Logging While Drilling: A Three-Year Perspective

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Logging while drilling (LWD) has been in commercial service since the late 1980s. Since then, the basic measurements in hardware, processing and interpretation—some incremental, some monumental—has furthered understanding of the sand and lost circulation material, mean mud flow rates are lower than in plain collars. However, demand for LWD measurements has increased in wells that require higher flow rates for effective hole cleaning.

Tool Technology

Basic LWD measurements—resistivity, neutron and density porosities and photoelectric factor—have not changed since their introduction (next page, below), but tool technology has undergone several refinements. These include a range of engineering improvements—from more robust sensor design, to more secure mounting of connectors and integrated circuits. These improvements have led to increased tool durability.

Because the tools are contained in drill collars, hardware takes up space inside the collar, reducing the cross-sectional area available for mud flow. This reduction in area, and erosion of tool components by


drainage of oilfield review
have remained the same, but evolution best ways to use the measurements. 

to mud flow, and by increasing the tool diameter. In 1991, the outside diameter of the CDR (Compensated Dual Resistivity) tool was increased from 6½ and 8 in. to 6¼ and 8¼ in., respectively. The 6½-in. CDN (Compensated Density Neutron) tool will be replaced in the near future by a 6¼-in. version. The 6¼-in. tools permit a maximum mud flow rate of 800 gal/min [50 liters/sec]; the 8¼-in. tool is rated to 1200 gal/min [76 liters/sec].

The most fundamental change in the nuclear tool is detector design. The first generation used a combination of helium (He) detectors, also used in wireline tools, and Geiger-Mueller detectors. Compared to Geiger-Mueller detectors, He detectors, have a broader dynamic range, do not need correction for spurious activation, are less affected by borehole salinity and have better statistics, permitting a higher rate of penetration (ROP). But they were not thought to be as rugged as Geiger-Mueller detectors. Field experience proved otherwise, and since 1990 the CDN tool uses He detectors only. Older tools are being retrofitted.

The CDN tool has a 7.5-curie 241 americium-beryllium neutron source and a 1.7-curie 137 cesium density source, both connected to a source retrieval assembly. In the first version of the tool, the sources and retrieval head were connected with a flexible steel cable. This has been replaced with a flexible titanium rod, giving more reliable retrieval and more accurate placement of the sources. Also improved is the density detector shielding, which eliminates sensitivity to spurious signals from the mud.

The CDN tool uses a full-gauge stabilizer with windows cut in the blades in front of the density source and gamma ray detectors. The 8-inch tool, because of its larger diameter, has the source and detector in the blade rather than in the tool body, which moves them closer to the formation.

<table>
<thead>
<tr>
<th>LWD Tools</th>
<th>CDR Tool</th>
<th>CDN Tool</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parameter</td>
<td>Measurement/Computation</td>
<td>Tool OD/Mud rate</td>
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<tr>
<td>Correlation</td>
<td>Dual resistivities (R_{ps}) and (R_{ad})</td>
<td>6½ / 600</td>
</tr>
<tr>
<td></td>
<td>Gamma ray (total API)</td>
<td>6¾ / 800</td>
</tr>
<tr>
<td>(R_t)</td>
<td>Dual Resistivities</td>
<td>8 / 850</td>
</tr>
<tr>
<td>(R_{to})</td>
<td>Thin beds</td>
<td>8¼ / 1200</td>
</tr>
<tr>
<td>Invasion</td>
<td>Natural gamma ray scintillation spectroscopy (Th, U, K)</td>
<td>9½ / 1400</td>
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<tr>
<td>Shale volume</td>
<td>Computed gamma ray</td>
<td></td>
</tr>
<tr>
<td>Porosity</td>
<td>Compensated neutron porosity</td>
<td></td>
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<tr>
<td></td>
<td>Compensated spectral gamma-gamma density</td>
<td></td>
</tr>
<tr>
<td>Lithology</td>
<td>Density-neutron crossplot (P_e)</td>
<td>6½ / 600</td>
</tr>
<tr>
<td></td>
<td>Under development</td>
<td>6¾ / 800</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(under development)</td>
</tr>
<tr>
<td>Rugosity, detection of free gas</td>
<td>Ultrasonic caliper(^1)</td>
<td>8 / 850</td>
</tr>
</tbody>
</table>

1. For 6½- and 8-inch CDN.
wipe away mud from in front of the sensors, thereby minimizing borehole effects. A locking mechanism is being retrofitted on the stabilizer to increase its resistance to slippage under high torque and jarring. New stabilizers with an integrated lock are under design and scheduled for release next year. A range of stabilizers, including undergauge sizes, has been added for use in horizontal and deviated holes.

A significant development in nuclear technology was the introduction in 1991 of the 8-in. CDN tool, and, in the near future, of a 6 1/2-in. version. Other than being able to operate in holes up to 12 1/4-in., the 8-in. tool has several features that distinguish it from the 6 1/2-in. tool. In the 8-in. tool, neutron and density detectors are both in stabilizer blades rather than in the tool body, as in the smaller tools. This design is preferred in the larger tool because locating the detectors in the tool body would have placed them too far from the formation and thereby degraded the measurement. The 8-inch tool also includes an ultrasonic caliper (see “Unocal, Indonesia,” page 21). The 6 1/4-in. version will have new electronics to increase the number of measurements per foot by a factor of four and will also have an ultrasonic caliper.
Two ultrasonic sensors are mounted 180° apart on stabilizer blades. The sensors function in a pulse-echo mode that allows the direct measurement of standoff, from which short and long axes of the borehole diameter are computed. The vertical resolution is 1 in. [25 mm] and accuracy of the diameter measurement is ± 0.1 in. [2.5 mm]. The caliper is used to correct the density and neutron porosity measurements for borehole effects and can be used as a borehole stability indicator (previous page, left). It can also be used for downhole detection of free gas—gas bubbles, not dissolved gas—through a combination of formation and “faceplate” echo signals (below and previous page, right). The faceplate echo is measured at the surface of the tool, at the mud/window interface. It is affected by gas content in mud, with echo amplitude increasing with gas content. The smallest amount of detectable gas is less than 3% volume of free gas. Real-time transmission of this information can shorten the time needed to detect gas influxes while drilling. This can simplify kill operations.

Memory of the CDN and CDR tools was doubled to 1 megabyte in 1991, and with the introduction of Anadrill’s second-generation MWD/telemetry system in 1991, downlink to the tools can be established while they are in the hole. Previously, tool operation—such as data sampling rate—had to be preset at the surface and was not adjustable once the tool was downhole. The downlink capability permits, for example, the operator to use one CDR sample rate during drilling and switch to a higher rate while tripping out, or to turn sampling off in front of casing, thereby saving memory. The current generation mud telemetry system permits transmission of data at up to 3 bits/sec.

Another advance is the introduction of a downhole shock measurement transmitted to surface. This measurement enhances selection of the bottomhole assembly (BHA) and drilling parameters, and may increase survival of MWD/LWD tools. Many failures of MWD/LWD tools result from high shock and vibration produced during drilling. Lateral vibration contains the most energy and does the most damage to downhole tools, the drillstring and drill bits. Traditionally, engineers predicted a rough running drilling environment from surface torque measurement and modeling of drillstring dynamics. But this is not a direct shock measurement and therefore does not properly account for all causes of vibration and for frictional loss between the surface and BHA. Now the driller can see the downhole environment in real time and adjust rotary speed, weight-on-bit and flow rate to eliminate or reduce shocks. The drilling engineer can also use this information to design BHAs less prone to vibration.

Anadrill’s downhole measurement of shock is made by an accelerometer near the telemetry electronics, 20 to 50 ft [6 to 15 m] above the bit. At a given time interval, typically 60 seconds, the cumulative number of shocks exceeding 25g is reported to the surface (next page). This 25-g value is considered the optimal limit for alerting the driller to possible mechanical failure.

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4. A g, for gravity, is a unit of force equal to the force of gravity exerted on a body at rest. It is used to indicate the force to which a body is subjected when accelerated. For example, 25g is 25 times the force exerted on the body as when it is at rest.
LWD/Wireline Comparisons

In the three years since LWD technology became available, the industry has found five main applications for these tools:

- **Insurance logging**, in case the well is lost, can't be logged with wireline tools or will yield poor-quality wireline logs.
- **Logging before invasion**, which may reveal hydrocarbon zones that might be missed by wireline time. In some high-permeability formations, borehole fluid displaces hydrocarbon from the near-wellbore rock, making the well look like a dry hole by the time of wireline logging. This effect may be more common in horizontal than vertical wells because the drainhole is exposed to full hydrostatic mud pressure for the long period required to drill the lateral section.
- **Geosteering and enhancement of drilling efficiency** (discussed below).
- **Savings in rig time in settings requiring the TLC (Tough Logging Conditions) system and offshore.**
- **Multiple pass logging**. Comparison logs made at different times can help distinguish pay from water zones, locate fluid contacts and identify true formation resistivity and density.

Tom Walsgrove of Amoco UK, who is responsible for introducing new technology to the company’s North Sea operations, has done a cost-benefit analysis of LWD vs. wireline logging that has wide application. He finds that LWD has a clear cost advantage when well deviation is 60° or more. At this deviation, triple combo wireline tools require conveyance by drillpipe with the TLC system. But LWD can be beneficial in other settings that are not so easily identified. It is for this gray area that Walsgrove has developed general criteria to help choose between wireline and LWD for basic formation evaluation.

He has found LWD cost-effective when:

- **Rig cost is high**. Rig cost high enough to make LWD attractive exists almost entirely offshore and where time-consuming TLC logging would be required. Most of the additional expense of a TLC operation is in rig costs, which run about $5000/hour in the North Sea. Amoco is looking to MWD/LWD as a means to cut this cost. Use of LWD may also accelerate selection of coring and casing points and perforation intervals, which can contribute to savings in rig time.
- **Water-base muds are used**. These typically yield poorer borehole conditions by wireline time than oil-base mud (OBM). Wireline tools may therefore be difficult to get

When CDR resistivity is not transmitted in real time. CDR data were acquired in memory mode only, since the data stream to the surface was confined to drilling optimization information. In this case, the memory logs (gamma ray, resistivity and density) showed the well trajectory went into the top of the pay zone at point A, only to go back out through the top of the pay zone at point B. The pay zone here was more than 10 feet [3 m] thick but the drill bit crossed only the top 10 feet. (Adapted from White, and Hansen and White, reference 9.)

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FIGURE 5-1

Details of CDN logs for the same well as above. The normalized short-spacing variance is not a regular product but used here to compute the rotational density output.

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Amoco finds that real-time data provide “an effective means of minimizing risk and reducing excessive operating costs” in exploration wells. Most of this savings is related to savings in rig time. To illustrate this point, Walsgrove cites an instance in which LWD reduced operating costs by allowing more accurate location of coring points within a sand/shale sequence.

“From our work on other wells in this area,” Walsgrove said, “I knew it was highly probable that the first core would be mostly shale with only minor sand stringers. But with MWD/LWD we were able to pick the coring point at the top of a thick sand unit. We saved ourselves the cost of cutting that wasted core, which typically takes a day—about $120,000.”

In another instance, the company spent several days drilling a rathole in basement, including cutting a terminal core that would confirm that the well was in basement before logging. If real-time gamma ray and resistivity logs had been used, the data would have indicated basement quickly, saving days of drilling.

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Details of CDN logs for the same well as above. The normalized short-spacing variance is not a regular product but used here to compute the rotational density output.
When geosteering was introduced, the CDR resistivity log was used for detecting hydrocarbons and the gamma ray log for finding marker beds and kick off points. Because the CDR measurement has higher resolution and precision than the typical MWD short-normal resistivity measurement, thin beds can be more easily identified. It is also more sensitive to boundaries between beds of contrasting resistivity—indicated in a deviated well by the characteristic peak on the log curve, called a horn—and has a greater depth of investigation (see “Why a Horn?” below).

Although resistivity remains the main headlight, a handful of operators have recently examined CDN density logs to see if they can contribute to geosteering (previous page, below). However, the CDN tool is always farther from the bit than the resistivity measurement so its contribution to steering may be as a confirmation of gamma ray and resistivity logs.

The measurement suite for geosteering may be the same as for formation evaluation (see “MWD/LWD Data Frames, next page). The suite typically includes resistivity, gamma ray, short- and long-spacing density and neutron porosity, downhole torque and downhole weight-on-bit to determine formation properties at the bit—with the addition of tool face, or direction and inclination (D&I). This tells the driller the orientation of the bent housing.§ Tool face is needed at a high update rate—typically, every 10 seconds but as fast as every few seconds is desirable for accurate steering with polycrystalline diamond compact bits. With these bits, more reactive torque is generated at the motor, making them go off course sooner than conventional bits. If a high update rate for tool face is used, the update rate on other data drops. The lower rate reduces resolution of petrophysical data, but not usually to a significant degree.

Walsgrove’s analysis indicates that wireline measurements are advantageous when:

- Equity decisions are a concern. Because wireline measurements remain the accepted standard, both from technical and legal standpoints, partners may shy away from relying only on LWD measurements when there is a possible equity debate. Some operators view LWD as less desirable in equity decisions because of the need to depth match it with wireline. Depth matching LWD to wireline is often straightforward, but may be complicated when invasion or borehole conditions cause large differences between LWD and wireline logs, or when driller’s depth varies nonsystematically with wireline depth. This can happen because of pipe stretch, compression or yo-yoing, or miscounted pipe stands. Absolute depth correction of LWD logs is sometimes done using a gamma ray from the cement bond log when casing is set—usually one to three days after LWD logging. This delay in absolute depth correction does not stall drilling-related decisions based on LWD information. The relative depths of features on the LWD log are used to reference formation tester sample, core and casing points.
- High temperatures (greater than 320°F [160°C]) are encountered. Wireline tools typically have a higher temperature rating than LWD tools, which are limited mainly by their use of batteries.
- Hole size is very large. The current maximum hole size for the CDN tool is 13¾ inches [35 centimeters (cm)], and for the CDR tool is 17½ inches [44 cm]; or 26 inches [66 cm] if mud is made with freshwater (1.5 ohm-m).

