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Timely Sealant Intervention Yields Bi-Directional Seal and Facilitates Completion Program Continuance

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Abstract

The subject well had successfully been drilled and was transitioning into the completion phase when a leak was observed in the 9 7/8" production casing. Diagnostics located the leak at 15,329 ft MD, just below the liner hanger. Due to the leak, the operator was unable to obtain the required casing tests to continue their completion program. The initial remediation attempt was a 100 bbl cement squeeze, during which injection rates ranged from 2 BPM @ 1740 psi to 4 BPM @ 2780 psi. Following the squeeze, the casing was tested to 4600 psi, and pressure dropped at a rate of 50 psi/minute. The liquid leak rate averaged 11.4 GPM across varying pressures. Given regulatory and operational constraints, along with a spread cost exceeding $1 MM daily, the operator was left with few options and little time to determine a forward path for the well.

A composite bridge plug was set below the suspected leak site with the workstring across the leak depth. Next, a pressure-activated sealant pill was blended and pumped down the 5" drill pipe and up the annulus with an HEC spacer on both sides. This sealant pill was composed of 4 separate blends, which were layered to promote optimal penetration. The annulus was then pressured up via the kill line until forming an initial seal around 1,500 psi. Once establishing an initial seal, a brief curing period was allowed before continuing to increase pressure in 500 psi increments up to the final pressure of 4600 psi. The sealant was held at this pressure for 2 hours to strengthen before performing 3 pressure cycles to stress and further strengthen the seal. A final 24-hour cure period then followed.

After a successful curing period, clean mud was circulated into the well followed by base oil to create an underbalance in the pipe for a 30-minute negative test. This test confirmed that a bidirectional seal had been achieved. The composite bridge plug was subsequently drilled out and the entire wellbore was tested to 4600 psi. After meeting all regulatory requirements, the operator continued with the completion scope. After perforating the zone and installing the gravel pack assembly, the leak site was permanently isolated with the installation of an isolation packer assembly.

Based on the constraints described above, alternatives considered included specialized cement blends, which were not immediately available, or a sidetrack operation. Due to the flexibility inherent to an in-situ pressure-activated sealant repair, technicians and sealant were able to be mobilized to the drillship within 24 hours. Additionally, the linear leak characteristics observed were well suited for a pressure activated sealant

repair. In comparison to the alternative sidetrack option, the sealant treatment yielded major economic, operational, and HSE advantages.

Introduction

While completing the subject subsea well, a deepwater Gulf of Mexico operator observed leakage from the recently installed 9 7/8" production liner. In response the operator performed diagnostics to ultimately locate the leak at 15,329’ MD, within the 9 7/8" casing pup just below the liner top (See Figure 1 below). Given the initial severity of the leak, a 100 bbl cement squeeze was performed with injection rates of 2 bpm at 1740 psi and 4 bpm at 2780 psi. After drilling out the squeezed cement, the leak had diminished but still persisted.

