Drilling for Coalbed Methane in the San Juan Basin With Coiled Tubing

In 2006, a coiled-tubing-drilling (CTD) pilot program was initiated in the San Juan basin consisting of seven wells, drilled in order of increasing complexity. The intention was to evaluate the capabilities of CTD and its potential for use in the San Juan basin. The rig used was a new, custom-built, coiled-tubing (CT)/rotary hybrid rig with a single-sized derrick, rotary table, and topdrive. This allowed the rig to drill with jointed pipe, handle and make up bottomhole assemblies (BHAs), and run liners and casing.

Introduction

The San Juan basin is approximately 9,000 sq miles in northwestern New Mexico and southwestern Colorado. Remaining recoverable gas reserves are estimated to be 12.9 Tcf, with 8.5 Tcf of this coalbed-methane (CBM) reserves. Since the first well was drilled in 1901, thousands of wells have been drilled in the San Juan basin. Most of these wells targeted gas reserves in the Picture Cliffs, Mesa Verde, and Dakota formations. Starting in 1988, wells targeting CBM in the Fruitland Coal began to be drilled. The basin currently contains approximately 30,000 producing wells, the majority of which are producing gas from the Fruitland Coal.

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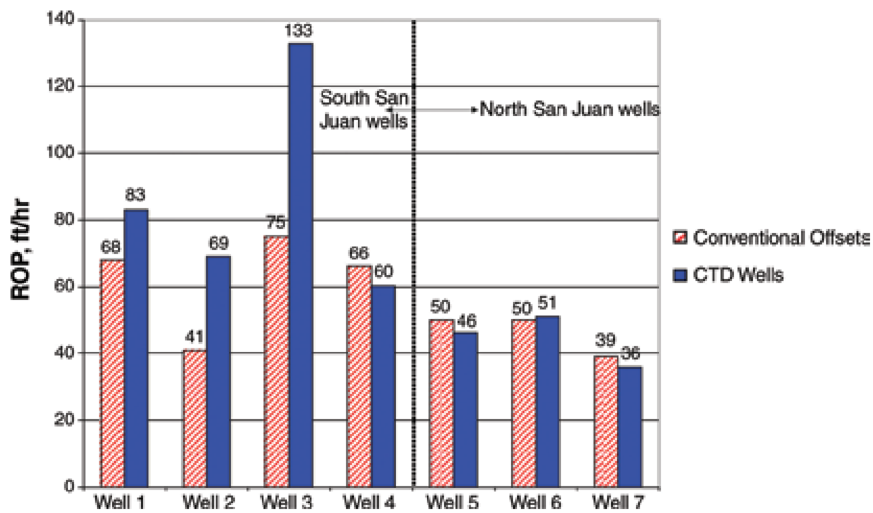

Fig. 1—Comparison of ROP for CTD vs. conventionally drilled offsets.

Pilot-Program Objectives

The drilling program was set up to evaluate the potential of CTD in the San Juan basin. Five major areas of performance were highlighted as key indicators of potential: rate of penetration (ROP), directional capability, rig mobility, re-entry/horizontal-sidetrack performance, and safety performance. Because of the high daily cost or spread rate of a hybrid CTD rig vs. the conventional rotary rigs in the basin, high average ROPs would be the key to enable CTD to compete economically with conventional rigs. Relatively higher average ROPs with CT had been documented in other areas. Along with higher ROPs, overall well-completion time has historically dropped with the use of CT because of CT trip speed and dog-leg-severity capability.

The wellbore directional plans included build-and-hold and S-shaped plans and horizontal sidetracks. All of the wells to be drilled except for the sidetracks, both vertical and directional, needed to be drilled with larger hole sizes ($8^3/_4$ and $6^1/_4$ in.) to accommodate the typical wellbore completions; this necessitated the use of larger, $3^1/_2$- and $2^7/_8$-in.-outside-diameter (OD) CT. Although directional work with large-size CT has been completed successfully, smaller-size CT typically is used for directional CTD work. The directional component of the program was complicated further by testing a rotary-steerable system (RSS) for directional control in the wells to be drilled. This was done successfully and was a world first in the industry.

