Technology Handles HP/HT Challenges

By Steve Wehrenberg

HOUSTON–The successful investigation and subsequent remediation of collapsed casing in a high-pressure/high-temperature Bossier Sand well with a static bottom-hole temperature of 398 degrees Fahrenheit and bottom-hole pressure of 17,642 psi illustrates the multifunctional capability of contemporary hydraulic workover/snubbing technology.

For this well, a 460,000-pound hydraulic snubbing unit was employed to replace the coiled tubing system initially dispatched to location. The aim was to investigate suspected collapsed casing at 16,000 feet, and afterwards, mill up and remove a cast iron bridge plug (CIBP) at 17,000 feet and six composite perforating plugs, and then clean out the well bore to 18,460 feet.

Prior to the hydraulic snubbing operation and shortly after completing four of the six planned stages, the operator landed three composite plugs and the cast iron plug above Stage 4, whereupon drilling out, the plugs were restricted with 3.2-inch maximum tool pass-through diameter. A pressure survey was run to check the working pressure and temperature restrictions.

A 24-arm caliper (Figure 1) confirmed a casing collapse and an HP/HT temp spinner log verified that a leak was communicating with the active gas source. Attempts to bleed down the well had been unsuccessful and any further attempts raised concerns of further aggravating the collapsed area. Consequently, the operator elected to replace the coiled tubing system with a snubbing unit.

Because of gas migration, surface pressures had increased from 11,000 to 12,000 psi. The gas was bled off the back side and bullheaded with 11.6 pounds/gallon calcium chloride (CaCl) brine down the 4.5-by-2.375-inch annulus to minimize the surface pressure. Consequently, the well was maintained in an underbalanced condition, resulting in no damage to the previously fractured formation.

HP/HT Challenges

In the oil and gas industry, the precise criterion that defines abnormal bottom-hole pressures and temperatures varies from region to region. In the U.K. North Sea, for instance, the official designation of an HP/HT well stipulates that it must have an undisturbed bottom-hole temperature of more than 300 degrees with a pore pressure gradient either exceeding 0.8 psi/foot or sufficient pressure to require using well control equipment rated to more than 10,000 psi working pressure. The for-
workover, a producing well must be shut in while the operation is being performed. Consequently, compounding the costs associated with lost production is the initial expense of killing the well and the expense required to reinitiate production once the re-entry operation is completed. By way of illustration, installing a completion string after a typical frac job requires the operator to first employ high-density fluid to kill the well. In addition to the costs of the brine and kill fluids are the rig-related expenses associated with running the pipe in the well bore. Historically, a coiled tubing unit has been brought in afterward and nitrogen was used to restart production, further increasing costs.

Based on the industry’s experience and expertise in the Barnett Shale in northern Texas, operators have become comfortable with drilling and completion practices in tight gas shales. Along with the Barnett, the methods have proved common and efficient in numerous other shales, including the emerging Marcellus gas shale and the Bakken oil shale. However, operators in the highly productive Haynesville Bossier Shale in East Texas and North Louisiana are encountering drilling and completion complications not experienced in other onshore shale plays. Typical Haynesville wells are drilled to 12,000-15,000 feet measured depths with bottom-hole temperatures exceeding 300 degrees and pressure gradients ranging in excess of 1.0 psi/foot.

**FIGURE 2**

**Early Rig-Assisted Snubbing Design**

The pressures and temperatures intrinsic to these wells have made drilling and completion methods more costly and time consuming than those of the Barnett, Marcellus, Bakken and the emerging Eagle Ford Shale play in South Texas. By and large, Haynesville operators have been forced to modify completion practices to overcome the constraints imposed by the HP/HT environment. Completing wells with coiled tubing had been the preferred approach, mainly because of its speed in moving in and out of a well bore. However, with the high pressures and extended depths of many Haynesville wells, operators are discovering that coiled tubing is no longer a viable option.

In many wells within such environments, using coiled tubing essentially must be discounted, primarily because of the inherent risks of pipe fatigue/failure, the need for ultrahigh pumping pressures, and the downhole mechanical friction resulting from the wall-to-wall contact fundamental with this technology. Consequently, operators in the Haynesville and similarly hostile drilling environments are focusing more of their attention on the operational, economic and environmental benefits of hydraulic snubbing technology.

**Snubbing Technology**

There was a time when the arrival of a snubbing unit on location was cause for alarm. Certainly, when snubbing was introduced to the industry, it was strictly for well control purposes. The industry needed a way to move tubulars in and out of a well bore under pressure, as well as re-enter and work over pressurized wells, and snubbing was the only means available to run tubing into a live or flowing well.

