# Measurements at the Bit: A New Generation of MWD Tools

**Measurements-while-drilling technology has moved down the drillstring to enlist the bit itself as a sensor. Drillers**
**time information about petrophysics and drilling mechanics without a lag between bit and sensors. This technical**
**ciency of directional drilling, enhance real-time formation evaluation, and ultimately create a more productive well.**

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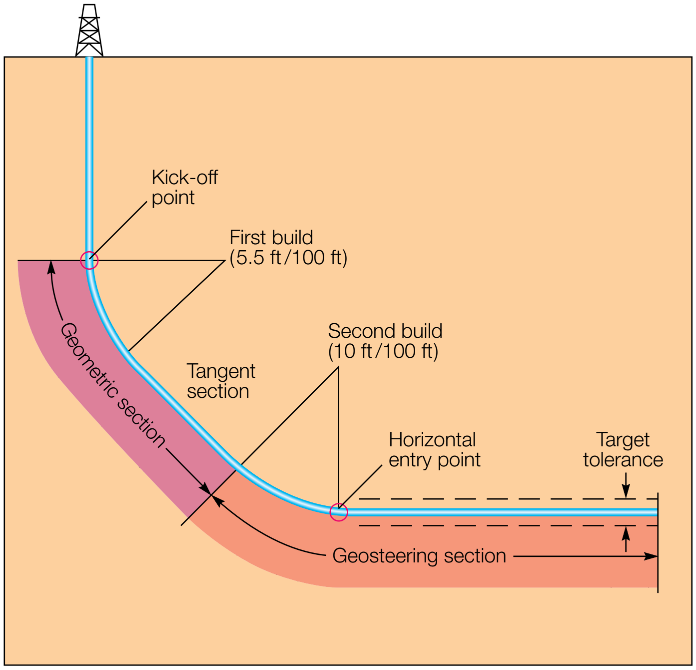

□***A typical horizontal well plan. Geometric drilling refers to drilling along a fixed, predetermined trajectory, generally based on offset data and a stratigraphic model. Decisions about steering are based only on real-time information about bit direction and inclination. Geosteering refers to navigating the borehole using geologic information in real time. Geosteering is possible with logging-while-drilling sensors, which are integrated into drill collars 40 to 100 ft [12 to 30 m] above the bit and steerable motor. Geosteering becomes more efficient with measurements at the bit.***

Conventional drilling of high-angle and horizontal wells is like piloting an airplane from the tail rather than the cockpit. Information required to land the well in the target formation is derived from sensors 50 ft [15 m] or more behind the bit or at the surface. Because these measurements—about well trajectory, drilling efficiency and formation properties—are remote from the bit, crucial drilling decisions are delayed and data may require more complex interpretation. In particular, course corrections are delayed by lag in measurements needed to make steering decisions, resulting in less drainhole in the pay zone. Also, maximum drilling efficiency requires information about mechani-

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In this article, IDEAL (Integrated Drilling Evaluation and Logging), GeoSteering tool, PowerPak, RAB (Resistivity-at-the-Bit), RWOB (Receiver, Weight on Bit and Torque tool), PowerPulse, CDR (Compensated Dual Resistivity tool), SFL (Spherically Focused Resistivity Log), AIT (Array Induction Imager Tool), CDN (Compensated Density Neutron tool) and FMI (Fullbore Formation MicroImager) are marks of Schlumberger.

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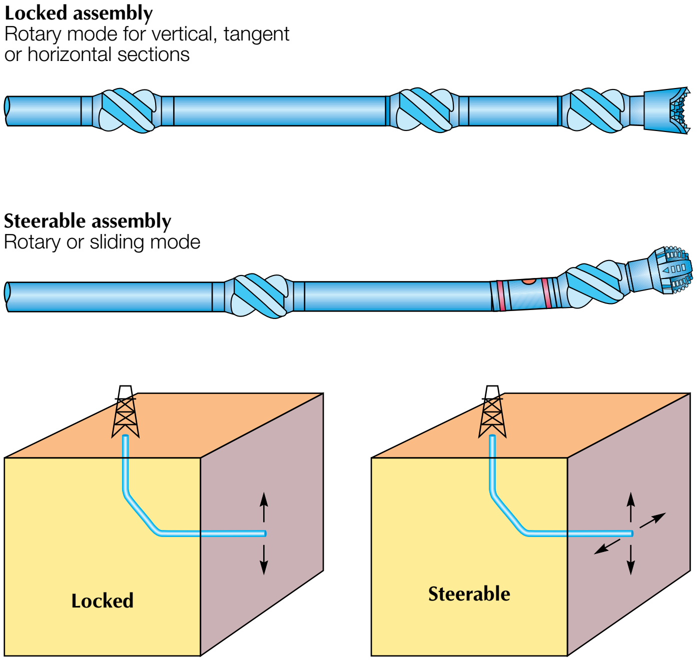
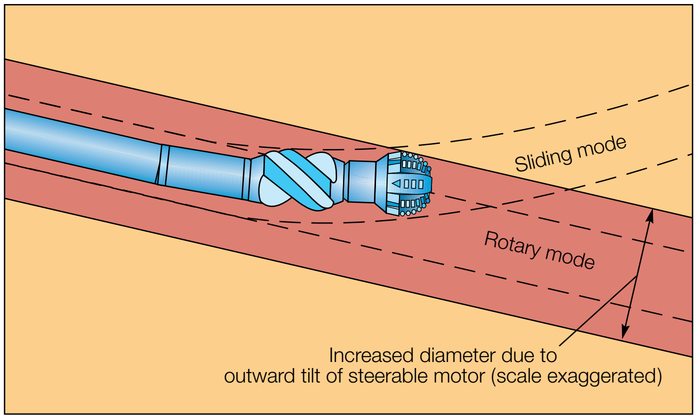
1. Betts P, Blount C, Broman B, Clark B, Hibbard L, Louis A, Oosthoek P: "Acquiring and Interpreting Logs in Horizontal Wells," *Oilfield Review* 2, no. 3 (July 1990): 34-51.

   *Logging While Drilling.* Schlumberger Education Services: Houston, Texas, USA, 1992.
2. For a review on horizontal drilling methods:

   Burgess T and Van de Slijke P: "Horizontal Drilling Comes of Age," *Oilfield Review* 2, no. 3 (July 1990): 22-33.



□***Typical bottomhole assemblies for horizontal drilling. A rigid, or locked, assembly is used for drilling a vertical, tangent or straight horizontal section. Rigidity increases with the number of stabilizers. This type of assembly permits only gradual changes in the vertical angle of the well trajectory. A steerable assembly with a downhole motor inside a bent housing can vary well trajectory vertically and to the left and right, and can change angle more quickly than a locked assembly.***



□***How well trajectory is changed. In rotary mode, both the bit and drillstring rotate and the bit cuts a straight path parallel to the axis of the drillstring above the bent sub. In sliding mode, only the bit rotates and the hole follows the axis of the bent housing below the bend.***

**and geologists now have real-**

**progress promises to improve effi-**

cal power delivered to the bit, which is inferred from surface measurements, degrading its accuracy. And resistivity measurements from logging-while-drilling (LWD) sensors in drill collars are limited to formation resistivity less than 200 ohm-m.[1]

Despite these limitations, horizontal and high-angle drilling have proved successful, especially in simple geologic settings—uncomplicated layer-cake structure. Nearly all these wells start vertically, with a conventional rotary bottomhole assembly (BHA) (*previous page*).[2] The drillstring and bit are rotated from the surface either by a rotary table on the derrick floor or a motor in the traveling block, called a topdrive. Drilling this way is called rotary mode. To kick off from vertical, the rotary assembly is replaced with a steerable motor—usually a positive displacement motor, driven by mud flow, in a housing bent 1° to 3° (*above, right*). When mud is flowing, the motor rotates the bit, but not the drillstring. This type of drilling is called sliding mode, because the drillstring slides along after the bit, which advances in the direction of the housing below the bend (*right*). The larger the angle of the bent housing, the sharper the curvature of the trajectory. The direction in which the bit is pointing, called toolface, is measured and sent to surface by measurement-while-drilling (MWD) equipment for real-time control of bit orientation. Measurements include azimuth, which is the compass bearing of the bit, and inclination, which is the angle of the bit with respect to vertical. Large changes in direction are made by lifting off bottom and reorienting the bent sub by rotating from surface. Small changes are made by varying weight on bit, which changes the reactive torque of the motor and hence toolface orientation.

