Slimhole rotary steerable system broadens applications

A slimhole rotary steerable directional drilling system can be used for short- and medium-radius horizontal wells, and with further development, may be used for conventional directional drilling applications

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Several drawbacks of steerable motor directional drilling systems exist, including those related to difficulties associated with sliding the drillstring along the wellbore when it is not rotated, maintaining tool face orientation, poor hole cleaning while "sliding," tortuous well paths and limitations on using aggressive bits.[1] These difficulties are eliminated with a rotary steerable system, because the motor itself is eliminated and the drillstring is continuously rotated. This allows the drillstring to slide freely through the hole, simultaneously facilitates cuttings removal and results in a significant increase in penetration rate over motor systems.

Amoco began developing a slimhole rotary steerable drilling system several years ago to provide a lower-cost lateral drilling system for drilling smaller-diameter, shorter-radius holes than was available at that time with mud motors. The system is commercially available and has been used to drill more than 40 wells for simple re-entry applications. Recent work has shown that the fundamental concepts may be applicable to general directional drilling applications. Activities are underway to broaden application of the system to include more complex re-entries, such as offshore directional wells. This article describes the curve-drilling portion of the system and provides examples of its use.

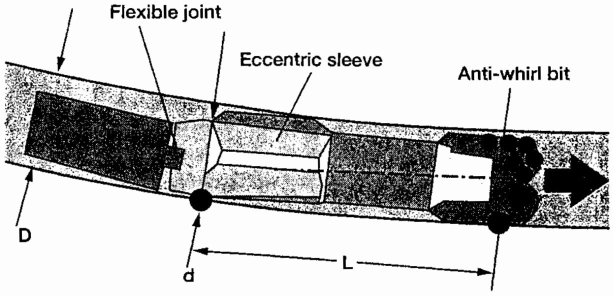

Fig. 1. Curve assembly geometry.

CURVE DRILLING ASSEMBLY

Directional drilling tools are generally designed to drill along a circular arc path, with a curvature designated in degrees/path length. The curvature expected by a specific tool configuration is typically defined by denoting three points of contact on the tool. For example, with a steerable motor system, these points might consist of the bit, stabilizer on the lower motor housing and stabilizer on top of the motor. The curvature is determined by the diameter of these three elements and any "bends" in the motor housing between the points. In this type of system, the bit axis is not required to coincide with the borehole centerline, therefore the bit may not drill in the direction that it is pointed, particularly when the entire assembly is rotated.[1]

An alternate system can be used to define bit trajectory where geometry is specified by two contact points and a third constraint provided when bit axis and borehole axis are coincident at the bit face. The last condition is satisfied when the bit drills where it is pointed. This type of directional control system can be achieved by the geometry shown schematically in Fig. 1.

The first point of contact is near the uphole end of the rotating bit mandrel, which is positioned off the borehole center by a distance, e. The second point of contact is at the bit, which is centered in the hole. These two points of contact, in combination with the distance between them, determine bit tilt with respect to a straight borehole. The bit rotates smoothly around both its centerline and the hole centerline at the bit face, which satisfies the third criteria for drilling along a circular arc. The radius of the circular arc is simply determined as:

$$R = L^2 / (2e) \qquad (1)$$

Where:

R = Radius of curvature, ft

L = Distance between contact points, ft

$e = (D - d) / 2$ = eccentricity, ft.

The geometry defined in Eq. 1 defines a unique circular arc; but forcing the drilling assembly to maintain this geometry is tricky. To drill the desired curvature, the hole must be in gauge, the bit must remain in the center of the hole and the top end of the mandrel must remain in the desired displaced position. If wellbore trajectory is disturbed in some way that causes it to be shorter than designed curvature, the bit is pointed to the outside of the curve and drills longer. Conversely, if the curvature becomes longer, the bit is

