Oilfield Review

Spring 2003

Borehole Seismic Innovation

Wellbore Imaging Update

Screenless Completions

Reservoir Sedimentology

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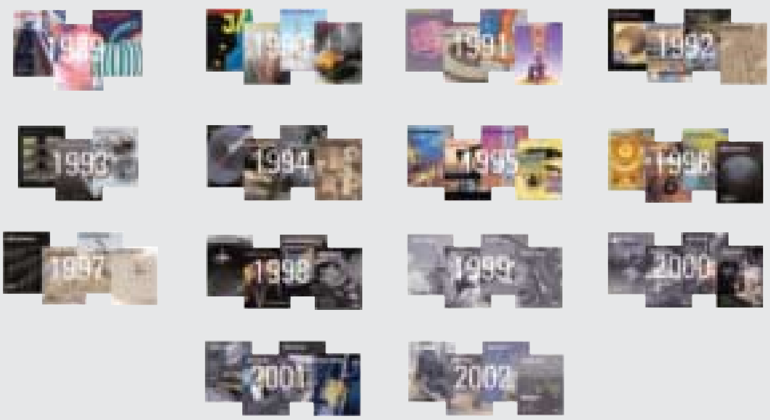

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Meeting Challenges with New Technology

Recent geopolitical events remind us that international and local volatilities affect most of the world's large hydrocarbon deposits and hinder long-term stabilization of supplies and prices. Even though energy demand is likely to grow, we must remain focused on cost-effective oil and gas exploitation. The petroleum industry needs to discover and develop new reservoirs, and at the same time, increase recovery from existing fields.

Technology and skilled people are the foundations for meeting this dual challenge and building a more successful energy business. In addition to steady improvements in environmental protection and wellsite health and safety, operators have realized major gains in operational efficiency and well productivity. These strides have come primarily through new technologies that dramatically change the way oil fields are discovered, developed and produced.

The latest advances in deepwater drilling rigs improve well-construction operations, reducing both time requirements and costs. Compared with conventional methods, monobore wells and new expandable tubulars allow drilling of smaller holes. Offshore, this translates into smaller risers and blowout preventers. Innovative well completions facilitate the application of these "lean-profile" drilling techniques.

Screenless completions, for example, offer cost-effective alternatives for rigless well interventions. To date, this sand-control technology has yielded encouraging results (see "Screenless Methods to Control Sand," *page 38*). Screenless techniques provide fullbore access across productive intervals and maximize reserve recovery by allowing completion of bypassed zones or rehabilitation of wells with plugged gravel packs and screen failures.

Improvements in directional drilling, logging-while-drilling and measurements-while-drilling, and new bit designs have led to record-breaking drilling achievements, including extended-reach wells that exceed 10 km [6 miles]. Because directional control is easier, wellbore trajectory can be adjusted rapidly if difficult drilling conditions are encountered, and we can accurately place wells within a few feet of an intended target. These are key factors in the shift to high-angle, horizontal and multilateral wells. One well with a complex trajectory or multilateral configuration that intersects several reservoir targets can achieve the same objectives as several vertical wells.

Advanced rotary steerable systems, topdrive rigs and superior drilling fluids facilitate rotation of the entire drillstring to minimize the risk of stuck pipe and promote hole cleaning in upper hole sections. Smoother boreholes significantly increase penetration rates and drilling efficiency, and facilitate subsequent well-construction operations.

Innovative cement systems improve primary cementing and zonal isolation by decoupling fluid characteristics from slurry density. Recent cementing technology provides a range of slurry densities from extremely low to extremely high without sacrificing compressive strength, hydraulic isolation or prevention of gas migration. Nondamaging polymer-free fracturing fluids based on viscoelastic surfactant technology improve both gravel packing and hydraulic fracturing. The net result is better field operations and enhanced productivity from depleted and ultradeepwater reservoirs alike.

As we undertake projects in deepwater and frontier areas, real-time monitoring of reservoir behavior using permanent sensors will help maximize asset value and financial performance. Sophisticated downhole gauges in intelligent completions supply continuous data and link with remote flow-control devices. This real-time information allows us to predict reservoir behavior, manage production and make adjustments that increase recovery.

Our success in timely and effective implementation of new technologies and maximizing their pass-along benefits depends on how we manage corporate and industry-wide knowledge. Lessons learned, best practices and expertise must be validated, retained and shared in an integrated environment. The speed of company intranets and the Internet give us unprecedented access to the best and most up-to-date information when decisions must be made, but these data must be validated and promptly available.

Knowledge databases are most effective when technical communities share information, learn from each other and reuse what is already known. Companies should reward knowledge sharing among employees to build on and apply existing resources and expertise. In this way, we can bridge the gap between advising and decision-making communities, thereby empowering everyone to use the knowledge available within the petroleum industry and our own organizations. Partnering with a service provider through an alliance also allows oil companies to extend their technical resources by integrating the technology and dedicated work force of the alliance partner.

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Angelo Calderoni has been vice president of Technical Services–Well Operation at division headquarters in Milan, Italy since February 2003. He joined Agip in 1979 as a junior drilling supervisor and worked in several operational and managerial drilling and completion positions in various countries. In 2001, he became general manager and deputy managing director in Venezuela, where he pioneered the Dación development, which is operated by an alliance between Eni Venezuela and Schlumberger. Angelo holds several patents in drilling technologies and is active in the SPE, serving as membership chairman of the SPE Italian Section from 1996 to 2000. He obtained a degree in electrical engineering at the University of Bologna, Italy.

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On the cover:

The sedimentary character of the Pennsylvanian Morrowan fluvial-deltaic deposits at Searcy Quarry, White County, Arkansas, USA, is clearly visible in the rock-wall face. Obtained from a test well about 140 feet [43 m] behind the quarry face, an FMI Fullbore Formation MicroImager* well log provides an excellent formation to wellbore image-log correlation. The reference scale is 5 ft [1.5 m] per color increment. Thanks to Rick Kear, Schlumberger Principal Geologist, New Orleans, Louisiana.

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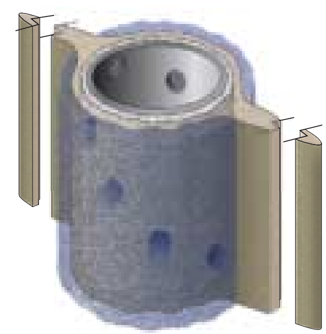
2 Superior Seismic Data from the Borehole

Borehole seismic surveys help oil and gas companies reduce exploration and development risk and enhance field value. Advances in borehole seismic acquisition, in the form of a new, versatile downhole receiver array and innovative source-positioning system, help geophysicists acquire large amounts of high-quality data cost-effectively. Case studies demonstrate how borehole seismic surveys illuminate targets and hazards ahead of the bit, produce images while anchored inside drillpipe, pin-point small-scale structures for development-well planning, characterize reservoir fluid content and image in three dimensions.

24 Wellbore Imaging Goes Live

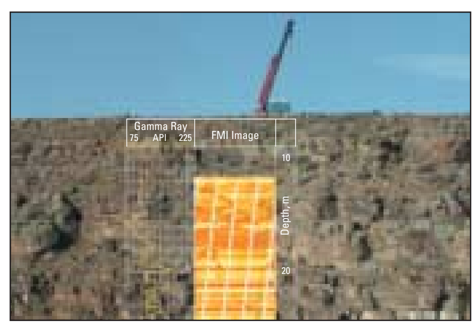
Advances in downhole instrumentation, telemetry and data processing are bringing real-time borehole visualization closer to the field. On-site drilling and petrophysical teams make fast, accurate operational decisions based on intuitive visual interpretations of the downhole reservoir environment. Wellbore construction and placement are optimized for maximum efficiency. This article reviews the basic technology of LWD imaging tools and techniques, and explores examples of how operators are using real-time imaging.

38 Screenless Methods to Control Sand



Novel well-completion techniques prevent sand influx without using mechanical screens. When engineered and executed carefully, these methods reduce cost and risk by eliminating conventional sand-control equipment and rig operations. This approach helps operators rehabilitate production and tap bypassed zones to improve reserve recovery; it also maintains fullbore access across pay intervals. We review associated rigless technologies and screenless applications in Saudi Arabia, the Gulf of Mexico and Italy.

54 Investigating Clastic Reservoir Sedimentology



Geoscientists are using a growing number of downhole tools to examine oil and gas reservoir sedimentology. New data-analysis and visualization software, coupled with new interpretation methods, exploit the expanding capabilities of borehole-imaging technology. Unprecedented levels of detail and sophistication improve reservoir models by incorporating sedimentological models, surface and subsurface analogs, and more detailed data and analysis. This article focuses on the contribution of today's borehole imaging tools to clastic reservoir optimization.

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82 New Books and Coming in *Oilfield Review*

Superior Seismic Data from the Borehole

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Understanding reservoir extent, content and performance requires the integration of spatially extensive information from surface seismic surveys with vertically sampled logs and other well data. Borehole seismic surveys are uniquely positioned to forge this link by quickly providing high-resolution, calibrated answers for drilling and development decisions.

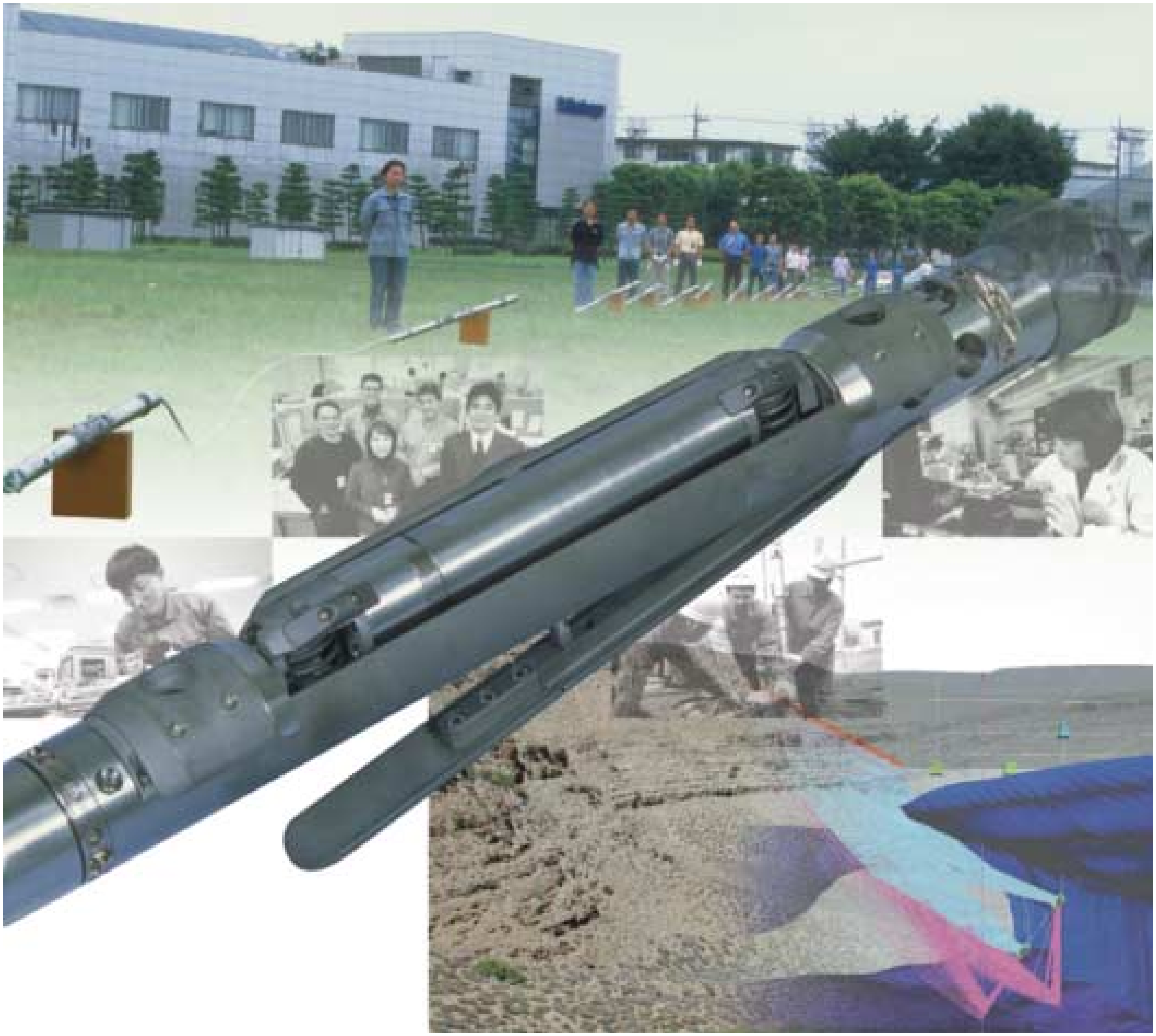
The value of any oilfield technology can be assessed in terms of its ability to reduce risk. It follows from this axiom that borehole seismic surveys bring high value to exploration and production (E&P) endeavors. They reduce risk in two important ways. First, they feed vital depth and velocity parameters to surface seismic surveys, effectively pinning seismically imaged layers to precise borehole depths and extending well information into the interwell volume. Second, they provide independent, high-resolution images and information about elastic properties to investigate hundreds of meters around the wellbore and beyond the current well depth.

The first of these risk-reducing methods was a basic well-tie technique designed to bring time-based surface seismic sections into the depth domain. From this humble beginning, geophysicists have since developed a wide variety of sophisticated calibration techniques. Drillers now plot an updated drill-bit location relative to the seismic section using time-depth information acquired with borehole seismic tools deployed while drilling.[1] Geophysicists can use log and borehole seismic data to predict seismic response and plan better surface seismic surveys.

Wave-propagation information from borehole seismic surveys helps enhance signals and suppress noise in processing surface seismic data acquired in the same area, improving the quality of new and existing survey results and restoring true amplitudes to processed data. Borehole seismic recordings of both compressional, P, and shear, S, waves, known as multicomponent recording, coupled with acquisition at multiple source-receiver offsets, help distinguish lithology contrasts from fluid-content changes. Multicomponent, multioffset seismic recording in the borehole also helps quantify directional wave-propagation effects caused by velocity

For help in preparation of this article, thanks to Phillip Armstrong, Fuchinobe, Japan; Bernard Frignet, La Defense, France; Andy Fryer and Les Nutt, Houston, Texas, USA; Kristian Jensen, Gatwick, England; Alberto Malinverno, Ridgefield, Connecticut, USA; Dwight Peters, Clamart, France; and Mark Van Schaack, Bergen, Norway.

1. Breton P, Crépin S, Perrin J-C, Esmersoy C, Hawthorn A, Meehan R, Underhill W, Frignet B, Haldorsen J, Harrold T and Raikes S: "Well-Positioned Seismic Measurements," *Oilfield Review* 14, no. 1 (Spring 2002): 32–45.
2. Anisotropy is the variation of a material property depending on the direction in which it is measured. Certain formations exhibit seismic velocity anisotropy, in which velocity measured parallel to bedding or fractures is different from velocity measured perpendicular.
3. Wuenschel PC: "The Vertical Array in Reflection Seismology—Some Experimental Studies," *Geophysics* 41, no. 2 (1976): 219–233.
   Christie P, Dodds K, Ireson D, Johnson L, Rutherford J, Schaffner J and Smith N: "Borehole Seismic Data Sharpen the Reservoir Image," *Oilfield Review* 7, no. 4 (Winter 1995): 18–31.
4. Breton et al, reference 1.

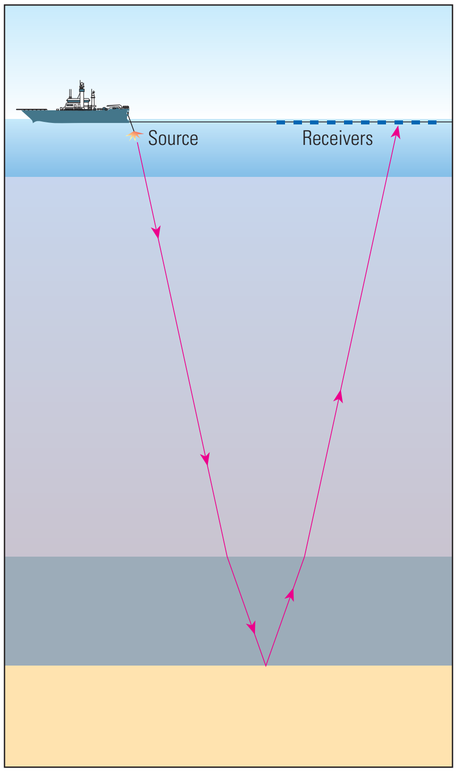


anisotropy.[2] Accounting for these effects during surface seismic processing provides more accurate images of the subsurface.

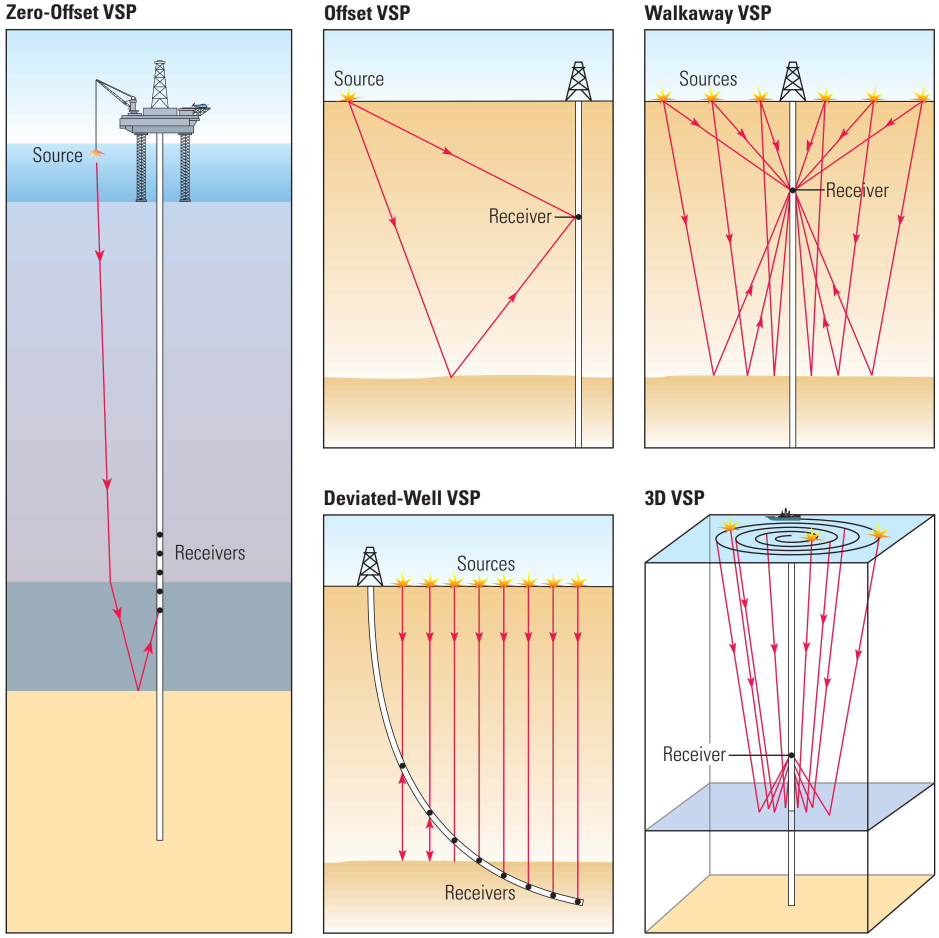
The second risk-reduction technique is borehole seismic imaging. This, too, has come a long way since the early days of the vertical seismic profile (VSP).[3] Simple seismic images now can be obtained from data recorded in the memory of borehole tools deployed as part of the drilling bottomhole assembly, giving drillers an indispensable look ahead of the bit to hazards, markers and target layers.[4]

In highly deviated holes, borehole seismic tools, like other wireline logging tools, have a history of deployment on drillstring. However, when drilling conditions demand full-scale surveys without removing drillpipe, surveys acquired by tools pumped through drillpipe can generate high-quality borehole seismic data. In addition, high-resolution seismic images can be acquired in deviated wells to help refine interpretations of reservoir structure, accurately delineate faults and stratigraphic variations, and aid in the planning and placement of sidetrack drainholes.

This article contains several examples of the newest applications of seismic surveys from the borehole. First, we describe advances in technology



^ Surface seismic acquisition, with a seismic source on or near the surface and receivers also located on or near the surface.



^ Borehole seismic acquisition, with an array of receivers in the borehole. In a zero-offset vertical seismic profile (VSP), the source is located near the rig (*left*). Other borehole seismic survey configurations include offset VSPs with the source offset from the well position; walkaways, with multiple source offsets in a line; deviated-well VSPs, sometimes called vertical-incidence VSPs, with the source vertically above multiple positions of the receiver in a deviated borehole; and 3D VSPs, with source lines in a grid or spiral above the target.

that make it possible to acquire large amounts of high-quality data efficiently and cost-effectively. Then, we present case studies that demonstrate the power of borehole seismic surveys to bring answers to a full range of users, from drillers and well planners to seismic interpreters, geophysicists and engineers.

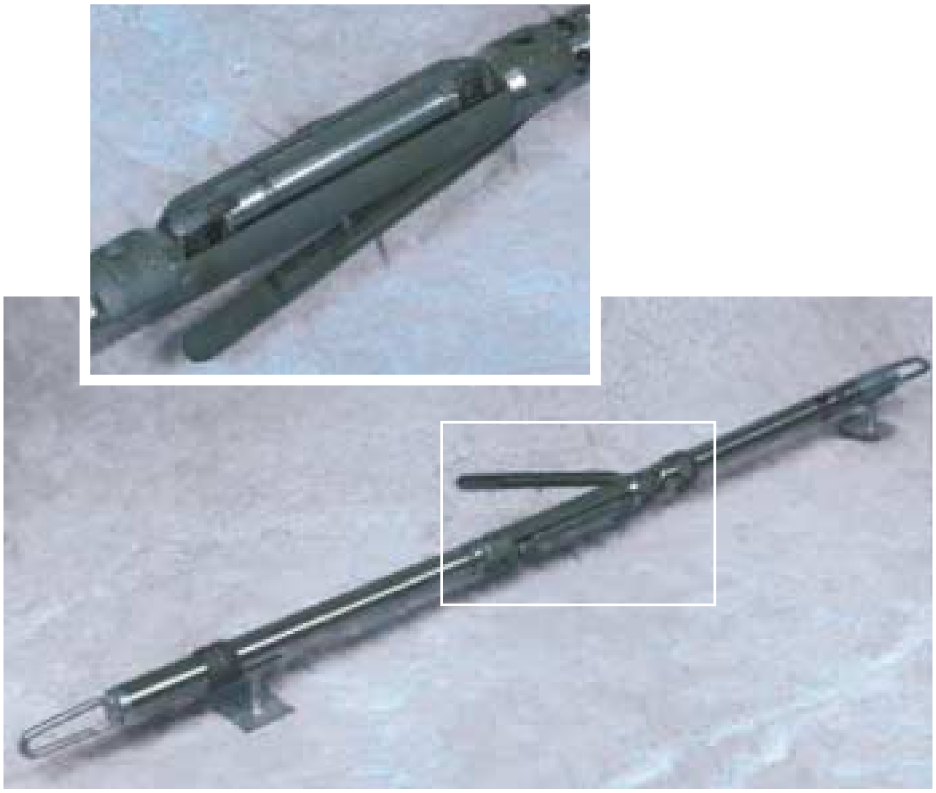
Borehole Advantages

Standard surface seismic surveys use a seismic source on or near the Earth surface that emits energy that reflects at subsurface interfaces and is recorded by a set of receivers also located on or near the surface (above left). The volume imaged by these surveys depends on subsurface structure, acoustic velocities and the disposition of sources and receivers, which can be deployed at numerous surface locations.

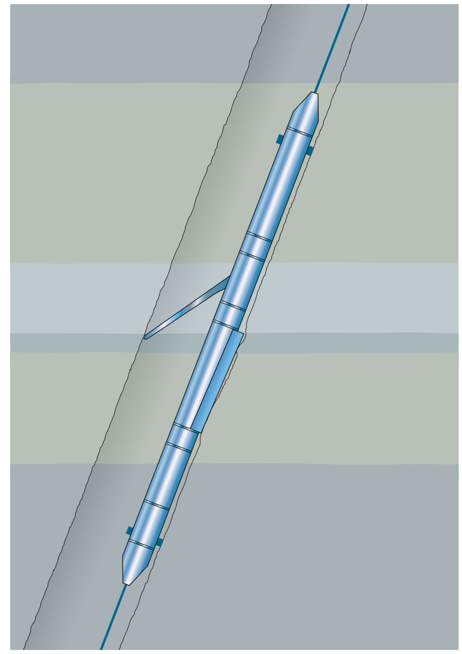
Borehole seismic surveys differ in that receiver locations are restricted to the confines of a borehole (above). While this constraint limits the image volume, it also confers several advantages to seismic surveys in the borehole. For example, waves that travel from a surface source, reflect off a subsurface reflector and then arrive at a borehole receiver are less attenuated by shallow low-velocity layers, having traversed them only once, instead of the two times traveled by surface seismic waves.

The borehole usually is a quieter environment than the surface, so receivers can collect data with higher signal-to-noise ratio. Receivers clamped in the borehole record multiple components of seismic energy in the form of converted shear and direct compressional waveforms, whereas towed marine seismic and standard land seismic acquisition methods record a single component of data that is processed to enhance only compressional arrivals.

Borehole receivers can record direct downgoing arrivals—or those signals that travel directly from the source without reflecting first. Changes in direct signal recorded at multiple calibrated borehole receivers help determine the attenuation properties of overburden layers. Knowledge of attenuation properties helps restore portions of signal lost during transmission of both borehole and surface seismic waves. Receivers can be positioned accurately at specified depths in the borehole, allowing geophysicists to derive a profile of layer velocities at the well location. This helps convert time-indexed surface seismic data to depth, so seismic images can be tied to well-log data, and drill-bit positions can be tracked on seismic sections.



^ The Schlumberger VSI Versatile Seismic Imager tool. Up to 20 of these multicomponent shuttles (*top*), spaced 3 to 20 m [10 to 66 ft] apart, can be configured and run in a single string. The tool was designed and built by Schlumberger engineers at the SKK Product Center in Fuchinobe, Japan (*bottom*) and is shown here on the lawn at SKK.



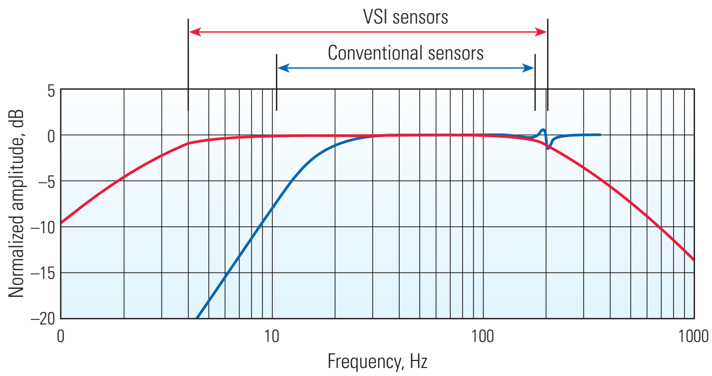
^ Anchored VSI shuttle. Each shuttle is acoustically decoupled from the main tool body and forcefully pushed against the borehole wall. The anchoring arm provides effective coupling of the sensor in boreholes ranging in diameter from 3½ to 22 in. [9 to 56 cm].

Versatile Tools for Improving Acquisition

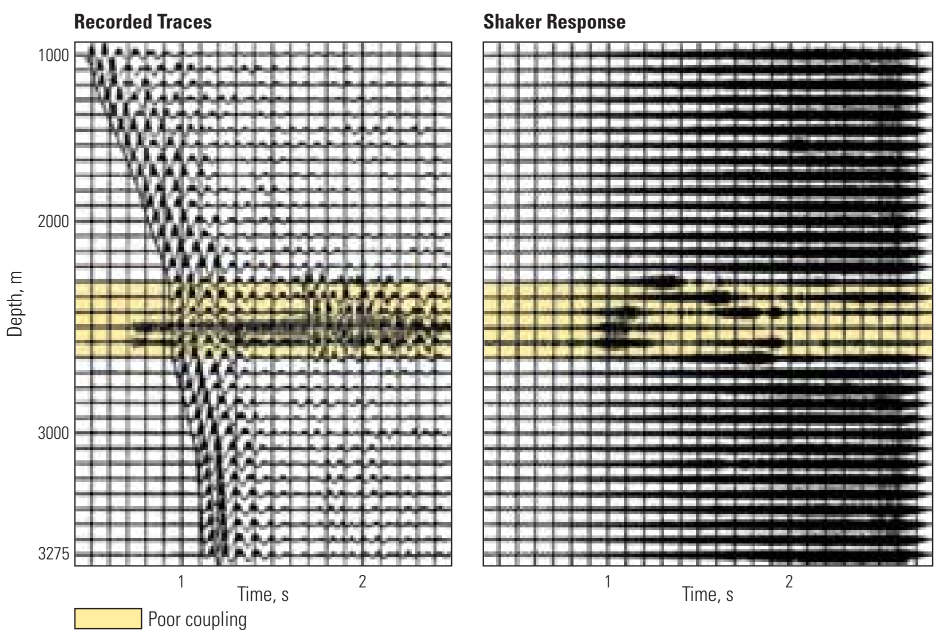
For Schlumberger, the foundation for high-quality seismic data from the borehole lies with the VSI Versatile Seismic Imager tool (above). This wireline tool consists of up to 20 lightweight, multicomponent sensor modules, called shuttles, whose sensor packages are acoustically decoupled from the main tool body. Each sensor package is pressed against the borehole wall with a force at least 10 times its weight (above right). This ensures that all components of particle motion in the formation are faithfully recorded, and improves signal-to-noise ratio. Strong anchoring, diminutive size and effective decoupling of the sensor package from the shuttle body provide the means for removing tool-harmonic noise and tube waves from the seismic response.[5] The tool can be anchored in hole sizes ranging from 3½ to 22 in. [9 to 56 cm] in diameter.

Spacing between shuttles can be set from 3 to 20 m [10 to 66 ft], depending on imaging requirements; most jobs are run with 15-m [49-ft] shuttle spacing. In one specially modified 20-shuttle tool, shuttle spacing was increased to 100 ft [30 m], allowing 2057 ft [627 m] of coverage from a single shot. Rapid deployment of the

5. Tube waves are wave multiples that travel up and down in the wellbore fluid, and can dominate the late-time portion of borehole seismic waveform data. Hydrophones are especially susceptible to the effects of these waves because hydrophones respond to pressure changes in the wellbore, while geophones are coupled to the formation and are less susceptible to these effects.



^ Response of VSI accelerometers (red), flat from 3 to 200 Hz. The ability to record frequencies below the 10-Hz lower limit and above the 100-Hz upper limit of traditional borehole geophones (blue) allows the VSI tool to record wide-bandwidth data for high-resolution images.



^ Real-time wellsite assessment of VSI shuttle anchoring quality. For each tool level, the shuttles are anchored to the borehole. Quality of the shuttle-to-borehole coupling is tested by activation of a shaker within each shuttle. If the shuttle is not anchored adequately (yellow shading), response to the shaker (*right*) is irregular, and recorded traces (*left*) contain noise.

mechanical anchor allows the tool to be unclamped and moved quickly to another level for efficient acquisition. The VSI array can be combined with other wireline tools, such as a gamma ray tool for accurate depth identification, an inclinometry tool for spatial orientation, or other logging, imaging and sampling tools for time- and cost-efficient data acquisition. Each VSI shuttle has a relative-bearing sensor to measure tool orientation in deviated holes.

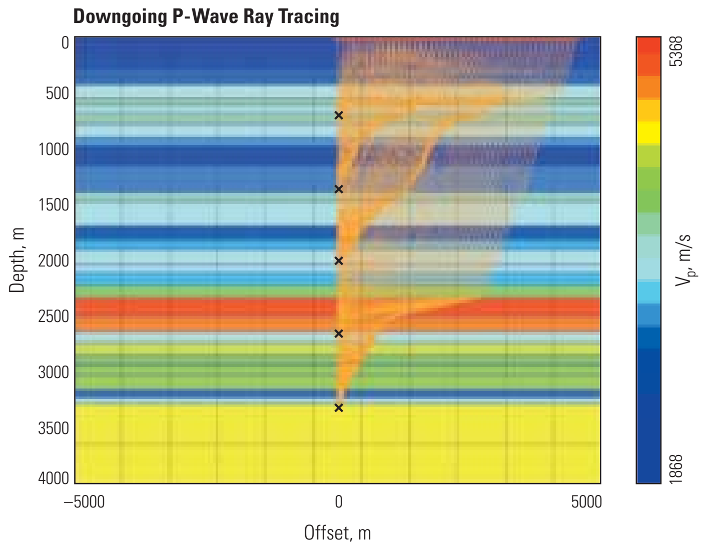
Each VSI sensor package contains a three-axis accelerometer. The accelerometer response, which is flat from 3 to 200 Hz, provides excellent sensitivity within the borehole seismic frequency band (top). The wide bandwidth and high-frequency sensitivity improve resolution, and the ability to record frequencies below 10 Hz makes signals from this tool especially useful for constraining acoustic-impedance inversions.

Borehole irregularities can make some borehole seismic tools difficult to anchor, preventing proper coupling between sensor and borehole. In the VSI tool, each shuttle contains a shaker that tests sensor-borehole coupling by emitting a sweep of frequencies in the seismic band. Once the tool is anchored, the field engineer activates the shakers and monitors the accelerometer response of each shuttle to detect poorly anchored shuttles. If the tool is adequately anchored, acquisition proceeds. If not, the tool is moved slightly to a new level, anchored and submitted to a new shaker test (below left).

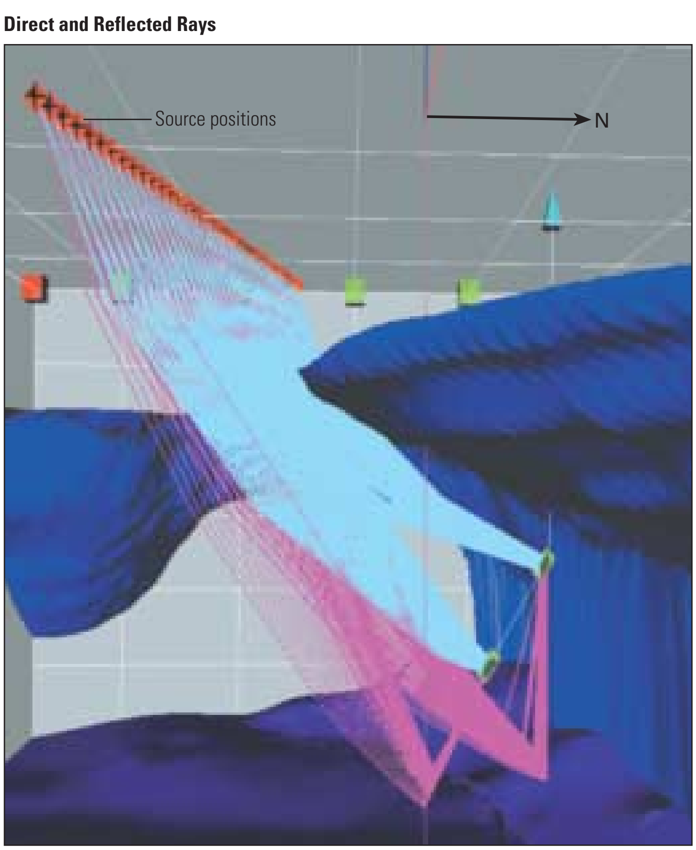
Determining the appropriate locations of sources and receivers in a borehole seismic survey requires modeling survey-acquisition response to an earth model. The two main types of modeling tools are full wavefront-propagation schemes—such as finite-difference models—and ray-tracing programs to visualize ray paths between source and receiver. A look at some recent ray-tracing results gives an idea of the complexity involved in designing borehole seismic surveys.

One example from a land survey acquired in Algeria shows the effects of high-velocity layers (next page, top). High-velocity layers create problems for both borehole and surface seismic surveys, acting as shields or baffles to wave propagation and giving rise to what is known as "bad data areas," where surveys fail to illuminate what is below the high-velocity layer. This type of problem can occur beneath volcanic and carbonate rocks, salt and other high-velocity formations. Low-velocity zones, such as weathered layers or formations charged with gas, also create wave-propagation problems. Borehole seismic surveys often are called upon to image what surface seismic surveys cannot, or to help plan more effective surface seismic surveys. Modeling helps acquisition crews place borehole receivers at optimal depths and surface sources at optimal locations.

Ray tracing in three dimensions allows survey planners to visualize the effects of other subsurface obstacles and assess how valid a simplified one-dimensional (1D) or two-dimensional (2D) solution may be in solving a given borehole seismic problem, or whether a full 3D VSP approach might be required. An example from the Gulf of Mexico shows rays bending under a salt overhang to arrive at two arrays of seismic receivers in a deviated borehole (next page, bottom). Direct and reflected rays travel from a line of sources to arrive at the receivers without having to propagate through salt.



^ Ray tracing through high-velocity layers to model borehole seismic acquisition in Algeria. The high-velocity layers bend rays (orange lines) severely, forcing survey planners to take care in positioning borehole receiver arrays (black x).



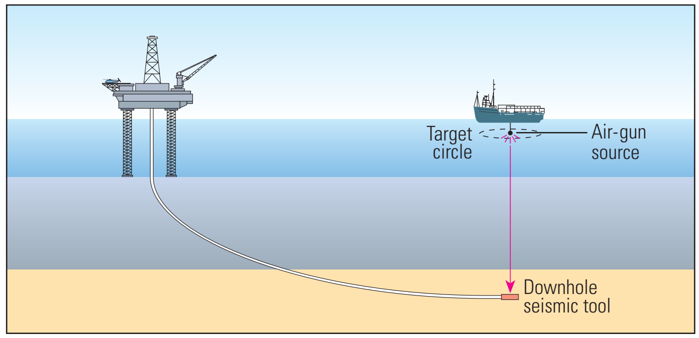
^ Three-dimensional ray tracing for a borehole seismic survey designed to image under a salt overhang in the Gulf of Mexico. Direct rays (blue lines) and reflected rays (pink lines) leave the sources (line of red cubes) and arrive at two receiver arrays in the borehole (green boxes).

Special requirements, such as long offsets, must be met for surveys designed to quantify velocity anisotropy. Similarly, if traces are to be analyzed for amplitude variation with offset (AVO) characteristics, the acquired data must contain the appropriate range of offsets. The time required to acquire long-offset data often must be balanced against the desire to minimize rig time. Modeling during survey planning can assess the priority of these requirements.

During the survey-planning stage, a seismic source is selected that will ensure that survey objectives are met. Amplitude and frequency content of the signal at the target depth are functions of the target depth itself, elastic properties of the overburden, and the seismic source—number and size of guns in an air-gun array, air-gun depth and firing pressure. Working with their WesternGeco counterparts, Schlumberger engineers have compiled a database with more than 150 far-field source signatures for numerous standard and high-performance air-gun sources at various water depths and firing pressures. This information helps survey planners choose the best source for the survey, and also allows acquisition crews to determine safe conditions for source deployment. Today's powerful sources can cause hull damage if fired too close to the deploying vessel. Information from the source-signature database can help determine a distance at which the source, which often is fired several hundred times in a single survey, may be fired safely.[6]

Another improvement in borehole seismic acquisition is the ability to control the position of the seismic source in offshore environments. In a zero-offset VSP, the air guns are deployed from the rig, and their position is easy to determine. However, for more complicated surveys, such as walkaways, deviated-well VSPs or 3D VSPs, the source is deployed from a seismic vessel maneuvered into positions that can span great distances. It is vital to know that the vessel is in the proper source-point position when the source is fired. The consequences of improper source position are potentially bad data, or no data at all. Time spent repositioning the vessel to reshoot missed shots costs survey and rig time.

6. Tulett JR, Duncan GA and Thompson PR: "Borehole Seismic Air-Gun Sources: What's the Safe Distance from a Ship's Hull?" paper SPE 74177, presented at the SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, Kuala Lumpur, Malaysia, March 20–22, 2002.



^ Positioning the source vessel over a borehole seismic tool for a deviated-well VSP. The vessel must navigate into positions exactly above the receiver, for all positions the receiver array takes in the borehole.

^ Display from the SWINGS seismic navigation and positioning system (*top left*), showing two source points on-target (green x) and one off-target (red x). The circle indicates the maximum distance from the planned source point the vessel may be for a shot to be considered on-target.

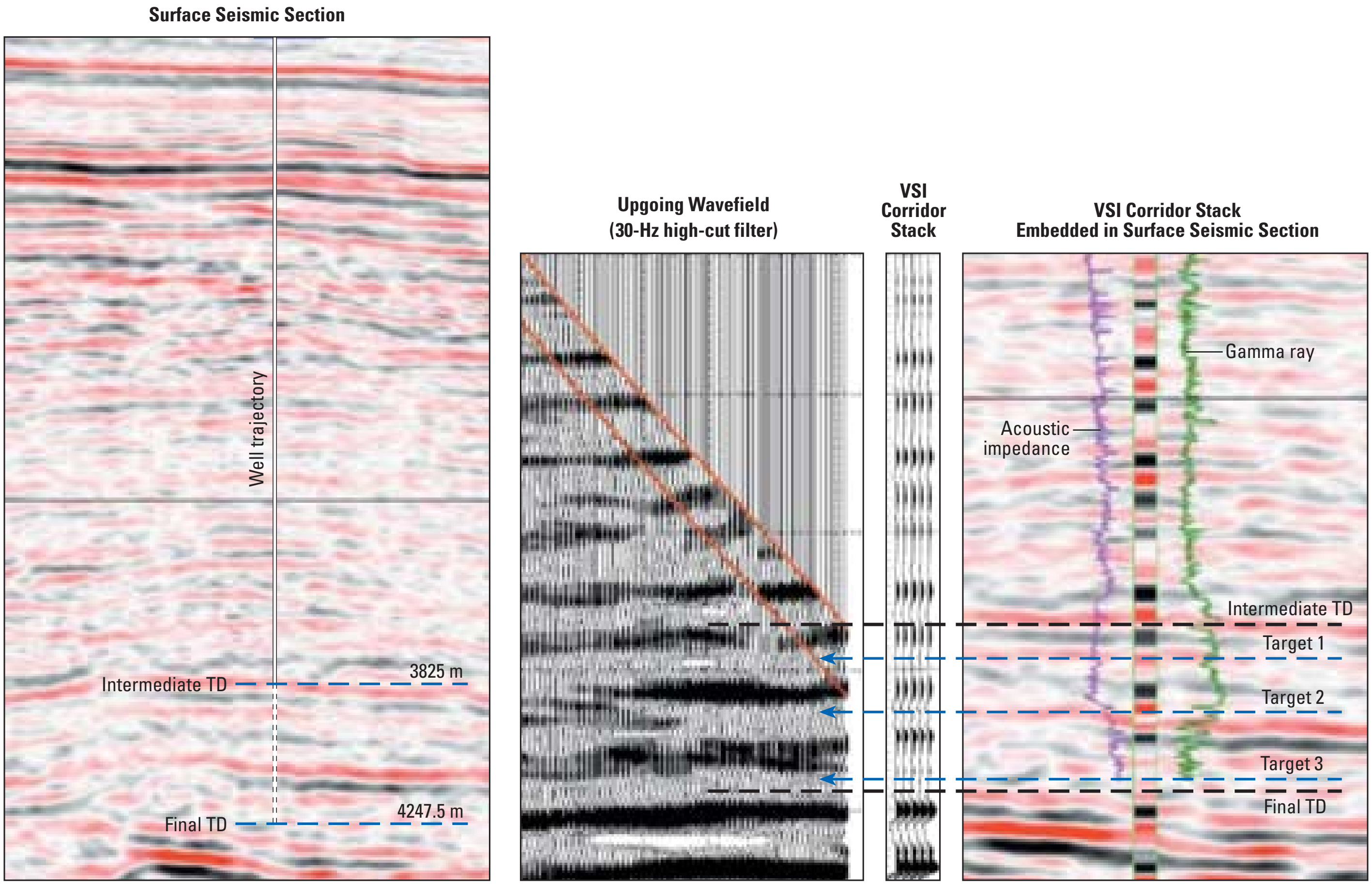
The SWINGS seismic navigation and positioning system was developed to accurately deploy equipment for surface seismic applications in shallow water. It has been updated and customized to add new functionality in source-vessel control on the supply vessels used for offshore borehole seismic acquisition. The system features two 12-channel global positioning system (GPS) receivers that output positions at the high update rate of 5 fixes per second. The positioning accuracy of the onboard GPS receivers is better than 1 m [3.3 ft], and determines source position within 3 to 5 m [10 to 16 ft]. The quality of the source-position measurement, called position-fix quality, is recorded as a quality-control factor.