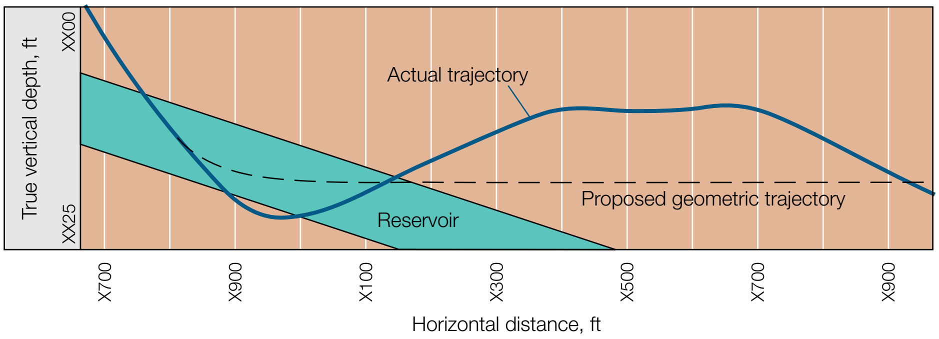
Once sufficient inclination has been built, straight or tangent sections can be drilled in several ways. One is with a conventional rotary, or "locked," assembly, which is rigid enough to allow fast, straight drilling. Small adjustments in inclination can be made by varying weight on bit or rotary speed. Large adjustments in inclination can be made with conventional rotary assemblies only by pulling out of the hole and varying the size and placement of stabilizers. Most horizontal sections, and some tangent sections, are drilled with a steerable motor while rotating the drillstring from surface. In this mode, the steerable motor behaves like a rotary BHA, maintaining both azimuth and inclination.

However, the presence of the steerable motor allows the driller to make course corrections without tripping the drillstring out of the hole. Generally, the driller tries to make as much hole as possible using a rotary assembly or a steerable motor in rotary mode. Rotation of the drillstring reduces the risk of getting stuck and allows faster drilling than in sliding mode.

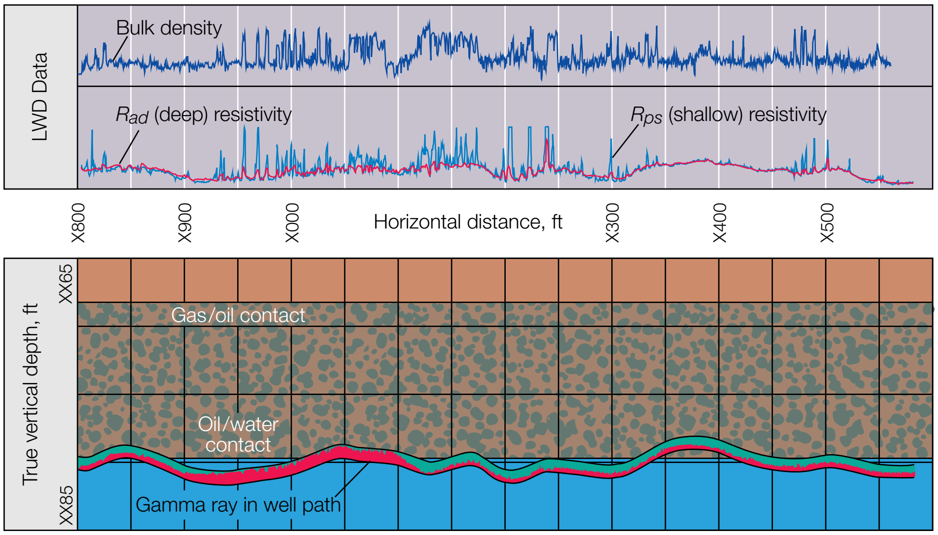
## Overcoming Limitations in Horizontal Drilling

Today, the *ability* to drill horizontally is undisputed, and records for the longest horizontal section are broken nearly as soon as they are set.[3] Yet, the *efficiency* of drilling and steering horizontally is limited by the distance between the bit and measurements. In drilling, for example, one way to define efficiency is the ratio of time spent making hole to the total rig time, including operations such as trips or hole conditioning. In the horizontal section, steering efficiency can be defined as the ratio of the length of the horizontal section in the pay zone to the total length of the horizontal section. How does lag between measurements and the bit limit these efficiencies?

In drilling with a downhole motor in rotary mode, a key limitation on efficiency is how much weight the driller can safely apply to the steerable motor. As the driller increases weight, the motor produces more torque, and power is torque times RPM. The more power, the faster the rate of penetration—up to a point. Excess weight may stall and eventually damage the motor, requiring an expensive trip for motor replacement. The goal is to apply as much power as possible, but within the operational limit of the motor. Power is estimated conventionally from surface measurements of mud flow and mud pressure. Motor RPM is roughly proportional to mud flow. Torque is roughly proportional to the increase in mud pressure when the bit is on bottom, compared to off bottom. Because of uncertainty in this estimation, a generous safety margin is maintained. This margin prevents the driller from applying optimal weight for a given formation, which reduces penetration rate.



**□*The risk of steering geometrically with inadequate information about reservoir dip—less drainhole in the pay zone. This North Sea well was successfully drilled beyond horizontal, but the reservoir dipped more than expected. Only about 15% of the drainhole was in the pay zone.***



Courtesy of Norsk Hydro

**□*Steering along the top of the oil/water contact in the North Sea using logging-while-drilling measurements.***

Perhaps the greatest limitation in conventional horizontal drilling is in steering efficiency. Wells are conventionally steered "geometrically"—along a path that has been predetermined based on nearby well data and geologic assumptions. Steering is based only on bit direction and inclination data. Gamma ray and resistivity measurements, if present, are made far from the bit and used only retrospectively. This technique is fine, as long as the target is thick, structurally simple and well known. But it is less effective when the target is thin, complex or insufficiently known for planning the well trajectory (*top*). And increasingly, with advances in three-dimensional seismics, operators are locating more intricate reservoirs and drilling more complex wells. Challenges today include thin beds and complexly folded or faulted reservoirs.

In these settings, sensors in drill collars allow replacement of basic geometric steering with more efficient geologic steering, or "geosteering"—navigation of the bit using real-time information about rock and fluid properties. A North Sea example shows how LWD sensors performed the dual purpose of geosteering and formation evaluation. Using mostly resistivity measurements, the driller geosteered a drainhole along the top of the

