Solution for the Repair of Holes in Production Tubing Without Rig and Without Wireline Operations

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Summary

The objective of this paper is to present the development and application of a tool to repair holes in oilwell production tubing, using a method that does not require rig and wireline operations to locate the depth of the hole. The tool locates the leak and repairs it in a single run, reducing the time required to re-establish well production. This article describes the operational mechanism of the tool and its installation process. Two repairs were performed in oil wells, one of which sealed a hole near the bottom of the tubing and the second of which sealed a hole near the surface. The holes were sealed in a fraction of the time required by current solutions. This newly developed tool is a cost-effective alternative for resolving oilwell-integrity problems.

Introduction

A well-integrity analysis determines whether formation liquids and gases are isolated by means of barriers from the intermediate geological layers crossed by the wellbore (Jackson 2014). On this topic, there has been a distinction between the terms "well-barrier failure" and "well-integrity failure" (King and King 2013). Barrier failures refer to individual problems in valves, production tubing, casing, and so on, whereas integrity failures occur when all barriers collapse and well fluids leak into the environment.

Oilwell-integrity studies all indicate that the production tubing is the element most prone to failure (Molnes and Sundet 1993; Vignes and Aadnoy 2008; King and King 2013). Production tubing is vulnerable because it is exposed to corrosive fluids and to solid particles that produce abrasion; it is also made up of hundreds of joints, each one of which increases the probability of a leak. In fact, the most common tubing-failure mode is leaks, followed by blockage, rupture, and collapse (King and King 2013). These well issues are the main reasons for workovers.

A workover is a process of maintenance or repair on an oil well. In many cases, when a barrier fails, performing the workover involves removing the downhole completion to replace or repair the defective elements. This process is expensive because it requires a rig and entails additional costs in replacement parts and the lost value of oil not extracted during the days that the repair is being made. Because of this, technologies have been developed to seal leaks in the production tubing without the use of a rig. It has been shown that, under certain conditions, these alternative repair methods can generate savings of approximately USD 1 million for the operating company (Burkhead et al. 2000; Andersen 2006).

The rigless repair process is executed in two stages. The objectives of the first stage are to assess the condition of the tubing and to locate the depth of the holes. This is performed by analyzing signal logs generated by various types of sensors run in with wireline (one or more times) along the entire length of the production tubing. In the second stage, the seal is run to the required depth and activated. Seals may be created using mechanical tools or chemical compounds.

Chemical seals are made using pressure-activated compounds (Romano and Roderi 2006). The sealant, which is initially liquid, undergoes a pressure drop as it passes through an orifice, and this pressure change polymerizes the compound, forming a solid seal only within the space of the hole. To apply this technology in a well, a plug is installed in the production tubing just below the hole, and then the compound is injected. When it passes through the hole, it is then activated. The rest of the sealant remains liquid and is removed from the well after the repair is completed.

Mechanical sealing tools consist of a fixed- or variable-length spacer pipe with packoff assemblies at each end that isolate the hole in the tubing and cause the fluid to flow through an internal duct in the seal (**Fig. 1**). They have a mechanical or hydraulic anchor mechanism to set the tool at the required depth. Depending on their anchor mechanism and their length, they can be installed in one or more runs with slickline, wireline, or coiled tubing. These seals are retrievable and are considered short- or long-term solutions for production-tubing leaks (Julian et al. 2006, 2008).

Currently, all systems for sealing leaks in production tubing require one or more sensor runs to locate the hole, and additional runs to position and activate the seal (Romano and Roderi 2006; Julian et al. 2006, 2008). Although there are technologies for repairing tubing without incurring rig costs, the operations, equipment, and analysis required to locate the hole add significant cost to the total price of the repair without guaranteeing the success of the operation (Julian et al. 2008). The ongoing push to minimize operating costs—driven by current low oil prices—means that the industry requires cost-effective solutions to repair production tubing in the shortest time possible. For this reason, the following study presents a tool that, after a well assessment, locates and seals holes in the tubing in a single run, without the need for sensor and wireline operations to locate the hole. The article is structured as follows: It first describes the tool's mechanism of operation and its installation process; it then discusses two cases of use of the equipment in oil wells; the third and fourth sections present the results and conclusions.

