Combining casing drilling, rotary steerable proves effective in directional application

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COMBINING A ROTARY steerable system (RSS) with casing while drilling operations seemed to be a natural way to eliminate the major weaknesses in motor bottom hole assembly (BHA) designs. Rotary steerable systems had not previously been used with casing while drilling because both are new technologies focused on different environments. Casing while drilling technology was developed on land operations while rotary steerables have been popular for offshore projects.

ConocoPhillips has drilled more than 100 wells in the Lobo trend of South Texas since 2001 using the new technique. As part of a technology demonstration project to accelerate the technology to offshore applications, two wells were drilled with an RSS. The first was an operational test conducted by drilling vertically with the RSS. The second was a full directional test with a build to 29° and then a drop to vertical, including a 100° directional turn.

CASING WHILE DRILLING

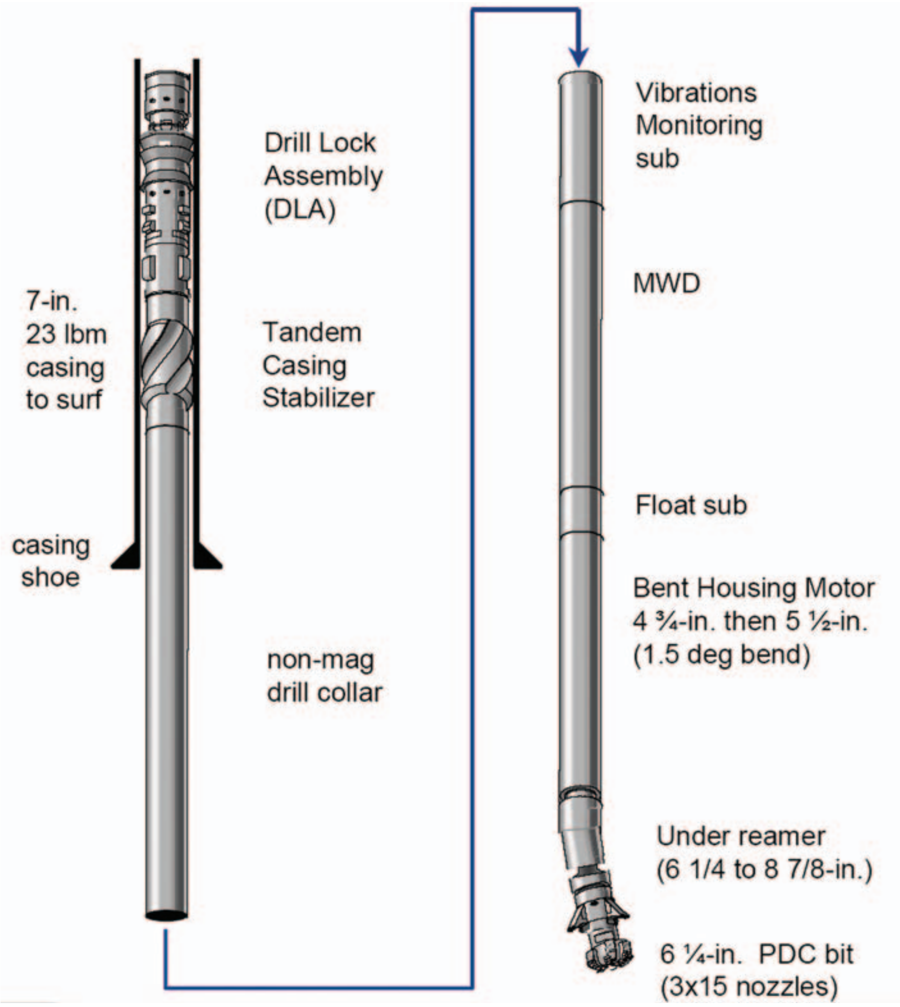
ConocoPhillips embarked on an active field development program in 1997 aimed at drilling hundreds of wells over the next few years in the Lobo trend of South Texas. Since that time, over 900 wells have been drilled through the Wilcox (Lobo) section ranging in depth from 7,500 ft to 13,000 ft. However, in 2001, after drilling about 600 wells, drilling efficiency had stagnated. A program was undertaken to find ways to reduce drilling costs sufficiently to extend the development potential in these fields for several years.

In the previous years, great strides had been made in increasing rate of penetration (ROP), drilling each hole section with a single bit, and in improving general rig operation efficiency. Any major reduction in drilling time had to address the flat time more than the "making hole" times. The most significant flat times were associated with keeping and protecting the hole, trouble time that averaged about 1.5 days per well, and casing running operations. Stuck pipe and lost circulation were the most consistent contributors to the trouble events and accounted for about 75% of the trouble time in 2000 and 2001.

