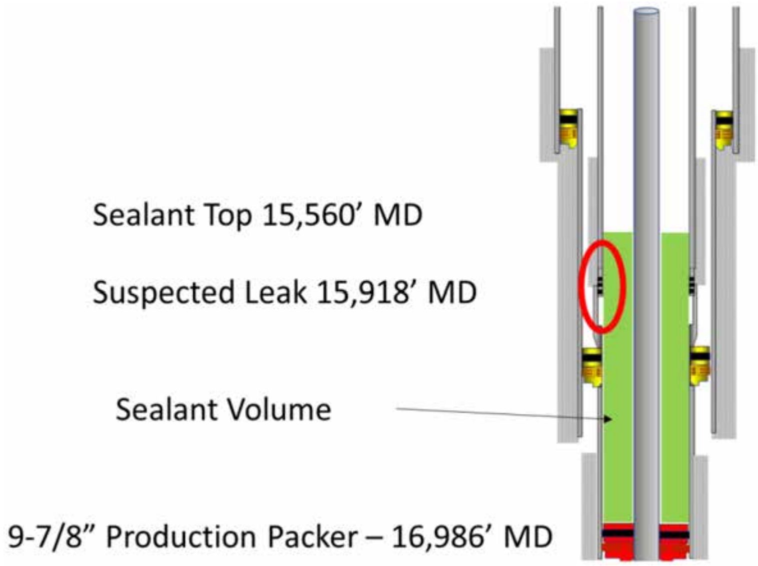

Figure 6—Planned Sealant Column

Deployment Method

In order to deliver the sealant into the annulus, a series of lube and bleed cycles were planned from 2000 psi to 5000 psi subsea tree pressures. The pressure limits were implemented avoid exceeding the collapse rating of the tie back as described previously and to prevent exceeding the pressure at which the annulus experienced the original pressure loss event. Based on calculated annulus compressibility of 4.5 bbls @ 3,000 psi, it was estimated that 17 lube and bleed cycles would be required to displace all 75 bbls of sealant into the annulus. For subsea applications, the sealant may be delivered in a variety of ways. For this application, it was planned to use 2" coiled tubing on board a marine service vessel as a down-line to introduce the sealant to the annulus. This would allow for the entire sealant volume and pump cycles to be efficiently managed at surface. The sealant would be stored in three mixing skids each containing 25 barrels of sealant. (Figure 7) The sealant was delivered to a triplex pump using a double-diaphragm pump where it would be then transferred to the sea floor through the 2" coiled tubing and into the well via flying lead and a j-latch hot stab. A 2-inch ball valve was included in the assembly to provide isolation as needed during the operation.