The navigation system includes a helmsman's position display to give a continuous indication of vessel position relative to the targeted shotpoint. Shotpoints are depicted within a circle that indicates the maximum acceptable distance the vessel may be from the center for the shot to be considered on-target (above right). If the vessel is within this circle, the shotpoint is displayed in green, meaning that the shot, if fired, will be on-target. If the vessel deviates from the desired position, the shotpoint is red, meaning the shot will be off-target (right).

The SWINGS system also features an ultra-high-frequency (UHF) telemetry link that relays source position and position-fix quality to the rig-based logging unit, where this information is displayed for quality control. The source position is passed immediately to the wireline data-acquisition unit and recorded with the acquired seismic data traces. This real-time pairing of navigation data with downhole seismic data removes the need to perform this arduous and time-consuming task in a computing center.

At the wellsite, borehole geophysicists use the Schlumberger proprietary WAVE Q-Borehole field processing system to process VSPs and deliver high-quality results quickly. With WAVE processing, field geophysicists can ensure the quality of acquired three-component data, generate time-depth-velocity plots, process zero-offset and vertical-incidence surveys through corridor stacking and acoustic-impedance inversion, plot rotated wavefields and generate reports.[7] When required, data from large surveys can be compressed to reduce data-transmission times from wellsite to computing center.

The combination of the new VSI borehole seismic acquisition tool, SWINGS enhanced source positioning and WAVE wellsite processing capability forms part of the suite of services known as the Q-Borehole integrated borehole seismic system. Equipped with these improved tools, Schlumberger geophysicists now can acquire high-quality borehole seismic data more cost-effectively than before. Specially trained borehole seismic personnel can perform sophisticated processing, such as inversion, on the rig. These tools have been deployed in many regions and environments, and will be available worldwide in the near future. The rest of this article contains examples showing how the new system provides answers for drillers, well planners, seismic interpreters and other geoscience professionals.



^ Improving upon surface seismic results with an intermediate look-ahead VSP acquired with a VSI tool. The look-ahead VSP, acquired at an intermediate well depth (*center*), shows three main events ahead of the bit and predicts final TD to be 4247.5 m [13,932 ft]. Final TD was reached at 4245.5 m [13,925 ft], within 2 m [7 ft] of the depth predicted by the intermediate VSP.

Answers for Drillers

Seismic surveys in the borehole can help drillers identify horizons and targets in a region ahead of and around the current well trajectory. Called look-ahead VSPs, these surveys are acquired during interruptions in the drilling process. If they are acquired and processed quickly, look-ahead VSPs provide vital information about targets and hazards early enough to influence drilling decisions.

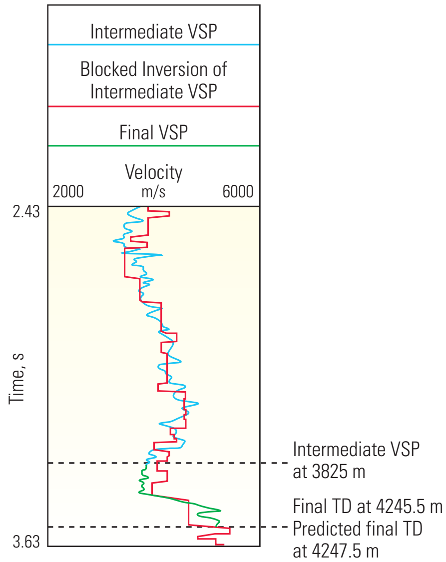
The broad bandwidth and high signal-to-noise ratio of borehole seismic surveys improve vertical resolution compared with surface seismic results. However, because these VSP surveys look ahead of the current bottomhole depth, beyond any receivers, they experience the same time-to-depth conversion uncertainties that plague surface seismic images. In addition to acquisition of VSP traces for imaging reflectors, numerous other steps are required to ensure accurate time-to-depth conversion for a reliable look-ahead image.

First, acquisition must record low as well as high frequencies. While high-frequency content is important for resolving small features, the low-frequency portion of the signal describes the overall increase of velocity with depth, which is vital for positioning imaged features at the correct depth. To invert the recorded arrival times and amplitudes to an acoustic-impedance profile, additional information and inferences are required to constrain velocities ahead of the bit to reasonable values. These typically come from estimated relationships between greater sediment compaction with depth, and increasing velocity and density with compaction. Walkaway surveys can provide the low-frequency velocity information that is missing from zero-offset VSPs.

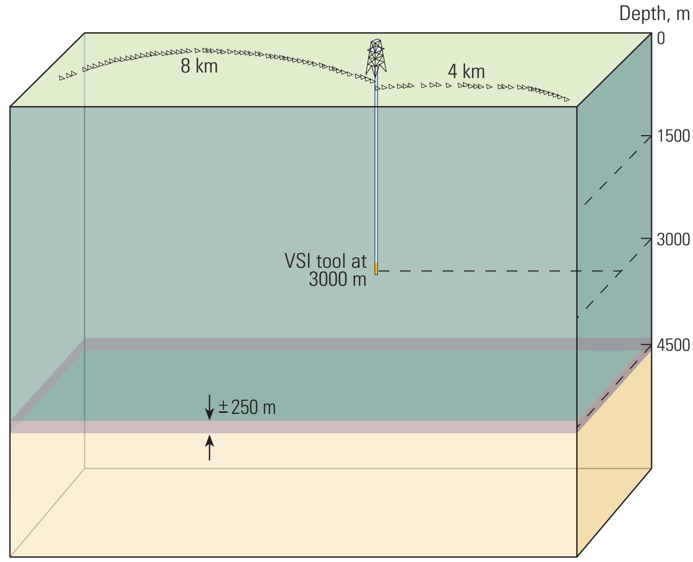
In one example, a North Sea operator faced drilling uncertainties in a vertical exploration well. After the well was drilled to within what was thought to be about 500 m [1640 ft] of final total depth (TD), the distances to three target horizons were still unknown. To see ahead of the current borehole depth of 3825 m [12,546 ft], an intermediate VSP was run using a rig-based seismic source and a VSI tool. From rig-up to rig-down, it took 7 hours to acquire 123 levels of data. The Schlumberger personnel processed data at the wellsite using WAVE field-processing software; stacked waveforms were sent to the nearby Schlumberger office for processing and inversion. Within a few hours of acquisition, the final results were available (above).

The VSI data set showed three main events ahead of the current well depth, and the inversion accurately constrained the depths of those

7. A corridor stack is a sum, or stack, of VSP traces processed to highlight primary reflections, then transformed into two-way time.



^ Comparison of velocity models obtained from VSPs run at intermediate and final TD. Velocities from the look-ahead VSP traveltimes (blue) and from the final VSP run at TD (green) overlay above the intermediate TD. Velocities inferred from acoustic-impedance inversion of the look-ahead VSP (red) are blocky, but do a reasonable job of predicting the velocity trend ahead of the intermediate depth to TD.



^ Configuration of a land-based look-ahead walkaway, with source positions along a 12-km [7.2-mile] line, target at 4500 m [14,760 ft], and the VSI tool with 12 shuttles spaced 15.12 m [50 ft] apart deployed 1500 m [4920 ft] above the target. Uncertainty in the target depth was ± 250 m [± 820 ft] before the look-ahead VSP was acquired.

targets, along with a prediction of the final target TD of 4247.5 m [13,932 ft]. The VSI results were used in the decision to set liner and then drill the final section to reach these targets. Final TD was reached at 4245.5 m [13,925 ft] within 2 m [7 ft] of the depth predicted by the intermediate VSP. A final VSP performed after drilling ended validated the inversion results of the intermediate VSP (above).

In a land example, the operator was drilling for deep, high-pressure gas. Success and safe drilling depended on tracking the position of the bit on a seismic section, where the gas-filled formation was clearly visible. However, at the depths in question—greater than 4500 m [14,760 ft]—time-depth conversion of the surface seismic data has large uncertainties. Before drilling, uncertainty in the target depth was estimated at ± 250 m [± 820 ft]. As an additional complication, much of the overburden was suspected of being anisotropic, with higher horizontal velocities than vertical velocities. If unaccounted for, anisotropy adds to the uncertainty in time-depth conversion and affects the quality and accuracy of the seismic image.

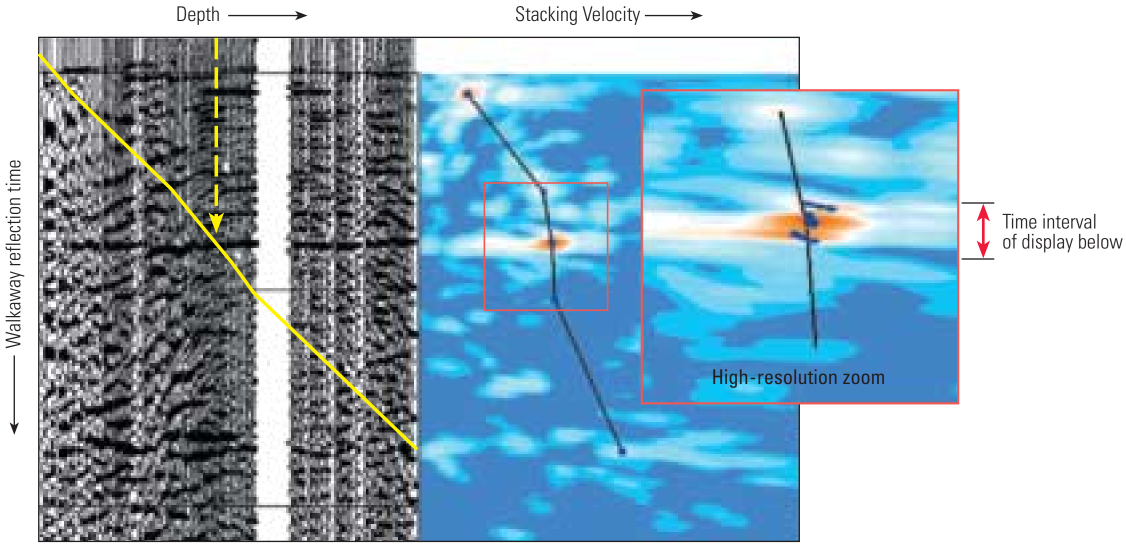
Plans were developed for an intermediate look-ahead VSP that could deliver an updated velocity field to improve the time-depth conversion and fine-tune the target depth quickly enough to allow drilling to proceed safely. It was determined that, with urgent processing, the data could be acquired and processed in 24 hours. At a position about 1500 m [4920 ft] above the target, a 12-shuttle VSI tool acquired an intermediate look-ahead zero-offset VSP and a walkaway VSP with source positions covering 12 km [7.2 miles] (above). The walkaway survey helped create an independent 2D image of the geological structure in the target area, and also contained long-offset data with information about overburden anisotropy that would enhance the look-ahead prediction.

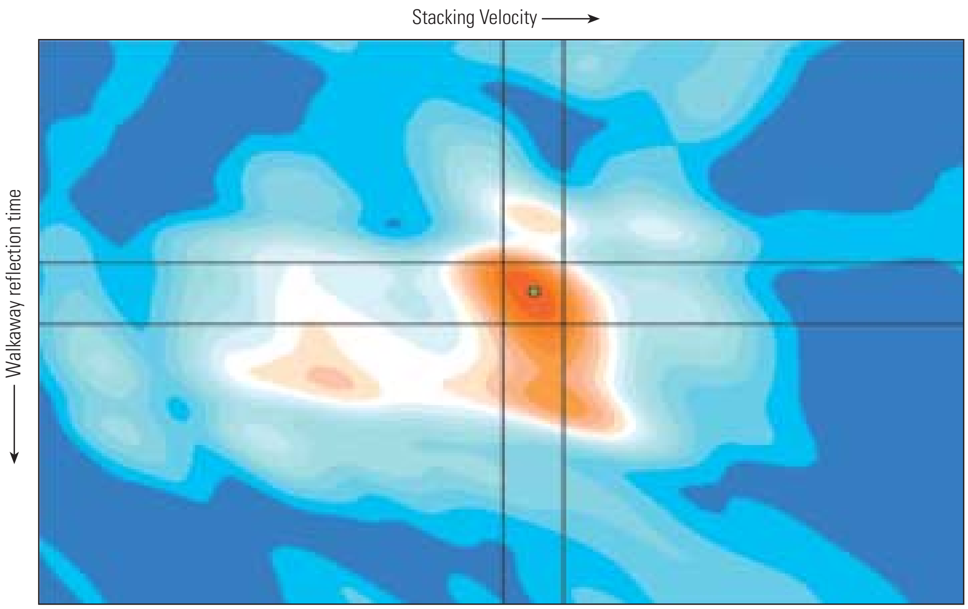
The first intermediate VSP, acquired at the same time as the walkaway survey and processed using stacking velocities and other information from the walkaway, reduced depth uncertainty to ± 75 m [± 246 ft]. A second intermediate VSP acquired 200 m above the target depth estimated by the walkaway reduced uncertainty to ± 10 m [± 33 ft]. Logging-while-drilling information acquired during the last 200 m provided gamma ray and resistivity correlation with a nearby well, further reducing uncertainty to ± 5 m.

The walkaway data set contained more information about long-wavelength velocity variation, and could be processed to predict the target depth with less uncertainty.[8] A first pass at processing the walkaway data used a simplified anisotropic velocity model with vertical transverse isotropy—each flat layer had vertical and horizontal velocities that remained constant within the overburden and below and could be described by two anisotropic parameters. Results from this processing step were delivered to the client via a secure Web site within the time period requested (next page). Once the total depth was reached, it was determined that this prediction, made from an intermediate well depth about 1500 m above the target, was within 58 m [190 ft] of the target.

Since that time, improvements have been made to the processing software, and it is now possible to automatically scan the data for depth-dependent anisotropy. By reprocessing using the depth-dependent anisotropic velocity model derived from the walkaway data, geophysicists now know that the walkaway data could have predicted TD within 5 m at a distance of 1500 m above the target. Intermediate walkaway VSPs run in the future can be processed in the same way for improved look-ahead predictions and reduced drilling risk.

8. For other examples showing how walkaway data with long-offset information help reduce uncertainty in formation properties: Malinverno A and Leaney WS: "Monte Carlo Bayesian Look-Ahead Inversion of Walkaway Vertical Seismic Profiles," presented at the 64th EAGE Conference and Technical Exhibition, Florence, Italy, May 27–30, 2002.
Bryant I, Malinverno A, Prange M, Gonfalini M, Moffat J, Swager D, Theys P and Verga F: "Understanding Uncertainty," *Oilfield Review* 14, no. 3 (Autumn 2002): 13–14.



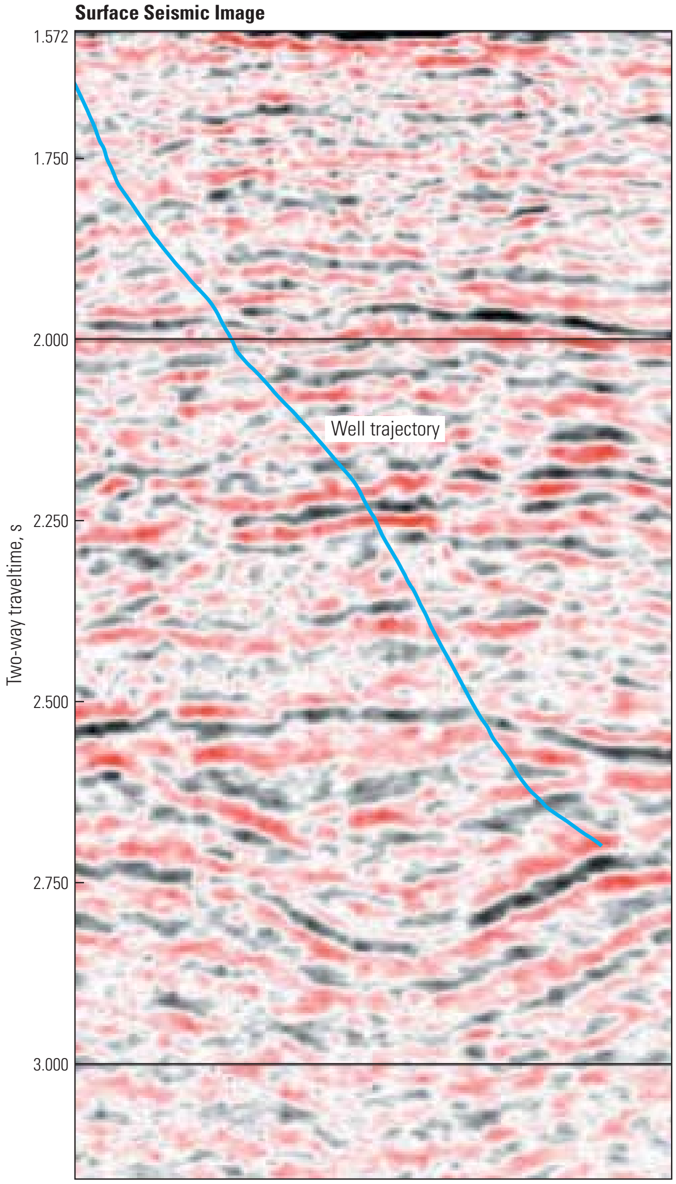


^ Target-depth prediction from velocity analysis of a walkaway VSP acquired 1500 m [4920 ft] above the target (*top*). The additional information from the long offsets in the walkaway brought uncertainty in the target-depth prediction down to approximately ± 58 m [± 190 ft], compared with the zero-offset VSP, which predicted the target depth to within 200 m [656 ft]. The target uncertainty of 58 m corresponds to the size of the darkest orange contour on the stacking velocity versus time plot (*inset at right*). This result from early processing, delivered to the client within 24 hours, assumed an anisotropic model, but with time- or depth-invariant vertical transverse isotropy (VTI) below the receiver. Target-depth prediction from velocity analysis of walkaway data is improved by allowing for more complex anisotropic velocity (*bottom*). After total depth was reached, the walkaway processing scheme was revisited and optimized. By allowing time- or depth-variant anisotropy below the receiver, uncertainty in the target-depth prediction was reduced to ± 5 m [± 16 ft] (orange contour). This new method now can be applied to other look-ahead walkaways for rapid predictions.

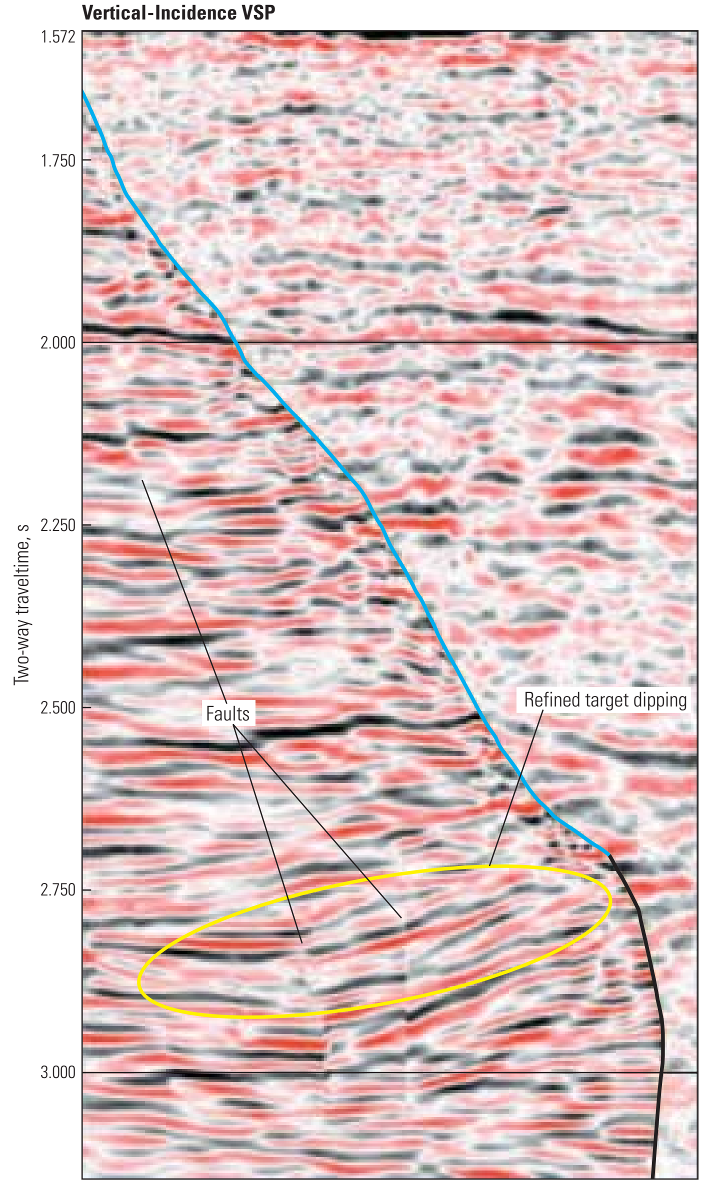
Enhancing Images in Development Projects

Geoscientists working on field-development projects are responsible for identifying promising targets within reach of existing wells. In many cases, the obvious traps have already been drilled. Any remaining reserves are contained in smaller, subtler features that can elude conventional surface seismic imaging. Images from borehole seismic surveys bring small structures and indistinct stratigraphic changes into focus and help asset teams place deviated drainholes with confidence.

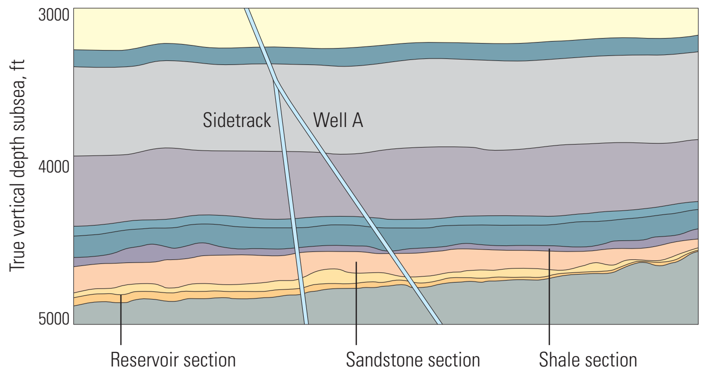
In one North Sea example, a deviated development well was planned to penetrate a target that was identifiable on existing surface seismic



^ Trajectory of a North Sea high-angle, directional development well (blue line) intended to penetrate a dipping target identified on surface seismic data.



^ High-resolution borehole seismic image, illuminating a target below the well path and revealing faults not clearly imaged in the surface seismic section. In the VSP image, the target horizon appears less continuous, with a different dip and crestal position than in the surface seismic section.



^ Cross section of layers, including a thin reservoir interval, intersected by high-angle directional Well A in the North Sea UK sector. A sidetrack was designed to penetrate what was interpreted to be a thicker part of the reservoir, but before the sidetrack was drilled, a vertical-incidence VSP was commissioned to image the reservoir more clearly.

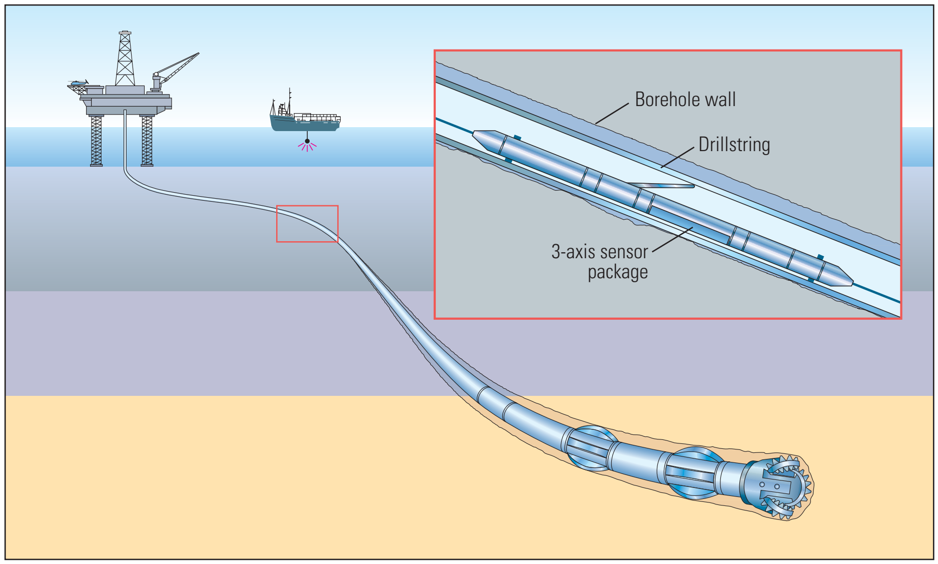
data (previous page, left). Before drilling, well planners needed to confirm the position and dip of the target horizon and neighboring structural features. Initial time-depth conversion of the surface seismic image relied on information from a nearby vertical well. However, lateral velocity variations acutely limit surface seismic depth-conversion accuracy. Depending on geological complexity, a time-depth conversion that was accurate at the control well may be tens of meters off where the deviated development well penetrates the target. A VSP image promised to reduce uncertainty by giving a clear picture of the region beneath the borehole.

A 210-level vertical-incidence borehole seismic survey acquired in 11½ hours provided data to refine the structural interpretation in the vicinity of the borehole. The high-resolution borehole seismic image illuminates the volume of subsurface below the well path and clearly reveals faults not discernable in the surface seismic image (previous page, right). The dip, continuity and extent of the target horizon as seen in the VSP image are significantly different from their representation in surface seismic data.

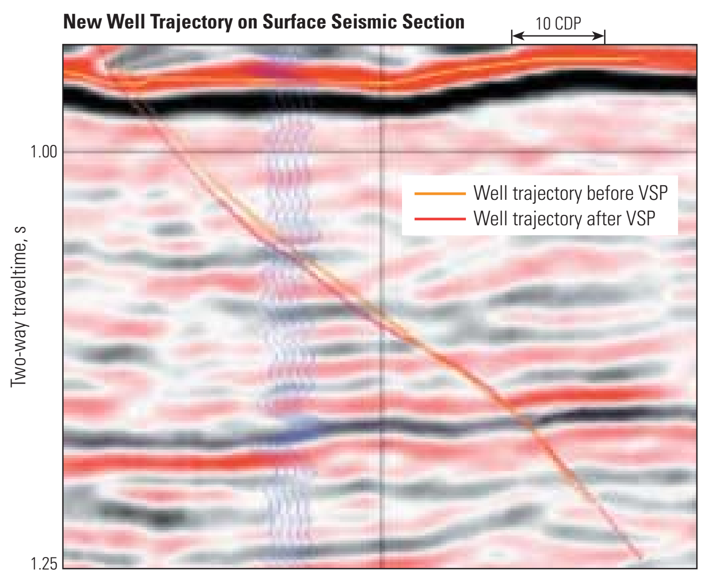
An operating company in the UK sector of the North Sea needed to acquire a VSP for velocity control and high-resolution imaging of target reflections below the well. The original deviated well had contacted only a thin, pinched-out reservoir section, so a sidetrack was planned to intersect the reservoir where it was presumed to be thicker (previous page, bottom). However, in some places the existing well deviated up to 60°, and conventional wireline logging was not recommended. Running the VSI tool on drillpipe would have required removing the drillstring.

Instead, the VSI array was pumped down the drillstring using the Through-Drill Seismic borehole seismic through drillpipe service, and the sensors were coupled to the drillpipe (above right). Between station levels of VSP acquisition, pipe reciprocation and limited mud circulation helped prevent stuck pipe. With the VSI tool, a vertical-incidence 160-level VSP was completed within 7 hours from rig-up to rig-down. The SWINGS seismic navigation system helped ensure accurate source positioning. Data quality was high, even when acquired through drillpipe and 13⅜-in. casing. Processing was carried out at the wellsite with the WAVE field-based software, and compressed stacked waveforms were sent to the office by e-mail for refined processing.

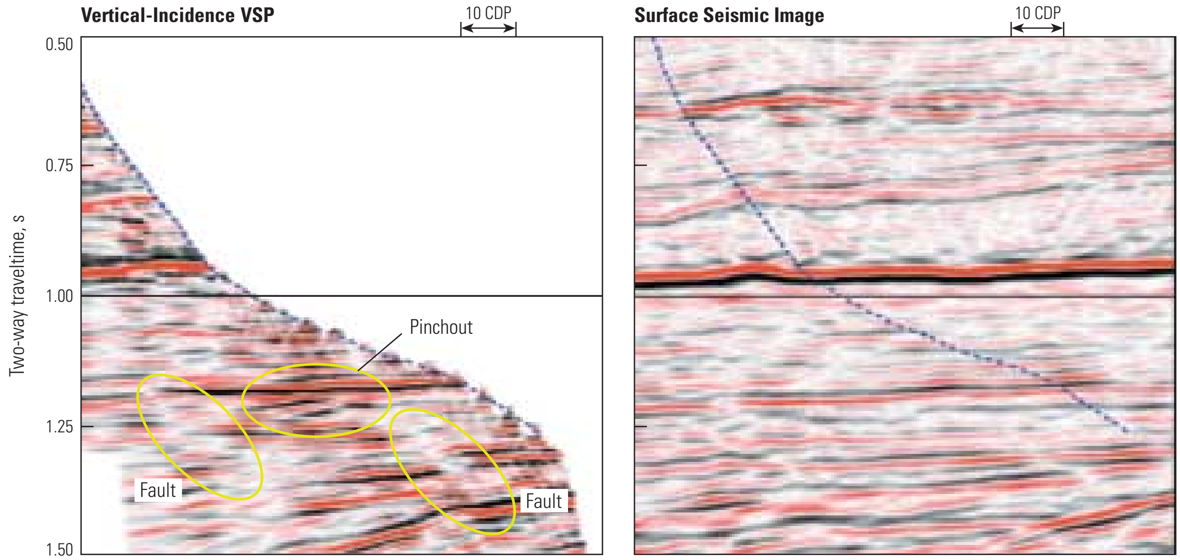
The VSP provided updated velocity information to reposition the well trajectory on the surface seismic image (right). Time-depth information from the VSP resulted in a modified



^ The VSI array, pumped down the drillstring and anchored inside the drillpipe to acquire an intermediate vertical-incidence VSP without pulling drillpipe. The VSI tool acquired high-quality data even through drillpipe plus 13⅜-in. casing.



^ Original (orange) and updated (red) well trajectories plotted on the surface seismic image. Time-depth information from the VSP tied the well TD to a later reflection in the seismic section than the original time-depth conversion. The blue traces represent the corridor stack, or the VSP reflections extracted along the borehole. The horizontal scale refers to common depth points (CDP).



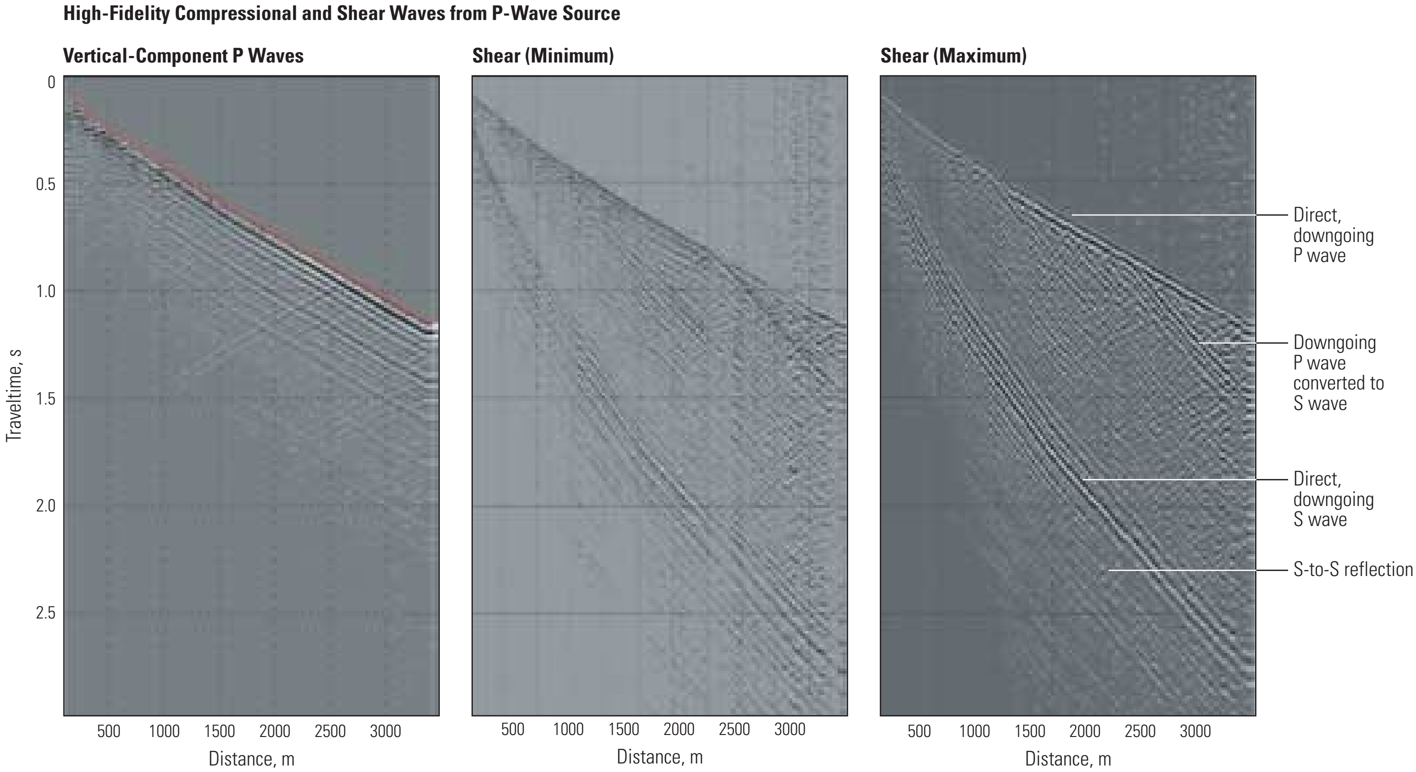
^ Seismic image obtained from the vertical-incidence VSP, showing higher resolution below the deviated well than did the surface seismic section. The VSP (*left*) image highlights faults and stratigraphic pinchouts that are not seen in the original surface seismic image (*right*).

trajectory and seismic tie to the well TD, with true TD at a later seismic reflection than originally supposed. The high-resolution seismic image obtained from the vertical-incidence VSP revealed structural and stratigraphic details that are not evident in the original surface seismic image (above). Faults and additional pinchouts were identified that could affect the success of the proposed sidetrack and subsequent production. Similar Through-Drill Seismic surveys have been acquired in boreholes with deviations from 7 to 90°.

In the prolific gas province of the Burgos basin of northern Mexico, PEMEX is reactivating the Cuitláhuac field (right). The 200-km² [78-sq mile] field has been producing from Oligocene-age sands since 1951. The field is composed of about 20 sand packages that have experienced predominantly NW-SE normal faulting. Each fault block acts as a separate production area, and has different pressures and seismic velocity variations.

PEMEX engineers sought new technology to help identify undrained areas, and found success with the results obtained by the VSI borehole seismic acquisition system. Using P and S velocities and impedances derived from zero-offset and offset VSPs, interpreters hope to track lithology and hydrocarbon-bearing sands to assist future well placement. The VSI tool records three-component wave motion with high fidelity,

^ Cuitláhuac field, in the Burgos basin, Mexico, producing since 1951. Multicomponent VSPs in Cuitláhuac field are helping PEMEX identify reservoir compartments that contain bypassed hydrocarbons.

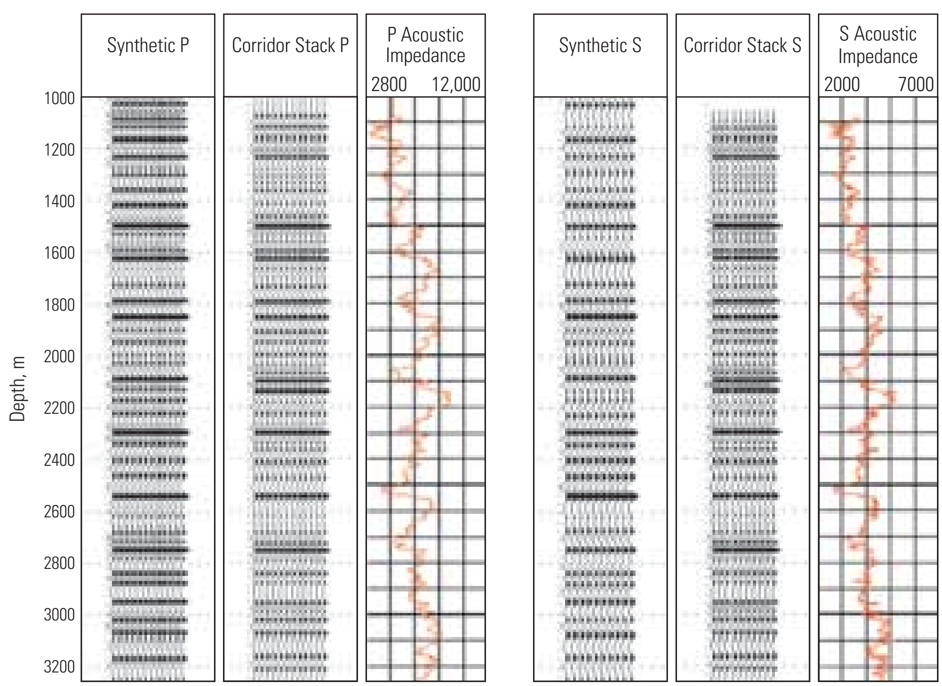


^ Multicomponent data from zero-offset, vertical-well VSP, processed to yield P and S wavefields. The acquisition configuration, with the source near the rig and the receivers in a vertical well, is not ideal for recording shear-wave energy. However, the VSI tool acquires excellent multicomponent data. The vertical component (*left*) contains P-wave arrivals. The tool's two horizontal components have been mathematically rotated to produce one component aligned with the direction of minimum (*center*) and maximum (*right*) S-wave energy.

producing accurate P and S wavefields even when the source type and acquisition geometry are not favorable.[9] An example from the Cuitláhuac field shows strong shear signals from a vibrating source designed to emit only P waves, in a zero-offset source geometry with nearly flat-layer geology (above). The panels of shear data show the expected downgoing P wave and P waves converted to both downgoing and upgoing S waves. In addition, there is an S wave propagating directly from the source along with S reflections.

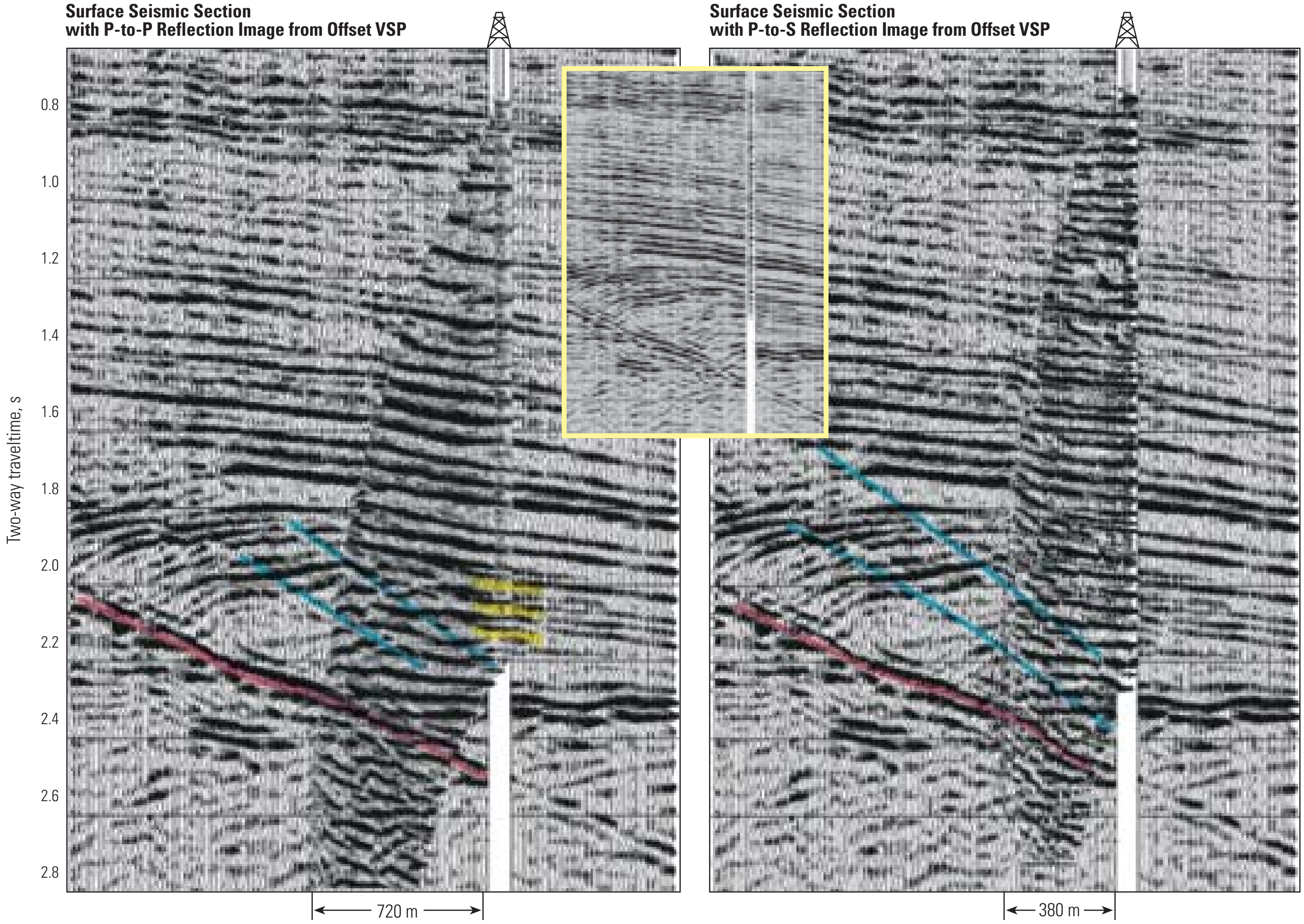
Processing these zero-offset VSP data for P-to-P reflections and S-to-S reflections yields two corridor stacks that may be compared with synthetic seismograms computed from compressional and dipole shear sonic logs calibrated with the VSP velocities (right). The excellent match

9. Armstrong P, Verliac M, Monroy N, Ramirez HB and Leite AO: "Shear Wave Applications from Zero-Offset VSP Data," presented at the 63rd EAGE Conference and Technical Exhibition, Amsterdam, The Netherlands, June 11–15, 2001.



^ Comparison of PEMEX VSP corridor stacks, synthetics and acoustic-impedance models for P and S wavefields. The high-quality match between corridor-stack data and synthetics shows that the acoustic-impedance model is a good representation of subsurface elastic properties.