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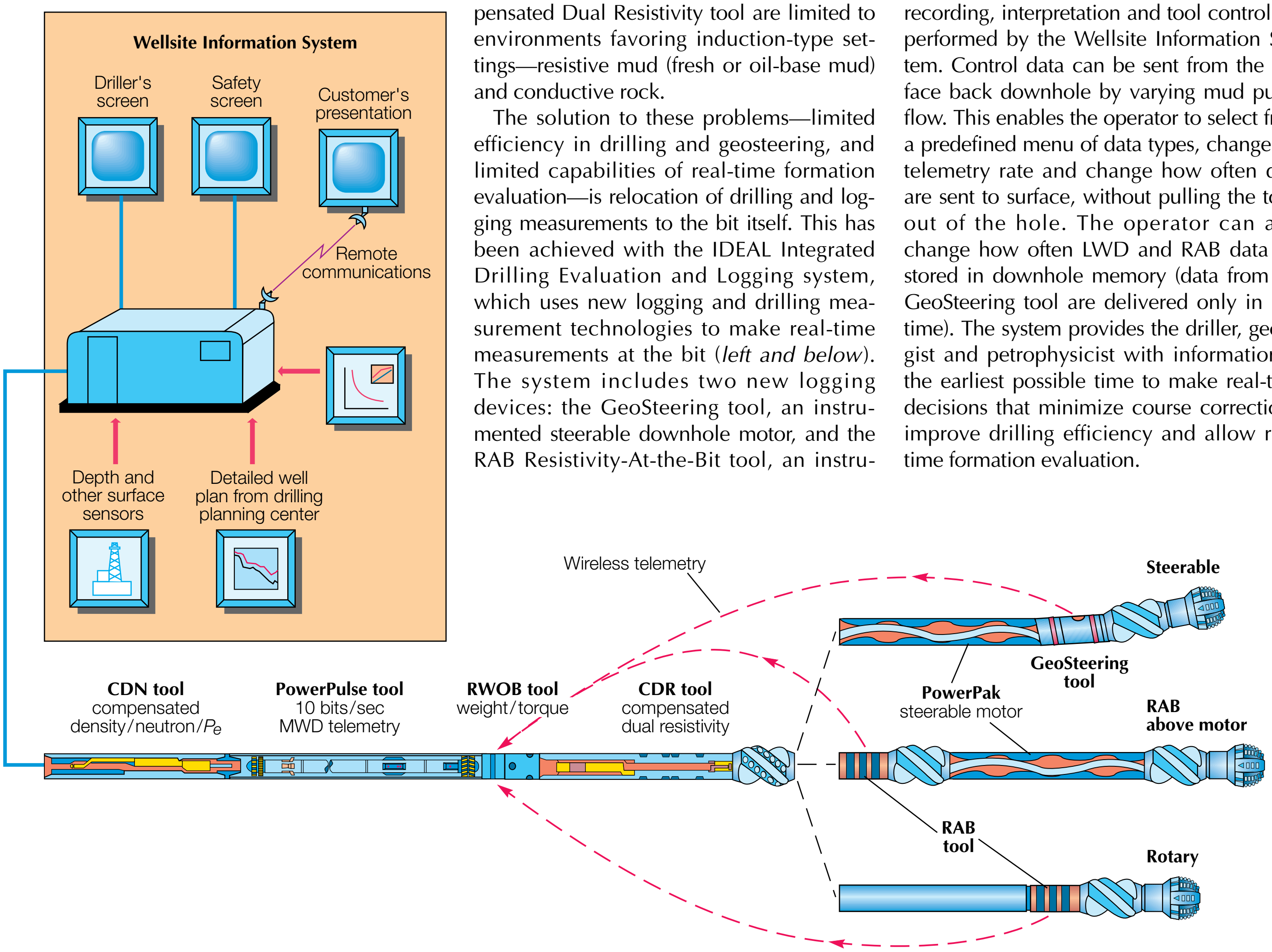
[3] In the Norwegian North Sea, Statoil recently drilled an extended reach well with a horizontal section of 24,000 ft [7000 m]. "Statoil Claims World Record in Extended Reach," *Oil & Gas Journal* 91, no. 7 (February 15, 1993): 31.

oil/water contact to avoid gas production (*previous page, middle*). Resistivity modeling from offset wells showed this contact should have a resistivity of about 0.6 ohm-m. When the value dropped, indicating water, the well path was turned up slightly; when resistivity increased, the well path was dropped slightly. Although these measurements enabled the driller to keep close to the pay zone, the well strayed into the water for 100 ft [30 m], between X900 and X000 ft. This was due to lag between the bit and resistivity sensors. By the time the resistivity sensors detected the fluid change, the bit had advanced 50 ft. It took another 50 ft to steer it back into the pay. Overall, 550 ft of this 750-ft section of the drainhole [167 m of 228 m] was in the pay zone—a respectable 73% steering efficiency, and a marked improvement over geometric steering.

In addition to reduced efficiency in drilling and geosteering, a third limitation of conventional horizontal drilling is in formation evaluation while drilling. Logging-while-drilling sensors reach the formation long before wireline measurements, and so generally view it before wellbore degradation, but some invasion has still occurred. Rapid invasion, called spurt, may mask true resistivity in some formations. Also, LWD resistivity measurements by the CDR Compensated Dual Resistivity tool are limited to environments favoring induction-type settings—resistive mud (fresh or oil-base mud) and conductive rock.

The solution to these problems—limited efficiency in drilling and geosteering, and limited capabilities of real-time formation evaluation—is relocation of drilling and logging measurements to the bit itself. This has been achieved with the IDEAL Integrated Drilling Evaluation and Logging system, which uses new logging and drilling measurement technologies to make real-time measurements at the bit (*left and below*). The system includes two new logging devices: the GeoSteering tool, an instrumented steerable downhole motor, and the RAB Resistivity-At-the-Bit tool, an instrumented stabilizer (*next page*). Measurements include gamma ray, several types of resistivity including a measurement at the bit, and drilling data such as inclination, bit shocks and motor RPM.

The technical leap that allows measurements to be made at the bit and below the steerable motor is a wireless telemetry system. This telemetry link sends data from sensors near the bit to the MWD tool up to 200 ft [61 m] behind the bit, a path that bypasses the intervening drilling tools, such as the steerable motor. The PowerPulse MWD system recodes and then sends data to surface in real time using mud-pulse telemetry at up to 10 bits per second. At surface, data recording, interpretation and tool control are performed by the Wellsite Information System. Control data can be sent from the surface back downhole by varying mud pump flow. This enables the operator to select from a predefined menu of data types, change the telemetry rate and change how often data are sent to surface, without pulling the tools out of the hole. The operator can also change how often LWD and RAB data are stored in downhole memory (data from the GeoSteering tool are delivered only in real time). The system provides the driller, geologist and petrophysicist with information at the earliest possible time to make real-time decisions that minimize course corrections, improve drilling efficiency and allow real-time formation evaluation.



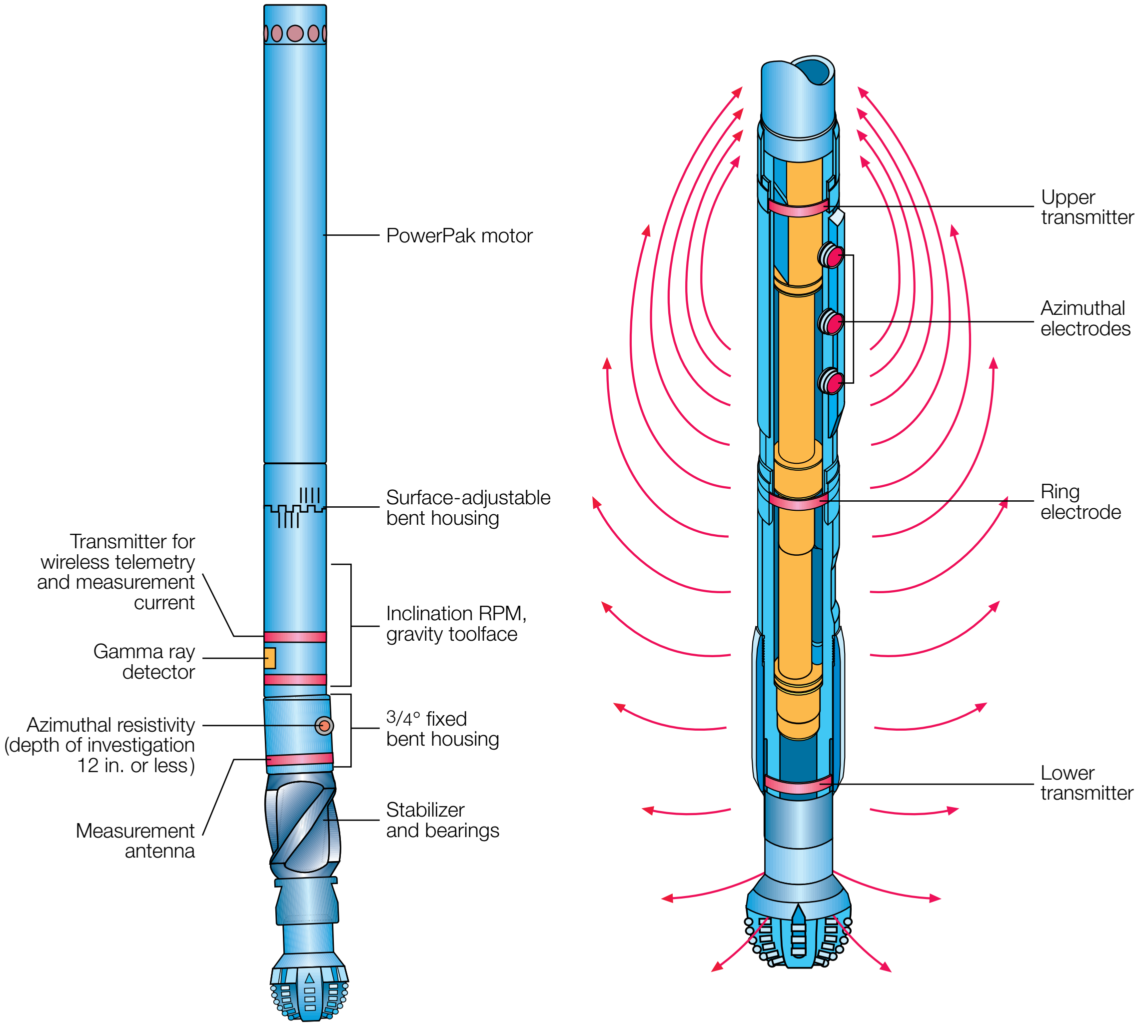
☐***Surface and downhole components of the IDEAL Integrated Drilling Evaluation and Logging system. New downhole tools are the GeoSteering tool, which is an instrumented steerable motor, the RAB Resistivity-At-the-Bit tool, which is an instrumented stabilizer, the PowerPulse MWD telemetry tool and the RWOB Receiver, Weight on Bit and Torque tool for downhole weight and torque on bit and for wireless telemetry of GeoSteering tool and RAB data. The RAB tool can be run next to the bit in a rotary assembly, or above the motor in a steerable assembly. Compatible downhole components include LWD tools, the CDN Compensated Density Neutron and CDR Compensated Dual Resistivity tools. The most significant advancement in the surface system, called the Wellsite Information System, is its interactive nature. Users can customize acquisition schemes and screen parameters, change scales, convert representations from depth to time and make annotations. Tasks such as data processing and integration are automated to free the user to make interpretations and advise on drilling decisions.***

