Reservoir Mapping While Drilling

Breakthroughs in lateral drilling technology have paved the way to economic success of several new plays and the revitalization of many old fields. However, success in horizontal and extended-reach drilling is not defined in terms of the distance drilled but rather by the extent to which the driller stays in zone. A new deep-reading electromagnetic logging-while-drilling service is helping well placement teams maximize reservoir exposure by identifying fluid contacts, faults and formation changes far from the wellbore.
Advances in drillbit design, rotary steerable systems, downhole sensors and logging-while-drilling technology have helped drillers set new distance records for lateral drilling while increasing reservoir exposure. These achievements, in turn, have led to substantial gains in oil and gas production. However, the nature of the data used to map a target can pose a significant challenge for operators seeking to maximize lateral footage through a pay zone.

Limits to seismic resolution and logging tool depth of investigation (DOI) can create uncertainty with regard to reservoir position, orientation and overall structure. Initially, geoscientists map formations on the basis of surface seismic data and by offset well data if available. Surface seismic data are characterized by great DOI—on the order of hundreds of meters—and by relatively coarse resolution. By contrast, well log data are characterized by shallower DOI—typically on the order of several centimeters—and by much finer resolution. Given the relatively narrow diameter of a wellbore compared to a seismic wavelet, the imprecision of seismic resolution leaves plenty of room for the wellbore to miss its mark. It is usually while a well is being drilled or afterward that logs and other data become available for use in refining seismic prospect maps; seismic data sketch the broad outline of a reservoir, and log data must fill in the details.

The disparity in resolution and DOI between seismic and well log data may spur an operator to drill an initial vertical pilot hole for locating formation tops and fluid contacts and refining seismic models prior to drilling a horizontal well through the reservoir section. In this process, the operator drills a hole to penetrate the pay zone from top to base. Logging data from the pilot hole help the well placement team ascertain structural dips and depths of key geologic markers, which they use to refine the existing formation model and adjust targets for the extended-reach well. The hole is then plugged back to a shallower depth to establish a kickoff point that will permit a smooth landing into the target formation.1

This approach, however, is not without uncertainty or risk. Perhaps the greatest risk stems from the fact that, at some scale, formations and their subordinate horizons tend to vary laterally (above right). Formation geometry, lithology or fluid saturation characteristics logged in the pilot hole may not extend for any appreciable distance beyond the pilot well. A formation model may differ dramatically from reality: Unconformities and pinchouts can change the thickness of a pay zone; grain size and water saturation often vary with depth or distance; and fractures, subseismic faults and changes in dip or other structural features can invalidate a model before it is verified by the bit.

Despite these geologic uncertainties, the operator must proceed on the assumption that the model based on pilot hole data also reflects formation characteristics at the landing point and beyond. In addition to their drilling costs, pilot holes carry the same risks as other drilling projects: lost circulation, stuck pipe and stuck tools, among others. High spread rates for deepwater drilling and challenging economics in shale plays also provide strong incentives to eliminate the cost of drilling pilot holes.

After extensive field testing, a new LWD service has been introduced to help map the subsurface and aid in precise placement of the wellbore within a target formation. This service helps bridge the gap between resolution and DOI that exists between the surface seismic data used to plan the reservoir development and the logging data used to steer and evaluate the wellbore. The GeoSphere reservoir mapping-while-drilling service uses deep-reading, directional electromagnetic measurements to detect fluid contacts and multiple formation boundaries more than 30 m [100 ft] from the wellbore. These reservoir-scale measurements provide timely data that operators need to guide real-time geosteering decisions. Well placement teams are using the GeoSphere service to accurately land wells, avoid unplanned exits from the reservoir, map multiple formation layers, develop interpretations of reservoir structure and reduce drilling risk while decreasing the need for pilot holes. GeoSphere mapping data are used to update and refine the operator's reservoir models.