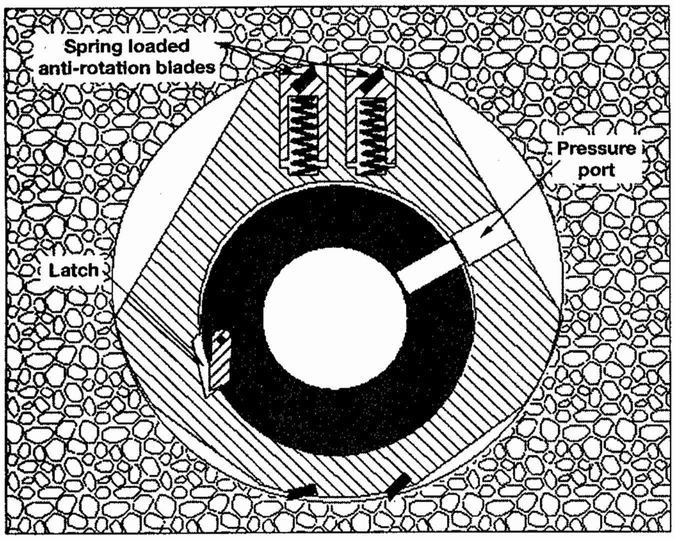

Fig. 2. Cross section through eccentric sleeve.

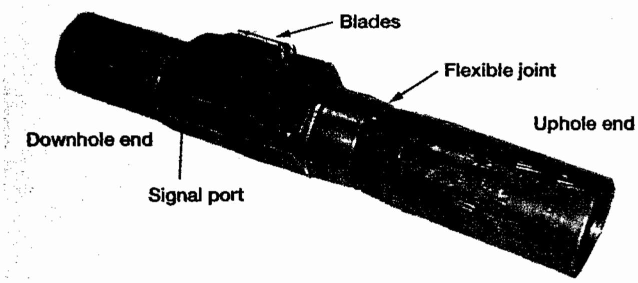

Fig. 3a. Photograph of a 6-in. curve drilling tool.

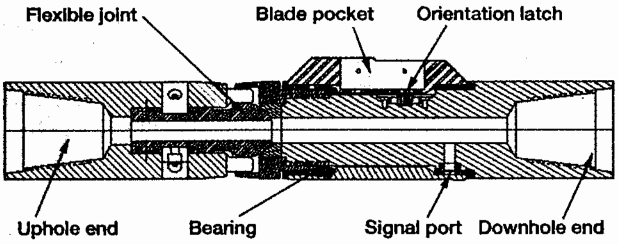

Fig. 3b. Drawing of a 6-in. curve drilling tool.

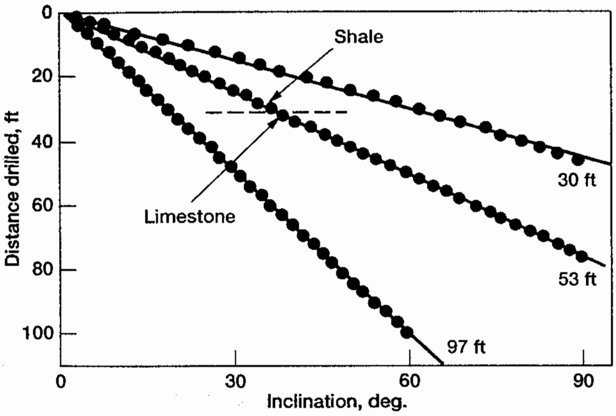

Fig. 4. Various curvatures drilled with the system.

pointed to the inside so that curvature tightens. In other words, the assembly tends to be self correcting to drill the designed curvature as long as the borehole is gauge; the bit has minimal side-cutting ability and constant orientation is maintained.

These requirements are met by designing the drill bit to drill a constant borehole diameter and remain in the center of the hole. The bit has a sliding bearing pad that contacts the borehole wall, and cutter positions are selected so that a lateral force from the cutters is directed toward the pad. This causes the borehole wall to form a portion of a journal bearing, and therefore stabilizes the bit as desired. This facilitates bit drilling without "side cutting" and prevents it from whirling.[2] (Whirling can be a serious problem because the joint prevents the drillstring from providing any rigidity and mass to dampen whirling tendencies.)

The uphole end of the mandrel is stabilized and oriented with a nonrotating, eccentric sleeve, Fig. 2. The mandrel rotates through the eccentric sleeve on bearings or bushings. The uphole end of the sleeve is designed to provide the appropriate amount of displacement from the borehole centerline and to provide lateral stability with lugs placed on either side of the sleeve, immediately below the joint. Blades on the thickest part of the sleeve minimize sleeve rotation due to frictional forces from drillstring rotation and provide a force to keep the sleeve displaced toward the outside of the curve.

