Wellbore Imaging Goes Live

Accurate wellbore placement relies on knowledge of stratigraphy, borehole trajectory and precise bit location within a reservoir in conjunction with state-of-the-art geosteering capability. Real-time data acquisition, advanced telemetry, wellsite data-processing and imaging systems are improving drilling efficiency, limiting operator exposure to subsurface risk and enhancing potential well productivity.

In the 1980s, measurements-while-drilling (MWD) and logging-while-drilling (LWD) tools brought basic directional and formation-evaluation information to the driller—some in real time. By the 1990s, LWD resistivities recorded downhole were being downloaded at surface and processed to create images for correlation and formation evaluation. Today, downhole instrumentation and data-compression technologies allow transmission of wellbore images and associated correlation data from bit to surface in real time.

Drilling wells with complex trajectories has become increasingly common. Wells that were once considered marginal are now being drilled and completed across multiple horizons, in multilateral configurations and even in deepwater environments. In addition to providing conventional formation evaluation, real-time data analysis and imaging facilitate precise wellbore placement, wellbore-stability evaluation and monitoring of critical drilling parameters. Accurate high-resolution measurements enhanced by three-dimensional (3D) real-time visualization provide information for making better, more timely decisions, resulting in significant advances in risk management and overall productivity optimization. Today's imaging and telemetry technologies allow both onsite and shore-based asset teams to evaluate a borehole, define an exact trajectory and characterize formations in real time before making costly drilling and production decisions.

Drilling engineers must focus on risk management and reduction of total well cost. Achieving a lower actual well cost than projected often is the benchmark of drilling success. Complex and fast-paced drilling operations rely on intuitive and intelligent products to aid in important decisions. Questions need to be answered quickly—where is the borehole, where is the bit going, what formation is being drilled and what are the downhole conditions? Real-time measurement, telemetry, imaging and software products are helping drillers answer these questions.

Since last reviewed in Oilfield Review, LWD imaging technologies have evolved to become real-time engineering tools. Wells are being geosteered through difficult trajectories, skirting hazards and connecting with thin pay or injection zones while avoiding collisions with other wells draining a reservoir. This article reviews the basic technology of LWD imaging tools and techniques, and explores examples of how operators are using real-time imaging technology to improve efficiency and precisely place the wellbore for optimal productivity.

Telemetry—Moving Data Upward

As LWD and MWD technologies advance and deliver increasing amounts of data, telemetry instrumentation has become a bottleneck to moving these large volumes of information to surface. Obtaining data in real time requires appropriately wide bandwidth and high data-transmission rates.

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The PowerPulse MWD telemetry system provides wireless data transmission from bit to surface. The tool's unique continuous-wave mud-pulse telemetry technique produces data-transmission rates as high as 12 bits per second (bps), up to four times faster than conventional mud-pulse telemetry systems (left). Real-time logs with data-sampling density equivalent to that of a wireline log are possible at drilling rates of 230 ft/hr [70 m/hr]. Signal-transmission speed and strength can be configured for specific drilling-fluid types and drilling depths.

Deepwater drilling presents additional telemetry challenges. Seafloor temperatures may be below 0°C [32°F] with hydrostatic pressure at the riser base in excess of 34.5 MPa [5000 psi]. Drilling fluid circulating up from warm bottom-hole conditions cools substantially as it travels up long, cold risers to surface. The surface-to-bottomhole temperature variance can dramatically affect the viscosity of some drilling fluids. Signal attenuation may increase as the fluid becomes cooler, potentially causing loss or degradation of the downhole signal. The latest telemetry-tool designs automatically adjust data-transmission rate as a function of temperature to reflect changes in mud viscosity and signal attenuation potential. In the Gulf of Mexico, USA, the PowerPulse system has achieved deepwater data-transmission rates of 6 bps at a 100-ft/hr [30-m/hr] penetration rate.

