New Directions in Rotary Steerable Drilling

Initially developed to drill extended-reach wells, rotary steerable systems are also cost-effective in conventional drilling applications because they reduce drilling time significantly. Improvements in rate of penetration as well as in reliability have prompted worldwide deployment of these tools.

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ADN (Azimuthal Density Neutron), CDR (Compensated Dual Resistivity), InterACT Web Witness, PowerDrive, PowerPak and PowerPulse are marks of Schlumberger.

Certain situations require advanced drilling technology (next page). Local geology might dictate a complicated well trajectory, such as drilling around salt domes, salt tablets or salt sheets. Reservoir drainage or production from a particular well might improve if a well penetrated multiple fault blocks or was constructed horizontally to intersect fractures or to maximize wellbore surface area within the reservoir. A multilateral typically drains several reservoir compartments. Small compartments in mature fields can also be produced economically if directional wells are located skilfully.

Operators drill extended-reach wells to reservoirs that cannot be exploited otherwise without unacceptable cost or environmental risk, for instance to drill from a surface location onshore to a bottomhole location offshore rather than constructing an artificial island. Drilling multiple wells from one surface location has been standard practice offshore for years and is now common in restricted onshore locations, like rain forests, for environmental protection. There are also instances in which the operator wants to drill a vertical wellbore, notably the deep well of the KTB Program (German Continental Deep Drilling Program), and uses a steering system to keep the hole straight.
In rare emergency situations, directional-drilling technology is essential, for example to construct relief wells for blowouts. Less dire situations, such as sidetracking around an obstruction in a wellbore, also benefit from the ability to control the wellbore trajectory. Further downstream, directional drilling is used to construct conduits for oil and gas pipelines that protect the environment.

Like other drilling operations, there is also a need for cost-effective performance in directional drilling: Drilling expenses account for as much as 40% of the finding and development costs reported by exploration and production companies. Offshore, eliminating a day of rig time can save $100,000 or more. Accelerating production by a day generates similar returns.

Clearly, without advanced directional drilling technology, it might not be physically possible to drill a given well, the well might be drilled in a suboptimal location or it might be more expensive or risky. Rotary steerable systems allow us to plan complex wellbore geometries, including horizontal and extended-reach wells. They allow continuous rotation of the drillstring while steering the well and eliminate the troublesome sliding mode of conventional steerable motors. The results have been dramatic: The PowerDrive rotary steerable system contributed to the drilling of the world’s longest oil and gas production well, the 37,001-ft [11,278-m] Wytch Farm M-16SPZ well, in 1999. This article reviews the development of directional drilling technology, explains how new rotary steerable tools operate and presents examples that demonstrate how these new systems solve problems and reduce expenses in the oil field.


Evolution of Directional Drilling Technology

There have been astonishing advances in drilling technology since the primitive cable-tool techniques used to drill for salt hundreds of years before the development of modern techniques. The advent of rotary drilling, whose timing and origins are subject to debate but which occurred around 1850, allowed drillers greater control in reaching a specified target. Further advances depended on the development of accurate surveying systems and other downhole devices.

Improvements in drilling safety have accompanied the progress in drilling technology. For example, pipe handling has been increasingly automated by “iron roughnecks” to minimize the number of workers on the rig floor. Unsafe tools have been removed, such as kelly spinners replacing spinning chains. Bigger and better drilling rigs handle loads more securely. Kick-detection software and use of devices that detect annular pressure changes help improve hole cleaning and retain well control. These and other advancements in modern drilling operations have reduced accidents and injuries substantially.

The first patent for a turbodrill, a type of downhole drilling motor, was awarded in 1873. Controlled directional drilling began in the late 1920s when drillers attempted to keep vertical holes from becoming crooked, sidetrack around obstructions or drill relief wells to regain control of blowouts. There were even cases of drilling across property boundaries to drain oil and gas reserves illegally. The development of the mud motor was a powerful complement to advances in surveying technology. Since then, positive-displacement motors (PDM), which are placed in the bottomhole assembly (BHA) to turn the bit, have drilled most directional wells. Exotic well designs continue to push the limits of directional-drilling technology, resulting in the combination of rotary and steerable drilling systems now available.

