WELL CONTROL AND INTERVENTION

Simultaneous drilling and snubbing
speed completion and production
Simultaneous drilling and snubbing speed completion and production in difficult Rocky Mountain fields

Advanced drilling and completion practices allow efficient production from a previously uneconomic play, while limiting impact on a sensitive environment.

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A tight gas formation on the Pinedale Anticline and in North Jonah Field of west-central Wyoming was discovered in the 1960s, but economical development of the fields was not possible using conventional methods and tools. Overpressured sands in these fields consist of stacked lenticular pods extending over a 5,000-ft interval. Completion of so many zones using conventional means was often not possible given the expense of early technology.

However, by combining time-saving new technologies with simultaneous drilling, completion and production operations, operators in the area have been able to develop the reservoirs quickly and successfully. To accommodate the time restrictions, Ultra Resources has developed a streamlined process in which wells are drilled with self-moving rigs, stimulated and then completed as live wells using hydraulic snubbing units provided by Boots & Coots. Simultaneous operation of drilling, wireline, fracturing and snubbing equipment on a single pad is common, Fig. 1. Produced gas and water from adjacent wells on a pad are used to drill out plugs during completion. An innovative package of flowback equipment even allows the sale of the gas produced during drilling and completion. This innovative approach allows the operator to realize revenue from drilled wells during completion.

SUMMARY OF PREVIOUS PRACTICES

Most of the development in the Pinedale/Jonah area is located on land controlled by the US Bureau of Land Management (BLM). In a portion of these areas, operations are only allowed to be conducted from mid-July through mid-November.

In previous development operations in the Lance and Mesa Verde Formations, a single well was drilled on each location. Individual sands were selected for completion and grouped into stages. After each stage was perforated and stimulated, stimulation fluids were flowed back and the stage tested. To test the next interval of interest, a Cast Iron Bridge Plug (CIBP) was set and the next stage was evaluated. This process required many days per stage, and was not started until drilling was complete and the rig was moved off the location. Typically, a stage would cover a thickness of 50–200 ft with multiple sands perforated.

After stimulation and testing, a snubbing unit was moved in to drill out the CIBPs. (During live-well operations, time consuming ram-to-ram stripping was used to move pipe.) The milling assembly was then pulled, and the completion string was run. The snubbing operation has historically been conducted with either stand-alone hydraulic snubbing units or hydraulic rig-assist snubbing units used in conjunction with a service rig, depending on availability of equipment and the anticipated flowing and shut-in surface pressures.

Drilling operations were conducted 24 hr/day but still took months to drill a well to 14,000 ft. Live-well completion operations were limited to daylight hours. Because stimulation and flowback

Fig. 1. Simultaneous drilling, snubbing, wireline and frac operations, as seen here, have allowed Ultra Petroleum to develop previously uneconomic reservoirs.
of each stage required about seven days, and the typical completion in these fields commingled two to seven stages, that method of completion often required more time than was economical.

**NEW PRACTICES AND TOOLS**

Numerous changes in operating practices were adopted to expedite gas delivery following completion of drilling. An average well can now be drilled in less than 40 days and in some cases 20 days. This has been done with advances in bits, motors, fluids and expedited rig moves.

**Multi-well pads.** The configuration of multiple-well pads was refined as self-moving drilling rigs were employed. Most pads accommodate only four wells, but multiple-well pads with 4–16 wells have been used successfully to limit the footprint of drilling and completion operations. The configuration of wells on the pad dictates the order in which the different completion operations are conducted and the specific equipment used.

**Self-moving rigs.** Two types of hydraulic drilling rig movement systems are currently in use; one that “walks” and one that “slides.” Previously, a rig move required four to five days. Self-moving rigs can move 25 ft in a matter of hours, exposing the newly drilled well for prompt completion operations.

**Snubbing units.** Once the drilling rig is moved to expose the wellhead, wireline and stimulation operations can begin. If the drilling rig is moved to an immediately adjacent well, a stand-alone hydraulic snubbing unit is then rigged up, Fig. 2. If more room is available, a service rig and rig-assist snubbing unit may be used.

The stand-alone snubbing unit used in this application with its accompanying BOP snubbing equipment has become known as a “quick rig.” Only two heavy lifts are required to assemble the BOP equipment and the entire snubbing unit on the wellhead. The top-to-bottom BOP equipment configuration for the “quick-rig” snubbing unit is as follows:

- 7\(\frac{1}{16}\)-in. spherical annular BOP
- 7\(\frac{1}{16}\)-in. single-ram BOP dressed with stripping rams and equipped with equalize and bleed-off loops
- 7\(\frac{3}{16}\)-in. spacer spool
- 7\(\frac{1}{16}\)-in. single-ram BOP dressed with stripping rams
- 7\(\frac{1}{16}\)-in. double BOP dressed with pipe “safety” rams in the upper cavity and blind rams in the lower cavity.

Stand-alone snubbing units can work in both the pipe-“light” and pipe-“heavy” situations, and have a powered rotary for the milling operation. This unit does not require any assistance from a service rig, but pipe has to be worked in single joints during time-consuming tripping operations. The stand-alone configuration is also better suited than a rig-assist unit to safely handle elevated surface pressures with the appropriately pressure-rated BOP equipment.

A rig-assist snubbing unit may be used if sufficient space is available to accommodate a service unit. A rig-assist is configured to handle the pipe-“light” situation and allows for the pipe to be stripped through an annular BOP during tripping operations. This type of snubbing/stripping operation is conducted for surface pressures up to 2,000 psi.