Recent developments in two-way tool communication, referred to as DownLink data transmission from surface to downhole tool telemetry, can be used to reconfigure the PowerPulse system downhole should key parameters change during a bit run. For example, before beginning to build angle in a horizontal well, real-time borehole orientation information is a priority; in the horizontal section, formation-evaluation measurements have greater importance. DownLink telemetry capability can also reconfigure signal-transmission speed and signal strength as required.

In addition to improved telemetry, the last decade has seen dramatic improvement in borehole visualization (left). Borehole data in the 1970s and 1980s were displayed as simple curves on a well-log track. Until recently, this continued to be the preferred, if not the only, method of displaying LWD data.

^ Limitations on rate of penetration (ROP) set by data rate. At 12 bits/second (bps), PowerPulse MWD telemetry technology allows penetration rates in excess of 230 ft/hr [70 m/hr] while continuing to receive high quality real-time logs and inclination and azimuth updates. Data rate and type can be adjusted to optimize measurement frequency against predicted ROP.

^ Improved visualization of borehole data. The quality and ease of interpreting data have improved considerably from the simple curves common in the 1980s. Data were first converted into color scale presented in two dimensions, then wrapped around a three-dimensional (3D) borehole. The 3D textured image on the right is easy to interpret—the borehole is over-gauge in the top section, enlarged in the center, and in-gauge in the lower section. Real-time, easily understood images provide the tools necessary to make quick and accurate drilling decisions.
Development of advanced borehole imaging and software analysis tools led to the display of image data in two dimensions (2D). Experienced log analysts can easily interpret 2D displays; however, the process is subjective and not intuitive, particularly to the nonexpert. At the end of the 1990s, 3D images provided a more straightforward visualization of the borehole. In 2001, developments in data-processing technology provided 3D textured images, making interpretation quick and easily understood. Today, a broader group of drilling personnel can appreciate the wealth of knowledge provided by borehole images.

Imaging the Borehole
LWD resistivity imaging is based on low-frequency laterolog-type measurements that generally require a conductive borehole fluid—approximately 70% of wells are now drilled with conductive drilling fluids. Several LWD resistivity-imaging tool designs are available that provide multiple depths of investigation in addition to resistivity at the drill bit (right). The GVR geoVISION resistivity tool provides multidepth measurements with 0.3-in. [0.762-cm] vertical resolution. These data are used to generate real-time resistivity images and to calculate formation dip for structural analysis and wellbore positioning (above).

Azimuthal density, ultrasonic caliper and geoVISION downhole MWD/LWD imaging resistivity data are often displayed as images. Comparing up- and down-quadrant data allows interpretation of apparent formation dip. While drilling structurally down-section, the down-quadrant measurement will image bedding features before the up-quadrant measurement—the opposite is true when drilling up-section. The offset between two bed-boundary measurements is used to compute apparent dip. Knowledge of apparent formation dip assists in real-time trajectory adjustment to


either drill down- or up-section stratigraphically or to drill parallel to bedding planes (above and right). Onsite handpicking of dips helps remove low-quality data and supplements intervals where automated dips cannot be computed, thereby emphasizing subtle trends that may otherwise be missed.

First Use—Real-Time Imaging for Well Placement

Discovered in 1975, the Breitbrunn/Eggstatt gas field is located in southern Bavaria, Germany (next page, top). Much of the field is depleted and currently is used for gas storage. During 1999 and 2000, a multidisciplinary team of geologists, petrophysicists, geomechanical and production engineers from RWE Dea and Schlumberger planned and executed a horizontal-injector drilling program in the Tertiary Chatt sandstone reservoir.

The northeast-southwest striking, anticlinal structure covers approximately 30 km² [11.5 sq miles] and consists, from top to bottom, of Sands A through H. Sands A through D are the original gas producers. The reservoir layers range in thickness from 5 to 15 m [16 to 49 ft] and are separated by impermeable calcareous shale. Initially, a vertical well produced the upper zones. In 1993, RWE Dea engineers converted the depleted A and B reservoir sands to gas storage. Gas was injected into Sand B, while Sand A was monitored for gas leakage.