Determining the inclination of a wellbore was a key problem in directional drilling until accurate measuring devices were invented. Directional surveys provide at least three vital pieces of information: the measured depth, the inclination of the wellbore and the azimuth, or compass direction, of the wellbore. From these, the wellbore location can be calculated. Survey techniques range from magnetic single-shot surveys to more sophisticated gyroscopic surveys. Magnetic surveys record the well inclination and direction at a given point (single-shot) or many points (multishot) using an inclinometer and a compass, a timer and a camera. Gyroscopic surveys provide more accuracy using a spinning mass pointed in a known direction. The gyroscope maintains its orientation to measure inclination and direction at specific survey stations. The industry is currently developing unintrusive gyroscopic surveying methods that can be used while drilling.

Modern measurements-while-drilling (MWD) systems send directional survey information to surface by mud-pulse telemetry—survey measurements are transmitted as pressure pulses in the drilling fluid and decoded at surface while drilling is in progress. In addition to direction and inclination, the MWD system transmits information about the orientation of the directional drilling tool. Survey tools indicate only where a well has been placed; it is the directional tools, from the simple whipstock to advanced steerable systems, that offer the driller control over the wellbore trajectory.

Before the development of leading-edge steerable systems, expedient placement of drill collars and stabilizers in the BHA allowed drillers to build or drop angle (above). These techniques allowed some control over hole inclination, but little or no control over the azimuth of the wellbore. In some regions, experienced drillers could take advantage of the natural tendency of the drill bit to achieve limited wellbore deviation in a somewhat predictable manner.

11. For several general articles about stuck pipe: Oilfield Review 3, no. 4 (October 1991).
Steerable motors, which use a downhole turbine or PDM to generate power and a BHA with a fixed bend of approximately $\frac{\pi}{2}^\circ$, were developed in the early 1960s to allow simultaneous control of wellbore azimuth and inclination. Today, a typical steerable motor assembly consists of a power-generating section, through which drilling fluid is pumped to turn the drill bit, a bend section of 0 to 3°, a drive shaft and the bit (below left).

Directional drilling with a steerable motor is accomplished in two modes: rotating and sliding. In the rotating mode, the entire drillstring turns in the same manner as ordinary rotary drilling and tends to drill straight ahead.

To initiate a change in the wellbore direction, the rotation of the drillstring is halted in such a position that the bend in the motor points in the direction of the new trajectory. This mode, known as the sliding mode, refers to the fact that the nonrotating portion of the drillstring slides along behind the steerable assembly. While this technology has performed admirably, it requires great finesse to correctly orient the bend in the motor because of the torsional compliance of the drillstring, which behaves almost like a coiled spring, twisting to the point of being difficult to orient. Lithological variations and other parameters also influence the ability to achieve the planned drilling trajectory.

Perhaps the greatest challenge in conventional slide drilling is the tendency of the nonrotating drillstring to become stuck. During periods of slide drilling, the drillpipe lies on the low side of the borehole. This leads to uneven fluid velocities around the pipe. In addition, the lack of drillpipe rotation diminishes the ability of the drilling fluid to remove cuttings, so a cuttings bed may form on the low side of the hole. Hole cleaning is affected by rotary speed, hole tortuosity and bottomhole assembly design, among other factors. Sliding-mode drilling decreases the horsepower available to turn the bit, which, combined with sliding friction, decreases the rate of penetration (ROP). Eventually, in extreme extended-reach drilling projects, frictional forces during sliding build to the point that there is insufficient axial weight to overcome the drag of the drillpipe against the wellbore, and further drilling is not possible.

Finally, slide drilling typically introduces several undesirable inefficiencies. Switching from the sliding mode to the rotating mode while drilling with steerable tools can result in a more tortuous path to the target (below right). The use of a rotary steerable system eliminates the sliding mode and produces a smoother wellbore (black trajectory).
numerous undulations or doglegs in the wellbore increase wellbore tortuosity, which in turn increases apparent friction while drilling and running casing. During production, gas may accumulate in the high spots and water in the low spots, choking production (above). Despite these challenges, directional drilling with a steerable motor remains cost-effective and is still the most widely used method of directional drilling.

The next advance in directional drilling technology, still in its infancy, is the rotary steerable system (RSS). These systems allow continuous rotation of the drillstring while steering the bit. Currently, the industry classifies rotary steerable systems into two groups, the more prevalent “push-the-bit” systems, including the PowerDrive system, and the less mature “point-the-bit” systems (left).

How Does a Rotary Steerable System Work?
The PowerDrive system is mechanically uncomplicated and compact, comprising a bias unit and a control unit that add only 12⅔ ft [3.8 m] to the length of the BHA. The bias unit, located directly behind the bit, applies force to the bit in a controlled direction while the entire drillstring rotates. The control unit, which resides behind the bias unit, contains self-powered electronics, sensors and a control mechanism to provide the average magnitude and direction of the bit side loads required to achieve the desired trajectory (below).