This article describes the architecture and operation of the GeoSphere service, which has been tested in more than 200 wells worldwide. Case studies from the North Sea and Australia demonstrate how data provided by this service guide operators in maximizing wellbore exposure to the pay zone.

The Landing and Beyond

Successful placement of a horizontal well requires the driller to land the bottomhole assembly (BHA) in a position that will permit maximum wellbore exposure to the reservoir. After kicking off from vertical, the driller builds angle to increase inclination until the well path attains the trajectory needed to intercept the reservoir target. The driller then holds the inclination constant while drilling the tangent section.
As the bit nears the reservoir, the well placement team evaluates real-time well data to determine when to trigger the final inclination change needed to complete the landing. The team bases this decision primarily on information from near-bit gamma ray or at-bit laterolog LWD data, sometimes supplemented with mudlog data and biostratigraphic analysis.

However, most conventional LWD tools have a fairly shallow DOI, which limits acquisition of measurements to a few centimeters or meters into the formation. Shallow DOI may leave well placement teams with little time for geosteering adjustments. Depth of investigation may thereby impact the accuracy of a landing, which in turn can significantly affect the productivity of a horizontal or extended-reach well. A poor landing decreases the likelihood of optimal well placement within the reservoir section; by contrast, a good landing reduces the amount of steering required to keep the well in the sweet spot. Landing shallower or deeper than necessary reduces the amount of lateral reservoir exposed to the wellbore, which ultimately results in lost production (above). Once the LWD tools are in the reservoir, their shallow DOI may not be adequate to warn of approaching bed boundaries or changing fluid contacts in time to prevent excursions out of the pay zone.

While precise well placement is required to maximize pay zone exposure, a high-quality borehole is also necessary for maximizing production. To this end, the directional driller must not only hit the target and stay in zone, but also must deliver a smooth hole with minimum tortuosity. These objectives may not be entirely achievable, given the structural and stratigraphic complexities of the formations encountered. Regardless of their cause, necessary deviations from the well plan to maintain reservoir contact will force a driller to change azimuth or build or drop angle to get back on track to the target. Missing a target or straying beyond the pay zone may lead to course corrections that increase wellbore tortuosity.

By reducing tortuosity, operators avoid problems that compromise drilling, completion and production operations. During drilling, tortuosity can lead to poor hole cleaning and drillstring buckling; in severe cases, it can keep a well from reaching TD as increases in torque and drag prevent transfer of weight on bit required to drill ahead. Tortuosity also creates difficulty in running casing and cementing it in place and can interfere with the installation of downhole completion equipment. Even after a well is put on production, tortuosity can impede flow at sumps, or low spots, where fluid and debris may collect. These sumps can also cause slugging and holdup problems.

Wellbore placement and quality are impacted by an operator’s ability to ascertain the surrounding environment. Vertical wells are much simpler to drill in that regard: Once the bit enters a target formation, the next event usually involves exiting through the bottom of that formation. In contrast, horizontal or extended-reach wells offer the operator the prospect of weaving in and out of a changing reservoir section. One of the early challenges in drilling lateral wells was the distance from the wellbore at which important geologic features could be detected. Reactions to changing scenarios detected at the last minute lead to insufficient trajectory corrections and less-than-optimal landings that adversely affect wellbore exposure to the reservoir. To avoid these problems, an operator needs the ability to detect formation and structural variations in time to provide effective course corrections.

**Toolstring Design**

To determine formation resistivity, many LWD and wireline services rely on multicomponent electromagnetic (EM) logging measurements. The GeoSphere reservoir mapping-while-drilling service exploits the directional sensitivity and deep-reading capability of EM signals to model formation geometry and characterize related properties in three dimensions. This LWD tool is designed to obtain multispacing, multi-frequency directional resistivity measurements. Geoscientists and drillers use these data to identify structural details and fluid contacts for optimum well placement within a reservoir and to refine the reservoir model. Although the GeoSphere service is not the first to provide this 3D visualization, the toolstring is designed to look much deeper into the formation than did earlier LWD tools.