The recent drilling program focused on the remaining original gas sands, C and D. These sands have sufficient porosity and permeability for gas storage. Reservoir quality deteriorates from Sand A downward, with greater geological and petrophysical heterogeneity in Sands C and D than in A and B.

Prewell studies achieved a structural-map accuracy of 0.1%—a maximum vertical depth variance of 1.5 m [5 ft]. Before drilling Sands C and D, the subsurface team adjusted log-derived formation-marker picks to a common baseline by resurveying well locations and using directional surveys from casing runs. A vertical pilot well and subsequent horizontal development wells validated mapping accuracy.

Petrophysical evaluations and historical knowledge of the reservoir depositional setting predicted the sands to be lenticular. The study also indicated that optimal gas-injection rates and storage capacity required horizontal wells to penetrate as many of the potentially isolated reservoir sand lenses as possible. Core data and FMI Fullbore Formation MicroImager borehole images generated while drilling a pilot well verified this interpretation.
Several high-quality reservoir sand lenses were identified as injection targets. However, calcareous concretions with varying packing density suspended in the target sands presented directional-drilling challenges. This and other stratigraphic uncertainties ruled out conventional geometric directional-drilling operations. Discussions between RWE Dea and Schlumberger led to the selection of real-time geoVISION imaging technology to support the geosteering operation.

The team believed that accurate real-time stratigraphic data and wellbore imaging would significantly improve geosteering decisions. Although LWD resistivity imaging was not new, images to date had been generated from data recorded in memory mode and downloaded at surface from the GVR tool during bit trips. Geosteering with real-time resistivity images had not yet been performed.

RWE Dea planned three 600- to 1000-m [1969- to 3281-ft] horizontal wells for both the C and D sands (below right). With a gentle U-shaped trajectory, wellbores would traverse the sands from the top to bottom and back to the top within each horizontal section.

Even though producing zones were depleted, a weighted drilling fluid was required to control borehole stress. Engineers selected a low fluid-loss polymer, calcium carbonate weighted, reservoir drilling-fluid system. In contrast to foamed drilling mud, this system allowed the operator to consider a wide selection of LWD, MWD and wireline-logging tools for geosteering and formation evaluation.

The GVR tool was run with an adnVISION Azimuthal Density Neutron tool, which provided nondirectional neutron porosity, azimuthal density and ultrasonic caliper logs. The GVR and adnVISION tool combination assessed porosity and net sand while drilling.

Wireline data collected during successful construction of the 12%-in. angle-building sections confirmed the high precision of prewell structural mapping. Correlation of LWD and well-log data suggests that the reservoir layers are composed of separate sand bodies. An effective storage well should penetrate all individual sand bodies.

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porous sand bodies, with the wellbore path cutting evenly across the entire thickness. All three 8 1/2-in. horizontal-well sections penetrated each sand layer twice. The end of each wellbore penetrated the overlying shale to provide an additional structural-map marker.

During drilling of lateral sections, computed dips from geoVISION resistivity real-time images defined the relative position of the borehole within the reservoir. Sinusoidal bed-boundary images point uphole when drilling down-section, and downhole when drilling up-section (below left). Measured depth (MD) logs were converted into true stratigraphic thickness (TST) logs using calculated dips from geoVISION resistivity data, structure maps and other MWD data. TST logs provided additional vertically oriented data to correlate bit position with the reservoir base. Data analysis was conducted on site and transmitted to the main office in Hamburg, Germany, for further processing.

Available bandwidth limited the number of measurements transmitted to surface. Tools were programmed to send real-time density image logs only from the right and bottom quadrants. The weight of the bottomhole assembly (BHA) tends to position the bottom sensors close to the formation, generally producing a more accurate measurement and higher resolution images. The right quadrant is preferred over the left because clockwise BHA rotation tends to press the sensors against the right side of a hole, again delivering higher quality data. Signal distortion resulting from tool standoff is minimal in this orientation.