The bias unit has three external, hinged pads that are activated by controlled mud flow through a valve. The valve exploits the difference in mud pressure between the inside and outside of the
bias unit (right). The three-way rotary disk valve actuates the pads by sequentially diverting mud into the piston chamber of each pad as it rotates into alignment with the desired push point—the point opposite the desired trajectory—in the well. After a pad passes the push point, the rotary valve cuts off its mud supply and the mud escapes through a specially designed leakage port. Each pad extends no more than approximately ½ in. [1 cm] during each revolution of the bias unit. An input shaft connects the rotary valve to the control unit to regulate the position of the push point. If the angle of the input shaft is geostationary with respect to the rock, the bit is constantly pushed in one direction, the direction opposite the push point. If no change in direction is needed, the system is operated in a neutral mode, with each pad extended in turn, so that the pads push in all directions and effectively “cancel” each other.

The control unit maintains the proper angular position of the input shaft relative to the formation. The control unit is mounted on bearings that allow it to rotate freely about the axis of the drillstring. Through its onboard actuation system, the control unit can be commanded to hold a fixed roll angle, or toolface angle, with respect to the rock formation. Three-axis accelerometer and magnetometer sensors provide information about the inclination and azimuth of the bit as well as the angular position of the input shaft. Within the control unit, counter-rotating turbine impellers mounted at opposite ends of the control unit develop the required stabilizing torque by carrying high-strength permanent magnets that couple with torque coils in the control unit. The torque transmission from the impellers to the control unit is controlled by electrically switching the loop resistance of the torque coils. The upper impeller, or torquer, is used to torque the platform in the same direction as drillstring rotation, while the lower impeller turns it in the opposite direction. Additional coils generate power for the electronics.

The tool can be customized at surface and preprogrammed according to the expected ranges of inclination and direction. If the instructions need to be changed, a sequence of pulses in the drilling fluid transmits new instructions downhole. The steering performance of the PowerDrive system can be monitored by MWD tools as well as the sensors in the control unit; this information is transmitted to surface by the PowerPulse communication system.

The datum used to set the geostationary angle of the shaft is provided either by a three-axis accelerometer or by the magnetometer triad mounted in the control unit. For near-vertical holes, an estimate of magnetic North is used as the reference for determining the direction of deviation. For holes that deviate more than a few degrees from vertical, the accelerometers provide the steering reference.

One of the many benefits of using a roll-stabilized platform to determine the steering direction is its insensitivity to drillstring stick-slip behavior. Additional sensors in the control unit record the instantaneous speed of the drillstring with respect to the formation, thereby providing useful data about drillstring behavior. Shock and thermal sensors are also carried by the control unit to record additional information about downhole conditions. Information about drilling conditions is continuously sampled and logged by the onboard computer for immediate transmission to surface by the MWD system or for later retrieval at surface. This information has helped diagnose drilling problems, and, coupled with the MWD, mud logging and formation records, is proving to be extremely valuable in optimizing future runs.
Getting from Here to There
Having the capability to control well trajectory does not guarantee a perfect well. Successful directional drilling involves careful planning. To optimize well plans, the geologist, geophysicist and engineers must work together from the outset, rather than working in sequence using an incomplete knowledge base. Given a certain surface location and a desired subsurface target, the directional planner must assess cost, required accuracy and geological and technical factors to determine the appropriate wellbore profile—slant, S-shaped, horizontal or perhaps a more exotic shape. Drilling into another wellbore, known as a collision, is unacceptable, so anticollision software is typically used to plan a safe trajectory.

It is also important to select the appropriate RSS for the job. For sticky situations, a tool with pad assemblies or other exterior components that rotate with the collar, such as the PowerDrive system, minimizes the risk of stuck pipe and allows backreaming of the wellbore. The RSS also must be capable of achieving the desired build rate.

Real-time communication and formation evaluation capabilities are critical to success in some situations. The PowerDrive system links to the Schlumberger logging-while-drilling (LWD) systems. A short hop, which is a short-distance telemetry system that does not require hard wiring, can be placed inside the PowerDrive tool to facilitate real-time upward communication (above). The short hop connects the PowerPulse telemetry system interface with the MWD system by sending magnetic pulses and confirms that instructions have been received from the surface.