A casing while drilling system was chosen for a five-well pilot project to evaluate the impact that this technology might have on the particular problems encountered at Lobo. Sufficient progress was made in drilling these first wells to justify moving to a second phase of drilling.

The second phase proved that casing while drilling could eliminate the formation-related trouble time experienced with conventional drilling. A major finding was the confirmation that lost circulation was almost completely eliminated, allowing the drilling of additional wells formerly considered uneconomical. The wells were not drilled trouble-free, but the trouble was associated with the mechanical equipment limitations, which were overcome on the phase-two wells.

Full-scale implementation of the Lobo casing while drilling program was initiated by bringing in three new rigs in late 2002 and early 2003. These 15,000 ft rigs ,built specifically for ConocoPhillips, were introduced to optimize the drilling



The bottom hole assembly with steerable motor above was used to casing directionally drill Well 83 in the Lobos field for ConocoPhillips. The assembly was positioned on the shoe joint of casing so that all components below the tandem stabilizer extended into the open hole below the casing.

process. They provided an increased hookload rating, much better mobility for intrafield moves, a reduced footprint, and a semi automated casing handling system.

The overall drilling program at Lobo has been scaled down, with one casing while drilling rig still operating. More than 100 wells have been drilled with casing in the area. The incidents of lost circulation have been almost totally eliminated in the casing drilled wells. The difficulty of balancing lost circulation at the intermediate casing shoe while controlling a reservoir pressure of up to 15 ppg during the trip out to run production casing has been eliminated. In some cases, casing drilled wells are completed with three strings of casing when four would be required if the wells were drilled conventionally.

ConocoPhillips is actively pursuing additional applications where drilling with casing might provide a similar improvement in drilling efficiency, but could provide a larger economic impact because of the higher drilling spread costs. A growing interest in redeveloping aging offshore properties where directional wells are required to traverse depleted zones with large pressure variations in the open hole section provides an excellent opportunity to benefit from casing while drilling. However, one impediment to directly transferring the Lobo experience to other areas is that directional wells are required for many of these higher cost applications while most of the Lobo wells are vertical.

Two Lobo wells have been casing directionally drilled using conventional steerable motors run as a retrievable drilling assembly. Two other wells have used motors for directional control in vertical wells. Although these wells demonstrated that it is possible to directionally drill with casing, they were not competitive with the drilling efficiency achieved with RSSs that are commonly used offshore.

A cooperative project was put together by ConocoPhillips Upstream Technology group and Lower 48 Exploration and Production group to demonstrate that rotary steerable directional systems and casing while drilling could be combined to capture the benefits of drilling with casing while maintaining the directional efficiency of rotary steerable systems.

The wells drilled in this program were the first ever use of RSS directional tools in an application where the well was cased as it was drilled.

RETRIEVABLE CASING

Casing can be used as all or part of the drill string in a number of ways, but they can be categorized as either retrievable or nonretrievable systems. Nonretrievable systems include both liner drilling and applications with full strings of casing where a fixed bit is used for drilling. The bit may be “drillable,” where it is drilled out in order to drill the next hole section, or it may be a conventional bit that is left in the hole at total depth (TD).

Retrievable systems allow the bit and BHA to be changed without tripping the casing. Use of a retrievable system is the only practical choice for directional wells because of the need to recover the expensive directional drilling and guidance tools, the need to have the capability to replace failed equipment before reaching casing point, and the need for quick and cost-effective access to the formations below the casing shoe.

A retrievable casing while drilling system has downhole and surface components that enable standard oilfield casing to be used as the drill string so that the well is simultaneously drilled and cased. The BHA can be changed without tripping casing. A wireline-retrievable drilling assembly is suspended in a profile nipple located near the bottom of the casing. The top component of the BHA that facilitates the attachment to the profile nipple is the drill lock assembly (DLA). The casing is rotated from the surface, and the drilling fluid is circulated down the casing through the BHA and back up the annulus.

The drilling assembly contains an underreamer and terminates in a pilot bit. It may include other conventional drillstring components such as a mud motor, stabilizers, drill collars, measurement while drilling (MWD), or logging while drilling (LWD) tools.

The pilot bit is sized to pass through the casing. The underreamer opens the hole to a size similar to what is normally drilled to run the casing. For example, a 6 ¼-in. pilot bit and 8 ⅞-in. underreamer are commonly used while drilling with 7-in. 23 lb/ft casing. The underreamer can be located immediately above the bit or above other components run in the pilot hole.