Azimuthal data become critical when drilling these heterogeneous reservoirs. Formation evaluation by quadrant allowed detailed stratigraphic interpretation. Right-quadrant data may indicate good reservoir quality while the bottom-quadrant log indicates poor quality (below right). These sections require special attention when designing perforations.

Oriented perforating requires accurate permeability mapping. After completing the drilling phase, the subsurface team prepared a final petrophysical evaluation establishing porosity, permeability and water-saturation levels, and a mineralogical model of the reservoir sands. Data from both historical-well cores and cores from the current project provided quality indicators in the evaluation. Petrophysicists inferred formation permeability from time-lapse logs and infiltration dynamics from LWD drilling and washdown data. The Stoneley sonic-wave slowness from the wireline DSI Dipole Shear Sonic Imager data provided another method for permeability determination.

There was a risk of sanding, so petrophysicists used both porosity and rock-mechanical information to determine the perforation intervals and their orientation. Wellbore images and oriented-perforating technology allowed for precise placement of injection sites within the sand bodies. Stratigraphic orientation suggested that distinct differences in the stability of perforation channels were possible. The completion team oriented perforation guns based on rock strength and stress anisotropy, taking care not to perforate an underlying bed boundary or carbonate concretion.

^ Real-time geoVISION resistivity data used in geosteering to determine whether drilling was up-section or down-section. In this example, drilling was from top to bottom and the borehole was not rotating, so no azimuthal data were collected.

^ Concretions and homogeneity. The geoVISION deep-resistivity image (left) shows a concretion positioned on the top of the hole (yellow) and extending down the right and left sides. Another concretion (yellow) is located on the bottom of the hole. The electrical caliper (right) is displayed as a red dashed line. The calculated diameter of invasion for the bottom quadrant is shown in blue, while the diameter of invasion for the right quadrant is in red. The diameter of invasion is computed by inversion of the resistivity data using shallow, medium and deep measurements. The presence of invasion is indicated. Computed invasion curves approach the caliper curve as expected when impermeable concretions are present.
Drilling, geosteering and perforation-strategy decisions throughout the project were largely based on analysis of real-time geoVISION resistivity images and MWD data. Real-time geoVISION resistivity imaging provided significant improvements in operational and geosteering efficiency enabling RWE Dea to double the horizontal borehole length. The combination of structure mapping, accurate well-trajectory control and real-time imaging led to placement of the initial wellbore to within one borehole diameter of the proposed target.

**Real-Time Imaging in North Sea Turbidites**

During 2001, Shell U.K. Exploration and Production planned and drilled a horizontal well in the Gannet complex, UK North Sea sector. The GE-03 well was designed to produce the southern flank of the faulted anticlinal Gannet E field. The well targeted the Orange and Pink sands, subdivisions of the Tertiary-age Forties turbidite sandstone. These deep marine sands typically have high net-to-gross pay intervals with 30% porosity and 1-darcy horizontal permeability. Completion engineers chose a gravel-pack screen completion to minimize sand production from poorly consolidated sandstones. Optimal drainage and the need to minimize early water breakthrough required positioning the horizontal-well sections as close as possible to the top of the Forties reservoir while penetrating both the Orange and Pink sand units.

Seismic data resolution was insufficient to accurately determine fault locations, structural dip and exact facies thickness. During prejob planning, engineers used static and dynamic reservoir models to define a projected well path within the producing zones. Forward modeling of expected geoVISION resistivity image-log response highlighted the benefits of real-time borehole-scale imaging for well placement (above). On the basis of this work, the Shell subsurface team chose to use real-time LWD resistivity-based geoVISION images for both geological analysis and trajectory adjustment while drilling.

7. Standoff is the distance between the external surface of a logging tool and the borehole wall. This distance has an important effect on the response of some logging measurements, notably, density and neutron porosity logs. For resistivity tools, the effect of standoff is taken into account in the borehole correction.