A pad on the sleeve opposite the blades provides a fixed point of interaction with the wellbore wall, and a slightly undergauge pad on the sleeve uphole from the blades limits movement of the sleeve if drillstring dynamic forces overpower the blade springs. The sleeve body downhole from the contact pads has clearance from the borehole wall to fit in any radius curve for which the tool will be used.

Altering the length of the rotating member between the bit and sleeve can change the radius of curvature. In practice, this is accomplished by installing various-length subs between the bit and mandrel passing through the sleeve.

Basic curve assembly performance. The curve assembly has been manufactured in 3⅞-in., 4½-in. and 6-in. sizes to run in 4½-in., 5½-in. and 7-in. casing, respectively. Most commercial applications have been with the 4½-in. tools. The 3⅞-in. and 4½-in. curve drilling assemblies are designed to use many parts in common to minimize inventory and spare parts cost. Fig. 3a is a photograph of the 6-in. tool, and Fig. 3b is a cross sectional tool.

The assemblies have been run in numerous curves at Amoco's Catoosa test facility to confirm that they drill properly. Fig. 4 shows results of drilling three curves with the 4½-in. curve assembly with various sub lengths ranging from 5 to 20 in. The resulting curvatures ranged from 30 to 97 ft. When inclination is plotted vs. measured depth, as shown in Fig. 4, a circular arc plots as a straight line, and the slope of the line can be used to determine an average radius of curvature. As evident from this figure, the curve assembly drilled with very consistent radii for each case.

Formation effects. Curve drilling tools have been run in a variety of formations, ranging from soft sands and

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shales to very dense limestones. Although no tests were conducted during the normal course of testing, specifically to determine effects of formation changes on the curve assembly performance, data was collected while drilling across a wide range of rock strengths. For example, Fig. 4 shows inclination data as the 4½-in. assembly (53-ft radius) drilled into the top of the dense Oswego limestone. The Oswego was encountered at about 30° inclination, and no appreciable change in build rate was observed, even though penetration rate in the limestone dropped to 25% of that in the shale, despite WOB doubling.

A few situations have been encountered in which the formation has a significant effect on curve drilling tool performance. Some formations are too hard for PDC bits. Little work has been done with roller cone bits with the slimhole rotary assembly, but in general, they seem less predictable than antiwhirl PDC bits.

The second situation where tool performance is questionable is in very soft formations. If the hole does not maintain adequate competence for the sleeve to grip and remain stationary, the assembly will not perform as expected. Good performance has been obtained in sands and shales where ROP has been well over 100 ft/hr, but cases have been encountered where build rate was definitely affected while drilling across a shale formation. A 10-ft rubbilized shale zone was drilled twice in the same well, and in both cases, the assembly not only failed to build angle through the shale zone, but also dropped slightly.

Steerability. The curve drilling assembly is capable of drilling a curve in any orientation, not just in a vertical plane. Fig. 5 shows an example where the assembly was oriented in one direction while drilling 60 ft, and was then oriented differently for the second 60 ft. In both cases, the well turned toward the assembly orientation as it should. In other cases, the tools have been used to drill along compound build-and-turn paths and to drop angle in a lateral section.

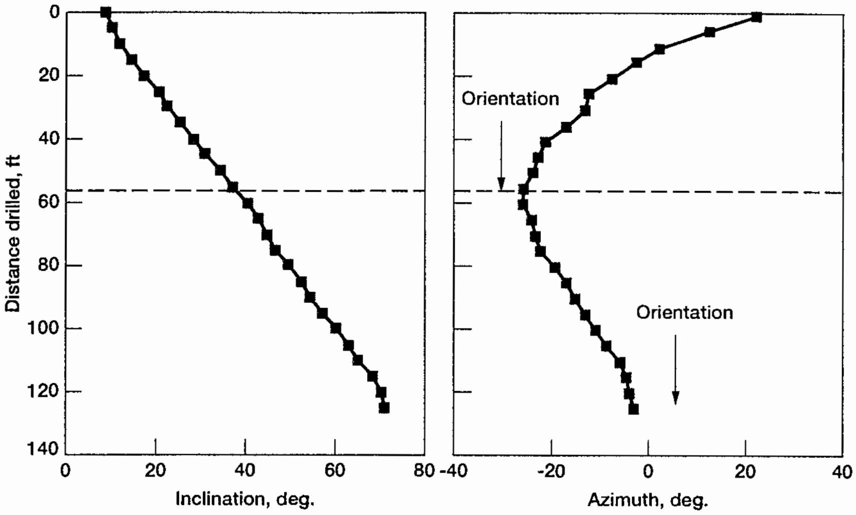

Fig. 5. Radius of curvature vs. sub length.