## Logging at the Bit for Geosteering and Petrophysics

The two new logging devices, the RAB tool and the GeoSteering tool, share many features in common but differ in important respects. The RAB tool provides real-time log measurements for high-quality formation evaluation. It is run, like the CDR tool, in a steerable assembly behind the motor or in a rotary drilling assembly immediately behind the bit. The GeoSteering tool enables the driller and geologist to make real-time correlation at the bit, detect hydrocarbons at the bit and steer the borehole for increased reservoir exposure (*next page, below left*). Both tools measure gamma ray, resistivity using the bit as the electrode, and "azimuthal" resistivity—focused at a narrow angle along the borehole wall.[4] The gamma ray sensor on the GeoSteering tool is shielded on one side to provide an azimuthal reading.

Resistivity at the bit is measured by attaching the GeoSteering or RAB tool directly to the bit and driving an alternating electric current down the collar, out through the bit and into the formation. The current returns to the drillpipe and drill collars above the transmitter. In water-base mud, returning current is conducted from the bit through the mud, into the formation and back to the BHA. In oil-base mud, which is an insulator, current returns through the inevitable but intermittent contact of the collars and stabilizers with the borehole wall, leading to a qualitative indication of resistivity. Formation resistivity is obtained by measuring the amount of current flowing into the formation from the bit, and normalizing it to the transmitter voltage. Axial resolution is determined by the length of the BHA below the lowermost coil, including the bit.[5] In the GeoSteering tool, resolution of resistivity at the bit is about 6 ft [1.8 m]; in the RAB tool, resolution of resistivity at the bit can be as fine as 2 ft [0.6 m].

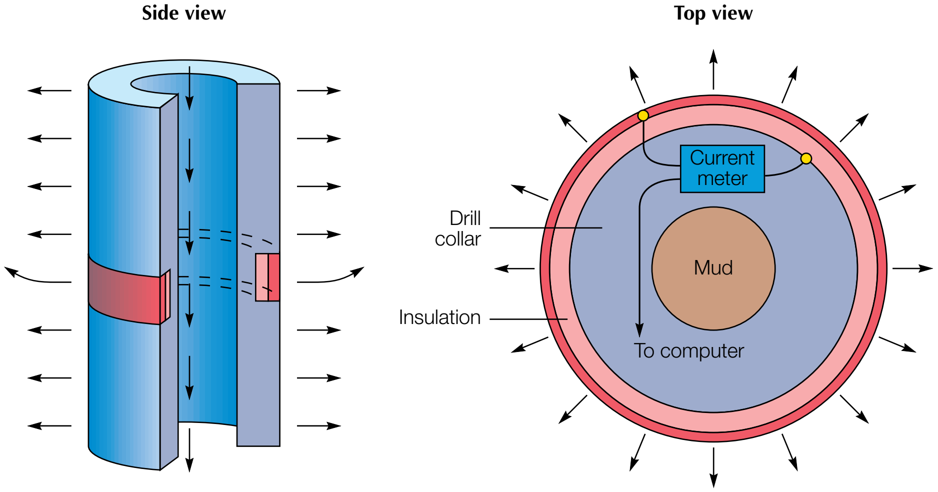
Azimuthal resistivity is measured from one or more button electrodes and, like the azimuthal gamma ray measurement, can be used to steer the bit. Both tools can be oriented in multiple directions to find the location of a lithologic or pore fluid boundary relative to the borehole—up, down, left or right—and thereby steer the bit. In rotary mode, the borehole circumference can be scanned, providing an average resistivity and the ratio of the highest button reading to the lowest button reading for a given a time frame. If the ratio is close to 1, the formation is homogeneous. If it deviates from 1 and jumps, a bed or pore fluid boundary was crossed and stationary (azimuthal) logging can indicate the direction to the boundary. If it deviates from 1 and changes slowly, anisotropy may be present. The GeoSteering tool has a single resistivity but-



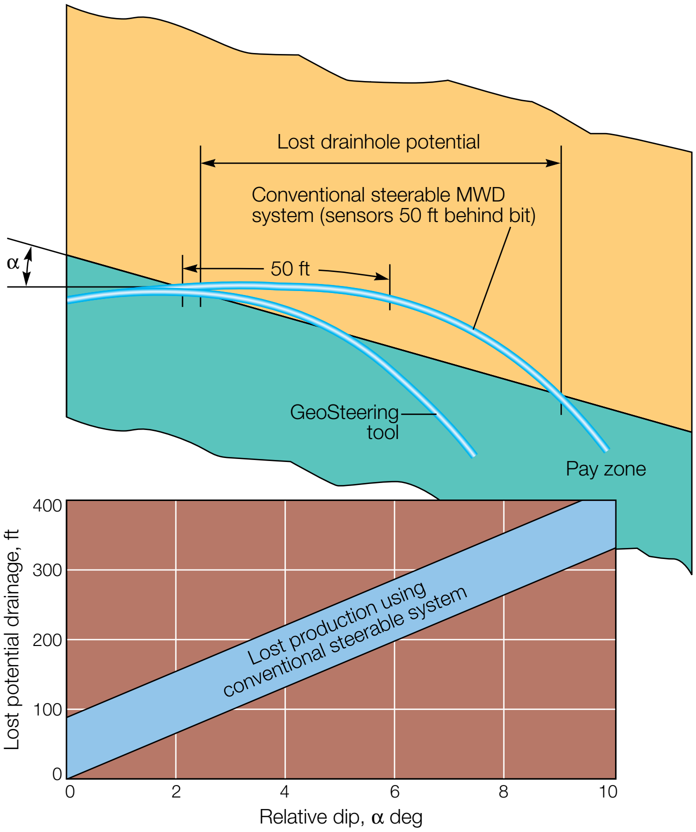
□***The GeoSteering and RAB tools. The GeoSteering tool is an instrumented steerable motor, meaning it can be used in rotary or sliding mode. The RAB tool is an instrumented stabilizer on a rotary assembly.***

ton within 5 ft [1.5 m] of the bit that provides an axial resolution of a few inches; the new RAB tool design has three buttons providing three depths of investigation, 3, 6 and 9 in., [7.6, 15 and 23 cm] for detection and evaluation of invasion.[6]

