Trends toward rotary steerable directional systems

Inefficiencies of steerable motor directional drilling systems provide motivation to accelerate introduction of rotary steerable directional systems

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Directional drilling will continue to be important in the petroleum industry for the foreseeable future as reserves in offshore locations, environmentally sensitive areas and locations with restricted surface access are developed. Emphasis on re-entries to extend the life of onshore and offshore production facilities and on horizontal completions to improve production rates and ultimate recovery will continue to place demands on directional drilling technology.

Directional wells are more expensive than vertical wells, and a moderate improvement in their drilling efficiency can provide significant cost savings. The introduction of mud motors provided the fundamental capability to drill directional wells, and application of steerable motors improved trajectory control and reduced trip time, but they are expensive and trouble-prone.

Amoco drilled about 90 new directional wells (inclination greater than 10°) in 1995 at a total well cost of $239 million. Directional wells made up 12% of total wells drilled, but accounted for 36% of total drilling expenditure. These wells included drilling 543,000 ft with mud motors at a cost of about $61 million. Steerable motor systems are often inefficient and potentially could be replaced by more efficient rotary steerable directional systems. Achieving an overall improvement in efficiency of at least 20% is not an unreasonable expectation.

The inefficiencies of directional drilling with steerable motor systems can be divided into two general categories—trouble time associated with running motors and low operational efficiency when operations are running "normally." Trouble cost is readily identified and therefore, receives most of the attention when investigating ways to reduce directional drilling costs. Considerable progress has been made in this area over the last few years, and any directional system will have a certain amount of trouble cost associated with it. Rotary steerable systems could potentially reduce trouble costs (depending on system complexity); but the real incentive for switching from motor systems to rotary systems is to provide a more efficient directional drilling system. This consideration is in addition to the ability of rotary steerable systems to accomplish some tasks that are not currently possible with steerable motors.

Efficiency improvements that may be achieved through introduction of a new technology are often not easy to quantify, even though they may be quite significant. As long as the job gets done with the currently used system, and no better system is immediately available, it is natural to concentrate efforts on improving the existing system rather than introducing a new system. In the past, inefficient processes have been accepted as the normal cost of doing business. But now, pressure is greater to reduce costs to maintain competitiveness.

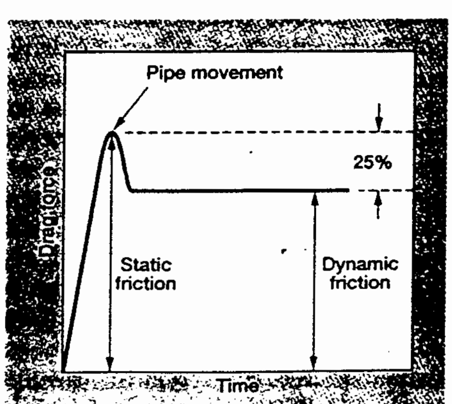

Fig. 1. Drag force reduced once pipe moves.

The following discussion is aimed at showing that drilling with steerable motor directional systems is inefficient, and that a significant improvement could be gained by introduction of rotary steerable systems. The objective of this article is not to put down motors, which have provided the backbone of directional drilling for three decades, but rather to show that considerable incentive exists for pursuing an alternative system.

LIMITATIONS OF STEERABLE MOTOR SYSTEMS

Steerable mud motors are run in a combination of "sliding" and "rotating" modes. The sliding mode is used to change direction or inclination by holding the drillstring rotationally stationary so that the bit can be oriented in a particular direction. The rotating mode is used to drill in a straight path (although the rotating mode may also be used to change inclination). Based on information from 172 directional wells from an offshore operation in which separate information for sliding and rotating is available, about 35% of the motor time on directional wells is spent in the sliding mode, although considerably less percentage of footage is drilled this way.