Other variables may complicate the choice between wireline and LWD. Amoco did a cost analysis for two wells in which both wireline and LWD services were run. In one well, discounting rig time, LWD cost 241% more than wireline. In this instance, the large difference was due to LWD tools sitting on the rig unused for 21 days because of unanticipated problems setting casing. If LWD had been run promptly, its cost would have been 100% more than wireline.

In the second well, LWD logs were made promptly. Although the LWD cost was slightly higher than wireline, when rig cost was added, LWD afforded a net saving. The LWD service was less expensive than in the first case because the operator needed only three days to mobilize and demobilize the tools, which were on a nearby rig.

Taking cost analysis one step further, Amoco modeled typical North Sea wells to determine the most cost-effective triple combo logging program. Wireline was marginally less expensive in the first example, which had:

- straight hole
- casing set at 8000 ft [2440 m] and average ROP of 30 ft/hour [10 m/hr] to reach total depth (TD) at 10,000 ft [3050 m]
- two days each to mobilize and demobilize the tools
- total rig operating cost of $120,000/day.

The second model was identical, except the well was deviated to 45° at 4000 ft [1220 m]. Although TD and the casing point were the same true vertical depth (TVD) as before, the openhole footage and total measured depth increased. Again, wireline offered a marginal savings. But when well deviation reached 70°, rig time associated with wireline cost exceeded LWD cost because TLC hardware would be needed to convey wireline tools. Financial analysis by another major oil company shows that lost-in-hole cost is always more expensive with LWD than with TLC methods, but that risk of losing the tools is lower with LWD than with the TLC system.

Why a Horn?

A polarization horn on a CDR log in a horizontal well indicates the tool is crossing a bed boundary. This horn occurs because of charge buildup at bed boundaries. Because this charge is caused by the signal from the logging tool, it therefore oscillates at the same frequency, acting like a secondary, weak transmitter along the bed boundary. This effect doesn’t occur in a vertical well, where bed boundaries are horizontal and parallel to the current loops generated by the tool. In this setting, the current loops do not cross interfaces between formations of contrasting resistivities and no secondary field is generated. But in a horizontal well, as the tool moves along the bed boundary, the current loops pass from one formation into another, generating a substantial secondary field. At each bed boundary, the received signal increases, producing the characteristic polarization horns. The magnitude of this polarization increases with the relative dip angle and the resistivity contrast between the beds.
Data Transmission: Real Time or Recorded?

Combined improvements in MWD telemetry and LWD technology now permit real-time transmission of any LWD data. But not all data can be sent at once, so a major decision is what data to send in real time and what to store downhole for retrieval when the BHA reaches the surface (see “A Second-Generation MWD/Telemetry System,” page 13). In the future, through-drillpipe wireline systems will be available to unload tool memory downhole.

The selection of real-time or downhole memory mode depends on the application, and may change from section to section, even in a single well. While real-time data help with drilling decisions, the more data sent uphole, the slower the update rate of each measurement, so the lower the resolution. The proper balance between real-time and recorded modes involves determining not only what data are needed when, but what data quality is needed. The goal is to get the right data at the right time.

The recorded-only mode is commonly used in formation evaluation for reservoir characterization in development wells. Real-time data are used mainly in formation evaluation for well management decisions, such as whether to run wireline logs and, if so, which ones; where to core and set casing; and when to plug the well, to adjust hole trajectory or mud weight, drill deeper or stop drilling. A typical real-time suite consists of directional surveys, resistivity measurements (resistivity from attenuation—deep, $R_{ad}$, and resistivity from phase shift—shallow, $R_{ps}$), gamma ray, short- and long-spacing density, neutron porosity, downhole torque and downhole weight-on-bit (right). Most of these data are updated every 26.5 seconds, equivalent to a 6-in. [15-cm] sample rate at an ROP of 70 ft/hour [21 m/hr]. In practice, twice the ROP—140 ft/hour [43 m/hr]—gives 12-in. [30-cm] sampling, sufficient for most real-time formation evaluation.

Amoco UK bases its selection of recorded vs. real-time data on comparison of data cost and quality. In exploration wells, the company usually transmits the CDR log in real time to improve drilling efficiency. In development wells, the company usually acquires LWD logs only in recorded mode. This reduces logging cost as a result of not having to run an MWD tool for direction and inclination data.

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**MWD/LWD Data Frames**

<table>
<thead>
<tr>
<th>Downhole Measurement</th>
<th>Transmitted Data</th>
<th>Update frequency (sec)</th>
<th>Equivalent ROP at two data points/ft</th>
</tr>
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<tbody>
<tr>
<td>MWD sync</td>
<td>$R_{ps}$</td>
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<td>68</td>
</tr>
<tr>
<td>$R_{ps}$</td>
<td>$R_{ad}$</td>
<td>26.5</td>
<td>68</td>
</tr>
<tr>
<td>$R_{ad}$</td>
<td>LWD GR</td>
<td>26.5</td>
<td>68</td>
</tr>
<tr>
<td>LWD GR</td>
<td>SS density</td>
<td>26.5</td>
<td>68</td>
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<tr>
<td>SS density</td>
<td>LS density</td>
<td>26.5</td>
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<td>DWOB</td>
<td>53</td>
<td>34</td>
</tr>
<tr>
<td>DWOB</td>
<td>VALT</td>
<td>53</td>
<td>34</td>
</tr>
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</table>

**Typical Formation Evaluation Setup**

<table>
<thead>
<tr>
<th>Downhole Measurement</th>
<th>Transmitted Data</th>
<th>Update frequency (sec)</th>
<th>Equivalent ROP at two data points/ft</th>
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</thead>
<tbody>
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<td>Gravity T/F</td>
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<td>170</td>
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<tr>
<td>GY [T/F]</td>
<td>$R_{ps}$</td>
<td>53</td>
<td>34</td>
</tr>
<tr>
<td>$R_{ps}$</td>
<td>$R_{ad}$</td>
<td>53</td>
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<tr>
<td>$R_{ad}$</td>
<td>LWD GR</td>
<td>53</td>
<td>34</td>
</tr>
<tr>
<td>GZ [T/F]</td>
<td>SS density</td>
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<td>34</td>
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<tr>
<td>SS density</td>
<td>LS density</td>
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<tr>
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<td>53</td>
<td>34</td>
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<td>GY [T/F]</td>
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<td>TN porosity</td>
<td>DWOB</td>
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<tr>
<td>GZ [T/F]</td>
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**Typical Geosteering Setup**

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<th>Equivalent ROP at two data points/ft</th>
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<td>$R_{ps}$</td>
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<tr>
<td>GZ [T/F]</td>
<td>DTRQ</td>
<td>53</td>
<td>34</td>
</tr>
</tbody>
</table>

DTRQ: downhole torque; VALT: MWD turbine voltage output, which is proportional to mud flow, so VALT acts as a downhole flow meter; T/F sync: a number identifying the sequence of measurement to be transmitted; GY and GZ [T/F] are values of the accelerometer measurements along the Y and Z axes; the tool is the X axis. GY and GZ are used to compute the orientation of the bent sub with reference to the high side of the hole. The DWOB measurement is downhole weight-on-bit. Many downhole measurements appear more than once in the left column, indicating that they are sent more than once per data frame.

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8. There are two tool face measurements. Magnetic tool face is in reference to magnetic north. Gravity tool face is in reference to the high side of the hole.

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Sample data frames from the North Sea, used for formation evaluation and geosteering.
The application of LWD in North Sea development wells is unique, having to do with how they are drilled. Many operators use MWD directional and gamma ray information to position the 9 5/8-in. [25-cm] casing just above the target. Some also use the CDR resistivity for this task. Casing is set and the hole drilled out with a “locked” BHA, in which stabilizers are arranged to minimize drift of the borehole. From this point, MWD is not used because the driller has to drill a straight hole a short distance and can’t miss the target. Once in the target, LWD measurements are used in memory mode to log the reservoir.

Four possible interpretations for a deep resistivity response in a horizontal well. More log data are needed to constrain the geologic model. There are no horns because the deep resistivity measurement tends not to show horns and because the resistivity contrast between beds is small. (From White, reference 9.)

Resistivity modeling of the uppermost resistivity horn shown on page 9, top. Here, formation dip, bed boundaries and resistivities were estimated from the geologic model and used to develop a model of \( R_t \) and a synthetic resistivity log. The model is confirmed because the synthetic log nearly matches the measured log.

This modeling was done because of a disparity between nuclear and resistivity logs. On page 9 (top figure), the density and gamma ray logs show that the zone between the two peaks appears to be a shale. But the resistivity log does not show the low value normally associated with shales in this area. Because the shale is thin (about 2 ft [60 cm]), it is possible that the large volume of rock investigated by the CDR tool prevented it from seeing the shale. This presented an ideal opportunity to run a resistivity simulation across this zone. The square log of \( R_t \) successfully simulated the measured log, reinforcing the model of the formation as a shale with significant lateral extent. (Adapted from Hansen and White, reference 9.)
Data Processing Advances

Most data processing routines for logs were designed for low-angle holes, typically less than 40°. Assumptions in the vertical well—azimuthal symmetry of formations and invasion around the borehole, no lateral variation in formation properties, and formations becoming older and deeper with measured depth—break down for directional and horizontal wells.9 The increasing use of LWD in horizontal and highly deviated holes has stimulated progress in the processing of LWD log data.

In directional and horizontal wells, data processing and interpretation is a two-step process. The first step, while the well is drilled, is to determine whether, when and where the well trajectory enters the geologic target and whether it stays there. This is done by monitoring formation evaluation information—cores, cuttings, MWD and LWD data—as the well is drilled, and then, modifying the well path as needed. The second step, which takes place after the well is drilled, is detailed appraisal of formation parameters for reservoir evaluation, well completion and field development. To meet these needs, and interpretation needs in conventional wells, several new data processing methods for LWD have been developed. These include:

- Prediction of CDR resistivity in high-angle and horizontal holes with varying relative dip between the borehole and beds, using the RangDB program (“rang dee bee,” for relative angles data base)
- Real-time phase-resistivity caliper and borehole correction to phase and attenuation measurements
- Correction of the CDR measurements for the effect of resistivity anisotropy
- Correction of the density measurement to account for elliptical holes.

Prediction of CDR resistivity in high-angle holes with varying relative dip. An objective of interpreting CDR logs in high-angle wells is to build up a model of the formation surrounding the borehole. This interpretation must be made with care because there may be insufficient data to develop a unique geologic scenario. Simulation of CDR logs may help clarify this process (see “Electromagnetic Tool Modeling,” page 22). Often, CDR response in a horizontal well can be predicted before drilling. This may be critical for identifying log signatures that show when a drill bit is entering or leaving a target. This prediction of CDR response in a well with constant, unchanging relative dip is achieved by using the CDRDIP module in the electromagnetic modeling package, ELMOD11 (previous page, right). But what about the typical high-angle well, where the well inclination changes continuously?

For this, a second-generation modeling program has been developed, RangDB. This prediction has several steps. The first step, as with any simulation, uses local knowledge and offset well data to provide a simple, layered model of the geology. This model is verified using ELMOD data to simulate the resistivity curve from the offset well.

The second step uses this model as input to several runs of CDRDIP at different angles (next page, left). The angles are chosen to represent the range of dips likely to be encountered along the trajectory. RangDB then computes values of phase shift and attenuation resistivities versus TVD interpolated at 1° deviation steps between

A Second-Generation MWD/Telemetry System

In 1991, Anadroll introduced a second-generation MWD telemetry system, which is used to convey MWD and LWD measurements. The new system, called the M3 MWD Telemetry tool (M for MWD; 3 for 3 bits/second), includes several notable departures from the first-generation system. Here are some highlights.

- A mud pulse modulator that resists jamming.
  At the heart of mud pulse telemetry is a downhole modulator that generates pressure pulses in the mud. It is placed in the path of the mud flow and opens and closes to generate pressure pulses. The first-generation modulator was occasionally jammed by debris and lost circulation material. The new modulator has better resistance to jamming because it is self-cleaning and has lower drag. It performs successfully in muds having up to 40 lb/barrel of loss circulation material.
- Reduction in transmission data error rate by an order of magnitude. This was accomplished in two ways. The new modulator permits a higher signal-to-noise ratio, and introduction of a downhole microprocessor allows finding and correcting errors in the data stream. After error correction, the received data contain less than 1 bit error per 1000 bits—an error rate of 0.1%.
  Most data processing routines for logs were designed for low-angle holes, typically less than 40°. Assumptions in the vertical well—azimuthal symmetry of formations and invasion around the borehole, no lateral variation in formation properties, and formations becoming older and deeper with measured depth—break down for directional and horizontal wells.9 The increasing use of LWD in horizontal and highly deviated holes has stimulated progress in the processing of LWD log data.

In directional and horizontal wells, data processing and interpretation is a two-step process. The first step, while the well is drilled, is to determine whether, when and where the well trajectory enters the geologic target and whether it stays there. This is done by monitoring formation evaluation information—cores, cuttings, MWD and LWD data—as the well is drilled, and then, modifying the well path as needed. The second step, which takes place after the well is drilled, is detailed appraisal of formation parameters for reservoir evaluation, well completion and field development. To meet these needs, and interpretation needs in conventional wells, several new data processing methods for LWD have been developed. These include:

- Prediction of CDR resistivity in high-angle and horizontal holes with varying relative dip between the borehole and beds, using the RangDB program (“rang dee bee,” for relative angles data base)
- Real-time phase-resistivity caliper and borehole correction to phase and attenuation measurements
- Correction of the CDR measurements for the effect of resistivity anisotropy
- Correction of the density measurement to account for elliptical holes.

