Short-Radius System Reduces Costs

By J. David LaPrade

TULSA–It is no secret that drilling a well horizontally offers the possibility of increasing well productivity by leaving more reservoir rock exposed. Because of this, the use of short-radius horizontal re-entry and completion technology to reactivate and rejuvenate existing fields is growing rapidly.

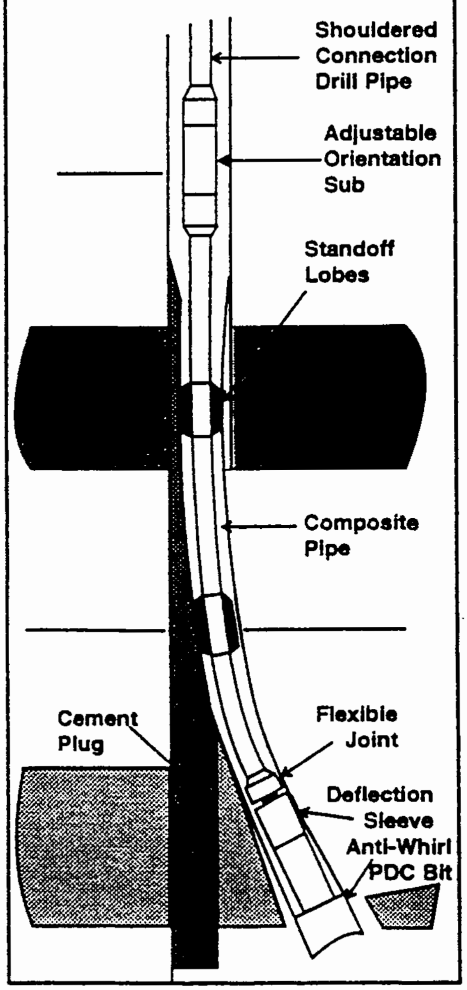
Amoco's new short-radius technology is gaining ground as a reliable alternative to conventional completion procedures. The technology can be applied at a lower cost and with less exposure than conventional mud motor systems.

Amoco initiated a project in 1989 to develop a short-radius lateral drilling system for completing and recompleting wells to enhance the economical production of oil and gas.

More than 200 test wells were drilled using the system at Amoco's Catoosa Test Facility near Tulsa. After the prototype tools were developed and tested, they were used to drill several wells in West Texas. These wells proved the basic capability to install a lateral drain hole at a reasonable cost with a top-drive power swivel and workover rig.

The system has been developed and tested to the point where it is a successful commercial service. Since the first quarter of 1995, more than 25 wells have been successfully drilled using the technology.

FIGURE 1
Rotary-Guided Short-Radius Curve Assembly



Major Impediment

A major impediment to the widespread use of short-radius lateral drilling for re-entries and completions has been cost. Economics in mature fields requires substantial cost reductions over the methods most often used for drilling horizontal wells.

The primary objective in developing this technology was to design a bottom-hole assembly low in cost to manufacture, repair and operate that could offer the capability to work inside 4.5-inch casing. The secondary objective mandated using surface equipment and cost structures associated with workover and repair services.

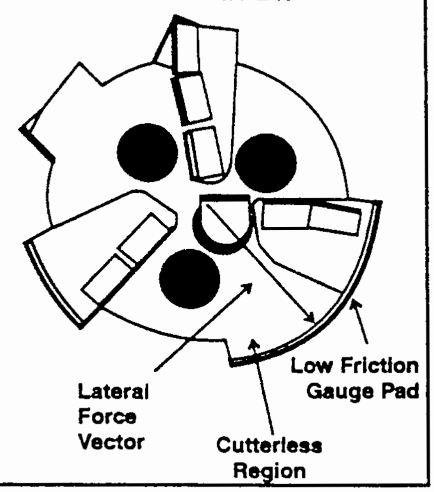
The key to successful exploitation of oil and gas reserves using short-radius horizontal drilling is ensuring that the targeted property meets certain criteria. For example, to be a good horizontal candidate, potential prospects must have good pressures and remaining reserves. Most importantly, however, prospects must have reservoir or well bore problems that cannot be solved with vertical holes.

Wells that experience gas or water coning, high-pressures and low volumes, or natural fracture systems are potential candidates. In addition, vertical wells that were near-misses structurally, or where a conventional completion did not work, or where severe well bore damage exists are also potential candidates.

System Capabilities

The Amoco system is capable of drilling a 3.875-inch hole from inside 4.5-inch casing, or a 4.5-inch hole from inside 5.5-inch casing and larger. Radius of curvature ranges from 30 to 90 feet, with lateral departures up to 1,000 feet. Multiple laterals can be drilled in opposing directions or in the same direction, with kick-off points spaced a minimum of eight feet apart. Compatibility with any circulating medium including mud, foam or air mist allows for a variety of applications.