Types of inefficiencies. Drilling in the sliding mode results in several types of inefficiency. The first is that the motor must be oriented and maintained in a particular orientation while drilling to follow the desired path. The motor is oriented by a combination of rotating the drill string and "working" the pipe to turn it to the desired direction. After it is positioned, torque in the drillstring is required to hold the motor in proper orientation against the reverse torque created by the motor as the bit drills. This can be beneficial when the frictional drag is relatively low, in that it allows the weight-on-bit (WOB) to be adjusted to change reactive torque, which in turn twists the lower end of the pipe and changes tool

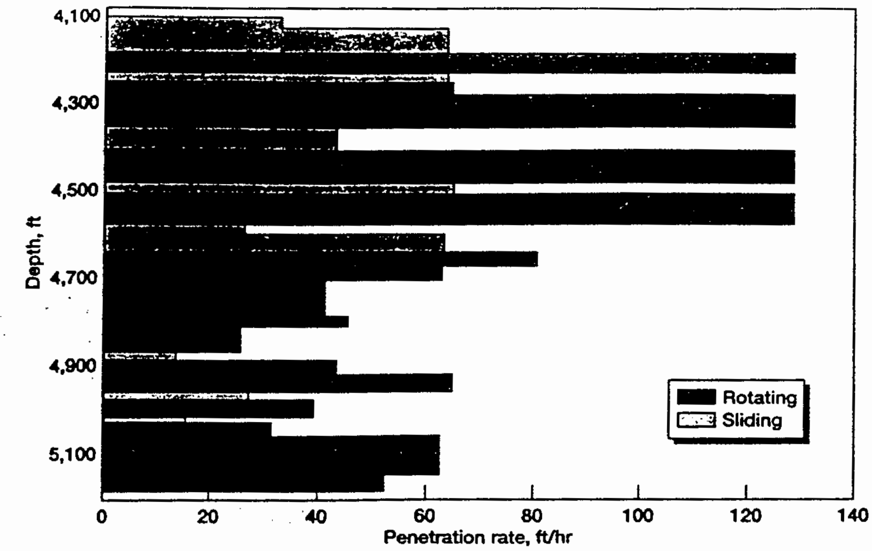

Fig. 2. Comparison of ROP while sliding and rotating.

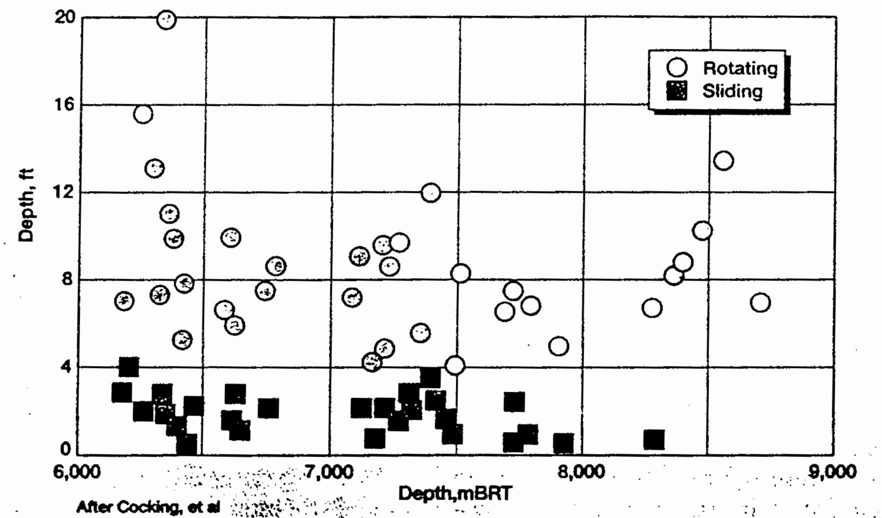

Fig. 3. Comparison of ROP while sliding and rotating.

face. Therefore, small changes in tool face can be made simply by adjusting WOB. This is detrimental in high drag cases because it is difficult to keep twist in the lower part of the string constant. Therefore, it can be difficult to maintain desired tool face.