Clear indications from these applications are that the curve drilling assembly drills where pointed and with good control of the curvature. The greatest limitations to drilling along the desired path, in any situation, is the resolution with which the assembly can be oriented precisely. The severity of this limitation is rapidly being cleared up by improved surveying and orientation techniques discussed later.

CURVE DRILLING SYSTEM OPERATION

The rotary steerable system can be operated in two primary ways. The original concept for using the system in shallow, vertical well reentry applications minimizes survey requirements. The assembly is initially oriented with either a magnetic or gyro single-shot survey. Then the sleeve is reoriented from surface observations as the curve is drilled. This orientation method is limited to well configurations and depths in which drillstring twist is not too great. Even under the best circumstances, it has a fairly broad window of accuracy, but this orientation method has been used for most commercial work with the tools.

The second orientation method uses either a conventional MWD tool or a wireline steering tool with wet-connect to make all orientations based on downhole measurements. This allows much better control of the eccentric sleeve to facilitate complex well paths and deeper and directional wells where drillstring twist is considerable, but is more expensive than the simple orientation that was originally used with the system. Only one commercial medium-radius well has been drilled with this orientation system, but it was quite successful, and others are planned.

For either orientation system, the eccentric sleeve must be oriented in the desired direction and corrected back to this direction after it slips due to rotational friction. A latch is provided to lock the sleeve to the mandrel in a predetermined orientation when the drillstring is rotated counter-clockwise, Fig. 2. When the latch is engaged, a port through the drillstring is opened to provide a negative-pressure signal to indicate that the sleeve is latched to the drillstring. This allows initial orientation of the sleeve and subsequent reorientations to be accomplished simply by rotating the drillstring counterclockwise until the sleeve is in the desired orientation.

System run with surface monitoring. When the system is run with the surface monitoring method, the curve assembly is made up with an orienting sub in the drillstring to provide for initially orienting the sleeve. While making up the BHA, the eccentric sleeve is rotated to the locked position, a scribe line is run up to the orienting sub, and the key in the orienting sub is aligned with the scribe line. After the drillstring is tripped into the hole, a survey tool is used to establish a surface scribe line that is directly in line with the high side of the eccentric sleeve when it is latched to the drillstring, Fig. 6.

Before the survey orientation tool is run, the drillstring is reciprocated to eliminate the twist. Each time the

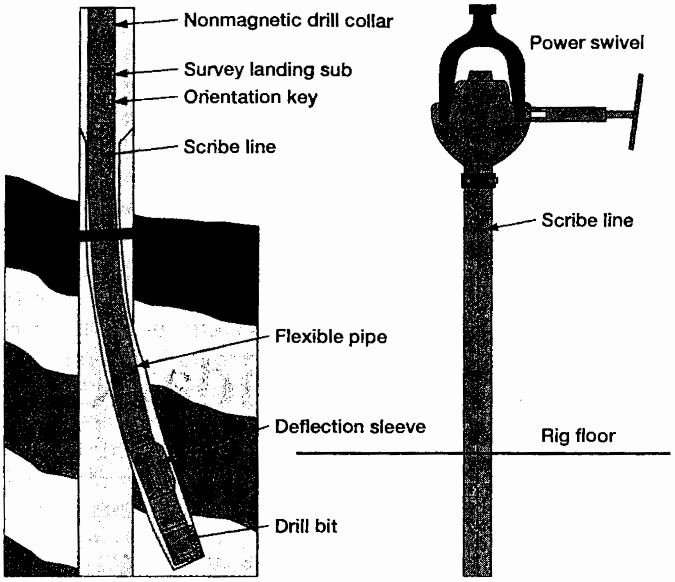

Fig. 6. System setup for surface monitoring.