Surface Seismic and Offset VSP Comparison

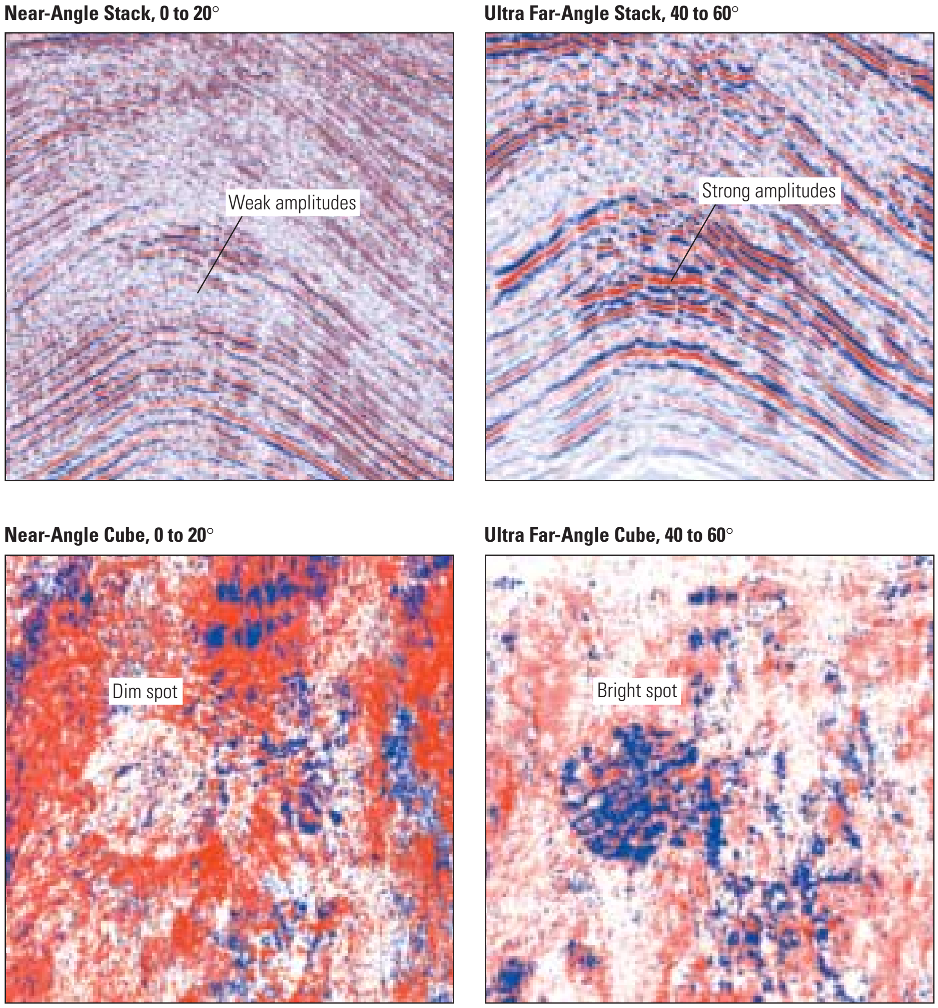


^ Comparison of surface seismic section and offset-VSP images from P-to-P reflections and P-to-S reflections. Productive sands are shown in yellow where they intersect the borehole. A regional fault is interpreted in red. The VSP images give clearer indications of smaller scale faults (blue) and broken reflections that are only implied in the surface seismic section (*inset*). The image derived from S-wave reflections (*right*) has higher vertical resolution, and therefore images finer scale features than the P-wave reflection image (*left*).

shows that the acoustic-impedance model fits the properties of the layers in the vicinity of the borehole, and that normal-incidence seismic amplitudes may be used to infer reservoir properties in this field.

The offset VSP data also were processed to produce images of the subsurface. One image shows the standard P-to-P reflections, while the other shows P-to-S reflections. Both show a good match with the surface seismic section at the well location (above).

PEMEX plans to use the P- and S-velocity and impedance information derived from these and other zero-offset and offset VSPs to constrain lithology and fluid-content interpretations from existing surface seismic data, as well as new multicomponent surveys currently being acquired. Velocity and attenuation information from the VSPs is expected to help in the processing of the multicomponent surface surveys and bring a clearer picture of bypassed hydrocarbons in the Cuitláhuac field.

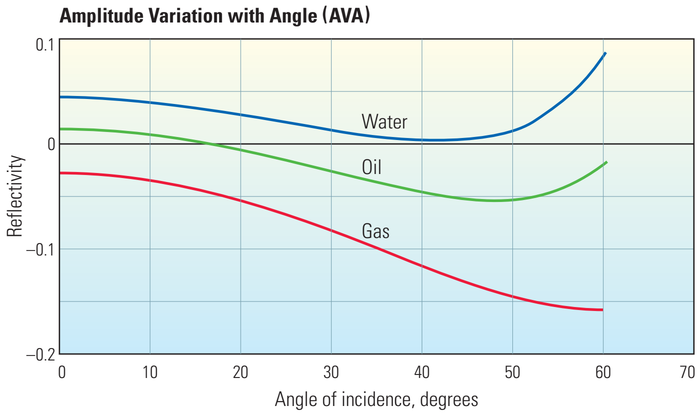


^ A domed structure in deep water offshore Nigeria explored by TotalFinaElf, exhibiting a strong amplitude variation with offset (AVO) signature. A seismic section through a 3D cube containing reflections from only near offsets (*top left*) shows weak, low amplitudes in a flat band near the crest of the dome. A section through the 3D cube containing long offsets (*top right*) shows high, strong amplitudes. A time slice through the near-offset cube (*bottom left*) indicates low amplitudes (dim spot) across the entire circular section of the dome. The time slice at the same time value through the far-offset cube (*bottom right*) indicates high amplitudes (bright spot) across the section of the dome.

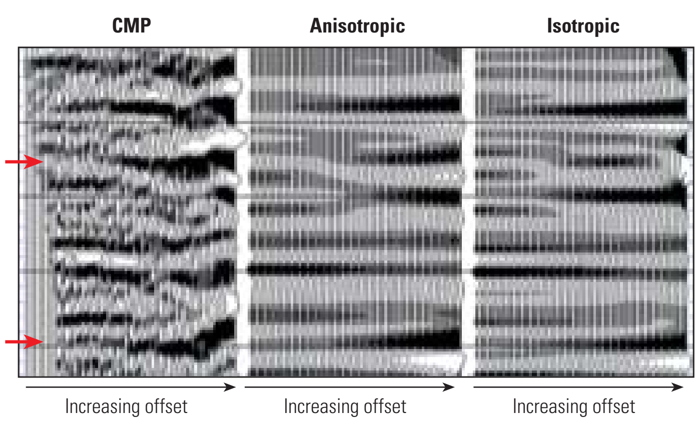
Hydrocarbon Indicators

In a deepwater field offshore Nigeria, TotalFinaElf – now Total – explorers were in the enviable position of evaluating a structure that many geophysical interpreters suspected contained hydrocarbons. The surface seismic expression of the dome features low, weak amplitudes in reflections from near-offset traces, and high, strong amplitudes in reflections from long-offset traces (above). This amplitude variation with offset (AVO)—sometimes known as amplitude variation with angle (AVA)—signature is characteristic of many hydrocarbon-filled sands.[10]

10. Chiburis E, Franck C, Leaney S, McHugo S and Skidmore C: "Hydrocarbon Detection with AVO," *Oilfield Review* 5, no. 1 (January 1993): 42–50.
Leaney WS, Hope RR, Tcherkashnev S and Wheeler M: "Long-Offset AVO and Anisotropy Calibration Deep Offshore Nigeria," presented at the 64th EAGE Conference and Technical Exhibition, Florence, Italy, May 27–30, 2002.



^ Amplitude variation with angle (AVA) for the deepwater Nigerian formation. Oil-filled and water-filled sand have similar, low-amplitude reflections for most angles of incidence, but some small differences may help distinguish one from the other. Assuming constant formation lithology and fluid saturation, amplitude in a water-filled section will decrease from slightly positive to near-zero at an angle of incidence around 40°, then become highly positive. Amplitude for an oil-filled formation will start out slightly positive but near-zero, then experience a polarity switch between 10 and 20°, taking on negative values before returning to zero at 60°.



^ Comparison of AVO information recorded in a 3D surface seismic survey (*left*) with predictions from anisotropic (*center*) and isotropic (*right*) velocity models. Amplitudes vary similarly with offset for the isotropic and anisotropic cases, but minor differences can be identified (arrows) that show the better fit to be between the surface seismic common midpoint (CMP) gather and the anisotropic synthetic gather. At the top arrow, the amplitudes exhibit a polarity reversal, varying from slightly positive at zero offset to largely negative at long offset. At the bottom arrow, the amplitudes vary from slightly negative at zero offset to even more negative at long offset.

However, water-filled sands may have a similar signature (left).

Fortunately for TotalFinaElf, the exploration well encountered significant oil reserves. The next challenge was to use borehole measurements to optimize appraisal drilling and help develop the field at reduced risk. This meant tracking lithology and fluid information away from the well by linking the seismic AVO behavior with petrophysical changes.

The fluid and formation characteristics that can be extracted from borehole measurements are vital constraints for interpreting AVO signatures. Changes in fluid and formation characteristics away from the well can be inferred by comparing actual AVO measurements to modeled responses. If any of the overburden layers exhibits anisotropy, this must be included in the model. Anisotropy affects the angle of propagating and reflecting seismic signals, and thus influences AVO interpretation.

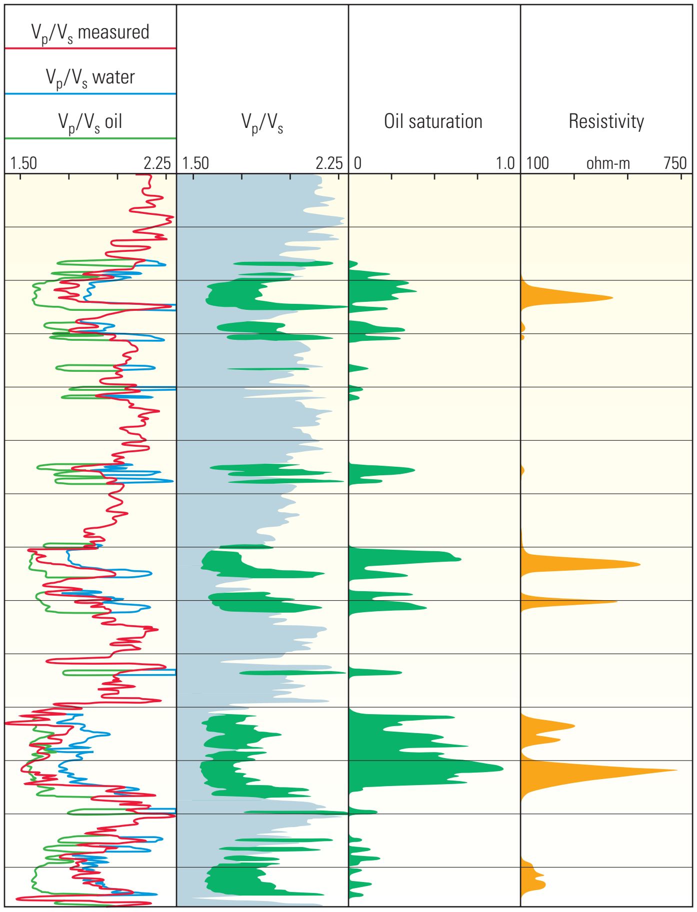
Walkaway VSP surveys with long offsets provide borehole-based AVO information, while density logs and borehole sonic logs of compressional and shear speeds are the necessary initial inputs to the elastic model. In this case, sonic velocities also give a good indication of oil saturation, and compare favorably with information from resistivities in the reservoir zone (next page, left). An advantage to characterizing fluid content with sonic-log data is the ability to use hydrocarbon-saturation information at a larger scale in seismic AVO modeling.

The TotalFinaElf prospect was mapped over more than a kilometer of vertical section using long-offset AVO attributes from a 72-level walkaway VSP and intermediate and final rig-source VSPs, all acquired with the VSI tool. The effects of anisotropy on the walkaway arrival times are clearly visible in a plot of recorded traveltimes compared with modeled traveltimes. When recorded times are compared with times expected from an isotropic velocity model, the difference, called the residual, increases with offset; a good match would show residuals of zero (next page, right). When recorded times are compared with times expected from a vertical transverse isotropic (VTI) anisotropic model, the residuals are small, near zero, showing a good match between reality and the model.[11]

11. A vertical transverse isotropic (VTI) medium has a vertical axis of symmetry. Elastic properties may vary vertically, but are constant in every horizontal direction.

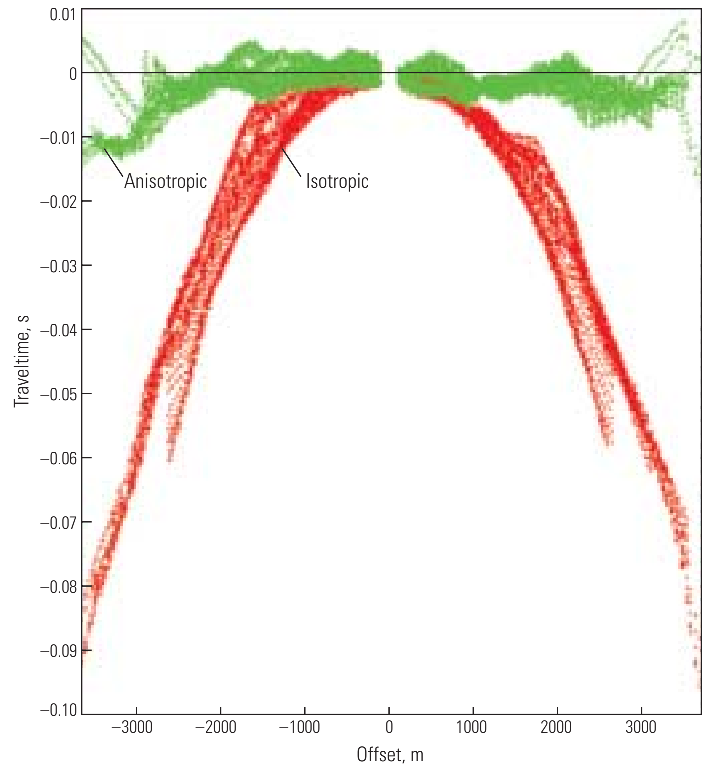
12. Dingwall S, Puech JC and Louden F: "Resolving an AVO Ambiguity with Borehole Acoustic Data—A Case Study," presented at the 65th EAGE Conference and Technical Exhibition, Stavanger, Norway, June 2–3, 2003.

Saturation from Sonic Logs



^ Hydrocarbon saturation in a deepwater Nigeria formation from the V_p/V_s ratio. For some formations, including this one, V_p/V_s ratio is a hydrocarbon-saturation indicator. Track 1 shows V_p/V_s ratios for three cases: oil-saturated (green), water-saturated (blue) and as logged (red). Modeled V_p/V_s values are computed using fluid-substitution methods developed by Gassmann. Inputs are compressional and sonic slownesses, density and gamma ray from wireline logs. Track 2 indicates the maximum (green) and minimum (light blue) V_p/V_s modeled or measured at each depth. Green zones highlight sands where V_p/V_s may serve as a hydrocarbon indicator. Track 3 plots oil saturation derived by comparing modeled with measured V_p/V_s. Resistivity from a deep induction log (Track 4) correlates well with the oil-saturation zones interpreted in Track 3, corroborating the fluid-content information in the sonic logs.

Walkaway Direct Traveltime Residuals

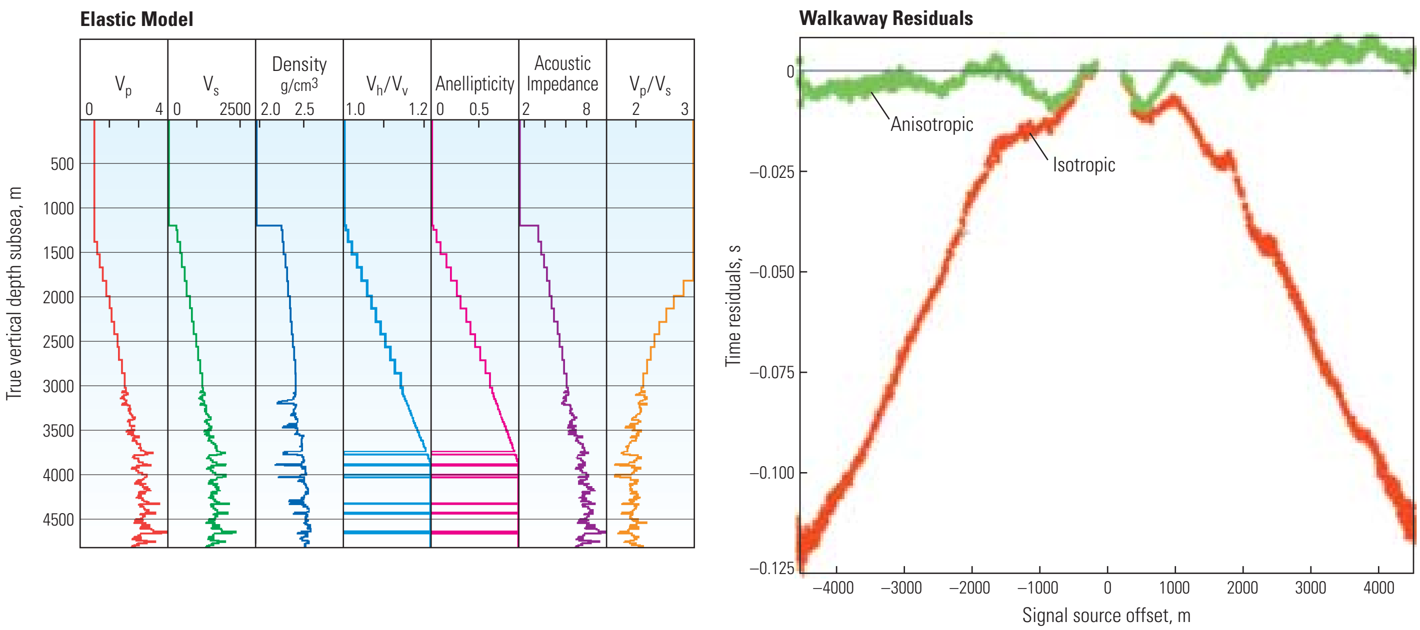


^ Walkaway traveltimes fitting an anisotropic velocity model better than an isotropic model. The differences between recorded arrival times and those predicted from a model are called residuals. Residuals from the isotropic velocity model (red) increase with offset; recorded arrival times are too early, indicating real horizontal velocities are faster than allowed by the isotropic model. Residuals from the anisotropic model (green), which allows horizontal velocity to exceed vertical velocity, are small and consistently near zero, showing that the layers sampled by the walkaway survey are anisotropic.

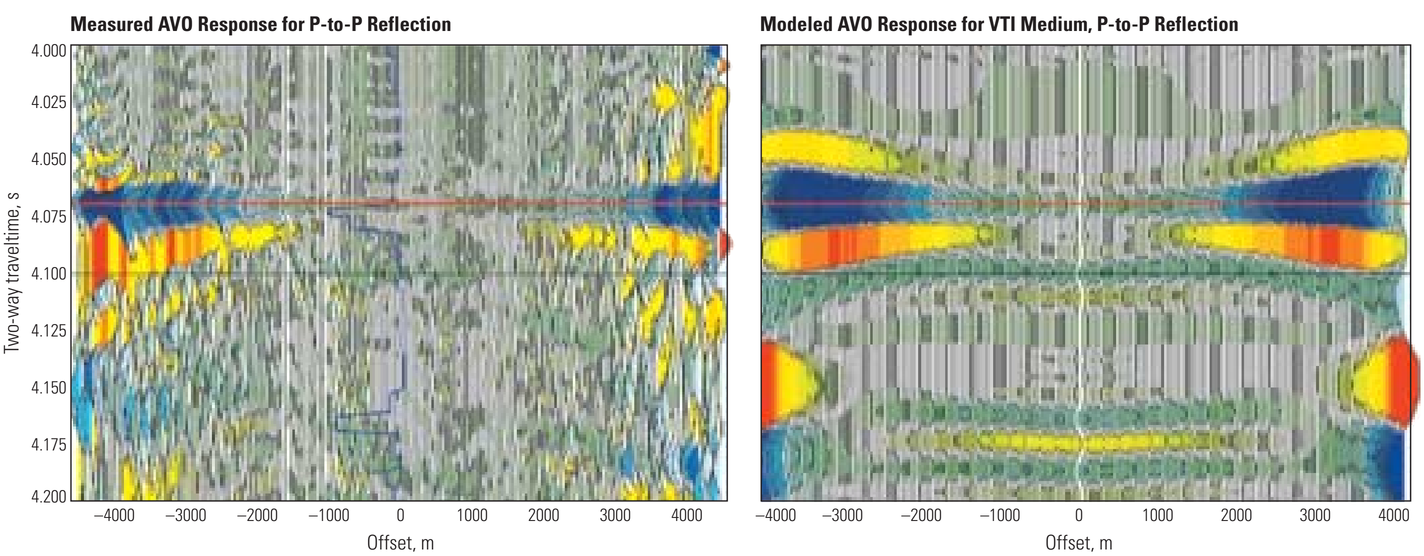
The effect of anisotropy on the AVO signature is more subtle, but still evident to geophysical interpreters. Comparison between surface seismic AVO data and synthetic AVO traces constructed from the anisotropic and isotropic models shows that the anisotropic model fits the data better (previous page, bottom). This shows the importance of including anisotropy in a model for AVO effects. Without the correct velocity model, AVO signatures could be misidentified and linked to changes unrelated to lithology or fluid content.

The extensive borehole geophysics data set acquired in this project has helped link petrophysical, fluid and elastic properties at the well with seismic AVO signatures that can be interpreted away from the well. Including anisotropy in the earth model will help extend the AVO information with confidence. TotalFinaElf geophysicists expect to use the walkaway data further for borehole-calibrated anisotropic prestack time migration of the 3D marine seismic volume acquired over the field.

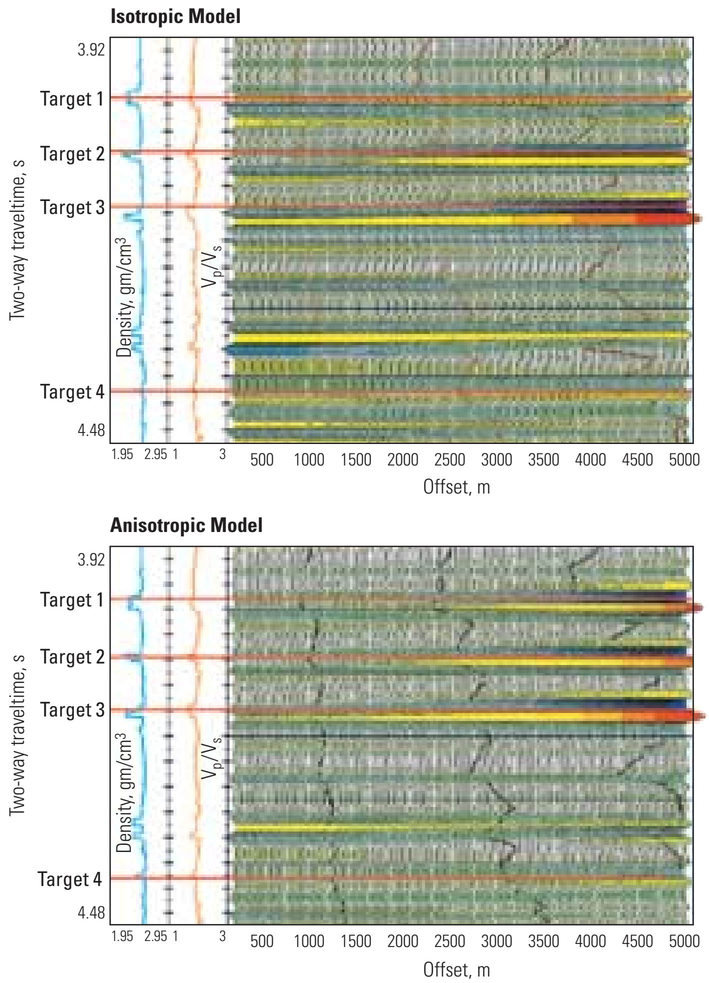
In another deepwater field offshore West Africa, a nearly vertical exploration well encountered the first of what was hoped to be multiple reservoir sands.[12] To assess reservoir quality away from the well, geophysicists wanted to measure and calibrate the AVO response of the top reservoir sand. The sand exhibited a flat AVO response to isotropic forward-modeling but a significant brightening of amplitude with offset on the common midpoint (CMP) gathers acquired. They also wanted to measure anisotropy in the overburden



^ Elastic model (*left*) for an offshore West Africa field, built initially from sonic and density logs and adjusted to include anisotropy in the shale layers. Shale layers are identified by a V_p/V_s ratio greater than 1.85. The residual plot (*right*) shows the difference between observed traveltimes and those from isotropic (red) and anisotropic (green) models.



^ Comparison between the observed walkaway AVO response (*left*) and the response modeled for an anisotropic formation (*right*) at a deepwater target (red horizontal line). Amplitudes vary from negligible at zero offset to highly negative at long offsets. A density log (blue curve) in the center of the measured AVO response (*left*) swings to the left at reservoir targets.



^ Isotropic (*top*) compared with anisotropic (*bottom*) modeling of surface seismic AVO response at four targets. The uppermost target, Target 1, is the level shown in the measured AVO walkaway data seen on page 20, bottom left. The isotropic model yields no perceptible amplitude variation with offset at this reflector, while the anisotropic model produces a clear brightening from dim, negative amplitudes at zero offset to bright, highly negative amplitudes at long offset. The phase angle curves plotted behind each set of modeled traces represent anles of 10°, 25° and 40°, from left to right.

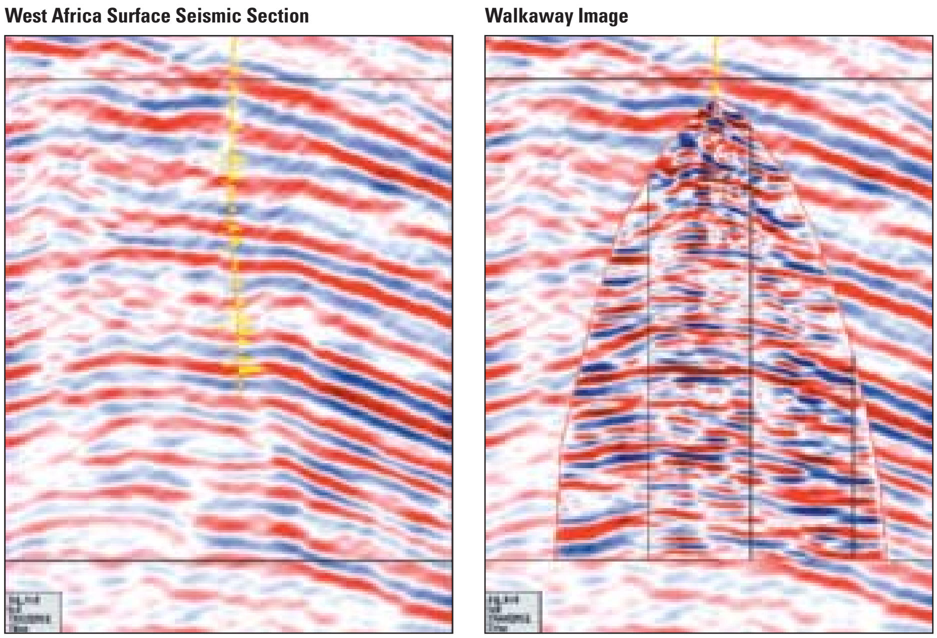
and intervening shales, and obtain a high-resolution image of the deeper reservoir targets.

Two perpendicular walkaway VSPs were acquired using an 8-level VSI tool clamped in a shale zone above the target reservoirs. Survey planning showed that for the velocities and structure expected, walkaway line lengths of 4.5 km [2.8 miles] would produce a suitable range of direct and reflection angles to characterize the AVO behavior of the target horizon at around 3900 m [12,795 ft] depth. The two survey lines intersected at the well position. The SWINGS navigation system assured source-position accuracy.

Overall data quality was excellent. Measuring anisotropy and identifying AVO anomalies require comparison between the walkaway data and synthetics from an isotropic elastic model. The elastic model was built from dipole sonic and density logs, and extended up to the seabed with the help of estimates of velocities and densities from compaction and lithology trends (previous page, top). The extension of this model to include anisotropy was achieved by vertical transverse isotropic (VTI) gradient traveltime inversion using the walkaway arrival-time information and the calibrated elastic model. Anisotropy in the sand-rich layers of the model could be switched off by following a V_p/V_s threshold criterion.

Anisotropy was found to be significant, with horizontal velocities surpassing vertical velocities by 20% in the shales. An AVO-processed common-receiver gather from the walkaway shows good correlation with a synthetic gather generated from the calibrated VTI model (previous page, bottom). The excellent tie validates the model used for AVO simulations. Anisotropy has a marked effect on AVO response, and must be taken into consideration when analyzing AVO behavior at the target levels (above). The Target 1 sand, which before walkaway calibration exhibited ambiguous AVO properties, shows a clear brightening, or increase in amplitude with offset, when anisotropy is included in the model.

The amount of anisotropy was greater than expected in the survey plan, and was found to dramatically modify ray paths, to the point where even the longest offsets did not reflect at large angles at the deepest target. Future survey planning needs to consider extremely long offsets if AVO information is needed at reflection angles greater than 40° in similarly anisotropic formations.



^ Surface seismic section from an offshore West Africa 3D seismic volume and a high-resolution walkaway image along the corresponding line. A corridor-stack trace (yellow) marks the borehole trajectory along the surface seismic image (*left*). The walkaway data (*right*), migrated using an anisotropic velocity model, appear to illuminate faults and other layer discontinuities that are not seen in the surface seismic section.

The anisotropic model was used to migrate the walkaway data, producing high-resolution images of reservoir targets below the well (above). The in-line walkaway image shows an excellent tie with a relevant line extracted from the 3D marine seismic volume, and illuminates targets with greater resolution than does the existing surface seismic survey.

3D Borehole Seismic Surveys

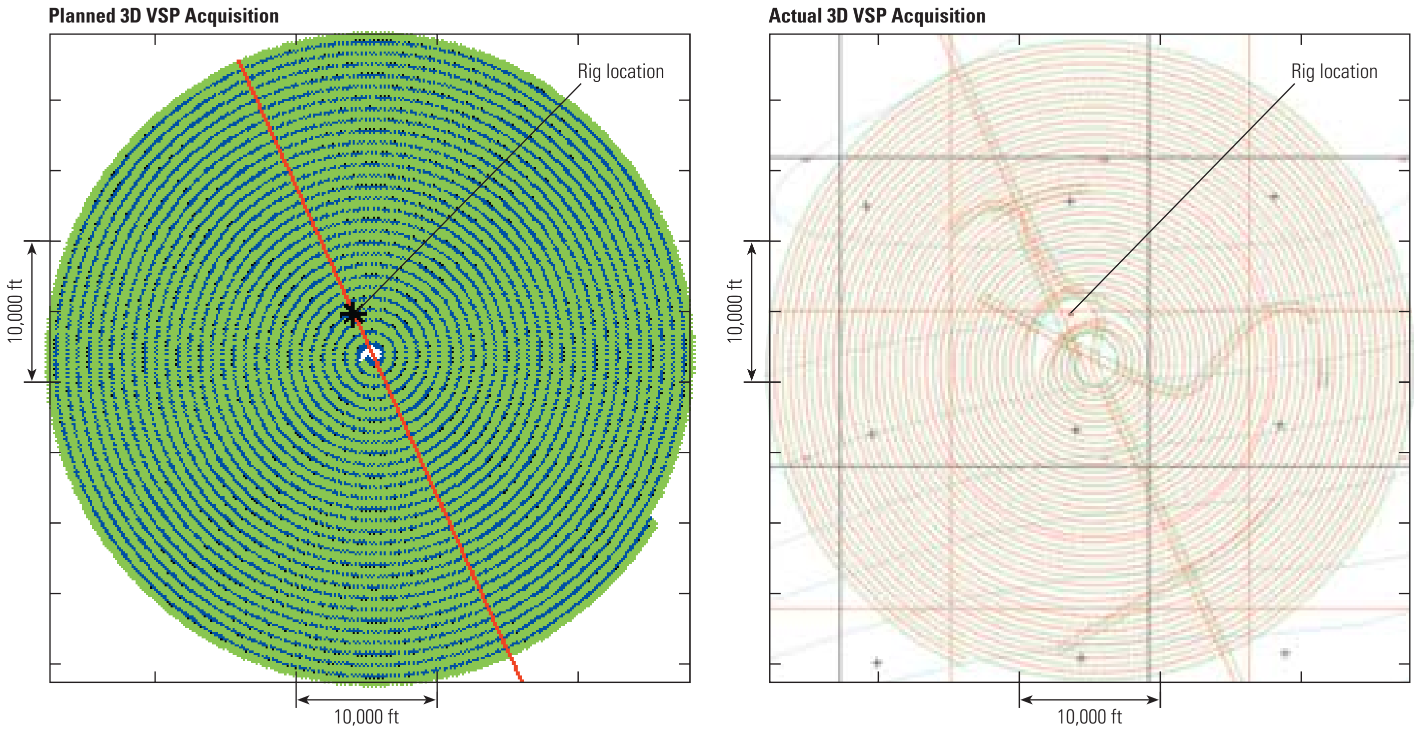
The widespread use of 3D surface seismic imaging has demonstrated the value of including a third dimension in the acquisition and processing of seismic data. In fact, many subsurface imaging problems cannot be solved without a 3D survey. When the problem also requires the survey to be performed in a borehole, the solution is the 3D VSP.

For one offshore operator seeking a high-resolution 3D image on the crest of a deepwater discovery, the 3D VSP proved highly successful. The aims of the 3D VSP were to obtain better definition of a significant bounding fault identified in surface seismic data; to refine the interpretation of compartmentalization and stratigraphic variation at the crest of the structure; and to optimize positioning of costly future development wells.

Preacquisition modeling determined that a spiral acquisition, with the source vessel navigating in a tight circular pattern over the well location, would yield maximum data in minimum rig time. A 16-km [10-mile] walkaway VSP would be acquired first and analyzed onboard to confirm the validity of the survey parameters planned for the 3D survey. A 20-shuttle VSI tool was modified to increase shuttle spacing to 100 ft. The resulting tool was 2057 ft [627 m] long, the longest tool string ever run on wireline at that time. The tool acquired data from within 18-in. casing, from depths spanning 11,725 to 9500 ft [3574 to 2896 m] measured depth.

Operating-efficiency concerns about tool-deployment speeds with such a long array were dispelled when the operating crew proved that the immense tool could be rigged up in 1½ hours, about half the time expected by the oil company representatives. The tool string remained in the same position for the walkaway and the 3D VSP.

The WesternGeco *Snapper* served as source vessel for the combined surveys. Presurveyed acquisition parameters planned for the 3D survey included shotpoint separation of 120 m [394 ft], distance between spiral arcs of 240 m [787 ft] and maximum spiral radius of 6 km [3.7 miles]. These parameters were selected by oil company experts to assure adequate imaging quality.



^ Planned geometry (*left*) compared with actual acquisition (*right*) for spiral 3D VSP and walkaway surveys. A 20-shuttle VSI tool with 100-ft [30-m] shuttle spacing acquired both data sets. Results from the 16-km [10-mile] walkaway VSP (red line on left figure) helped geophysicists validate acquisition parameters for the 3D survey. The center of the spiral was offset from the rig. The actual 3D survey geometry closely matched the planned spiral. In the actual survey, a red x denotes the port source, green denotes the starboard source.

After the last walkaway shot, the *Snapper* navigated into position at the center of the spiral, and acquired the 3D survey using a flip-flop source configuration, firing air guns from the left, then the right, side of the vessel, in an alternating pattern. By starting at the center of the spiral, the most important data could be acquired first, in case unforeseen weather changes forced cancellation of the survey. The actual acquisition geometry followed the plan to a high degree of accuracy (above). Oil company representatives determined final spiral acquisition parameters by analyzing the walkaway data processed using in-house imaging techniques.

In a 3D VSP, the acquisition system not only has to store large amounts of data but also be in a ready state to record the next shot. The time between shots is called cycle time. On this deepwater project, Schlumberger engineers aimed to acquire the data with a 13-second cycle time using 2-ms sampling, and actually achieved a 12-second cycle time. Total nonproductive time was only 6% in 58 hours of operating time.

The high-resolution imaging power and target coverage of 3D VSPs and today's other complex borehole seismic surveys rely on a series of recent developments: the carefully engineered multicomponent VSI tool and accompanying acquisition technology; advanced understanding of anisotropic wave propagation; and the ability to model three-dimensional survey-acquisition response to an earth model all contribute to successful seismic surveys in the borehole.

Improvements can still be made in certain areas. Characterizing the seismic source is one topic on which work continues. Some borehole seismic experts consider that digital recording of the full source signature at each shot is necessary to ensure that subsequent borehole seismic processing fully preserves amplitudes. Monitoring source response at each shot permits the acquisition crew to correct for any source variation or failure. Source-signature consistency is particularly desirable for processing walkaways that will be used as a reference for AVO calibration.

The time spent properly designing, acquiring and processing a borehole seismic survey is paid back by achieving key objectives such as accurate time-depth conversion, high-resolution images, enhanced illumination of subtle features, reliable quantification of anisotropy and more confident interpretation of fluid and lithology from AVO data—all aimed at reducing risk in the search for oil and gas. –LS

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.

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1. Bargach S, Falconer I, Maeso C, Rasmus J, Bornemann T, Plumb R, Codazzi D, Hodenfield K, Ford G, Hartner J, Grether B and Rohler H: "Real-Time LWD: Logging for Drilling," *Oilfield Review* 12, no. 3 (Autumn 2000): 58–78.
2. Bargach et al, reference 1.

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.[1] Today, downhole instrumentation and data-compression technologies allow transmission of wellbore images and associated correlation data from bit to surface in real time.

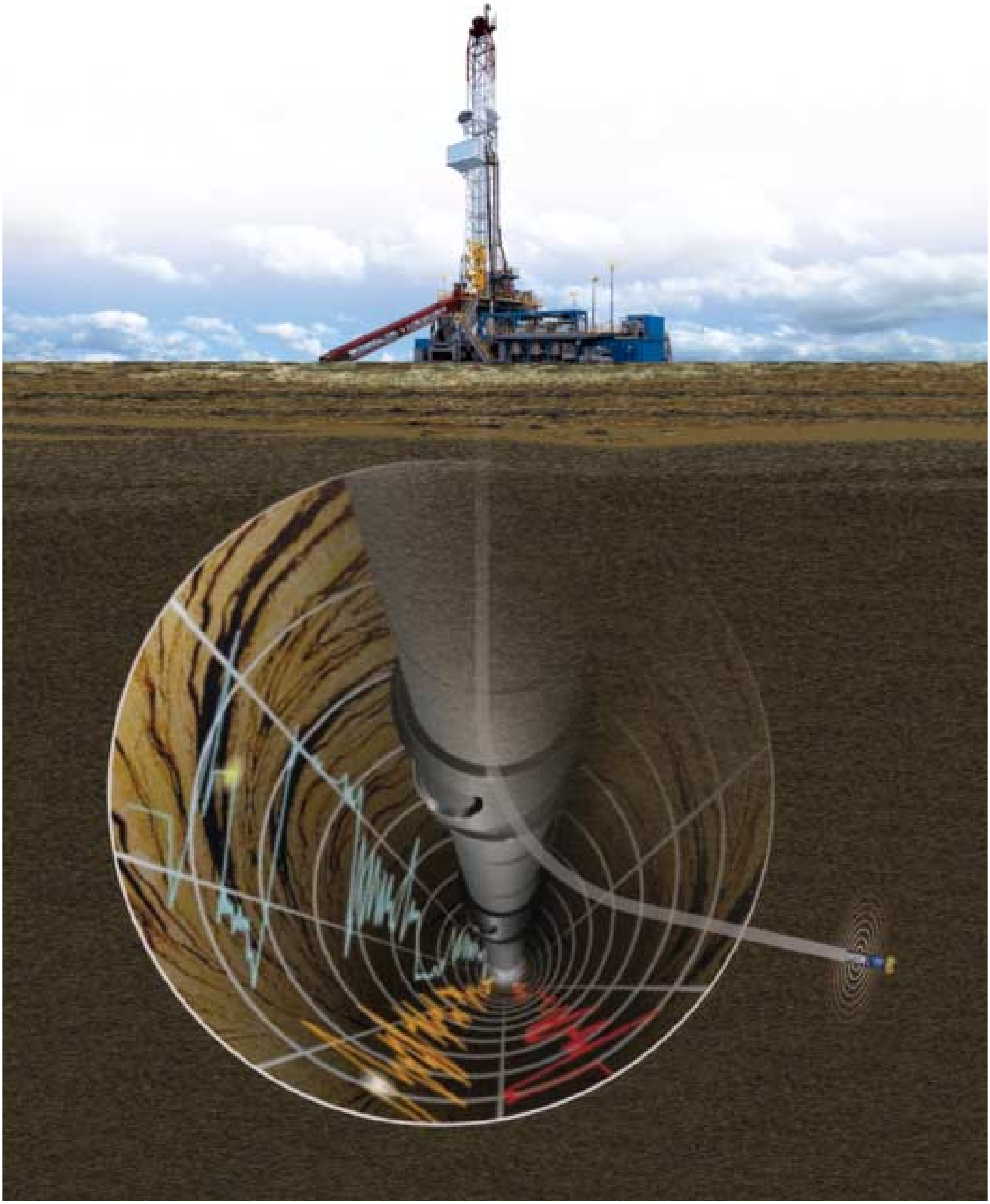
Drilling wells with complex trajectories has become increasingly common. Wells that were once considered marginal are now being drilled and completed across multiple horizons, in multilateral configurations and even in deepwater environments. In addition to providing conventional formation evaluation, 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.

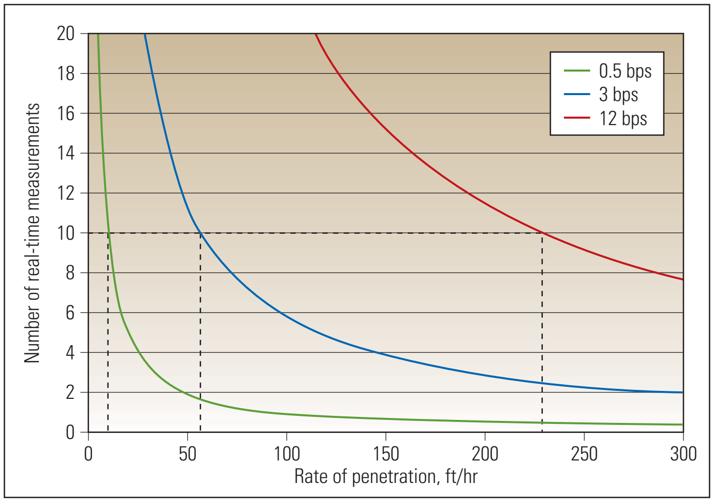
Drilling engineers must focus on risk management and reduction of total well cost. Achieving a lower actual well cost than projected often is the benchmark of drilling success. Complex and fast-paced drilling operations rely on intuitive and intelligent products to aid in important decisions. Questions 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.[2] 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.

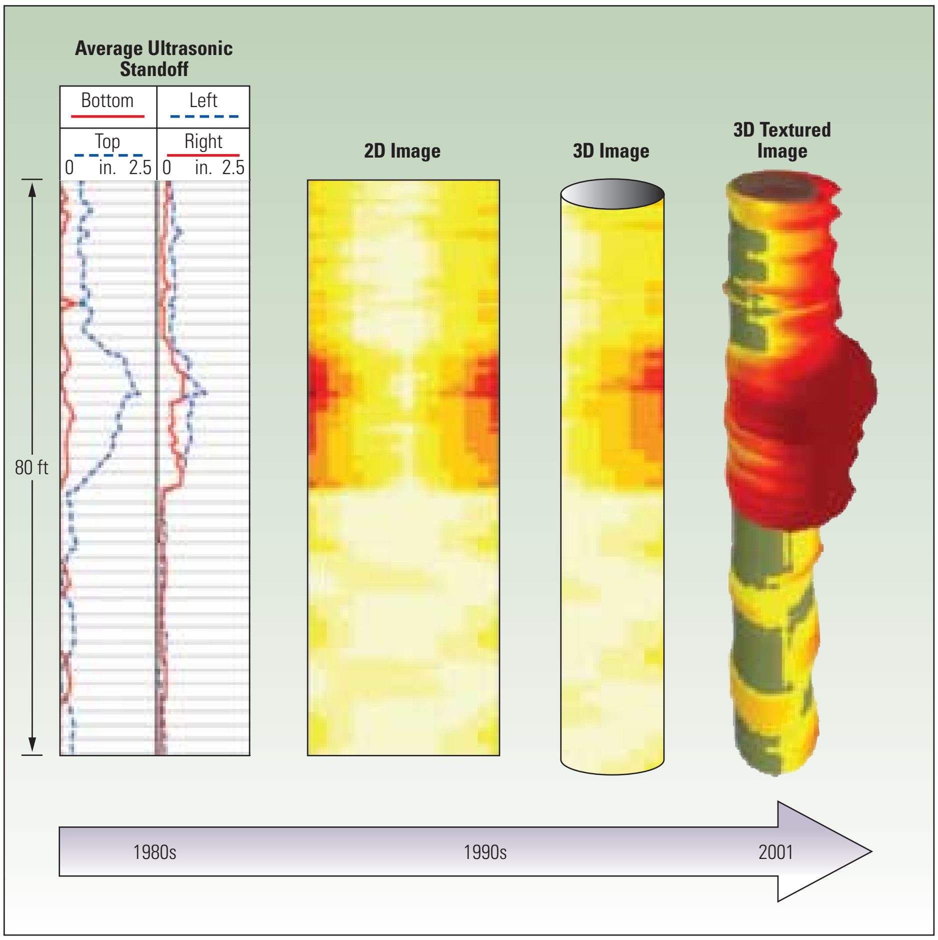
Telemetry—Moving Data Upward

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.





^ 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.