Rig Equipment

The drilling rig was a custom-built hybrid CT unit. At the time of the project, it was the only rig running in the lower 48 states with the capability to drill large-size wellbores with either CT or jointed tubulars. However, the hybrid concept is not new, as rigs of similar construction have drilled and completed successfully more than 450 wells on the North Slope and many vertical wells in Canada. The layout

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was similar to most land drilling rigs, and all of the main rig components were trailer mounted. The full-length paper details the rig specifications.

ROP

One of the strongest selling points for CTD has been ROP. With better downhole motors, polycrystalline-diamond-compact (PDC) bits, and the absence of connections, CTD ROPs have been increasing. In areas such as Canada, rates as high as 650 ft/hr have been achieved consistently with large-diameter CT rigs drilling vertical wellbores. Even in areas where CTD has not had faster on-bottom ROPs than conventional rigs, the fast trip times and absence of connections have led to better-than-average ROPs.

Fig. 1 shows that for this project, ROPs in the four wells in the South San Juan basin were comparable to or better than those of conventional offsets. Each well had periods of slower penetration rates that were formation related. Typically, while in the slower-ROP portions, higher than normal weight on bit (WOB) was required to maintain penetration rates. However, at times WOB would spontaneously climb rapidly, causing a motor stall. This, coupled with the fact that picking up the bit 10 to 20 ft and resetting the bit typically helped ROP, led to a consensus that weight transfer was an issue.

Smooth weight transfer is sometimes difficult to achieve in more-deviated wellbores. When the nonrotating CT is pushed through the cuttings bed that forms in deviated CTD wellbores, it often will hang up until a higher snubbing force is applied and then slide ahead rapidly. This movement often will transfer a large amount of weight to the bit, resulting in a motor stall. However, data from Well 6, the most deviated wellbore to date, seemed to refute the earlier assumption that weight transfer was the problem area.

The issue was found to be the injector control system. The injector could not feed CT at a rate less than 50 to 60 ft/min. This led to constant manipulation with the CT feed control to feed CT but avoid stacking too much weight and stalling the motor. This was particularly true while drilling harder formations in the portion of the wellbores below 1,500 ft true verical depth (TVD).

The average-ROP trends (Fig. 1) show significant improvement over the normalized offset performance using conventional rigs. The average increase in ROP in the first four wells was 36%, despite Well 4 coming in 22% slower than its offsets. However, Well 4 was a directional wellbore compared to vertical offsets. When adjusted for comparison to vertical offset wells, Well 4 was within 12% of the offset wells. The two wells drilled in the North San Juan, Wells 5 and 6, also had encouraging results with regard to ROP. Well 5 was only 8% slower than offset S-shaped wellbores, and Well 6 was actually 1% faster than those same offsets despite several experimental PDC bits being run while drilling it.

Bit selection for Wells 3, 4, 5, and 6 was first made with RSS in mind. All of the bits run were designed for stability and directional capability. The bits' profiles were shorter, leading to a more stable bit. The bit stability was intended to limit vibration and allow wells to be drilled in one run. This was accomplished only once, in Well 3, but only two bits in the entire project showed severe wear. The rest were pulled because of a mismatch with the formations drilled. The bits also were selected with the push-the-bit RSS in mind. The major design component for this aspect was the gauge cutters and their effect on the ability of the RSS to hold and change direction. Designs with gauge cutters on each blade and on alternating blades were tested, with each type performing well.

Bit balling while drilling was never an issue; however, packing off bit junk slots while tripping through cuttings beds and shales with nonrotating pipe was an issue. Therefore, the bits selected had large junk slots to prevent this from happening.