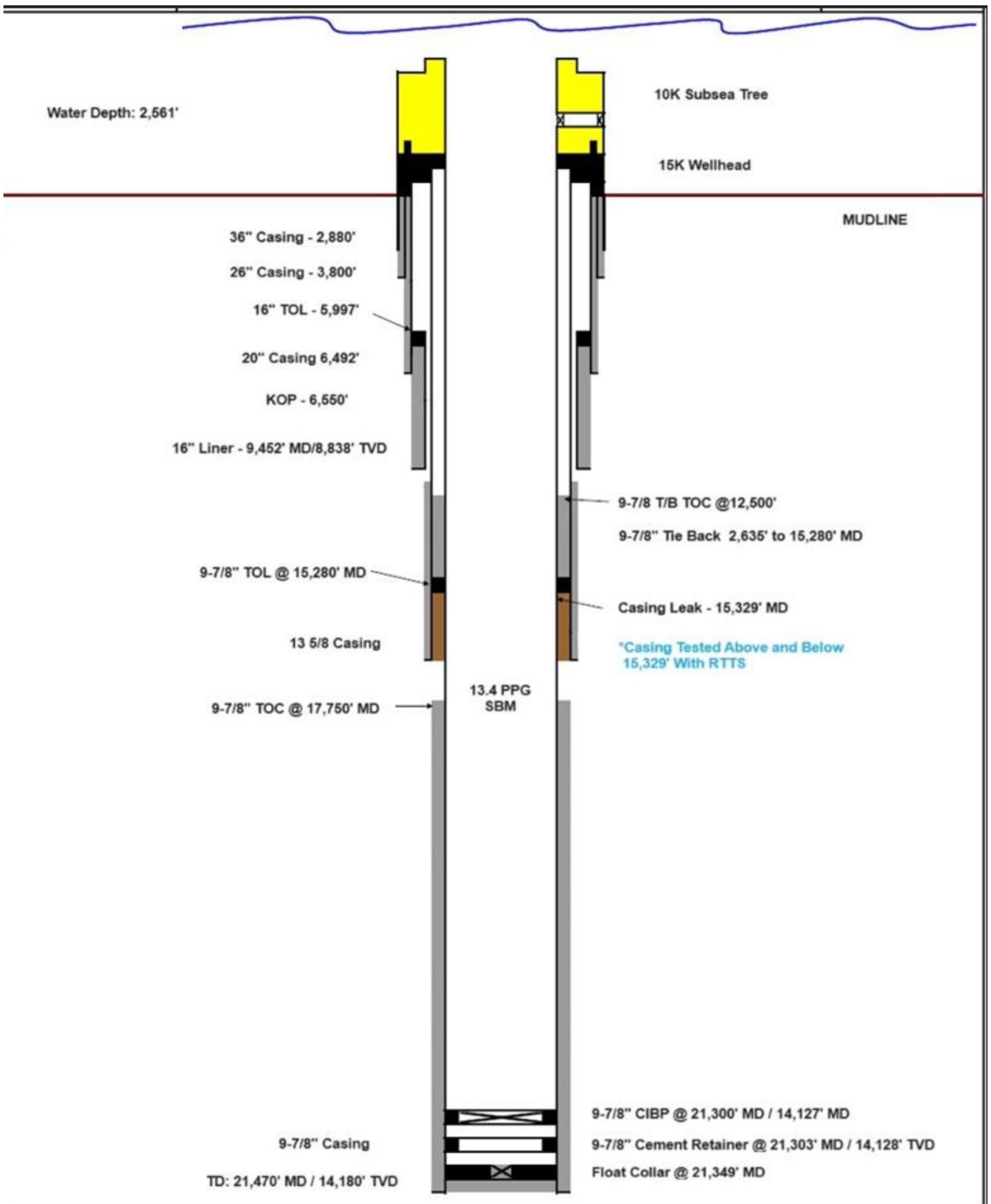

Figure. 1—Subject Wellbore Schematic with Indicated Initial Leak Location

To evaluate the current leak severity, the operator injected 22.75 bbl 13.4 ppg SBM to pressure the production casing to 4600 psi. Once established, a sustained pressure decay averaging 50 psi/min was noted. After 50 minutes of decline, this diagnostic test was concluded and the production casing was bled, returning 16 bbl SBM. Given the volume discrepancy attributed to leakage from the system, the initial leak rate was estimated to be roughly 5.7 GPM. Additional diagnostics were also performed with leak rates up to 11.4 GPM at 4600 psi test pressure. Figure 2 below is a sample from one of these leak rate tests to exemplify the behavior of the leak.

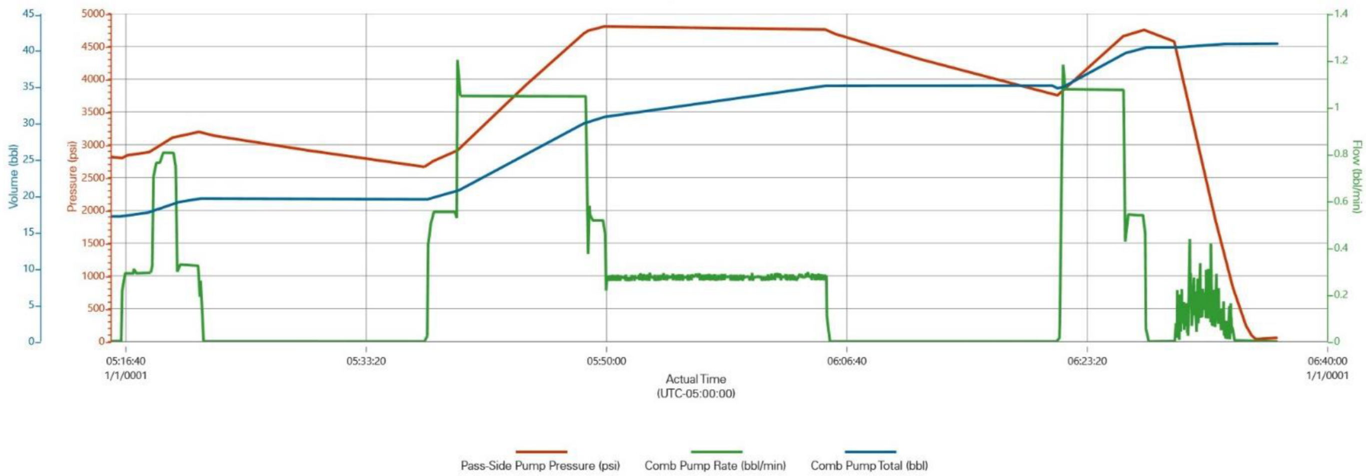

Figure. 2—Operator Performed Diagnostic Pressure Trend with Injection Volumes and Rates

The emergence of this leak put further completion operations at a standstill while the operator contemplated potential remediations. Given a daily spread cost exceeding $1MM, a prospective solution needed to be identified and implemented in short order to minimize non-productive time and associated expenditures.