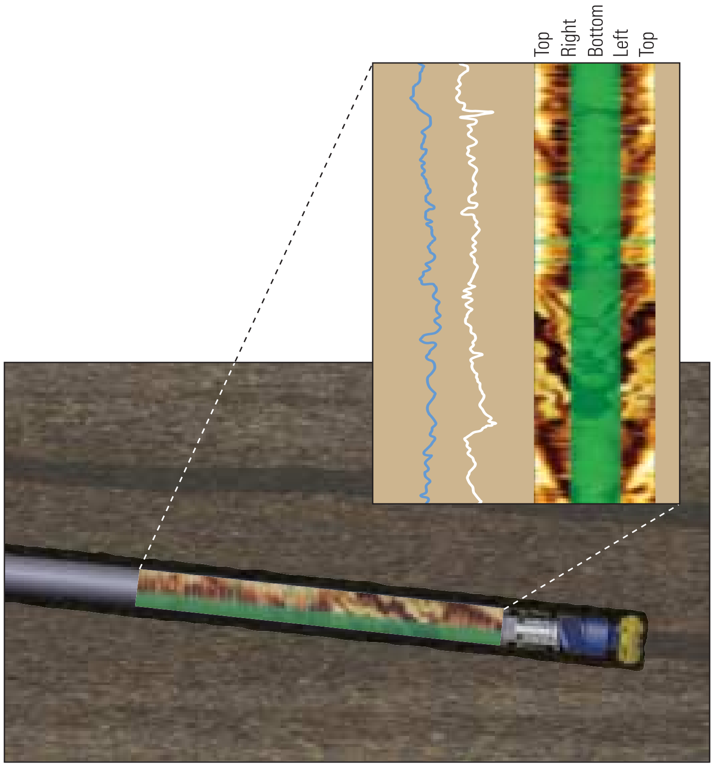
^ Improved visualization of borehole data. The quality and ease of interpreting data have improved considerably from the simple curves common in the 1980s. Data were first converted into color scale presented in two dimensions, then wrapped around a three-dimensional (3D) borehole. The 3D textured image 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.

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.

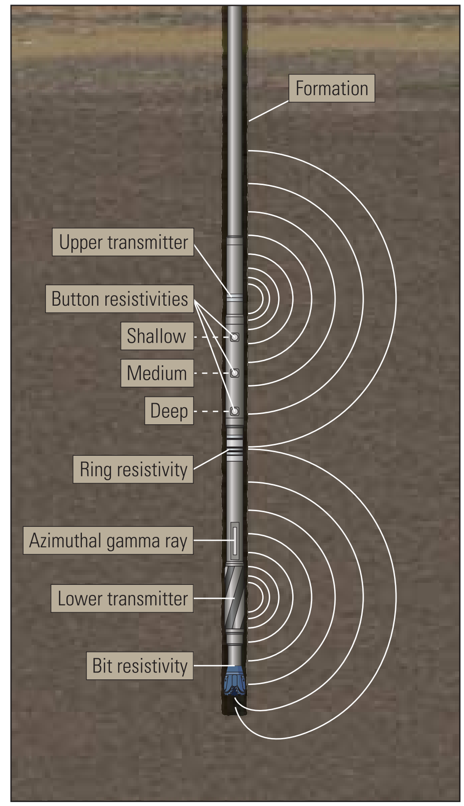
Deepwater drilling presents additional telemetry challenges. Seafloor temperatures may be below 0°C [32°F] with hydrostatic pressure at the riser base in excess of 34.5 MPa [5000 psi].[3] Drilling fluid circulating up from warm bottomhole conditions cools substantially as it travels up long, cold risers 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.[4]

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.



^ Real-time wellbore images as unfolded cylinders. The bottom of the hole is represented by the center of the image track (green) followed by right and left sides with the top of the hole denoted by the extreme left and right image edge.



^ GVR measurement physics. The diagram depicts toroids energizing an electromagnetic field around the GVR tool. Sensors detect local field strengths resulting from varying formation conductivities. Sensor current is emitted while firing upper and lower transmitters sequentially to provide a borehole-compensated resistivity measurement. Shallow, medium and deep buttons and ring and bit resistivities provide five depths of investigation. The buttons are located on a removable stabilizer sleeve. The low-frequency laterolog-type measurement requires a conductive borehole fluid. However, bit resistivity is available in oil-base mud as long as formation contact is maintained. The tool also provides an azimuthal gamma ray measurement.

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.

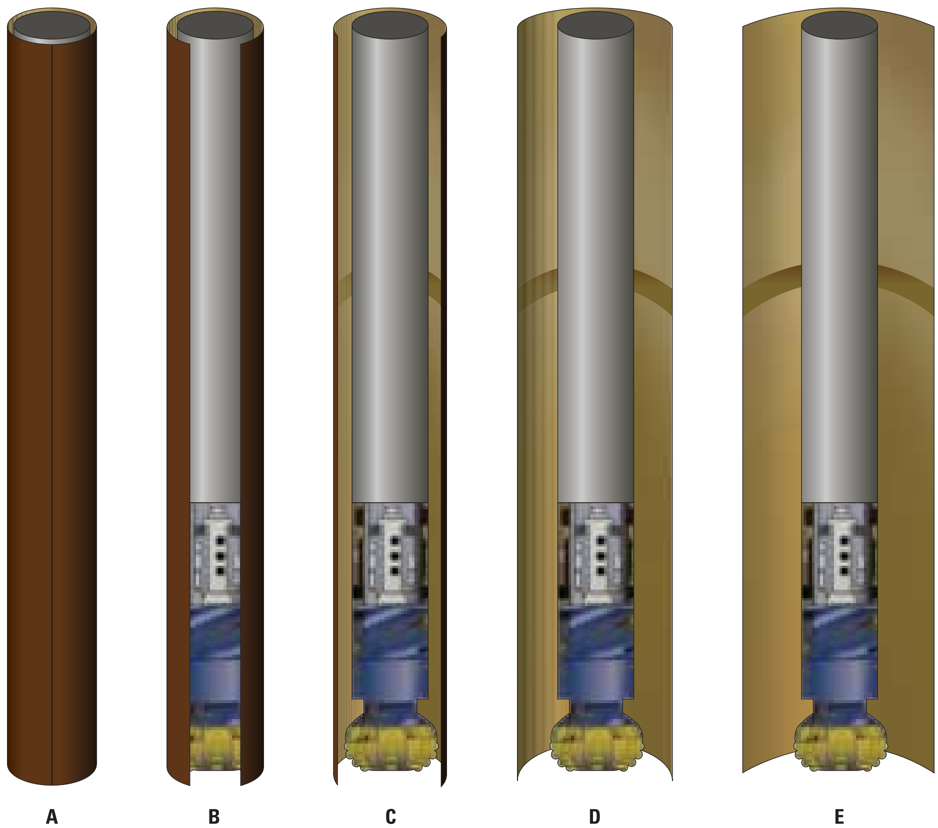
Imaging the Borehole

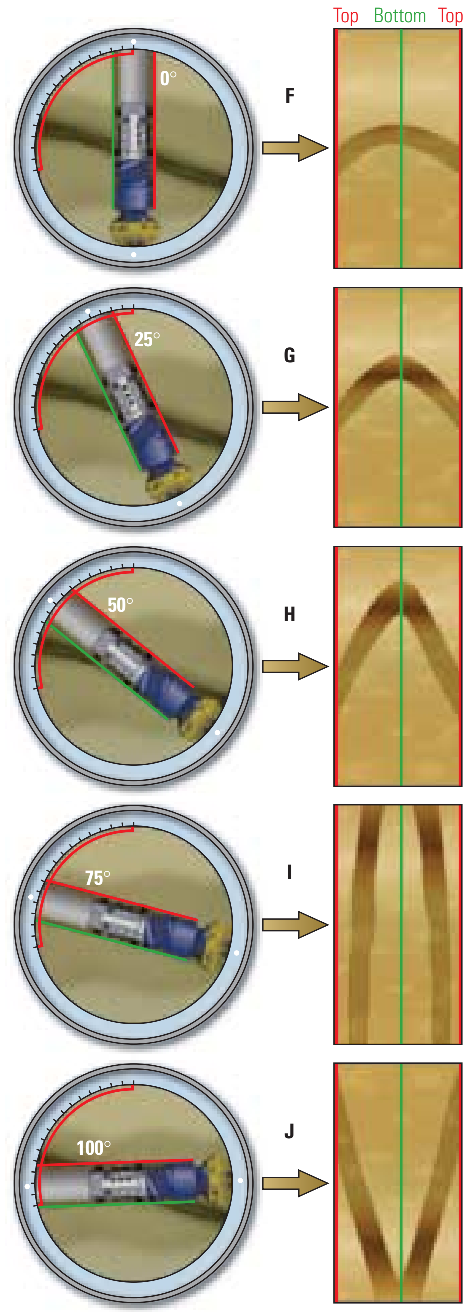
LWD resistivity imaging is based on low-frequency laterolog-type measurements that generally require a conductive borehole fluid—approximately 70% of wells are now drilled with conductive drilling fluids. Several LWD resistivity-imaging tool designs are available that provide multiple depths of investigation 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

3. Brandt W, Dang AS, Magne E, Crowley D, Houston K, Rennie A, Hodder M, Stringer R, Juiniti R, Ohara S and Rushton S: "Deepening the Search for Offshore Hydrocarbons," *Oilfield Review* 10, no. 1 (Spring 1998): 2–21.

4. Lassoued C, Dowla N and Wendt B: "Deepwater Improvements Using Real-Time Formation Evaluation," paper SPE 74397, presented at the 2002 SPE International Petroleum Conference and Exhibition, Villahermosa, Mexico, February 10–12, 2002.





^ Imaging while drilling up- and down-section. Images A through E depict the wellbore being opened and laid out as the borehole would be represented in geoVISION resistivity log format. In Images F through J, inclination is adjusted from vertical, through horizontal, to 100° off vertical. The bedding plane is parallel to the wellbore at an inclination angle of about 75°. Images F, G and H reflect drilling down-section—the geoVISION resistivity image points up. In Image I, drilling is parallel to the bedding plane—geoVISION images are approximately parallel. In Image J, the bedding plane has been crossed and drilling is up-section—geoVISION images point down.

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.[5] 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.[6]

The northeast-southwest striking, anticlinal structure covers approximately 30 km^2 [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.

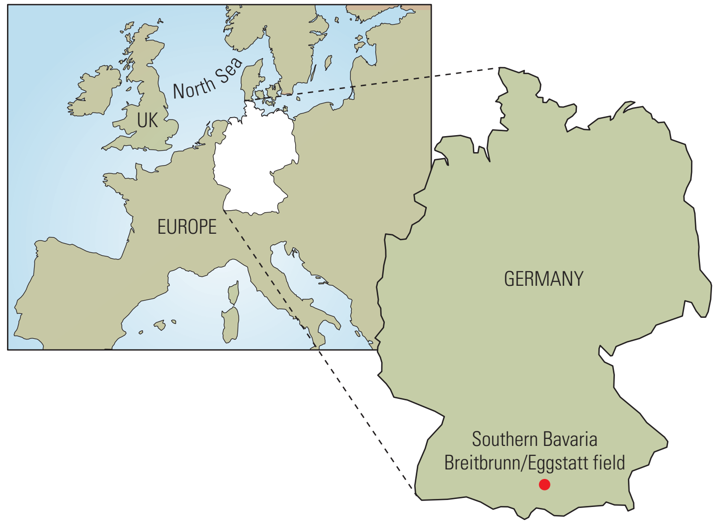
Even though producing zones were depleted, a weighted drilling fluid was required to control borehole stress. Engineers selected a low fluid-loss polymer, calcium carbonate weighted, reservoir drilling-fluid system. In contrast to foamed drilling mud, this system allowed the operator to consider a wide 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.

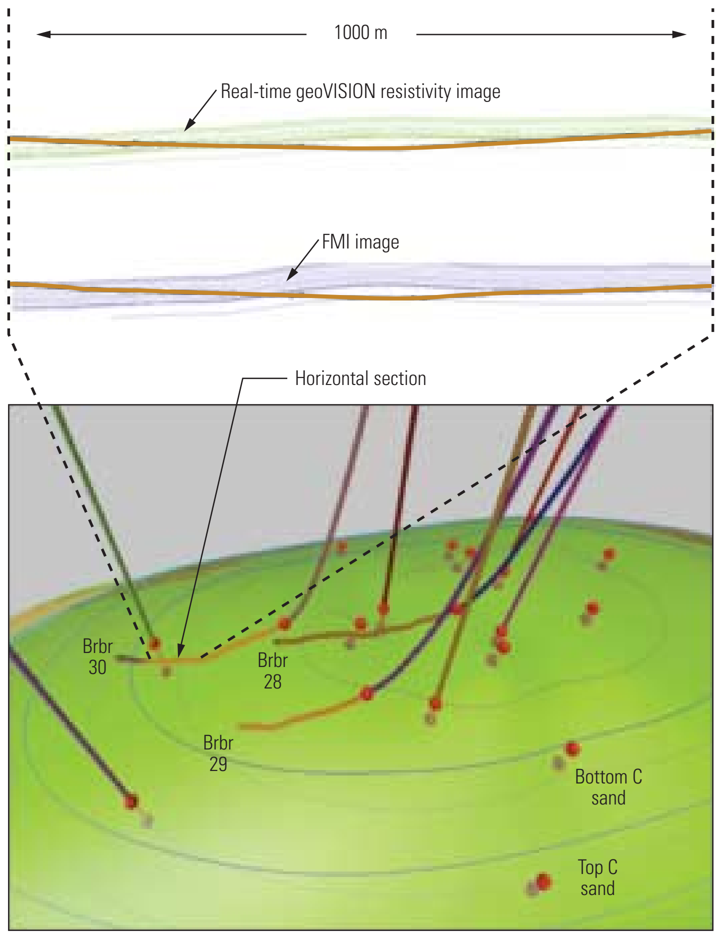
Wireline data collected during successful construction of the 12½-in. angle-building sections confirmed the high precision of prewell structural mapping. Correlation of LWD and well-log data suggests that the reservoir layers are composed of separate sand bodies. An effective storage well should penetrate all individual

5. Bary A, Crotogino F, Prevedel B, Berger H, Brown K, Frantz J, Sawyer W, Henzell M, Mohmeyer K-U, Ren N-K, Stiles K and Xiong H: "Storing Natural Gas Underground," *Oilfield Review* 14, no. 2 (Summer 2002): 2–17.

6. Rohler H, Bornemann T, Darquin A and Rasmus J: "The Use of Real-Time and Time-Lapse Logging-While-Drilling Images for Geosteering and Formation Evaluation in the Breitbrunn Field, Bavaria, Germany," paper SPE 71331, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, September 30–October 3, 2001.



^ Breitbrunn/Eggstatt gas field in southern Bavaria, Germany.



^ Sand C anticlinal structure. Vertical historical wells are shown, as are the three newly drilled horizontal wells, Brbr 28, 29 and 30. The upper inset shows two cross sections taken along the horizontal wellbore (orange). The lower section is constructed from bedding dips derived from wireline FMI Fullbore Formation MicroImager data while the upper cross section is constructed from bedding dips derived from geoVISION borehole images. The similarity of the images indicates the quality of the real-time GVR measurements.

porous sand bodies, with the wellbore path cutting evenly across the entire thickness. All three 8½-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.

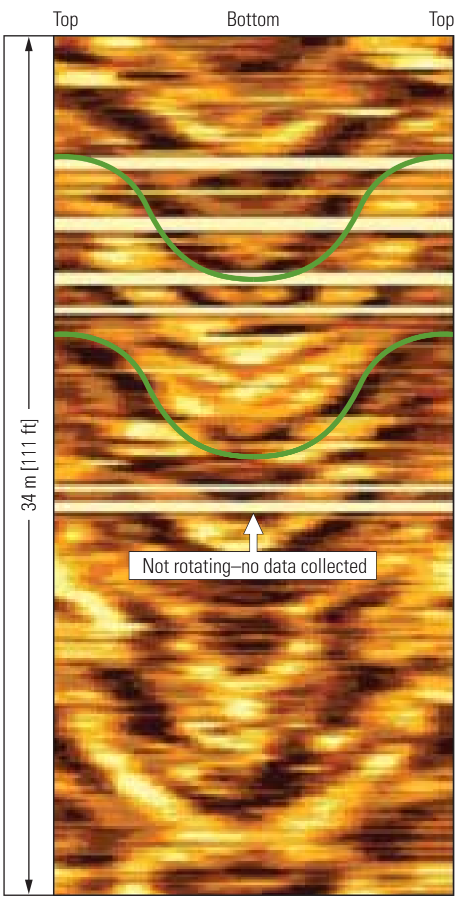
During drilling of lateral sections, computed dips from geoVISION resistivity real-time images defined the relative position of the borehole within the reservoir. Sinusoidal bed-boundary images point uphole when drilling down-section, and downhole when drilling up-section (below left). Measured depth (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.[7]

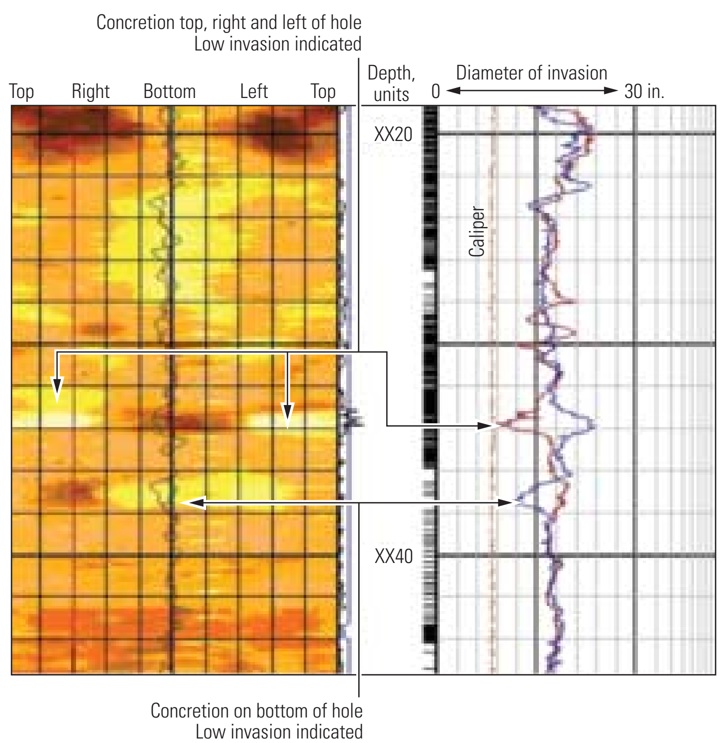
Azimuthal data become critical when drilling these heterogeneous reservoirs. Formation-evaluation by quadrant allowed detailed stratagraphic interpretation. Right-quadrant data may indicate good reservoir quality while the bottom-quadrant log indicates poor quality (below right). These sections require 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.[8]

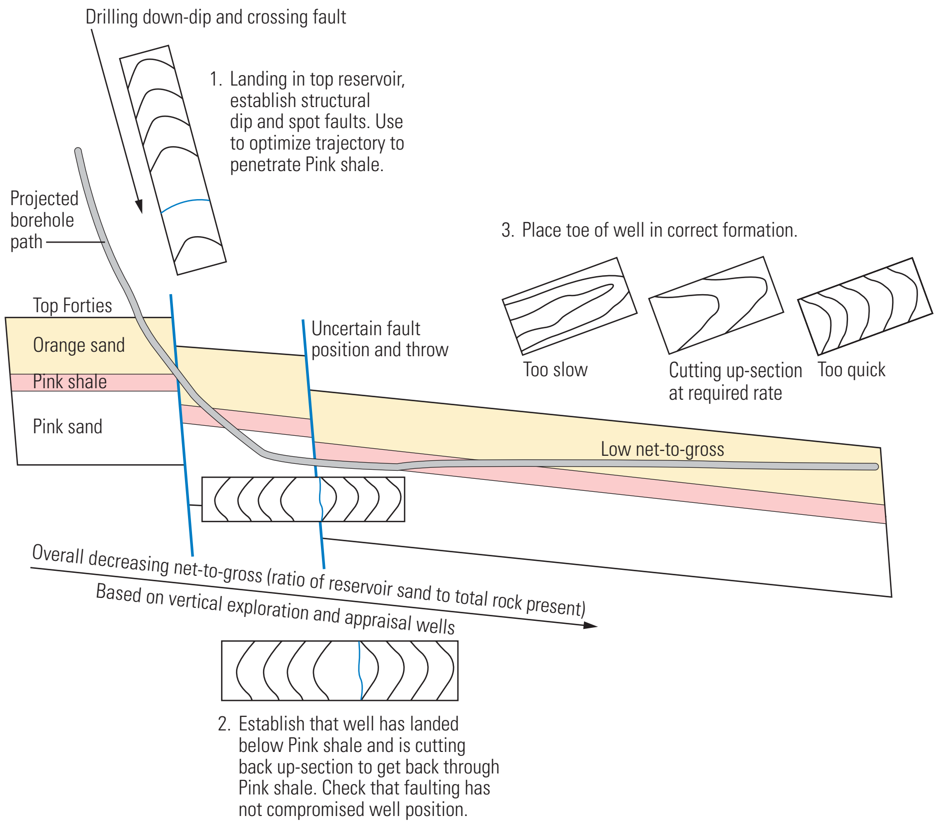
There was a risk of sanding, so petrophysicists used both porosity and rock-mechanical information to determine the perforation intervals and their orientation. Wellbore images and oriented-perforating technology allowed for precise placement of injection sites within the sand bodies. Stratigraphic orientation 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 cutting up-section as indicated by the downward-pointing sinusoids (green lines). The horizontal, light-colored stripes are intervals of trajectory adjustments using the mud motor. In these intervals, the bottomhole assembly 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.



^ Shell GE-03 forward-modeled predrill well plan. Benchmarks 1 through 3 were used to monitor borehole-drilling progress noting expected geology and intended geoVISION resistivity image response along the borehole path. The variation in image sinusoidal amplitude indicates the relative tool to bedding-plane angle.

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.

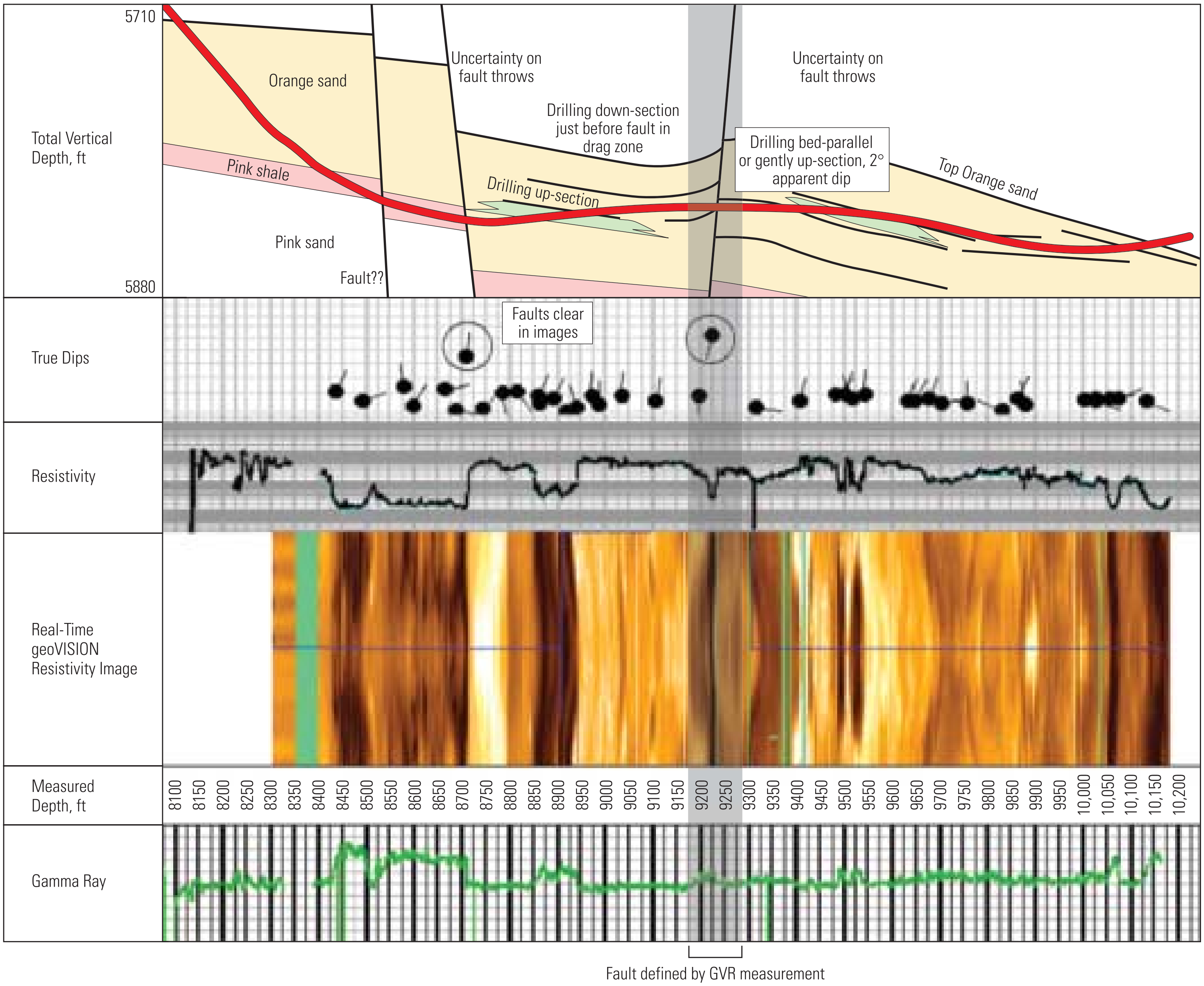
Real-Time Imaging in North Sea Turbidites

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.[9] Completion engineers chose a gravel-pack screen completion to minimize sand production from poorly consolidated sandstones.[10] 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).[11] 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.
10. For more on gravel packing: Ali S, Dickerson R, Bennett C, Bixenman P, Parlar M, Price-Smith C, Cooper S, Desroches J, Foxenberg B, Godwin K, McPike T, Pitoni E, Ripa G, Steven B, Tiffin D and Troncoso J: "High-Productivity Horizontal Gravel Packs," *Oilfield Review* 13, no. 2 (Summer 2001): 52-73.
11. Borehole scale refers to resolvable formation features smaller than the borehole diameter.



^ Shell GE-03 cross section interpretation (*top*) of image data while drilling. Gamma ray, geoVISION resistivity image log, resistivity data and true dips picked from real-time images are displayed on a compressed scale below the interpretation. The GVR measurement has identified an additional fault (gray vertical band) at 9225 ft [2812 m]. This required modifying the planned trajectory to stay within the reservoir sand.

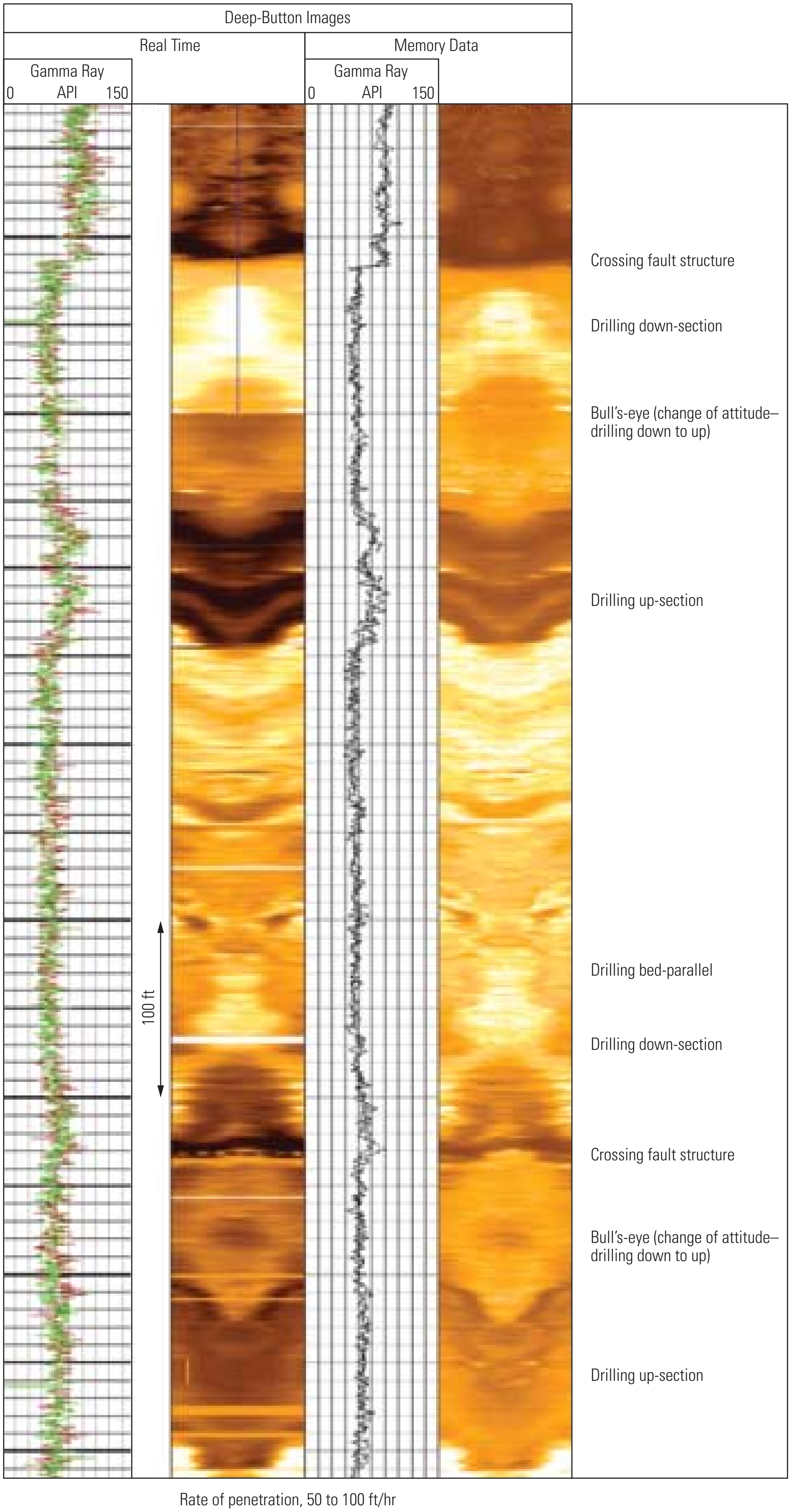
The BHA consisted of the PowerDrive rotary steerable system for directional control and a GVR tool for gamma ray, resistivity and real-time imaging. An APWD Annular Pressure While Drilling sensor monitored equivalent circulating density (ECD). The PowerPulse MWD tool provided telemetry, direction and 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 wellbore 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,



< Shell GE-03 geoVISION resistivity data summary. Real-time geoVISION resistivity and gamma ray image data (Tracks 1 and 2) are shown alongside gamma ray and image data downloaded from the GVR tool's memory once the BHA was back on surface (Tracks 3 and 4). Real-time image logs while drilling clearly show the wellbore cutting up and down through bedding planes and drilling bed-parallel. As drilling progressed, these data were used to acquire true formation dip and fault orientation while building a subseismic geological cross section.

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.[12]

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

12. In the petroleum industry, biostratigraphic analysis often denotes the use of terrestrial (pollen and spores) and marine (diatoms, foraminifera, nannofossils) microfossils to determine the absolute or relative age and depositional environment of a particular formation, source rock or reservoir of interest.

Identifying Borehole Fractures and Failures

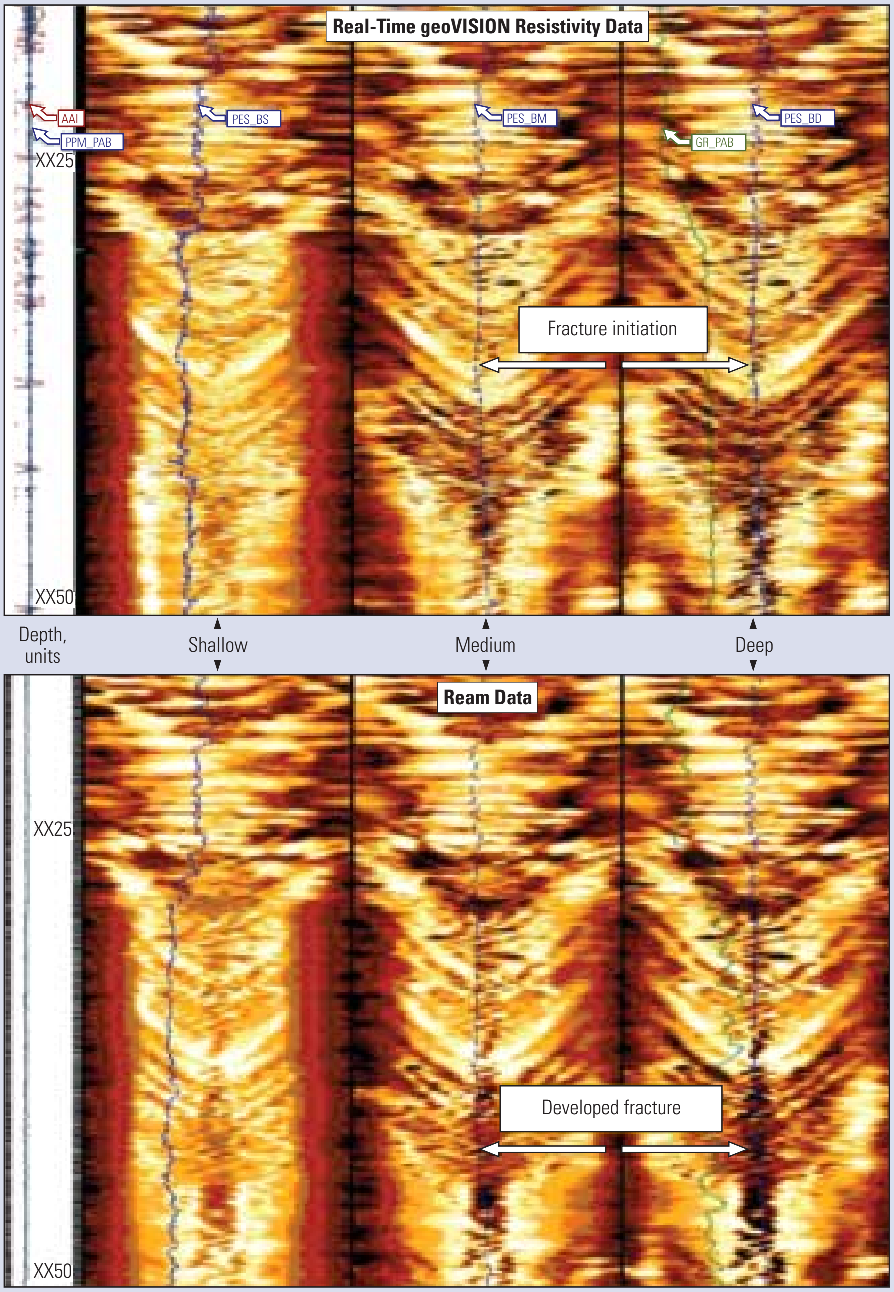
Recognizing borehole failure and instability, and understanding how and why failures occur, are vital to successful drilling operations. Properly managing borehole stability minimizes nonproductive time and is central to drilling optimization. When stresses around a borehole exceed formation strength, 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.[1] 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.[2]

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.

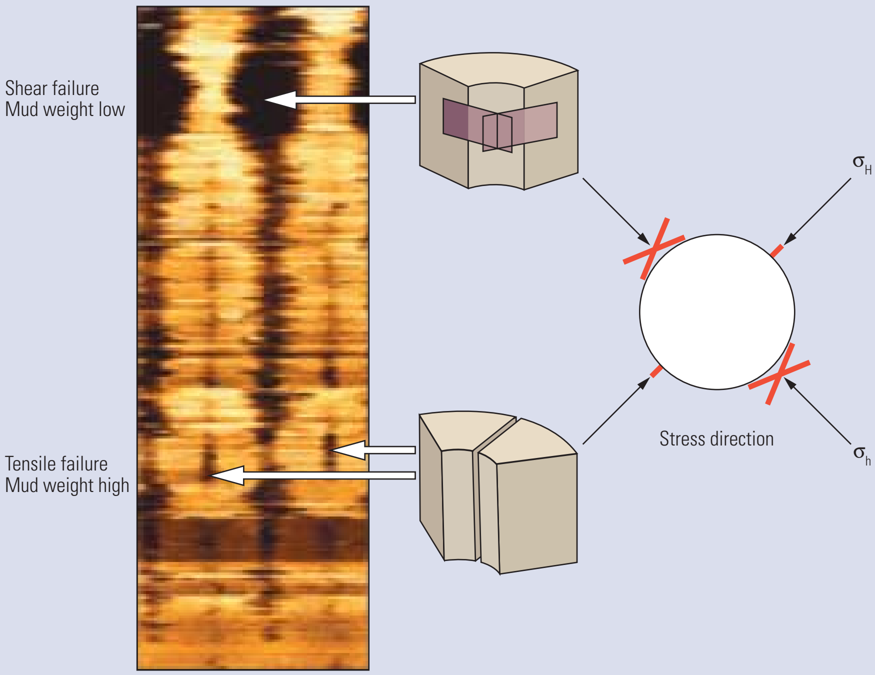
real-time subseismic-scale cross sections constructed from the geoVISION data defined the borehole's location.[13] Confident that the borehole was correctly positioned, the subsurface team allowed drilling to proceed.

The driller placed the horizontal reservoir section at 5710 to 5880 ft [1740 to 1792 m] TVD, or 8150 to 10,250 ft [2484 to 3124 m] measured depth (MD) with all well objectives being met. At TD, ultrasonic caliper and adnVISION tools determined porosity and measured hole size before gravel-packing operations.

Faster geological decision-making led to several key drilling-efficiency gains:
- minimizing nonproductive circulating time off-bottom for geologic analysis of borehole position
- mitigating risk of becoming "lost" geologically, avoiding a sidetrack
- confirming optimal wellbore placement in real time, so that planning and completion lead-time was not compromised.

The well successfully penetrated the intended maximum productive horizon. The geoVISION resistivity images and associated data provided new structural information for inclusion in the geologic model. Problems occurred running the completion that required redrilling of the GE-03 well. Geologic cross sections generated from geoVISION resistivity image data helped Shell confidently position the new wellbore. GeoVISION resistivity imaging and other data provided Shell with a better understanding of the Gannet E field and its hydrocarbon recovery potential.

13. Subseismic geologic features have a size below the resolution of seismic data and therefore cannot be clearly visualized on seismic sections.



^ 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.

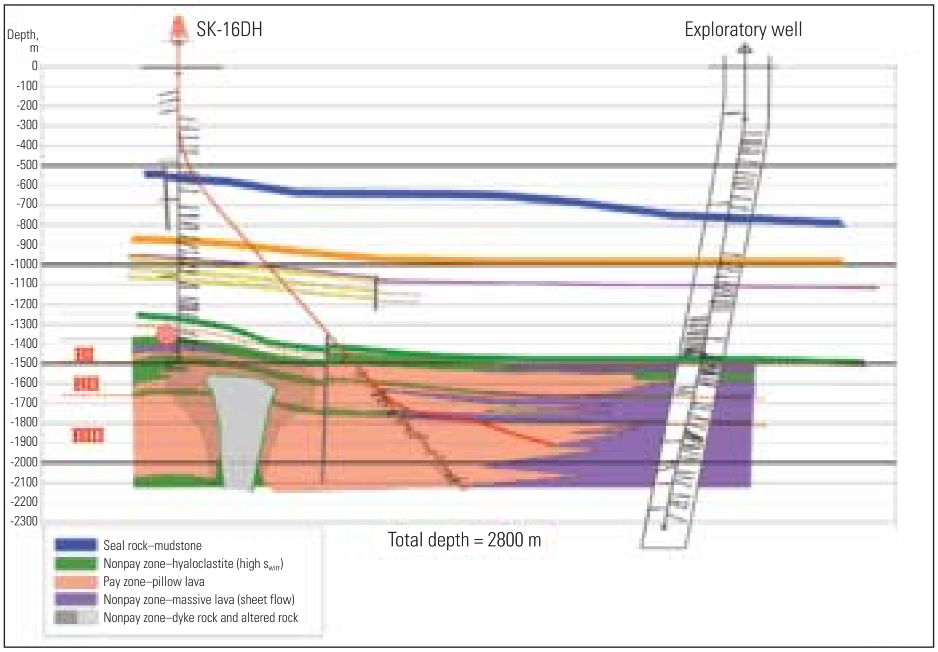
The application of geomechanical models that incorporate image and pressure data has a direct and immediate impact on drilling optimization and well-completion design. Results from these models help generate recommendations for remedial strategies that might not have been considered. The ability to distinguish 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.

1. Bargach et al, reference 1, main text.
2. Bloys B, Davis N, Smolen B, Bailey L, Houwen O, Reid P, Sherwood J, Fraser L and Hodder M: "Designing and Managing Drilling Fluid," *Oilfield Review* 6, no. 2 (April 1994): 33–43.

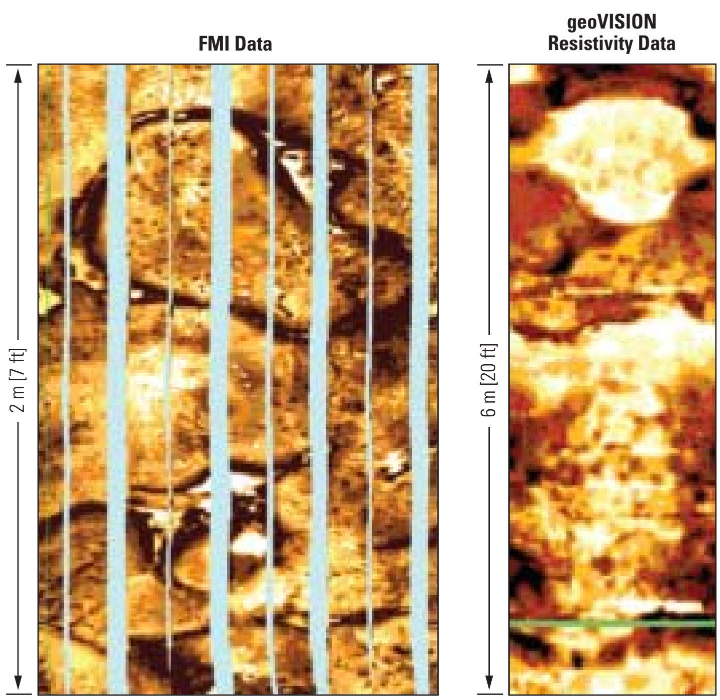
Directional Drilling in a Volcanic Reservoir

Volcanic deposition generates irregular formation facies with absent or indefinable bedding planes. As such, interpretation methods differ significantly between sandstone, carbonate and volcanic reservoirs. This, along with unpredictable fault trends, makes volcanic-rock directional drilling a challenge.

During the summer of 2002, JAPEX (Japan Petroleum Exploration Co., Ltd.) drilled the SK-16DH directional well in the Yurihara field, a volcanic area in northern Honshu province, mainland Japan. Several months before drilling began, JAPEX and Schlumberger collaborated on the design of a well plan to improve and optimize drilling performance and wellbore placement.



^ JAPEX SK-16DH post-drilling structural cross section. An earlier exploratory well (right) failed to locate productive pillow lava. While drilling the SK-16DH well, productive pillow lava was encountered at the kickoff point then lost while drilling near horizontal. As the angle was dropped, a second pillow-lava bed was encountered just below a thin mudstone caprock. Real-time geoVISION resistivity image logs provided the information necessary to keep the wellbore path within the pay zone section.



^ 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 side-track-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.

The operator anticipated difficulty in maintaining reservoir contact while drilling through nonsedimentary volcanic reservoir rock.