Description of the Equipment

The tool that has been developed and patented detects and seals holes or cracks in production tubing located above the jewelry (hardware). The tool's design and installation mechanism make it possible to locate the hole and stop it precisely at the anchor site with a single run. This solution omits the operation of locating the hole with electronic sensors, enabling the tubing to be repaired in less time and at a lower cost in relation to conventional technology. If necessary, the tool can be retrieved with slickline.

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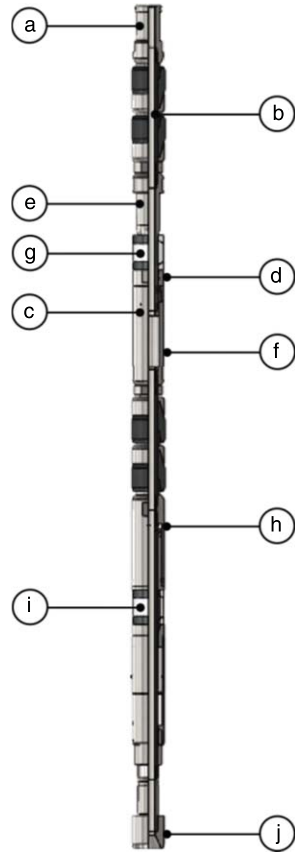

Fig. 1—Components of the tool.

The main components of the equipment are the upper and lower seals, an extension, a hydraulic positioner, and a bypass used in the retrieving operations (Fig. 1). The tool has a fixed length of 6 ft and is manufactured for use in $2^7/_8$-in., $3^1/_2$-in., $4^1/_2$-in., and 5-in. production tubulars. The technical specifications are presented in **Table 1.** It can be installed in producing wells, either vertical or directional, without causing significant restrictions to the flow. It is made of AISI 4140 steel, with seals made of hydrogenated nitrile. These materials may vary depending on the properties of the well fluid, to increase the resistance of the tool to corrosion and abrasion.

Size (in.)	Weight (lb/ft)	Maximum OD (in.)	Minimum ID (in.)	Length (ft)	Pressure Rating (psi)
$2\frac{7}{8}$	6.4–8.7	2.220	0.800	6.0	5,000
$3\frac{1}{2}$	9.2–10.2	2.865	1.200	6.0	5,000
$4\frac{1}{2}$	11.6–15.1	3.650	2.000	6.0	5,000
5	15–18	4.100	2.200	6.0	5,000

Table 1—Technical specifications of the tool.

Hole Detection, Activation, and Anchoring. The tool acts as a piston in the production tubing, descending by means of the hydraulic thrust applied from the surface by a positive-displacement pump. The pumped fluid enters through the fishing neck [Fig. 1 (a)], passes through the upper cylinder [Fig. 1 (b)], and pressurizes the rupture disk [Fig. 1 (c)]. A standing valve in the lower end of the tubing string causes the fluid displaced by the descent of the equipment to be discharged only through the hole in the production tubing **[Fig. 2 (left)].** The leak rate during the tool displacement is obtained from a flowmeter installed in the surface pump. Tests have been proposed to quantify the damage in the tubing or other downhole tools, by measuring the leak rate from the tubing to the annulus and other well parameters (Rocha-Valadez et al. 2016).

The tool continues to descend until the rubber stop blocks the flow through the hole in the tubing [Fig. 2 (right)]. The low compressibility of the fluid stops the tool precisely in the position of the hole; this pressurizes the production tubing, and, at that moment, the pressure is increased from the surface to break the shear pins [Fig. 1 (d)] that attach to the top piston [Fig. 1 (e)]. The piston drops through the extension tube [Fig. 1 (f)] and expands the upper seals [Fig. 1 (g)].

To actuate the bottom piston, the pressure on the surface is raised until the top disk is broken [Fig. 1 (c)]. The fluid pressurizes the chamber of the second piston [Fig. 1 (h)] and breaks the shear pins. The displacement of the piston expands the bottom seals [Fig. 1 (i)].

Subsequently, the surface pressure is raised to 2,500 psi to test the seating and to rupture the disk on the lower end [Fig. 1 (j)]. Applying this procedure opens the duct so that well fluid rises through the string. Finally, the tool is set by installing a tubing stop on the fishing neck. Running the tubing stop with slickline allows the setting depth to be determined. The reader will notice that this repair mechanism works when there is only one hole in the tubing.