An innovative BOP configuration adopted for completion operations allows annular stripping at pressures up to 4,000 psi. For pressures above 2,000 psi, an additional annular BOP is used below the stripping stack supplied with the rig-assist snubbing unit. The lower annular BOP contains the full wellhead pressure, and the pressure between the two annular BOPs is maintained at half of the wellhead pressure. For example, when working on a well containing 3,000 psi wellhead pressure, 1,500 psi would be maintained between the two annular BOPs such that a 1,500 psi differential was maintained across each annular element.

This configuration allows completion operations to proceed at a much faster rate than would be allowed by ram-to-ram stripping.

The BOP equipment used with a hydraulic rig-assist snubbing unit is comprised of the following components, from top to bottom:

- 7\(\frac{1}{16}\)-in. spherical annular BOP
- 7\(\frac{1}{16}\)-in. single-ram BOP dressed with stripping rams
- 7\(\frac{1}{16}\)-in. drilling cross, equipped with equalize and bleed-off loops
- 7\(\frac{1}{16}\)-in. single-ram BOP dressed with stripping or pipe “safety” rams
- 7\(\frac{1}{16}\)-in. spherical annular BOP (for surface pressure above 2,000 psi).

This configuration is easily rigged up in a single lift by using the rig’s drawworks to hoist the snubbing unit and the BOP equipment off a body-load truck into position on the wellhead. The snubbing unit is assembled above the well service contractor’s hydraulically operated double BOPs, and dressed with pipe rams in the top cavity and blind rams in the lower cavity. The double BOP is typically connected to a separate accumulator apart from the snubbing unit or the well service rig’s hydraulic systems and is placed a distance of 75–100 ft from the wellhead in the path of primary egress in case of an emergency during the operation.

Using the rig-assist configuration allows for quicker trip times because the snubbing unit only handles the pipe during the pipe-“light” situation. When the pipe-“heavy” situation is reached, pipe is run by the rig’s drawworks as it is stripped through the surface pressure-control equipment.

The rig-assist configuration also allows for the tubing string to be worked in double stands, which greatly decreases the trip time to pull the milling assembly and run the tubing back in the well for the completion. The passive rotary bearing allows for pipe rotation in the pipe-“light” situation, but the rotary motion must be supplied by a hydraulic power swivel.

The use of the snubbing units also decreases the cost and environmental impact of the overall completion by eliminating the need to produce, transport and dispose of kill fluids.

**24-hour operations.** Previous live-well completion operations were conducted only in the daylight, because visibility is critical for safety during pressure operations. Current operations employ a large
array of light plants to provide safe visibility at all hours.

**Flow-through frac plugs.** Also key to minimizing completion time is the use of several new tools. Perhaps the most important of these is the aluminum Flow-Through Frac Plug (FTFP), a drillable plug that allows only upward flow, so stimulation fluids cannot enter the previously treated stages isolated below.

Operators once were very careful to select only the most promising sands for completion, and the total sand thickness opened per well averaged 50–70 ft. These sands were grouped into stages for stimulation. More efficient completion practices now allow operators to open 600–1,000 ft of total sand thickness.

**Independently fired perf guns.** The FTFP is used in combination with a perforating system that allows independent firing of tandem guns. After treating one stage, a setting tool and FTFP are run at the bottom of an assembly of perforating guns. First, the FTFP is set to isolate the previously treated stage, and then each sand in the next stage is perforated. The newly perforated sands are then stimulated, and the process is repeated until all sands have been treated. Stages typically include one to six sands, and flowback is delayed until several stages have been treated.

**Producing while completing.** Produced gas and water are used for drilling out FTFPs. Another important change in operational practices is the use of sand traps, high-volume separators, diffusers and trash catchers during flowback operations and during the drillout of FTFPs. Together, the snubbing units and flowback equipment allow production to be maintained during the entire completion operation including the drilling out of FTFPs. It is not uncommon in the Pinedale/Jonah area to sell gas while drilling out the FTFPs, whereas previously the gas would be flared to a pit.

**CONCLUSION**

The solid application of new technology and teamwork by Ultra Resources, Boots & Coots and Ultra’s other drilling and completion contractors has overcome many difficult obstacles in the Pinedale/Jonah area. Wells in this area are now being drilled and completed in a much shorter time than was previously possible.

Simultaneous operations make it possible for a single pad’s operations to include two drilling rigs, a frac crew, two wireline crews, two crane crews and two snubbing units working safely together.

With the use of snubbing units and appropriate flowback equipment, it is now possible to begin realizing a return on investment even before the completion is finished. This is a good example of how a snubbing operation can help an operator in a non-critical well-control role. Another advance has been a major decrease in environmental impact due the improvements in equipment and in the overall drilling and completion process.

**THE AUTHORS**

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Gabe Gibson is a senior well control engineer for Boots & Coots. His 16 years of well control experience include surface intervention operations to cap, control and kill both on- and offshore wells. Mr. Gibson was involved in the preliminary design, fabrication and deployment of abrasive pipe-cutting equipment, and has extensive experience with both rig-assist and stand-alone hydraulic snubbing equipment to control high-pressure live-well situations. Mr. Gibson graduated from Oklahoma State University in 1991 with a BS in engineering technology.

John B. Garner is vice president of engineering for Boots & Coots. He is responsible for all well control engineering activities and oversees a staff of engineers involved in well intervention and response. John has worked on numerous well control situations, from pressure control of HPHT and deepwater wells to surface and subsurface blowouts. He also served as senior well control engineer for the Iraqi oil well fires during the initial stages of the US invasion of Iraq in March and April 2003. John holds a BS degree in mechanical engineering from Texas A&M University and has over 27 years’ experience in drilling and petroleum production. He is a licensed professional engineer in Texas.

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