A top drive rotates the casing for drilling and is used to torque up the connections. The casing string is rotated for all operations except slide drilling with a motor and bent housing assembly for oriented directional work.

The casing is attached to the top drive with a casing quick-connect system without screwing into the top casing connection. The hardware includes a slip assembly to grip either the exterior or interior of the pipe (depending on pipe size) and an internal spear assembly to provide a fluid seal to the pipe. It is operated with the hydraulic top drive control system. This quick-connect system speeds up the casing handling operation and prevents damage to the threads by eliminating one make/break cycle.

Single joints of casing are picked up from the pipe rack and placed in the V-door to then be picked up with a single joint elevator attached to the system. The joint is hoisted as the top drive is raised, stabbed into the top of the casing string in the rotary table, gripped by the quick-connect dies, torqued to specifications, and then drilled down in a conventional manner.

These retrievable drilling assemblies have been used to drill over 800,000 ft (280 casing intervals) in commercial wells with retrievable and re-runable tools. ConocoPhillips has drilled approximately 80% of these wells. A relatively small portion of these casing intervals, 13 to be exact, have been drilled with retrievable directional assemblies while drilling with 7-in. and 9 ⅝-in. casing.

Sufficient experience has been gained while drilling commercial vertical wells to determine the reliability and ruggedness of the tools and to quantify the advantages provided in retrievable drilling assemblies. However, casing directional drilling is still in its infancy. Optimized practices and procedures have not been completely developed.

TWO EMERGING TECHNOLOGIES

Early applications of casing while drilling provided an opportunity to develop surface equipment and procedures to effectively handle casing, equipment to protect the casing and connections while drilling, and a robust and reliable system for locking and unlocking the BHA to the casing.

The initial application and subsequent evolution of the system components were primarily focused on onshore vertical wells where the cost of learning could be tolerated. This development work identified field applications that would benefit from reducing lost circulation and eliminating problems associated with drilling depleted zones. Although these wells have a specific problem addressed by drilling with the casing, they were mostly vertical, eliminating a level of complexity in operations. Casing while drilling has developed to the point where these operations are routine, and the hardware operates as reliably as other rig systems. However, the difficulties in applying PDM technology to casing directional drilling remain.

Meanwhile, RSSs were being developed to solve problems in wells at the other end of the scale. It had become difficult to use PDM steerable systems in extended-reach directional and horizontal wells where the ratio of displacement to true vertical depth is high. Orienting a motor for a directional correction was taking as many as six hours at measured depths of 25,000 ft or more. RSSs, while very expensive, eliminated orientation or sliding operations and made it possible to drill wells such as the record breaking Wytch Farm Well M-16 to 37,000 ft MD.

As RSSs improved, became more durable, and costs went down, they were applied to less technically demanding offshore projects. At first RSSs were applied on deepwater wells. As the significant efficiency in directional operations became well known, directional operations moved away from motors to RSSs in the North Sea, the Gulf of Mexico shelf, and other offshore developments. RSSs are now used in about 60% of offshore directional wells.

Successes in reducing losses in historically problematic formations have sparked interest in applying casing while drilling to similar situations offshore. The difficulties in casing directional drilling posed a roadblock. Directional operations with PDMs in smaller hole sizes were not effective. RSSs were, therefore, an obvious avenue to investigate. The difficulty was that there was very little overlap in logistics and methodologies for merging these two technologies. At this point, participants from **ConocoPhillips**, **Tesco**, and **Schlumberger** pooled resources to test this approach to casing directional drilling.

A TWO WELL TEST

Applying the use of a rotary steerable system to casing directional drilling was not as simple as shipping a set of tools. The following questions arose:

• Will there be difficulties with stiffness ratios and vibrations?

• What will be the directional control and tendency?

• How can the rig supply higher revolutions per minute (rpm) for effective RSS use?

• How will the flow and pressure requirements of RSS and MWD systems impact casing directional drilling operations?

After operations begin on a directional well, the trajectory objectives must be met or the well would have to be abandoned. Risks and contingencies have to be quantified.

The ConocoPhillips-Tesco-Schlumberger team decided on a two-well test program. First, an RSS would be deployed in a vertical well. An RSS has a verticality mode in which the tool senses deviation away from vertical and then thrusts the bit back to vertical. This process takes place in a closed-loop fashion. The tool is added to the BHA. No MWD system is needed, and the tool operates automatically, virtually transparent to drilling operations. This well would test the BHA configuration, operational functionality, and directional performance of the RSS in the retrievable drilling assembly. Downhole-recorded data would confirm tool operations. The standard single-shot surveys would confirm the directional performance of the system. This test could run from 500 ft to the entire 7-in. section. Operations could return to the standard BHA configuration if there were significant problems.