FIGURE 2
Curve Assembly Amoco Anti-Whirl Bit



The system consistently drills a predictable radius of curvature in the desired direction, resulting in a smoother planar well bore, which facilitates drilling the lateral and completing the well. Vertical target accuracy is plus or minus two feet, and azimuth is plus or minus 20 degrees.

The system is rotary steerable, and there are no mud motors, steering tools or MWD tools. The system is purely mechanical and very simple in design. The downhole components of the system (Figure 1) include:

- The primary drill string;
- Adjustable orientation sub;
- Flexible drill string;
- Curve assembly; and
- The bit.

The primary drill string is normally 2.875 inches, and must be shouldered-

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connection drill pipe (DSS. AOH. PH-6). The flexible drill string consists of two or more joints of composite drill pipe for radii less than 50 feet. Steel tubing, such as Q125 or SN135, are used for radii greater than 50 feet. The curve assembly consists of an orientable, eccentric, nonrotating deflection sleeve and knuckle joint for flexibility and axial transmission of torque to the bit.

PDC Bit

The Amoco bit (Figure 2) is an anti-whirl, bi-center, low-friction PDC bit. Consistent and reliable angle build and improved directional control is a result of stabilizing the PDC bit to continually point along a curved path. The design of the bit enables it to cut only in the direction it is pointed.

The cutters are positioned so that they direct a lateral force toward a smooth pad on the gauge of the bit, which contacts the bore hole and acts as a bearing by transmitting a restoring force to the bit. This force rotates with the bit, continually pushing a side of the bit that does not have gauge cutter chips against the bore hole wall. This design minimizes the side cutting action that is typically observed with PDC bits and results in consistent well bore diameter.

The system drills a curved path by continually pointing the bit along a tangent to the curved path. A contact point on the bit and smooth contact ring at the flexible knuckle joint establishes two contact points and controls the bit tilt. Tool design tilt allows the curve assembly to run smoothly, drill a hole uniform in diameter, and negates the effects of varying lithology changes. Various radii of curvatures are easily obtained by increasing or decreasing the distance between the two contact points.

Azimuth or target direction is established by gyro orientation of the eccentric deflection sleeve. Once oriented in the desired direction, the gyro is released and orientation is monitored by pump pressures at the surface. These signals are monitored throughout the curve drilling process, as repositioning of the sleeve is required to maintain target direction.

Rotary Process

Lateral drilling is strictly a rotary process. The lateral drilling assemblies are not steerable, and there are no deflection sleeves or orientation signals.

At present, there are two lateral drilling assemblies, and both use the anti-whirl PDC bit to achieve a smooth well bore and obtain fairly consistent responses. Of the two lateral assemblies, one is engineered for gentle rise with angle build rates of 7 to 11 degrees per 100 feet. The second is for maintaining inclination, and produces near-neutral responses of -2 to 2 degrees per 100 feet.

The assemblies work on the same principle as any directional drilling assembly. Both have been found to drill with minimal walk, right or left, but inclination is somewhat sensitive to formation and weight on the bit.

The predominate application of short-radius horizontal drilling is for re-entries, a procedure that requires the sectional milling of at least 20 feet of casing. Following sectioning, a cement kick-off plug is set in the vertical well bore just below the kick-off depth. Cement is brought up through the sectioned interval, and 60 to 100 feet inside the casing.

This multi-purpose plug must provide zone isolation from the original completion and mechanical strength for the curve assembly to side track. Open-hole completions, either from existing wells or new wells, can be kicked off from formation or a squeeze cement plug.

Torque, weight on bit, drill-off rate, and cuttings are monitored during the kick-off procedure as the bit makes the transition from drilling 100 percent cement to 100 percent formation. This transition usually occurs after drilling a minimum of six feet, and can be greater depending on the radius of curvature.