Over the years, however, operators have recognized the wide-ranging benefits of snubbing other than in well control situations. Today, snubbing has evolved into a multipurpose technology offering a host of operational and economic benefits in drilling, workover and completion applications. From its early use solely for well control purposes, snubbing soon evolved as a highly functional means of properly completing wells that were difficult to control.

The original process involved using a series of blowout preventers that were engineered to allow stripping of the pipe from ram-to-ram with minimal friction, thereby extending operational life. In early snubbing units, two sets of slips, positioned upside down held the pipe in place. One set of slips remained stationary and the other traveled on a set of cables attached to the rig blocks. With the advent...
of the hydraulic unit, the cable-type design began to phase out.

The original units were a “rig assist” design, whereby they had to rely on power supplied from the draw works and traveling blocks on the drilling rig to move pipe in and out of the well bore. The first rig-assisted design, as shown in Figure 2, was engineered around a series of sheaves, cables and/or chains, counter weights and slip bowls. Once the unit was rigged up, the sheaves were placed so that as the traveling blocks hoisted up, the unit would snub “in hole.” The well pressure pushed the tubulars out of the hole, while the descent of the traveling blocks controlled the speed at which the pipe snubbed out of the well bore. In those first units, the slip bowls, BOPs, valves and other components were operated manually. Consequently, for this process to be successful, it relied to a great extent on the rig and snubbing crews working closely together.

Hydraulic Systems

With steady advances in both hydraulics and pneumatics, rig-assisted snubbing units were eventually displaced with highly engineered hydraulic snubbing/workover systems. Today’s hydraulic snubbing units are self-powered, highly mobile and self-contained systems that can be used either inside a derrick or as a standalone unit when no rig is on location. A 600,000-pound, self-contained hydraulic unit has a lift rating of 300 tons, while a hydraulic rig-assisted unit has a lifting capacity of 170,000 pounds, or if used in conjunction with a rig, the equivalent lifting capacity of the rig.

Hydraulic snubbing units are operated from the work platform located on top of the hydraulic jack assembly. If required, from this position the speed of the pipe and the slips can be controlled in much the same way as the rotary table. Stationary and travelling slips are operated sequentially to grip the pipe as it is snubbed into the well with one operator controlling the BOPs and equalizing valves, and another employing the counterbalance system to coordinate the pipe handling.

Furthermore, snubbing units can be used to introduce a range of pipe sizes into the well and can be employed to snub tubing, drill pipe and even casing in exceptional circumstances. Today, snubbing units are engineered in a wide range of sizes, from smaller through-tubing units to those large enough to effectively run 9 5⁄8-inch casing handling hook loads of 300 tons.

On both land and offshore installations, the rigging up of snubbing units is relatively uncomplicated and comparatively time efficient. Snubbing operations on floating rigs or wells completed subsea are rare, but the units have been used effectively offshore for both well control and intervention operations.

Modern snubbing units can perform any of the tasks required of a conventional rig and do so while working in an under-balanced state. The benefits of working over an oil and gas well in its natural under-balanced state continue to be realized every day. Furthermore, in areas where using high-density mud and completion fluids raises the risks of formation damage as well as water block, the ability of a snubbing unit to function effectively, depending on the well requirements, with zero to minimal fluids have helped increase and prolong production dramatically.

This is especially true in wells producing from an HP/HT environment, where the cost of the mud and high-density brines combine to dissuade operators from working over or recompleting wells in need of maintenance to sustain production capacity. In some areas, using snubbing in workover operations is relatively common, typically in applications where the well is allowed to continue flowing as remedial work is performed.

FIGURE 3

Final BOP Stack Design on Bossier Sands Well

Prejob Planning

Prior to initiating the casing investigation and remediation operation on the suspected casing-collapsed HP/HT Bossier Sands well, the tri-axial loading stresses that would be applied to the tubulars were calculated and reviewed. Tri-axial loading is a combination of torque, tension and differential pressure based on the von Mises principle that would be applied to the tubular simultaneously during a snubbing operation. Since all three forces are working together at the same time, tri-axial loading puts the highest stresses on a tubular. Even though tri-axial loading is the most prevalent cause of downhole tubular failures, surprisingly, it also is commonly overlooked.

Accordingly, one of the first prejob activities was to model and calculate the tri-axial loading expected when designing the combination string. The combination string was engineered to achieve the highest degree of over pull in the event the string became stuck.