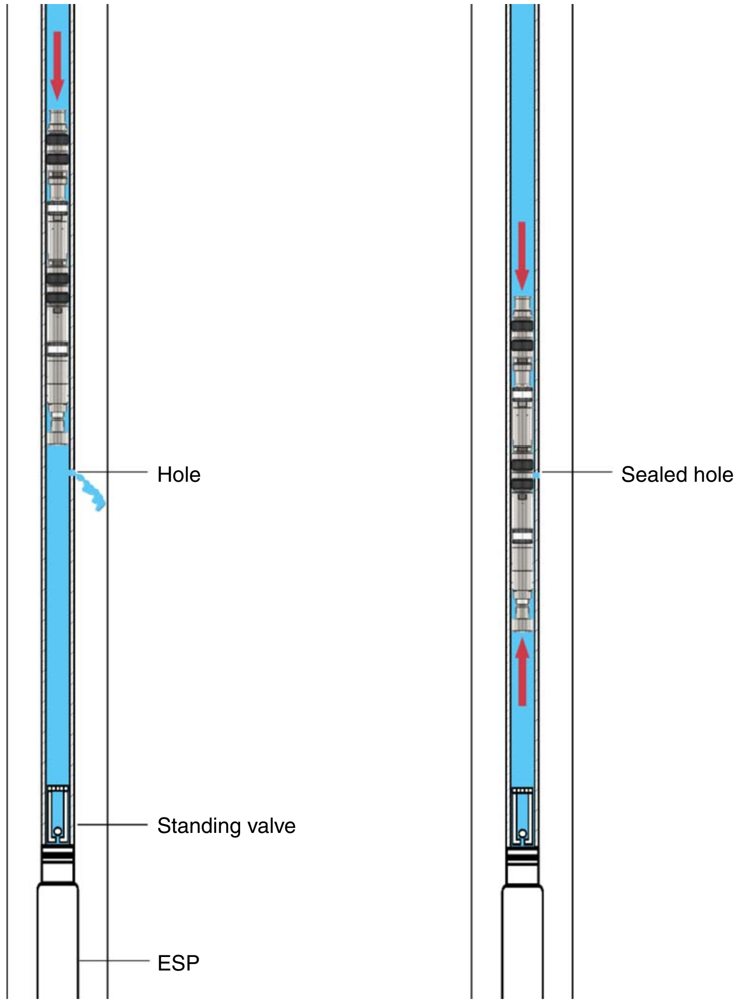

Fig. 2—(Left) The tool descends by means of hydraulic thrust, and the displaced fluid flows through the hole. (Right) When the hole is sealed, the fluid contained in the bottom part prevents the tool from continuing to move.

Performance Tests

The processes of selecting, assessing, and installing the equipment in two oil wells in oil fields of the Ecuadorian Amazonian forest are described next. The wells were closed because of leaks in the production tubing. After evaluating several repair alternatives, the operator elected to use the solution presented in this work. The tool was tested in several wells, but, in some cases, it failed to repair the existing leak. Later inspections proved that, in these wells, there was more than one hole in the tubing string.

Selection of Candidate Wells. To use the solution and install the equipment, the details of the downhole completion must be analyzed to confirm that the wells meet the following characteristics:

- The nominal diameter of the production tubing, from the wellhead to the liner, must be uniform to be able to diagnose the condition of the production tubing and install the equipment.
- It must be possible to install a standing valve at the lower end of the tubing string.

If the wells meet these requirements, the tools will be prepared and the installation equipment will be mobilized to the selected locations.

Assessment. The wells were kept closed during the assessment and the installation of the tools. In the first stage of the assessment, an inner-diameter gauge was run down the production tubing with a slickline to ensure that there were no obstructions that would block the movement of the packoff tool. Both wells had sliding sleeves; thus, it was necessary to confirm that they were closed. Otherwise, a slickline run would be required to close them.