Wellbore Cleaning and Stability

Wellbore cleaning is always a concern in CTD operations. The lack of rotation by CT typically results in inadequate hole cleaning. As long as the annular velocities in vertical wellbores are at least 120 ft/min, hole cleaning should not be an issue. However, in deviated wellbores, large cuttings beds form on the low side of the wellbore while drilling with CT. If fluid properties are not maintained and proper drilling practices are not followed, the risk of losing weight transfer to the bit and even sticking the CT exists. For deviated and horizontal wellbores, annular velocities should be at least 240 ft/min. For Wells 1, 2, and 3, hole cleaning was considered a secondary issue; but as the drilling program progressed to highly deviated wells, hole cleaning was more of a concern. Wells 1, 2, 3, and 4 had significant wellbore-stability issues that were not seen in wells later in the program.

Wells 1, 2, 3, and 4 were drilled to total depth (TD) with few or no wellbore-cleaning or wellbore-stability issues during drilling. Drilling practices that were followed involved wiper trips, frequent pickup and slack-off weight checks, and high-viscosity sweeps. Well 4 saw the introduction of alternating low-viscosity/high-viscosity sweep sets; however, drag never was seen as an issue, so improvement was hard to quantify. At times, seepage losses were observed but never developed into a serious problem while drilling. The only well with serious losses, Well 1, had these losses occur during a cleanout run after attempting to log the wellbore. After two trips, the losses were finally healed with fine-carbonate and fibrous lost-circulation material. The losses were attributed to a depleted coal seam in the Fruitland Coal. Mud weights for the freshwater and gel mud were kept between 8.9 and 9.1 lbm/gal while drilling all wells in the south. Clay inhibitors were run in all of the mud systems for the CTD pilot program on the basis of experience in the basin.

Each of the first four wells had significant amounts of large shale cavings brought out during trips out of the hole and wiper trips. Before pulling off bottom or disconnecting the CT connector, the shakers were circulated clean. In most cases, this took 20 to 30 minutes at rates between 7 and 12 bbl/min before the large cavings cleared the shakers. Tight spots were common during trips with lower pump rates. A direct correlation between the amount of overpull, tight spots, and pump rate could be seen during the operation. Well 3 had the worst of these problems, with packing off occurring during the trip out after TD was reached. This was caused by the 0.25-in. undergauge stabilizer on the RSS catching and pulling shale cavings up the hole during the trip. After this, special care was taken to stop and clean up the wellbore before pulling into the surface-casing shoe.

Before running casing, cleanout runs were needed on all wells except Well 3. In all of the cleanout runs, multiple bridges and numerous areas of overpull were encountered. As with drilling, the cleanout runs brought up larger cavings. The large cavings came from an unnamed relatively unconsolidated formation well above the coal. The cleanout runs met varying degrees of success. After experimentation, the practice of pulling out of the open hole slowly (less than 20 ft/min) and pumping at minimum rate was deemed to be optimal. Although counterintuitive to current drilling practices, this seemed to cause the least number of bridges to form.

Running casing was problematic for the first four wells, with running time to casing TD averaging 24 hours for each well. This did not compare favorably with the typical 6 to 8 hours for conventional offset wells. Well 4 took two attempts to run casing to bottom. The first attempt was made with a side-jetting casing shoe. After a cleanout run, the shoe was replaced with a bull-nosed shoe with only down-jetting action. Several hard bridges were encountered on the second run, but the casing was able to be washed down. While the cleanout run may have helped, the change in casing-shoe hydraulics was the primary reason the casing landed on the second attempt.

In the North San Juan basin, Wells 5, 6, and 7 had noticeably less wellbore instability. However, as wellbore deviation increased, so did concerns with hole cleaning. The two S-shaped pad wells, Wells 5 and 6, did not have any wellbore-stability issues during drilling or running casing. The mud systems for these wells were similar to the previous systems on Wells 1, 2, 3, and 4. The major difference was the ability to run a much higher mud weight because of less-depleted formations. The mud weights for Wells 5 and 6 started at 8.5 lbm/gal and ended at 10.3 lbm/gal and 10.0 lbm/gal, respectively, 1.0 lbm/gal higher than the previous wells in the south.