Prediction of CDR resistivity in high-angle holes with varying relative dip. An objective of interpreting CDR logs in high-angle wells is to build up a model of the formation surrounding the borehole. This interpretation must be made with care because there may be insufficient data to develop a unique geologic scenario. Simulation of CDR logs may help clarify this process (see “Electromagnetic Tool Modeling,” page 22). Often, CDR response in a horizontal well can be predicted before drilling. This may be critical for identifying log signatures that show when a drill bit is entering or leaving a target. This prediction of CDR response in a well with constant, unchanging relative dip is achieved by using the CDRDIP module in the electromagnetic modeling package, ELMOD11 (previous page, right). But what about the typical high-angle well, where the well inclination changes continuously?

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Resistivity logs for beds dipping 0° to 85°, showing development of horns as a bed boundary is crossed at increasingly shallow angles. The 0° example is a modeled CDR log, based on an induction log in a vertical well. The others are modeled CDR logs using the CDRDIP program. These logs show that variation in dip angle, even when adjusting for true bed thickness, gives logs of different character. Comparing curves at the 4-ohm-m reference line shows that resistivity creeps upward with increasing dip angle.

Comparison of phase and wireline calipers. At a few places—140 to 170 feet, 240 and 430 feet—the caliper while drilling reports a larger value than the wireline reading, perhaps due to swelling shales. The phase caliper at 60 ft reads between the two wireline values because it reports an average borehole size. Limitations of the phase caliper’s vertical resolution cause it to miss some of the thinner sands. Note that the shales are almost uniformly washed out to 17 in. (43 cm).

(From Rosthal et al., reference 12.)
Resistivity caliper and borehole correction. The phase caliper is computed from the raw phases of a 2-MHz electromagnetic wave measured at two receivers and from the phase shift between the receivers.\textsuperscript{12} The raw phase is strongly dependent on mud resistivity and borehole size, whereas the phase shift is only slightly affected. Since mud conductivity is known, the measurement can be used to calculate large changes in borehole diameter from bit size in conductive muds (previous page, bottom). This caliper can be used to monitor borehole stability during drilling or tripping. Calculation of the phase caliper does not require special equipment and does not compromise the tool’s standard measurements. Mud, however, must be at least 1 siemens/m (S/m) [1 mho/m] more conductive than the formation. Accuracy of the borehole diameter measurement is $\pm 1/2$ in. [1.3 cm], the vertical resolution is about 36 in. [91 cm], and it will work in borehole diameters up to 24 in. Because the phase caliper works best for large variations in borehole diameter, it complements the ultrasonic caliper, which works best where borehole variation is no larger than about 6 in.

The calculated borehole diameter can be used to apply a borehole correction to the two resistivity measurements. This correction is needed most in large boreholes filled with very conductive muds.

Resistivity anisotropy code. Resistivity anisotropy—different resistivity values in horizontal and vertical directions—may produce markedly different resistivity logs of the same bed measured in a vertical well and measured in a well deviated more than 70° (below). Resistivity anisotropy is typically seen in formations with laminations less than about 3 in. [8 cm] thick, with alternating high and low resistivities. Induction and CDR resistivity measurements in such a formation will read lower in a vertical well than in a horizontal well. The opposite is true for a laterolog resistivity measurement. A code to handle this problem, and correct the resistivity measured in the deviated well, was

\[12.\text{ Rosthal RA, Best DL and Clark B: “Borehole Caliper While Drilling From a 2-MHz Propagation Tool and Borehole Effects Correction,” paper SPE 22707, presented at the 68th SPE Annual Technical Conference and Exhibition, Dallas, Texas, USA, October 6-9, 1991.}\]
Resistivity modeling showing that resistivity anisotropy explained why pay zone resistivity in a horizontal well was higher than expected. The model demonstrates that inequality between horizontal and vertical resistivities could reproduce the measured log results. The right inset shows that anisotropy is represented by a series of thin beds of alternating high- and low-resistivity streaks. The two models, one vertical (0°) and the other horizontal (89°), successfully reproduced the measured log responses—4-ohm-m in the vertical well and 9 to 10 ohm-m in the horizontal well.

(From Leake and Shray, reference 10.)

A pronounced dielectric effect causing an anomalously high, deep attenuation measurement. This example is from a volcanic rock in a North Sea well. The expected dielectric constant for this formation was about 50, whereas the actual value was over 500. The same effect, but not as dramatic, has been observed in shales in the US Gulf Coast, Alaska and the Far East.

Evidence for anisotropy came from the ELMOD resistivity modeling program that was able to simulate both the wireline (vertical) and LWD (horizontal) logs. The model configured the top 3 ft [1 m] of pay as a series of high- and low-resistivity streaks, which represents the effects of formation anisotropy. CDR logs were simulated in this setting in a vertical well and a horizontal well. Although these logs do not represent a unique solution, they reproduced the field results (above, left).

Existing CDR software was modified to output a continuous log of horizontal and vertical resistivities. Inputs are \( R_{pd} \) and \( R_{ps} \) and the angle between the hole and the bed in question. The vertical resistivity component is used only for the calculation, not for true resistivity. The horizontal component correlated closely with that measured by the induction log in the vertical well.
Another advance concerns correcting CDR measurements in conventional wells (deviated less than 40°) for dielectric effects. In formations with a high dielectric constant—typically highly resistive rock and some shales—the $R_{ad}$ value is anomalously high. Significant elevation of $R_{ad}$ occurs in most shales and some volcanic rocks. The problem is evident in thick shales, where there is no invasion and no borehole effect, yet $R_{ad}$ exceeds $R_{ps}$ (previous page, bottom). A log processing routine has been developed that uses $R_{ad}$ and $R_{ps}$ to solve for the dielectric constant and correct resistivity for dielectric effects.

The routine uses information about dielectric constants collected from analysis of 300 rock samples worldwide, performed at Schlumberger-Doll Research, Ridgefield, Connecticut, USA. A data base was then compiled, relating dielectric constant to conductivity as a function of frequency.

The data base provides an estimate of the dielectric constant as a function of conductivity at the 2-MHz frequency of the CDR tool. An anomalously high $R_{ad}$ value results when the actual dielectric constant is larger than the estimated value. The dielectric processing program for the CDR tool computes from the two recorded CDR resistivities an apparent dielectric constant and its corresponding, dielectrically corrected resistivity, $R_{dps}$, for epsilon, the symbol for dielectric constant. The program does this automatically, but a chartbook-type version of this correction is shown (below).

**Interpretation Advances**

Many advances in LWD pertain to log interpretation in horizontal wells, a setting in which LWD commonly has economic advantage over basic wireline measurements. One interpretation consideration being given more attention, with the growing number of horizontal wells, is gravity segregation of fluids in the invaded zone (next page, top).

An example of this was seen in a North Sea deviated gas well logged with LWD while tripping three days after drilling. There were two CDN density outputs: bulk density and the rotationally corrected density. A greater rotational density than bulk density suggested an oval hole. Amoco thought the greater rotational density value was not

![Correction for dielectric effect on 6 1/2-inch CDR logs. The red curve, just below the top of the tan, is the estimated dielectric value versus resistivity, derived from lab studies. This curve predicts, for example, that a phase shift of 5° will produce an $R_{ps}$ of 11 ohm-m and an attenuation of 5.2 dB will produce an $R_{ad}$ of 19 ohm-m. These correspond to estimated dielectric values of about $\varepsilon_{ps}=45$ and $\varepsilon_{ad}=40$, respectively. The intercept of these two resistivity values, however, gives the dielectrically corrected resistivity, which is 12.5 ohm-m. The line on which the intercept falls indicates an apparent dielectric constant of 180, four to five times greater than the predicted dielectric constant. The dielectrically corrected resistivity always falls between the other two resistivities, $R_{ad}$ and $R_{ps}$, making it a robust computation.](image)

13. A dielectric constant is a measure of the ability of a material to store electric charge for a given applied field strength. A dielectric is a material having a low electrical conductivity compared to that of metal. Fresh water, for example, has a dielectric constant of about 80; quartz is 4.65. The shale dielectric constant varies strongly with frequency of the electromagnetic field and with mineral content. It typically has a dielectric constant of up to 10,000 at induction log frequency (10 to 40 kHz), 100 to 200 at CDR log frequency (2 MHz) and 5 to 25 at the frequency of the EPT (Electromagnetic Propagation Tool) (1.2 GHz). Measurement of the dielectric constant, in the case of the EPT tool, is used to distinguish two fluids that have the same resistivity: fresh water vs. a mixture of saltwater and oil.


due to ovalization but because invaded fluid, after three days, lay on the low side of the hole. “Since the introduction of LWD, failure to account for density variation associated with invasion in gas-bearing reservoirs could lead to an erroneous interpretation,” Walsgrove said. “Now I mentally model what’s going on in the formation before I begin log analysis.”

Amoco has progressed in its interpretation of LWD logs in deviated holes. A case in point is a highly deviated well that penetrated a known oil zone, but that LWD logs indicated anomalously high water saturations as determined from the deep resistivity \( R_{dd} \) log. The zone in question was a sand/shale sequence. Close examination showed that the deep resistivity was being suppressed so much by the overlying shales that the sands looked wet (see “Amoco, North Sea,” page 20). This suppression effect was proved by modeling the formation and using tool response functions to predict log response.

Advances have also been made in interpretation of nuclear logs. Since the introduction of LWD, differences have sometimes been noted between wireline and LWD nuclear logs in the same well. Recent work has shed light on two mechanisms for this disagreement: differences in how the tools make their measurements and changes in wellbore conditions in the time between logging with LWD and wireline—namely, displacement of reservoir fluid by invading mud filtrate of a different density, chemical alteration of shales by drilling mud and increased rugosity. How these effects influence the preference for wireline or CDN logs is summarized (right).

For density measurements, the main difference in response to wellbore conditions is due to the different mechanical arrangement of the tools. Wireline density tools use pad-mounted sources and detectors that are held against the formation, minimizing perturbation of the signal by mud. The CDN tool makes its measurement through a full-gauge stabilizer (the same as bit size). As long as the hole remains in gauge, the stabilizer removes virtually all mud from in front of the sensor, yielding a reliable measurement. The rotational density algorithm can correct for a small degree of standoff—1 to 2 in. [3 to 5 cm], depending on mud weight and mud chemistry. Greater standoff exceeds the algorithm’s ability to furnish a usable correction.

For neutron measurements, different designs of wireline and LWD tools also cause differences in how the tools respond to wellbore conditions (next page). The wireline neutron measurement is made from a mandrel pressed against the borehole wall, whereas the CDN measurement is made from a tool centered in the borehole. The borehole effect for the wireline tool is not important compared to the mudcake effect. On the contrary, the borehole size effect on the CDN tool is large because the tool is centered in the hole. The wireline tool standoff effect is comparable to the CDN borehole effect in amplitude.

### Comparison of how wellbore conditions affect CDN and wireline density measurements. (From Allen et al, reference 17.)

| Wireline Hole Condition | CDN Hole Condition | Results
|------------------------|-------------------|---------|
| Smooth and in-gauge | Smooth and in-gauge | Excellent agreement
| Smooth, in-gauge with mudcake | Smooth, in-gauge with mudcake | Rotational processing required
| Smooth and enlarged | Smooth and enlarged | Time-lapse density interpretation possible
| Smooth, enlarged with mudcake | Smooth, enlarged with mudcake |
| Smooth and altered formation density | Smooth and altered formation density |
| Enlarged and rugose | Enlarged and rugose |
| Enlarged, rugose and altered formation density | Enlarged, rugose and altered formation density |
Comparison of wireline and CDN density and neutron porosity logs in a vertical south Texas well drilled with fresh mud. Above and below the bar, the hole was smooth and in gauge during CDN logging. The zone marked by the bar was logged with the CDN tool during a bit trip after being open several hours. Here, the CDN $\Delta \rho$ is high, consistent with a 9 pounds per gallon (lbm/gal) mud weight, and DCAL is close to zero. This combination of readings indicates the hole was enlarged enough to prevent the CDN tool from maintaining contact with the formation. The combination of a well-stabilized BHA and lack of hole deviation produced this standoff. By wireline time, the caliper indicates mudcake had formed. Arrows mark rugose intervals where wireline density reads too high. In these intervals, the CDN measurement would be preferred, while in the zone by the bar, wireline density would be preferred. (From Allen et al, reference 17.)

Charles Flaum of Schlumberger in Montrouge, France, studied CDN density logs and helped solve a key problem in horizontal drilling: knowing whether a formation boundary is crossed from above or below.

Flaum examined the rotational density output in a horizontal well that both entered and exited the top of a pay sand (page 9, top). The rotational correction makes use of the statistical variance of the near-detector count rate as the tool turns in the hole. In this computation, a normalized statistical variance of 1 indicates an in-gauge hole, assuming no radial variation in density. When the hole is in gauge, further excursions of the variance are not caused by changes in standoff but by the tool crossing a density boundary at a low angle. These deflections may be used to determine whether the well is approaching a density contrast boundary from above or below. Flaum found that in a smooth hole drilled with undergauge stabilizers, the variance will have a positive shift in the absence of a density contrast boundary. If a denser formation approaches from below, the variance will increase until the boundary is passed. If a denser formation approaches from above, variance will decrease. The opposite effects will be observed if the approaching formation is of lower density. The density “horns” may also help identify boundaries between beds that have insufficient resistivity contrast to produce horns on the resistivity log.

These advances in LWD technology and technique are some of the innovations being combined in new ways with drilling-related measurements that are more quantitative. This synergy of LWD and drilling measurements may take geosteering, now a new technique, into the realm of the commonplace. This will lead to the next step, which might be called geodrilling—real-time merging of petrophysical and drilling data to find more efficient and safe ways not only to position the bit, but also to drill the well.