It was necessary to check that the leak was not caused by a failure in the sliding sleeves. A standing valve was installed on the seating nipple a few feet under the sliding sleeve—if a valve is already installed, it must be removed to inspect its condition. With a hydraulic-pump unit, the tubing was pressurized using water, and the leak rate into the annulus (LR1) was recorded. The valve was removed from the bottom nipple, and an F-profile standing valve was installed in the upper-seating nipple of the sliding sleeve. The tubing was then pressurized, and the leak rate (LR2) was recorded. The leak rates LR1 and LR2 were equal, which meant that the sliding sleeve was sealed and the leak was in the production tubing. The assessment described here only ensures that the leak is in the tubing, but does not allow us to know if there is more than one hole or where they are located.

Installation. After the assessment, the tool was installed by running it in with a hydraulic-pump unit inside the production tubing. Water was used to do so, at a pressure ranging from 50 to 400 psi. A sensor was installed on the injection tubing to monitor and record surface-pressure variations while running the tool, detecting the hole, and breaking the shear pin. The seal-expansion mechanisms were activated at pressures greater than 900 psi.

After installation, a pressure test was performed to ensure that the tool was set. It is recommended that the pressure applied not exceed 3,000 psi. After passing the pressure test, a tubing stop was installed on the tool. During this operation, the setting depth was recorded, and the well was reactivated.

Results

This section describes the characteristics of the wells and their operational status before and after the tool was installed successfully. It also includes pressure logs obtained during the installation of the equipment. The tool was used in 2016.

Well A. Well A is a production well with electrical submersible pumps. It was completed in late 2015, with 3½-in. production tubing inside 9⅝-in. intermediate casing and 7-in. production casing. A sliding sleeve was located at a depth of 10,200 ft and a seating nipple at 10,225 ft. The well averaged 525 B/D, and was closed because of a leak in the production tubing.

The assessment was made, and the tool was run through the production tubing. **Fig. 3** shows the pressure log on the surface during installation. Initially, the tool was run at a pressure of 200 psi and a flow rate of 1,208 B/D, then was raised to 400 psi with a flow rate of 1,903 B/D. The tool sealed a hole and stopped at a depth of 8,492 ft, which increased the tubing pressure to approximately 700 psi. The shear pins broke at 900 psi. Running and activation took approximately 1 hour.

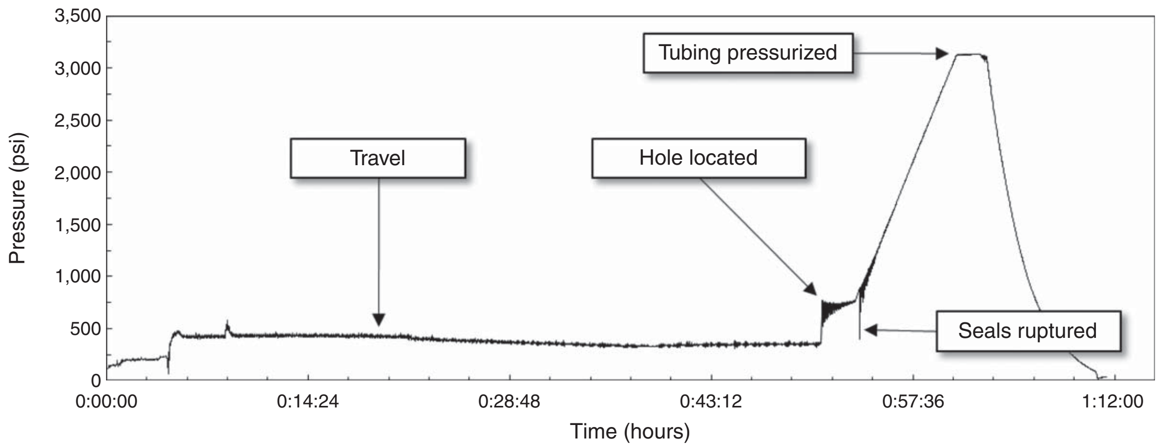

Fig. 3—Pressure log during installation in Well A; the seal reached the hole after approximately 1 hour.

The production tubing was pressurized to 3,130 psi to confirm tool setting. A tubing stop was installed over the fishing neck of the seal to prevent upwelling through the borehole from displacing it. Logs following well reactivation reveal that production returned to the original level, demonstrating the effectiveness of the technology that has been developed. The tool operated for 7 months, until the well's basic sediments and water increased and a workover was scheduled to perforate into another sand.