In regard to equipment requirements,

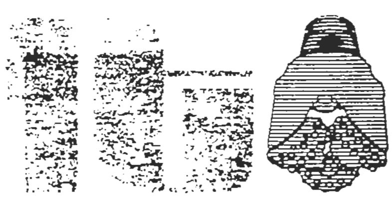

FIGURE 3

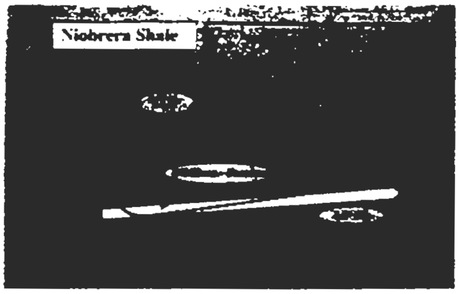

FIGURE 4

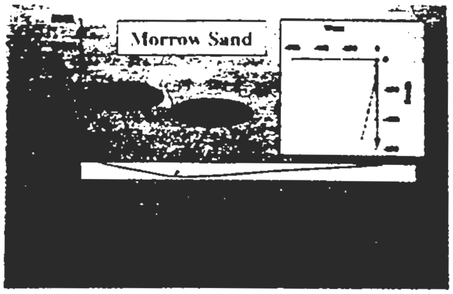

FIGURE 5

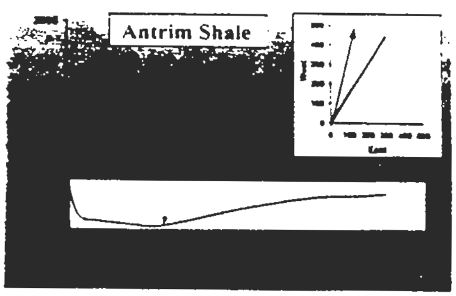

Figure 3, left, illustrates a 90-foot radius drilled with air in the Niobrera Shale in Wyoming. Figure 4, center, shows a 45-foot radius drilled with oil-based mud in the Oklahoma Morrow Sands.

Figure 5, right, depicts a 30-foot radius drilled with water-based mud in the Antrim Shale in Michigan.

many types of workover rigs have been used in conjunction with the system, ranging from small pole units to five- and six-axle carriers. Drilling rigs have been used in several instances, but are not necessary.

A top-drive power swivel, the most predominate of which is the Bowen 2.5, is used to rotate the drill string and bit. A single conductor wireline unit is used for gyro orientation and to run all electronic and magnetic surveys. Circulating and solids control equipment vary depending on formation conditions.

Preparing A Well Plan

Planning begins with completion requirements. The kick-off point is determined by the length of the lateral and radius of curvature. Bed thickness, structural dip, and desired azimuth should be well defined. Additional factors to consider when planning the well path are potential problems that could arise with heaving, sloughing or swelling shales. Slow penetration rates can be encountered because of pyrite, anhydrite or chert, and should be avoided when possible.

Once all data is reviewed, a proposed well path is chosen, the kick-off point is selected, and a well bore preparation schematic is prepared. Prior to commencing operations, a pre-spud meeting is held.

Lower Cost

In comparison to typical mud motor systems, overall total well cost can be considerably lower. This cost difference is attributable to the fact that the Amoco system does not use mud motors, steering tools or MWD, and kick-off is achieved from a cement plug as opposed to a whipstock.

Simple parts maintenance of the downhole assemblies translates into quick on-site repair time, eliminating costly standby time charges resulting from shop repairs. Spare parts are plentiful, and cost pennies on the dollar compared to other systems. Inspection and repair charges are minimal, and lost-in-hole liability is greatly reduced. In fact, the operator is often limited to $20,000 exposure.

Average well costs range from $65,000 to $125,000, depending on location, depth and the complexity of the drilling plan. These costs include all equipment and services required for preparation, sectioning and cementing, gyro orientation, and drilling a 50-foot radius of curvature and up to a 700-foot lateral departure.

Figures 3-7 illustrate the versatility and reliability of the technology. The tools have performed consistent regardless of lithology, drilling fluid, radius of curvature, or drill string. The Amoco system is a simple short-radius lateral drilling and completion technology that costs less to manufacture and operate than other systems, and requires lower-costing support equipment. ❒

References

[1]"Short-Radius Lateral Drilling System," *Journal of Petroleum Technology*, February 1993.

[2]"Slim Hole Directional Drilling System," Amoco Production Company, October 1994.

[3]"The Development and Application of a Short-Radius Lateral Drilling and Completion System," Amoco Production Company, August 1993.

FIGURE 6

**Dual-Opposing Lateral
Oklahoma Dutcher Sand**

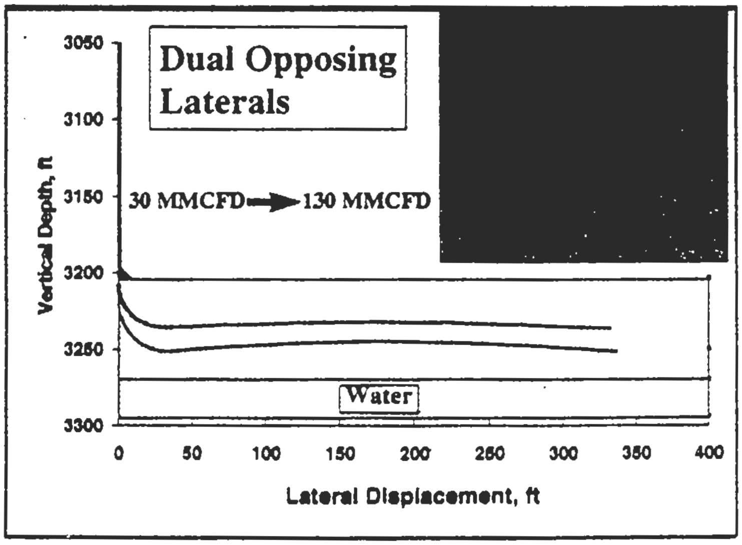

FIGURE 7

**Dual Lateral in Different Zones
Texas Brown Dolomite**