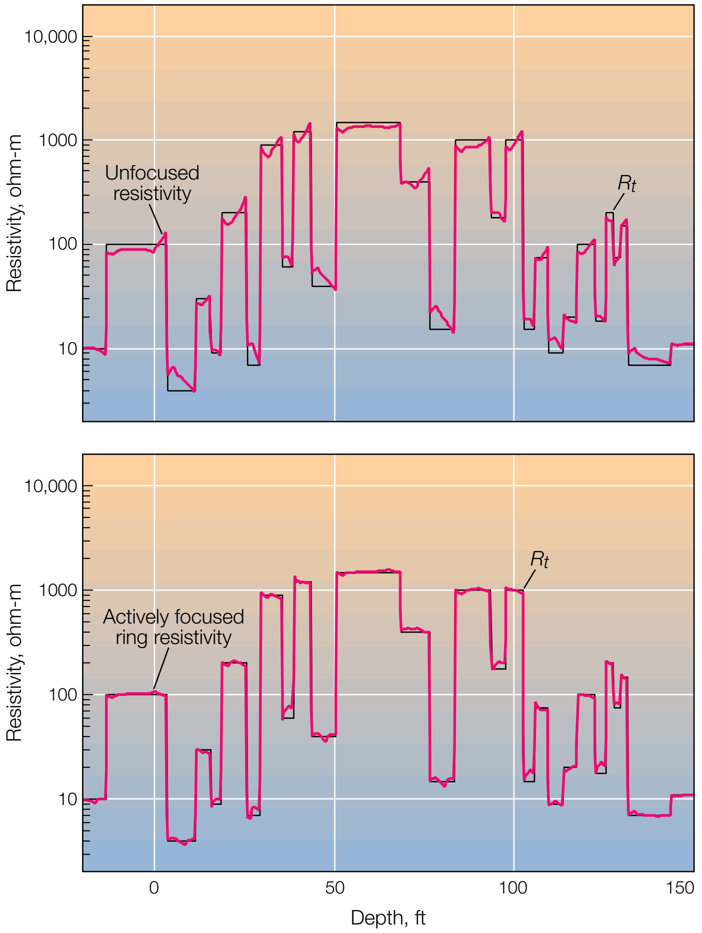
In the RAB tool, a fourth depth of investigation, 12 in. [30 cm], is provided by a ring resistivity measurement 5 ft behind the bit (*right*). This measurement is focused to a high axial resolution by addition of a second transmitter near the bit (*below, right*). Ring resistivity is like azimuthal resistivity in



☐***Principle of ring resistivity measurement. The measurement current is forced into the formation by current flowing out the bottomhole assembly above and below the ring.***



☐***Comparison of geosteering efficiency for a conventional MWD/steerable bottomhole assembly vs. one in which formation evaluation measurements are made at the bit. This assumes the systems can steer at 6° per 100 ft [30 m]. If the relative dip between the formation floor/roof and the drainhole is as small as 3°, a conventional MWD system takes twice as long to reenter the target formation as a system with measurements at the bit.***



☐***How focusing improves axial resolution of RAB ring resistivity response in a modeled formation.***

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4. The term "azimuthal" here descends from vertical well terminology, in which the azimuth refers to a compass bearing with respect to the side of the borehole wall.
5. "Vertical" resolution does not apply in a horizontal well and is instead called "axial," describing resolution with respect to the borehole axis.
6. Depth of investigation here means radial distance from the borehole wall into the formation.

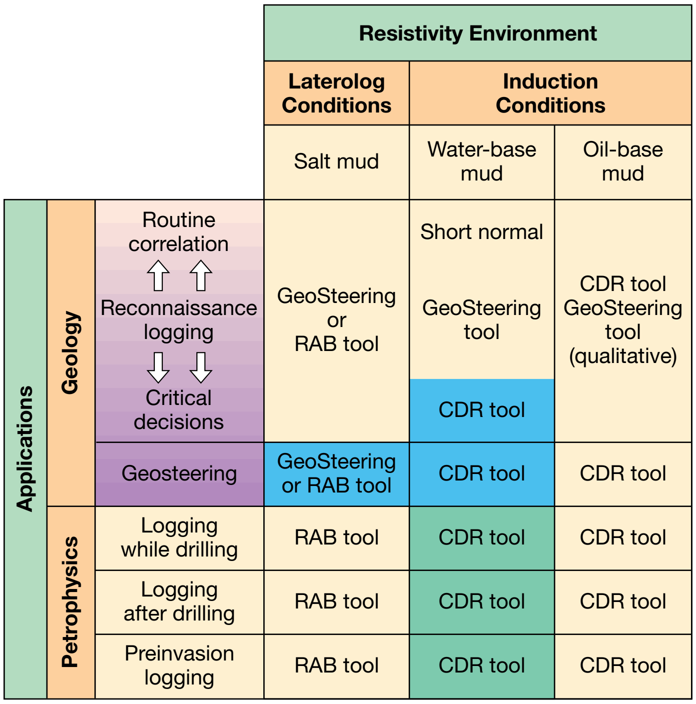
rotary mode, but the larger surface area of the ring compared to the button allows greater precision. The ring measurement can detect beds thinner than 2 in. [5 cm]. Neither azimuthal nor ring resistivity measurements function in oil-base mud because the mud acts as an insulator.

Although they are not laterolog measurements, azimuthal and ring resistivities work best in laterolog-type settings—conductive (salty) mud and/or resistive formations. They complement the resistivity measurement of the CDR tool, which is optimized for induction-type environments. Capabilities of the GeoSteering and RAB tools show how their applications differ (*right*).

## Surface Control for Measurements at the Bit

Because the GeoSteering tool is an instrumented steerable motor, it enables the driller to steer the bit on a geometric or geologic path through the pay zone. The driller's window into the bit is the Wellsite Information System, which includes a display for checking and revising the structural and stratigraphic model, and updating the drilling trajectory (*next page, top*). This screen is intended mainly for real-time management of horizontal drilling. In this example, steering was guided by the logging-while-drilling CDR measurement 70 ft [21 m] behind the bit, but the screen functions the same way with GeoSteering tool data. Input for this display is the simulated true resistivity ($R_t$) profile (A) built by the company geologist and log analyst using offset log data to model the earth vertically below the well. While the well is drilled, this $R_t$ profile and the actual well trajectory are input to a program that models CDR log response at various relative dips (B).[7] Comparison of the curves in (B) and the logs measured in real time (C) indicates how close the model is to reality—both modeled and measured logs advance across the screen during drilling. Misalignment of modeled and measured responses means the dip must be changed, or structure

| Functionality | RAB Tool | GeoSteering Tool |
|---|---|---|
| Resistivity at the bit | | |
| • Rotary BHA (replacing the near-bit stabilizer) | ✓ | |
| • Motor BHA (run below the motor) | | ✓ |
| Resistivity operates in oil-base mud | Qualitative | |
| Quantitative laterolog-type $R_t$ | ✓ | |
| Gamma ray | ✓ | ✓ |
| Azimuthal gamma ray | | ✓ |
| Real-time data | ✓ | ✓ |
| Wireless telemetry | ✓ | ✓ |
| Single-axis inclination | ✓ | |
| Triaxial inclination | | ✓ |
| Downhole memory | ✓ | |
| Combinable with CDR/CDN tools | ✓ | ✓ |
| Three-button array | ✓ | |
| Qualitative single-button resistivity | | ✓ |