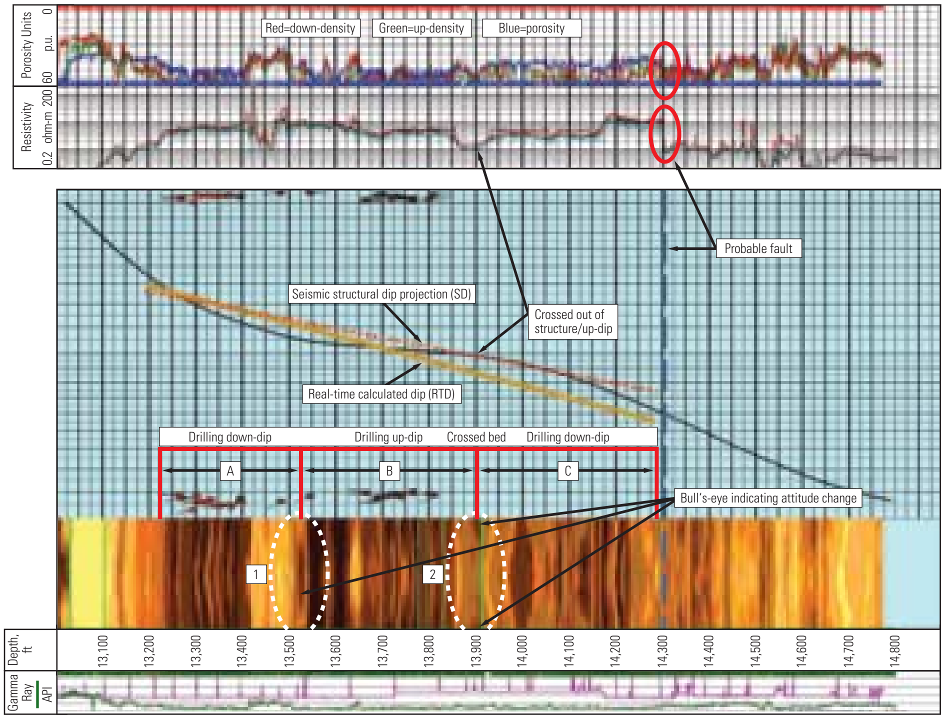
The Yurihara field development project was conceived in 1999. Production and depletion studies suggested that proper design and placement of multiple horizontal wells would triple the current production. Engineers from JAPEX and Schlumberger concluded that wireline-conveyed FMI data would establish target 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 12½-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. The subsurface team established the kickoff point at 2000-m [6562-ft] MD (above left). 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.



< ConocoPhillips real-time trajectory adjustment. Prewell seismic analysis estimated structural dip (SD) at 5.6°, as represented by the red dashed curve. Section A, 13,210 to 13,510 ft [4026 to 4118 m], was drilled as planned with density images showing a down-dip trend. Bull's-eye #1, an image artifact characteristic of changing borehole attitude at the beginning of Section B, 13,510 to 13,860 ft [4118 to 4225 m], indicates a change in relative trajectory from down- to up-structure. During drilling of Section B, computer-generated dips showed beds dipping at a greater angle than predicted by seismic data. At the end of Section B, a significant change in resistivity indicated the proximity of the wellbore to a reservoir boundary. Real-time density images provided the geosteering team with the information needed to order the correct trajectory change that placed the bit attitude slightly down-structure (Section C) as demonstrated by Bull's-eye #2 at 13,910 ft [4240 m]. Drilling continued to a measured depth of 14,300 ft [4359 m], where a fault (red oval, top tracks) not visible on seismic data was encountered.

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 between density and resistivity image data during the drilling operation.

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 nonconductive 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 on the real-time density image, 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 and drilling 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

Screenless Methods to Control Sand

Combining proven oilfield technologies allows operators to achieve solids-free production in many of today's challenging oil and gas developments. This approach provides viable, cost-effective alternatives to conventional sand-control methods for completion or rehabilitation of wells that produce sand, especially when applied rigless—without conventional rigs.

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Produced sand causes various problems from removal, handling and disposal of fill inside casing or surface equipment to serious well-completion failures. These problems often compound, jeopardizing future remedial well interventions and long-term wellbore viability. Leaks, production delays, low hydrocarbon recovery factors or loss of well control may occur if sand erodes wellbore equipment or surface wellheads, pipes and facilities. In a catastrophic failure, access to reserves can be lost if costs to sidetrack or drill a new well are prohibitive.

In some reservoirs, weakly consolidated, but relatively competent zones can be completed without installing mechanical screens to keep sand—formation grains and migrating fines, or small rock particles—from entering a wellbore. In the past, operators have used gravel packing or frac packing in formations of this type. These two methods rely on the particle-bridging characteristics and filter mechanisms of sand-exclusion screens in open hole or inside casing with annular gravel packs and also propped hydraulic fractures in the case of frac packs.

Screenless completions use techniques other than conventional "internal" packs to prevent perforation failure and subsequent production of formation solids (next page). Screenless methods maintain well productivity and sand-free inflow by combining one or more of the following six field-proven technologies:

- optimal perforation phasing, orientation and size
- wide tip-screenout (TSO) fractures across all perforations
- proppant-flowback control
- chemical formation consolidation, or stabilization
- cementing unwanted permeable gravel-pack intervals
- selective coiled tubing treatments.

When planned and implemented carefully, these techniques control sand, reduce overall cost and risk, enhance productivity and improve hydrocarbon recovery.

This article reviews screenless methods and associated rigless techniques that came into more widespread use during the mid-to-late 1990s. We present results from applications in Saudi Arabia, the Gulf of Mexico and Italy to illustrate the effectiveness of oilfield technologies, new and old, in innovative combinations that prevent sand production.

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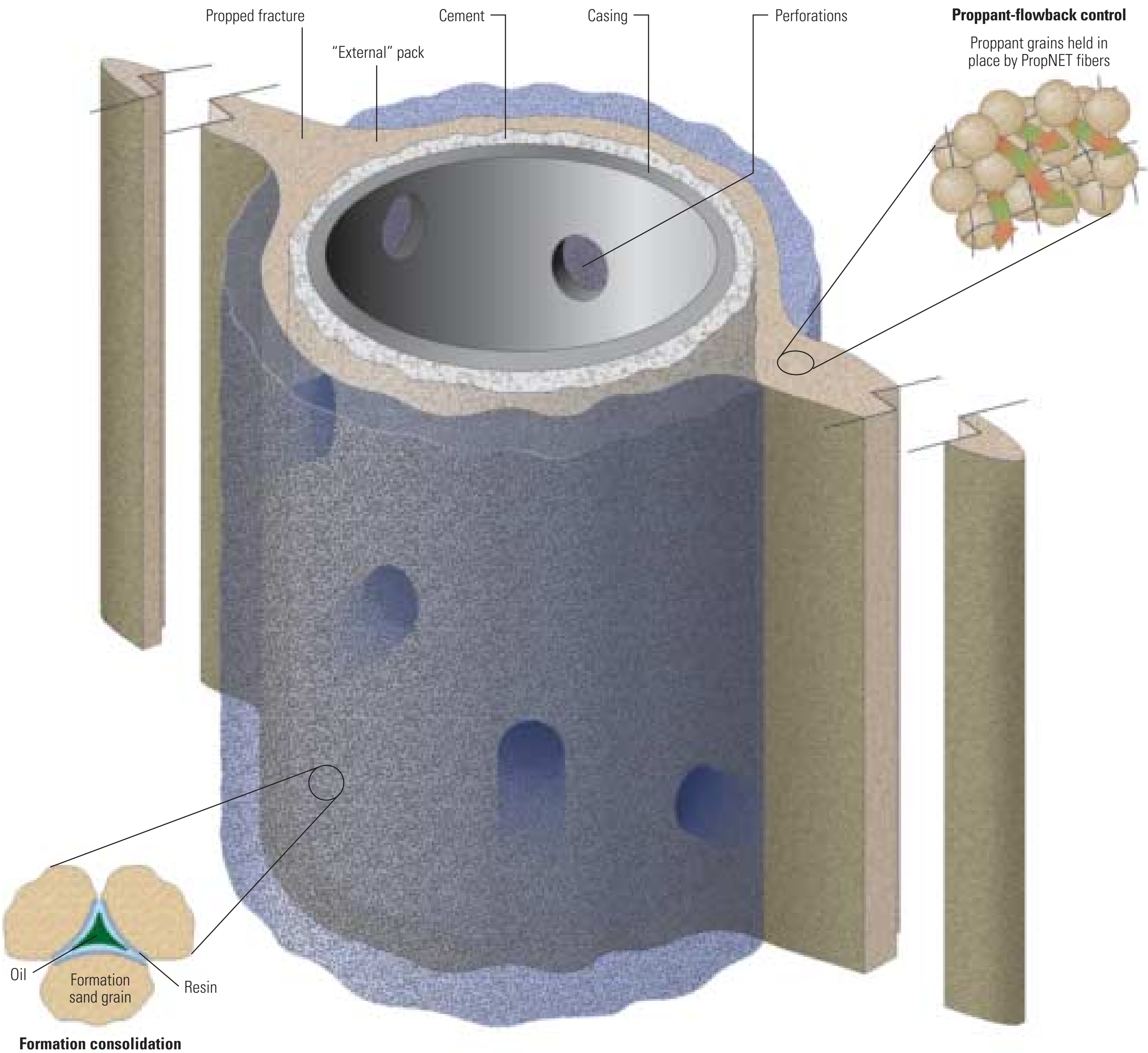
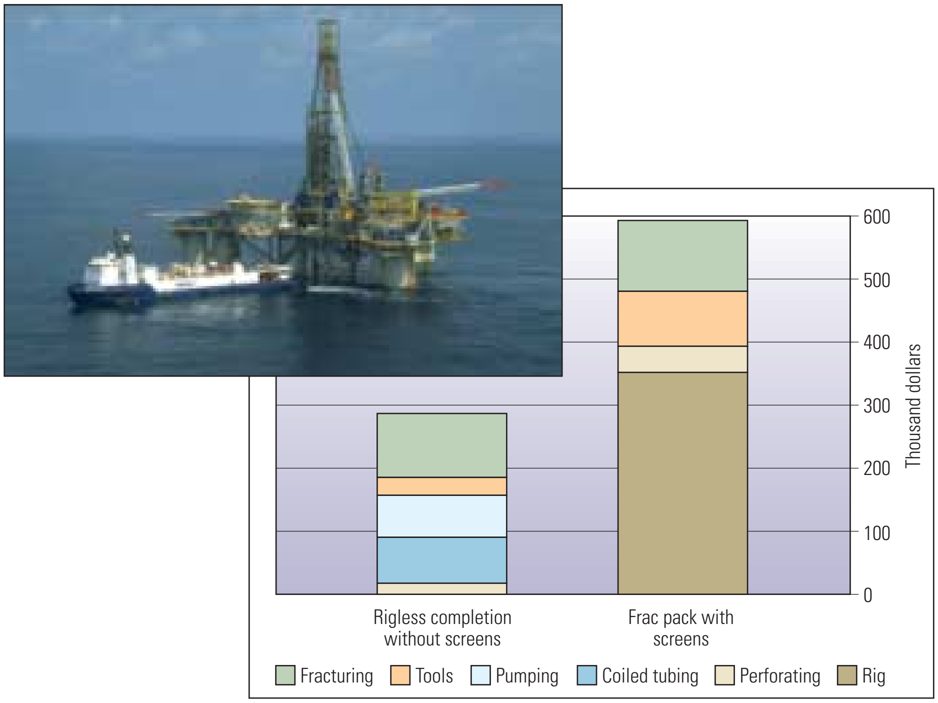


^ Screenless completions. Rigless methods prevent sand influx without screens or annular packs by combining optimized perforating, chemical formation consolidation, or stabilization, and tip-screenout (TSO) fracturing with proppant-flowback control fibers to create an "external" pack (*top left*). Resin-coated proppants (RCP), PropNET hydraulic fracturing proppant-pack additives, or both, help stop proppant and formation sand production (*top right*). Formation consolidation involves injection of a resin system into the formation to form a stronger bond between individual grains (*bottom left*).



^ Screenless completion versus frac packing with internal screens. Rigless sand-control methods require additional pumping and coiled tubing services, but elimination of mechanical screen assemblies, more complex downhole equipment and conventional rig operations reduces costs significantly.

Rigless Interventions

Screenless completions avoid the limitations and productivity restrictions of internal gravel packs and screens. Screenless completions do not restrict wellbores across pay intervals. This full-bore access provides additional flexibility for subsequent well logging and data gathering, remedial repairs and recompletions, reservoir monitoring and production management, and control of water or gas inflow.

In addition to simplifying completion operations and reducing installation risks, this approach decreases cost by eliminating screen assemblies and associated equipment, complex downhole tools, and the fluid volumes and pumping operations that are required to place gravel around screens (above).

Screenless completions can provide primary sand control in newly drilled wells or lateral sidetracks, especially for casing sizes and wellbore configurations that preclude the installation of mechanical sand-exclusion screens. In addition, they are used to complete bypassed zones in existing wellbores. Wells without screens and gravel packs that begin to produce sand can be recompleted using screenless techniques.

Screenless techniques do not require drilling or workover rigs. These methods can be performed using coiled tubing, which further reduces completion and remedial intervention costs. This makes screenless methods particularly attractive and cost-effective for initial completion of bypassed zones. These methods are also applicable for repairing wells with plugged gravel packs or eroded screens.

Evolving Techniques

In the early 1990s, companies began evaluating methods to prevent sand influx by mitigating formation failure and perforation breakdown in unstable formations. Since that time, operators and service companies have worked together to develop and optimize rigless sand-control techniques. These efforts led to optimized perforating practices for sand management—control and prevention—as well as increased hydraulic fracturing and frac packing for sand control.[1]

Amoco used "up-and-under" fracturing in the North Sea Valhall field during the 1980s.[2] Statoil applied a similar technique called indirect vertical fracturing (IVF) to control sand in the North Sea Gullfaks field without installing screens and gravel packing.[3] These methods involve perforating competent shale or other high-strength intervals adjacent to weaker target pay zones, followed by fracturing treatments designed to grow vertically into the producing formation (next page). Initiating hydraulic fractures from a strong, stable zone delays or prevents the onset of sand production resulting from pressure depletion.[4] The IVF technique requires detailed formation lithology and in-situ stress data, but is effective when applied judiciously.

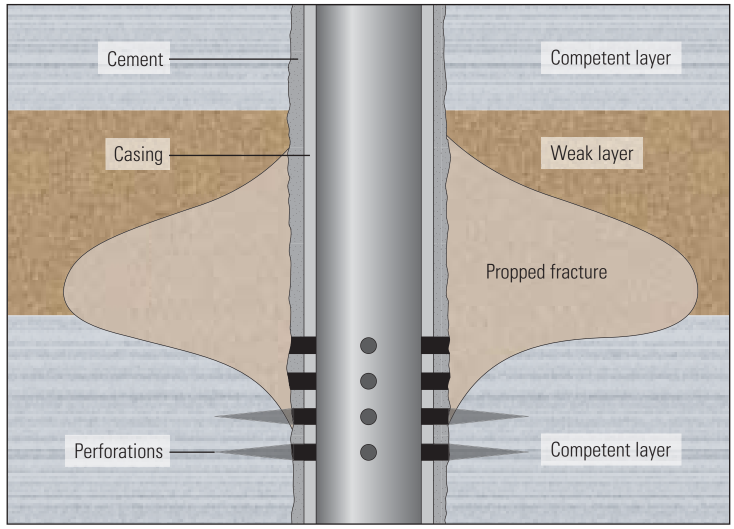
Dalen Resources Oil & Gas Company and Ely & Associates perforated limited 30-ft [9-m] intervals at 0° phasing and used TSO fracturing to prevent sand production.[5] The objective was to create a wide, stable hydraulic fracture packed with resin-coated proppant (RCP) to reduce sandface drawdown pressure and stop proppant flowback as well as produced sand. PT. Caltex Pacific Indonesia, now a division of ChevronTexaco, used a similar technique and a 180° perforation phase angle in Duri field, a heavy-oil steamflood project in Indonesia.[6] During the mid-1990s, Amoco Norway, now called BP Norge, successfully used the same general approach to prevent chalk production from more than 70 horizontal wells in weak North Sea chalk formations.[7] Perforating short intervals—5 ft [1.5 m] or less—at the beginning, or heel, and the bottom, or toe, of horizontal sections induced hydraulic fractures across all perforations. Rigorous testing confirmed that, within certain limitations, RCP could control proppant flowback.

Fracture conductivity—width—affects the pressure drawdown that can be applied before formation sand is produced from perforations not covered by the fracture and proppant pack. Arco E&P Technology, Arco Indonesia, Inc. and Vastar Resources, an Arco subsidiary at that time, developed and applied a technique to predict fracture geometries and properties that prevent sand production.[8] Corpoven, formerly a unit of Petróleos de Venezuela S.A. (PDVSA), also applied this concept to control sand production from deep wells in high-stress formations.[9] In addition, forcing dynamic fractures to close immediately after stimulation operations minimized early onset of sand production.

Subsequently, operators placed greater emphasis on controlling production rates and drawdown pressures during cleanup and recovery of treatment fluids, well testing and initial production to ensure successful fracturing treatments. Because perforation failures initiate at a critical pressure, keeping differential pressures below that critical level during production helps maintain long-term stability. Operators can establish production rates that optimize drawdown pressures during treatment cleanup and hydrocarbon production to prevent formation and perforation failure that might initiate sand production immediately after completion operations.

These techniques contribute to successful screenless completions. However, optimizing cleanup procedures after hydraulic fracturing requires careful consideration of several factors. Flow regime—two- or three-phase flow—viscosity of returning stimulation and reservoir fluids, maximum allowable flow velocity in perforation tunnels and proppant type play important roles in maintaining screenless completion integrity after treatment execution.

Results vary from application to application, but screenless methods generally provide effective sand control. Operators attribute this success to teamwork, efficient completion practices and lessons learned from worldwide experience, in addition to effective fracturing treatment designs and execution, and willingness to try new technology and combinations of techniques. Screenless techniques create a variety of well-completion opportunities that vastly outweigh any limitations from the physical absence of mechanical screens.



^ Early screenless completion in the North Sea. The "up-and-under," or indirect vertical fracturing (IVF), technique was used by Amoco in the Valhall field to control chalk production, and by Statoil in the Gullfaks field to control sand in reservoirs with relatively thick, interbedded sandstones and shale layers. Hydraulic fracture treatments designed to propagate into a nearby hydrocarbon-bearing formation are initiated by perforating a shale or stronger zone. Fracture height and length grow rapidly through the weaker producing interval, with the initial fracture section in the more competent layer acting to exclude formation sand from the wellbore.

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Perforating and Fracturing

For new wells and bypassed zones in existing wells, screenless completions begin with optimized perforating practices. This first step addresses perforation phase angle and orientation, perforated interval length, and the size and number of holes, or shot density.[10] For successful sand control and fracturing treatments, perforating strategies should be designed so that perforations lie in or near the preferred fracture plane (PFP), or maximum in-situ stress direction.

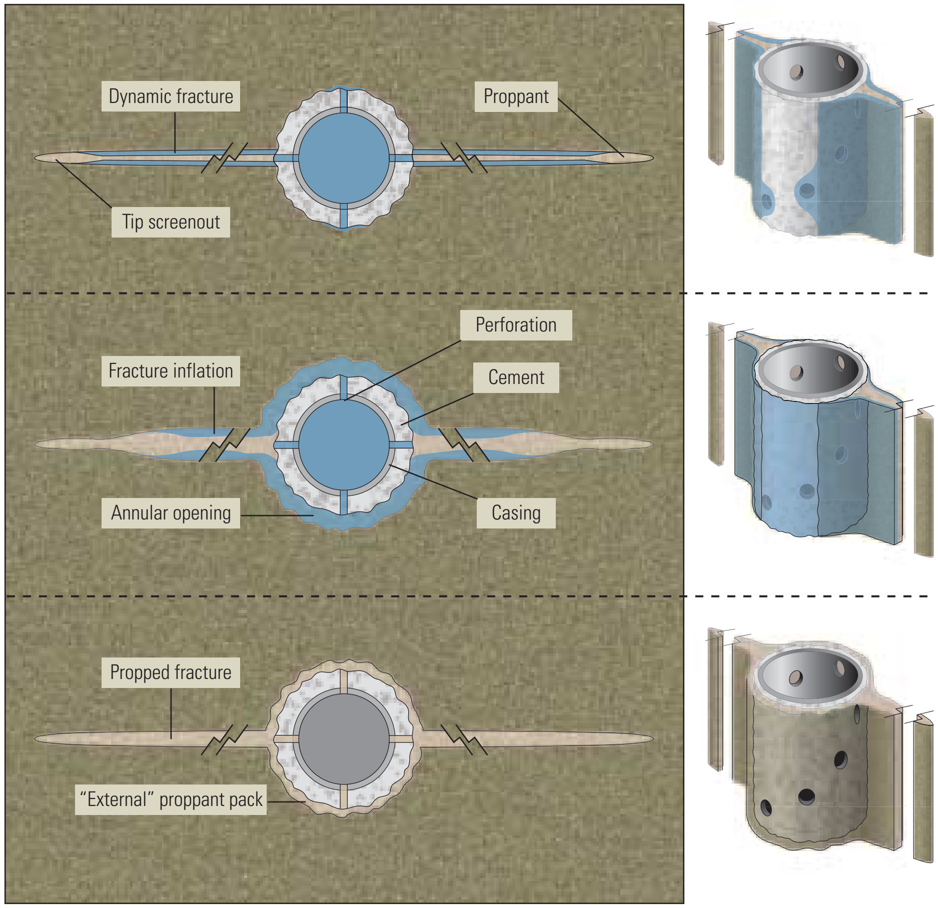
After perforating, TSO fracture treatments are performed to inflate dynamic fractures and create wider propped widths that generate a proppant ring, or "external pack" (right).[11] These specialized fracture treatments bypass near-wellbore damage and stimulate well productivity by connecting individual formation laminations or layers and establishing a conductive, stable and long-lasting flow path from reservoir to wellbore.

Screenless methods achieve success only when well-developed TSO fractures with stable proppant packs cover all perforations and prevent sand from entering the wellbore. Untreated perforations that are not optimally aligned and directly connect formation and wellbore leave potential pathways for sand production.

If stress directions are unknown, a 0° phase angle maximizes the number of perforations that communicate with a hydraulic fracture (next page, top). If stress directions are known, perforating guns with 0° or 180° phasing oriented in the PFP mitigate tunnel failure and sand influx, both with and without consolidation treatments (next page, bottom). Optimal phasing or oriented perforations also reduce near-wellbore flow-path restrictions, or tortuosity. Tortuosity increases fracture-initiation pressure and pressure drops across completion intervals that occur during injection of fracturing fluids and proppants.

Orienting perforations in the proper direction requires knowledge about formation in-situ stresses and directions along with the technical capability to economically orient perforating guns. Special tools such as the oriented four-arm calipers, DSI Dipole Shear Sonic Imager and FMI Fullbore Formation MicroImager tools, supplemented with local knowledge and regional stress maps, help engineers determine stress magnitudes and directions.

In the past, only motorized downhole wireline tools or tubing-conveyed perforating (TCP) systems rotated from surface could actively orient guns. Recently, however, Schlumberger deployed the Wireline Oriented Perforating Tool (WOPT) to orient guns in near-vertical and high-angle wells—inclination angles from about 0.3° up to about 60°—and the OrientXact tubing-conveyed oriented perforating system for near-horizontal wells.[12]

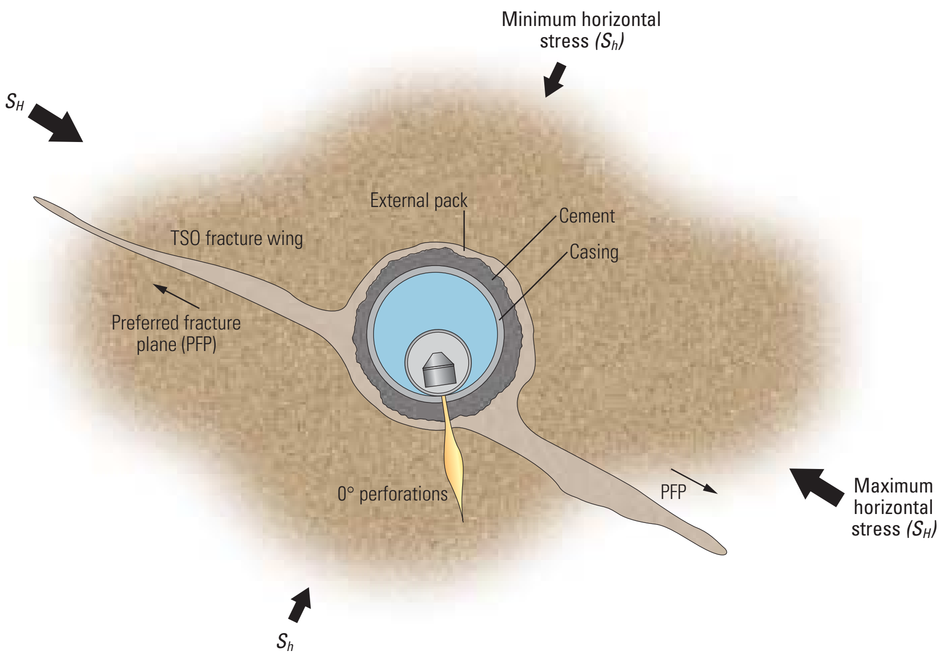


^ Fracturing for screenless completions. Specialized stimulation designs generate tip-screenout (TSO) fractures using proppant-carrying fluids that leak off early in a treatment. Dehydration of this slurry causes proppants to pack off at biwing fracture tips, halting length propagation, or extension (*top*). Pumping additional slurry causes dynamic fractures to inflate as proppants pack back toward the well (*middle*). This promotes grain-to-grain contact after fracture closure and creates wide, high-conductivity fractures that connect discrete formation layers and establish linear flow to the well. A TSO treatment causes enough formation displacement over short intervals to create an annular opening around the wellbore. This "external pack" becomes packed with proppants and covers perforations that are not aligned with the PFP. This prevents sand production from nonaligned perforations, and further reduces near-wellbore pressure drop (*bottom*).

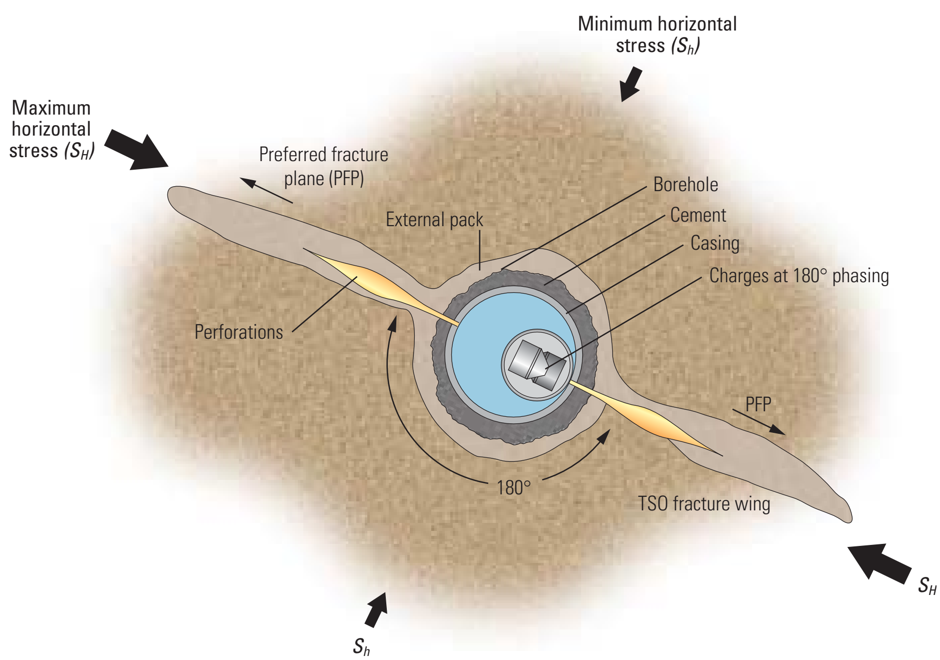
Because of the emerging status of screenless techniques, perforations in vertical wells should be restricted to a maximum interval of 20 to 40 ft [6 to 12 m] at least until experience dictates that this interval can be extended confidently. For high-angle wells with inclinations greater than 10°, where multiple fractures may develop, perforated intervals should be less than 6 ft [1.8 m]. Limiting perforated-interval lengths improves fluid placement, and increases the probability that TSO fractures will cover the perforations and form an effective external pack completely around the wellbore.[13] Shorter intervals also improve proppant packing by providing high net pressure near the wellbore.

Completion engineers select perforating charge type and shot density based on required pressure drops while pumping the fracture treatment and producing the well. Perforation diameter must be sufficiently large to avoid proppant bridging and premature screenouts, but small enough so that after the dynamic fracture closes, the propped width at the wellbore completely covers the entrance holes in casing walls, thus blocking sand influx. Limiting the number of shots minimizes untreated perforations.

Hydraulic fracturing reduces the pressure drop across completion intervals, which minimizes perforation failures and sand production. The external pack and large surface area of proppant packs created during TSO fracturing also prevent sand from entering a well. Most screenless stimulations include additional measures to stabilize the proppant pack.



^ Optimal perforation phase angle. From rock mechanics, we know that hydraulic fractures propagate in the direction of maximum horizontal stress (S_H), or along the preferred fracture plane (PFP). When in-situ stress directions are unknown, a 0° perforating-charge phasing increases the probability that all perforations will connect with the TSO fracture. Perforations at other angles—30, 60 and 90° phasing—may not intersect the fracture.



^ Orienting perforations in the right direction. If in-situ stress directions are known, perforating guns with charges at 0° or 180° can be aligned in the preferred fracture plane (PFP), perpendicular to the minimum horizontal stress direction (S_h), so that the TSO fracture will cover all perforations. Proper orientation reduces or eliminates complex near-wellbore flow, or tortuosity, which increases fracture initiation and treatment pressures.

Controlling Proppant Flowback

Propped fractures extend past near-wellbore drilling and completion damage that reduces permeability to create a conductive, linear flow path to the well. Like produced sand, proppant flowback is detrimental to well productivity and producing operations, and also fracture stability. Screenless completions lack internal annular gravel packs and mechanical screens inside the casing to stop sand from entering the wellbore with produced fluids. It is imperative that proppants remain inside hydraulic fractures, especially when formations must be chemically consolidated.

Proppants flowing at high rates erode completion equipment, tubulars, control valves and wellheads. In low-rate wells, proppants moving back into a wellbore can settle inside the casing and cause production to cease if productive intervals become completely covered. Proppant flowback also contributes to formation failure and perforation collapse, creates pathways for formation sand influx, and reduces production. Specialized materials, such as resin-coated proppant (RCP) and Schlumberger PropNET hydraulic fracturing proppant-pack additives, or both applied together, help maintain fracture stability and integrity.

Several types of RCP are available, but only a few are suitable for screenless completions. Curable RCP interacts with treatment fluids and may set up in the casing after a premature screenout, making removal difficult. Precured RCP does not provide sufficient flowback control and should not be used in screenless completions in any case because the resin functions primarily to increase crush resistance. In general, a partially cured RCP is preferred because it minimizes fluid interactions and provides fracture stability while lowering the risk of proppant packing off and setting up inside the wellbore.

10. Behrmann et al, reference 1.
11. In standard fracturing, the fracture tip is the final area that is packed with proppant. A tip-screenout design causes proppant to pack, or bridge, near the end of the fractures in early stages of a treatment. As additional proppant-laden fluid is pumped, the fractures can no longer propagate deeper into a formation and begin to widen or balloon. This technique creates a wider, more conductive pathway as proppant is packed back toward the wellbore.
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12. Almaguer J, Manrique J, Wickramasuriya S, Habbtar A, López-de-Cárdenas J, May D, McNally AC and Sulbarán A: "Orienting Perforations in the Right Direction," *Oilfield Review* 14, no. 1 (Spring 2002): 16–31.
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PropNET fiber technology uses randomly oriented carbon fibers that create a physical, rather than chemical, barrier that reinforces proppant packs and inhibits flowback (below left).[14] The fibers are added continuously to fracturing fluids at the wellsite and mix with proppants during pumping. Experience indicates that PropNET fibers allow immediate flowback to improve treatment-fluid recovery after fracturing. This capability is attributed to the building of a mechanically reinforced network that interlocks proppant grains. Unlike RCP, this technology does not depend on temperature-sensitive curing processes or other chemical reactions. The fibers are inert and compatible with all fracturing fluids, including ClearFRAC polymer-free frac fluids based on viscoelastic surfactants (VES).

PropNET fibers and proppants are easier to remove than RCP alone, which can cure and bond together inside the wellbore under certain conditions. These specialized fibers do not have temperature, closure-stress or shut-in time limitations before, during or after fracturing. Because PropNET fibers do not bond with proppants, performance is not affected by reservoir depletion, crushing of individual grains or closure-stress cycling from producing and shutting in wells.

^ Proppant-flowback control. Carbon fibers mixed and pumped with proppants and fracturing fluids form a random, net-like structure in the proppant packs of hydraulic fractures. PropNET fiber widths are several times smaller than average proppant diameters. Specially engineered fiber lengths allow contact with more than 30 proppant particles. These factors ensure pack conductivity and stability, even if localized flow exceeds critical rates and causes a few proppant particles to move or break away. Fibers strengthen and reinforce the pack by interweaving among individual proppant grains. This promotes particle bridging and distributes stress for increased pack stability, while still allowing high production rates.

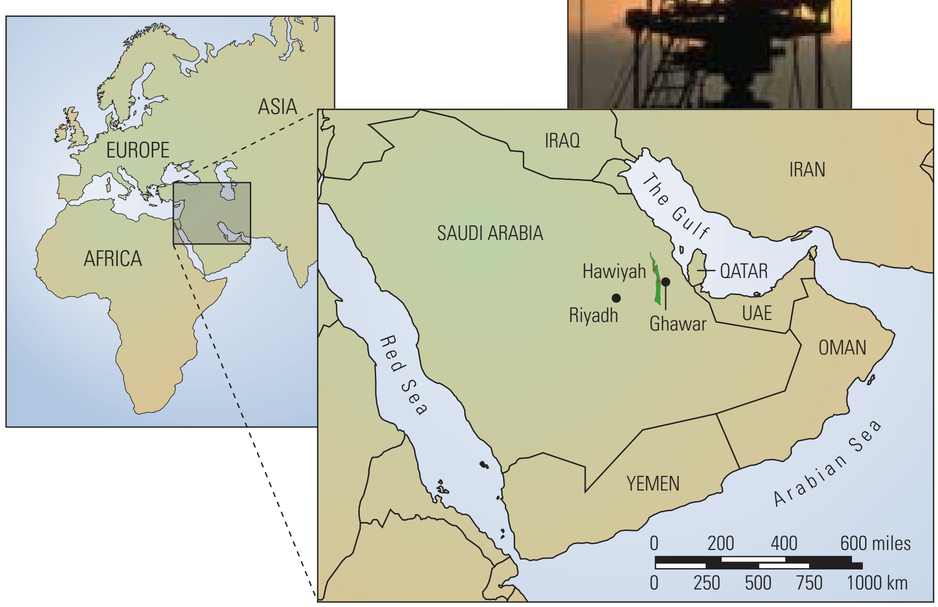
When high production rates and maximum proppant-flowback control are required, fibers combined with resin-coated proppant provide reliable proppant-flowback control under a wider range of conditions than either RCP or PropNET fibers alone. PropNET fibers reinforce the RCP to provide additional resistance to rate changes, production cycling and increasing closure stress as reservoirs deplete, especially for extremely high-rate wells.[15] PropNET fibers also improve proppant suspension and transport in wellbore tubulars and dynamic fractures, and reduce frictional pressures during pumping operations as verifed by field measurements.

Saudi Arabia: Fracturing for Sand Control. In 1995, Saudi Aramco began developing nonassociated gas reserves in the Ghawar field of Saudi Arabia, including construction of gas-handling facilities (below).[16] The newly built Hawiyah gas plant, with processing capacity of 1.6 billion scf/D [46 million m^3/d], required 400 MMscf/D [11.5 million m^3/d] of "sweet" gas with no hydrogen sulfide [H_2S] to operate efficiently. Production from wells in the Jauf reservoir, a weak sandstone with bottomhole pressure and temperature of 8750 psi [60 MPa] and 300°F [149°C], was critical in meeting this requirement.

This formation lies at a depth of 13,500 to 14,400 ft [4115 to 4390 m]. Wells produce sweet gas at 10 to 60 MMscf/D [286,000 to 1.7 million m^3/d], but it is difficult to maintain solids-free output at these high rates. Excessive sand influx necessitates repeated wellbore cleanouts and causes internal pipeline corrosion by stripping chemical inhibitors off pipe walls.

Conventional sand-control methods were not considered as part of the field-development plan. Gravel-packed screens would restrict production rates and the wells could not have met plant production targets, requiring Saudi Aramco to drill additional wellbores. In addition, TSO fracture stimulations were not always successful because misaligned perforations caused near-wellbore tortuosity, or flow-path restrictions, that increased fracture-initiation and injection pressures. This limited net fracturing pressure and the capability to achieve optimal fracture width, height and length. Standard perforating resulted in unpacked perforations that were pathways for produced sand.

Attempts to control sand with conventional screenless techniques were not successful so a team of Saudi Aramco and Schlumberger experts reevaluated perforating, hydraulic fracturing and proppant-flowback strategies.[17] Using the PowerSTIM well optimization process, these specialists compiled a set of comprehensive formation-evaluation, reservoir-characterization, fracture-stimulation and well-test data to improve stimulation and completion design,



^ Ghawar field, Saudi Arabia.

execution and evaluation.[18] This approach helped the team analyze, optimize and implement several innovative practices.

Based on the best available data and up-to-date field responses, the joint completions team developed and calibrated improved petrophysical and formation mechanical-properties models. The new sand-prediction model differentiated the more competent, or stable, layers from those prone to sand production. This improvement helped engineers make decisions about perforating practices and perforation placement.

The Jauf team thoroughly investigated and improved two key aspects of these well completions. First, they developed fracturing techniques using the best combination of oriented perforations, treatment fluids, proppants and flowback-control additives. Second, they implemented screenless techniques, including perforation specifications—interval length, hole size and placement—proppant type and size, and chemical and fluid systems to optimize gas output and minimize sand production.

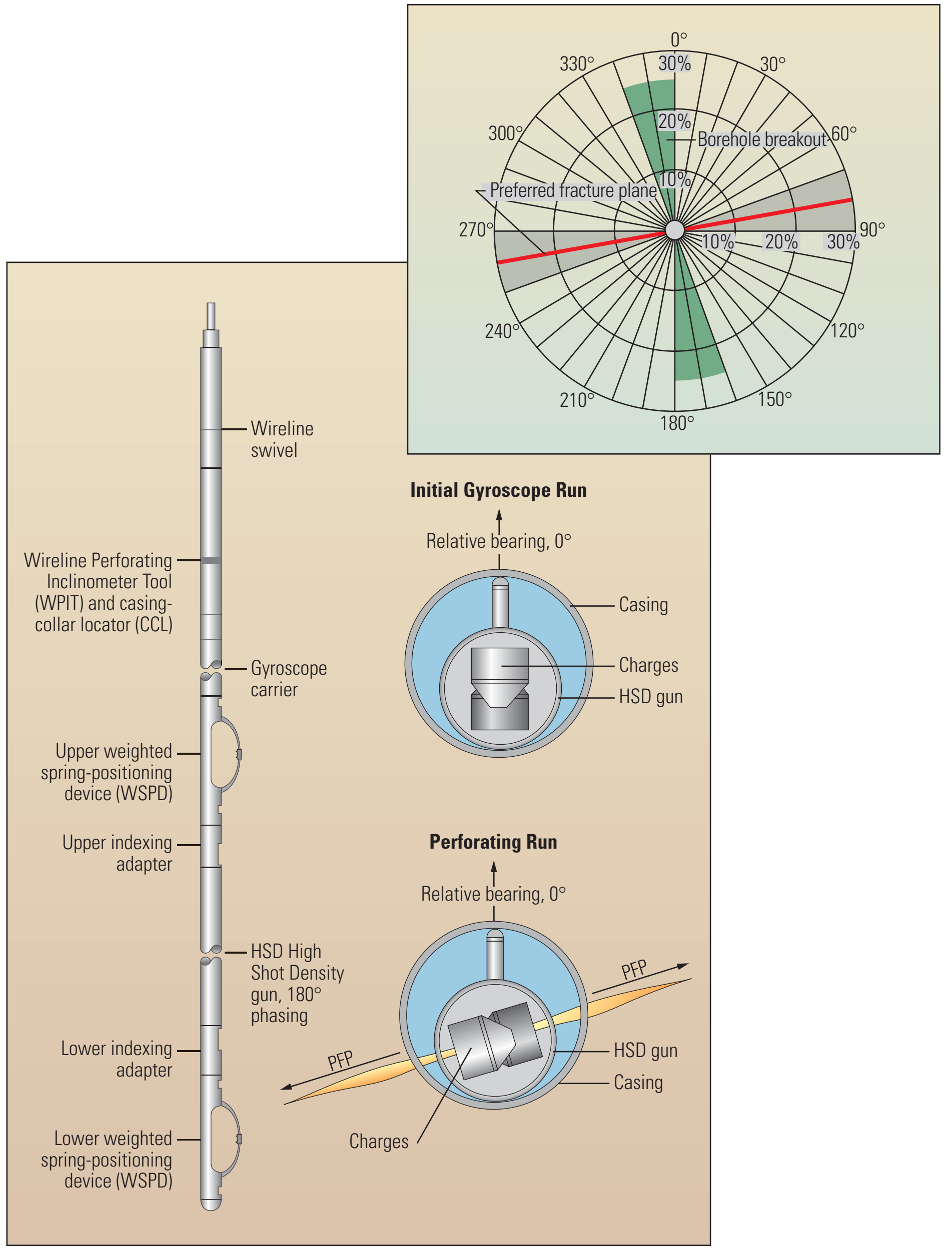
Screenless methods have been the key to successful gas-well completions in the Jauf reservoir. The objective of producing sand-free gas at economic rates and reasonable drawdown pressures was achieved by multiple means:

- perforating only stable intervals
- perforating one interval per well
- limiting perforated interval length
- using intermediate-strength RCP
- using fiber flowback-control additives
- orienting perforations in the PFP
- forcing fracture closure immediately after treatments
- designing special flowback procedures.

The revised completion strategy avoided perforating within 10 to 20 ft [3 to 6 m] of weak zones as identified on stress profiles. Perforated intervals were limited to single lengths of 30 or 40 ft to ensure fracture coverage of all perforations, create an external pack at the wellbore, and prevent sand flux from untreated perforations.

The combination of intermediate-strength RCP and high-temperature PropNET Gold fibers also was used to stop proppant flowback and help control produced sand. Finally, carefully evaluating and adjusting post-treatment production helped Saudi Aramco achieve and maintain initial sand-free rates.

Perforations properly aligned with the PFP minimize unpacked tunnels that can contribute to sand production. Saudi Aramco chose the Wireline Oriented Perforating Tool (WOPT) and guns with 180° phasing to perforate in the direction of maximum formation stress and PFP orientation at an 80° or 260° azimuth (above).



^ Wireline-oriented perforating. The Schlumberger Wireline Oriented Perforating Tool (WOPT) can be run in near-vertical and high-angle wells with inclination angles from 0.3 to about 60° (*left*). Developed initially for oriented fracturing, the WOPT is also used for sand prevention and screenless completions. This tool orients standard hollow-steel carrier guns with charges at optimal 0 or 180° phasing in a predetermined direction. Saudi Aramco, a primary user of oriented perforating, deploys the WOPT system to facilitate TSO fracturing. The Ghawar field PowerSTIM team used borehole breakout identified on FMI Fullbore Formation MicroImager logs to confirm an east-west maximum stress and PFP orientation in the Jauf formation at an azimuth of about 80° or 260° (*right*).