Well B. Well B is a production well with electrical submersible pumps. It was completed with 3½-in. production tubing inside 9⅝-in. intermediate casing and 7-in. production casing. A sliding sleeve was installed at a depth of 8,417 ft. The well averaged approximately 150 B/D and was closed because of a leak in the production tubing.

After the assessment, the tool was hydraulically run through the production tubing at a pressure of 300 psi and a flow rate of 1,440 B/D **(Fig. 4).** The tool stopped at a depth of 80 ft. The pressure was increased to 1,350 psi, and the shear pins broke and the rupture seals ruptured. Travel and anchoring took less than 5 minutes because of the shallow setting depth. The production tubing was pressurized to 2,600 psi to confirm that the device was anchored. Finally, a tubing stop was installed above the seal, and the well was reactivated. The post-installation production logs show that well production returned to its original level. **Table 2** shows the operational analysis of the wells in this study vs. repair technology using wireline operations (Burkhead et al. 2000). Note that the cost and the time of repair using the tool described here are a fraction of the cost and time needed for traditional technology.

Limitations of the Tool Developed. The tool will not be able to seal leaks in production tubing when there is more than one hole. This limits its applicability because in most wells there could be more than one hole in the tubing string. The tool can fail when there is linear corrosion that would prevent seals from isolating the leak zone. The installation may not yield the expected results because of poor assessment of the condition of the downhole completion. In addition, other holes may appear after installation. The number of pressurized cycles could cause the tool's seals to fail, resulting from extrusion.

Conclusions

A tool was developed to seal holes in production tubing with no rig and without wireline operations. The equipment successfully sealed the holes and allowed the reactivation of two wells using a process that is simple to operate. Although the operating mechanism limits the application of the tool to wells with a single hole in the tubing string, the solution presented is a valid alternative when a rapid and economical intervention is required. The success rate in the installation of the tool could increase if a previous evaluation is made to determine the number of holes in the tubing.

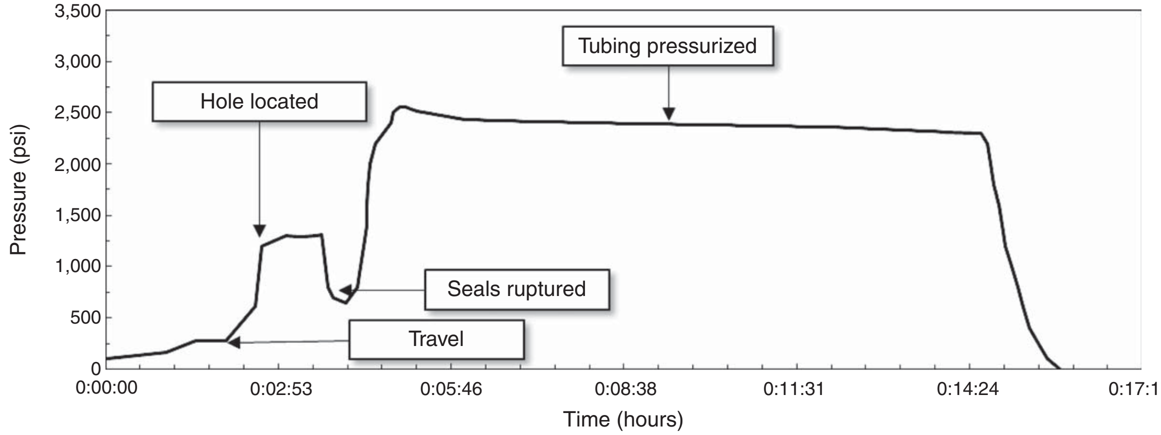

Fig. 4—Pressure log during installation in Well B; the installation time was short because the hole was only 80 ft from the surface.

	Well A	Well B	Well C
Technology used	Hydraulic tool	Hydraulic tool	Straddle + wireline
Assessment time (hours)	9	8	72–96
Repair time (hours)	2.5	1.33	
Approximate total cost (USD)	11,000	11,000	150,000

Table 2—Comparison of repair times and costs between the tool presented in this work and a wireline-guided patch.

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SI Metric Conversion Factors

bbl × 1.589 873	$E-01 = m^3$
ft × 3.048*	$E-01 = m$
in. × 2.54*	$E-02 = m$

*Conversion factor is exact.

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