The second problem with operating the motor in slide mode is that cuttings removal is inhibited, particularly in high-angle holes.[1] Drillstring rotation strongly contributes to complete removal of drilled cuttings and prevents them from settling on the low side of the hole. Inefficient cuttings removal requires additional rig time for circulating, short trips and wiper trips and, if ignored, can cause stuck pipe and increased pressure loss, which will increase chances of lost circulation.

The third potential problem is that the drillstring often cannot be lowered continuously and smoothly, which prevents the motor from being run at its optimum conditions. When the drillstring is stationary, frictional resistance to axial sliding is dependent on static coefficient of friction, drillstring weight and well geometry. When the drillstring is slacked off at surface to add weight to the bit, the slack-off must overcome friction for the drillstring to slide. As soon as the drillstring begins to move, the coefficient of friction changes from static value to dynamic value, which typically results in about a 25% reduction in friction, Fig. 1. This means that the minimum WOB increment is about 25% of total frictional drag in the well.

For example, if normal drag in the well is 50,000 lb, a slack-off at surface of 67,000 lb below neutral hook load would be needed to cause the pipe to move down. As soon as the pipe starts to slide, coefficient of friction is reduced by 25%, and the pipe slides until the combined load from WOB and dynamic friction equals surface slack-off. In this particular example, the minimum WOB increment that could be applied would be 17,000 lb. Therefore, a significant drill-off is required before additional weight is added to prevent motor stalling. Of course, if the drillstring is rotated, friction is always dynamic and, therefore, a negligible limitation could exist on WOB increment. Also, in cases where penetration rate (ROP) is high enough to continuously feed off the drillstring, there will be a negligible limit to WOB increment.

Lower penetration rate. Combination of these three factors results in sliding ROP being considerably less than rotating ROP. Fig. 2 shows an example from an Amoco well where a motor was being run with a roller cone bit, and drilling was alternated from sliding to rotating, as is typical for directional operations. A definite decrease in ROP occurs for each sliding interval. Fig. 3 shows recently published data that further demonstrates the adverse effect of sliding on ROP.[2] This data for extended-reach wells indicates that not only is sliding ROP less than rotating ROP, but a point can be reached where sliding is no longer a possibility. The relatively recent introduction of thrusters is aimed at reducing the severity of the sliding problem, but can be used only with relatively non-aggressive bits, as discussed below.

The directional wells mentioned above were examined by looking at the ratio of sliding ROP to rotating ROP (Rs/Rr) in each well and comparing these values for PDC and roller bits. For about 23% of the cases, sliding ROP was actually higher than rotating ROP in the same well. This may be caused by the fact that most sliding occurs early in the well where rock is softer and ROP is higher. For the remaining 132 cases, the average sliding ROP is only 67% of rotating ROP for roller cone bits and falls to 47% of rotating ROP for PDC bits. Many specific cases indicate sliding ROP less than 10% of rotating ROP.

Bit selection problems. This leads to the fourth problem: the best bit for the formation often cannot be used, which results in ROP being lower than it would be for non-directional wells. The effect of minimum WOB increment on bit selection can be easily demonstrated in Fig. 4, which shows ROP and corresponding torque for three 8½-in. bits: relatively soft formation insert bit (series 517), standard PDC bit (series M332) and aggressive PDC bit (series M121). Clearly, PDC bits drill much faster than roller cone bits at normal operating conditions.

Also shown in this figure is typical maximum operating torque that can be generated by a 6½-in. (⅚ lobe) slow-speed motor that would be used with these 8½-in. bits. If the minimum increment in WOB that can be applied is 25,000 lb, then neither of the PDC bits can be used, because they will always be in either the unloaded or stalled condition. The roller cone bit could be operated between 15,000 and 40,000 lb WOB without stalling the motor and would drill at about 20 ft/hr, but if PDC bits could be run efficiently, ROP would be several times faster.