Bit selection for rotary steerable systems is greater than for steerable motor assemblies because toolface control is good even when aggressive drill bits are used. Directional control with a PDM and an aggressive bit can be difficult because an aggressive bit may generate large fluctuations in torque. Variations in torque alter the toolface to the detriment of directional control. A short, polycrystalline diamond compact (PDC) bit, for example the Hycalog DS130, maximizes the performance of the PowerDrive rotary steerable system. The versatility of the PowerDrive tool also permits the use of other bit designs, such as roller-cone bits.

Rotating the drillstring improves hole cleaning dramatically, minimizes the risk of stuck pipe, and facilitates directional control. The power at the bit is not compromised by the need to perform slide drilling operations. Directional control can be maintained beyond the point where torque and drag make sliding with a motor ineffective. The benefits of increased ROP compared with a traditional sliding assembly are realized when using the PowerDrive system.

PowerDrive Systems in High Gear
Since its first commercial run in 1996, the PowerDrive tool has demonstrated that elimination of sliding while directionally drilling dramatically increases the overall rate of penetration. The elimination of the sliding mode also makes unusual well trajectories possible, as the following case histories demonstrate.

There have been 230 PowerDrive tool runs to date, including thousands of hours of operation in more than 40 wells. The longest single run drilled a 5255-ft [1602-m] section.

In the Njord field of the Haltenbanken area off western Norway, operator Norsk Hydro first used the PowerDrive system to drill the reservoir section of the A-17-H well, finishing 22 days ahead of schedule. This success set the stage for a much more challenging multitarget well with a sinuosoidal profile to manage the dual challenges of geological uncertainty and poor reservoir connectivity. The A-13-H well was drilled with the PowerDrive system in April 1999. The unusual W-shaped trajectory was planned to penetrate the primary reservoir in multiple fault blocks (next page, top).

The well penetrated the heterogeneous Jurassic Tilje formation, which is predominantly sandstone with minor occurrences of mudstone and siltstone, in four fault blocks. The reservoir is compartmentalized by steeply dipping, hydrocarbon-sealing fault planes separated by as much as 30 to 50 m [98 to 164 ft] of throw. An additional complication is that horizontal permeability in the Tilje reservoir is significantly better than vertical permeability, so producing it from a horizontal wellbore is preferable.

14. A full discussion of bit selection is beyond the scope of this article, but will be addressed in an upcoming Oilfield Review article. For this discussion, an aggressive bit is one that has been designed to drill quickly using long cutters that produce large cuttings. Less aggressive bits have shorter teeth that produce smaller cuttings by grinding. Other issues that affect bit function include rotary speed, weight on bit, torque, flow rate and the nature of the formation being drilled.
Real-time porosity, resistivity and gamma ray measurements from the ADN Azimuthal Density Neutron and CDR Compensated Dual Resistivity systems allowed the operations team to geologically steer the well into the desired location using the RSS. Intentional departures from the planned trajectory were decided on the basis of real-time formation evaluation measurements. The InterACT Web Witness system transmitted data in real time from the Njord drilling platform to the operations offices in Kristiansund and Bergen so that the drilling and geological operations team could make timely drilling decisions.15

In the past, a fishhook-shaped well would have been drilled to intersect the reservoir in just two fault blocks. The combination of the RSS and real-time formation evaluation enabled a seek-and-find approach, rather than guesswork, in an area in which seismic uncertainty is as much as 100 m [328 ft], to optimize the trajectory and improve reservoir drainage by drilling into four fault blocks. The penetration of the additional fault blocks saved the expense and risk of drilling another well. The A-13-H well would have been impossible to drill with conventional directional drilling technology. Using the rotary steerable system cost $1 million less than the previous well in the field because it cut well construction time by half. Use of PDC bits with the PowerDrive tool more than doubled ROP.

Rotary steerable systems open up new horizons for well planning, reservoir management and even field development. Rotary steerable systems mean that fewer wells are drilled, but those that are drilled penetrate more targets. By intersecting four fault blocks rather than two, the A-13-H well achieved the geological objectives of two wells and improved reservoir drainage dramatically. Well placement can be optimized by real-time trajectory adjustments based on measurements by combining the newest real-time formation evaluation tools with the PowerDrive system. Smaller platforms with fewer slots require smaller investments while optimizing field drainage and reducing the cost per barrel.

The PowerDrive system extended the life of the Njord field as a whole because of the flexibility of the system. It has allowed access to reserves that would have been considered uneconomic with standard technology.