<table>
<tr><td colspan="3"></td><td colspan="3">Resistivity Environment</td></tr>
<tr><td colspan="3"></td><td>Laterolog Conditions</td><td colspan="2">Induction Conditions</td></tr>
<tr><td colspan="3"></td><td>Salt mud</td><td>Water-base mud</td><td>Oil-base mud</td></tr>
<tr><td rowspan="6">Applications</td><td rowspan="3">Geology</td><td rowspan="2">Routine correlation<br>⇧ ⇧<br>Reconnaissance logging<br>⇩ ⇩<br>Critical decisions</td><td rowspan="2">GeoSteering or RAB tool</td><td>Short normal<br>GeoSteering tool</td><td rowspan="2">CDR tool<br>GeoSteering tool (qualitative)</td></tr>
<tr><td>🟦 CDR tool</td></tr>
<tr><td>Geosteering</td><td>🟦 GeoSteering or RAB tool</td><td>🟦 CDR tool</td><td>CDR tool</td></tr>
<tr><td rowspan="3">Petrophysics</td><td>Logging while drilling</td><td>RAB tool</td><td>🟩 CDR tool</td><td>CDR tool</td></tr>
<tr><td>Logging after drilling</td><td>RAB tool</td><td>🟩 CDR tool</td><td>CDR tool</td></tr>
<tr><td>Preinvasion logging</td><td>RAB tool</td><td>🟩 CDR tool</td><td>CDR tool</td></tr>
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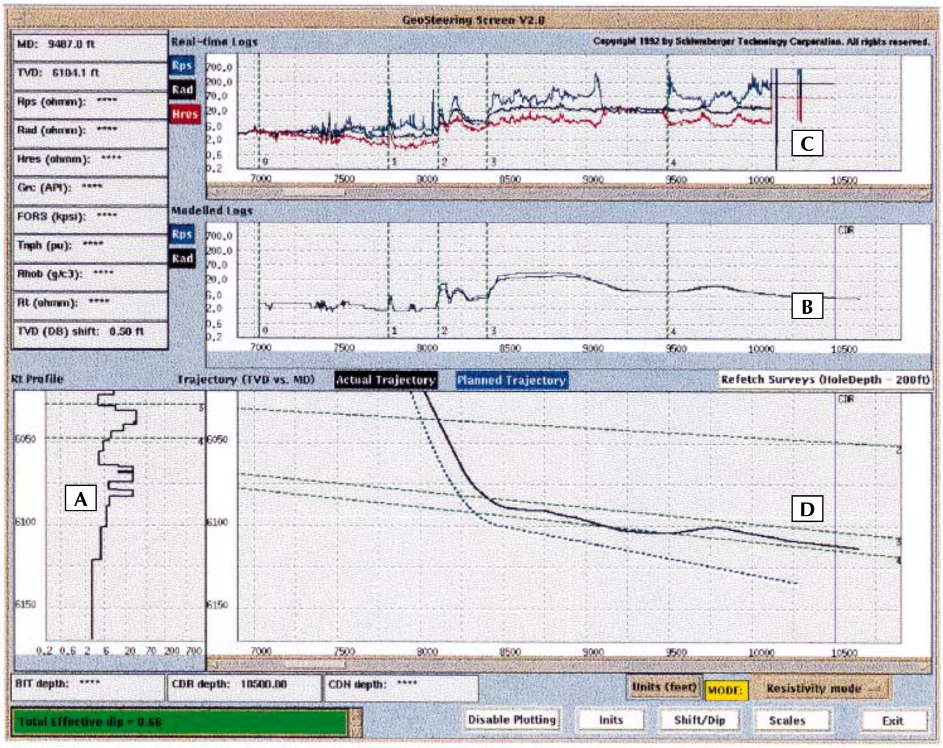
🟦 GeoSteering and CDR tools may be run together.

🟩 RAB and CDR tools may be run together.

□***Comparison of RAB and GeoSteering tool specifications*** (top) ***and applications*** (bottom)***. Although both tools have many features in common, they differ in certain respects. The RAB tool can be run at the bit in rotary mode for formation evaluation. The GeoSteering tool, an instrumented steerable motor, provides measurements for correlation, hydrocarbon identification and drilling mechanics data. Determining the optimal choice of tools*** (bottom) ***—CDR, RAB, GeoSteering tool or some combination—requires evaluating the information needed and the borehole environment. Here, only three resistivity environments are shown. However, many wells encounter more than one environment.***

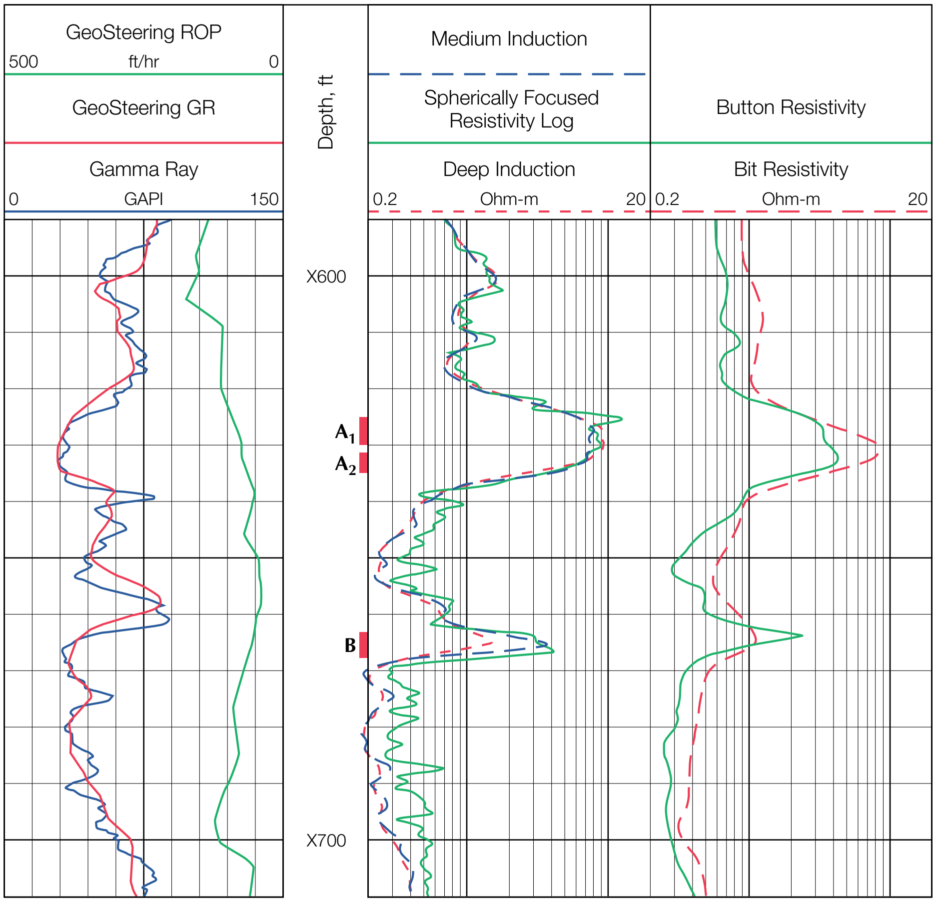
moved up or down. Changes in the geologic model result in automatic changes to the modeled logs. In this way, the model can be iteratively modified until it matches the real-time data, indicating the correct model for depth and dip of the structure. In the measured logs, *Hres* means horizontal resistivity, a computed value that includes inclination data to compensate for the effects of dipping, anisotropic beds.[8] In place of resistivity mode, modeling may also be done based on gamma ray with formation strength, neutron-density response or RAB measurements.

Resolution of both GeoSteering tool and RAB resistivity measurements is sufficient for hydrocarbon detection and lithologic correlation (*below*). The multiple depths of investigation and high resolution of the focused RAB measurements also provide formation



MD: 9487.0 ft
TVD: 6104.1 ft
Rps (ohmm): ****
Rad (ohmm): ****
Hres (ohmm): ****
Grc (API): ****
FORS (kpsi): ****
Tnph (pu): ****
Rhob (g/c3): ****
Rt (ohmm): ****
TVD (DB) shift: 0.50 ft
BIT depth: ****
CDR depth: 10500.00
CDN depth: ****
Total Effective dip = 0.66
MODE: Resistivity mode

□*Geosteering through a North Sea pay zone using the GeoSteering screen to guide the drill bit.*



□*Comparison of wireline induction and GeoSteering tool bit and button resistivities for a Gulf of Mexico well. Separation of the bit and button curves is due to the different physical nature of the measurements and different locations of the sensors. Bit resistivity is from current injected directly from the bit whereas button resistivity is an azimuthal laterolog-style measurement made about 5 ft [1.5 m] above the bit.*

*In zones A1 and A2, bit resistivity is able to fully resolve $R_t$ in the thick bed, except for the thinnest streak, resolved only by the SFL Spherically Focused Resistivity Log. Invasion doesn't appear to affect the measurement. Button resistivity, however, flattens out at X624 to X629 ft because drilling was stopped at the bottom of A1, increasing the time between drilling and logging from 5 minutes to 18 minutes. The flat response is from invasion masking $R_t$. At zone B, fast drilling through quick resistivity changes spreads out sample points of the GeoSteering measurement. It missed the peak at X664 ft because sample points fell on either side of the highest value.*