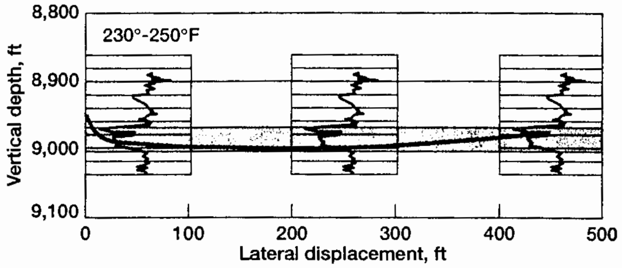

Fig. 8. Deepest lateral drilled with system.

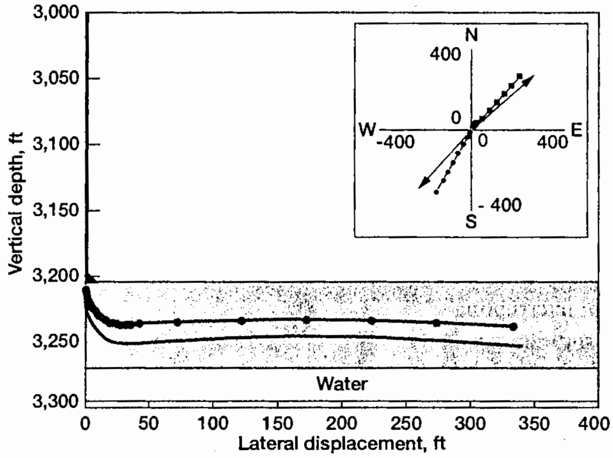

Fig. 7. Dual opposing laterals in a gas storage field.

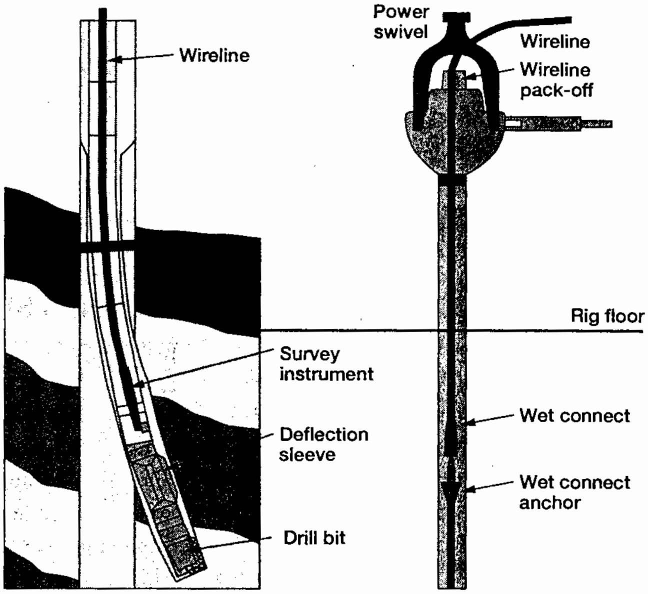

Fig. 9. System run with wireline steering tool.

sleeve is to be reoriented:

- Drillstring rotation is stopped
- The assembly is picked up off bottom
- The drillstring is rotated counterclockwise until the pressure port opens, indicating that the sleeve is locked to the drillstring
- The drillstring is rotated farther until the surface scribe line is pointed in the target direction, and
- The drillstring is then reciprocated to bring the downhole end in line with the surface end.

This procedure has been used to drill laterals in more than 40 commercial onshore vertical wells, that were typically less than 6,000 ft. Fig. 7 shows one field application of the system in which dual 30-ft radius curves and laterals were drilled in a relatively soft sandstone. Shown on this plot are the desired direction and actual direction achieved. Directional control of better than ±20° is difficult to achieve with this control method. Fig. 8 shows the deepest well drilled with the system to date.[3]

System run with downhole monitoring. All drilling with Amoco rotary steerable tools prior to the last half of 1996 was done with the surface orientation monitoring procedure described above. This orientation method is not adequate for deep or directional wells, where significant drillstring twist exists or in cases where the directional target requires a directional accuracy greater than about ±20°. For deep and directional wells, a direct measurement of sleeve orientation is required. Drillstring orientation can be determined with either a wireline steering tool or an MWD tool, but drillstring orientation is equivalent to sleeve orientation only when a reference point on the drillstring is aligned with the high side of the sleeve. The point at which the drillstring is rotationally aligned with the sleeve can be determined by the decrease in pump pressure created by opening the pressure port.