—JMK

16. Others have noted the special case of invasion in a horizontal well. See Woodhouse R, Opstad EA and Cunningham AB: “Vertical Migration of Invaded Fluids in Horizontal Wells,” Transactions of the SPWLA 32nd Annual Logging Symposium, Midland, Texas, USA, June 16-19, 1991, paper A.

Amoco UK first decided to use LWD when a 60° development well had reached TD and the operator could not get wireline tools downhole. The cause of difficulty was suspected to be post-drilling degradation of the borehole. A triple combo LWD suite made a single trip in the well. The logs appeared valid, except for a density discrepancy—0.03 g/cm³ too high.

In a subsequent well, drilled with oil-base mud, Amoco determined that a comparison was required between LWD and wireline measurements. The LWD-wireline comparison showed excellent agreement. The $\rho_b$ from LWD and wireline almost match (right). The LWD neutron porosity, however, was lower than wireline particularly in shales because the LWD measurement, unlike the wireline measurement, accounts for a combination of thermal and epithermal neutrons and here was significantly affected by epithermal neutrons.

Examination of the LWD logs shows that the higher vertical resolution of the CDR tool in this conductive environment (less than 2 ohm-m), compared to the wireline medium induction resistivity log, improved calculation of water saturation in thin sands (right). This resulted in a lower water saturation, increasing the determined oil in place.
Unocal has drilled a series of wells with MWD/LWD tools in offshore Kalimantan, Indonesia. A notable gas discovery was made in the second exploration well in the Serang field. LWD was planned over a long section. The objectives were to evaluate the CDN measurements, obtain real-time CDR measurements for comparison with wireline logs in a nearby well and provide early detection and evaluation of pay zones.

Use of OBM complicated evaluation with wireline logs because the mud masked many pay zones on mud logs. The real-time CDR log, however, identified pay zones in what turned out to be a significant gas discovery. Downloading of CDN data confirmed the top of the gas sand had been penetrated. These gas sands were later verified by formation tester sampling. These zones could have been mistaken for oil zones because of deep invasion at the time of wireline logging.

The CDR log was 60 minutes or less behind the bit and the CDN log was less than 3 hours behind the bit. The CDN differential caliper, between tracks two and three, indicates the hole was still in good condition at this time, with no washouts greater than $\frac{1}{2}$ in. But at wireline logging, five days later, washouts went off the scale—recorded subsequently at 16 in. (40 cm).

In the lower gas sand, above 7200 ft, the wireline caliper shows a slight oscillation associated with a regular corrugated effect on the borehole from turbodrilling. In this interval, the maximum density from the CDN tool is higher due to better contact with the formation than that of the wireline tool.


July 1992
Resistivity modeling is used as far back as 1927, when Conrad Schlumberger first reasoned how current from an electrode spreads out into the formations around a borehole. But he would have called it “theorizing.” Characteristics were assigned to the formation (the formation model) and the laws of physics, usually in idealized form, were used to predict analytically the response made by some electrode configuration (the sonde, or tool, model) to the modeled formation. Both theoretical and experimental modeling have passed through many stages since then.

Early experimental modeling used small electrodes in “infinite” saltwater baths. Later, tool responses were studied using mock-up sondes in more realistic environments created by using thin impermeable membranes to separate waters of different salinity. For a number of years, a resistor network was used at the Schlumberger-Doll Research laboratory in Ridgefield, Connecticut USA. This network, consisting of tens of thousands of electrical resistors, simulated resistivities in borehole, invaded zone and virgin formation. In addition, theoretical calculations of sonde responses to layered and invaded formations generated books of departure curves. This theoretical approach was especially important for tools that had large depths of investigation or were not readily adaptable to laboratory experiments.

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Large improvements in computing capability have introduced qualitative changes in interactive modeling is possible even on personal computers. Program packages for simple one-dimensional (1D) modeling are commonplace: two-dimensional (2D) and three-dimensional (3D) modeling are practical in many special cases, although they generally require the use of mainframes or supercomputers. Two-dimensional modeling permits examination of axially symmetric radial variations—for example, treating zero-dip layering and coaxial invasion simultaneously. Three-dimensional modeling also handles azimuthal variations such as circumferentially irregular caves or invasion, sonde eccentering and dipping beds.
Modelling Versus Inversion

The distinction between modelling—frequently “forward” modelling—and inversion is sometimes muddled. The latter typically attempts to “back out” true resistivity, $R_t$, directly from the log with a minimum of assumptions. The best known example of this approach is vertical deconvolution through the use of inverse filters. In its purest form, this method requires only that the vertical response function (VRF) of the tool be known accurately. In practice, VRFs are usually formation dependent, so approximations must be used. Nevertheless, deconvolution has been employed successfully, running in real time on logging unit computers. Artifacts may appear, however, if inverse filters overreach in trying to achieve fine vertical resolution or if the 2D assumptions implicit in the filter are violated.

In modeling, on the other hand, the analyst suggests an environmental model. This trial model includes a description of the borehole and formation geometry and “parameter values”—numbers assigned to variables such as borehole diameter and bedding dip, thickness and resistivity. Then, the tool physics—a model in its own right—is used to compute an expected log, which is compared with the field log. If the match isn’t good enough, the initial trial model is altered and the calculation repeated. This process is iterated until the two logs match satisfactorily. Several criteria for the quality of match are used, from simple eyeballing to the more sophisticated least-squares and maximum entropy methods described later. The model’s geometry or parameter changes are executed interactively, using the analyst’s intuition and experience, or automatically, if computers and programs of sufficient power are available.

Modeling intrinsically yields consistency with the field log, even though the solution isn’t unique. This nonuniqueness is seldom a serious problem, however, because the range of possible formation models can be severely constrained by local knowledge from cores and logs. An extreme example of this condition shows two grossly different models that predict the same deep induction log (above). But in practice, almost any additional log with vertical resolution of about 1 foot [30 cm] or less (gamma ray, EPT Electromagnetic Propagation Tool, dipmeter or photoelectric factor, $P_e$) would resolve this ambiguity.

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In this article, AIT (Array-Induction Imager tool), CDR (Compensated Dual Resistivity), EPT (Electromagnetic Propagation Tool), Phasor and MicroSFL are marks of Schlumberger. Cray is a mark of Cray Research, Inc. Connection Machine is a mark of Thinking Machines Corp. VAX is a mark of Digital Equipment Corp.

**Examples of Formation Evaluation**

The economic importance of modeling is illustrated by a North Sea reserves calculation based on induction log interpretation carried out with a Schlumberger program called Induction Sonde in Multilayered Media (ISMLM). This is a 1D induction modeling code for layered media that neglects borehole and invasion effects. It handles up to 150 parallel dipping layers. Invasion was considered negligible because the well was drilled with oil-base mud.

The measured deep induction log, initial trial formation model and computed log are shown in the first model (above, left). High-resolution details of the trial model were provided by an EPT log. The effects of the first model revision are based on the analyst’s experience. The analyst changes the thicknesses of conductive beds, adds layers to the sands, and improves the depth match between the induction and EPT curves. Since visible discrepancies between the field log and the modeled log remained, further model revisions were needed to achieve the final results (above, right). The final model reduced the well’s estimated average water saturation from 9.7% to 7.2%. Because the hole is deviated 56°, the log-measured depths (MD) are greater than the true vertical depths (TVD), and bed thicknesses are similarly magnified. This MD expansion of scale, obvious in highly deviated wells, will be observed again in a later example.

Subsequent to this work, the ISMLM code was made part of the Electromagnetic Modeling package, called the ELMOD program. The program consists of 1D and 2D codes that compute the responses of electric logging tools to models of downhole environment. The programs can be run at any Schlumberger Data Services Center or on a Schlumberger VAX workstation. Configurations include induction and laterologs in multiple horizontal beds with borehole and invasion, and induction and CDR Compensated Dual Resistivity logs in multiple dipping beds without borehole or invasion. Other tool environments and fast induction codes are being evaluated for addition to the package. Other codes in this program can be used for dipping bed interpretation.

In the dipping bed interpretation using the ELMOD program, bed boundaries were provided by the Phasor deep induction log, and apparent dip of 38° by the dipmeter log. Discrepancy between the field induction log and initial computed log led to revision of the trial model and a recomputed log (next page, top). This improved the fit, but one more iteration—fine-tuning the shapes of some beds and adjusting for overcompensation—yields an excellent visual match (ELMOD Simulation Three). Although the final model is not a unique representation of...
Modeling simulation using the ELMOD program for interpretation of a deep induction Phasor log in a North Sea well with apparent dip of 38°. The initial trial model was refined in two steps, left to right, until agreement was reached between the model-computed and field logs. Simulation Three was consistent with the log analyst's knowledge of the field.

**Summary of Induction Modeling Programs**

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<th>CPU Time</th>
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</tbody>
</table>

1. Well Logging Technical Report, No. 7. Houston, Texas, USA: University of Houston Well Logging Laboratory, October 30, 1986. These programs are available to supporters of the laboratory, a consortium including most of the major oil companies.
4. IBM 3090
5. VAX 11/780

true resistivity, it was consistent with the analyst’s knowledge of the field, and the predicted water saturations were accorded a high degree of confidence.

Many more computer programs for a variety of electrical logging measurements have been developed by service companies, oil companies and universities. Some are available for commercial use, others only for research purposes (see “Summary of Induction Modeling Programs,” above).
Modeling for Bit Guidance in Horizontal Drilling

Forward modeling is serving needs other than conventional log interpretation, such as guiding the bit while drilling deviated or horizontal wells and evaluating the influence of adjacent (shoulder) beds on horizontal well logs.

Recent modeling studies in horizontal wells make clear that conventional rules-of-thumb don’t apply. Predictions have been made of responses of induction and focused electrode tools to shoulder beds, an important subject when logging thin beds or in horizontal wells exhibiting vertical drift. Because the induction tool is relatively unaffected by the borehole, its calculations were carried out analytically. For the focused electrode tools, however, the borehole is an essential part of the problem, so forward modeling was carried out with a 3D finite-element method (FEM) computation, a much larger enterprise. This investigation concluded that the electrode devices are more sensitive to conductive than resistive shoulder beds, indications of which had appeared earlier, and that the opposite is true for induction tools. This behavior is the reverse of that observed in vertical wells. In the calculated responses of these tools to the boundary between two beds of 1 ohm-m and 10 ohm-m, the characteristic polarization horn is clearly visible on the induction curve (above, right). This horn appears when surrounding beds have high resistivity contrast and the bed boundary dips more than about 45°. It is created by oscillating polarization charges induced at the bed boundary.

Another modeling study explored the effects of dipping beds and laminated formations on induction and CDR tool responses. Since the CDR model assumes point dipoles, the code was first qualified by comparison with exact FEM calculations for horizontal multiple beds and with test tank experiments covering dips of 0° to 90°. This study predicted that both dip and shoulders can cause shallow resistivity, Rps, and deep resistivity, Rpd, to separate, with Rps reading closer to R, Prominent polarization horns appear at high-dip bed boundaries when resistivity contrast is large, and the CDR tool makes resistivity anisotropy apparent (Rps > Rpd), the effect increasing with dip angle.

Oxy USA used forward modeling extensively while drilling horizontally into the Cruse sand in La Salle Parish, Louisiana, USA. To avoid the problem of water coning they had observed in vertical wells, Oxy engineers planned to penetrate horizontally into the top 10 feet [3 m] of the 40-foot [12-m] thick Cruse. Resistivity models of marker beds and of the pay sand itself were created from induction logs in two nearby vertical wells. Then, logs expected in the horizontal well were computed for the CDR tool used in Logging While Drilling (LWD). This 2-MHz resistivity tool provides two outputs: Rps from a phase-shift measurement, and Rpd from attenuation. No one knew accurately in advance what the logs would look like as the well curved through the markers and into the Cruse. In addition, actual borehole inclination is often not exactly as planned. Therefore, prior to drilling, ELMOD's dipping-bed code was used to compute CDR logs expected at several apparent dips. Thus, the right modeled log would be available immediately for comparison with the field log when the actual relative dip became known while drilling.

Since the two CDR resistivity measurements have different depths of investigation, the curves are predicted to separate just


Anderson et al, reference 8.
before the highly inclined tool leaves the cap shale and enters the sand. Also, at the sand's upper boundary, the $R_{ps}$ curve predicts the characteristic polarization horn. This horn is expected to be somewhat broader on the field log than on the computed log because modeling calculations ignore the borehole and the finite size of the tool's transmitter and receiver dipoles. These features are visible on logs modeled for the planned inclination of the borehole (85°) at the top of the target sand, and on actual field logs (below). The boundary of the Cruse is located precisely, confirming that the bit entered the sand at the desired depth.

Modeling played a role in interpreting an unexpected logging observation within the target zone. Differences between shallow and deep CDR readings seemed too large to explain by invasion because CDR measurements are made shortly after a section is drilled. Furthermore, the vertical-well induction logs measured only 4 ohm-m, while in the nearly horizontal well, the CDR deep attenuation measurement approaches 10 ohm-m. In the vertical well, core analysis from the upper part of the Cruse suggested modeling it as a series of high- and low-resistivity streaks. Logs calculated on this model agreed with both the vertical deep induction log and horizontal $R_{rad}$ measurements, confirming that the formation resistivity is anisotropic. This study led to development of a CDR software package that provides continuous logs of calculated horizontal and vertical resistivities, using measured apparent resistivity and relative dip angle as inputs.

How Modeling Calculations Are Carried Out

Prior to starting the modeling process, many analysts apply chartbook corrections to the field log. These corrections make the field log more accurate—closer to $R_p$, for example—and allow the use of simpler models and faster computer programs for modeling. Then, the corrected field log and all other constraining information are used in setting up the initial trial formation model. Less frequently, the uncorrected field log is used, and the burden of accounting for features like borehole, invasion, shoulder and skin effect is borne by the formation model, tool model and computing code. In this case, the environmental corrections are accounted for simultaneously, as preferred, rather than sequentially, as when applying chartbook corrections. Unfortunately, this approach requires large programs and long computer times.

