Innovating
WHILE DRILLING

Expandables, deepwater MPD moving into mainstream as drilling automation, automated MPD come into focus
Many Marcellus operators drill the vertical sections of their horizontal wells using an air rig. Contractors are experienced in this technique, which has proven cost-effective in the northeastern US. When the kickoff point is reached, the well is cased and the air rig is demobilized.

When it is time to drill the curve section and the lateral, the borehole is mudded up and a traditional rotary rig or top drive is used for the remainder of the well. To optimize drilling efficiency, different bits are used to drill the curve and the lateral. The three sections of the borehole are therefore drilled with two different rigs and at least three different drill bits.

Recently EOG Resources wanted to reduce the number of drilling days and pipe trips on one of its Marcellus shale wells by drilling the 7 9/16-in. curve section and subsequent lateral in a single bit run. This challenged the conventional wisdom of the area, which called for one bit designed especially for curve drilling followed by another designed for high-speed lateral drilling. Engineers knew that no penetration rate would be high enough to overcome the time lost making a pipe trip to swap out the bits.

A second incentive came from a desire to reduce mud motor and measurement-while-drilling (MWD) failures that were suspected to originate when aggressive, high-rate bits were applied to drill the lateral.

Two schools of thought were reflected in the bit designs typically used to drill Marcellus wells. To drill the curve section of the hole, a bit had to be able to drill the lateral section of the borehole using an air rig. Contractors are experienced in this technique, which has proven cost-effective in the northeastern US. When the kickoff point is reached, the well is cased and the air rig is demobilized.

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achieve the desired build rates, typically 8°/100 ft to 16°/100 ft, while ensuring good directional control. The resultant borehole had to have a smooth and accurate trajectory to facilitate running pipe and deploying the stimulation and completion equipment.

On the other hand, a polycrystalline diamond compact (PDC) bit that could be run on a positive displacement motor in rotary mode with a lower bend angle was needed to efficiently drill the lateral section. In addition, good borehole cleaning in the lateral was essential to ensure high penetration rates could be sustained without excessive vibration, bit plugging and pack-off of the bottomhole assembly (BHA). It seemed that the two requirements were in direct conflict with one another.

A TEAM EFFORT

A Smith Bits drilling team of field engineers, design engineers and hydraulics experts accepted the challenge to design and manufacture a bit that could drill the 7 ¾-in. hole to total depth in a single run at a lower overall cost. The team had several tools at its disposal. Firstly, the IDEAS integrated drill bit design platform recognizes that bits cannot be designed in a vacuum. They must always be built as an integral part of the total drilling system.

Next, the i-DRILL engineered drilling system design for predictive BHA modeling identifies solutions that minimize potentially destructive vibrations and stick-slip during drilling. The DBOS drill bit optimization system for rock properties is also used. Bit hydraulics are optimized using YieldPoint RT drilling hydraulics and hole-cleaning simulation program matched to the specific well under consideration.

Lastly, the DRS drilling record system containing data from more than three million bit runs helps engineers locate similarities among proposed designs and drilling performance. EOG provided BHA data from offset wells, along with mud properties and drilling records.

SHALE-OPTIMIZED STEEL BODY

Given the key parameters of good drilling efficiency and effective borehole cleaning, a single design stood out from the rest. The Spear shale-optimized steel body PDC drill bit offered the highest potential to address the challenges of drilling Marcellus shale wells in a single bit run while delivering good directional control, high penetration rates and effective borehole cleaning.

The benefits of the leading curve section bit were combined with those of the leading lateral borehole performer to create the new 7 ¾-in. SDI513 Spear bit (Figure 1).

Switching from the traditional matrix body to steel allowed a significant improvement in junk slot area, providing a larger area for cuttings flow. This, coupled with a unique hydraulic design, directed drilling fluid to sweep across the cutting surfaces to keep them clean and minimize regrinding that robs energy from cutting new rock. Where vibration is predicted, optional Lo-Vibe depth of cut control inserts can be fitted behind the shoulder and gauge cutters. Bit vibration is the principle cause of excessive cutter wear and poor drilling efficiency.

Tall, thin steel blades are easier to cool and keep clean because of greater fluid flow. They proved to achieve target build rates in the curve section while maintaining good toolface control, and fast penetration in the lateral while maintaining desired direction and inclination. In addition, blades and nozzles did not pack up with shale during drill pipe connections.

Cutter design and placement have been optimized in the new bit as has its hydraulic performance. Nozzles are placed to provide maximum cutter cleaning and sweeping of drill cuttings up and out through the expanded junk slots. This prevents wasteful regrinding of cuttings that robs energy from penetrating new rock (Figure 2).

With a short makeup length to ensure desired dogleg severity, the new bits have successfully been run with a typical stearable BHA configuration consisting of bit, PDM, universal bottomhole orientation sub, non-magnetic drill collar and non-magnetic flex joint under the following operating parameters:

- PDM speeds ranging from 0.28 rev/gal to 0.66 rev/gal;
- PDM configurations: 6 ⅜-in. 4:5 lobe, 7.5 stage and 7:8 lobe, 4.8 stage;
- Motor bend angles ranging from 1.5° to 2.6°;
- Flow rates ranging from 350 gal/min to 500 gal/min;
- Weight on bit ranging from 2,000 lb to 20,000 lb;
- Drilling fluid weights in the curve ranging from 9.7 lb/gal to 10.3 lb/gal;
- Drilling fluid weights in the lateral ranging from 10.3 lb/gal to 11.3 lb/gal.

SMOOTH AND STRAIGHT, WITH A SINGLE BIT

The results tell the story. The 6,241-ft curve section and lateral were drilled...
efficiently using a single 7 7/8-in. SDi513 drill bit. After kicking off the vertical wellbore at around 5,250-ft in a northerly direction, the well trajectory built quickly to horizontal as it was steered around to the southwest, which was continued at high ROP to total depth (Figure 3).

No issues were recorded due to vibration or buildup of drill cuttings in the lateral. A comparison with the drilling performance recorded on offset wells showed that the new bit completed the curve and lateral sections in 2.7 days less time than average offset wells. In addition to reducing the time interval to get the well on production, EOG calculated that $175,000 was saved in rig time and bit costs.

Drilling is both an art and a science. The art comes from the experience of the drillers and well design engineers. The science comes from the bit design engineers who match the best bit designs to the drilling challenges. The Smith Bits Spear family of PDC bits offers an opportunity to achieve the goal of one-bit curve and lateral, and the bit configurations fine-tune each bit’s performance for the rock being drilled. Saving just one bit trip can result in a more economical project than drilling fast but with two or more bits. Spear drill bits continue to bring a new level of performance to the Marcellus, as well step-changes are being experienced in the Eagle Ford and Haynesville.

Figure 3: A smooth curve and a straight lateral were drilled using a single drill bit on a Marcellus shale well constructed by EOG Resources in Pennsylvania.

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