8. For more on lambda permeability: Herron MM, Johnson DL and Schwartz LM: “A Robust Permeability Estimator for Siliciclastics,” paper SPE 49301, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, September 27–30, 1998. A Stoneley sonic wave is a type of large-amplitude interface, or surface, wave generated by a sonic tool in a borehole. Stoneley waves can propagate along a solid-fluid interface, such as along the walls of a fluid-filled borehole. They are the low-frequency component of signal generated by sonic sources in boreholes. Analysis of Stoneley waves can provide estimation of the locations of fractures and permeability of the formation. Stoneley waves are a major source of noise in vertical seismic profiles.

9. Net-to-gross is the volumetric ratio of reservoir sand to total rock present.


11. Borehole scale refers to resolvable formation features smaller than the borehole diameter.
The BHA consisted of the PowerDrive rotary steerable system for directional control and a GVR tool for gamma ray, resistivity and real-time imaging. An APWD Annular Pressure While Drilling sensor monitored equivalent circulating density (ECD). The PowerPulse MWD tool provided telemetry, direction and inclination information while transmitting all downhole data to surface at a rate of 6 bps, a transmission rate sufficient to generate real-time geoVISION resistivity images.

A water-base drilling fluid provided compatibility with the gravel-pack completion planned for the horizontal wellbore section. The conductive water-base fluid also provided the environment necessary for geoVISION imaging.

The borehole was to be drilled to the top reservoir, placing the beginning of the horizontal section, also known as the heel, in the Pink sand and then drilling a horizontal drain back through the Pink shale into the Orange sand (above). The far end of the horizontal section, or toe, was likely to encounter a lower net-to-gross Orange sand sequence as observed in nearby offset wells. Wellbore placement in the Orange sand sequence was crucial. During drilling of the horizontal section through the sand-shale layers, geoVISION resistivity images verified penetration of oil-bearing sands. These real-time images were useful in monitoring and adjusting trajectory angle. Building angle too slowly could result in drilling parallel along only one sand or shale horizon. Drilling up-section too quickly could result in penetrating weak overlying shale, resulting in loss of productive wellbore length and potential borehole collapse that would compromise completion-hardware placement (see “Identifying Borehole Fractures and Failures,” page 34).

While the reservoir section was being drilled, a satellite communications link continually transmitted geoVISION images and associated Digital Log Interchange Standard (DLIS) data from the rig to a subsurface team in Aberdeen.
Scotland. After processing the data on a UNIX workstation using the BorView borehole-imaging product of GeoFrame system software to enhance image quality, the onshore team interpreted the images in real time. Hand-picked dips based on formation features visible in the images updated the geological model at a finer scale than could be achieved from seismic data.

The geoVISION image data provided fault orientation and locations while determining wellbore trajectory relative to projected formation dip. Interpretations were validated by comparison to biostratigraphic analyses and cuttings data from the rig.

The real-time imaging and drilling data tools delivered valuable structural information (left). GeoVISION resistivity images and other data analyzed while drilling the angle-build section indicated formation tops slightly deeper than projected but with the expected structural dip. Although more frequent than anticipated, faulting in the horizontal section was clearly visible on the geoVISION resistivity images. Assuming extensional fault movement, often attributed to tensile stress, dip direction could be determined and a sense of displacement inferred. Image interpretation indicated that because of faulting, only a minimal section of the Pink sand was encountered.

Average resistivity and gamma ray log curves alone would not have adequately identified the location or orientation of faulting. Despite small deviations from the geological prediction, the...
Recognizing borehole failure and instability, and understanding how and why failures occur, are vital to successful drilling operations. Properly managing borehole stability minimizes nonproductive time and is central to drilling optimization. When stresses around a borehole exceed formation strength, irreversible shear or tensile deformations occur in the near-wellbore area.

Wellbore images acquired by resistivity or azimuthal density neutron LWD tools can be used for fault identification and fracture diagnosis. Both fracture direction and failure mode can be determined, allowing for more accurate diagnosis and treatment.