Although further advances in computing power will likely change the picture in the future, current practice usually requires the log analyst to construct an initial trial model and propose changes at each iteration. “Feel” or “intuition” are frequently the basis for doing this, often acquired from field experience or published studies of tool responses to specific environmental features. In the last five years there has been a surge of such studies that, themselves, were...
Purely analytical methods, using exact mathematical solutions, employ codes that run rapidly and require only modest computer memories. This makes them well suited to the small computers readily available to most log analysts, but they are intrinsically limited to simple geometries such as invasion with no layering or layering with no invasion.

From this standpoint, numerical methods are ideal. They break intractable mathematical problems into smaller, more manageable pieces. Numerical methods, such as 2D- and 3D-FEM codes, can solve differential equations in almost any geometry. The FEM is widely used in research and engineering, from the design of automobile bodies to the study of diffusion over corrugated surfaces.

A typical logging application is the numerical solution of Maxwell's equations for induction tools. This problem eventually reduces to solving a (usually) large number of simultaneous linear equations by matrix methods.\(^{13}\) The immediate objective is to find the electromagnetic field's vector potential at the nodes, or intersections, of a 3D grid, in the most general case. Simpler grids (above) can be used in solving axially symmetric (2D) problems. The complete grid may extend hundreds of feet vertically and radially to adequately cover the electromagnetic field. In one modeling exercise, the grid was terminated where the vector potential had fallen 15 orders of magnitude—to zero for practical purposes—from the starting point near the transmitter. Grid size increases with distance from the transmitter in regions where both vector potential and generalized geometric factor are falling slowly. This increases computational efficiency, with negligible loss in accuracy. In 1982, a CDC CYBER 750 computer typically took five hours to compute 25 feet \([7.6 \text{ m}]\) of induction log.\(^{14}\) Today, the whole log takes only 15 minutes on a Cray supercomputer. Most pure FEM codes need a fast vector processor or a Cray unit to run with reasonable turnaround times. Unfortunately, this means interfacing from a remote site, a capability with only limited availability at present.

Hybrid techniques that retain the advantages of both purely analytic and purely numerical methods have been developed. They typically break the problem into two

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### Tool Responses to Environmental Features

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<td>Dip, shoulder radial resistivity variation</td>
<td>4, 10</td>
</tr>
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4. Reference 9, main text.
7. Reference 7, main text.
Comparison of hybrid and finite-element modeling calculations for deep and shallow laterologs. The two methods yield nearly identical logs, but the hybrid calculation uses only one-eighth as much computer time (2 1/2 minutes on an IBM 3081) as the complete finite-element calculation.

Hybrid modeling calculation of deep and shallow laterologs in 25 beds. Calculating time increased to 12 minutes (compare with figures above), but most of the additional time was used in segmenting the log and recombining the pieces, rather than in the computation itself.


A sampling of codes and computer times used in modeling induction tool responses. Dashed boundaries indicate cases for which geometric factor theory was used; solid boundaries indicate use of Maxwell’s equations. Times shown are for 50-foot [15-m] sections of log, where boundaries exist, and for a single-point calculation where one infinitely thick bed is indicated.

Least-Squares and Maximum Entropy Matching Criteria

Subjective eyeballing can usually evaluate the fit between the field log and the modeled log. But two other matching criteria, least squares and maximum entropy (MEM), have received attention. They are of interest, however, more because they use algorithms that converge automatically to their respective best-fitting models than because of their inherent objectivity. No human intervention is needed to alter the model at each iteration. In application, these criteria lead to computational methods that are different from one another and from the manual interactive approach.

One application of the least-squares criterion picks the set of formation parameters that minimizes the sum of the squares of differences (SSD) between the field log and the log derived from the assumed formation model. In the language of statistics, the mean square deviation, or variance, between the two logs is minimized. For example, with initial trial values of thickness and resistivity assigned to each bed in the model, the program computes the predicted log and finds the SSD between it and the

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field log. Then, the model’s bed thicknesses and resistivities are automatically changed to reduce the SSD. This procedure repeats until the SSD converges to a minimum.

Computing time depends, as in other iterative schemes, on how close the initial model log is to the field log. To keep this time short, the user frequently minimizes the number of parameters to be optimized since computing time increases with this number. Also, if some parameters “interfere” with one another—produce similar effects on the log—their precision is adversely affected even though they are optimally determined in the least-squares sense.

Consider an application of the least-squares method to a set of simulated logs (right). The initial trial model used parameter values estimated by a standard interpretation. Because flushed zone resistivity, $R_{w0}$, values were assumed known from the MicroSFL resistivity tool, the modeling program was called upon to determine the pay zone thickness in addition to $R_t$ and invasion diameter in each of the three beds. This early-1980s calculation took 20 minutes on an IBM 360, using FEM. Today it can be done on a workstation in under 60 seconds.

The maximum entropy criterion comes from Shannon’s information theory and has been used for reconstruction of blurred satellite photographs and for extracting signals from noisy data. It leads to a different method of calculation\(^\text{17}\) although the method bears some similarity to the least-squares approach—differences between field log and modeled log are used in calculation of $\chi^2$, a quantity related to the SSD. With respect to the use of $\chi^2$, the maximum entropy method can be considered an extension of the least-squares approach. The actual algorithms employed reduce $\chi^2$ iteratively, while maintaining entropy close to its maximum at each iteration. This procedure selects the unique least-squares solution having maximum entropy.

There is an important difference between the MEM and least-squares methods. The final model selected by the MEM is the smoothest possible profile rather than the one that yields a minimum SSD. Of all possible models, it is the one that has minimum information content (in the information-theory sense) consistent with the field log. Consequently, this criterion inhibits the appearance of artifacts that sometimes show up when using the least-squares method. Unfortunately, the MEM is computationally expensive. The cost is reduced if a priori knowledge of bed boundaries is included in the initial model, as with other methods, but cost remains the main impediment to wider MEM use at present.

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Nevertheless, the MEM can provide a form-

mation model from an induction log, with-

out assuming knowledge of bed boundaries (left). The synthetic “field” log was calcu-

lated by applying geometric factor theory (for simplicity) to the $R_t$ distribution shown, and geometric factor theory was thus used in representing tool response in the forward modeling. Oscillations visible in the thicker beds are not a consequence of the MEM, but result from so-called blind frequencies in the Fourier spectrum of the deep induction’s VRF. These oscillations are readily suppressed by adding information from the medium induction. Addition of the medium induction contributes a smoothing effect. An actual example shows how well an MEM-predicted log matches its corresponding field-measured induction (below, left).

The Future
Further developments in modeling are already in the pipeline. Generally, these take two forms, depending on the computation size envisioned. One effort is aimed at providing a computed log in about one minute, using interfaces that are suitable for workstations. These should make the process more analyst-friendly, through features like entry of parameters in graphical format and windows that display the field log, the computed log and the model, including its parameters, dips and boundaries.

The other development arena involves extending the capabilities of large computers. Primarily intended for use in tool design, these studies are deep into the 3D domain, using the FEM for modeling computations that take hours even on a supercomputer. Still more exploratory are investigations of advanced algorithms and automatic code generation for speeding up complex calculations. Some algorithms are being applied in commercial seismic processing using parallel computers like the CM-2 Connection Machine. —JT

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**Oklahoma Formation**

A deep induction field example comparing the log computed by the maximum entropy method with the measured log. The predicted final-model profile is also shown.
Mixed-Terra 3D Seismics in The Netherlands

3D seismics is an exploration technique that improves the success ratio of wildcat wells. Cost-efficient at sea and on land, it has also proved its worth in mixed terrains. This article describes the planning, acquisition and processing of perhaps the most difficult 3D mixed-terrain survey ever made.

Since the late 1970s, the exploration and production company Nederlandse Aardolie Maatschappij b.v. (NAM), jointly owned by Shell and Exxon, has been systematically acquiring three-dimensional (3D) seismic coverage of its Dutch concessions. Most of these surveys have been for exploration, a pioneering trend when the surveys were begun—3D seismic technology was initially heralded as a tool for improving reservoir characterization. But the financial risks have paid off. In 1988, 12 of NAM’s 15 exploration wells struck pay, an astonishingly high proportion.1

The terrain has not been easy. The people of the Netherlands not only have harnessed every square meter of their land for urban, agricultural or industrial use, but through dyke building have steadily claimed vast areas of subsea land called “polder.” The

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Aerial view of the Europort near Rotterdam, with 3D seismic survey grid superposed—distance between lines is 400 m. The grid indicates the ideal shooting and receiving positions. In practice, equipment has to circumvent obstacles. Additionally, the survey has to cope with the ever-changing terrain, from water to land and back again. The 15-km by 25-km survey took 6 months.

Carsten Petersen
Assen, The Netherlands

Horst Brakensiek
Markos Papaterpos
Hannover, Germany
The survey area measures about 15 by 25 kilometers [9 by 15 miles] and is composed of five types of terrain. The southwestern section comprises mainly farmland. This is bordered to the north by the Eurowest with its web of canals through which about 200 large boats, for example oil tankers, and numerous smaller vessels ply daily, and the largest conglomeration of refineries in Europe. The eastern section covers suburbs of Rotterdam. To the northwest is again farmland, and then an area of land, 9 by 9 km [6 by 6 miles], entirely covered in greenhouses. Northwest of the greenhouses is beach, protected as a wildlife sanctuary. If that were not already daunting enough, the countryside is crisscrossed with canals, large and small. Densely populated, the complex terrain provides endless challenge to the versatility of seismic crews as they coordinate complex shooting configurations.

NAM’s progress has been steady. Thousands of square kilometers of land and nearshore coast have been surveyed using 3D techniques. The work has concentrated in two main areas, in the northeast of the country including the giant Groningen gas field, and in the southwest, in and around the cities of Rotterdam and The Hague (left).

The southwestern area is particularly challenging for both acquisition and processing. Some of the surveys have to contend with a mix of near-shore marine areas, harbors, urban sprawl, sections of land covered in greenhouses, and farmland. Typically, three different sources are used—airguns, dynamite and vibrators—and two types of receivers—geophones and hydrophones. The several combinations of source and receiver produce seismic traces that require careful phase correction during processing.

In addition, the processing must contend with very difficult statics. Statics describes the time correction that must be applied to each individual trace to neutralize the effect of the unconsolidated weathering layer. In the Rotterdam area, the weathering layer varies dramatically in both thickness and acoustic velocity—two key controlling parameters—from one geophone station to the next.

Despite these problems, 3D surveys here have yielded valuable results. NAM reports identifying potential pay and then drilling a discovery well beneath the Shell refinery in the Europort, Rotterdam. This article describes the seismic acquisition of one of the last pieces of the puzzle for this southwest survey area by PRAKLA in 1990/91 and accompanying processing challenges.

Planning

The survey area measures about 15 by 25 kilometers [9 by 15 miles] and is composed of five types of terrain. The southwestern section comprises mainly farmland. This is bordered to the north by the Eurowest with its web of canals through which about 200 large boats, for example oil tankers, and numerous smaller vessels ply daily, and the largest conglomeration of refineries in Europe. The eastern section covers suburbs of Rotterdam. To the northwest is again farmland, and then an area of land, 9 by 9 km [6 by 6 miles], entirely covered in greenhouses. Northwest of the greenhouses is beach, protected as a wildlife sanctuary. If that were not already daunting enough, the
The last group to be approached, perhaps one month before the survey reaches their land, is the farmers. To defuse tension that may arise when geophysicists deploy equipment and explosives on valuable farmland, NAM and the Dutch farmers’ union have agreed to a third party performing farm permitting. Farmers are an important group to maintain good relations with—NAM surveys touch up to 20,000 farmers every year. A must be bent and squeezed to get around them, but the new grid must also satisfy the environmental and safety concerns of municipalities, private companies, landowners and the public. Three months before the survey begins in a particular area, NAM contacts the various state authorities to obtain permission to conduct the survey and discuss these matters. Simultaneously, a representative of the survey contractor, called a permit man, contacts the private companies—there were over 50 major companies in the refinery area alone.

The overall planning therefore took shape as follows: The survey party would begin in easy territory in the farmland in Block 1. They would then move up to the harbor area at the top of Block 1, gaining wider experience with an increasingly large array of equipment. Flexibility was to prove the key to accomplishing the difficult stages to schedule, and this early training period proved essential for party members to gain familiarity with all types of equipment.

During the summer, the survey would then move to Block 2 and survey the mouth of the port and its beach area. Toward autumn, the party would split, with a smaller group surveying the beach and adjoining offshore area in Block 3 and the majority of the crew deployed in Blocks 4 and 5, the remaining harbor area and the Rotterdam suburbs. As winter approached, the crews would recombine to survey the farming area of Block 6 and then finish with the greenhouses in Block 7 (above, right).

Once the overall sequence was established, detailed arrangements could begin. Consistent with earlier surveys, the 3D survey was to map the subsurface with an areal resolution of 20 m—that is, the survey area was subdivided into a mosaic of bins, each measuring 20 m by 20 m (see “Conversion Glossary, right). This coverage is obtained by arranging source rows and receiver lines on a much coarser grid measuring 400 m by 400 m. A grid this size was therefore superimposed on the map.

The coarse grid provides the ideal positioning of sources and receivers arranged along the vertical and horizontal lines of the grid respectively. In reality, of course, obstacles of all kinds stand in the way. The grid must be bent and squeezed to get around them, but the new grid must also satisfy the environmental and safety concerns of municipalities, private companies, landowners and the public. Three months before the survey begins in a particular area, NAM contacts the various state authorities to obtain permission to conduct the survey and discuss these matters. Simultaneously, a representative of the survey contractor, called a permit man, contacts the private companies—there were over 50 major companies in the refinery area alone.