Fig. 9 schematically shows the curve drilling tool run with a wireline steering tool and wet connect. The curve tool is made up at surface, and a conventional mule shoe orienting key is aligned to the high side of the sleeve when the pressure port is open. The drillstring is tripped into the hole, and the wireline steering tool is then run and seated on the mule shoe key. At that point, the wireline is cut and attached to the anchor portion of the wet connect. The remainder of the drillstring is tripped in and wireline is reheaded and attached to a sinker bar and the retrievable portion of the wet connect. This assembly is then run through a pack-off in the top of the swivel and stabbed onto the anchor portion of the wet connect.

The well can then be circulated freely, and the drillstring can be rotated as desired. The anchor portion of the wet connect, instrument housing and mule shoe all have adequate clearance for drilling fluid circulation. When the drillstring is rotated, the instrument housing, anchor portion of the wet connect and wireline in between rotate with the drillstring. The wireline from the pack-off and retrievable part of the wet connect remain stationary as the drillstring rotates.

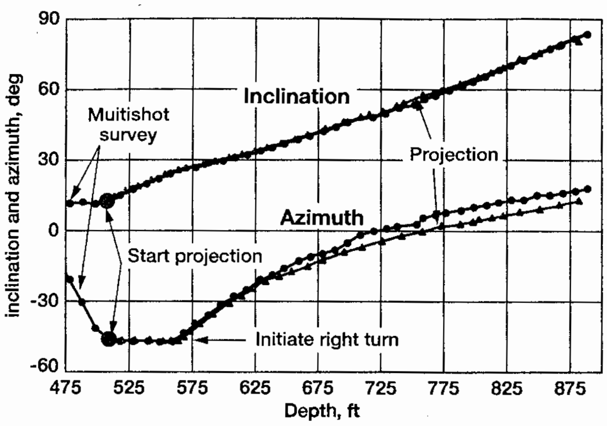

Fig. 10. Compound build-and-turn.

Rotating the drillstring counterclockwise until the pressure port opens indicates that the latch is engaged; further rotation orients the sleeve. The drillstring is then rotated farther to the left until the desired orientation is indicated on the steering tool display. Often, reciprocating the pipe after it is rotated left can facilitate this process. This allows torque to be worked smoothly to the sleeve to minimize the chance of over-correcting the sleeve. As soon as the steering tool indicates that the sleeve has moved to the correct orientation, the drillstring is rotated right to disengage the latch to leave the sleeve in the proper position.

The process of orienting the sleeve is almost identical to that used for orienting a mud motor, except that as soon as the sleeve statically moves to the correct position, the drillstring torque can be released by rotating to the right. With a mud motor, torque and resulting drillstring twist must be held constant as the bit drills ahead to keep the motor oriented. Therefore, it should be possible to orient the sleeve for any conditions where a motor could be oriented. Further, it should be much easier because holding torque in a nonrotating drillstring is not required while drilling ahead.

Any time drillstring rotation is stopped, the steering tool will directly indicate the inclination and direction (assuming it is run in a nonmagnetic collar). If the pressure port is open, the steering tool also displays sleeve orientation. Therefore, when one wants to check directional progress, drillstring rotation is stopped with the pressure port open and downhole orientation, inclination and direction are immediately displayed.

To make a connection, the pack-off is released and wireline is pulled. Normally it is necessary to pull only a few hundred feet to get the wet con-

nect back into the swivel. After adding a joint of pipe in the normal manner, the wet connect is run back to the anchor while the connection is torqued up.

Test results. Recent tests were conducted with a 6-in. curve drilling tool developed for offshore Trinidad applications in 7-in. casing using the steering tool procedure described above. The four main objectives of the test were:

- Demonstrate that the tool could be used with a snubbing unit to drill the correct curvature
- Sleeve slippage could be made low enough so that the sleeve would require resetting no more often than once each stroke of the snubbing unit (10 ft)
- The tool could be used to make a compound turn and build at a predictable rate, and
- The tool could be oriented with a steering tool and wireline wet connect system.