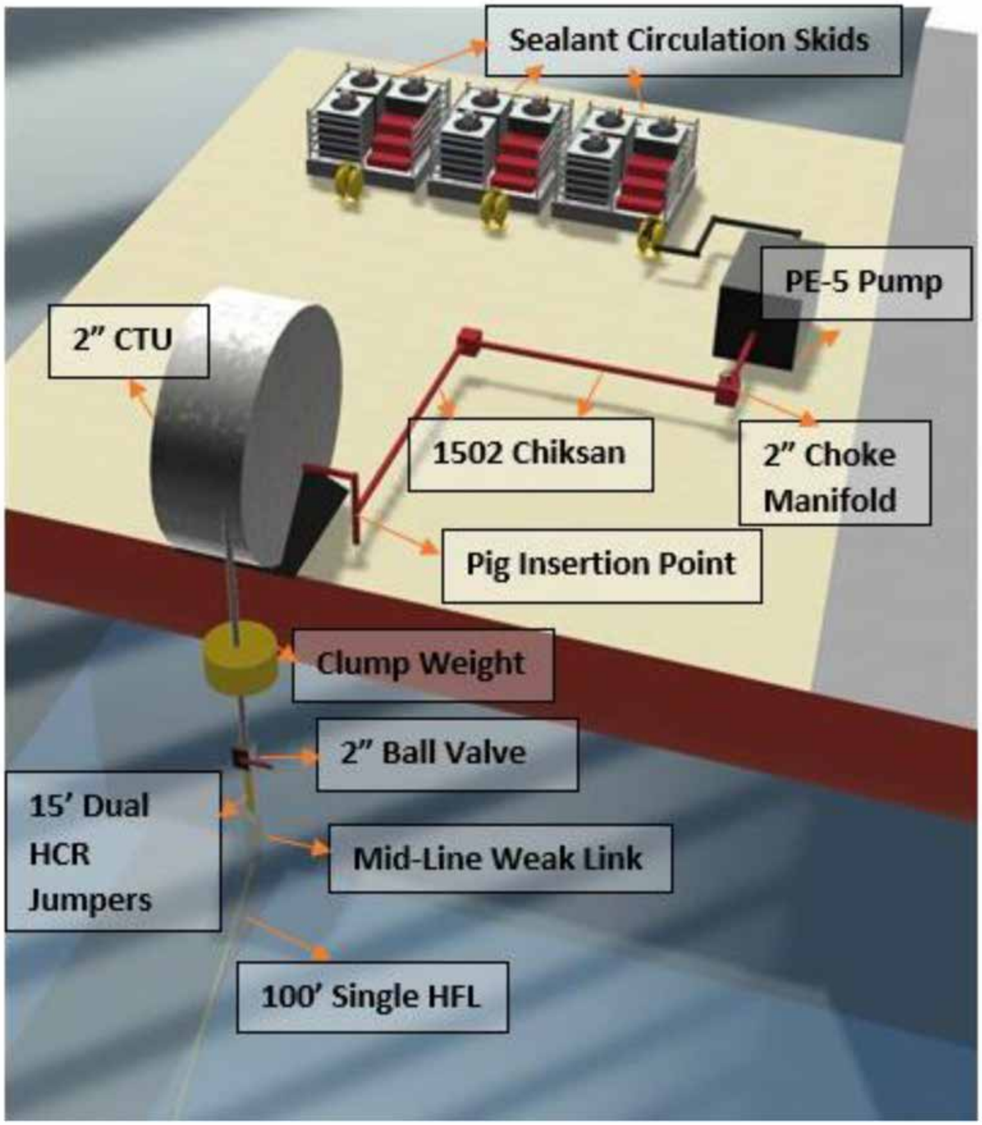

Figure 7—Sealant Deployment System

When reviewing the specifications of well head equipment, it was noted that the flow path to the annulus through the internal tree cap (ITC) had a restriction of 0.156 inches. The sealant blend selected for this operation would be too aggressive to be passed through this restriction. Therefore, an external tree cap (ETC) was modified which provided for a suitable flow path to the annulus. The ITC was to be removed and replaced with the ETC prior to lube and bleed operations. (Figure 8) The sealant then could enter the A annulus through via the hot stab into the receptacle on the ROV panel of the modified ETC. (Figure 9) An SIT was performed to verify that liquid sealant could be applied through a representation of this setup successfully without experiencing a pressure drop that would cause it to solidify prematurely.