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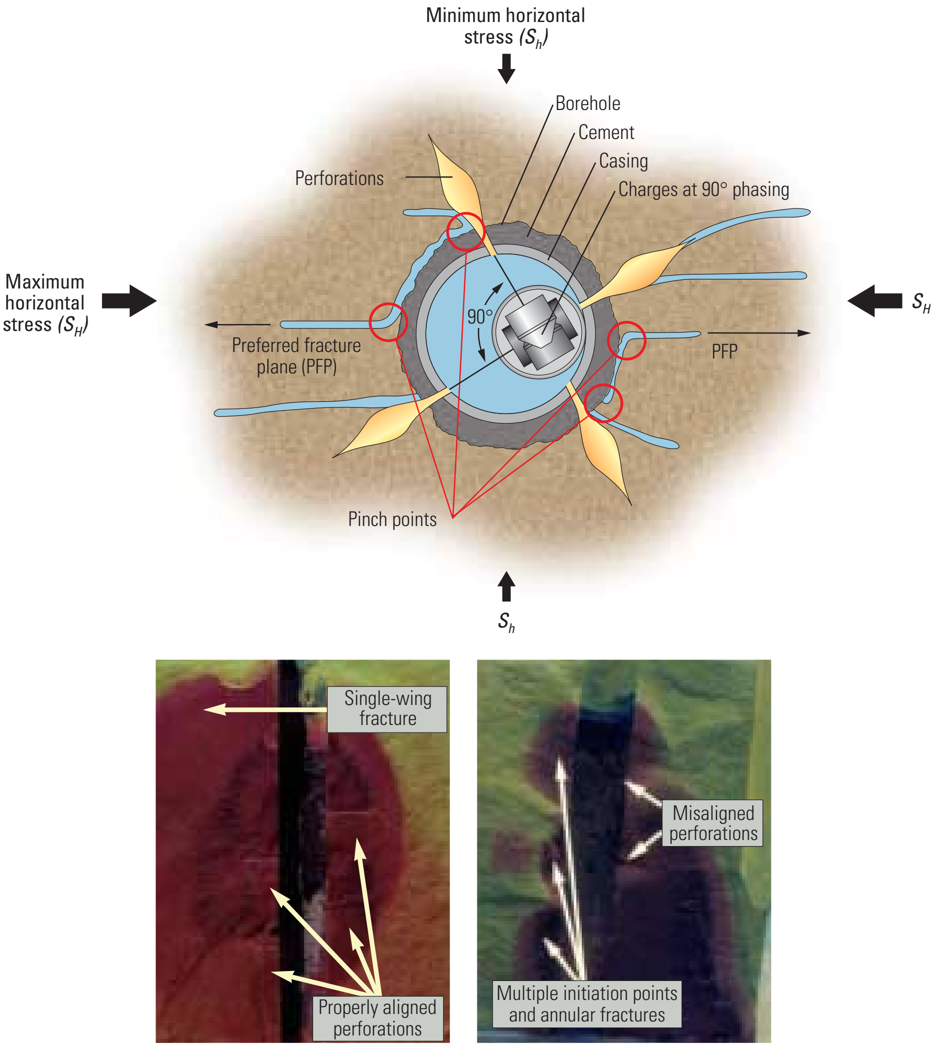
18. For more on PowerSTIM stimulation and completion optimization: Al-Qarni AO, Ault B, Heckman R, McClure S, Denoo S, Rowe W, Fairhurst D, Kaiser B, Logan D, McNally AC, Norville MA, Seim MR and Ramsey L: "From Reservoir Specifics to Stimulation Solutions," *Oilfield Review* 12, no. 4 (Winter 2000/2001): 42-60.



^ Fracturing considerations. Hydraulic fracture initiation can occur at various discrete points on the wellbore radius if perforations are not aligned with the preferred fracture plane (PFP), or maximum horizontal stress (S_H). Developing fractures travel around casing and cement or turn to align with the PFP. This results in complex near-wellbore flow paths, or tortuosity, including competing fractures, pinch-point flow restrictions and fracture wings that curve or have poor alignment with the wellbore (*top*). Perforations oriented close to the PFP, or path of least resistance, minimize fracture-initiation and treating pressures. In full-scale laboratory tests on formation blocks under triaxial stress, perforations in the PFP resulted in a dominant single-wing fracture with minimal tortuosity and lower injection pressures (*bottom left*). In the same test, misaligned perforations resulted in multiple fracture initiation points (*bottom right*).

Oriented perforating reduces treating pressures and creates wider fractures, which also reduce turbulent, or nondarcy, flow and drawdown pressure during production, further mitigating sand production (above).

Fracture stimulations prior to oriented perforating failed to deliver sand-free gas at required rates, but Saudi Aramco observed positive results with the first application of oriented perforating and screenless completions. Analyzing prefracture injectivity and minifracture treatments with DataFRAC fracture data determination services confirmed significant reductions in fracture-initiation pressure for wells with oriented perforations. Pressure losses during pumping operations dropped from about 2000 psi [13.8 MPa] for conventional perforating to less than 600 psi [4.1 MPa] in wells with oriented perforations.

Improved hydraulic fracturing execution and increased well productivity demonstrate the effectiveness of oriented perforating. Fracture stimulation treatments prior to implementation of the revised well-completion strategies that were devised by the joint team resulted in extended flow periods to clean up wells after treatments. In one case, it took 55 days to achieve solids-free production. Optimized screenless technologies and improved flowback procedures reduced this cleanup period to as little as five days in some cases.

Saudi Aramco routinely limits perforated intervals, and is one of the largest users of oriented perforating services. The company completes most wells in the current Jauf stimulation program with the WOPT system. To date, screenless techniques have achieved sand-free gas rates even at high production rates and after cycling production on and off for several months.

Formation Consolidation

Existing completions and some new wells have perforations that are not oriented in the preferred fracture plane or at optimal 0° or 180° phasing. These "nonaligned" perforations can become a source of sand production, especially at higher rates and drawdown pressures. Formation consolidation, historically by injection of organic resins, addresses this problem by binding individual formation grains together (next page).[19] In combination with TSO fracturing and PropNET fibers, this technique stabilizes a limited collar-shaped volume around wellbores and perforations when resins are evenly diverted across perforated intervals.[20]

Some resins create a high-strength consolidated region while only moderately reducing formation permeability. Using these systems maintains some productivity after consolidation even without fracturing. Other systems impair formation permeability significantly or completely seal off the near-wellbore region. Subsequent TSO treatments extend propped fractures beyond the altered zone to connect with the undamaged formation and control sand production.

Formation consolidation strengthens weakly consolidated formations and minimizes risk of sand influx from nonaligned, potentially untreated perforations. Flowback-control additives in proppant packs prevent sand production from perforations in communication with the hydraulic fracture. The formation around perforations that do not communicate with the fracture is stabilized by the resin and is less likely to produce sand.

In wells with existing conventional gravel packs, consolidation stabilizes gravel in the perforations and in annular packs between screens and casing. This step can enhance or extend well productivity. During TSO fracturing, consolidation techniques also help prevent premature screenouts by limiting treatment-fluid losses into highly permeable existing gravel packs or the near-wellbore region. The success of these treatments depends strongly on optimized fluid-system chemistry, engineered and controlled fluid placement and wellbore physics.

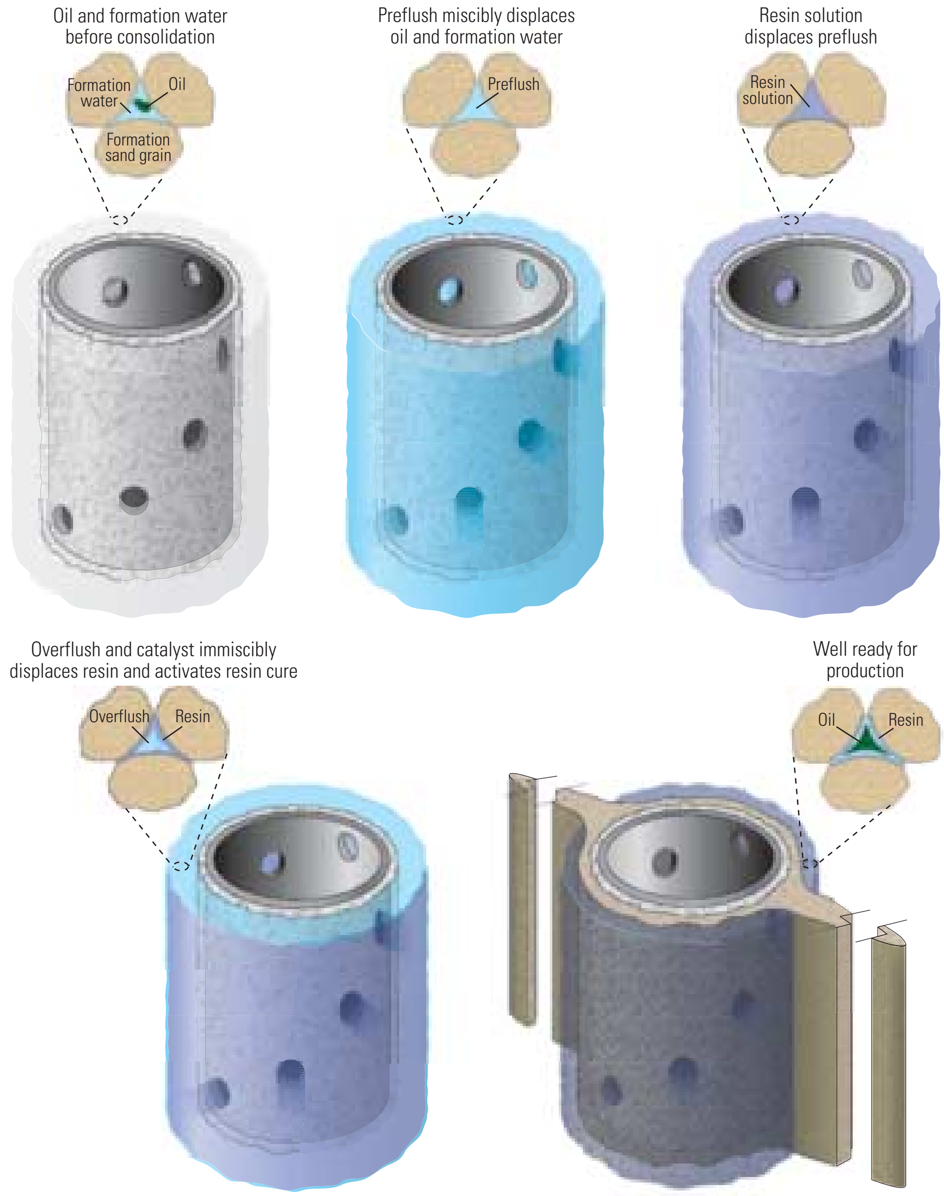
Schlumberger offers epoxy-based SANDLOCK sand control systems using resin and furan-based K300 systems. Recommended depth of penetration for these systems is 2 to 3 feet [0.6 to 0.9 m] into a formation. These systems rely on multiple stages of injected fluids, which limit effective placement in heterogeneous intervals. Current resin systems are limited to treating intervals of about 20 ft.

SANDLOCK treatments begin with a preflush to clean the formation volume near a wellbore and leave sand-grain surfaces oil-wet and ready to bond with the resin. The resin system is mixed into a water-base carrier fluid, usually linear hydroxyethylcellulose (HEC), and pumped into the rock matrix. The SANDLOCK system has an internal catalyst, and a curing agent is mixed with the resin, so the reaction begins immediately after mixing. Catalyst concentration determines available pumping time. This system has been used successfully for proppant-flowback remedial operations, but has limited application in screenless completions other than gravel-pack remediation because it does not penetrate formations with less than 1-darcy permeability.

The K300 system uses an external catalyst that is pumped after placing resin in the formation to initiate curing. Consequently, treatment procedures are more complicated. Like the SANDLOCK system, a preflush is pumped first, followed by K300 resin; no carrier fluid is used. The next step involves pumping a viscous overflush, usually linear HEC fluid, to sweep excess resin away from the near-wellbore region. In the final stage, an external catalyst is pumped. Unlimited resin-placement time is one advantage of this approach, but uncertainty about effective in-situ downhole mixing of catalyst and resin is a disadvantage.

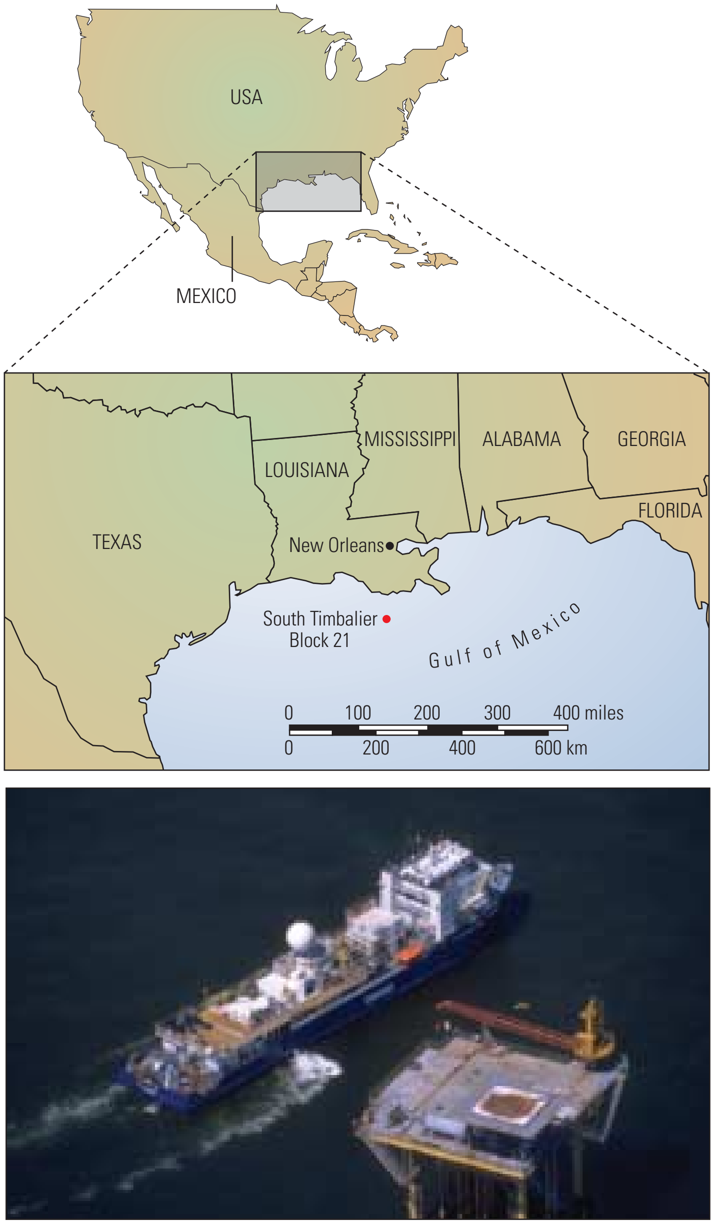
Formations are fractured during screenless completions, so there is no requirement to use systems that retain formation permeability. This greatly simplifies in-situ consolidation treatments. As a result, Schlumberger employs a novel technique that uses the water-base OrganoSEAL organic crosslinked gel system, which was developed for water-control applications. This single-stage treatment completely fills matrix pore spaces and shuts off near-wellbore permeability. TSO hydraulic fracturing restores well productivity.

The OrganoSEAL-R system can be pumped down wellbore tubulars and diverted with solid agents to treat interval lengths of up to 50 ft [15 m], but coiled tubing is the preferred placement method. This consolidation system costs significantly less, is more environmentally friendly and is easier to clean out of the wellbore than resin systems. OrganoSEAL-R fluids can be easily squeezed into annular gravel packs, but flow less readily into the formation because of differences in gravel and rock-matrix permeability. This makes fluid placement across an entire zone for gravel-pack remediation feasible.



^ Formation consolidation. Chemical consolidation before fracturing stabilizes completion intervals that do not have optimal or oriented perforations (*top left*). Typically, a resin system is injected into the formation using conventional pumping services or coiled tubing. These treatments consist of three basic stages: pretreatment acid and surfactant preflush to displace formation water and hydrocarbons (*top middle*), resin injection (*top right*), catalyst injection and viscous overflush with a shut-in period that allows the resin to cure (*bottom left*). This procedure is followed by TSO fracturing to bypass the consolidated region and reconnect with the unaltered rock (*bottom right*).

19. Parlar M, Ali SA, Hoss R, Wagner DJ, King L, Zeiler C and Thomas R: "New Chemistry and Improved Placement Practices Enhance Resin Consolidation: Case Histories from the Gulf of Mexico," paper SPE 39435, presented at the SPE International Symposium on Formation Damage Control, Lafayette, Louisiana, USA, February 18–19, 1998.
    Ott WK and Woods JD: *World Oil Modern Sandface Completion Practices Handbook*. Houston, Texas, USA: Gulf Publishing Company (2003): 113-114.
20. Nelson EB, Brown JE and Card RJ: "Sand Control Without Requiring a Gravel Pack Screen," U.S. Patent No. 5,551,514 (September 3, 1996).



^ South Timbalier Block 21 field, Gulf of Mexico, USA.

Gulf of Mexico: Slimhole Sidetrack

In November 2000, J.M. Huber Corporation assumed operational responsibility for the South Timbalier Block 21 field in the Gulf of Mexico south of Louisiana, USA (above).[21] At that time, the company identified an untapped reservoir compartment and drilled a directional sidetrack from nearby Well 48 to develop updip reserves. Well logs and sidewall cores confirmed 22 ft of oil from measured depth (MD) 11,772 to 11,794 ft [3588 to 3595 m].

The target upper Miocene sandstone was relatively clean with average porosity of 28%, permeability ranging from 100 to 500 mD and a 5800-psi [40-MPa] bottomhole pressure supported by a strong waterdrive. Typically, these Miocene formations require sand-control measures. Based on a history of sand production in the field and a previously completed interval of the same zone in Well 48, completion engineers planned to gravel pack 2⅜-in. screens inside a 5-in. liner.

However, during drilling operations, the 5-in. liner became differentially stuck above the planned total depth (TD). This forced the operator to cement the string at 11,101 ft [3384 m] MD as intermediate casing and run a 3½-in. liner to TD at 12,160 ft [3706 m] MD (next page, left). A smaller conventional gravel pack was not practical because it would restrict production. J.M. Huber and Schlumberger solved this dilemma with screenless technology.

The revised well completion combined optimized perforating, formation consolidation and TSO fracturing with a proppant flowback-control additive with careful control and monitoring of initial cleanup and production rates. Analysis of past screenless procedures and experiences worldwide, particularly unsuccessful completions, confirmed that when any of these techniques or associated guidelines is misapplied, chances of success decrease significantly.

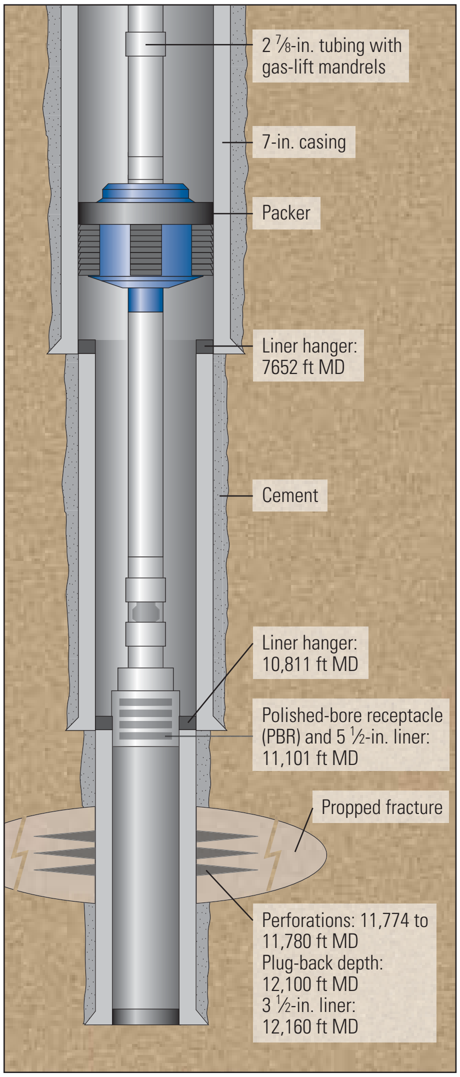
Well 48, originally drilled in the 1960s, could not support a conventional rig intervention from its small caisson structure. For this reason, the operator used a jackup rig to support completion operations, including wireline, coiled tubing and high-pressure pumping equipment. After cement was drilled out of the 3½-in. liner, the screenless completion was performed in four stages:

- optimized perforating
- coiled tubing acidizing and consolidation
- TSO proppant fracturing with PropNET fibers
- coiled tubing wellbore cleanout.

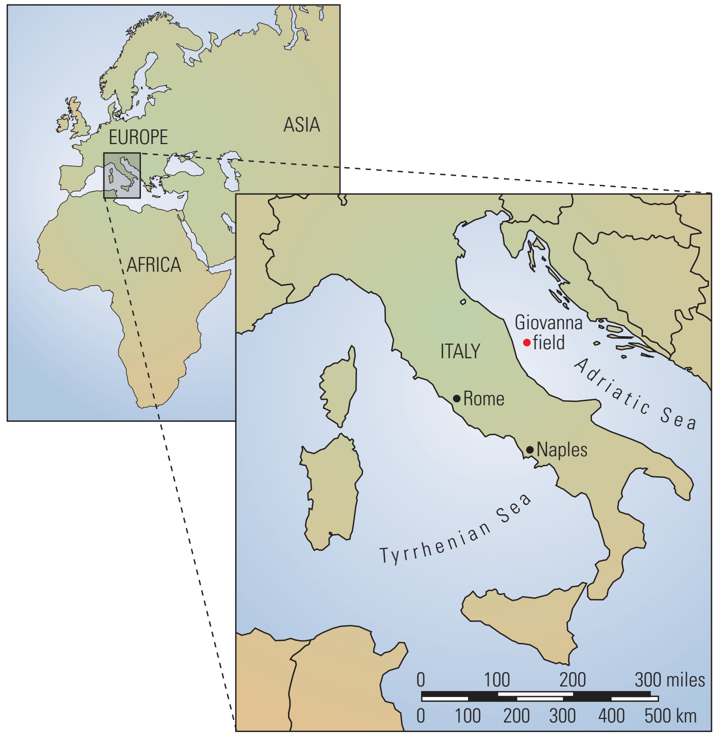
NODAL production system analysis determined that a 6-ft perforated interval could produce 400 B/D [63.6 m^3/d] with less than 100 psi [689 kPa] of pressure drawdown at the sandface. Based on SPAN Schlumberger Perforating Analysis modeling software, J.M. Huber and Schlumberger representatives selected charges to create a 0.33-in. [8.4-mm] diameter entrance hole in the casing. This perforating job was designed to achieve the required production rate and prevent sand influx by helping to ensure that the propped fracture would cover the perforations completely.

Perforation density was limited to 6 shots per foot (spf) to improve treatment placement and reduce the likelihood untreated perforations. A phasing of 0° further ensured that perforations would communicate with the propped fracture. The engineering team, however, still worried that proppant flowback might initiate sand production. This dictated the need for a consolidation treatment prior to fracturing. Engineers chose K300 furan resin, which could be placed across the short perforated interval using coiled tubing, to stabilize a volume of formation around the wellbore.

Resins tend to reduce formation permeability to some extent, but hydraulic fractures extend past the consolidated near-wellbore region. Chemical consolidation prevents sand



^ Redesigned completion. During drilling of the Well 48 lateral sidetrack at a 40° borehole inclination angle, shallow pressure-depleted zones caused the original 5-in. liner to become stuck at 11,101 ft [3384 m] MD, so it had to be cemented in place. This setback required that an additional 3½-in. liner be run to TD at 12,160 ft [3706 m] MD. A polished-bore receptacle (PBR) designed to accept a seal assembly was run at the top of the 3½-in. liner. The redesigned completion had a packer with 2⅞-in. tubing above and below it set in 7-in. casing to allow for through-tubing fracturing operations. Tubing-movement calculations verified equipment stability, and computer fracture simulations determined safety limits during the TSO fracture treatment.



^ The Giovanna field offshore eastern Italy.

production early in the life of a well, but by itself may not control sand influx in later stages of reservoir depletion. This soft, or weakly consolidated, formation also required a short, wide propped fracture to control sand by reducing flowing pressure drop and preventing sand influx through perforations.

For this job, the operator used a low-guar, borate-crosslinked fracturing system that was compatible with reservoir fluids. A 20/40 mesh, stress-cured, ceramic RCP was selected to avoid crushing of the proppant at the 8000-psi [55-MPa] formation stress. PropNET fibers were added to proppant-laden fluid stages. The TSO fracture treatment, performed from a stimulation vessel, placed 9096 lbm [4126 kg] of proppant in the formation out of a total 13,204 lbm [5989 kg] pumped. Decreasing pump rate at the end of the job avoided excessive surface treating pressures. Controlled flowback immediately after pumping ceased initiated rapid forced closure of the hydraulic fracture.

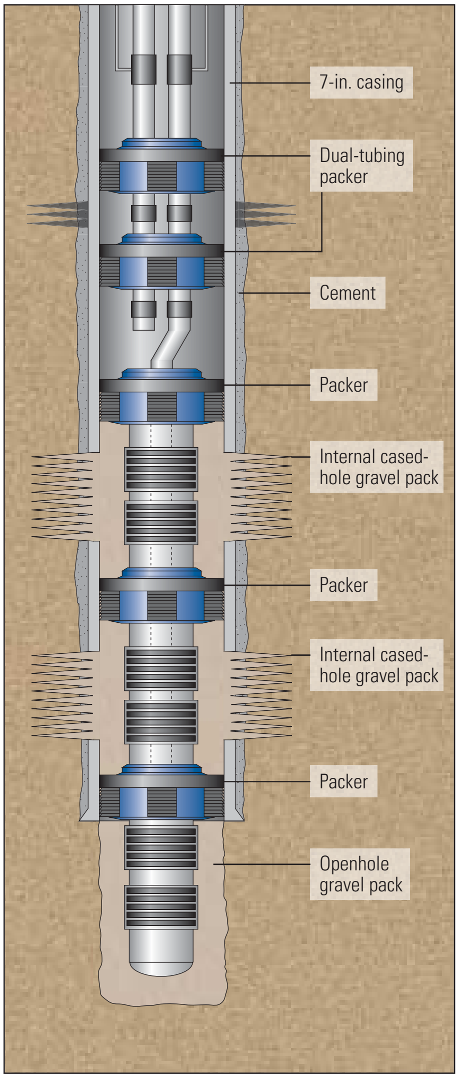
Initially, the well tested at a rate of 535 B/D [85 m^3/d] of oil and 4 MMscf/d [114,560 m^3/D] of gas with a tubing pressure of 3700 psi [25.5 MPa]. NODAL analysis confirmed a fracture permeability of 200 mD and a slightly negative skin effect. This indicated that the zone was stimulated and would produce better than undamaged formation. After more than a month, hydrocarbon rates stabilized at about 500 B/D [79.5 m^3/d] of oil and 2.5 MMscf/D [71,591 m^3/d] of gas with a 3500-psi [24.1 MPa] flowing tubing pressure (ftp).

One year after pumping the sand consolidation treatment, this well was still flowing 220 B/D [35 m^3/d] of oil, 850 B/D [135 m^3/d] of water and 380,000 scf/D [10,882 m^3/d] of gas at a 1520-psi [10.5-MPa] ftp. There was no significant sand production during the first year of production.

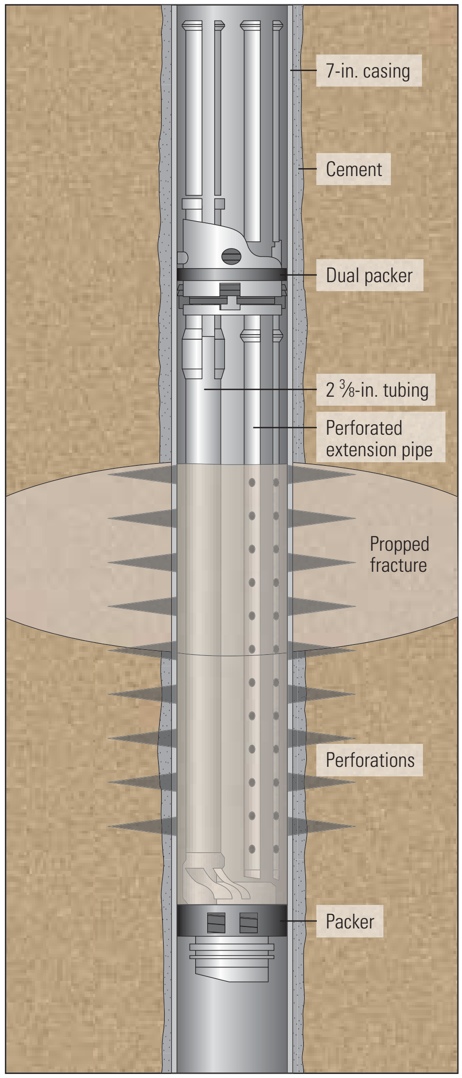
Offshore Italy: Dry-Gas Completions

Eni S.p.A. E&P Division applied screenless technology to address sand production in Adriatic Sea fields off the eastern coast of Italy (above).[22] Many reservoirs in this area comprise interbedded

21. Riddles C, Acock A and Hoover S: "Rigless, Screenless Completions Solve Sand Control Problems in Two Offshore Fields–Part 1," *Offshore* 62, no. 6 (June 2000): 48–50, 98.
22. Pitoni E, Devia F, James SG and Heitmann N: "Screenless Completions: Cost-Effective Sand Control in the Adriatic Sea," paper SPE 58787, presented at the SPE International Symposium on Formation Damage Control, Lafayette, Louisiana, USA, February 23–24, 2000; also in *SPE Drilling & Completions* 15, no. 4 (December 2000): 293–297.
    Heitmann N, Pitoni E, Ripa G and England K: "Fiber-Enhanced Visco-Elastic Surfactant Enables Cost-Effective Screenless Sand Control," paper SPE 78323, presented at the 13th SPE European Petroleum Conference, Aberdeen, Scotland, UK, October 29–31, 2002.
    Pitoni E, Ripa G and Heitmann N: "Rigless, Screenless Completions Solve Sand Problems in Two Offshore Fields–Part II," *Offshore* 62, no. 7 (July 2002): 64–68, 109.



^ Typical Adriatic Sea wellbore configuration.



^ Giovanna field: Well 6, Pool 10, screenless completion.

layers of sand, silt and clay. Pay intervals have low to moderate permeability and historically produce formation solids, which requires sand-control completion methods. Typically, Eni combines several sedimentary groups into "pools" that are completed with conventional gravel packs and produced separately. Some wells have more than 10 distinct pools.

Most wells are dual completions with two parallel strings of 2⅜-in. tubing. A gravel pack cannot be installed for the short string of wells with 7-in. casing, which limits the number of pools that can be completed in a single wellbore (above left). Accessing other pools requires expensive recompletion operations with conventional rigs. In 9⅝-in. or larger casing, a single, selective gravel pack can be installed for the short string, but full-scale workovers are needed to complete additional intervals.

Without sand control, however, upper zones become choked by sand in a short time, often less than two years. Effective and reliable screenless methods allow completion of multiple layers through the short string without regard to casing size and without bypassing or deferring production of reserves. This approach reduces drilling and completion costs significantly and allows more gas zones in a well to be produced efficiently, even with smaller 6⅛-in. boreholes and 5-in. casing.

Like other developments in this area, the Giovanna field consists of heterogeneous laminated and stratified reservoirs with a gas relative permeability that is low—about 12 mD. These "dirty" sandstones have clay contents as high as 50%. Produced sand and migrating fines cause productivity declines that significantly reduce field output. An upper zone in Giovanna Well 6 was selected for a screenless completion field trial. Eni initially completed this well with dual 2⅜-in. tubing in December 1992, but the wellbore filled with sand in less than two years and had to be shut in (left).

Eni and Schlumberger evaluated each step of the screenless-completion process—perforating, formation consolidation, fracturing for sand control and optimal treatment-fluid selection. Optimized perforating was not an option because the well had existing perforations and a slotted-pipe extension across the target interval. Low permeability limited matrix injection rates and prevented the use of conventional formation-consolidation resins. The remaining option was to remove sand fill from the wellbore and perform a TSO fracture treatment with effective proppant-flowback control.

A relatively low fracture-closure stress—3000 psi [20.7 MPa]—simplified proppant selection, but choosing a mesh size was more difficult. Larger proppant sizes maximize fracture conductivity, but smaller sizes prevent formation particle migration. Wide TSO fractures reduced the likelihood of fines transport by decreasing drawdown pressure and flowing gas velocity in the formation during production. Therefore, a proppant size that could control sand production, but not fines invasion, was chosen.

After comprehensive fracturing studies and simulations, Eni chose a ClearFRAC fluid to meet fracturing objectives. ClearFRAC VES fluids consistently demonstrate superior proppant suspension and transport characteristics, even at low viscosities. Minimizing fracturing-fluid viscosity and optimizing fluid leakoff helped achieve a short and wide TSO fracture in the Giovanna Pool 10 formations, which had not been possible previously with conventional polymer-based fracturing fluids. PropNET fibers were added to keep proppants inside the fracture.

Prior to fracturing, coiled tubing cleanout operations removed sand fill inside and around the perforated extension pipe. A sand plug was placed, or spotted, with the top at 5754 ft [1754 m], leaving 39 ft [12 m] of open perforations for fracturing. Because of platform space limitations, all slurry stages for the fracture treatment were batch-mixed in tanks with independently controlled paddles and recirculating pumps to ensure better fluid mixing and consistency.

This screenless treatment was pumped through the existing completion and performed without a conventional rig. Monitoring net pressure ensured generation of a mature TSO fracture with adequate width. Wellsite observations of surface tanks and treatment lines confirmed that the PropNET fibers helped suspend proppant in the low-viscosity slurry.

A coiled tubing wellbore cleanout was performed and the well placed on production. The

39-ft zone produced gas with no formation sand, fines, proppant or fibers, and at more than twice the initial gas rate and flowing pressure of the original completion. Giovanna Well 6 produced sand- and fines-free for two and a half months.

PropNET fiber effectiveness depends on friction between proppant particles and individual fibers. Proppant size, roundness and surface texture, and fracture closure pressure as well as fiber length contribute to robust, stabilized fractures. In laboratory tests, PropNET fibers create extremely stable packs, even at zero closure stress. This was confirmed in Giovanna Well 6. No proppant was produced from the "stress-free" annular pack behind the perforated extension pipe.

Offshore Italy: Ongoing Improvements

Based on the successful rehabilitation of production from Pool 10, Eni immediately scheduled major workovers for this well and two others.

Eni used programmable, continuous blending equipment to perform additional treatments on two zones of the short string in Giovanna Well 20. The zones have not yet been produced because field-development plans call for other intervals to be depleted first. However, the high net pressures achieved during both of these screenless treatments indicated favorable fracture geometries that should prevent sand production.

In nearby Annalisa field, a secondary zone was completed through the short string of a well with dual tubing using screenless methods. Without screenless technology, this interval could not have been completed and produced. The well initially produced at economic gas rates, but sand production occurred before the zone was shut in to open the primary zone. Post-treatment analysis indicated that the TSO fracture did not develop enough width because insufficient net pressure was achieved. A shortage of premixed fluid quantities during the Annalisa field frac pack highlighted the importance of continuous onsite mixing and blending of treatment fluids, proppants and additives for treatment consistency and quality control.

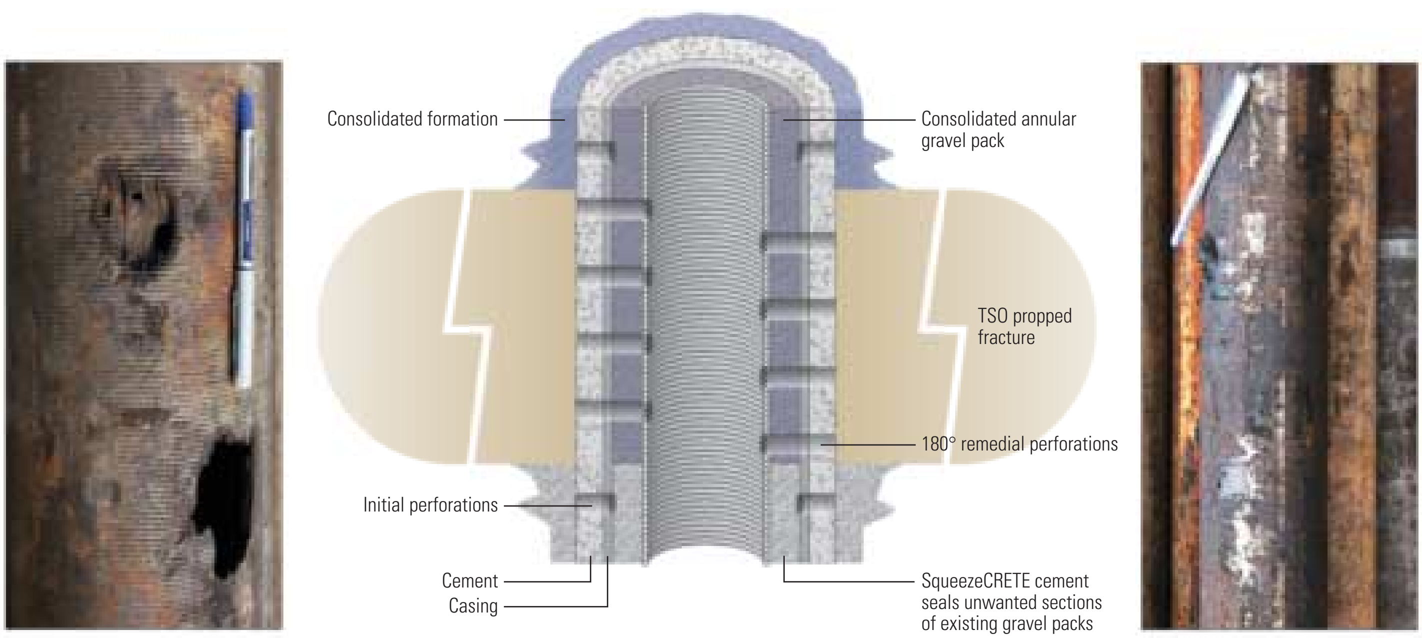
Adequate net-pressure buildup to create optimal fracture geometry is difficult to achieve in soft formations, such as these Adriatic Sea reservoirs. Eni prefers low-viscosity, brine-base fluids for compatibility with Adriatic Sea formations, but their high fluid leakoff characteristics often do not generate the required fracture geometry. Polymer-base fluids, with low fluid leakoff, create fractures that are long and narrow, and may result in excessive vertical fracture height without achieving a TSO.

Using nondamaging ClearFRAC fluids, Eni and Schlumberger tailored fluid characteristics to match reservoir characteristics and optimize fracture geometry. However, even with extremely low fluid viscosities, achieving effective proppant suspension capabilities while maintaining sufficient fluid leakoff is possible only by reducing pump rates at an early stage—often halfway through a treatment. This requires prompt wellsite decisions based on real-time monitoring of net fracturing pressure to achieve optimal TSO fracturing.

Some screenless completions in the Adriatic Sea were considered successful while others had mixed results because of operational rather than technical limitations. All these attempts provided valuable lessons regarding this emerging technology and implementations of novel rigless techniques in future well completions and remedial interventions.

Offshore Italy: Gravel-Pack Remediation

Screenless completions provide a cost-effective means of restoring production in gravel-packed completions that fail because the screens are eroded by sand or plugged with fines, hydrocarbon deposits or scale. This method can be implemented without using conventional rigs to pull completion tubulars, equipment and screens. Initial applications targeted gravel packs up to about 50 ft in length and utilized coiled tubing. These remedial treatments are a multistage process, using standard techniques and fluids, such as the OrganoSEAL system, to consolidate annular gravel packs between existing screens and casing before perforating and fracturing (below).



^ Gravel-pack repair. Screenless techniques provide alternatives for rehabilitating existing completions that have eroded (*left*) or plugged (*right*) screens. Coiled tubing is run to clean out the wellbore, displace produced fluids and place, or spot, a consolidation chemical across and above sand-exclusion screens. These steps are followed by a pressure squeeze to force treatment fluids into the gravel-pack annulus (*center*). The main objective is to shut off gravel-pack permeability and prevent a wellbore fracture screenout caused by annular fluid loss. Chemical consolidation of the annular pack also keeps perforation tunnels open after reperforating and performing a TSO fracturing treatment. "Micro" cement technology, such as SqueezeCRETE fit-for-purpose slurries, can penetrate and seal off unwanted sections of gravel-packed screens.

Fit-for-purpose SqueezeCRETE cement fluid solutions can shut off unwanted sections of gravel packs that are longer than 50 ft. These specially engineered cement slurries penetrate farther into proppant packs than other "micro" cements without bridging or dehydrating during placement. This technique helps avoid excess loss of treatment fluid and premature screenout in existing gravel packs.[23]

Jetting across a treated interval using coiled tubing tools with fluid nozzles on a rotating head removes consolidation chemicals from inside the screens. No attempt is made to remove the consolidation system from gravel behind the screens. Wells then are recompleted with optimal perforations using deep-penetrating charges to provide sufficient penetration into the formation and large enough entry holes in casing to facilitate fracturing success. After reperforating, the screen and consolidated gravel pack are stimulated with a TSO fracture treatment that includes proppant-flowback control additives.

Because of the Giovanna field screenless successes, Eni recognizes rigless application of screenless methods as a practical alternative to rehabilitate wells once believed to require conventional rig interventions. Rigless techniques also allow recompletion of wells with gravel-packed screens that fail or plug. Giovanna Well 14 was the first candidate well for screenless rehabilitation of failed screens without pulling and replacing the completion equipment.

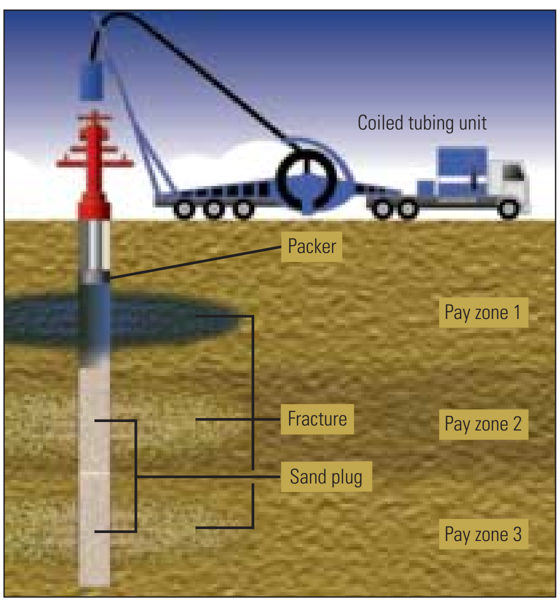
Downhole conditions, reservoir compaction and a long completion interval presented operational challenges. The lower section of screen and gravel pack was shut off with a SqueezeCRETE cement slurry to reduce the target interval below 30 ft. In addition, the reperforated interval allowed coiled tubing access to just the first 12 ft [3.7 m], so the TSO fracture probably did not cover all of the perforations, which resulted in early fines migration.

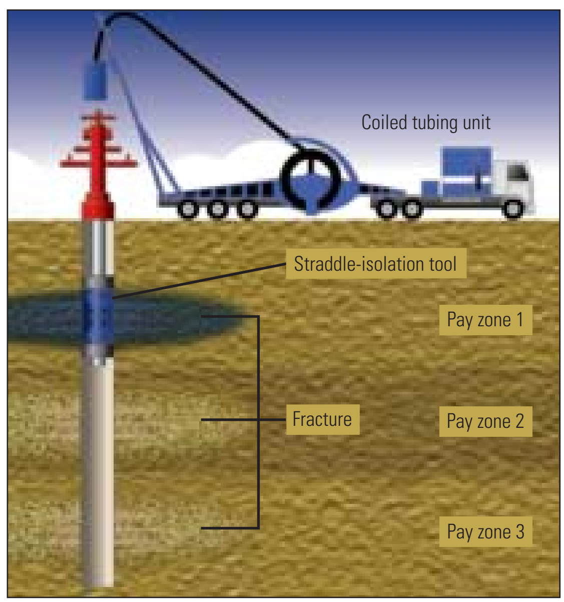
Another screenless completion was identified and scheduled for an uncompleted interval in Giovanna Well 16, but reservoir compaction buckled the production equipment and made reentry impossible. Several additional screenless completions are planned in other fields where the dilemma facing completion teams is that remaining gas reserves in target layers are insufficient to justify the expense and risk of conventional rig operations. Dual-well completions were equipped with a sliding side door (SSD) at one or more perforated intervals within their short or long production strings. Before screenless completions were performed under these conditions, surface tests were used to verify the feasibility of fracturing through an SSD. Full-scale yard tests assessed potential erosion and pressure integrity of the SSD after pumping significant volumes of proppant-laden fluid under field conditions.

These surface tests were performed in four stages with pressure tests and visual inspections conducted after every stage. After pumping 87,000 lbm [39,462 kg] of proppant at concentrations up to 12 pounds of proppant added (ppa), the SSD valve was tested to 3000 psi [20.7 MPa]. Visual inspection confirmed only minor superficial erosion effects, verifying that large volumes of proppant-laden fluid can be pumped through an SSD valve without jeopardizing its pressure integrity and without significant erosion. Subsequently, SSD devices installed downhole have been closed, successfully pressure tested and reopened following screenless treatments in several Adriatic Sea wells.