The above discussion is based on laboratory drilling data, but concepts presented are valid and observed in field operations. The problem with running aggressive bits, such as most PDC bits, can be shown from both specific field cases and much broader sets of data. Fig. 5 shows that when ROP data from the 172 wells are grouped by ratio of Rs/Rr, a direct correlation exists between reduction in ROP while sliding and higher use of PDC bits. Even though PDC bits may be the best bits for drilling the formation, they are often impractical to run because of their adverse effect on sliding ROP.

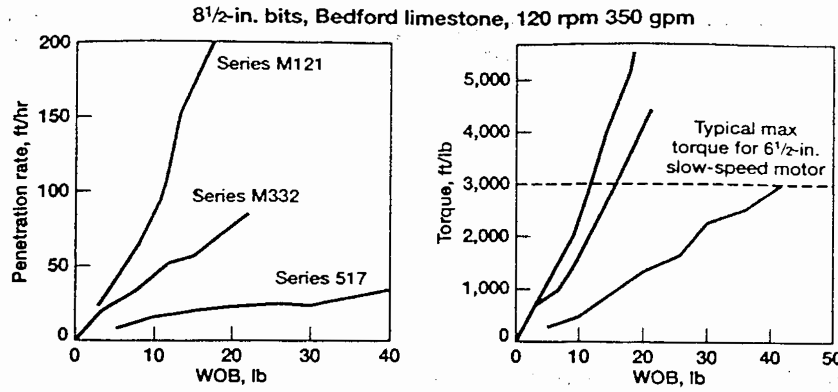

Fig. 4. ROP and torque response for three different levels of bit aggressiveness.

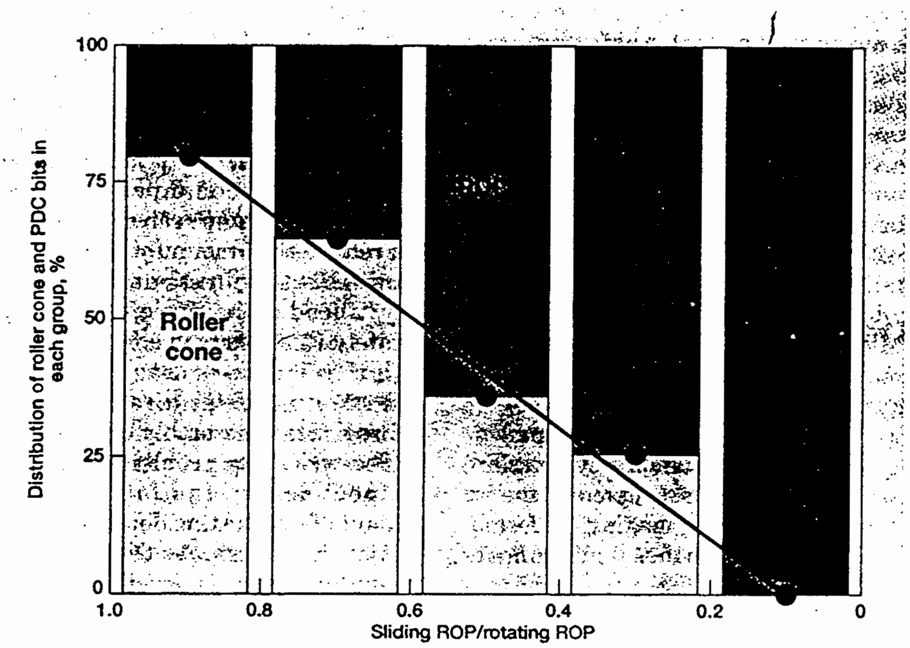

Fig. 5. Effect of PDC bit on sliding ROP.