The toolstring comprises one transmitter sub and two identical receiver subs—in some cases three receiver subs may be used (next page, top right). The transmitter sub has a tilted antenna and can transmit EM signals into the formation at six frequencies below 100 kHz. These frequencies

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3. Tortuosity, a measure of deviation from a straight line, may be used to describe wellbore trajectory. In a well, the tortuosity can be quantified by the ratio of the actual distance drilled between two points, including any curves encountered, divided by the straight-line distance between those two points. Thus, as a wellbore deviates away from a straight trajectory, it becomes more tortuous.

4. Properties that vary with direction are said to be anisotropic. Resistivity anisotropy, differences in horizontally measured resistivity versus vertically measured resistivity, is a common phenomenon in rock.
cies are selected to provide optimal signal-to-noise ratio and measurement sensitivity. Each receiver sub has three antennae, which are tilted for azimuthal sensitivity.

The transmitter and receiver subs are available in two diameters—6 3/4 in. and 8 1/4 in.—allowing operations in hole diameters from 8 1/2 in. to 14 3/4 in. Each sub is 4 m [19.7 ft] long. To allay concerns regarding the effects of stabilizers on BHA performance, the collars are slick—they have no stabilizers.

The subs are configurable for placement at various locations within the BHA and may be separated by other LWD or MWD tools; receiver subs can be placed from 5 to 35 m [16 to 115 ft] away from the transmitter sub (below). Placement in the BHA sets the transmitter-receiver spacing, which is a critical factor affecting the EM signal’s DOI. In a resistive formation, the DOI is typically comparable to maximum antenna spacing; in a conductive setting, DOI is approximately half the antenna spacing. The DOI may be influenced by factors such as distance from the tool to a formation boundary, formation resistivity, thickness of formation layers and resistivity contrast between layers. The EM frequency also affects DOI; high-frequency measurements are typically used for short transmitter-receiver spacing and shallow DOI, whereas low-frequency measurements are used for long transmitter-receiver spacing and deeper DOI.

The deep-reading capability of the toolstring is enhanced by flexibility to configure transmitter output power and receiver gains to accommodate variable transmitter-receiver spacings and formation resistivity contrasts. Given the variability of formations to be drilled, prejob simulation is important for evaluating performance of various toolstring configurations. The transmitter-receiver spacing and the expected resistivity environment will affect the optimum frequency range used downhole. A prejob model helps the LWD engineer evaluate how spacing and frequency will affect DOI and the toolstring’s capability to resolve expected formation characteristics. The placement of the transmitter and receiver subs depends on client objectives and the formation characteristics that define transmitter-receiver spacing. In complex BHAs, power availability and telemetry bandwidth might influence BHA design. All of these factors must be considered during prejob modeling.

**Real-Time Multilayer Inversion**

For the wellbore to achieve maximum reservoir exposure, well placement team members must closely monitor formation structure and respond to changing lithology as they guide the wellbore laterally through a reservoir. GeoSphere EM measurements are directionally sensitive and thus provide valuable inputs for well placement and reservoir characterization. These data are processed using a real-time stochastic inversion algorithm to generate a multilayer formation resistivity model. The model is appended with continuous updates while drilling progresses, thus enabling well placement experts to track drilling progress while identifying fluid contacts or other boundaries within the reservoir.

The GeoSphere technology is capable of obtaining directional EM measurements at various frequencies and transmitter-receiver spacings. For a given frequency and transmitter-receiver spacing configuration, the toolstring measures a nine-component tensor between transmitter and receiver. These measurements are inverted in real time to provide multilayer model results, in which the number of layers and the layer thicknesses and resistivities fit the tool measurements and are consistent with frequency, spacing, sensitivity and DOI of each measurement. In addition, the resistivity anisotropy, dip and other structural aspects of the formations surrounding the wellbore can be estimated from the models.