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A farmer’s working life is constantly being adjusted to accommodate the weather, and as a result seismic crews have to do likewise. A string of geophones laid across a field one day may have to be relocated to the edge of the field the next because the weather changes and potatoes have to get planted.

Throughout the planning and even during the survey, all participants from the individual farmer to the major corporation require constant liaison. Videos are shown to harbor officials explaining how seismic surveys work, demonstrating the need for their participation to ensure contractor boats do not tangle with supertankers; mayors must be reassured that vibrating trucks will leave street surfaces as they found them.

Slowly, deviations from the ideal grid are agreed upon by all parties and a realistic survey plan takes shape. Generally speaking, sources are more of a problem than receivers. Unless an obstacle is truly insurmountable, organizations and landowners tolerate placement of hand-sized geophones where the grid stipulates. Sources on the other hand require relatively large equipment and usually cannot be constrained to the grid (left). An exception is in the water, where airguns carried on pontoons can get to any location once shipping has been accounted for. A team of four vibrator trucks, used in urban areas at night, has to stick to roads. And explosives, used in the fields and—yes, in greenhouses—suffer their own special restrictions.

All the while, surveyors must keep track of every relocation of a source or receiver. Moving source locations from their ideal position raises the issue of how one ensures an even coverage in each 20-m by 20-m bin. But this begs the more basic question of how sources and receivers arranged on an ideal 400-m by 400-m grid provide the required 20-m by 20-m coverage. Let us answer the last question first.

Three-dimensional land seismics are usually performed with receivers laid along several widely spaced parallel lines and shooting points distributed along a line orthogonal to the receivers (next page, top). In the Rotterdam survey, 480 receiver groups were distributed along four lines, 120 groups per line, each group comprising several geophones or hydrophones connected in series to boost signal at the expense of noise. Shots were fired sequentially at ten equally spaced stations between the two middle receiver lines.

This configuration provides 4800 seismic records, whose reflection midpoints define the rectangle of coverage. To get the requisite coverage, that is putting a midpoint in...
each 20-m by 20-m bin, the spacing between successive receiver and source positions has to be twice 20 m, or 40 m. This means that the distance between receiver lines, equal to ten source points, has to be 400 m and each receiver line is 4.8 km long. At any moment, the survey team is therefore deployed over a 4.8-km by 1.2-km area, shooting ten positions between the two middle lines (below). The rectangle of coverage measures 2.4 km long by 0.8 km wide.

Once the ten shots are complete, the survey then steps either right or left, and the entire process is repeated. This provides a similarly sized rectangle of coverage overlapping the previous one and creating a swath of coverage 0.8 km wide. The logistics of stepping are relatively simple because most of the receivers can remain in place. Just a few groups must be added to the advancing end of the four receiver lines, while those on the receding end are picked up and transported ahead for future use.

When the survey reaches the edge of the survey area, the entire top or bottom receiver line is picked up, and relaid the other side of the remaining three lines. Shooting then recommences in the middle of the new configuration and the survey progressively steps in the opposite direction. This provides another swath of overlapping coverage that overlaps the previous swath. Every point on the ground gets covered by just two swaths.

NAM stipulated a fold of 12, so every point on the ground had to be covered by six overlapping rectangles in a given swath. Since each rectangle measures 2.4 km long, the stepping distance therefore had to be 2400/6 = 400 m. This explains the coarse 400-m by 400-m survey grid. Now for the original question: How does the survey team allow for shot point deviations from the ideal grid?

The solution follows the principle that when a source is moved left or right from its proper position, reflection points remain unchanged if receivers are moved an equal distance in the opposite direction (below). In practice, receivers are not moved at all. The source is moved in 40-m increments orthogonal to the shooting line or parallel to the receiver lines. The receivers can then be reconnected at the recording truck to simulate physical relocation by the requisite number of 40-m steps. Each of these manipulations is worked out in advance from the detailed planning and performed without interrupting the day’s schedule.
Seismic equipment worth $20 million, 137 personnel, 88 vehicles and over a dozen vessels were needed to conduct NAM's 3D mixed-terrain survey. The 6-month operation was completed without accident.

A variation of this technique, called undershooting, solves the problem of being unable to shoot in extensive areas that vibrators cannot access or where dynamite is prohibited (left). In these cases, source positions are shifted to an adjacent 400-m block in the direction of the source line and shooting takes place during the previous or following swath when the receiver lines are also effectively shifted by one 400-m block. Undershooting ensures full coverage in the most complex areas.

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</table>

Seismic undershooting used when extremely large obstacles prevent shooting anywhere near the required grid position.
Execution
The physical reality of recording swaths of 12-fold coverage across harbor, urban environment and farmland amounts to a platoon of men and equipment, trained for peak efficiency (previous page, below). One hundred and thirty-seven men headed by a party chief included seismologists, recording teams, shooters, drilling teams, dynamite crews, cable support groups, maintenance and administration. But the crew could not be constrained by labels. Everyone worked at several jobs to maintain the flexibility the mixed terrain demanded.

To get around on land, the crew logged 400,000 hours driving 2 recording trucks, 2 explosive trucks, 59 light trucks, 6 liaison vehicles, a mobile workshop, 6 vibrators and 12 small drill rigs. Specifying a parking space at PRAKLA’s base for each vehicle represents a trivial yet significant example of the organization required to keep track of the vehicle population and ensure its efficient use.

At sea and in the harbor, there was a shallow-water survey vessel, the S.V. Solea, two very shallow-draft airgun poppers—the Sara Maatje and a specially constructed pontoon that could turn on its axis—and a small flotilla of chase and supply boats. The shallow-draft poppers can operate in only 75 centimeters of water, eliminating the use of explosive, a boon to the local fish population (above). Explosives can kill fish because the high-frequency content of the explosion excites natural oscillations in their air bladders destroying their buoyancy control. Airguns, on the other hand, have been shown not to harm fish.

To record the survey, the party deployed equipment worth $20 million: 1700 field station units—compact, weatherproof boxes that digitize the seismic signal from a group of receivers and on command transmit the data to the recording truck—316 miscellaneous electronics packages such as power units and repeater units, 1700 spread cables used to connect the field station units to the recording truck, 66 bay cables—weighted hydrophone streamers for laying across the bottom of waterways crisscrossing the survey area—and 20,400 geophones.

Essential to the survey was simultaneous deployment of marine and on-land equipment—the shooting area of 4.8 km by 1.2 km frequently covered both shipping lanes and the bordering land. Activity in the water had to be coordinated with the harbor authorities and police, to avoid shipping. Often both airgun poppers were deployed to save the time just one would have taken to negotiate the maze of shipping docks.

Bay cables, however, were the worst problem (left). Easily shifted from their original locations by tides or the hefty wake of a supertanker, they were also cut by boats setting anchor to aid maneuvering in tight spaces. Practically none of the 66 bay cables was serviceable at the end of the survey. Because of bay cables being cut and also because of the generally complex terrain, two recording trucks linked to different segments of the receiver lines and operating in synchronization offered a recording versatility and speed that would have been impossible using the usual one.

Despite the extreme complexity of the survey, no accident marred the 174-day operation. Both NAM and PRAKLA certainly did not stint on attention to safety procedures. In the refinery area, for example, the survey team had to learn and adhere to
each refining company’s separate in-house safety code. Equally, the survey team had to maintain safety standards of subcontractors— for example, pilots hired to help lay bay cables. Safety would always be on the agenda of the daily morning briefing sessions when plans for the next 24 hours would be firm up.

Environmental concerns were also ever present, particularly in the farmland and greenhouses where the crew used explosive as seismic source. Being reclaimed land, most of this area averages an elevation a few meters below sea level, and shot holes drilled conventionally for explosive would have flowed water and possibly contaminated the surrounding land.

The solution was to create holes without water circulation, by pushing or hammering drillpipe to a depth between 12 and 20 m and using a disposable aluminum point attached to the bottom of the drillpipe to facilitate penetration into the earth (below). The explosive charge was then inserted down the drillpipe, followed by cardboard tubes filled with bentonite clay. As the drillpipe was pulled out of the ground, the cardboard tubes remained in the hole gradually filling with ground water. This swelled the bentonite, sealing the hole from the environment and as a bonus providing perfect tampering for detonation.

Further precautions were required to protect the sterile growing environment of the greenhouses. To avoid tramping in unwanted microbes and bacteria, the crew were obliged to don white surgical coats and clean boots (below).

A critical part of the operation was providing overlapping coverage with GECO’s marine survey. This was carried out in stages that covered progressively shallower water (next page, top). First came GECO’s survey using deep-sea vessels that could approach the shoreline to almost 10-m water depth. Then, PRAKLA deployed the S.V. Solea, a shallow-water survey boat with a draft of only 1.3 m. Towing a 1800-m streamer equipped with 72 hydrophone groups spaced every 25 m, the S.V. Solea continued coverage to around a 2-m [7-ft] water depth and also in an area of sea near a long breakwater that GECO’s larger boats with longer streamers could not negotiate.

Finally, the shallowest water up to the beach was surveyed by laying geophone cables along the beach and using the pontoon to air-pop along orthogonal shooting lines in the water. This provided coverage up to the conventional land survey. As much as possible, the crew limited activity to high tide so the pontoon could get as close as possible to the beach area.

Coverage and data quality are the key ingredients of a successful survey. The even coverage of the PRAKLA survey, both at sea and on mixed terrain, attests to thorough planning and execution (next page, bottom). Thereafter, it is up to data processors to create order in the millions of records and through exquisite manipulations of deconvolution, stacking and migration form an accurate, focused picture of the subsurface.
Ensuring coverage in the near-shore area where GECO’s deep marine survey abutted PRAKLA’s mixed-terrain survey. The transition zone was surveyed in four stages moving from sea to land. First the deep sea survey, then a shallow water survey using the shallow-draft S.V. Solea, then very shallow water coverage using an airgun popper in the surf and geophone lines spread on the beach, and finally the land survey.

Binning maps showing abutting coverage in the two main surveyed areas—the 15-km by 25-km mixed-terrain area and a shallow-marine area in the northwest that links with a deep-marine 3D survey conducted by GECO.
Processing
This survey posed two special challenges for processors: correctly assessing the effect of the weathering layer, in a series of processes called statics correction, and accounting for the different source signatures of airguns, dynamite and vibrators. It was decided that differences between geophone and hydrophone responses were too small to have a noticeable effect and were ignored.

The goal of statics correction is to time-shift every trace so the entire survey looks as though it was made from a depth datum situated in consolidated rock somewhat below the weathered layer. This removes the effect of surface topography and travel time in the weathered layer which often varies greatly on land. Without statics corrections, land seismic sections often have a choppy appearance, with reflectors showing poor or no continuity. Applying the time-shifts restores continuity.

The essentially flat topography of the Rotterdam area poses no problems, but the weathered layer is complex (below). Near the shore, at least two layers must be considered, dunes of dry sand with low velocity lying on top of wet sand with high velocity. Farmland often sits on peat that has very low velocity and varies unpredictably in thickness, up to 10 m [33 ft] thick. The shipping channels appear to have eroded all trace of the weathering layer where water depth exceeds 10 m. In the refinery area built on reclaimed land using rubble from World War II bombing, the surface layer is fast, but there may be underlying weathering material of much lower velocity.

How does the crew go about measuring the weathering layer’s velocity and thickness? Several approaches must be used together. One is the refraction survey, a miniature seismic survey designed to catch only energy that is reflected from the base of the weathering layer or refracted along it. Suitably plotted, this information can yield the required velocity and thickness. In the countryside, a small explosive charge set in a hole 2 to 3 m deep provides the energy, and a geophone array comprising 24 geophones spread over about 100 m [328 ft] picks up the signal. The entire operation is conducted by a specialized crew of four who manage perhaps four or five surveys a day, about two for every square kilometer of the main survey (above). In urban areas, explosive is ruled out so PRAKLA devised a small truck-conveyed hammer drop as an alternative source, essentially a large weight
dropped from a height of 2 m onto a base plate placed on the ground. In water, refraction surveys are ruled out.

Weathering information is also obtained at every shot point in the main survey that uses explosive. Shot holes are usually drilled to just below the weathering layer, so placing a geophone near the top of the hole automatically measures the travel time through the layer. Additional data come from picking first breaks on every recorded trace in the main survey, a Herculean task that is simplified by semiautomatic picking programs functioning on workstations. A first break indicates the first reflecting interface, presumed to be the bottom of the weathering layer.

Initially, NAM hoped to interpolate weathering zone thickness and velocity across the survey area from information derived from refraction surveys. But this failed to adequately describe the weathering zone’s extreme variability, and the resulting statics corrections failed to pull reflectors into line. The first-break picking method was then employed to fill in detail.

Two steps in the processing chain are actually required to complete the statics correction. The first, called field statics, uses all the available data on the weathering layer described above to perform an initial normalization of the traces to a datum. This improves reflector continuity. But because of inherent uncertainty about the weathering layer, choppiness in reflector continuity often remains. This must be eliminated in a second step called residual statics, in which adjacent traces in a gather are cross-correlated and then shifted to improve continuity for reflectors judged to represent continuous interfaces in the subsurface. Statics correction is the single most important step in processing the data from the Rotterdam area, as these results demonstrate (below, left).

The second processing challenge was matching data recorded using three different types of sources. This is necessary because each source type has a distinct signature. An explosive source provides the sharpest pulse of acoustic energy. The airgun’s signature may contain small reverberations due to the bubble oscillating as it rises to the surface. In practice, several airguns are used together and tuned to eliminate the bubble effect.