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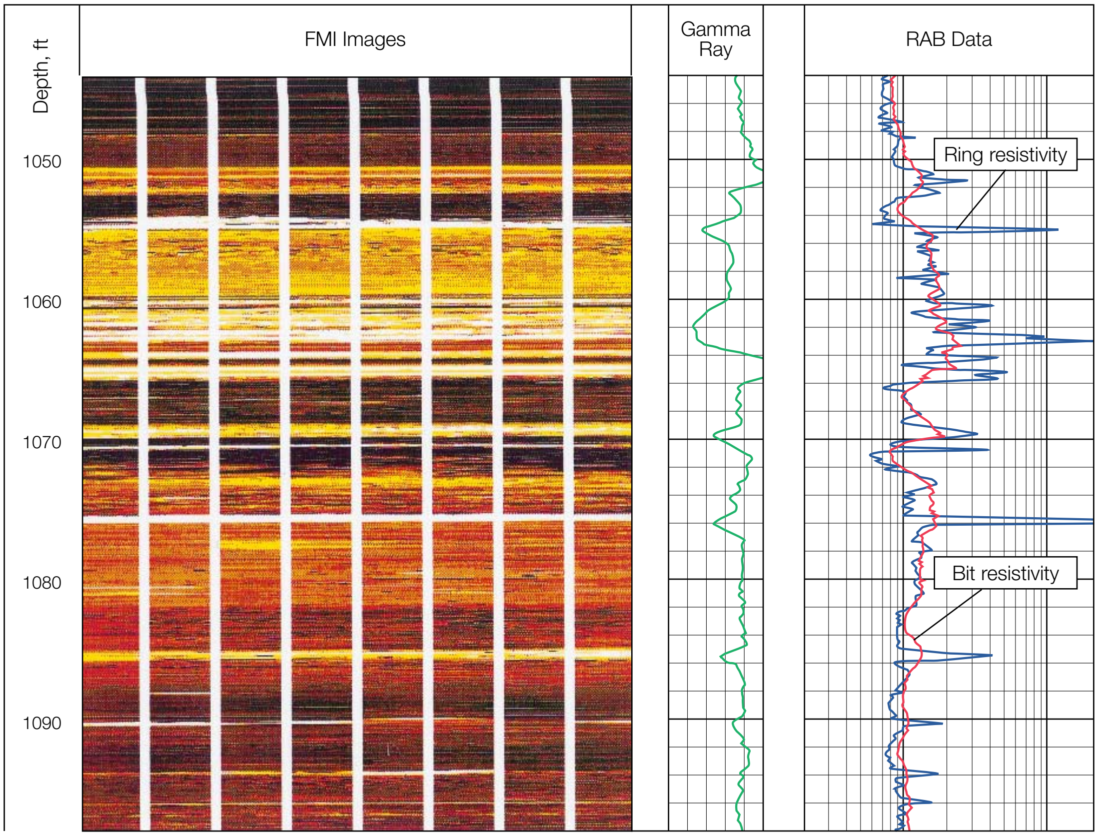
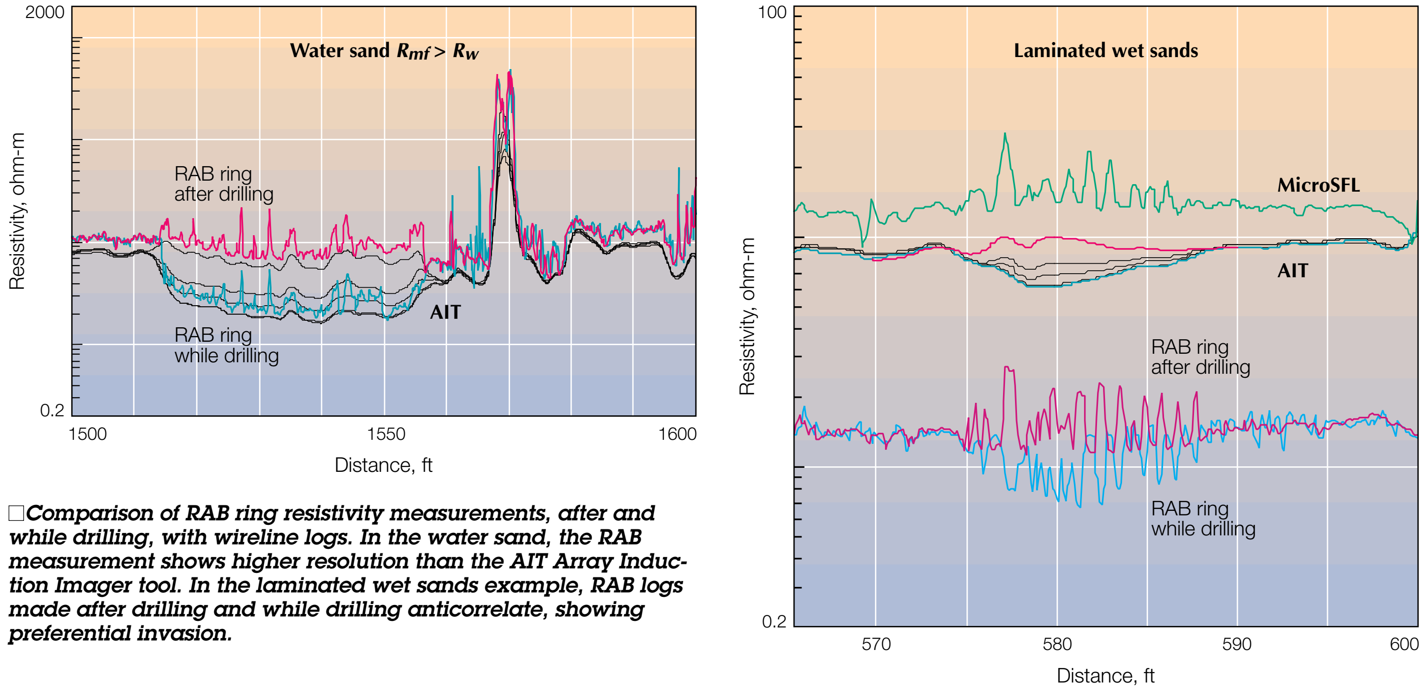
7. Bonner S, Clark B, Holenka J, Voisin B, Dusang J, Hansen R, White J and Walsgrove T: "Logging While Drilling: A Three-Year Perspective," *Oilfield Review* 4, no. 3 (July 1992): 13-15.
8. For effects of anisotropy:

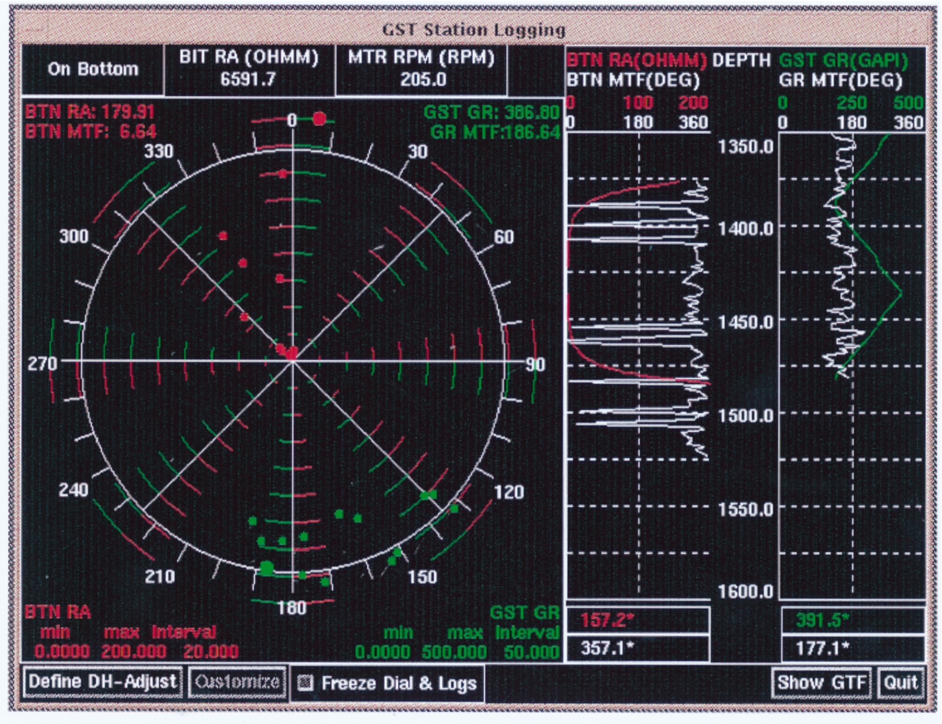
   Tittman J: "Formation Anisotropy: Reckoning With its Effects," *Oilfield Review* 2, no. 1 (January 1990): 16-23.