Many factors cause or contribute to borehole failure. Tensile failure from excessive equivalent circulating density (ECD) is quite common. Excessive mud weight, annular cuttings buildup, and rates of running casing or drillpipe into the wellbore can cause high ECD. Often, the exact cause of borehole failures goes undefined (right).

The state of stress around the borehole influences drilling efficiency and hole stability. Most geological forces acting on the borehole are compressive and produce shear failure. Other structural forces act to pull rock grains apart, resulting in tensile failure. Shear and tensile failure mechanisms can, and most often do, act independently. Mud weight and drilling-fluid chemistry are often used to minimize the negative effects of unconstrained borehole stresses.

Failure mechanisms have specific associated fracture signatures on borehole images (next page). Each failure mode has a unique pressure regime of high or low mud weight or ECD. The geoVISION imaging technology, coupled with APWD measurements, allows real-time identification of potential failure modes and provides early warning of borehole-instability problems. Drillers can take remedial action for managing borehole instability based on failure diagnosis.

Fracture identification with images. In this example, drilling-induced fracture development can be seen between XX25 and XX50 in a calcareous shale section. Arrows in the real-time geoVISION resistivity image show the onset of a sequence of isolated fractures on the low side of hole (top). A few hours later, the geoVISION resistivity data collected during reaming indicated development of a single, long fracture with increased width across the same depth interval (bottom). Curves show shallow-, medium- and deep-resistivity measurements from left to right.
The application of geomechanical models that incorporate image and pressure data has a direct and immediate impact on drilling optimization and well-completion design. Results from these models help generate recommendations for remedial strategies that might not have been considered. The ability to distinguish natural features and formation properties from drilling-induced artifacts improves both petrophysical and geological interpretations.

Recognition of natural fractures, a source of potential fluid influx or loss, can be important in managing drilling risk and safety hazards.

Shear versus tensile failure. This example shows both breakouts and drilling-induced fractures over the same interval, suggesting the mud weight is both too high (tensile failure) and too low (shear failure). While this may appear contradictory, both failures can result from a narrow mud-weight window caused by highly unbalanced far-field horizontal stresses. With mud weight too low, formation fluids may enter the wellbore or the wellbore may fail; if too high, the wellbore may be fractured, resulting in loss of circulation.

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The operator anticipated difficulty in maintaining reservoir contact while drilling through non-sedimentary volcanic reservoir rock.

The Yurihara field development project was conceived in 1999. Production and depletion studies suggested that proper design and placement of multiple horizontal wells would triple the current production. Engineers from JAPEX and Schlumberger concluded that wireline-conveyed FMI data would establish target markers from a proposed pilot hole, although a real-time imaging solution would be needed for trajectory control in the horizontal section.

JAPEX performed studies that established proprietary methods for FMI evaluation in volcanic reservoir rock. Similarities between FMI and GVR measurement techniques imply that similar procedures could be used for real-time image interpretation.

Drilling of a 12 1/4-in. pilot hole at 45° inclination began on June 23, 2002. The drilling plan called for an FMI tool run at TD to establish the directional kickoff point, initial trajectory and resistivity markers. Borehole irregularities precluded the FMI logging tool from reaching TD. A GVR imaging tool logged the lower pilot-hole section. The petrophysical team picked dips by hand from processed FMI and geoVISION resistivity data. Indications of oil and gas confirmed the presence of reservoir rock.

With resistivity and gamma ray markers as a guide, drilling the horizontal section began on July 18, 2002. In the reservoir, drillers adjusted direction and inclination using real-time geoVISION resistivity images. Data were transmitted to JAPEX in Tokyo, Japan, for further evaluation. Drilling relatively featureless volcanic rock does not allow calculation of formation dip with any degree of certainty. Despite the absence of dip calculations, real-time images of the productive pillow-lava rock helped the wellsite team keep the borehole path within reservoir boundaries (left). Image-guided drilling continued for 25 days. The wellbore path was maintained within the target reservoir at an average inclination of 87° through MD of 3100 m [10,171 ft].