Success of the vertical well test along with lessons learned would lead to approval for drilling a full directional well. The BHA for the second well would be more complex. An MWD system and full directional drilling operations would be needed to follow a planned trajectory. The inability to drill directionally would possibly require changing rig operations to conventional drillpipe drilling, a significant expense.

VERTICAL TEST

The verticality test took place in Well 89 about 30 miles northeast of Laredo, Texas, in June 2004. Operations with 9 ⅝-in. casing, 8 ½-in. bit, and 12 ¼-in. underreamer had drilled to 588 ft where the 9 ⅝-in. casing was cemented in place. A 4 ¾-in. RSS and a 4 ¾-in. drill collar were added to the standard verticality BHA on 18 June 2004. This configuration was run from 614 to 4,821 ft in 105 hours. Single-shot surveys taken about 500 ft apart showed the well was nearly vertical. Drilling proceeded normally. Higher-than-expected casing vibrations were attributed to the longer BHA stick-out. The run was terminated at a planned replacement of the underreamer. The operation continued to the 7-in. section TD of 7,620 ft. The RSS was retrieved, inspected and found to be in good order. The RSS was returned to the shop, where the operational data were extracted from the tool. A gyro survey of the 7-in. casing drilled section was taken.

The operational data showed that the RSS directional control unit did not stabilize on a gravity reference until 14:40 on 21 June 2004. At this time the bit was at 3,710 ft. Because of verticality or a tool problem, the tool had been unable to determine which way was up and, as a result, had been ineffective. The well had drifted out to 2.25° of inclination at 3,600 ft. At 3,800 ft, the well snapped back to a nearly vertical 0.25°. The RSS problem resolved itself at 3,710 ft, the tool became directionally functional, sensed the inclination, and brought the well back to vertical. Verticality continued for the remainder of the test. There is not much directional data in a verticality test, but a review of the operations and performance led to approval for the second, full directional, test.

FULL DIRECTIONAL TEST

Most of the wells in the Lobo trend development are vertical. Well 91 was no exception, but a unique opportunity presented itself. The proposed location was about 1,200 ft to the south of Well 79, which was drilled in March 2004. The team proposed to use the old location of Well 79 and drill an S-shaped trajectory over to the target location of Well 91. While this would save the costs of building a new location, the additional costs of a directional well are more than three times the location costs. This was the best option to test RSSs in a full directional trajectory, because a directional well was not planned for the remainder of 2004.

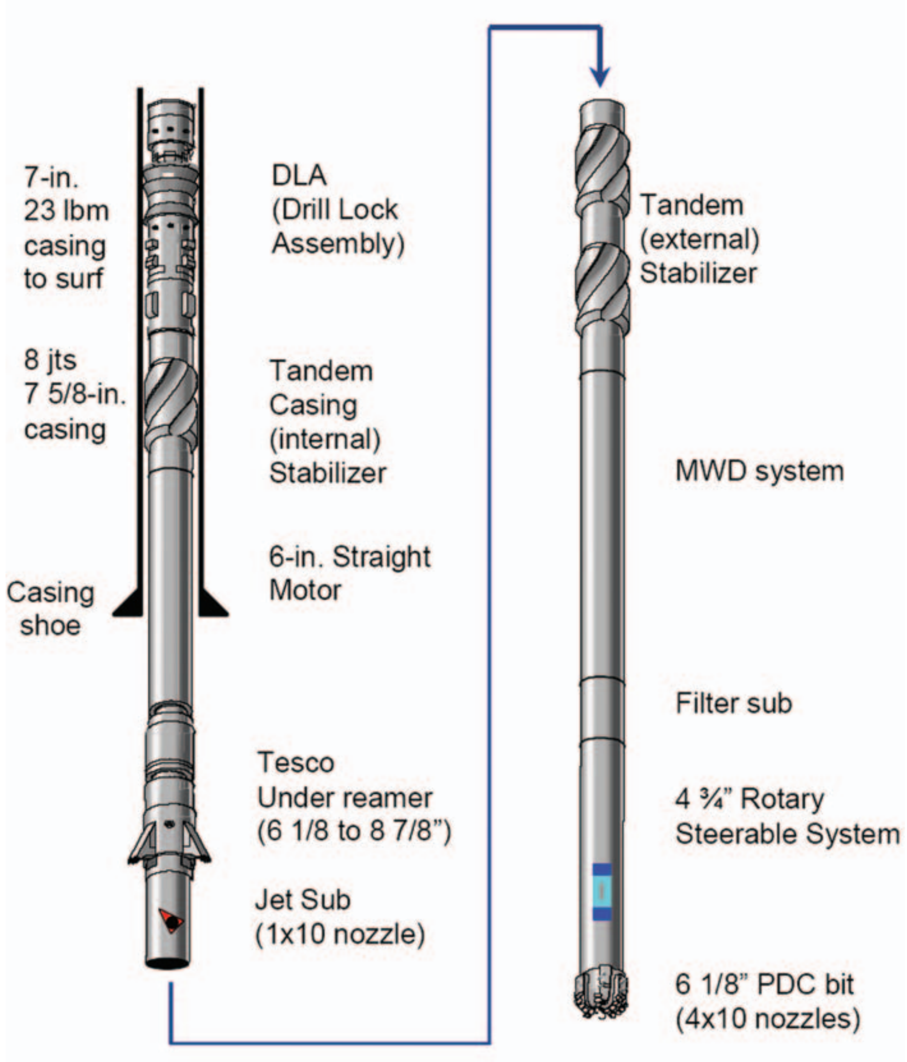
A review of the Well 79 pad showed that the remaining open space for the rig put the well in nearly a direct line between its target location and the rig. This location added complications to the trajectory design. The basic plan called for a build to 29° and then a drop into the target 1,200 ft away. Now the trajectory would have to be routed around Well 79 to avoid colliding with the producing well. Well 91 would kick off along an azimuth that was 40° east of the target azimuth, build to 29° and start a 100° turn to the right. During the later stages of the turn, the drop would be initiated, bringing the well into the target. This profile resembled those used on large multi-well offshore platforms.