Vibrators sweep through the seismic frequency spectrum and produce records that must be convolved with the sweep to pro-

duce a usable trace. The vibrator’s effective source signature differs from the other two in that it is zero-phase, meaning that it is symmetrical about time zero, the effective time of shooting. The other two are minimum phase—nothing before time zero but then as much energy as possible immediately afterward (below).

Matching sources amounts to converting the minimum-phase traces produced by explosive and airgun to the zero phase of traces produced by vibrators, the approach favored by NAM, or conversely converting the vibrator traces to minimum phase. In each case, the match has to account for the detailed differences in source signature, even between dynamite and airgun, and also the filtering effect of the recording instrumentation. If the processing proceeds in minimum phase, the results are generally transformed to zero phase right at the end. This maximizes the resolution of the seismic image. Comparing the difference between results obtained from a section surveyed in the southeast corner of the survey area and processed with and without matching sources attests to the importance of source matching (below).

Achieving successful acquisition and processing in this difficult terrain did not happen overnight. The Dutch PRAKLA crew progressively gained experienced in complex environments over several years, and NAM has been forthright in its help, advice and encouragement. In the future, acquisition will ease with the introduction of adaptable telemetry systems that permit the elimination of cabling where needed, simplifying logistics on the ground. —HE

Without Source Matching

With Source Matching

A section from a neighboring survey in the Rotterdam area before and after source matching, showing superposed reflectors obtained from processing data obtained with three different sources—dynamite, airgun and vibrators. Before matching, reflectors superpose poorly. After matching, reflectors superpose well, as evidenced by the increased black in the section.
Interest in drilling slimhole wells with coiled tubing is high. So far, only a few experimental wells have been drilled and many technological issues remain unresolved. But if these challenges are met, coiled-tubing drilling could become the medium that finally delivers slimhole wells across the industry.

In recent years, workover and logging using coiled tubing has become increasingly widespread (above).1 During workover operations, coiled tubing has been used successfully to drill out cement plugs and remove scale—in most cases harder to drill than formation. Now attention is focused on coiled-tubing drilling as a technique to deliver cost-effective slimhole wells for both exploration and production.2

Slimhole wells are normally defined as having at least 90% of their diameter less than 7 in. They are drilled using rotary rigs that are much smaller than normal rigs—about 20% of their weight, requiring about a quarter of the drill site area. Over half of drilling costs depend on factors other than drilling time, such as construct-

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1. For details of coiled-tubing hardware and its applications to workover and logging:

ing the drill pad and access roads, moving the rig, and the cost of casing and consumables like mud. A coiled-tubing unit (CTU) is even smaller than a slimhole rig, is easier to mobilize and requires less equipment and personnel. Its smaller site requirement leads to lower civil engineering costs. The smaller, quieter CTUs have a reduced environmental impact.

There are also particular benefits offered by use of continuous tubing. It avoids the need for connections, speeding up trip times and increasing safety—many drill floor accidents and blowout/stuck-pipe incidents occur when drilling is stopped to make a connection. CTUs have pressure control equipment designed to allow the tubing to be safely run in and out of live wells. The stripper above the blowout preventers (BOPs) seals the annulus during drilling and tripping. This offers increased safety during drilling—similar to having a conventional rig’s annular preventer closed all the time. This safety feature also facilitates underbalanced drilling, in which drilling is carried out while the well is flowing.

A range of different uses has been proposed for slim holes drilled by a CTU (right). So far, lateral production and vertical re-entry wells have been drilled. These experimental wells were designed to prove that the technique can effectively meet design specifications.

Three re-entry horizontal production wells have been drilled in the Austin chalk, Texas, USA, using 2-in. directionally-controlled coiled tubing with 37/8-in. bits. In an effort to prove the efficacy of coiled-tubing drilling for exploration, a vertical well was deepened in the Paris basin, France, using 11/2-in. coiled tubing with 37/8-in. bits. This was also a re-entry, but a new vertical well is also planned.

This article reviews one of the Austin chalk wells and the Paris basin well. Then it will look at the technological challenges arising from these experiences.

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**Lateral Re-Entry for Production**

Last year, Oryx Energy Company re-entered a vertical well in the Pearson field, Texas, USA, completed in Austin chalk. Horizontal drilling in Austin chalk using mud commonly encounters almost total lost circulation. To reduce mud losses, formation damage and costs, water is often used as drilling fluid. This decreases bottomhole hydrostatic pressure to less than formation pressure—underbalanced drilling. To combat annular pressure from formation flow during drilling, conventional rigs use a rotating stripping head or rotating BOPs to seal the annulus. The wells are killed each time a trip is made.

By using a CTU, which has its annulus sealed throughout drilling by the stripper, Oryx was able to run in and out of hole without killing the well. This improved safety and avoided the expense and potential damaging effects to the formation of pumping brines to kill the well prior to tripping.

To prepare the well, Oryx used a conventional service rig to remove the existing completion hardware, set a whipstock and sidetrack out of 4 1/2-in. casing at a true vertical depth of 5300 ft [1615 m]. Drilling was then continued using 2-in. coiled tubing, downhole mud motors, wireline steering tools, a mechanical downhole orienting tool and 3 7/8-in. bits. An average buildup rate of 15°/100 ft [15°/30 m] was achieved and a horizontal section drilled for 1458 ft [444 m]. The main bottomhole assembly (BHA) components were:

**Drillstring**—Oryx employed a reel comprising 10,050 ft [3060 m] of 2-in. outside diameter coiled tubing with 3/8-in. mono-conductor cable installed inside the tubing.

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Orientation tool—Because coiled tubing cannot be rotated from surface to alter drilling direction, a downhole method of changing tool face orientation is needed. To achieve this, Oryx deployed a mechanical tool that converts tubing reciprocation into rotation—compression rotated the tool face to the right, extension to the left. Once adjusted, the tool face was locked in place using a minimum 250-psi differential pressure across the tool.

Directional survey tool—The survey tool inside a nonmagnetic collar relayed directional information to surface via the wireline.

Directional BHA—Two assemblies were used, depending on the build rates required—a double-bend assembly consisting of a conventional 2⅞-in. bent housing mud motor coupled to a single bent sub, or a steerable assembly comprising a single-bend motor.

Bit—Thermally stable diamond bits were used to drill the curve and build sections and polycrystalline diamond compact (PDC) bits to drill the lateral section.

Oryx’s motive for drilling this well was to prove that coiled tubing could be used to drill a lateral well in a controlled manner. This was achieved—the final wellbore trajectory came within a 50-ft [15-m] vertical window along the horizontal section (above).

Because this well was the first of its kind, new techniques had to be developed, and much of the drilling equipment had to be adapted from existing conventional hardware. Orienting the tool face was not difficult, but maintaining it was hard because of the unpredictable reaction of the coiled tubing to the torque generated by the drilling motor’s rotation. Drilling was also slowed by failure of BHA components, particularly the orienting and directional survey tools.

These difficulties affected the final cost analysis. Total cost was estimated by Oryx at twice that of using a conventional rig—nondrilling time was responsible for nearly 40% of this (below). However, as purpose-designed equipment becomes available and drilling procedures are refined, coiled tubing should deliver more cost-effective, slimhole, lateral wells.

**Vertical Exploration Well**

Last year, Elf Aquitaine embarked on a series of trials to determine whether coiled tubing could be used to drill slimhole wells, cutting exploration drilling costs. The goal of the first well was to demonstrate that a CTU can drill a vertical well sufficiently fast, cut cores and test formations. Elf envisions initially drilling these slimhole wells with a single openhole section—avoiding the need for casing—with the surface casings set using low-cost, water well rigs.

This first trial involved the re-entry of well Saint Firmin 13 in the Paris basin. The plan was to use the CTU to set cement plugs across the existing perforations at 2120 ft [646 m] and then drill a 2105-ft [642-m] vertical section of 3⅞-in. diameter. Directional measurements using a coiled-tubing-conveyed survey were to be taken every 500 ft [150 m]. Then a 50-ft interval was to be cored and logged. Finally, a zone was to be flow tested by measuring pressure between two straddle packers.

The trial was carried out by Dowell Schlumberger using a trailer-mounted CTU with a reel of about 6000 ft [1830 m] of 1½-in. tubing. To avoid the need for costly modifications, standard surface hardware, like injector head with stripper and BOP stack, were used. A workover rig substructure was installed over the existing wellhead to act as a work platform.

The operation encountered difficulties at the outset—not with the drilling but with the integrity of the well’s 30-year-old casing. After cement plugs were set, the well would not hold the 360 psi above hydrostatic pressure required to withstand the anticipated formation pressures. Because of this, drilling depth was limited to 2955 ft [901 m] which allowed limestone coring but did not extend to a high-pressure aquifer.

The drilling BHAs employed a high-speed, low-torque motor with PDC bits. For coring, a high-torque motor was used. The drilling and coring assemblies were made to hang vertically by incorporating heavy drill collars into the BHA, creating a pendulum assembly. At the start, the deviation at the casing shoe was 2° and, as expected, the BHA did not build angle—at 2362 ft and 2795 ft [720 m and 852 m], the deviation angles were 2⅞° and 2⅞° respectively. During drilling, the rates were comparable to those drilled by conventional rigs at work in the area. This showed that a CTU can drill vertical wells at commercial rates. Two cores were cut and retrieved with good recovery—meeting the second objective of the trial.
Because the program had to be revised to avoid high-pressure zones, no oil-bearing formation could be tested. To prove the testing technology and meet the third objective, a drawdown test was carried out on a zone between 2221 ft and 2231 ft [677 m and 680 m]. The FSTS Formation Selective Treatment System was deployed with its two packers straddling this zone. The formation was successfully isolated and, if it had been a reservoir, would have produced into the coiled tubing (above).

Looking to the Future
In addition to proving that coiled tubing can be used to drill wells, the trial pointed out how procedures could be changed and where future hardware development is required. For example, rate of drilling could be increased by incorporation of measurement-while-drilling tools to make directional surveys, improving surface handling and weight-on-bit (WOB) control techniques and better optimization of the BHA.

To address these issues, Dowell Schlumberger has assembled a multidisciplinary task force with Sedco Forex and Anadrill. Its wide-ranging agenda covers equipment needs, operational and safety procedures, tubing limits and personnel requirements.

Equipment needs—The Elf job utilized a workover rig substructure. In the future, a purpose-built substructure will be employed. Standing 10 ft [3 m] off the ground and over the wellhead, this substructure will act as the drill floor to make or break the BHA and also to support the injector head.

The BOPs will be mounted below the injector head directly on top of the wellhead, casing or christmas tree. If the hole diameter is less than 4 in. [10 cm], 4 1/16-in., 10,000 psi coiled-tubing BOPs will be used. If the hole is larger, a standard set of 7 1/16-in., 5000 psi drilling BOPs will be used instead. In both cases an annular preventer will also be incorporated into the stack (below and next page, left).

In the directional wells drilled so far using coiled tubing, BHA direction has been altered using reciprocation of an orienting tool. This technique has the dual disadvantages of interrupting drilling and requiring manipulation with pressure in the tubing, which has a severe fatiguing effect. The task force has therefore designed BHAs that incorporate an orienting tool controlled by using mud flow rate.

Directional information can be sent to surface either using wireline or mud-pulse telemetry. Wireline offers real-time transmission of high volumes of information. How-
ever, having wireline in the tubing requires a high level of maintenance and cuts down pumping options—like acidization treatments. To avoid the need for a cable link, the task force has adapted Anadrill’s SLIM1 measurement-while-drilling system—which uses mud pulse telemetry—so that it fits inside a 3\(\frac{1}{16}\)-in. diameter nonmagnetic drill collar (right).

The chemistry of muds used when drilling with a CTU is not expected to be significantly different from muds used in conventional wells. However, the technique does have some special rheological requirements. In a re-entry well, the coiled tubing/casing annulus may be relatively large—perhaps 2 in. inside 7 in.—slowing the annular velocity of the fluid and possibly compromising the cuttings-carrying capacity of the mud. Further, because the fluid is pumped through small-diameter tubing, friction must be kept to a minimum by using low solids muds with low viscosities and yield points. To mix and treat drilling
Comparison of gas kicks in 5000-ft wells drilled using coiled-tubing and conventional methods with 3 1/8-in. and 6 1/2-in. BHAs, respectively. SideKick software was used to compare the effects of influxes that gave similar annular heights. In both cases, the driller’s method was used to circulate out the kick, during which casing shoe pressures were about the same. Because of its smaller annular volume, the well being drilled by CTU experienced much smaller pit gains.

When drilled with a CTU, the annulus is larger—particularly in re-entry wells—ECD is not a factor and dynamic kill cannot be applied. To evaluate other well-kill strategies, the task force used SideKick software to model gas influxes in a full size well being drilled conventionally and a slimhole well being drilled by a CTU.8

The SideKick model was used to assess the significance of the volume of influx. First, it modeled influxes that gave comparable heights of gas in conventional and coiled-tubing annuli (about 7.5 and 3 barrels, respectively). The shut-in casing pressure (SICP) at surface and the casing shoe pressure (CSP) were broadly similar in both wells (left). But in modeling an influx of 7.5 barrels in the slim and conventional annuli, the SICP and CSP in the coiled-tubing well were much higher—double or more.

Therefore, early detection of gas influxes during coiled-tubing drilling is vital. The CTU’s stripper seals the annulus and ensures that the mud return line is full, improving the reliability of delta flow measurements—the difference between mud flow rate in and out of the well. Delta flow is measurable down to 10 gal/min [0.8 liter/sec], permitting rapid detection of kicks after allowing for the volume increase due to cuttings. In the mud pits, resolution of conventional level sensors is improved by having mud tanks with a smaller base area than is normal.

All drilling operations are subject to safety regulations limiting operational equipment to zones—in Europe, Zone I allows only the most stringent explosion-proof equipment, Zone II the next most, and so on. Ironically, the compactness of a CTU complicates compliance with these regulations.