Success of the SK-16DH drilling project demonstrated the accuracy of geosteering using real-time resistivity imaging, even in volcanic reservoir rock. Downhole drilling risks were minimized while accurately placing the wellbore. During 2003, geoVISION resistivity real-time imaging and geosteering will help place additional horizontal wellbores in the Yurihara field. Because of this drilling project, surface hydrocarbon-handling capacity will be tripled in early 2004.

Unusual image character of pillow lava. Pilot-hole FMI data were used to generate the left image, while the right image was compiled from the sidetrack-section geoVISION resistivity data (note different scales). In these excerpts from the JAPEX SK-16DH well, the absence of bedding planes and structural character is typical of pillow lava, also known as ellipsoidal lava. When underwater basalts erupt, the congealing of extrusive lava results in elongated mounds formed by repeated oozing and quenching of the molten rock. A flexible crust forms around the newly extruded material, forming the pillow-like structure. Pressure builds until the crust breaks and new basalt extrudes like toothpaste, forming another pillow. The sequence continues, potentially forming a thick bed of volcanic material.

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Imaging in Nonaqueous Environments

Resistivity-based imaging technologies, such as the GVR tool, require conductive borehole fluids—their use is generally precluded when drilling with oil- or synthetic-base mud. In contrast, density tools function independently of drilling-fluid type, enabling real-time density-based imaging even in nonconductive environments.

The adnVISION development project built on the successful deployment of real-time geoVISION resistivity imaging systems. Adaptation of GVR telemetry technology to the adnVISION density tool required only minor modification of the encoding algorithms. The GVR tool utilizes 56 azimuthal data points, or bins, while the adnVISION tool uses only 16. Dropping from 56 to 16 data bins effectively reduces image resolution, although sufficient image quality remains for geosteering and structural analysis.

The current hardware and software configuration allows only one real-time image type to be transmitted at a time, either density or resistivity. A DownLink signal to the tool can switch transmitted data types at a time, either density or resistivity. A DownLink signal to the tool can switch transmitted data types, data-telemetry and analysis systems.

ConocoPhillips Petroleum Company, operating in the Norwegian sector of the North Sea, applied adnVISION density-imaging technology on their Ekofisk platform. The engineering team, utilizing real-time density images, properly placed a borehole through a production horizon in a synthetic drilling-fluid environment—a non-conductive fluid.

Primarily based on data from adnVISION density images, the subsurface team adjusted borehole trajectory, allowing the driller to follow the productive-zone bedding plane. At 13,500 ft [4114 m], real-time density images indicated bedding planes dipping more than expected. Prewell seismic interpretations predicted 5.6° bedding-plane dip, while real-time calculations indicated 6.2° of dip. At 13,900 ft [4236 m], the reservoir boundary was crossed. Noting a trajectory shift from down-structure to up-structure and viewing real-time density images, the geosteering team ordered the driller to drop angle, returning the borehole to a down-structure drilling attitude within the target structure (above). As a direct result of real-time imaging, the borehole remained on target and penetrated an additional 400 ft [122 m] of pay.

Real-time density imaging allowed the operator to quickly recognize and compensate for unanticipated structural-dip variance, a situation that could have resulted in being lost-in-hole, potentially requiring a sidetrack well. The application of the adnVISION system in nonconductive environments is a significant advancement in real-time imaging technology.

Future Vision

The oil and gas industry is striving to reduce well-construction cost while increasing production. In response, operators are drilling fewer, but more challenging, high-productivity multi-target wellbores, and doing so in increasingly demanding environments.

Operators and service companies alike continue to focus on obtaining, moving and analyzing data for decision-making processes at increasingly faster rates. The continued emphasis on delivery and processing of real-time reservoir information is likely to bring about significant advances in downhole instrumentation, data-telemetry and analysis systems.

Real-time data acquisition and imaging technologies, in conjunction with advanced satellite and network communications systems, will lead the way to enhanced productivity, lower downhole risk and improved return on investment. — DW

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