Another complication added to the well operations design. Specifications called for the 9 ⅝-in. casing to be set at 1,270 ft. The 9 ⅝-in. casing point for Lobo wells varied between 550 and 2,400 ft. Experience showed that the deeper casing point wells had more problems with vibrations and casing whirl when drilling the 7-in. section. Adding a straight PDM to the BHA above the underreamer addressed this problem. This addition was a significant operational change from the test in the vertical Well 89. Therefore, the dynamics of the BHA were different and the MWD was run below the motor.

There were some operational problems holding the correct azimuth and then stabilizing the turn, Drilling passed around the nearby well and turned toward the target location. Twenty-six trajectory commands were sent to the RSS in the drilling of this section. Twenty-four of these were judged to be directionally effective.

The kickoff run continued to 4,067 ft, where pressure spikes indicated BHA problems. The BHA was retrieved by wireline. The motor was locked up and a washout was found in the body of the RSS, although it was judged operational before the trip out. The motor was removed from the BHA and not replaced. The bias unit of the RSS was replaced and drilling continued. Drilling was slower, and it was difficult to keep surface turns above 60 rpm. The run was terminated when a replacement motor arrived on location.

The motor was reinstalled on the third run, restoring the BHA to the design configuration. Drilling proceeded normally for 200 ft before the ROP dropped significantly. An error was discovered when the BHA was pulled: the wrong size underreamer had been run. The underreamer stabilizer was 6 ¼-in. when it should have been 6 ⅛-in., the bit size. This too-large stabilizer piece had worked until harder formations were encountered. The underreamer was replaced, and drilling continued normally until 5,420 ft where the casing became differentially stuck. This event caused 50 hours of lost time. Directionally, the build and turn had been finished, and the drop was underway. Drilling continued to 6,360 ft. The well was now at 4° of inclination. A pressure drop indicated a washout in the BHA. Surface inspection showed the washout in the connection between the jet sub and external tandem stabilizer. The jet sub was dropped from the BHA and drilling continued to section TD of 6,950 ft.



The BHA for casing directional drilling with a rotary steerable system for Well 91 was 112 ft long with 85 ft stick-out below the shoe of the 7-in. casing.

CONCLUSIONS

Directional wells can be drilled with casing using steerable motors but success is difficult to achieve in holes smaller than 8 ½-in. The smaller sizes of BHA components required to fit through small holes give less-than-optimal power to steer the underreamer and bit.

RSSs can be effective in 8 ½-in. casing-drilled holes. Directional control in the pilot hole is sufficient to guide the larger casing to a directional target.

In casing-drilled wells, pressure and flow operational requirements of RSSs require consideration when selecting nozzle size and BHA design.

The casing string design for casing-drilled directional wells is different from that in vertical wells. Directional wells have more side forces and are more susceptible to differential sticking.

MWD systems run below mud motors can maintain reliable data transmission. The signal attenuation was less than expected. The MWD survey should be taken in the quiet time when the pumps are down instead of when the pumps first come back up after the connection, as is the common practice.