Hole cleaning was accomplished mostly through sweeps. On Well 5, weighted sweeps were considered the best option to reduce cuttings-bed buildup in the wellbore and had shown the best cleaning performance. However, an unforeseen problem occurred with the weighted sweeps. When the sweeps went through the RSS, the seals for the pads on the RSS tool would blow out. This did not cause a complete RSS failure; it simply limited the effectiveness of the tool. The weighted sweeps were attempted at low pump rates, one-third of the normal drilling rate, and the same problem occurred. The second option was a low-viscosity sweep, followed by a high-viscosity sweep. The idea with this type of sweep was to stir up the fine-cuttings bed first with the turbulent low-viscosity sweep and then sweep it out with the high-viscosity sweep. Once the issue with weighted sweeps was discovered, the low-/high-viscosity sweeps were used exclusively to clean the hole. These wells did not have the caving issues that the other wells had; however, the sweeps did bring back a significant amount of fine cuttings. This indicated that the cuttings bed that forms during CTD operations was being swept out of the wellbore. Running casing in these wellbores posed no problems, with each casing string going to TD with no issues. In addition to good wellbore cleaning and wellbore stability because of higher mud weight, the casing OD being 20% smaller ($5^1/2$ vs. 7 in.) than the previous wells was a contributing factor to the successes in running casing.

The final well was a re-entry consisting of a horizontal sidetrack into the Fruitland Coal completed with a slotted liner. Because a thick coal with a good cleat system was expected, the mud used was a low-weight brine to limit losses. The maximum weight during drilling was 8.9 lbm/gal, and the only losses seen were seepage losses to the formation. During drilling, several unconsolidated portions of the coal seam were encountered, particularly close to the formation transition. Low-/high-viscosity sweeps again were used to keep the hole clean of the caving coal during drilling. One of these areas showed overpulls while pulling through and bridging when running back after TD was reached. The problem area was finally cleaned up by multiple wiper trips concentrated around the trouble zone, with gradually reduced pump rates to minimize disturbing the formation. On this well, the liner went to the drop-off point with no problems.

Jointed-Tubular Use

The main advantage of a hybrid drilling rig was its ability to handle jointed tubulars and tools as well as CT. With the rig topdrive, there was the ability to drill with jointed pipe in addition to CT operations. This capability was used only to drill surface wellbores, run casing, and handle BHAs. However, it could have been used to mill windows, conduct fishing operations, or finish wells that CT was unable to finish. Running casing and handling BHAs were the biggest advantages of the hybrid rig. In a previous CTD pilot program, 50% of the wellbores were lost as a result of the time lag between the service CT unit leaving and the workover rig attempting to run liner. The wellbore-stability issues experienced during this project indicate that having the ability to run casing immediately provided a distinct advantage in this area.

Conclusions

The project was deemed a success. Within a short span of seven wells, the team was able to overcome a relative lack of basin knowledge for field personnel, new and inadequately trained rig crews, and a reasonably new and untested rig and the equipment issues that go with that. In addition, hole-stability and hole-cleaning issues were overcome, new technologies for the basin (RSS on CT and PDC bits in North San Juan) were proved, and safety and environmental standards were maintained to generate seven producing wells that will be the base for future CTD development in the San Juan basin.

This project was far more costly than conventional offsets, in part because of the tremendous learning curve encountered, as well as higher-priced short-term service contracts. Also, the focus of the project was to evaluate the performance of CTD in the basin and determine if economically competitive drilling with CT was feasible. A full-scale development-drilling program would result in significant improvement in average-ROP performance as basin and CTD knowledge improved. The inherent time savings of CT through faster trip and rig-up times would become more pronounced. **JPT**