In the Paris basin well, the Zone II classification was specially reduced by the authorities from a 100-ft to a 50-ft radius from the wellhead. If the radius had been any larger, it would have extended the zone’s requirements to the cars on the edge of the lease (next page). Changes in local regulations and in equipment classification may be required in the future.

Tubing limits—Coiled tubing had a slow start as a workover service because of unreliability and propensity for unpredicted failure. To combat this, Dowell Schlumberger has developed a better understanding of the factors governing tubing fatigue; this is now being applied to drilling operations.9

Repeated use of coiled tubing has three types of limitation:
• Pressure and tension limits—the burst and collapse pressures and the maximum tension and compression at various pressures. These are analogous to the limits experienced by drillpipe and can be calculated through tests and carefully avoided during operations.

• Diameter and ovality limits—the degree to which the pipe is collapsed, ballooned or mechanically damaged. This also has an analogy in drillpipe where damaged pipe and couplings have to be detected. With coiled tubing, the physical shape of the tubing can be continuously monitored during the job to detect damage.

• Life limits—primarily due to bending in the pipe at the gooseneck and on the reel as it is spooled on and off, often with the tubing pressured. Anticipating life limits of tubing has proved difficult, but is vital to avoid catastrophic failure. At its crudest, the fatigue of a reel of tubing can be equated to the number of times it is run into and out of the well—termed cycles. After extensive research, Dowell Schlumberger has developed a way of assessing coiled-tubing fatigue that is more sophisticated than simply counting cycles—the CoilLIFE model. During jobs, all tubing movement and pressures are monitored and recorded. The CoilLIFE software then calculates the amount of life remaining in the string. It takes into account the relative severity of each cycle, the nature of the fluids that have been pumped and the sequence in which the cycle occurred—which affects the accumulated damage.

Personnel requirements—The number of personnel required for coiled-tubing drilling is likely to be about 50% of that needed for conventional operations. Not only are day-to-day operational requirements lower, but the number of service personnel can also be reduced. For example, when running casing, the mud system could be employed to mix and pump cement—eliminating the need for a cementing engineer. All the drilling information, along with basic mud logging data and general surface data, will be centralized in a computerized information system, eliminating the need for a full-time mud logger.

—CF
The introduction of the DSI Dipole Shear Sonic Imager tool, which measures shear waves in all types of formations, has stimulated development of new applications for measurements of shear wave speed, \( V_s \), and its reciprocal slowness. Slowness measurements—shear, compressional and Stoneley—can help improve identification of rock lithology and fluid content, and assist borehole and surface seismic interpretation. In addition, shear wave slowness provides the critical link in calculating rock shear stiffness and bulk compressibility, two quantities invaluable for planning fracturing operations and controlling production to avoid sanding. A new log of the pore-fluid bulk modulus \( K_f \), based on DSI measurements, shows promise as an indicator of hydrocarbons in sandstone formations.

Before the development of shear wave logging tools, shear waves created by traditional tools using monopole sources were measurable only in fast, or hard, formations. Consequently, geophysicists based their interpretation schemes largely on measurements of the more accessible compressional speed, \( V_p \). To begin extending interpretation of both \( V_p \) and \( V_s \) measurements, researchers at Schlumberger-Doll Research in Ridgefield, Connecticut, USA drew from three sources: Biot-Gassmann theory, laboratory measurements of gas-saturated, quartz sandstones and contact theory.

The theoretical groundwork for the \( K_f \) log lies in the Biot-Gassmann equations, which describe how compressional and shear waves travel through a fluid-filled porous medium such as oil-saturated rock:

\[
\rho_c V_p^2 = K_p + K_b + \frac{4N}{3}
\]

and

\[
\rho_c V_s^2 = N.
\]

In these equations, the composite density \( \rho_c \) is made up of density contributions from water, hydrocarbon and rock. \( N \) is the rock frame shear modulus—shear modulus describes how a body deforms under a shear stress. \( K_b \) and \( K_p \) are the bulk moduli of the rock frame and pore space, respectively—bulk modulus measures a body’s resistance to a change in volume under pressure. The Biot-Gassmann theory also shows that \( K_p \) and \( K_b \) are related via pore-fluid bulk modulus \( K_f \), the bulk modulus of the rock grains \( K_m \), and porosity \( f \):

\[
K_p = \frac{\alpha^2}{\frac{\alpha - \phi}{K_m} + \frac{\phi}{K_f}},
\]

where

\[
\alpha = 1 - \frac{K_b}{K_m}.
\]

Readily available shear wave measurements from the DSI tool combined with the Biot-Gassmann relations gave researchers a handle on \( N \), but they still needed to know more about \( K_m \), \( K_b \) and \( K_p \) for evaluating \( K_f \). Laboratory data—ultrasonic measurements of shear and compressional velocities plus porosity measurements on gas saturated, pure quartz sandstones—yielded the necessary information on these elastic properties. Plots of \( K_b \) and \( N \), calculated from the data,
depend in part on the porosity of the rock because the grain contact area, and thus the force transmitted increases as porosity decreases. Mathematical expressions describing the theory confirm experimental results that $K_b$ and $N$ are nearly linear functions of porosity and that the ratio of moduli for the dry rock, $K_b/N$, is independent of porosity and equals 0.9 for quartz sandstones.

With all parameters in the Biot-Gassmann equations either known or derived from log measurements, interpretation in shaly sands proves fairly straightforward. First, the shear frame modulus $N$, calculated from measurements of $V_s$ (measured $N$), is compared to $N$ calculated from the porosity-dependent equation based on lab data (predicted $N$). Porosity for the latter equation comes from independent measurements, such as the neutron-density log. If the measured $N$ matches the predicted $N$, the formation is interpreted as a clean sand; if it doesn’t match, the formation is considered a shale. Next, setting $K_b = 0.9N$ in the Biot-Gassmann equations allows one to first solve for $K_p$, then for $K_f$.

A $K_f$ log from the Gulf of Mexico shows the correlation between $K_f$ value and the presence of hydrocarbons (next page). A $K_f$ value of 0 corresponds to gas, and water has a higher $K_f$ value than oil. The log indicates gas from 2343 to 2350 meters; oil from 2350 to 2365 meters and from 2368 to 2373 meters; and water throughout other intervals.

Side-by-side comparisons of logs from the Gulf of Mexico well demonstrate the consistency of the $K_f$ log with neutron-density, resistivity and gamma ray logs. Shales were detected at the depths marked using two techniques. First, the measured $(V_p/V_s)^2$ is greater than the predicted value. Second, the measured $N$ is significantly below the predicted $N$ for water-saturated sands.

Tracks seven through nine compare the measured $V_p$ with theoretical predictions assuming the formation is filled with water, oil and gas, respectively. The match between measured and predicted $V_p$ for gas reveals a partial gas saturation from 2344 to 2350 meters. This agrees with the $K_f$ log, which has values of less than 1 at the same depth intervals. According to the veloci-

$K_b$ and $N$ as a function of porosity for pure quartz sandstones.

Laboratory data show that $K_b/N$ is a constant 0.9, independent of porosity.

versus porosity reveal a nearly linear porosity dependence (top). In addition, the data establish that the ratio $K_b/N$ is a constant 0.9, independent of porosity (middle). Finally, the lab data show that $K_m$ for quartz equals 36 Gigapascals (GPa).

The laboratory findings on $K_b$ and $N$ were consistent with Hertz-Mindlin contact theory, which models unconsolidated rock as a random packing of spherical, elastic grains. According to contact theory, any force applied to the rock is transmitted at the grain contacts, where one grain touches another. The grain contacts consequently govern the rock’s bulk and shear moduli, and hence its compressional and shear velocities. Each grain contact can be thought of as two coil springs that move in directions tangential and normal to the contact surface. The stiffnesses of these contacts
Taking Advantage of Shear Waves

The introduction of the DSI Dipole Shear Sonic Imager tool, which measures shear waves in all types of formations, has stimulated development of new applications for measurements of shear wave speed, \( V_s \), and its reciprocal slowness. Slowness measurements—shear, compressional and Stoneley—can help improve identification of rock lithology and fluid content, and assist borehole and surface seismic interpretation. In addition, shear wave slowness provides the critical link in calculating rock shear stiffness and bulk compressibility, two quantities invaluable for planning fracturing operations and controlling production to avoid sanding. A new log of the pore-fluid bulk modulus \( K_f \), based on DSI measurements, shows promise as an indicator of hydrocarbons in sandstone formations.

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In these equations, the composite density \( \rho_c \) is made up of density contributions from water, hydrocarbon and rock. \( N \) is the rock frame shear modulus—shear modulus describes how a body deforms under a shear stress. \( K_b \) and \( K_p \) are the bulk moduli of the rock frame and pore space, respectively—bulk modulus measures a body’s resistance to a change in volume under pressure. The Biot-Gassmann theory also shows that \( K_b \) and \( K_p \) are related via pore-fluid bulk modulus \( K_f \), the bulk modulus of the rock grains \( K_m \), and porosity \( \phi \):

\[
K_p = \frac{\alpha^2}{\alpha - \phi} \left( \frac{K_m}{K_f} + \frac{\phi}{K_f} \right),
\]

where

\[
\alpha = 1 + \frac{K_b}{K_m}.
\]

Readily available shear wave measurements from the DSI tool combined with the Biot-Gassmann relations gave researchers a handle on \( N \), but they still needed to know more about \( K_m \), \( K_b \) and \( K_p \) for evaluating \( K_f \). Laboratory data—ultrasonic measurements of shear and compressional velocities plus porosity measurements on gas saturated, pure quartz sandstones—yielded the necessary information on these elastic properties. Plots of \( K_b \) and \( N \), calculated from the data,
depend in part on the porosity of the rock because the grain contact area, and thus the force transmitted increases as porosity decreases. Mathematical expressions describing the theory confirm experimental results that $K_b$ and $N$ are nearly linear functions of porosity and that the ratio of moduli for the dry rock, $K_b/N$, is independent of porosity and equals 0.9 for quartz sandstones.

With all parameters in the Biot-Gassmann equations either known or derived from log measurements, interpretation in shaly sands proves fairly straightforward. First, the shear frame modulus $N$, calculated from measurements of $V_s$ (measured $N$), is compared to $N$ calculated from the porosity-dependent equation based on lab data (predicted $N$). Porosity for the latter equation comes from independent measurements, such as the neutron-density log. If the measured $N$ matches the predicted $N$, the formation is interpreted as a clean sand; if it doesn’t match, the formation is considered a shale. Next, setting $K_b = 0.9N$ in the Biot-Gassmann equations allows one to first solve for $K_p$, then for $K_f$.

A $K_f$ log from the Gulf of Mexico shows the correlation between $K_f$ value and the presence of hydrocarbons (next page). A $K_f$ value of 0 corresponds to gas, and water has a higher $K_f$ value than oil. The log indicates gas from 2343 to 2350 meters; oil from 2350 to 2365 meters and from 2368 to 2373 meters; and water throughout other intervals.

Side-by-side comparisons of logs from the Gulf of Mexico well demonstrate the consistency of the $K_f$ log with neutron-density, resistivity and gamma ray logs. Shales were detected at the depths marked using two techniques. First, the measured $(V_p/V_s)^2$ is greater than the predicted value. Second, the measured $N$ is significantly below the predicted $N$ for water-saturated sands.

Tracks seven through nine compare the measured $V_p$ with theoretical predictions assuming the formation is filled with water, oil and gas, respectively. The match between measured and predicted $V_p$ for gas reveals a partial gas saturation from 2344 to 2350 meters. This agrees with the $K_f$ log, which has values of less than 1 at the same depth intervals. According to the veloci-

versus porosity reveal a nearly linear porosity dependence (top). In addition, the data establish that the ratio $K_b/N$ is a constant 0.9, independent of porosity (middle). Finally, the lab data show that $K_m$ for quartz equals 36 Gigapascals (GPa).

The laboratory findings on $K_b$ and $N$ were consistent with Hertz-Mindlin contact theory, which models unconsolidated rock as a random packing of spherical, elastic grains. According to contact theory, any force applied to the rock is transmitted at the grain contacts, where one grain touches another. The grain contacts consequently govern the rock’s bulk and shear moduli, and hence its compressional and shear velocities. Each grain contact can be thought of as two coil springs that move in directions tangential and normal to the contact surface. The stiffnesses of these contacts

$K_b$ and $N$ as a function of porosity for pure quartz sandstones.

Laboratory data show that $K_b/N$ is a constant 0.9, independent of porosity.
ties, oil occurs in the sands from 2350 to 2352 meters and 2354 to 2368 meters. The $K_f$ log also indicates oil. Finally, agreement between measured and predicted velocities shows water in the sands from 2372 to 2379 meters. The $K_f$ log shows salt water at those depths. In all cases, these findings mirror an interpretation of the gamma ray, neutron-density and resistivity logs.

The new information offered by the $K_f$ log has spawned several potential applications. The $K_f$ log may help identify low resistivity pay in unconsolidated sands where resistivity contrast is small. Because the acoustic signals and responses of the DSI tool are relatively unaffected by steel, the log may identify hydrocarbon type behind casing. Most importantly, the $K_f$ log represents a key component in integrating wellbore DSI interpretation with near-well seismic measurements such as amplitude variation with offset (AVO).

Consistency of interpretation from conventional and sonic logs taken in a Gulf of Mexico well.

AVO, the change in seismic reflection amplitude as a function of incident angle or offset, is used to distinguish hydrocarbon prospects from lithologic effects. The $K_f$ log will allow researchers to isolate the effects of formation fluid on the seismic response while logs of the frame moduli, $K_p$ and $N$, will isolate the effects caused by lithology. The next chapter in $K_f$ log research involves characterizing $K_f$ behavior in other formations.

—TAL

## Acknowledgements and Further Reading

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In this focus, the DSI (Dipole Sonic Imager) tool is a mark of Schlumberger.


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