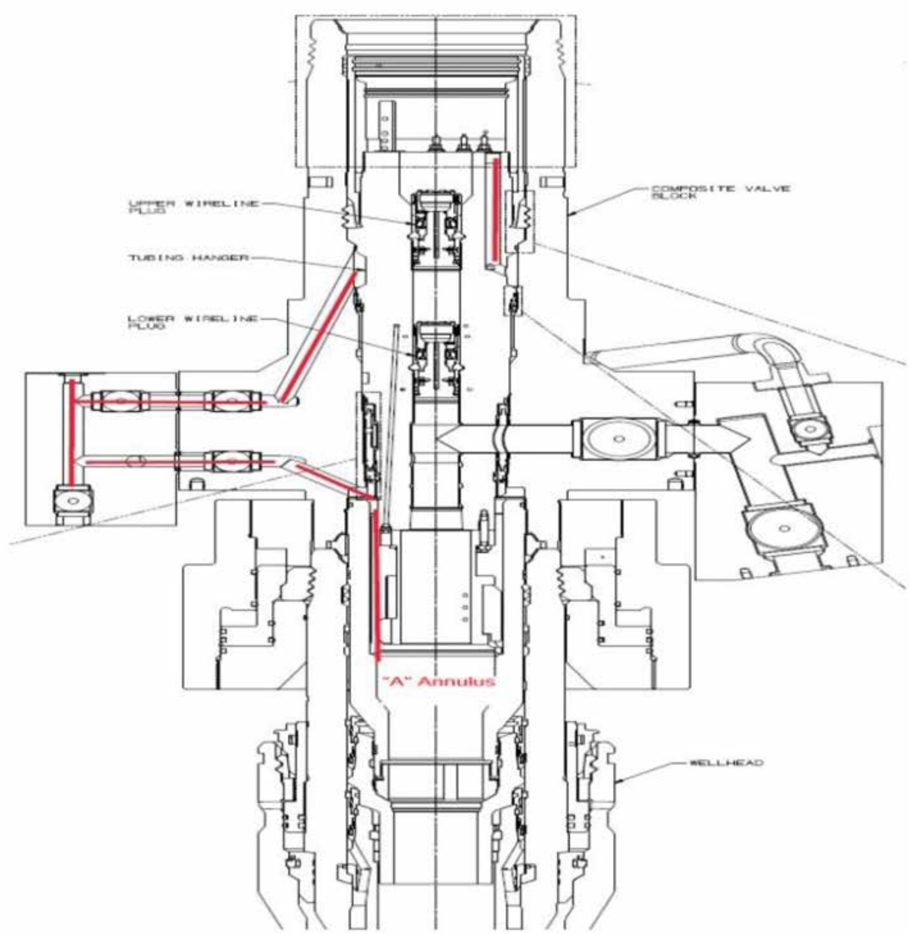

Figure 8—Annular Flow Path

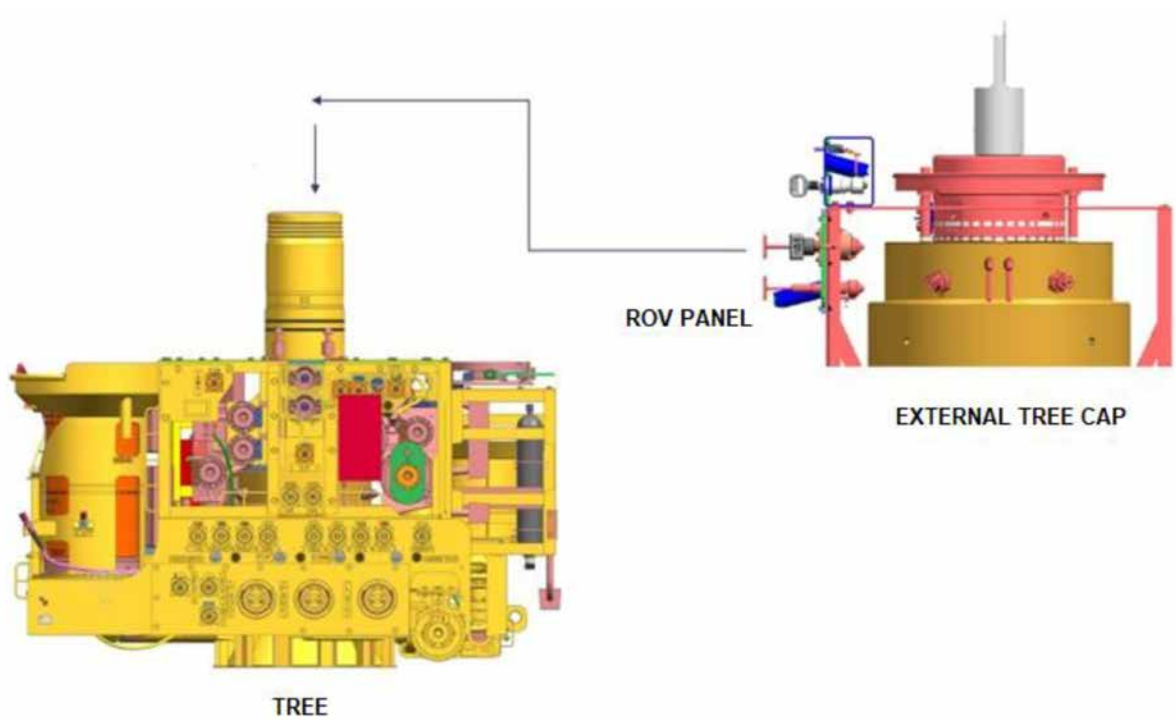

Figure 9—External Tree Cap

Sealant Deployment

Once the program had been established and all necessary approvals had been obtained from operator management and BSEE, the coil unit and sealant deployment kit were loaded on the marine service vessel in preparation to get underway to the location. Sealant was preloaded into the coil prior to moving to location. A pig was placed in the coil which was then followed by the sealant. This would assure that the coiled tubing was full of sealant and would remain homogeneous while transported to location. Following this and other preparations, the vessel made its way to location.