The next phase of prejob planning was to design the BOP stack to accommodate ram-to-ram stripping and well control, while also providing redundancy. Even though the well had been loaded with 11.6 pounds/gallon CaCl brine, the surface pressures were maintained from 7,000 to 9,000 psi. The final BOP stack design included nine BOP rams and three full-bore frac valves in the top-down configuration shown in Figure 3 (all with an internal diameter of 7.062 inches). The final stack designed also incorporated three choke manifolds ranging from 20,000 psi to 15,000 psi.

Furthermore, a key consideration during prewell planning was the importance of incorporating snubbing/pipeline guides. During snubbing operations, compressive forces are applied to the tubular. Without lateral support for the tubular or inadequate guiding, the tubular can buckle, losing all compressive loading capacity. Typically, helical and sinusoidal tubular buckling are the most common types that occur both downhole and at the surface.

Project Execution

After confirming suspected casing problems on the drilled multizone completed Bossier Sands well, the CT unit was brought in to remove the CIBP at 17,000 feet and the six HP/HT composite plugs. Wireline runs earlier revealed a restricted inside diameter of 3.2 inches at 15,995 feet. Soon after the CT unit arrived on location, concern was raised over whether the system could pass through the damaged casing area. More-
over, the operator was concerned that the bottom-hole temperature of 398 degrees and the 17,642 psi calculated bottom-hole pressure would negatively impact the CT unit’s downhole motor performance. Table 1 lists the well’s parameters.

In addition to the restricted passage area and the challenging downhole conditions, using coiled tubing would require high-density fluids to lower the surface pressure, which would further hamper the unit’s ability to establish the necessary pump rates. Accordingly, should well control become an issue, fears of the well collapsing became a tangible concern.

Although the operator initially considered employing weighted mud to overbalance the well bore, that approach was readily discounted because of apprehension that doing so could damage the reservoir of the new completion. Consequently, all of the well site considerations led the operator to replace the CT unit with the 460,000-pound hydraulic snubbing system.

Because of the 4½-inch casing, the largest tubing for the project was 2.375 inches outside diameter. After looking into the parameters of the completion and the suspected tight spot in the casing, a combination string was designed consisting of API class P110 and S135 tubulars engineered to achieve maximum over pull at surface. API P110 tubulars possess minimum and maximum yield strengths of 145,372 and 178,411 pounds psi, respectively.

After all the well control equipment was in place, the snubbing unit was rigged up on location (Figure 4). The BHA consisted of a reverse clutch mill, two dual flapper valves and two profile nipples.

The execution of the project was rather straightforward, beginning with running in the hole to remove the CIBP and the six frac plugs. The snubbing unit provided a snubbing capability of 230,000 pounds. Total rig up height was approximately 80 feet to the top of the snubbing basket.

As mentioned, gas migration caused surface pressures to increase from 11,000 to 12,000 psi. At that point, the gas was bled off the back side and bullheaded with 11.6 pounds/gallon CaCl brine down the 4.5-by-2.375-inch annulus to minimize surface pressure. The well was maintained in an underbalanced condition, resulting in no damage to the previously fractured formation. Because of safety concerns related to the surface pressures, the operation was carried out during daylight hours. Even so, the entire operation was completed successfully in 120 working hours.

FIGURE 4

Hydraulic Snubbing System
Rigged Up on Location

Snubbing operators are shown here running pipe from the work basket of the 460,000-pound hydraulic snubbing unit on the Bossier sands well. The entire operation was completed successfully in 120 working hours.

TABLE 1

Bossier Sands HP/HT Well Specifics

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Specification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well Type: Gas</td>
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<tr>
<td>Bottom-Hole Pressure: 17,642 psi</td>
<td></td>
</tr>
<tr>
<td>Bottom-Hole Temperature: 398 degrees F</td>
<td></td>
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<tr>
<td>Surface equipment: 4.062 inch 20M</td>
<td></td>
</tr>
<tr>
<td>Completion fluid: 11.6 pounds/gallon CaCl</td>
<td></td>
</tr>
<tr>
<td>Maximum surface pressure: 12,000 psi</td>
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Steve Wehrenberg is a technical adviser for Boots & Coots with particular expertise in well intervention. He joined Boots & Coots in 2008 and began providing solutions for operators in tight gas plays and HP/HT applications throughout North America. Previously, Wehrenberg worked at Halliburton in various roles with increasing responsibility, from field operations, to global well intervention instructor and North America technical adviser. Wehrenberg has more than 22 years of experience in the oil and gas industry. He is a board member of the Intervention & Coiled Tubing Association and the Society of Petroleum Engineers Young Professionals Mid-Continent chapter.