***Comparison of RAB and FMI Fullbore Formation MicroImager logs in an Oklahoma, USA well, showing good agreement on features as thin as 1 in. [2.5 cm].***



***Comparison of RAB ring resistivity measurements, after and while drilling, with wireline logs. In the water sand, the RAB measurement shows higher resolution than the AIT Array Induction Imager tool. In the laminated wet sands example, RAB logs made after drilling and while drilling anticorrelate, showing preferential invasion.***


GST Station Logging

On Bottom

BIT RA (OHMM) 6591.7

MTR RPM (RPM) 205.0

BTN RA: 179.91
BTN MTF: 6.64

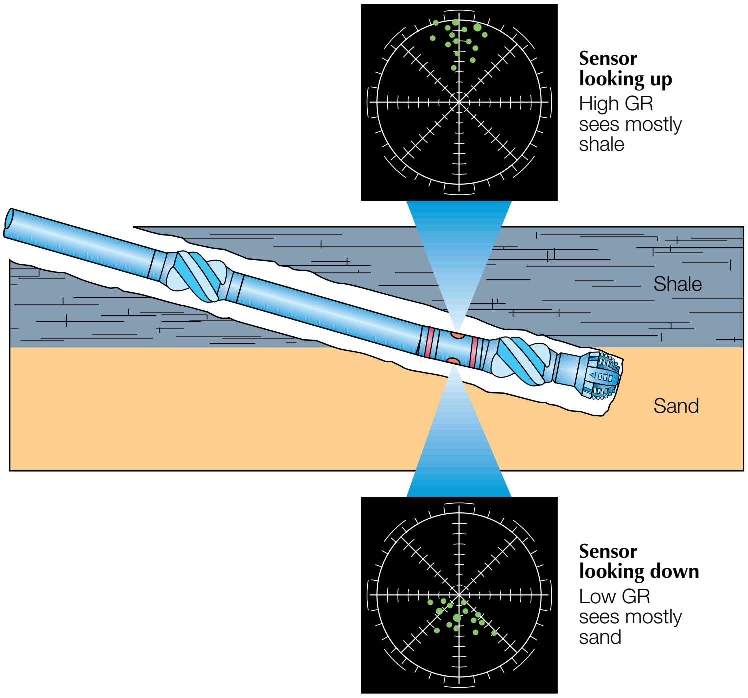
GST GR: 386.80
GR MTF:186.64

BTN RA
min max Interval
0.0000 200.000 20.000

GST GR
min max Interval
0.0000 500.000 50.000

157.2*
357.1*

391.5*
177.1*



☐***The GeoSteering Station Logging screen*** *(top)* ***is used by the directional driller mainly for foot-by-foot steering of a horizontal well, and*** *(bottom)* ***a schematic of gamma ray response in a station logging polar plot, looking up and down when crossing a sand/shale boundary. Directional reading of log values at points around the borehole circumference tells whether the bit has penetrated the roof or floor of the pay zone, or a fluid or lithology boundary. Logs in this display are "button" (BTN) resistivity, measured by a button a few feet above the bit; gravity toolface (GTF)—bit orientation with respect to the top of the hole—and gamma ray (GR) a few feet above the bit. The circular plot shows resistivity*** *(red)* ***and gamma ray*** *(green)* ***values vs. toolface, in which 0 is the top of the hole. The origin is a resistivity or gamma ray value of zero. In this example, each interval is 50 API units for gamma ray, 20 ohm-m for resistivity. The two measurements are 180° apart because the sensors lie on opposite sides of the tool. Each point represents a measurement at a given toolface and time. A sudden rise or fall along a certain toolface helps the driller recognize not only the presence of a boundary, but also its direction relative to toolface. The largest dot shows the most recent value, which corresponds to the endpoint on the log. As many as 20 dots can be shown. The update can take place as often as every sample point, with the oldest data point dropping out at each update.***

evaluation-quality information (*previous page, top*). Applications include prompt location of coring and casing points, and monitoring of invasion by logging after drilling (*previous page, bottom*).

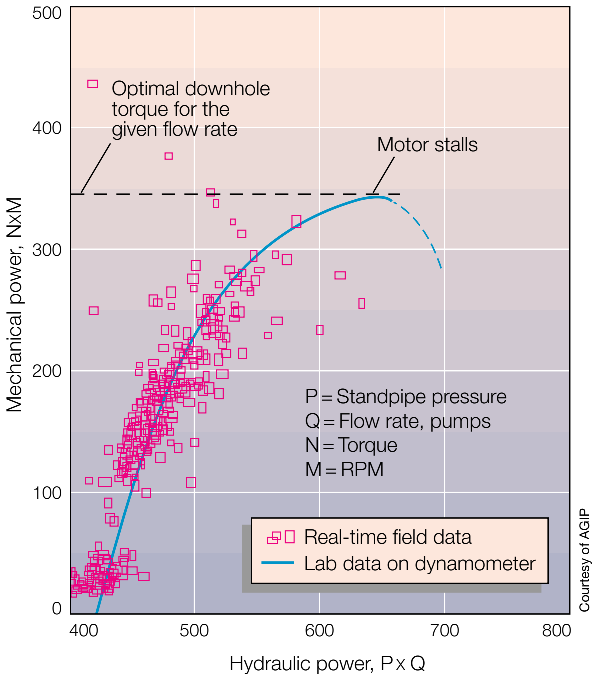
Applications of the tools are linked with interpretation packages in the Wellsite Information System. Geosteering, for example, is further enhanced by the merger of lithology data with directional drilling data. Conventionally, the driller uses a display that reports only bit tool face—up, down, left or right. It tells nothing directly about lithology or pore fluids. The IDEAL drilling system includes a display of resistivity and gamma ray by tool face (*above*). This shows the driller not only where the bit is pointing, but also whether it has penetrated a boundary between formations or pore fluids. It allows the driller to instantly confirm entry into the pay zone or promptly redirect the bit back into the target formation.

### Improving Drilling Efficiency

The most significant advancement for improved drilling efficiency is downhole measurement of RPM, provided by the GeoSteering Tool. Together with downhole measurements of weight and torque from the RWOB tool, these measurements allow the driller to operate the motor near the peak of the power curve (*right*). Higher power to the bit means faster penetration.

A near-bit measurement of downhole shock—from bit bouncing or pipe slapping the borehole wall—provides the driller with more accurate information about optimal drilling speed and weight on bit. This translates into longer bit life, fewer bit trips and less shock-related damage to the wellbore and drillstring.

Other improvements for drilling efficiency are an array of alarms in the Wellsite Information System. These alarms are displayed in front of the driller on a color monitor and address situations that account for most drilling difficulties, such as stuck pipe, kicks, washouts and bit damage. These events or their precursors are flagged with alarms that alert the driller not only about potential drilling trouble, but also about conditions that could threaten rig safety. The alarms are based on integrated interpretations using surface and downhole data.



**□*Power curve for a downhole motor. In this example, the driller ran the motor conventionally, using surface measurements to derive mechanical power. The penetration rate was 40 to 60% of what could have been achieved by running higher up the curve. Use of downhole measurements of torque and motor RPM allows the driller to work closer to the optimum point on the curve, and obtain a higher rate of penetration.***

Another improvement of the surface system is better depth control, critical for proper steering and evaluation of a horizontal drainhole. Improvement in depth accuracy comes mainly from sampling drawworks rotation and hook load at high frequency. The drawworks is a drum that spools and unspools cable that moves the traveling block up and down to lift and lower the drillstring. Drawworks rotation is related to depth added or subtracted. Hook load is needed to determine when the pipe is "in slips"—clamps that hold the drillstring when it is not supported by the hook on the traveling block. Hook load is at a minimum when pipe is in slips. Drawworks sampling during that period is not counted because the pipe is stationary. The higher sampling frequency reduces error introduced during rapid travel of the drillstring, when sample points become less dense. Improved software logic lets the system know automatically the precise times that pipe goes in or out of slips. This saves having to make periodic recalibration to driller's depth, which is based on a tally of pipe sections and the length of each section. These and other improvements keep the Wellsite Information System depth readings within an average of 0.1% of driller's depth.

Drilling with at-the-bit measurements is still in its infancy, but promises to make the driller's job more quantitative, improving drilling and steering efficiency. Petrophysical measurements near the bit draw closer to the uninvaded formation. On the horizon is the real-time merging of geosteering data with seismic data and reservoir models. This will permit update of field maps as the well is drilled, finally integrating the data bases of exploration and development. —LS, JK