Another factor that contributes to the limited use of aggressive PDC bits with motors is that when WOB is increased, an increase in motor pressure causes a further WOB increase due to the tendency for the drillstring to elongate when internal pressure is increased. For example, consider a situation where axial stick slip of the drillstring is not severe and a 5,000-lb WOB increment can be achieved. The additional increase in WOB due to increase in motor pressure would be 500 lb, 2,000 lb and 3,000 lb, respectively, for the roller cone, less aggressive PDC and most aggressive PDC bits. This would allow the roller cone bit to be easily operated between a WOB of 35,000–40,500 lb, with a resulting penetration rate of 27 ft/hr.

The less aggressive PDC bit could be operated between 8,000 and 15,000 lb WOB, with a resulting ROP of 53 ft/hr, while the more aggressive PDC bit could be operated between 3,500 and 11,500 lb WOB, with a resulting ROP of about 60 ft/hr. All these projections are based on not exceeding maximum motor pressure of 700 psi. Even a few motor stalls when trying to run the more aggressive PDC bits would negate the potential benefit of higher ROP. Therefore, the practical solution is to run the less aggressive bit.

The introduction of thrusters, tandem motors and higher power motors is aimed at reducing the severity of these problems. Providing more power from the motor can improve drilling efficiency and is one way to help overcome some problems inherent in steerable motors. Thrusters may provide a benefit in some cases, but because of their positive pressure feedback (similar to that described for the drillstring above), they are effective only with non-aggressive bits.

What does this mean? First, it clearly shows that ROP while sliding is often less than when rotating and implies that the drilling process while sliding results in inefficient drilling. Second, and less obvious, the detrimental effect does not just affect operations while sliding. Since most steerable motor runs require some sliding, the directional driller attempts to pick a bit that will allow him to slide if needed. This causes him to run much less aggressive bits and results in ROP always being slower (even when rotating) than if the best bit could be picked for the formation. *Continued*

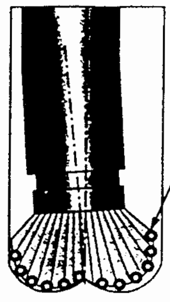

Fig. 6. Non-uniform cutter loading while rotating a steerable motor.

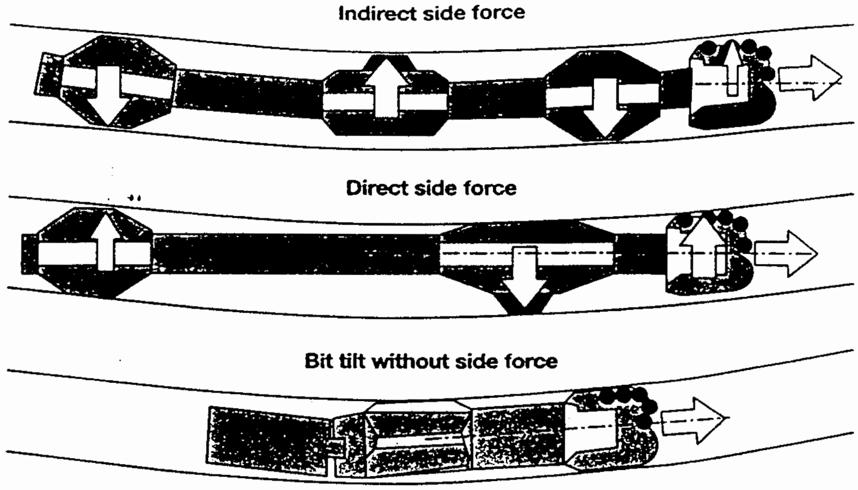

Fig. 7. Bit trajectory control mechanisms.

Lower motor/bit performance. Also, motor systems are failure-prone. Based on a recent study of motor failures, about 42% of Amoco's motor runs ended in motor failures for sizes 4¾ in. and smaller, and 28% of motor runs between 5 and 9⅝ in. were terminated with a failure. Not only does the motor fail often, but it is likely that motor vibration contributes to a high rate of MWD failures. When one watches a motor being run on a test stand, it is surprising that an MWD tool ever works with a motor.