Upon arrival at location, operations commenced to deploy the sealant into the 'A' annulus of the well. The operation may be summarized as follows:

1. Retrieve internal tree cap (ITC) and outer tree cap (OTC) from tree with ROV.
2. Install modified external tree Cap (ETC).
3. Overboard CT and hot stab into ETC. Test.
4. Introduce 75 bbls of sealant into the production 'A' annulus by Lube and Bleed method.
5. Close ETC isolation valve and disconnect CT and recover to surface.
6. Hot stab into ETC with ROV and push remaining sealant into annulus with MEG.
7. Close AAV (Annular Access Valve) and test.
8. Bleed remaining pressure to flowline and displace tree to MeOH.
9. Recover ETC.
10. Install ITC and OTC and test.

The lube and bleed cycles were performed with annular pressure thresholds from approximately 2100 psi to 5000 psi. Time was allowed for the sealant to fall between pressure cycles to ensure little to no sealant volume loss when bleeding the annulus pressure back to the production flow line. In total, nineteen lube and bleed cycles were performed to inject 71.4 bbl pressure activated sealant. (Figure 10) Once all sealant volume had been loaded into the coil, following the 14th cycle, a tail pig was inserted to once again ensure sealant pill homogeneity. The remainder of the cycles were performed using 14.7 ppg $ZnBr_2$ brine as a push fluid until all of the sealant was displaced from the coil into the annulus.

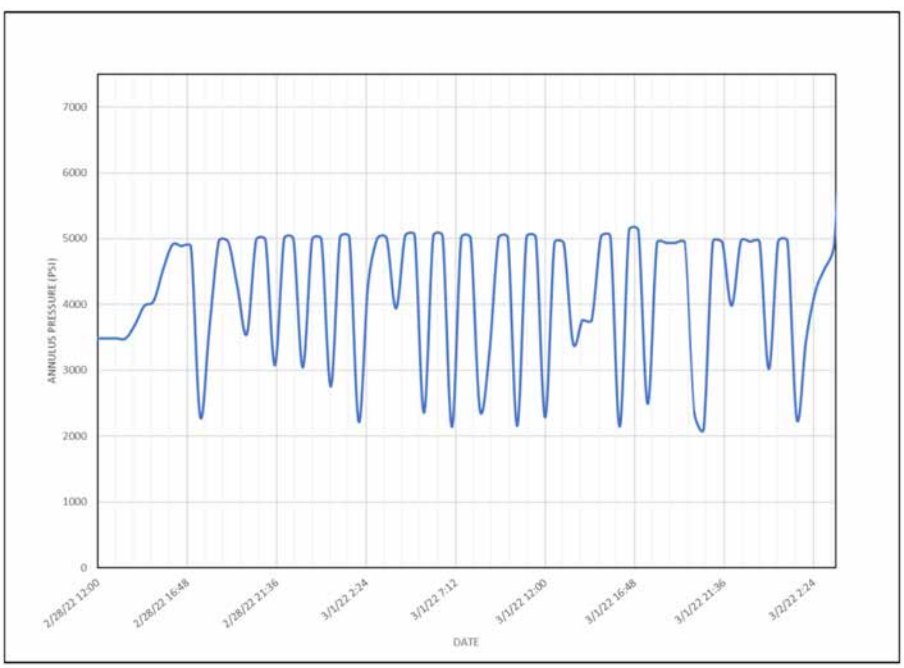

Figure 10—Annular Lube/Bleed Pressure Cycles

Results

After placing the sealant in the annulus, twelve hours was allowed to assure that the all of the material had time to settle on the packer and accumulate to the desired depth. Following this, the well was brought on line to induce warming and thereby increase the annular pressure. The production rate was brought up in increments as to maintain control over the annular pressure and not exceed the operating pressure envelope. The original pressure event occurred when the annular pressure approached 6,000 psi. The annular pressure limit was set to 5,000 psi as a precautionary measure. The production rate was gradually brought up over the following weeks allowing the temperature and annular pressure to reach steady state. (Figure 11) Following this, the rate was safely increased to near the original production rate without another pressure loss event.