A total 474 ft was drilled with the tool using a 1⅜-in. steering tool and wet connect. The well was built up to 25° inclination (with a left turn followed by constant direction) and then a right turn was initiated while continuing to build. Drilling intervals of 5–15 ft were used between orientation checks. At about 800 ft, while drilling a shale formation, the test was shut down for a three day weekend. After returning, sleeve slippage for the first 5-ft interval was quite large, but settled back to about 2° per foot after the sleeve was buried in new hole.

Using average orientation of the sleeve for each interval and assuming a constant radius of curvature of 260 ft, predicted well inclinations and directions were calculated and plotted against the survey data, Fig. 10. Inclinations are very close to predictions, and actual well direction is slightly to the right of predictions. This indicates that average sleeve orientation is slightly to the right of the average of initial and final orientations. This may indicate that, when the sleeve is initially repositioned, it slips to the right before a groove is established, so that the final orientation is a better representation of mean sleeve position.

The results shown in Fig. 10 quite conclusively demonstrate that the curve drilling tool can be controlled to drill compound curvatures. The well was drilled without a nonmagnetic collar, so no directions were measured during drilling. The tool was simply oriented according to a schedule (relative to high side). The projected well path was then predicted with Eq. 2 and Eq. 3 (shown below) by starting at an initial point (505 ft, 13.5° inclination and N47W) on the well survey, calculating a new inclination and direction based on the orientation and distance drilled and then using this calculated inclination, calculated direction, actual drilled interval and average orientation to calculate a new inclination and direction.^{4}

This procedure was repeated for all drilled intervals. Therefore, any error between where the tool drilled and where it was oriented would result in an error that would be integrated along the well path. The good agreement between projected well path and well path measured with a magnetic multishot survey indicated that the tool drilled with a constant and repeatable radius of curvature

and drilled in the direction the bit was pointed.

For the calculation noted above:

$$\alpha_n = \cos^{-1}(\cos\alpha\cos\beta - \sin\alpha\sin\beta\cos\gamma) \quad (2)$$
$$\varepsilon_n = \varepsilon + \tan^{-1}(\tan\beta\sin\gamma/(\sin\alpha + \tan\beta\cos\alpha\cos\gamma)) \quad (3)$$

Where:
α=initial inclination, rad
α_n=new inclination, rad
ε=initial azimuth, rad
ε_n=new azimuth, rad
$\beta = d / R$, rad
R=radius of curvature
l=distance along curve.

During the normal course of drilling, the sleeve slowly rotates to the right, due to rotating drillstring friction. The theoretical effect of tool slippage on the effective radius of curvature can be calculated. If one assumes that the curve tool is initially oriented sufficiently left of the target so that one-half the slippage occurs on the left of target orientation and the other half occurs on the right of target orientation, then actual hole direction will be minimally affected.

The effective build rate will be less than expected if the tool did not slip at all by an amount. For example, a total tool slippage of 30° during a drilling interval would cause the effective radius of curvature to be about 1% greater than expected for constant orientation. A slippage of 60° results in a decrease in build rate of only 5%. Therefore, when slippage is controlled to about 2°/ft, the sleeve will usually require orienting only at each connection. To have confidence to run for this long, a method of monitoring sleeve orientation while drilling is needed.

ADDITIONAL WORK

Application of the rotary steerable tool could be broadened by development of two fundamental capabilities beyond what has been discussed above. First, providing a capability to monitor orientation of the eccentric sleeve while the drillstring is rotating would improve system efficiency and minimize drilling interruptions. This capability should be available quite soon and will initially be implemented via the wireline wet connect system. A side benefit of this improvement is that the pressure port is eliminated.

The second improvement would be to have the capability to shift the curve drilling tool from curve drilling to straight drilling, and vice versa. This would reduce need to rely on the curve drilling tool to drill a precise radius of curvature, allow lateral drilling to commence without tripping out after the curve was completed and allow directional corrections to be made while lateral drilling. Although the desirability of this feature has been recognized for some time and a practical method of providing it has been designed, it is farther from commercial application than continuous sleeve monitoring.

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