When steerable motor systems are operated in the rotating mode, the bit is prevented from engaging the formation in the manner that is optimum for cutting and wear efficiency. The bit axis is tilted with respect to hole axis, and therefore, the bit is always instantaneously loaded more on one side than the other, Fig. 6. As the bit rotates, the side that engages the formation is continuously changing. In other words, a portion of the hole is cut by a rotary "rasping" action rather than a continuous machining action that is best for PDC bits. This causes the bit shoulder and gauge to wear at a higher rate than when run with more uniform loading and often defeats the "anti-whirl" design features that are used to provide a smooth operating bit.

Steerable motor systems achieve their directional control by a combination of "bit tilt" and "bit side" cutting. This causes prediction of the curvature that results from a particular motor/bit combination to be imprecise and makes the performance dependent on formation characteristics. This is overcome by designing the build rate while sliding to be greater than the average build rate needed to accomplish directional objectives. The time distribution between sliding and rotating is then adjusted to maintain an adequate directional performance. Using an over-aggressive build rate can reduce the amount of sliding and assure that the directional driller can stay "ahead of the curve," but unfortunately, this results in a tortuous well path that increases drag and torque and often requires a reaming run before a rotary assembly can be used.

The tortuosity problem is further compounded by the fact that the amount of side cutting depends on formation hardness. As the bit drills through bed boundaries, this tends to cause ledges. The inability to take full advantage of anti-whirl bit features exacerbates the ledge problem. This overall poor hole quality often results in difficulty in running casing and liners with upsets and centralizers and reduces the quality of electric logs.

ROTARY STEERABLE ALTERNATIVE

Many deficiencies of the motor steerable systems discussed above can be significantly reduced or eliminated by the use of a rotary steerable directional system, where the bit is directed along a desired path while being powered by continuous drillstring rotation. This eliminates drillstring hang-up, provides good hole cleaning and, more importantly, allows the best bit to be used for the formation being drilled. Elimination of the motor from the directional assembly may allow MWD/LWD measurements to be made closer to the bit. These improvements should provide a 20–30% improvement in drilling efficiency, even if the mechanical failure rate of the rotary steerable tools is no better than that for motors.

There are several rotary steerable systems under development, including ones by Camco[3], Baker Hughes INTEQ (BHI)[4], Cambridge Drilling Automation, Appleton[5], DDD Stabilizers[6] and a slimhole system developed by Amoco.[7] The Camco, BHI and Amoco systems appear to be closest to commercialization, although one from Cambridge Drilling Automation has been under development longer and has recently had a successful field run.[8] Several other systems are in various stages of prototype development.

COMPARISON OF SYSTEMS

A rotary steerable system can be classified in several ways, but probably the two most significant are the method of orientation (automated dynamic or manual) and the mechanism used for directional trajectory control. Tools that use an automated dynamically controlled orientation mechanism are by nature much more complicated than manually oriented systems. They generally include some type of onboard instrumentation to determine orientation of the tool, a source of power and an actuation mechanism that adjusts orientation of the tool to maintain a previously established orientation.

Manually oriented systems are generally oriented by manipulating either mud flow, drillstring rotation and/or axial drillstring movement. Manually oriented systems are oriented similar to the way steerable motors are currently oriented. Some use an automated orientation mechanism, but orientations are made at each connection rather than dynamically while drilling.

Directional trajectory can be controlled by applying a lateral force to the bit, tilting the bit or a combination of these two, Fig. 7. Arrows indicate contact forces between the assembly and borehole wall. Both Camco and BHI systems use automated orientation mechanisms and control well trajectory by applying a side force directly to the bit. An expandable non-rotating stabilizer on the BHI assembly exerts a static side force on the borehole wall to create a lateral reaction force in the opposite direction at the stabilizer and bit.