Making up the toolstring. GeoSphere subs can be positioned throughout the BHA, and other LWD or MWD tools may be placed between the transmitter and receivers. This spacing affects depth of investigation, which is proportional to the distance between the transmitter and receiver. A prejob model of sub positions within the toolstring, in addition to a model of formation resistivity contrasts, will help determine the frequency required for accurate characterization of the formation. (Adapted from Seydoux, et al, reference 5.)
The stochastic inversion algorithm employs few model constraints—overall bounds for resistivity, apparent dip and anisotropy values—along with a maximum parsimony criterion to calculate the simplest models that are consistent with the data. The algorithm iteratively adds or deletes layers as necessary to honor the constraints of tensor components, each of which has its own DOI and sensitivity. This process uses a probabilistic approach to estimate formation parameters; instead of requiring the inversion to develop only the most likely solution, a distribution of model solutions fitting the data is computed for each inversion station (below). The distribution consists of tens of thousands of formation models and quantifies the uncertainties for estimating the most likely formation model solution. Although the number of formation model solutions computed by the inversion is high, their distribution is computed in less than a minute to provide current inversion results—even at high drilling rates of penetration.

GeoSphere inversion of simulated data. The simulated formation consists of a 2-ohm.m upper shale (brown) above a 30-ohm.m reservoir (tan) with resistivity decreasing to a 1-ohm.m lower shale. Two resistivity profile distribution histograms are presented here for inversion stations (Points A and B). At each measured depth, a distribution of resistivity profiles is generated from the statistical inversion, with the P50 median value (inset, purple) shown as a color map over the entire length of the trajectory. Four other quantiles (inset, P05 to P95) provide information regarding the uncertainty of the distribution and thus show sensitivity limits of the measurements. The inversion also solves for relative dip of the formation.

At Point A, a 20-m DOI can be inferred from the spread of quantiles. At Point B, the inverted resistivity profile distribution indicates that the tool is within the reservoir, and the DOI is extended to 28 m, owing to an increase in resistivity of the volume investigated. At the same time, a declining resistivity ramp profile is delineated below the tool position. In both plots, the uncertainty in the position of the reservoir top, reservoir resistivity and reservoir thickness may be interpreted. This uncertainty decreases as quantiles converge when the toolstring gets closer to the reservoir. (Adapted from Seydoux et al, reference 5.)
This probabilistic inversion provides an unbiased estimate of the formation resistivity surrounding the wellbore. The inversion is suitable for complex geologic settings because it requires no user input, thereby reducing the risk of misinterpreting geologic structures, or the fluids contained therein, based on mistaken assumptions. By integrating results from the unbiased inversion with previously developed exploration and production models, operators can confidently update their interpretations in a timely manner. From these updated models, well placement teams can validate or modify drilling trajectories to account for changing conditions in the subsurface.

Avoiding Water at Ekofisk

The Ekofisk field, located on the Norwegian Continental Shelf, was discovered by Phillips Petroleum Company in 1969 and was put on production in 1971 (above). Operated by ConocoPhillips Skandinavia AS, this North Sea field consists of fractured chalks stacked in an elongated dome. The field produces from the Ekofisk formation and the underlying Tor formation. These chalk formations are characterized by high porosities of between 25% and 45% and low permeability between 1 and 10 mD. A tight zone—the EE unit—separates the lower Ekofisk from the Tor.

The field has undergone water injection since 1987. From its peak annual production rate of more than 20 million m³ [126 million bbl] oil equivalent in 1977, production from the field declined by more than half in eight years. Limited gas injection, combined with extensive water injection and several new installations at the field, helped to restore production to near peak levels during the late 1990s; but after 10 years, production started to decline again.

The chalks of Ekofisk field, despite their low matrix permeability, proved to have high matrix waterflood displacement efficiency. The fractured sections of the reservoir experience more rapid water flooding, while the remaining of


the reservoir floods later. Over time, this complex distribution of reservoir water and pore pressure has made it difficult to map remaining pay accumulations.