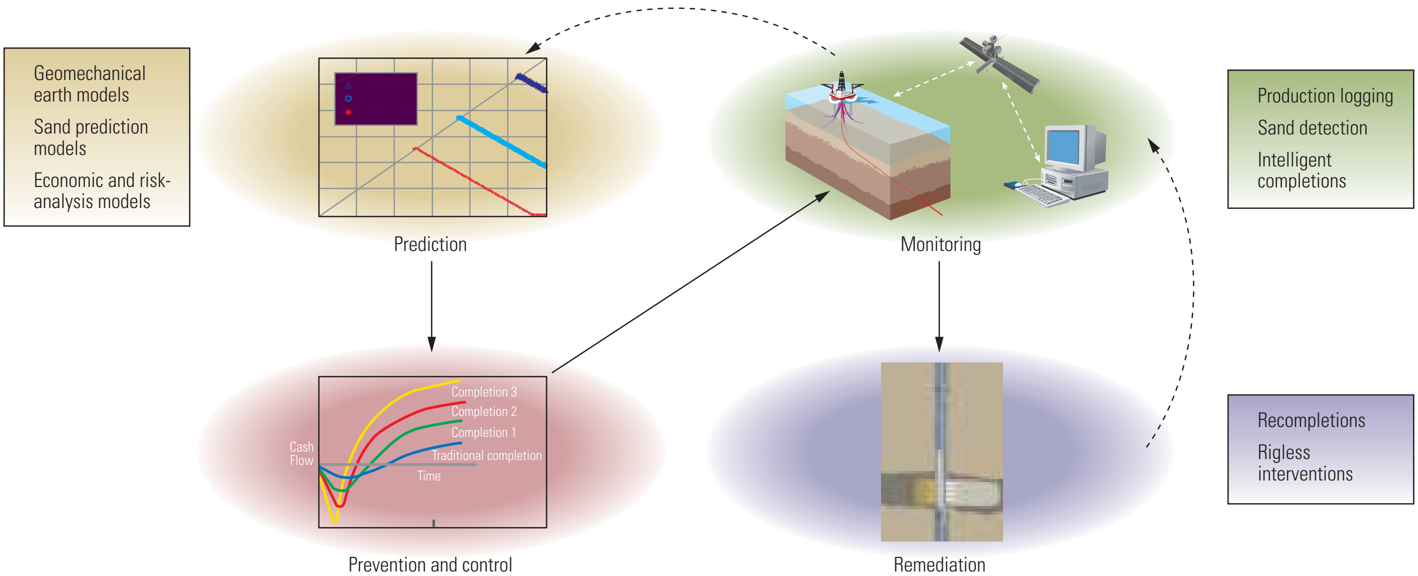
23. Boisnault JM, Guillot D, Bourahla A, Tirlia T, Dahl T, Holmes C, Raiturkar AM, Maroy P, Moffett C, Mejía GP, Martinez IR, Revil P and Roemer R: "Concrete Developments in Cementing Technology," *Oilfield Review* 11, no. 1 (Spring 1999): 16–29.

24. Degenhardt KF, Stevenson J, Gale B, Gonzalez D, Hall S, Marsh J and Zemlak W: "Isolate and Stimulate Individual Pay Zones," *Oilfield Review* 13, no. 3 (Autumn 2001): 60–77.





^ Coiled tubing-conveyed fracturing. CoilFRAC stimulation through coiled tubing service facilitates formation consolidation and hydraulic fracturing of individual or multiple zones in a single operation. A tension-set coiled tubing packer and sand plugs can be used for zonal isolation. Pumping schedules for each zone include extra proppant to spot a plug across fractured intervals before moving up to treat the next zone (*left*). The CoilFRAC ST straddle tool system seals above and below target intervals to isolate individual zones for selective stimulation. The tool can be moved quickly from one zone to another without pulling out of the well (*right*).



Decreasing formation stability →

Natural completion	Stimulated completion	Manage produced sand	Screenless-completion methods	Conventional sand-exclusion methods
Optimal perforating	Optimal perforating TSO fracture stimulation	Optimal perforating Artificial-lift design Downhole desander	Optimal perforating TSO fracture stimulation Proppant-flowback control Formation consolidation Cement technology Selective coiled tubing treatments	Optimal perforating Proper gravel placement Cased-hole gravel pack Openhole gravel pack Frac pack Expandable screens

^ The sand-management solutions approach.

Selective Treatments

In addition to proppant-flowback control, the success of screenless completions relies heavily on effective placement of stimulation fluids and complete fracture coverage across all open perforations. With coiled tubing as the conduit for proppant-laden fracturing fluids, multiple pay zones can be treated consecutively during a single mobilization (previous page). The CoilFRAC stimulation through tubing service using a CoilFRAC ST straddle tool system selectively isolates individual intervals to achieve optimal fracture width and conductivity without conventional drilling-or workover-rig intervention.[24]

Screenless completions offer a viable alternative when conventional sand-control methods are economically unattractive or cannot be applied. This approach allows production from zones that previously could not be completed. Screenless techniques are straightforward and can be reapplied later in the productive life of a well if the need arises. Increasingly, operators recognize this technology as an enabling well-completion strategy for both well completions and production rehabilitation.

Sand-Management Solutions

Operational problems associated with sand influx adversely affect well and reservoir productivity, jeopardize wellbore longevity, limit remedial-intervention options and impact field profitability adversely. Ensuring that perforation tunnels and the surrounding formation remain stable is an important element of sand-management efforts (above).

Selecting screenless candidates, therefore, is an important aspect of well-completion planning and execution that requires careful formation evaluation and characterization using the highest quality production data as input to sand-prediction models, fracture-design programs and reservoir simulators. SandCADE software and other mechanical models establish maximum critical drawdown pressures and flow rates to avoid proppant flowback during cleanup and production phases.

Currently, wells that benefit most from screenless methods are those with configurations that make installation of internal completion assemblies difficult, undesirable or even impossible. However, applications for rigless techniques will increasingly involve recompletion of wells to tap marginal reserves that do not economically justify conventional rig-based operations. Screenless results to date clearly prove the viability of this emerging technology, which provides attractive solutions to avoid otherwise deferred production and lost reserves.

Screenless techniques are an important element in advanced sand-management strategies, but they will not replace conventional sand-control methods. In some reservoirs, however, they provide cost-effective alternative strategies to eliminate or manage sand production over the productive life of a well or field development. Current research and development efforts are directed at improving computer models for predicting sand production and providing enhanced risk assessment. These efforts will ensure the effectiveness of increasingly sophisticated well perforating and completion techniques. —MET

Investigating Clastic Reservoir Sedimentology

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Geoscientists use a robust arsenal of tools to expand their knowledge of reservoir characteristics and to model reservoir behavior. Borehole imaging offers geologists the high-resolution data needed to investigate detailed aspects of reservoir sedimentology. Optimal exploitation of oil and gas assets is more likely when geologists understand the geologic processes that dictated the character of sedimentary reservoirs.

For hundreds of years, geologists have sought to understand the origin of sedimentary rocks and the depositional processes that formed them, and to develop clear methods to describe and classify them. This discipline, called sedimentology, has a clearly established economic value. The petroleum geologist must study sedimentological factors across a range of spatial scales, from grain size to reservoir continuity. While individual sediment grains are small and seemingly insignificant, sediment-transport distances can be huge, and the rock formations created through sedimentation vary tremendously in size and properties. These factors are used to create reservoir models from which reservoir experts predict and assess production behavior in response to field-development and enhanced-recovery steps.

Within each of the many recognized depositional environments there are subdivisions—subenvironments and depositional facies.[1] Some facies are recognizable because sedimentary features observed on surface outcrops, fullbore cores and borehole images indicate a given environment. However, many facies are less distinct. The depositional setting influences the thickness, distribution and internal architecture of siliciclastic or carbonate formations during deposition, and strongly affects the eventual reservoir characteristics.

This article highlights borehole imaging and interpretation techniques that help define clastic reservoir sedimentology. Case studies demonstrate the significance of borehole images in developing depositional analogs and reservoir models, and for making field-development decisions with more certainty.

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1. Facies reflect the overall characteristics and origin of a rock unit that differentiate the unit from others around it. Mineralogy and sedimentary source, fossil content, sedimentary structures and texture distinguish one facies from another.
2. Alsos T, Eide A, Astratti D, Pickering S, Benabentos M, Dutta N, Mallick S, Schultz G, den Boer L, Livingstone M, Nickel M, Sønneland L, Schlaf J, Schoepfer P, Sigismondi M, Soldo JC and Strønen LK: "Seismic Applications Throughout the Life of the Reservoir," *Oilfield Review* 14, no. 2 (Summer 2002): 48–65.

   Frorup M, Jenkins C, McGuckin J, Meredith J and Suellentrop G: "Capturing and Preserving Sandbody Connectivity for Reservoir Simulation: Insights from Studies in the Dación Field, Eastern Venezuela," paper SPE 77593, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, September 29–October 2, 2002.

Significance in Sedimentation

Understanding the sedimentary history of a reservoir offers many advantages to specialists involved in every stage of the life of a field, from exploration to field abandonment. A basin's architecture and sediment sourcing influence exploration strategy. Once field development begins, reservoir sedimentology can be described at several scales from a variety of sources. Surface seismic images, wellbore data—including borehole seismic data and borehole images—and core data are crucial for succesful reservoir exploitation (see "Superior Seismic Data from the Borehole," *page 2*). Sedimentological information from wellbore data can be especially helpful when defining broader reservoir stratigraphy for planning offset wells and trajectories for kickoff, horizontal and multilateral wells. Interpretations of borehole images obtained from devices such as the FMI Fullbore Formation MicroImager and OBMI Oil-Base MicroImager tools commonly provide detailed descriptions of sedimentary features, especially bedding. This helps geologists predict the architecture and local distribution of productive reservoir rock.

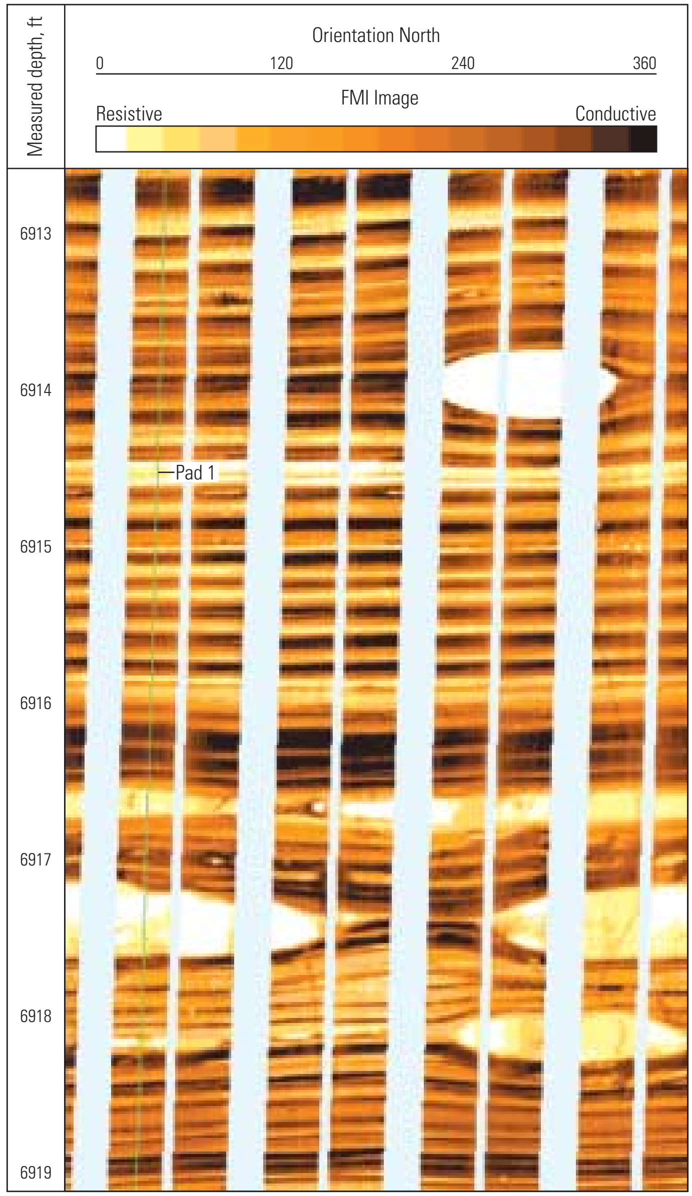
Geologists and engineers studying mature fields have consistently seen that initial field models describing connectivity of the reservoir—both lateral and vertical—tend to be simplistic. Underestimating reservoir complexity may have significant financial implications, because initial drainage strategies might not produce the predicted recoverable hydrocarbon reserves. Conversely, overestimating complexity may lead to drilling too many wells in well-connected reservoirs, wasting valuable resources. Reservoir-modeling and time-lapse (4D) seismic imaging capabilities have significantly reduced the uncertainty in reservoir development, but those models are only as good as the data on which they are built.[2]

High-resolution measurements are essential when assessing small-scale reservoir heterogeneity.[3] Although standard logs may not be sufficient to identify these complexities, borehole images can provide details on internal bedding and bounding surfaces that help characterize the strata exposed in the borehole (right). Engineers formulate completion and stimulation strategies based on reservoir heterogeneity and bedding, factors directly related to sedimentary processes.[4] Quantitative analysis of thin beds using borehole image data can potentially identify productive-pay sections previously bypassed because they appeared too shaly or too wet. In a sand-count analysis example from western India, thin, silty sand beds are clearly resolved on processed FMI images. Using cutoffs on the sharpened synthetic resistivity (SRES) output from calibrated image data, a comparison of high, medium and low net-pay scenarios can be made in highly laminated sequences (next page, top).[5]

Tools of the Trade

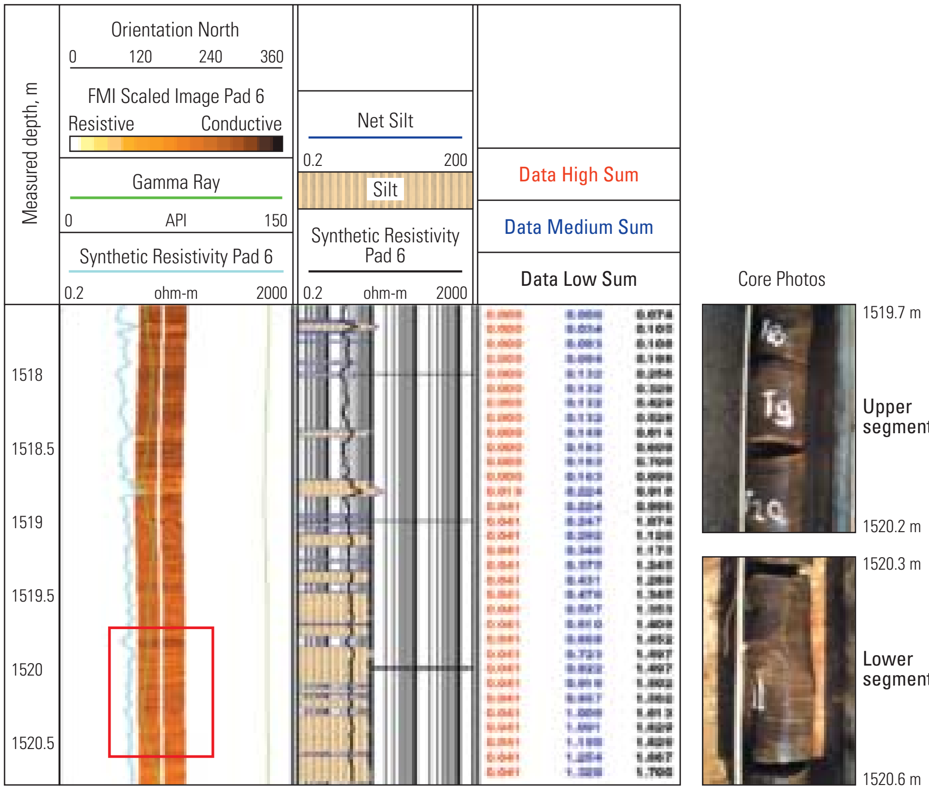
Many tools are available to geoscientists to describe and model reservoir geology. Prominent among them are borehole imaging tools, which have experienced several technological breakthroughs since the 1950s; these tools now deliver high-resolution data across a broad range of challenging operating environments.[6] Borehole imaging technology was extended to logging-while-drilling (LWD) operations in 1994, allowing operators to optimize placement of wells in the reservoir (see "Wellbore Imaging Goes Live," *page 24*).

New tools are not restricted to downhole acquisition; software tools also play a major role in the successful application of borehole imaging to reservoir sedimentology. The GeoFrame borehole geology software includes an integrated suite of tools that enables geoscientists and petrophysicists to thoroughly analyze borehole data. GeoFrame software provides experts with an integrated set of applications to process and analyze formation-dip data, interpret sedimentological features such as paleocurrent bedding,



^ Identifying sedimentary features. High-resolution borehole images, from tools like the FMI device, allow geologists to locate and identify features at or near the borehole wall that are rarely observed using standard well logs. Certain diagnostic features can help geologists reconstruct the depositional environment in which sedimentation occurred. This image shows resistive nodules—white on the image—interpreted to be concretions that might indicate periodic flooding. The bedding around the concretions has undergone postdepositional compaction as indicated by the compression of the bedding above and below the concretions.

3. Sovich JP and Newberry B: "Quantitative Applications of Borehole Imaging," *Transactions of the SPWLA 34th Annual Logging Symposium*, Calgary, Alberta, Canada, June 13–16, 1993, paper FFF.
   Anderson B, Bryant I, Lüling M, Spies B and Helbig K: "Oilfield Anisotropy: Its Origins and Electrical Characteristics," *Oilfield Review* 6, no. 4 (October 1994): 48–56.
   Delhomme JP: "A Quantitative Characterization of Formation Heterogeneities Based on Borehole Image Analysis," *Transactions of the SPWLA 33rd Annual Logging Symposium*, Oklahoma City, Oklahoma, USA, June 14–17, 1992, paper T.
4. Behrmann L, Brooks JE, Farrant S, Fayard A, Venkitaraman A, Brown A, Michel C, Noordermeer A, Smith P and Underdown D: "Perforating Practices That Optimize Productivity," *Oilfield Review* 12, no. 1 (Spring 2000): 52–74.
   Cosad C: "Choosing a Perforation Strategy," *Oilfield Review* 4, no. 4 (October 1992): 54–69.
5. Cheung P, Hayman A, Laronga R, Cook G, Flournoy G, Goetz P, Marshall M, Hansen S, Lamb M, Li B, Larsen M, Orgren M and Redden J: "A Clear Picture in Oil-Base Muds," *Oilfield Review* 13, no. 4 (Winter 2001/2002): 2–27.
   Shray F and Borbas T: "Evaluation of Laminated Formations Using Nuclear Magnetic Resonance and Resistivity Anisotropy Measurements," paper SPE 72370, presented at the SPE Eastern Regional Meeting, Canton, Ohio, USA, October 17–19, 2001.
   Ray S and Singh C: "Quantitative Evaluation of Net Pay Thickness from Clastics of Western India Using High Resolution Response from Electrical Images," presented at the Fifth SPWLA Well Logging Symposium, Makuhari, Chiba, Japan, September 29–30, 1999.
   Boyd A, Darling H, Tabanou J, Davis B, Lyon B, Flaum C, Klein J, Sneider RM, Sibbit A and Singer J: "The Lowdown on Low-Resistivity Pay," *Oilfield Review* 7, no. 3 (Autumn 1995): 4–18.
6. Cheung et al, reference 5.
   For more on the applications of borehole imaging tools: Luthi S: *Geological Well Logs: Their Use in Reservoir Modeling*. Berlin, Germany: Springer-Verlag, 2001.

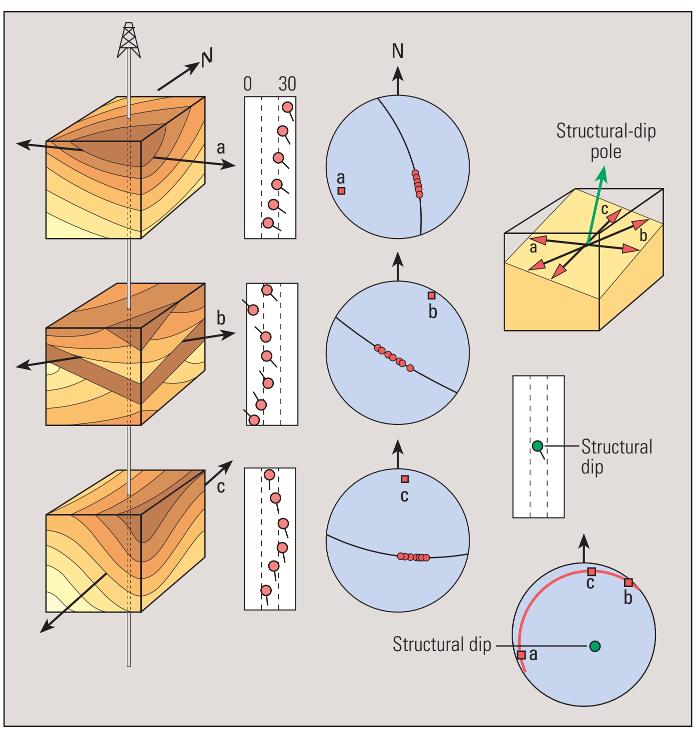


^ Sand-count analysis for thin-bed evaluation. A silty sand interval in western India was processed for net-pay percentage using the high-resolution sand-count analysis. Standard logging measurements lack the resolution to properly characterize thinly laminated sequences. With various resistivity cutoffs, SRES outputs from FMI data (Tracks 1 and 2) can be used to define high, medium and low net-pay scenarios. In this case, using a medium-resistivity cutoff of 3.0 ohm-m, 46% of the 3.3-m [10.8-ft] gross interval was determined to be pay, allowing more precise reserves predictions. The red box indicates the interval covered by the core photographs (*right*).

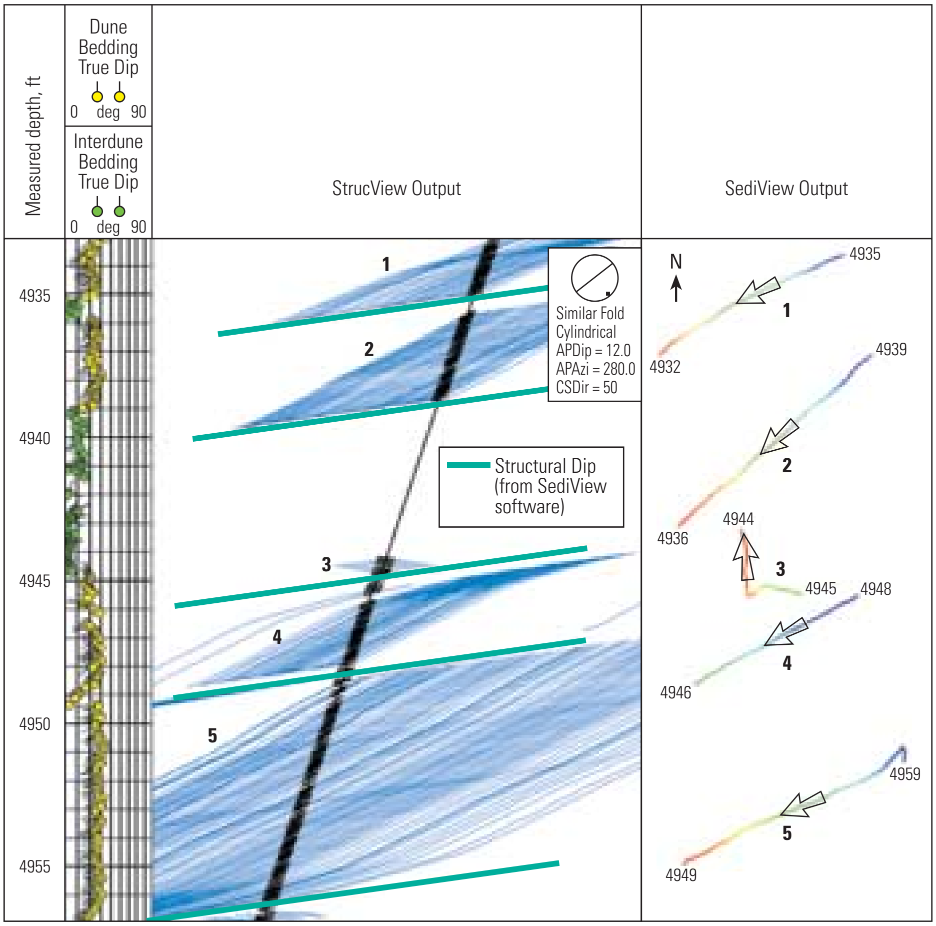
assess rock textures and lithologies to differentiate facies, interpret structural features like faults, and characterize natural fractures to estimate their productive potential.

After field data are processed to create borehole images, the BorView borehole imaging application allows geoscientists to examine image data in various formats and scales. Detailed and interactive dip-plane selection produces extremely accurate formation-dip information that can be used in other applications to further refine the analysis. For example, the SediView application within GeoFrame system software helps geologists determine and correct for structural dip. Commonly, shales produce the best representation of structural dip in a wellbore because they typically are deposited in low-energy environments and exhibit flat bedding, or zero dip. Subsequent tilting of the strata produces structural dip and alters the true orientation and dip magnitude of stratigraphic bedding.

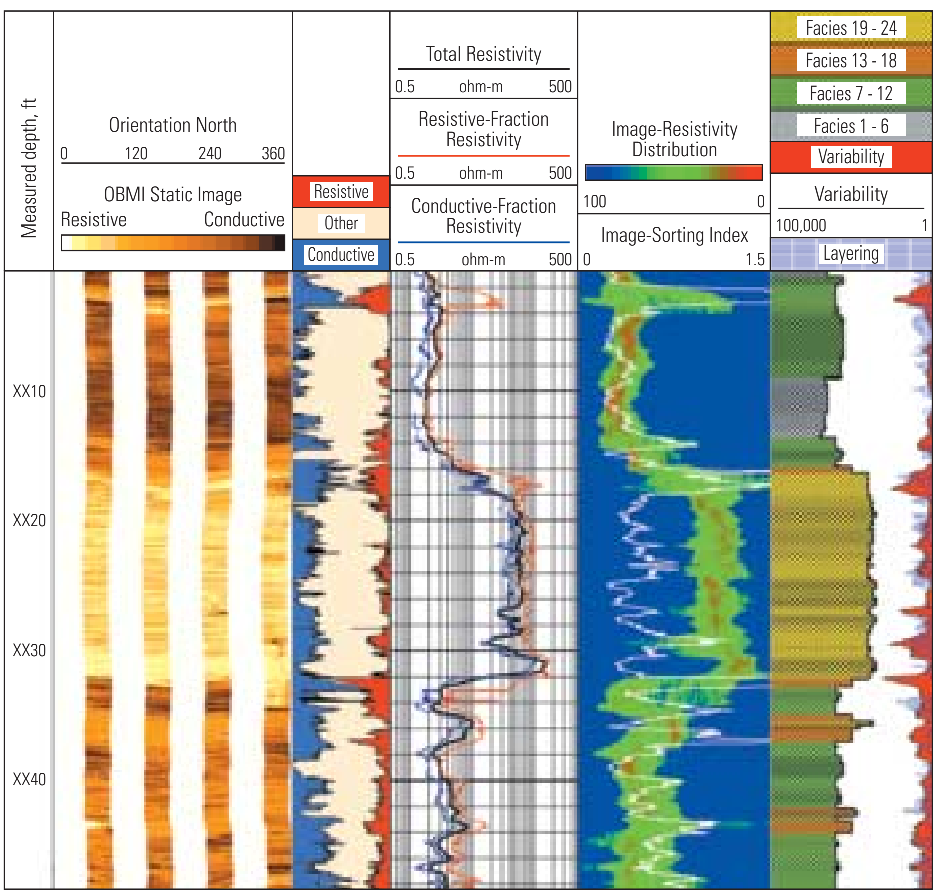
SediView software uses the principle of the local curvature axis (LCA) technique and great circle analysis to determine an accurate and representative structural dip. That dip is then removed to determine what the internal bedding or crossbedding was before being structurally altered (below).



< Principle of the local curvature axis (LCA) method. Sedimentary structures and their axes are depicted along with their corresponding dipmeter response (*left*). All are affected by the same structural-dip component. Bedding surfaces in each structure are plotted on a Schmidt net and poles of each surface are determined (*middle*). When these poles fit a great circle, a local curvature axis is computed for each sedimentary structure—*a*, *b* and *c*. The structural dip can then be determined by plotting the LCAs on a Schmidt plot (*bottom right*); if the LCAs follow a great circle, this great circle corresponds to the structural dip (*middle right*). The upper right diagram depicts the structural dip, and shows the three sedimentary axes and the pole of the structural-dip component (green arrow).



< Sedimentological representation using the StrucView tool. StrucView software (Track 2) shows the internal bedding (blue) within an ancient sand-dune complex. Dip data were acquired using the FMI tool (Track 1). SediView software was used to determine and remove the structural dip (green), and compute vector plots for each dune (Track 3). The vector plots are color-coded according to depth within each of the five dune intervals. The analysis of these eolian, or wind-blown, sands clearly shows that the dominant prevailing wind direction was from the northeast.

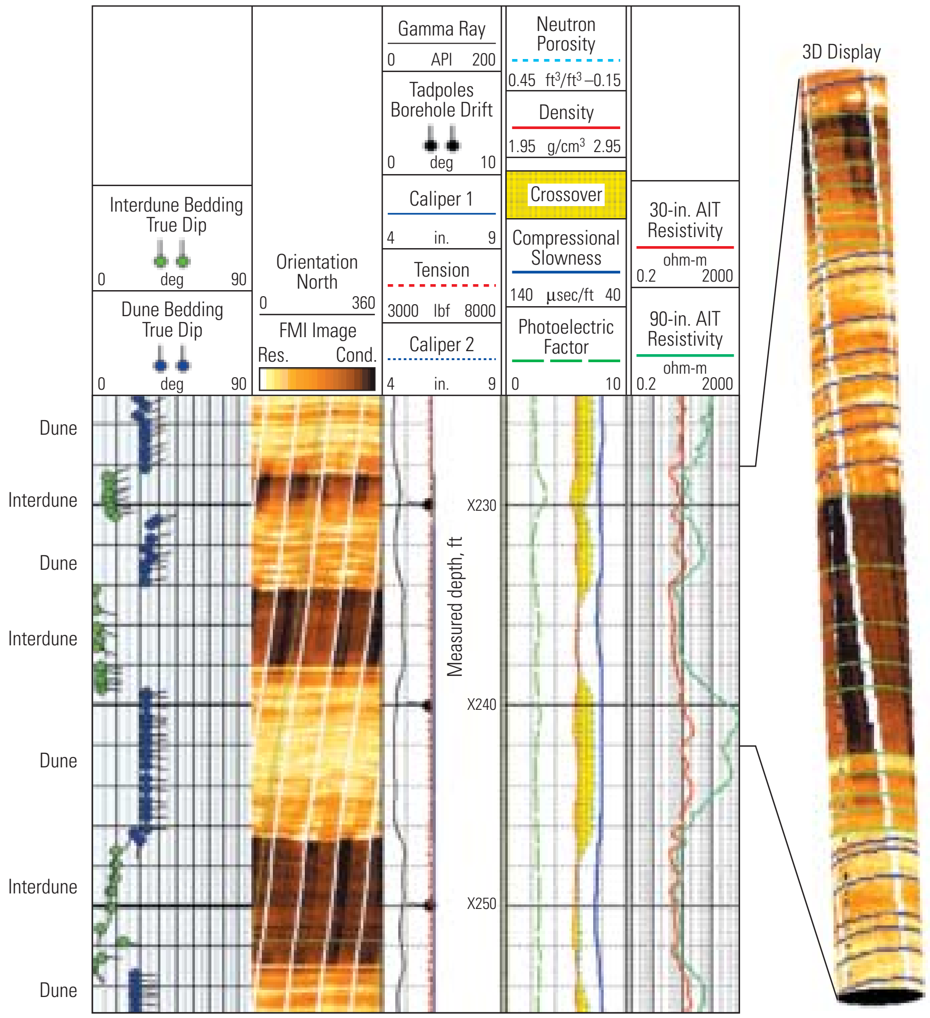


< Facies differentiation by evaluating grain-size sorting. SandTex software calculates an image-resistivity spectrum every 1 in. [2.5 cm], in this case, from OBMI data (Track 1). An image-sorting index is calculated from the percentile distribution of the spectrum. Locally, any points more or less resistive than a well-sorted sand are counted as part of the resistive or conductive fractions, respectively (Track 2). Although within short intervals, silt within sand would show up as part of the conductive fraction, its resistivity would normally be quite different from that of shale. For this reason, the resistivities of the fractions are calculated (Track 3). Track 4 displays the image-resistivity distribution and a calculated sorting index—a low value meaning more well-sorted. Openhole logs then are combined with the high-resolution image data to generate a facies description that captures much of the textural content of the images (Track 5). Local image variability and layering are also computed and shown on Track 5.

Some environments lack shales, making the structural dip of the reservoir difficult to determine. For example, in fluvial and eolian environments, the SediView method often resolves structural dip, enabling interpreters to remove the structural-dip component for an improved representation using StrucView GeoFrame structural cross section software. The strike of a channel can be determined from the paleocurrent direction, or the orientation of a dune can be revealed from the prevailing wind direction (previous page, top). Vector plots of sediment-transport indicators from SediView software supply geologists with prevailing water and wind directions during the time of deposition, which greatly influence the shape, continuity and trend of sand bodies (right). Additionally, sand-body characteristics directly impact reservoir size, anisotropy and compartmentalization.

When analyzing reservoir sedimentology, geologists must differentiate individual stratigraphic layers within the sedimentary sequence. Boundaries between sets or packages of internal bedding can represent abrupt changes, for example, changes in depositional energy, sediment-transport direction or sediment supply. The GeoFrame Sequence stratigraphic boundaries tool detects boundaries using log-curve shape analysis and helps characterize grain-size trends within each sediment package. Understanding these trends and their vertical successions helps geologists define facies relationships. This, in turn, assists in correlation and mapping, sand-quality assessment and the determination of specific depositional environments.

Another GeoFrame tool, BorTex texture classification software, also works to discriminate facies by classifying textures derived from borehole image data. BorTex software is used to characterize carbonate porosity and distinguish facies.[7] Schlumberger experts recently developed new sand-texture analysis software for use in sand-shale sequences. Taking advantage of high-resolution data from FMI, Formation MicroScanner or OBMI tools as well as standard log data, the SandTex tool computes the image-resistivity distribution across the reservoir-sand intervals. The distribution relates directly to grain size, enabling the SandTex software to characterize grain-size sorting, an important factor in defining reservoir facies (previous page, bottom). The character of a specific facies influences the eventual reservoir architecture on a local scale, while spatial relationships between different facies impact larger-scale issues, such as reservoir continuity and connectivity.



^ Eolian sand dune and interdune facies. A detailed analysis in BorView software helps characterize the different facies associated with eolian sand deposition. The dominant wind direction during deposition is shown by the blue dips and exhibits the consistency commonly found in barchan or transverse dune deposition (Track 1). The lower angle green dips represent the interdune facies. The FMI borehole image in Track 2 clearly shows sharp contacts between the two main facies in this section. Track 3 displays caliper and borehole-orientation data, Track 4 contains porosity and lithology information, and Track 5 shows AIT Array Induction Imager Tool resistivity data. A 3D representation of the wellbore aids visualization (*right*).

Characterizing Facies for Enhanced-Oil Recovery

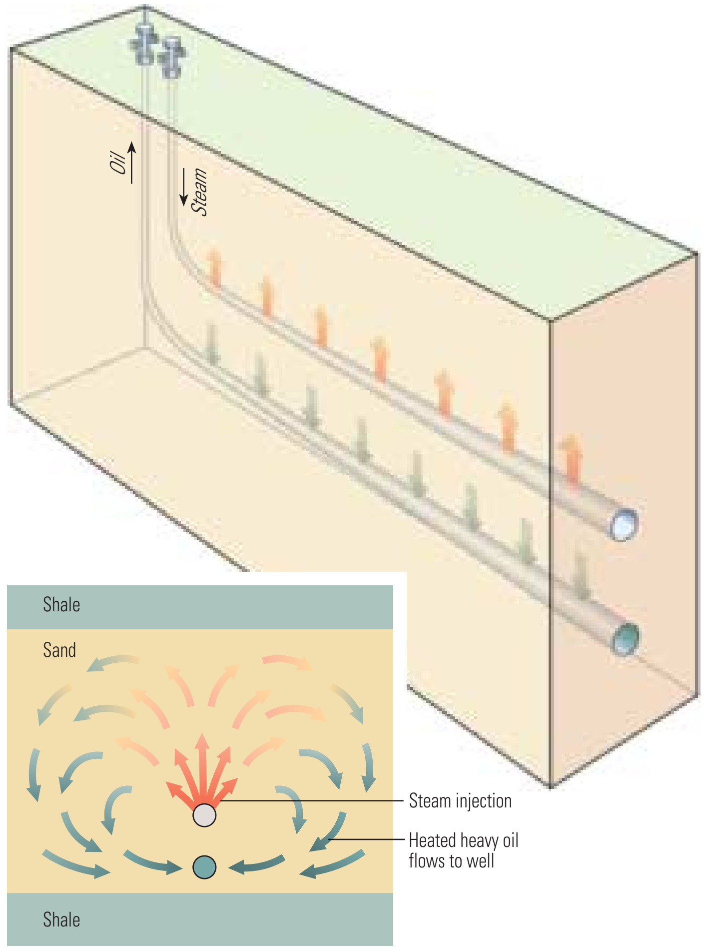
Reservoir architecture affects well tests and production-decline behavior.[8] Stratigraphic boundaries, such as unconformities, pinchouts and amalgamation surfaces, can drastically reduce hydrocarbon recovery during primary production and enhanced-recovery stages. Impermeable clay-rich or shale layers in and around reservoir facies, and even stratification or crossbedding within a sand body, influence the effectiveness of

7. Akbar M, Vissapragada B, Alghamdi AH, Allen D, Herron M, Carnegie A, Dutta D, Olesen J-R, Chourasiya RD, Logan D, Stief D, Netherwood R, Russell SD and Saxena K: "A Snapshot of Carbonate Reservoir Evaluation," *Oilfield Review* 12, no. 4 (Winter 2000/2001): 20–41.

   Russell SD, Akbar M, Vissapragada B and Walkden GM: "Rock Types and Permeability Prediction from Dipmeter and Image Logs: Shuaiba Reservoir (Aptian), Abu Dhabi," *Bulletin of the American Association of Petroleum Geologists* 86, no. 10 (October 2002): 1709–1732.

8. Deruyck B, Ehlig-Economides C and Joseph J: "Testing Design and Analysis," *Oilfield Review* 4, no. 2 (April 1992): 28–45.

^ Athabasca oil-sands deposit. Alberta's oil sands, also called tar sands, contain more than 400 billion m³ [2.5 trillion barrels] of bitumen in place, giving Canada the largest reserves of ultraheavy oil and bitumen in the world. The Athabasca deposit holds the vast majority of Canada's bitumen reserves.



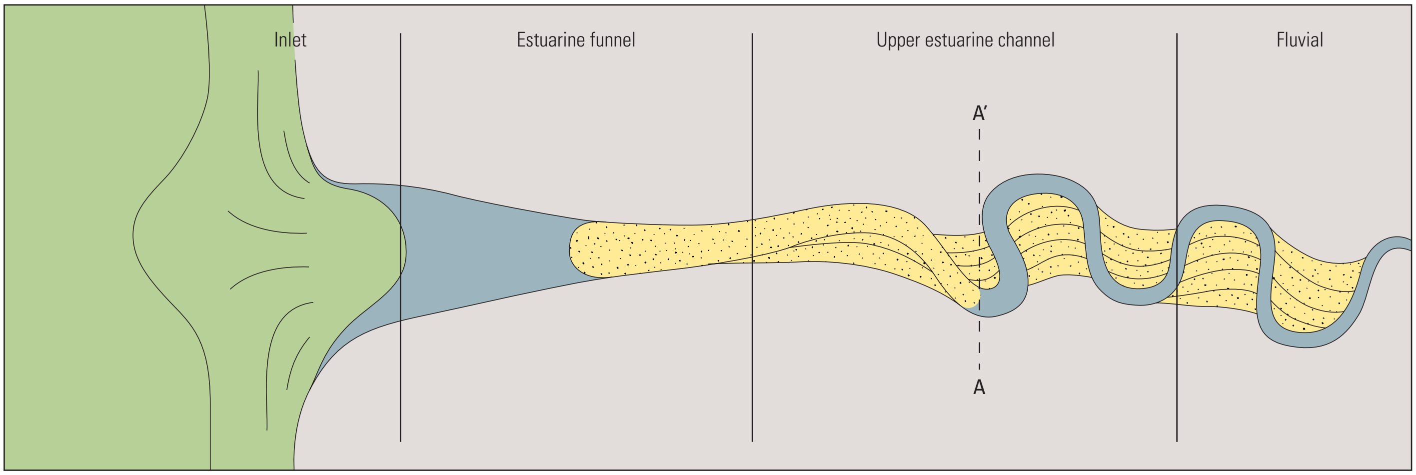
^ In-situ steam assisted gravity drainage (SAGD) design. Steam is injected into the upper steam-injection well. The steam heats the surrounding bitumen-saturated sand and mobilizes the oil. The mobilized hydrocarbons, under the force of gravity, migrate to the production well. When permeability barriers hinder this process, oil-production rates decline, steam/oil ratios increase, and reserves are left behind. The optimal SAGD design is achieved when the volume of steam coverage is unimpeded by impermeable layers of shale or clay, also called lateral accretions, associated with meandering fluvial systems. Careful well placement also minimizes steam requirements.

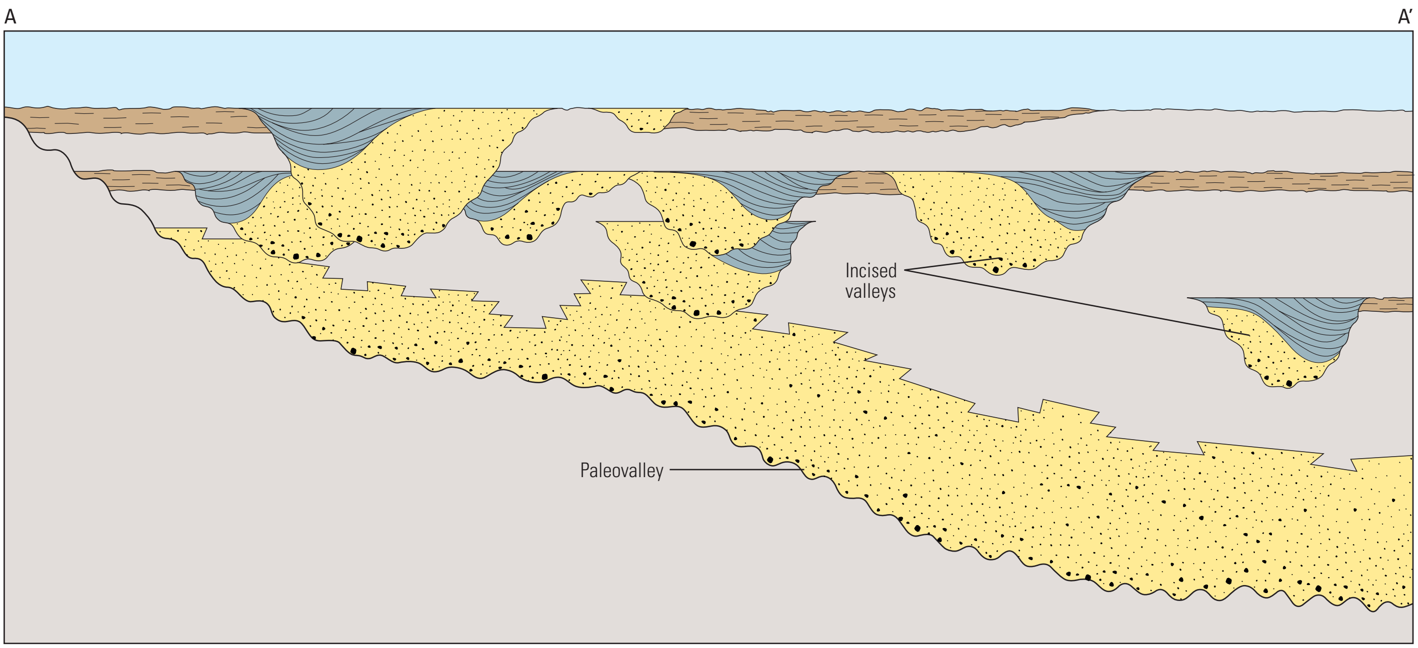
enhanced-recovery techniques.[9] When developing steam-injection strategies to enhance heavy-oil recovery, high-resolution borehole images are crucial to characterize the reservoir and surrounding facies.