PowerDrive tool performance in 1999 averaged a mean time between failures of 522 hours in the United Kingdom. In 2000, UK activity has increased to three or more runs per month. Typical drilling operations include complicated designer wells with multiple build and turn sections. In 1998, the Wytch Farm M-17 well was drilled through the narrow Sherwood sandstone reservoir and between two faults using the PowerDrive tool.16 This well set the current record for a bit run, drilling 1287 m [4222 ft] in 84 hours while achieving a 110° turn at high inclination (below).

Longest bit run at Wytch Farm. The PowerDrive tool was used in two runs on the M-17 well, the second of which established the field record for longest bit run, with 1287 m of 8½-in. hole drilled in 84 hours. The plan view of the well trajectory (left) shows the 110° turn. The three-dimensional view (right) illustrates the high inclination that accompanied the turn. Use of the PowerDrive tool saved seven days of rig time.
Maximizing the cost-effectiveness of expensive directional wells with complex trajectories is a major challenge facing drilling engineers. Success depends on drilling tools that offer inherent efficiency, reliability and capabilities that supersede conventional systems. In Malaysia, the PowerDrive rotary steerable system demonstrated its prowess in two wells, the Bekok A1 ST and A7 ST, for operator Petronas Carigali. In both wells, the system performed flawlessly, with no failures and no restrictions to drilling operations, such as having to backream. Steering was excellent in both cases despite the relatively soft formations being drilled.

On Bekok A7 ST, 1389 m [4557 ft] were drilled at an average of 51 m/hr [167 ft/hr], with hole inclinations varying from 40 to 70 degrees. Builds and turns averaged 3°/30 m [3°/100 ft] [left]. By optimizing bit selection, weight-on-bit, mud flow rate and rpm, PowerDrive technology achieved a 45% higher penetration rate than the best ever recorded with downhole motors: The PowerDrive tool drilled 513 m/day [1683 ft/day], saving five days of rig time, while the best motor performance, in the Bekok A5 well, was only 360 m/day [1181 ft/day]. Valuable rig time was also saved because wiper trips decreased from a traditional average of one per 300 m [980 ft] to one per 700 m [2300 ft]. The well reached total depth in only two-thirds the time specified in the drilling plan, resulting in significant cost savings.

On Bekok A1 ST, the PowerDrive system was used to drill 1601 m [5253 ft] of the 8 1/2-in. [21.6-cm] landing section of the well, cutting three days from the scheduled drilling program (next page, top left). Rates of penetration were 300% higher than those experienced with conventional assemblies in offset wells, with correspondingly fewer wiper trips. Minimal tortuosity, no micro doglegs and a smooth wellbore face allowed rapid, trouble-free deployment of the 7-in. [17.8-cm] liner. Total savings through use of the PowerDrive system are estimated at US$200,000.

The second development well in a field in the Viosca Knoll planning area was the first application of a rotary steerable tool by a major operator in the Gulf of Mexico. The operator’s goal in selecting the PowerDrive system was to save rig time by increasing ROP with improved hydraulics and also improving hole cleaning above the levels achievable with a steerable PDM configuration. These improvements would help mitigate or eliminate expensive and time-consuming stuck-pipe problems caused by expanding shales—a frequent occurrence in the area—and allow tighter control on the equivalent circulating density of the drilling mud. Use of the rotary system would
ensure that cuttings were held in suspension at all times, overcoming settling problems associated with sliding during PDM operations.

The PowerDrive system was used to drill out from the 9 5/8-in. [24.4-cm] casing shoe at 11,660 ft [3554 m]. After a formation integrity test was performed, the fluid system was displaced with 14.9 lbm/gal [1.79 g/cm³] diesel-base drilling mud. This was the first time the tool had been used with diesel-base fluid, so the potential for problems was anticipated. The tool successfully drilled 2767 ft [843 m] at a turn and drop rate of up to 1.6° per 100 ft [30 m] (right).

The planned directional profile included drilling a 1300-ft [396-m] tangent section before dropping and turning left through two geometrically tight targets. The tangent, or hold, section allowed the team to evaluate the directional performance of the system before initiating the turn. Excellent penetration rates were achieved while steering with the PowerDrive tool. The small pressure drop across the tool allowed better use of available hydraulic horsepower compared to a steerable motor. Flow rates were some 50 gal/min [0.2 m³/min] higher than previous motor runs, promoting improved hole cleaning and faster rates of penetration. Hole-cleaning efficiency was monitored using an annular pressure sensor in the MWD string so that the hole could be cleaned as quickly as it could be drilled.