The well planning team at ConocoPhillips opted to use the GeoSphere service for landing and drilling a horizontal well. The team first sought to locate the tight EE horizon between the Ekofisk and Tor formations—a key marker used for landing the well. After landing, drilling would be conditional, based on formation water saturation. The goal was to geosteer within the upper Tor formation, but maintaining optimal position would involve more than simply steering along formation structure. Reservoir models indicated that the lateral section might encounter injected water within fractured intervals of the uppermost section of the upper Tor (TA) unit—which the operator wanted to avoid.

The well planning team targeted the oil-saturated part of the TA unit and needed the GeoSphere service to provide guidance in geosteering within the pay zone, identifying any water zones above and below the proposed lateral and locating the tighter middle Tor (TB) unit below the wellbore. The operator was also concerned that water breakthrough into the TA zone might compel an early decision to TD the well, thus a constant evaluation of the lateral section was needed to continue drilling. The tool’s capability for deep imaging around the wellbore would also be useful in observing faulting at a distance and revealing aspects of the reservoir pertinent to completion design such as determining the best intervals to perforate.

The GeoSphere service was utilized while drilling out of casing, allowing the operator to detect a resistive marker 50 ft [15 m] TVD below the wellbore. As the driller continued to build angle to 60°, the service located horizons within the Ekofisk formation some 60 ft [18 m] TVD (100 ft [30 m] MD) away from the wellbore. The top of the EE unit, the thin layer above the Tor formation, was detected 79 ft [24 m] below the wellbore. The service was used to resolve the contact between the EE unit and the upper Tor’s TA unit although it lay 50 ft MD ahead of the bit (above). As the wellbore intersected the middle of the Tor TA unit, the well planning team instructed the directional driller to increase inclination to 89.6° to land the well within the lower part of the TA unit.

While the lateral section was being drilled, the well intercepted a 40-ft [12-m] fault, and well planning geologists recommended increasing inclination to 94° to remain within the target reservoir. The GeoSphere inversion indicated that despite crossing the fault, the wellbore still remained in good quality reservoir within the TA unit. It also detected a low-resistivity zone below the wellbore, which was the water-filled TB unit of the Tor formation. As drilling of the lateral section proceeded, the GeoSphere toolstring continued to track the position of the TB unit some 40 ft TVD beneath the wellbore. Later, it detected a steeply dipping conductive boundary, interpreted as a fault, while the fault was still 90 ft [27 m] TVD above the BHA. Resistivity measurements indicated the zone beyond the fault would be wet, which was subsequently confirmed by conventional LWD measurements when the wellbore crossed the fault. Anticipating other conductive zones along with the potential for increasing pore pressure, the well planning team elected to TD the well after drilling more than 1,800 ft [550 m] MD of a hydrocarbon-filled lateral section (next page).
A matter of scale. The reservoir-scale mapping displays much finer resolution for navigating the reservoir than would be possible using seismic data alone. The deep-reading capabilities of the GeoSphere toolstring enabled early detection of the EE unit 79 ft below the wellbore, giving the operator advance notice to prepare for landing the well in the lower TA unit. Cold colors—blues and greens—indicate conductive or low resistivity layers such as shale or water-bearing sands. Warm colors—oranges and reds—indicate high resistivity typical of oil- or gas-bearing sands (top). In addition to mapping the structure and fluid content of the TA unit, the GeoSphere inversion also mapped the TB unit, even though the wellbore had not penetrated that interval. This information helped the operator extend the well horizontally through the TA reservoir while maintaining optimal standoff from the water-filled TB unit. The TB unit, as detected by the GeoSphere inversion (bottom, red line) compares favorably to that picked on the surface seismic display (yellow line).
Defining a reservoir. Even though data obtained from a pilot hole confirmed the presence of the reservoir and identified dip at the pilot hole entry point, the overall geometry of the reservoir top could not be estimated using the data obtained from the pilot hole and other offset wells. To reduce depth uncertainty inherent in seismic modeling of the reservoir, the Santos well placement team relied on directional, deep-reading measurements to define the upper and lower limits of the reservoir. As drilling continued, the operator was able to map the lateral extent of the reservoir. Gamma ray (top, green) and resistivity (red, blue, orange and black curves) readings from other LWD tools indicating clean sand and pay, compare favorably with the GeoSphere color map (middle). The lower panel highlights the discrepancy between the top of the reservoir and oil/water contact as determined by the seismic predrill model and those determined by the GeoSphere reservoir mapping-while-drilling service.
After providing early warning of the approaching landing zone, the service helped the well planning team map the oil-rich zones within a waterflooded reservoir and for up to 100 ft around the well. GeoSphere measurements also assured the operator that the wellbore trajectory had not bypassed the intended target. Furthermore, water saturation changes indicated by the LWD toolstring were used to assist in determining perforation intervals during the completion phase.