The Camco system applies a dynamic force to the bit, but the result is similar to the BHI system. Since the bit has a much higher side-cutting characteristic than the stabilizer, the wellbore path is directed toward the force applied to the bit. The wellbore curvature is determined by the amount of side cutting relative to straight ahead penetration. The axis of bit rotation in both systems is always angled with respect to hole axis at the bit by an amount determined by radius of curvature and tool geometry. This bit tilt tends to counteract bit deflection due to side cutting. Both systems are automatically activated and deactivated to follow a commanded path.

The Appleton and DDD systems are very similar in that both apply an indirect side force uphole from a near-bit stabilizer to provide a side-cutting force and bit tilt. For these tools, the near-bit stabilizer acts as a fulcrum, which allows bit side force and bit tilt to operate in the same direction. The primary deflection mechanism is still bit side cutting, but bit tilt and side cutting act complementary rather than opposed, as in the BHI and Camco tools. This method of directing the bit is a classic case of using three points to determine a curvature. These tools may also be used without a near-bit stabilizer to provide a direct side force to the bit.

The Amoco system uses a manually oriented non-rotating sleeve and flexible joint to cause bit axis to be tangent to hole centerline at the bit face. The curvature is defined by position constraints offered at the bit and eccentric sleeve, and the requirement that bit axis is tangent to hole centerline at the bit face. This trajectory control method depends on curvature being determined by two contact points and vector direction of the bit axis. If wellbore trajectory is disturbed in some way to cause it to be shorter than designed curvature, the bit is pointed to the outside of the curve and drills longer; conversely, if curvature becomes longer, the bit is 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 and the bit is designed to prevent side cutting.

For low build rates and many formations, no practical difference may exist between the deviation control mechanisms of any of these tools. As the build rate increases and/or formation gets harder, a directional control system where bit axis and borehole axis are aligned may be better because of more uniform loading of the break-over and gauge cutters on the bit. This portion of the bit is normally the most susceptible to wear while directional drilling. Therefore, in developing a new directional system, it seems advantageous to attempt to minimize gauge wear.

The Camco, BHI and Cambridge (and possibly others) systems offer automated orientation mechanisms. Clearly, if reliability and operating costs are not prohibitive, the automated system is better. Even so, there probably are many wells where a manual orientation system is adequate and provides advantages over steerable motor systems which are also manually oriented.

Small diameter holes provide a special challenge for rotary steerable systems because motor problems here are most pronounced. Even though the need may be greatest, it will be more difficult to design automated orientations systems in the small tool sizes needed for slimhole wells than to develop them for larger hole sizes. These small diameter holes are also the most likely to require high build rates. The trajectory control mechanism used in the Amoco system readily allows much higher curvatures than could be achieved with the other two systems.

THE FUTURE

Steerable motor directional drilling systems have provided the drilling industry with a tool that has allowed directional wells to be effectively drilled in many situations. These systems also introduce considerable inefficiencies in the drilling process and, in some extended-reach applications, are not adequate to meet current demands. Rotary steerable systems offer the capability to eliminate many of these deficiencies. The question to be answered over the next few years is "how will the transition from motor steerable systems be made to rotary steerable systems?".

Fully automatic systems are being introduced primarily on very expensive extended-reach wells where they provide a capability that does not currently exist with motor-driven systems. These systems can be run economically in extended-reach wells even when their cost is very high. Therefore, the service provider can recover their development cost faster, while providing minimum direct competition with motor markets. Over time, these tools will become less expensive and more readily available so that they can move into the general directional drilling market, beginning with the most expensive applications and moving toward less expensive applications.

An opportunity exists for a simpler system to be introduced to market at the other end of the spectrum. This system may have less capability to compete in the expensive extended-reach market, but it offers cost and efficiency advantages in the smaller hole re-entry drilling market. From this entry point, the smaller system will evolve to where it is effective for conventional directional drilling. It is expected that over the next few years, a majority of directional wells will be drilled with some type of rotary steerable system.

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