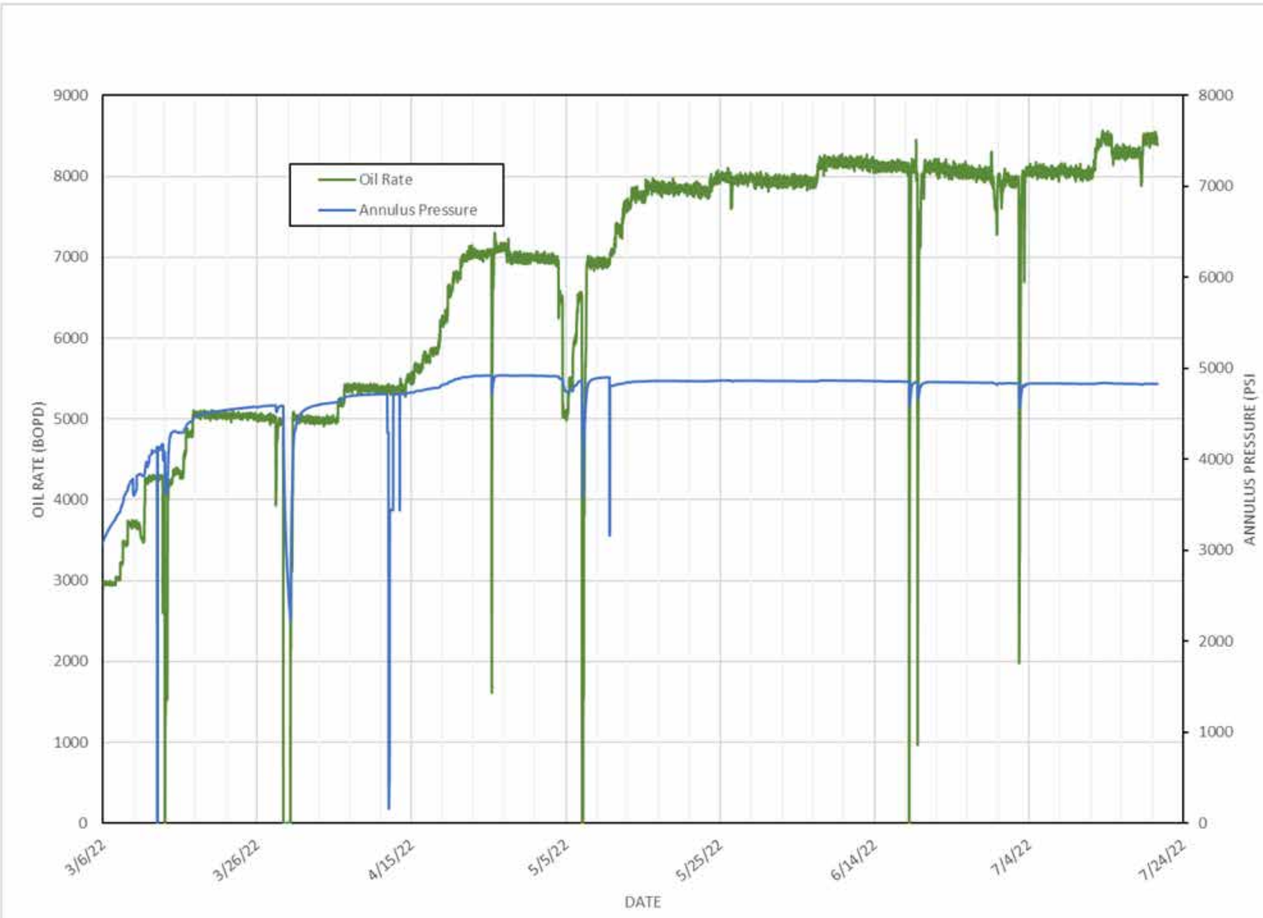

Figure 11—Annular Pressure and Rate Trend

Conclusion

Given the complexity and risks involved in performing rig workover operations in subsea wells, it is advisable to explore every option prior to moving forward. These endeavors can certainly seem to be an open-ended proposition from a time and cost perspective should issues arise during the operation. As evidenced by this case history, the operator was able to apply a long-term solution to the well integrity issue while realizing substantial cost and time efficiency.

As compared to a side-track operation, this operation saved an estimated 70 million dollars. Additionally, the time required to bring the well back online was greatly minimized by comparison. The elapsed time from the pressure event to the return to production was 162 days and actual time on location was a mere 5 days. This not only demonstrates the value of the sealant approach but illustrates an efficiency in planning and executions across the multiple service providers that were involved in this operation.

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