Mapping Reservoir Boundaries Offshore Australia

While drilling a prospect offshore northwest Australia, geoscientists with Santos Ltd had to contend with some 10 m [33 ft] of uncertainty in seismic depth control. The Santos well placement team sought to land the well as close as possible to the top of the reservoir, then steer the trajectory to achieve optimal positioning with respect to the oil/water contact (OWC). Logs from a pilot hole helped confirm the presence of a thick sand, showed the depth of the OWC and determined formation dip at the pilot hole. However, the orientation of the reservoir and geometry of its crest could not be inferred with accuracy. Despite suboptimal structural control, the Santos well placement team had to drill a landing that would position the well for maximum reservoir exposure.

Santos selected GeoSphere technology to reduce geologic uncertainties and map structure, dip, fluid contacts and reservoir boundaries. The BHA included a rotary steerable system, GeoSphere transmitter and receivers, PeriScope LWD tool, TeleScope high-speed telemetry service and adnVISION azimuthal density neutron tool. Upon exiting the casing shoe, the toolstring detected the top of the reservoir 6 m [20 ft] TVD below the proposed well path and identified the OWC 19-m [62-ft] TVD beneath the reservoir top. As a consequence, the well placement team was able to ascertain the structural geometry and assess the drilling trajectory prior to landing the well (previous page).

Real-time mapping of the reservoir and OWC proved crucial in optimizing and maintaining structural positioning within the reservoir. Interpretations of the reservoir structure and fluid contacts from the GeoSphere service were later integrated into the operator’s 3D geologic model to update drilling and field development plans.

The Big Picture

The spacing between a transmitter and receiver affects a logging tool’s depth of investigation, and the GeoSphere toolstring uses this relationship to attain greater DOI than that of conventional LWD tools. Its deep-reading directionally sensitive measurements drive a continuous real-time automatic multilayer inversion that gives well placement teams a broader perspective on the geology surrounding a wellbore. This expanded view of the subsurface helps geoscientists and drillers bridge the gap between conventional LWD data and surface seismic data to identify fluid contacts, subseismic faults and other geologic details not defined through surface seismic data.

By presenting mapping-while-drilling information in real time, the GeoSphere service can have a significant impact on well placement decisions that ultimately influence production. A well can be steered along a path defined by boundaries observed above and below the wellbore—most commonly, the top of the reservoir and the water contact at its base. This broader view of the reservoir helps the driller to drill a longer productive interval with a smooth well path, resulting in increased recovery through the pay zone.

At the office, mapping-while-drilling data can subsequently serve as a basis for developing strategies to optimize production in complex or marginal fields. These data are also used to identify new targets in neighboring sands. GeoSphere reservoir scale measurements provide higher resolution than do surface seismic data, leading to a tighter integration with other reservoir information. Complementary information from surface seismic data, along with conventional LWD or wireline logging data, can be integrated with GeoSphere inversion results to create or refine structural models for increased understanding of the reservoirs and the fluids they contain. —MV