Statement of Theory and Definitions

As part of their evaluation, three major options were identified and considered:

1. Pressure-Activated Sealant Treatment
2. Specialized Cement Blends for further squeezes
3. Sidetrack operation

Given the persistent leakage post cement squeeze, a mechanical intervention via a sidetrack was initially considered as a means of isolating the leak, while allowing the operator to access the same zone. A mechanical fix of this nature has a high likelihood of success in remediating the initial leak, but it also has high exposure to risk on cost, time, wellbore stability, and HSE factors. Additional cost for tubulars, liner hanger(s), cementing, and ancillary directional drilling equipment would be incurred on top of the daily growing spread cost as the sidetrack would be drilled and completed. The operator's cost estimate of performing this sidetrack was in the tens of millions assuming all went to plan. Time would be needed for the operator to redesign the completion to optimize the sidetrack with existing well design, along with considering potential heterogeneities along the changed well trajectory. Although unlikely, in the event that a new leak was to emerge along the sidetrack, the operator would be placed back in the initial scenario with even more constraints on potential remediation options.

As a lower footprint and lower cost option, the operator considered further cement squeezes using specialized blends to promote better penetration into the leak site, and thereby more effective sealing of the leak path. A major hindrance for this option was availability. With the drillship in place on location, a multiple day delay in the niche components and/or blends would translate to a multi-million-dollar cost implication.

A pressure-activated sealant approach offered the benefit of a rapid mobilization, with the capacity to custom blend the sealant based on the observed leak characteristics. The prospective sealant for this application works under the basis of pressure differential; when spotted at the leak site, the flow creates differential pressure which in turn causes the sealant to polymerize and solidify only within the leak site. The mechanisms for this sealing action are proprietary, but once polymerized, the cured sealant creates a flexible, solid seal with hardness similar to a 60 to 80 durometer elastomer. Any excess sealant in the system not subjected to the pressure differential through the leak remains liquid, able to be flushed out of the system post repair. An initial repair procedure is generated by the sealant supplier in collaboration with the operator based on analysis of the operator provided data. Once on location, specialized sealant technicians perform diagnostics to get a snapshot of the leak characteristics present under varying conditions directly before the treatment. This diagnostic information can then be leveraged to optimize the sealant blend and application procedure "on the fly" to provide the highest possible mechanical chance of success. This flexibility makes sealant repair well suited for a wide range of leak severities and situations, with minimal downtime necessary to address dynamic or sporadic leaks. Economically speaking, across all leak types, a sealant repair is often multiple orders of magnitude lower than the cost of a mechanical intervention, with a much quicker duration.

Based on their consideration of the above options and factors, the operator ultimately selected a pressure-activated sealant methodology to remediate the subject well integrity issue. Once notified of this, the sealant supplier was able to mobilize sealant, equipment, and technicians to the drillship in under 24 hours.

Description and Application of Equipment and Processes

As the drillship was on location, the sealant concentrate supplied for the operation was able to be blended in the cementing tanks present onboard. Using 13.6 ppg $CaBr_2$ brine, four sealant formulations were blended at varying strengths, totaling 20 bbl. Prior to sealant blending, a composite bridge plug was set below the leak site to allow for proper pill placement. A 50 bbl HEC spacer pill was prepared and displaced down the 5" drill pipe, followed by each of the four 5 bbl sealant pills. Following this, a 50 bbl HEC spacer pill was used to ensure sealant quality as the pills were displaced. Sealant density and viscosity were engineered to allow the wellbore fluid to stratify as to allow optimal sealant delivery at the leak depth. After all spacer and sealant pills had been injected, 210 bbl of 13.4 ppg SBM was pumped for displacement to depth.