Rotary steerable drilling in the Gulf of Mexico. A development well in a field in the Viosca Knoll area was drilled using a rotary steerable system to improve ROP and hole cleaning. The proposed trajectory is shown in blue. The PowerDrive tool achieved the desired trajectory, as shown in red in the vertical section view (top) and plan view (bottom). The rotary steerable tool was removed after drilling 2767 ft and a PDM drilled the remainder of the hole at a rate that was two and one-half times slower.
Overall, the PowerDrive assembly was used to drill 420 ft [128 m] of cement and the shoe track and formation from 11,660 to 14,427 ft [3554 to 4397 m]. This was achieved in 42 drilling hours at an average penetration rate of 66 ft/hr [20 m/hr]. At 14,427 ft measured depth, it became apparent that the rotary steerable system was no longer receiving commands from the surface. The tool continued to drill according to the last command received, a low-side orientation that induced a slight turn to the right. At this stage, it was imperative to initiate a left-hand turn, and a trip was required to retrieve the tool. Because the nature of the failure was unknown initially, and because the wellbore temperature was approaching the temperature limits of the rotary steerable assembly, a conventional steerable motor was selected to finish drilling the interval.

Subsequent analysis confirmed that an elastomer bearing had failed, allowing the turbine power assembly to rotate eccentrically in the tool collar. Wear inside the collar indicated that the turbine fins were striking the inner collar wall, preventing the tool from receiving new commands. It was later determined that the mud had degraded the bearing material. For future applications, an upgraded, more durable elastomer has been developed, proven effective and is now in use.

The results with a steerable motor on the following run provided an interesting comparison of the efficiency of the two systems because the same type of bit was run, the same formation was drilled and similarly demanding directional work was performed. Penetration rates achieved while rotating with the conventional steerable motor approached those of the PowerDrive system. However, the extra time necessary to orient the toolface, along with lower penetration rates while sliding, greatly increased overall drilling times. The steerable motor drilled 1303 ft [397 m] in 48 hours at an average ROP of 27 ft/hr [8.2 m/hr], almost two and one-half times slower than the PowerDrive system.

This example clearly demonstrates that increased ROP offsets higher rig rates and more than compensates for the additional expense of the rotary steerable tool, resulting in overall time and cost savings (left). This well was drilled 10 days ahead of plan. Nevertheless, further improvement in rotary steerable drilling performance remains a key objective for Schlumberger.

Driving into the Future

The ability of the PowerDrive rotary steerable system to drill long sections quickly and reliably has led to high demand for the 39 tools now available. The manufacturing of 16 additional PowerDrive tools during the first quarter of 2000 increased worldwide access to these systems. The tools are manufactured in the UK, but maintenance and repairs are performed in several regional centers, close to where the tools are used.

The PowerDrive675 system, the 6&frac34; in. tool described in this article, is now proven technology (right). Schlumberger is working to set new industry standards for rotary steerable systems. The PowerDrive900, a 9-in. push-the-bit tool designed to drill 12&frac14; in. and larger holes, is undergoing field trials at present, with commercialization expected in the second half of 2000.

A point-the-bit tool design, whose drilling trajectory is determined by the bit direction rather than the orientation of a longer section of the BHA, will fulfill demands for greater bit and stabilizer selection, including bicenter bits, and higher build rates. Schlumberger has tested a prototype point-the-bit tool in various locations worldwide and drilled upwards of 100 ft/hr [30 m/hr]. This prototype tool extends the flow and temperature ranges of the push-the-bit systems while maintaining a relatively compact size. Survey data are gathered close to the bit and sent to the surface for real-time trajectory feedback and control. For each of these systems, the goal is cost-effective drilling in mainstream operations, rather than the current economic restriction to only the most extreme applications. Operators certainly will continue to push the limits of reach and depth (left).

Further refinements in remote communication links to operator offices will allow experts to receive data, consult with rig personnel and send back commands to the mud pumps, a critical capability when drilling complex wells. Eventually, the shape of wellbores will be limited only by economics and ingenuity. —GMG

Benefits of the PowerDrive system. Continuous rotation of the drillstring improves many aspects of well construction and ultimately translates into saving time and money.

Extending the envelope. Reach of 10 km [6.2 miles] or more is possible at relatively shallow depths. Displacement becomes restricted with increasing depth, as shown by the purple envelope.