With all pills spotted, the drillship then picked up one stand of drill pipe and closed the annular rams in preparation for the prescribed pressure sequence. Via the kill line, 13.4 pg SBM was injected to establish an initial seal at 1600 psi. Casing pressure was then monitored over the next 3 hours, and allowed to fall 200 psi before bumping up pressure back to 1600 psi. Six roughly 0.5 bbl injections were performed before casing pressure had stabilized, indicating that a seal had been created. Pressure was then increased to 2000 psi, but slowly dwindled back to the earlier obtained initial seal pressure. When increasing to 2500 psi, a similar behavior was noted and to pressure cycles were performed, whereby the casing was bled to 0 psi, then re-pressurized to 2500 psi immediately afterwards. Following the second cycle, pressure ultimately stabilized at 2300 psi. Next, two attempts were made to increase to 3000 psi before stabilizing at 2924 psi. After monitoring at this pressure level, three injections to 4000 psi were performed, but were only able to sustain 2423 psi.

Given the response to the prior steps, the sealant pressure sequence was modified to reduce pressure increases to 150 psi each to limit further sealant consumption. From the previous pressure stability level, the casing was worked up to 3000 psi and holding. The injected sealant was then allowed to cure for 1 hour. This process was repeated up to 3600 psi, and followed by another 1 hour cure period. These small pressure steps then continued up to 4000 psi, and a 6-hour cure/ monitoring period was allowed to evaluate sealant performance at this level. Over this period, pressure had decreased to 3969 psi, or roughly 5 psi per hour. With the observed improving resiliency, 150 psi pressure steps continued up to 4650 psi. Once again, a 6-hour cure period was held and saw minimal pressure decline.

As the above level was the desired test pressure for the operator, further cycles were performed to promote seal durability. Three pressure cycles were performed whereby casing pressure was bled down in descending roughly 1500 psi increments (3000 psi, 1500 psi, and 100 psi) and monitored at the lower pressure for 15 minutes, then pressured up to test pressure and monitored for 30 minutes. After concluding the cycles, a 24-hour cure period was commenced, with additional cycles down to roughly 50 psi to be performed every 3 hours. At the end of the cure, resultant casing pressure was at 4519 psi. It was monitored at this level for four hours and no pressure decline was observed. See Figure 3 below for the pressure manipulation schedule described above.

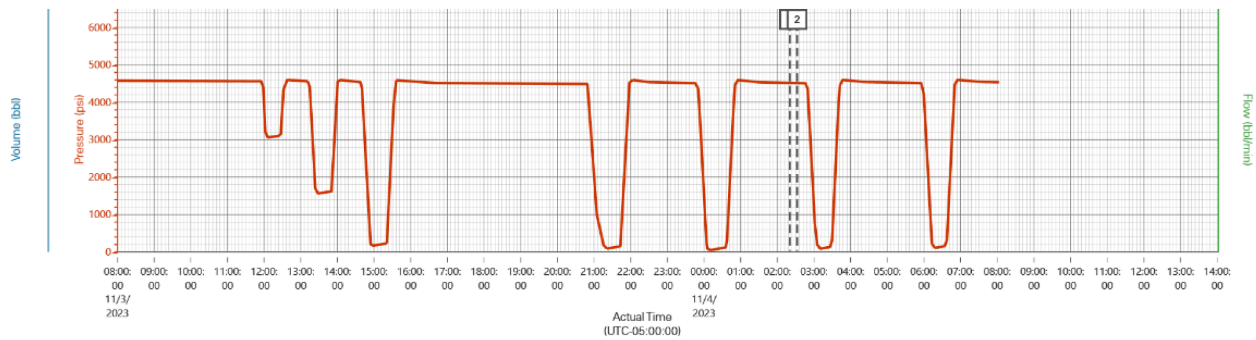

Figure. 3—Casing Pressure Trend For Cycles Following Establishment of a Seal

With the seal now established, the drillship ran-in-hole with the drill pipe to below the newly repaired leak site and the wellbore was reverse circulated out with clean SBM. The drill pipe was pulled to surface and the plug running tool was exchanged for a string mill with rock bit. As the casing had nearly been fully circulated, 64 bbl of base oil was injected to create an underbalance in the pipe in preparation for the operator to perform a negative pressure test on the repair. The pressure test began at 68 psi, and no pressure increase was noted over the 30-minute test. Next, a positive pressure test was performed at 4600 psi successfully.

Presentation of Data and Results

Sealant technicians were demobilized from the drillship after the operator achieved the initial successful positive and negative pressure tests. The operator repeated these tests to prove restored integrity, satisfying regulatory requirements and allowing them to continue on with their completion. In total, the sealant treatment took less than a week to remediate the leak. With the green light from the regulator, the operator permanently sealed off the repaired leak with an isolation assembly composed of a packer and tubing. An updated wellbore schematic is included below in Figure 4.

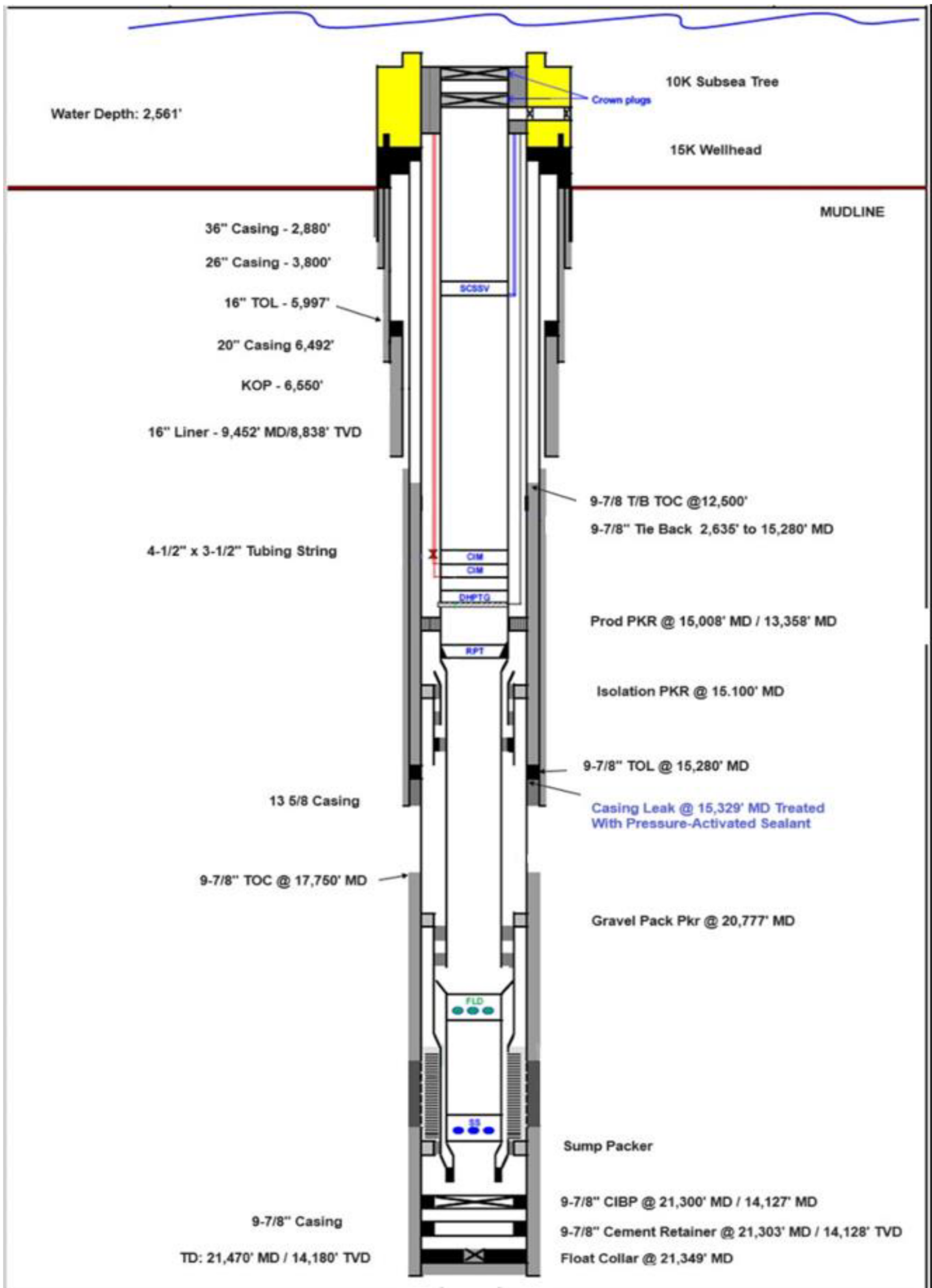

Figure. 4—Post Repair Wellbore Schematic Showing Final Isolation of the Repaired Leak Site

Conclusions

In a complex subsea operating environment, commonplace well integrity issues during the development of offshore infrastructure can threaten the safety, development, and economic viability of a project immensely. Often, as in this case, when faced with leaks or operational complications, the cost of identifying, deliberating on, and selecting a remediation methodology is compounded by high costs associated with the equipment spread on location. With this in mind, pressure-activated sealant has the ability to provide an extremely flexible, tailored solution for a vast array of subsea equipment. Additionally, the small footprint of a sealant treatment allows for integrity restoration with less risk, cost, time, equipment, and personnel than many other approaches available.