Alberta, Canada, is estimated to have the largest volume of crude bitumen in place, about 400 billion m³ [2.5 trillion bbl].[10] The bitumen-rich deposits, also called oil sands or tar sands, occur in three areas: Athabasca, Cold Lake and Carbonate Triangle (above left). These deposits, located in northeastern Alberta, comprise the Wabiskaw and McMurray formations. Open-pit mining is the most common technique used to extract the sand and bitumen from shallow depths. However, when these formations are deeper than 75 m [245 ft], in-situ extraction technology called steam-assisted gravity drainage (SAGD) is proving to be a more viable technique.[11]

The SAGD oil-recovery technique requires two horizontal wells: an upper well for injection and a lower well for producing the oil mobilized by the steam. This technique works effectively when steam from the injection well flows unimpeded into the strata above, and when the heated oil flows unimpeded to the production well below (above right). When permeability barriers hinder this process, oil-production rates decline, steam/oil ratios increase and reserves are left behind.

Petro-Canada has been characterizing the McMurray formation to optimize SAGD performance in its oil-sands projects. The McMurray formation, which contains most of the bitumen in the Athabasca sands, was deposited during an early Cretaceous period transgression in a paleovalley 200 km [120 miles] wide.[12] A dynamic transgressive phase interrupted the McMurray sand deposition several times, resulting in a rapidly varying depositional history. The most significant sedimentation for hydrocarbon accumulation occurred in low-stand fluvial-estuarine incised valleys, where a meandering river system deposited reservoir-quality point-bar sands, containing several distinct facies, each with





^ McMurray formation depositional model. A significant portion of the McMurray formation was deposited in an upper estuarine-channel environment within a drowned incised valley (*top*). The internal architecture of the McMurray strata is also shown (*bottom*). The dominance of lateral accretions—shale and clay beds—at the top of most of the channels and the presence of intensive bioturbation suggest that tidal-estuarine influences existed.

different reservoir properties (above).[13] The McMurray sands range from 20 to 58 m [65 to 190 ft] thick, maintain high porosities from 30 to 35% and are extremely permeable, with permeabilities commonly from 3 to 10 darcies.

This sedimentary sequence is complex. Despite the immense quantity of data, including well log and core data from closely spaced wells, it is difficult to correlate zones, even over short distances. To properly assess the bitumen resources and sedimentology of the oil sands, fullbore coring is standard practice. This practice consumes 10 to 15 hours of rig time per well, plus other costs associated with coring and core handling.

9. Corbett PWM, Ringrose PS, Jensen JL and Sorbie KS: "Laminated Clastic Reservoirs: The Interplay of Capillary Pressure and Sedimentary Architecture," paper SPE 24699, presented at the 67th SPE Annual Technical Conference and Exhibition, Washington DC, USA, October 4–7, 1992.

   Weber KJ and van Geuns LC: "Framework for Constructing Clastic Reservoir Simulation Models," *Journal of Petroleum Technology* 42, no. 10 (October 1990): 1248–1297.

   Weber KJ: "How Heterogeneity Affects Oil Recovery," in Lake LW and Carroll HB Jr (eds): *Reservoir Characterization*. Orlando, Florida, USA: Academic Press (1986): 487–544.

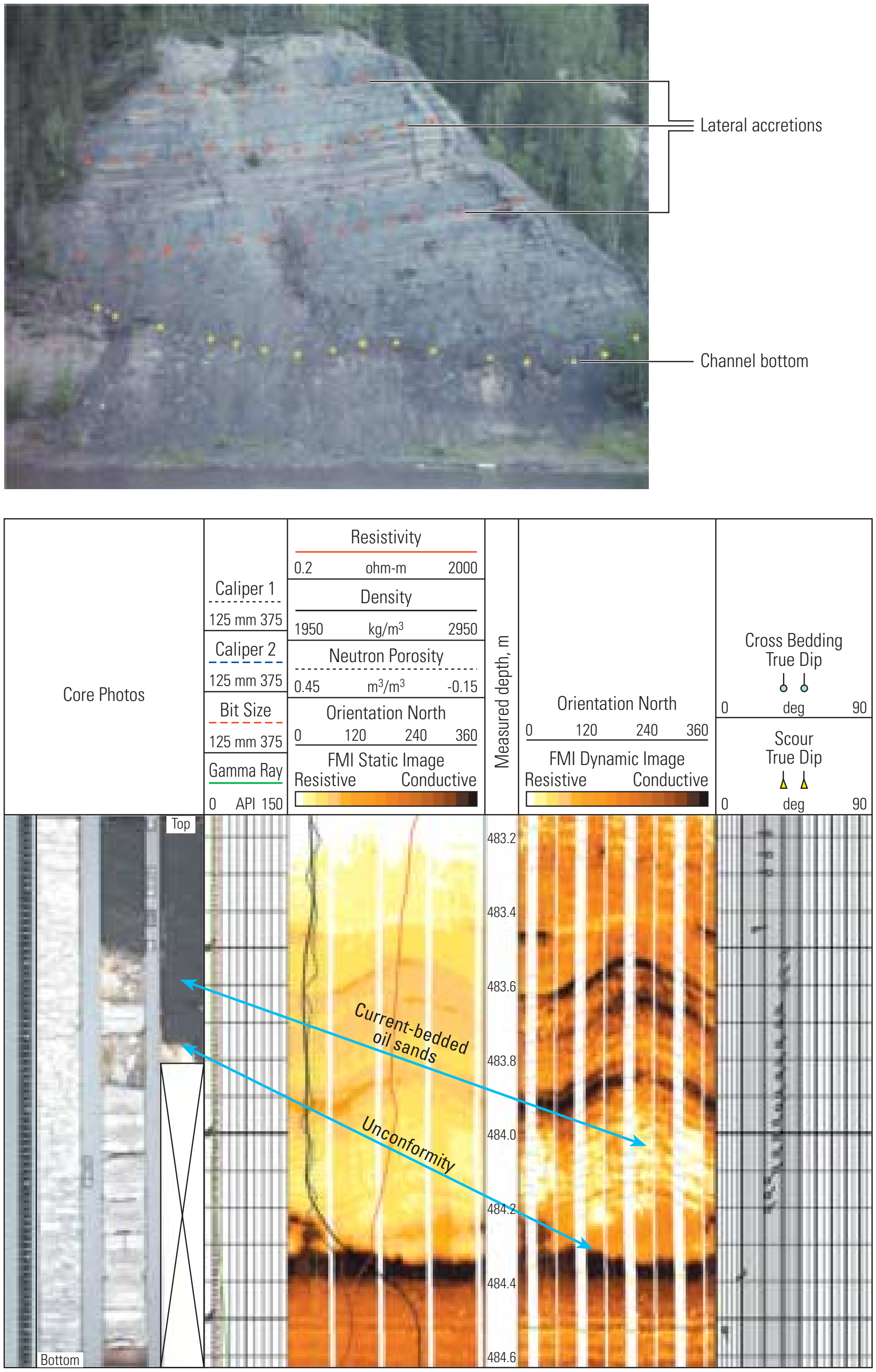
10. Bitumen is a naturally-occurring, inflammable organic matter formed from kerogen in the process of petroleum generation that is soluble in carbon bisulfide. Bitumen includes hydrocarbons such as asphalt and mineral wax. Typically solid or nearly so, and brown or black, bitumen has a distinctive petroliferous odor. Laboratory dissolution with organic solvents allows determination of the amount of bitumen in samples, an assessment of source-rock richness.

    Hein FJ, Langenberg CW, Kidston C, Berhane H, Berezniuk T and Cotterill DK: *A Comprehensive Field Guide for Facies Characterization of the Athabasca Oil Sands, Northeast Alberta*. Alberta Energy and Utilities Board and Alberta Geological Survey (2001): 422.

11. For more on exploiting heavy-oil reservoirs: Curtis C, Kopper R, Decoster E, Guzmán-Garcia A, Huggins C, Knauer L, Minner M, Kupsch N, Linares LM, Rough H and Waite M: "Heavy Oil Reservoirs," *Oilfield Review* 14, no. 3 (Autumn 2002): 30–51.

12. Transgression refers to the migration of a shoreline out of a basin and onto land during the accumulation of sequences through deposition, in which beds are deposited successively landward because sediment supply is limited and cannot fill the available accommodation space. A transgression can result in sediments characteristic of shallow water being overlain by deeper-water sediments.

13. Hu YG and Lee DG: "Incised Valleys Versus Channels: Implications for McMurray Formation Bitumen Mapping and Exploration," presented at the Annual Meeting of the Canadian Society of Petroleum Geologists, Calgary, Alberta, Canada, June 3–7, 2002.



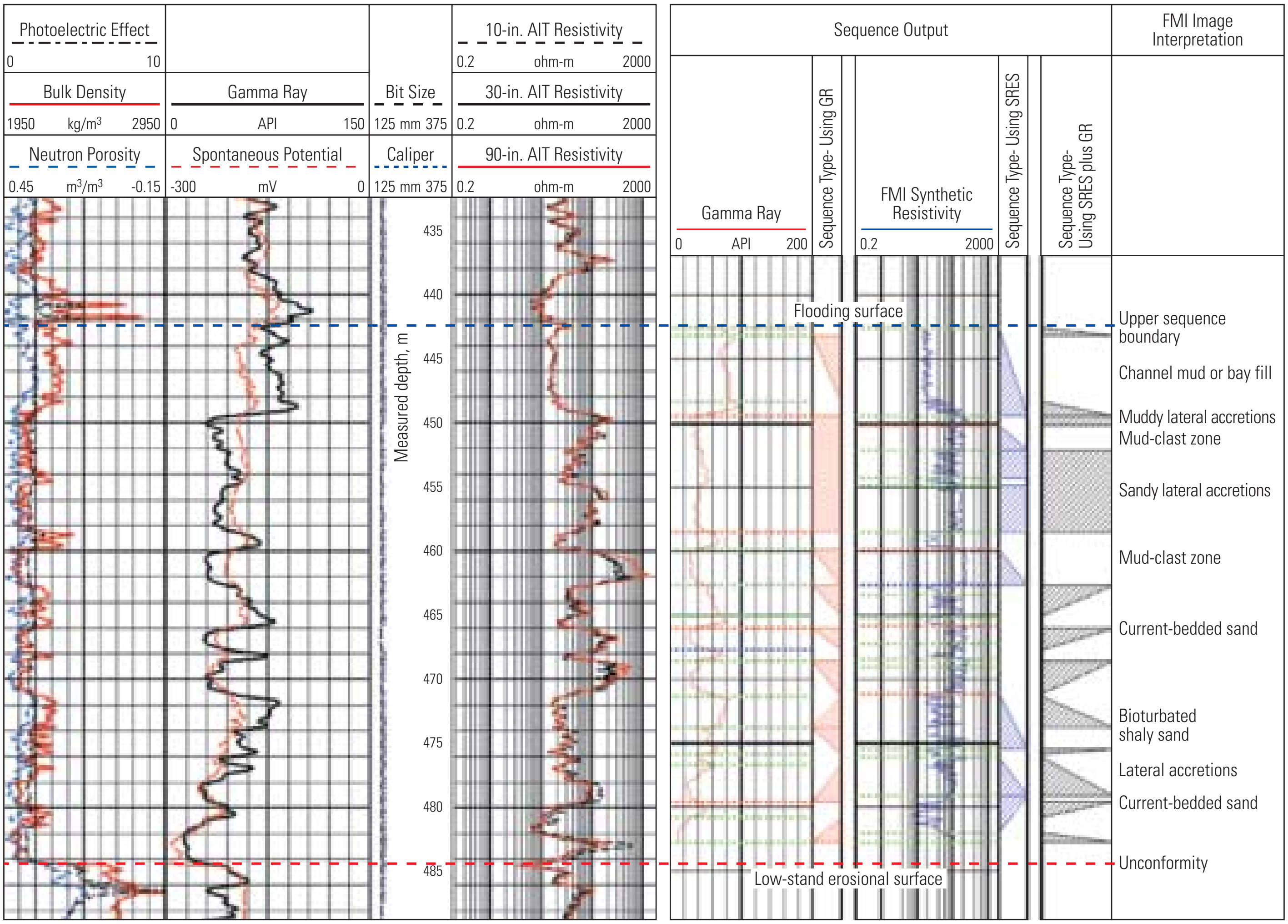
^ A McMurray formation outcrop near the town of Fort McMurray, Alberta, Canada. The outcrop, about 50 m [165 ft] in height, shows at least five fining-upward point-bar sequences (*top*). The base of this channel is indicated by yellow dots. Each succession has massive cross-stratified, bitumen-saturated sandstone in the lower part, which is darker on the outcrop, and inclined discontinuous stratifications, which are lighter on the outcrop. These stratifications are interpreted as lateral accretions (red dots). Core photographs and an FMI image 1.4 m [4.6 ft] in height shows the unconformable contact between the McMurray oil sand above and the Paleozoic carbonate rocks below (*bottom*). This unconformity cannot be observed in the outcrop shown because it is slightly below the water surface at the bottom of photograph.

Borehole images from the FMI tool identify and determine the orientation of stratigraphic boundaries within the McMurray oil-sand deposit (left).[14] The stacked channel sands of the McMurray Formation are bounded on the bottom by an erosional surface, or unconformity, on the Paleozoic carbonate rocks. It is bounded on the top by a transgressive flooding surface upon which the Wabiskaw marine sediments were deposited.

The interpretation and integration of FMI data with other log-derived information, along with fullbore core data from vertical wells and rock outcrops, are providing insights into critical sedimentological factors that directly affect SAGD effectiveness. This detailed comparison between outcrop, cores and FMI images allows Petro-Canada and Schlumberger geologists to identify different facies within the McMurray formation and to infer paleocurrent directions. Using the FMI tool potentially reduces the number of cored wells and the costs associated with fullbore coring. In some cases, borehole imaging techniques acquire data across high-porosity sand intervals that may be missed when coring, if core recovery is poor.

Determining grain-size relationships, such as fining or coarsening upward, within sand layers aids the identification of facies. In the subsurface, this is usually accomplished using standard log data, such as gamma ray or neutron. Geologists examine the grain-size trends to identify successions of facies that exist within the sediment sequences, learning more about the depositional processes that shaped the reservoir. Conventional curve-shape analysis methods, for example using gamma ray only, are sometimes unreliable because they do not describe the depositional history. In the McMurray interval, higher resolution measurements are required to recognize the depositional complexity. Using the high-resolution synthetic resistivity (SRES) data from the FMI tool, the Sequence application can automatically identify intervals as fining upward, coarsening upward or as having a blocky character. This analysis is combined with an integrated interpretation of the FMI images and cores to produce an advanced sedimentological analysis that gives geologists a more accurate depiction of the significant facies to consider when drilling SAGD wells (next page).

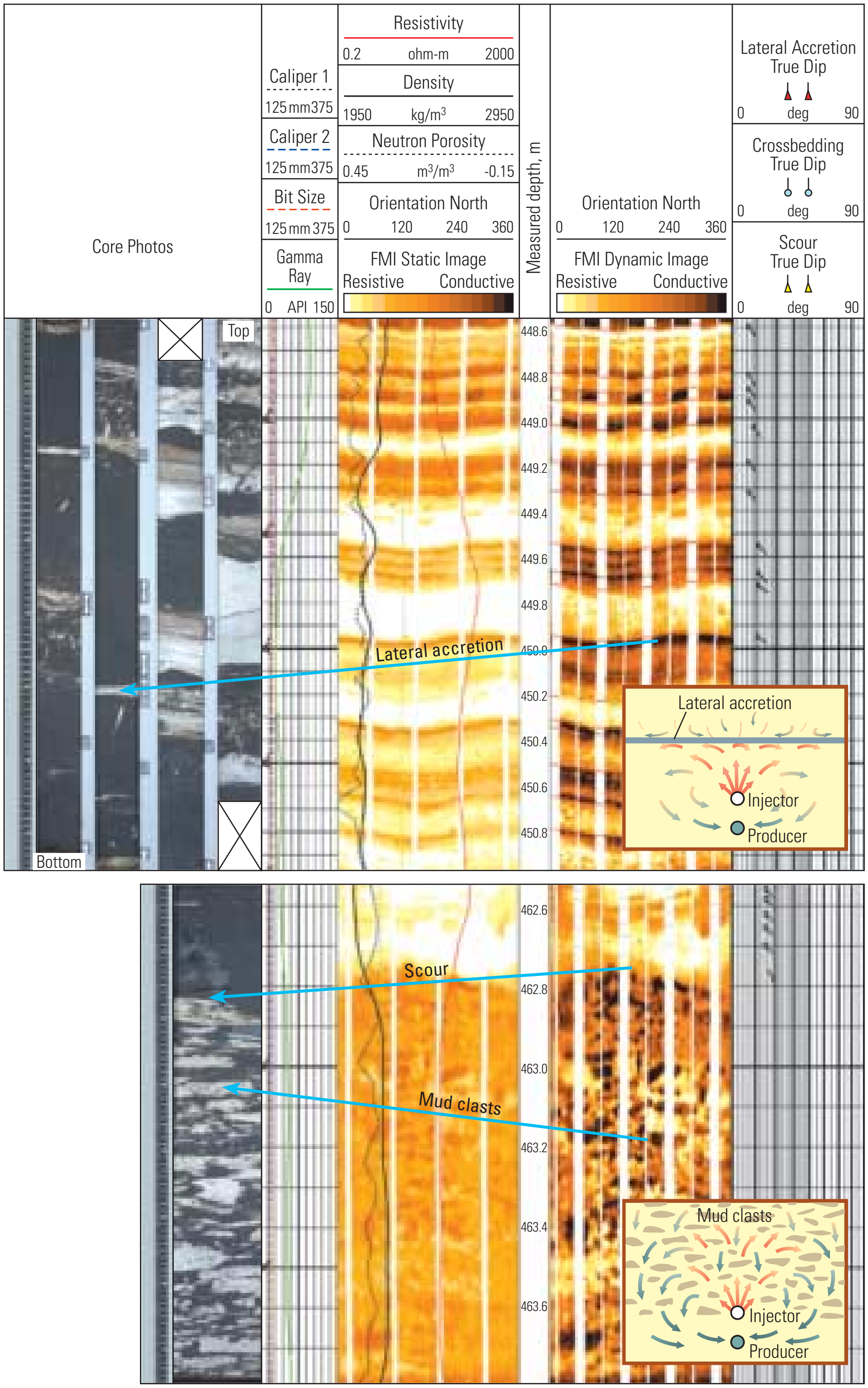
14. Hein et al, reference 10.



^ Using the Sequence tool for facies definition. At first, the Sequence program used only the input from the gamma ray log to define three curve-shape trends, or sequence types—coarsening upward, fining upward, and blocky or relatively constant grain size (Track 4). This analysis did not provide an adequate solution to capture the stratigraphic complexity, so the high-resolution synthetic resistivity (SRES) FMI output was scaled to the AIT tool 30-in. response and used to improve the trend analysis (Track 5). Lastly, both SRES and gamma ray were used to generate an improved sequence-type description (last track on right, or Track 6). Comparing the sequence types with the image sedimentology analysis, geologists can authenticate the curve-based sequence stratigraphy analysis. Significantly, blank sections in the analysis correspond to mud-clast zones. Also, flooding surfaces and low-stand erosional surfaces can be clearly seen on the image. Porosity and lithology data are shown in Track 1, gamma ray and spontaneous potential are shown in Track 2, caliper is shown in the depth track and resistivity data are shown in Track 3.

Advanced sedimentological analysis is helping to differentiate certain facies that have similar appearances on standard logs, but affect SAGD oil recovery in drastically different ways. Meandering estuarine systems produce point-bar sand deposits that commonly contain lateral accretions, or low-permeability clay layers, deposited in the top portion of the fining-upward point-bar sands during periods of flooding or slack water. Although lateral accretions may have limited lateral extent, their top, shaly portions are detrimental to the SAGD process because they can hinder the steam-chamber growth locally into the bitumen-rich point-bar sands above them. These low-permeability layers appear to prevent mobilized oil from migrating down to the production wellbore.

Another facies, identified as mud-clast zones, looks similar to shaly sand on standard logs. Shaly intervals are not considered pay, but mud-clast zones are, since the clast zones' matrix is clean bitumen-saturated sand. Clast zones allow



^ Lateral accretions versus mud-clast zones. The top of these point-bar sequences can become mud-dominated. The presence of lateral accretions reduces the total producible hydrocarbons because accretions hinder the SAGD process (*top*). However, mud-clast zones can be considered pay and can add to reserves since SAGD steam will rise up through them, effectively treating and draining these intervals (*bottom*).

steam to penetrate and migrate upward. The FMI images easily differentiate mud-clast zones from the shaly sands that are frequently seen disrupting the upper part of lateral accretions (left).

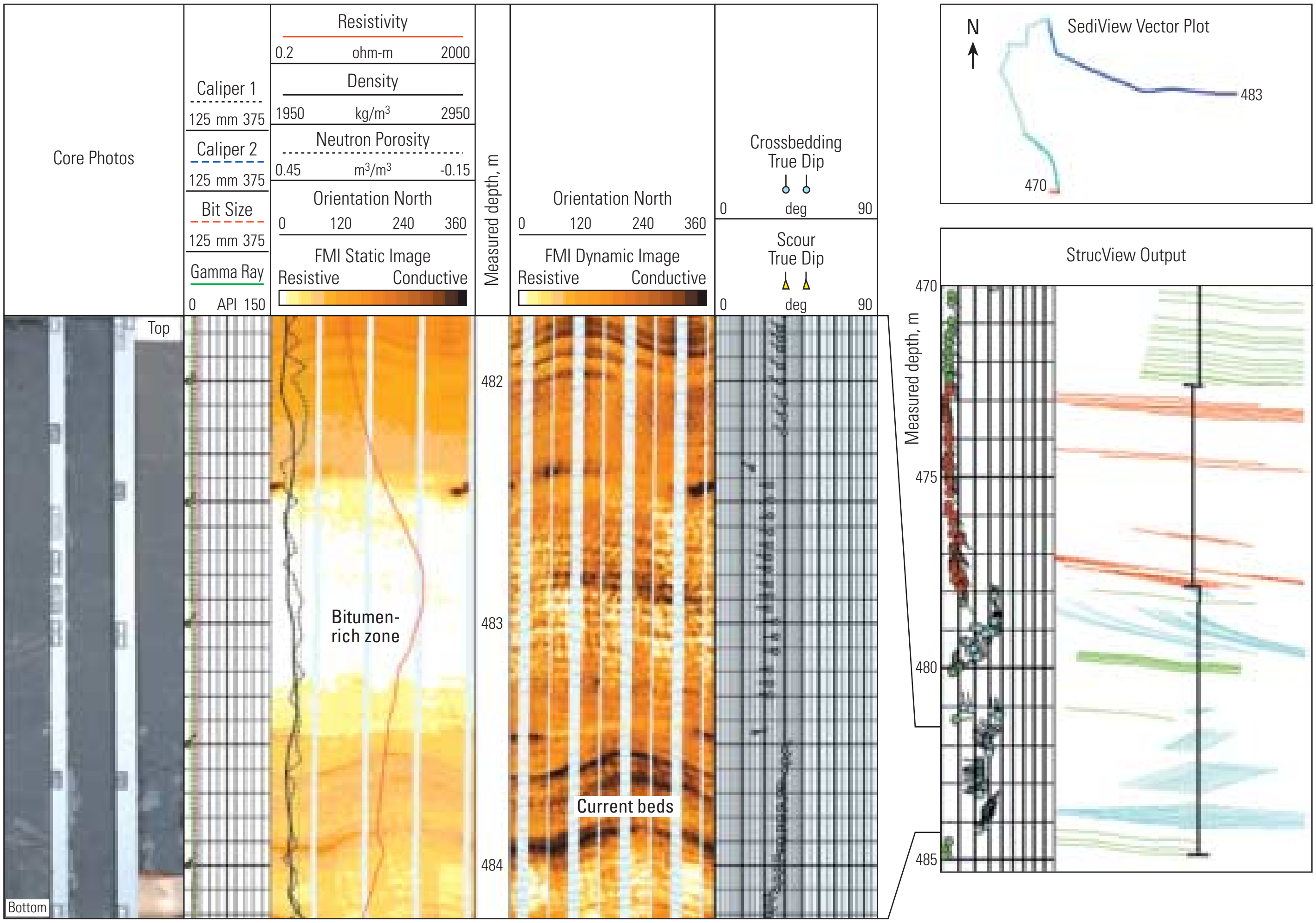
The FMI tool has proved useful in analyzing sand-body orientation and geometry. Sedimentological features may be difficult to see on the core because of dark bitumen staining but are easily observed on the FMI images. Current bedding on the borehole images shows that the direction of river flow was approximately north during the McMurray sand deposition, but varies throughout the sequence. Interpreting tidal influences on sand deposition helps construct a more accurate geologic model. Current bedding associated with fluvial-estuarine processes also reflects the trend of the sand body; this is important information for effective development of bitumen fields for Petro-Canada.

With this directional information, a sand-trend analysis can be performed using the SediView tool (next page). Image data also provide operators with relative bitumen content between zones of similar characteristics—a lighter static image indicates higher bitumen content. This relationship has been established by numerous core comparisons. Another sedimentological feature identified on borehole images is bioturbation, commonly associated with estuarine environments. Aside from providing facies information, bioturbation can drastically affect eventual rock characteristics, most prominently reservoir permeability.

In Petro-Canada's efforts to characterize the McMurray formation, FMI images have been useful in resolving facies because they mimic core-facies data. These images enable geologists to differentiate those facies that impede SAGD from those that do not. Viewed as a good way to optimize coring, borehole imaging offers cost benefits, complete data across poor core-recovery intervals, information about bitumen content, sand trend and sand geometry.

The Deepwater Challenge

Submarine fans, commonly composed of accumulations of sand, are some of the world's most prolific sand-rich reservoirs. Many are located in deepwater environments. The enormous cost of finding and producing hydrocarbon reserves makes deepwater reservoir-development strategies much different from those of typical fields. Ideally, time to first oil must be minimized for prospect viability, fewer wells tend to be drilled for reservoir evaluation, and increasing use of subsea installations means that well interventions are extremely costly and difficult.[15] As a result,



^ Typical stacked, incised channels separated by scour surfaces. The StrucView tool graphically depicts the major types of bedding found within the upper estuarine-channel environment of the McMurray oil sands; they include paleocurrent bedding (blue), accretionary bedding (red) and low-angle and low-energy bedding reflecting structural dip to the south-southeast (green) (*bottom right*). This is a north-northwest to south-southeast cross section and shows the paleocurrent direction to be dominantly to the north in the lower section, but a west-to-northwest direction in the midsection. The upper part of the point bar, above 480 m [1570 ft], indicates a sediment-transport direction change to the southeast. The StrucView cross section direction was selected to enhance the current bedding. The FMI images from a small section in this interval show the appearance of current bedding in the dynamically processed image to the right and a bright bitumen-rich zone on the static image to the left (*left*). Bedding is difficult to see on cores, but is clearly observed on the FMI image. The dip-vector analysis from SediView software tracks the paleocurrent direction as this interval was deposited and indicates a meandering point-bar environment, probably tidally influenced (*top right*). This analysis suggests that more sand development can be expected to the north of this well position.

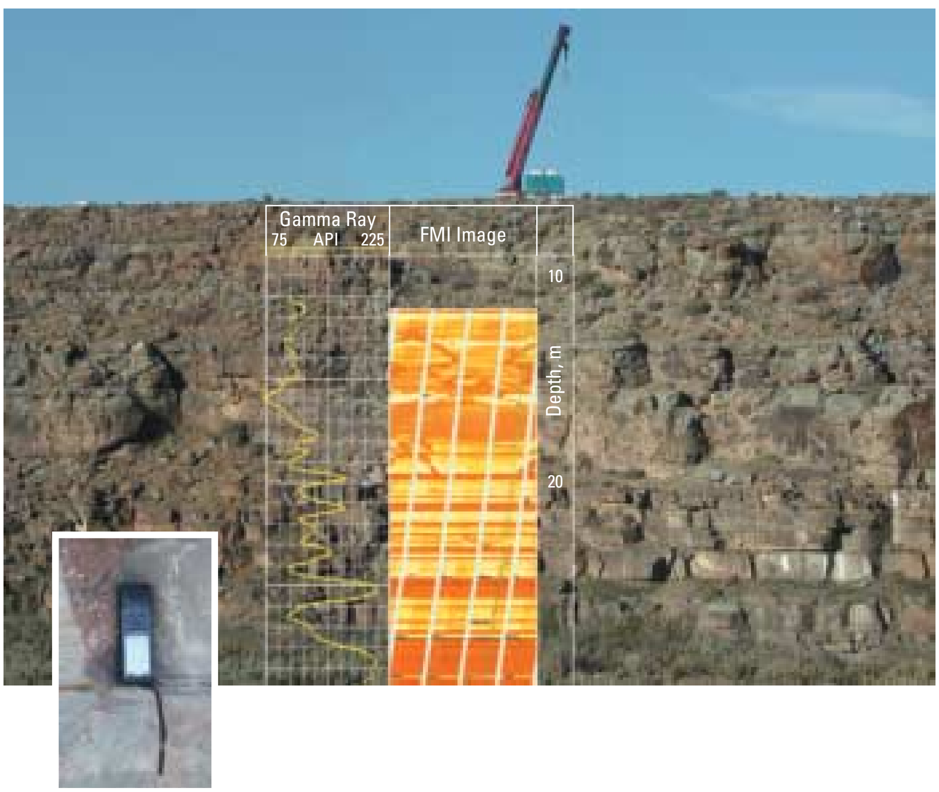
geologists must understand and model these reservoirs with significantly less well-log data, borehole images and cores. This scarcity of field-specific information has led to the increased study of exploration- and reservoir-scale submarine-fan and turbidite analogs to help geologists model the complex distribution and architecture of these reservoirs.[16]

A recent global study of the industry's use of depositional analogs shows that two-thirds of the companies surveyed not only use analogs but also believe that their use reduces risk and uncertainty. It also found that both geologists and engineers benefit from detailed analog studies, because these analogs bolster confidence in exploration and field-development modeling and subsequent decision-making.[17] Given the difficulty of studying recent modern deepwater sedimentary systems, researchers study ancient outcrop analogs.[18]

The Novel Modeled Analog Data for more efficient exploitation of deepwater hydrocarbon reservoirs (NOMAD) research project, launched in 2001, aims to reduce development costs associated with deepwater reservoirs. Sponsored by the European Union, NOMAD is a joint project of industry and academia. The participants

15. Carré G, Pradié E, Christie A, Delabroy L, Greeson B, Watson G, Fett D, Piedras J, Jenkins R, Schmidt D, Kolstad E, Stimatz G and Taylor G: "High Expectations from Deepwater Wells," *Oilfield Review* 14, no. 4 (Winter 2002/2003): 36–64.
16. Turbidites are sedimentary deposits formed by turbidity currents in deep water at the base of the continental slope and on the abyssal plain. Turbidites commonly show predictable changes in bedding from coarse layers at the bottom to finer laminations at the top, known as Bouma sequences, that result from different settling velocities of the particle sizes present. The high energy associated with turbidite deposition can result in destruction of earlier deposited layers by subsequent turbidity currents.
Dromgoole P, Bowman M, Leonard A, Weimer P and Slatt RM: "Developing and Managing Turbidite Reservoirs—Case Histories and Experiences: Results of the 1998 EAGE/AAPG Research Conference," *Petroleum Geoscience* 6, no. 2 (2000): 97–105.
17. Sun SQ and Wan JC: "Geological Analog Usage Rates High in Global Survey," *Oil and Gas Journal* 100, no. 46 (November 11, 2002): 49–50.
18. Purvis K, Kao J, Flanagan K, Henderson J and Duranti D: "Complex Reservoir Geometries in a Deep Water Clastic Sequence, Gryphon Field, UKCS: Injection Structures, Geological Modelling and Reservoir Simulation," *Marine and Petroleum Geology* 19 (2002): 161–179.

^ The Karoo basin study area. Within the Karoo basin lies the Tanqua fan complex and more than 640 km^2 [250 sq miles] of exposed strata.



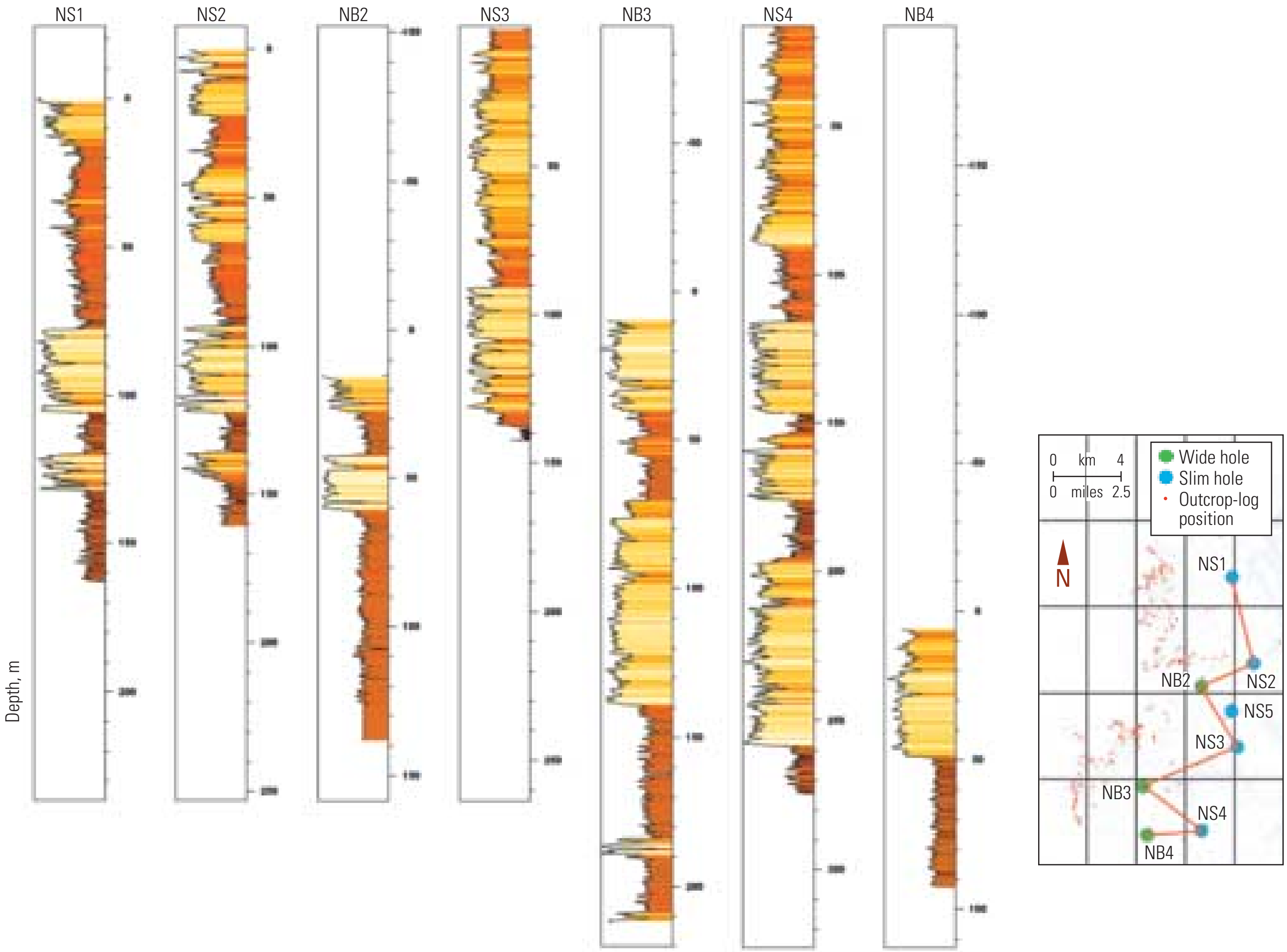
^ Mapping the outcrops. High-quality outcrops, such as this one exposing Fan 4 below the NB2 well location, enabled the NOMAD team of geologists to map the sedimentological details of the fan complex. Accurate mapping was facilitated by global positioning systems (GPS) and geographic information systems (GIS) (*inset*). The FMI image and gamma ray log from the well immediately adjacent to the outcrop are overlaid and compare directly with the outcrop.

include Statoil; Schlumberger; Delft University of Technology, The Netherlands; University of Liverpool, England; and the University of Stellenbosch, South Africa. The goal of the project is to improve the industry's ability to characterize deepwater reservoirs through the development of a detailed three-dimensional (3D) geological model using a vast supply of surface-outcrop data from the Tanqua subbasin submarine fan complex in South Africa.

The project area is southwest of the Karoo foreland basin (left). A Paleozoic clastic wedge of sediments—the Cape Supergroup—within the basin reaches a thickness of 8000 m [26,250 ft]. Two subbasins were formed during the Permian and Triassic periods, the Tanqua subbasin being one of them. The five Permian Tanqua fans have been studied extensively during the last ten years, laying solid technical groundwork for the NOMAD project.[19] The correlation of facies across the region from mapped exposed strata enhanced the modeling of the broad distribution of the fans. This led to an improved understanding of the depositional settings of five deepwater turbidite fan systems.[20]

From oldest to youngest, Fan 1 represents the most distal basin-floor position; Fans 2 and 3 are more proximal in a depositional dip sense, while Fan 4 represents a well-exposed depositional strike section. The lowest four fans are from a basin-floor environment, while Fan 5, the uppermost fan, appears to have been deposited on a submarine slope. Within each fan sequence, the architecture of sand bodies varies principally from channels to sheet sands.

Geological data from a variety of sources have been acquired on the submarine fans in the Tanqua subbasin, including the examination and mapping of rock outcrops at unprecedented levels of detail and accuracy using global positioning system (GPS) and geographic information system (GIS) technology. Additionally, seven shallow wellbores—four 4-in. diameter wells and three 6-in. diameter wells—were drilled. A total of 1186 m [3891 ft] of fullbore core has been extracted, and comprehensive suites of wireline logs were acquired on the 6-in. diameter wells, including Platform Express, ECS Elemental Capture Spectroscopy, NGS Natural Gamma Ray Spectrometry logs and FMI images. The wellbore locations were strategically placed with respect to the available outcrops, surface mapping and local subsurface geology (left). Cores from the seven wells were of excellent quality and underwent thorough analysis, including sedimentological core logging and digital core photography.



^ Correlating the fans in the Tanqua subbasin study area. Correlating the deepwater fans in the study area was challenging. Generally, the fan complex thins as mud content increases to the north, supporting a northerly downstream or basinward direction. The fan names and boundaries have been removed, as have the crosswell correlation markers. A plan view of the well locations is also shown (*right*).

The wireline logs also were of excellent quality, were crucial for correlating key surfaces, sand bodies and sedimentary facies across the project area, assessing rock properties and defining mineralogy (above).

Because of erosion and limited exposure, outcrops often do not allow precise assessment of stratigraphic thickness and subtle sedimentological features. Wellbore data helped determine the true stratigraphic thickness from observed thickness at outcrops, allowing more precise correlation of key flow units within submarine fans across the project area. This was especially important in the less resistant, silt- and mud-rich interfan deposits because of their relatively poor outcrop exposure. Additionally, it was particularly difficult to assess a narrow range of grain sizes, the amount of bioturbation and subtle bed boundaries—bed-thickness indicators—from the outcrops alone. In contrast, detailed core studies provided valuable additional information on all these parameters and allowed accurate description and quantification of the full facies variation. Cores and logs proved crucial for proper correlation of fans, depositional features and facies, leading to the construction of more robust 3D geological models.

Detailed outcrop logs and photographs are now being correlated with log, image and core data to expand the model beyond outcrops and wells to assist modeling of the interwell volumes, and also to provide a link to common well data acquired in exploration and production. Eventually, when the depositional analog is used to develop reservoir models, field data will be input to provide the dynamic information—for example, pressure and fluid type—necessary for successful simulation.

19. Wickens HdeV: "Basin Floor Fan Building Turbidites of the Southwestern Karoo Basin, Permian Ecca Group, South Africa," Unpublished PhD thesis, University of Port Elizabeth, Cape Town, South Africa, 1994.

Bouma AH and Wickens HdeV: "Permian Passive Margin Submarine Fan Complex, Karoo Basin, South Africa: Possible Model to Gulf of Mexico," *Transactions of the Gulf Coast Association of Geological Sciences* 41 (1991): 30–42.

Rozman DJ: "Characterisation of a Fine-Grained Outer Submarine Fan Deposit, Tanqua-Karoo Basin, South Africa," in Bouma AH and Stone J: *Fine-Grained Turbidite Systems.* American Association of Petroleum Geologists, Memoir 72 / SEPM Special Publication 68. Tulsa, Oklahoma, USA: American Association of Petroleum Geologists (2000): 292–298.

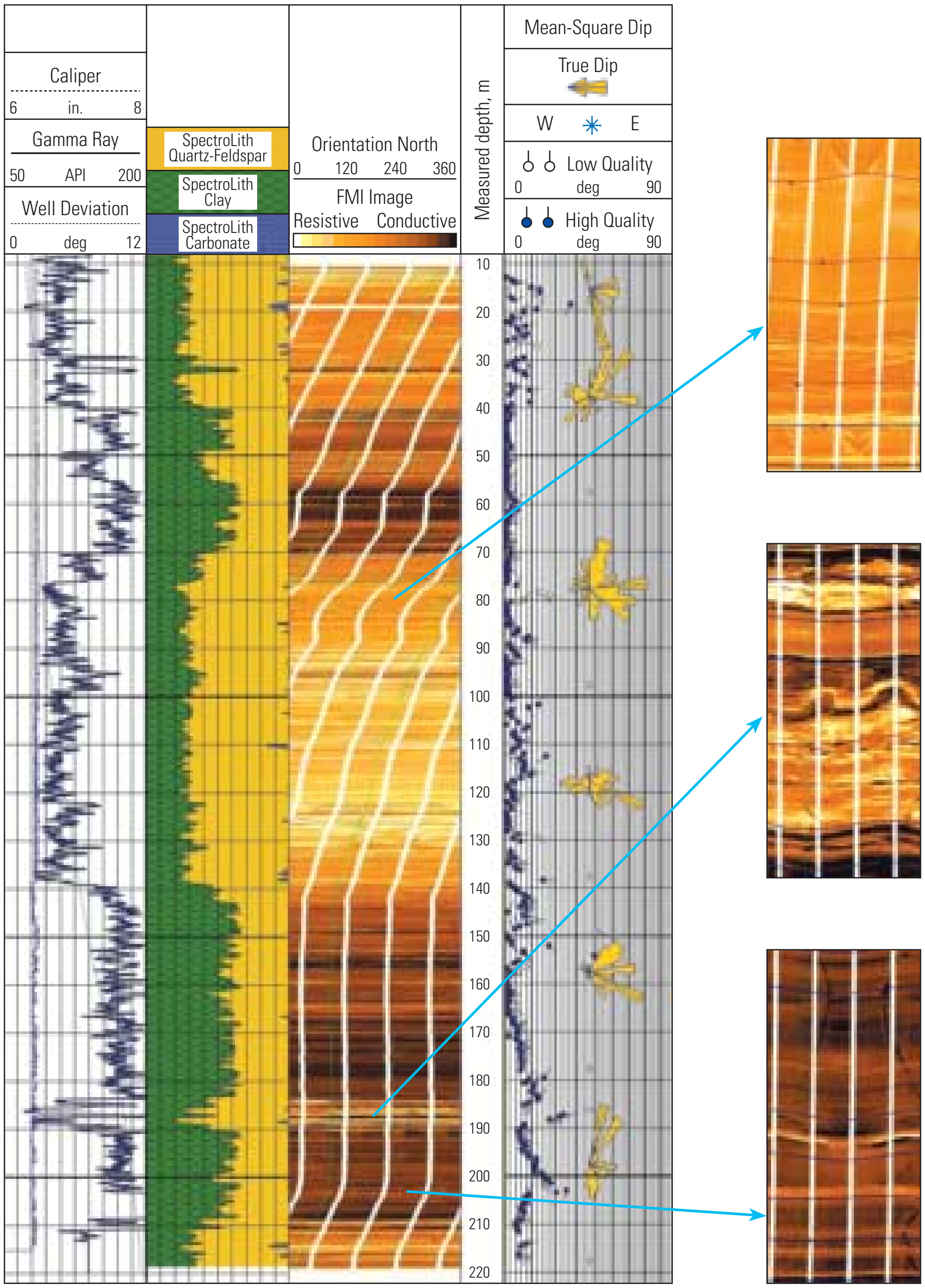
Bouma AH and Wickens HdeV: "Tanqua Karoo, Ancient Analog for Fine-grained Submarine Fans," in Weimer P, Bouma AH and Perkins BF (eds): *Submarine Fans and Turbidite Systems: Sequence Stratigraphy, Reservoir Architecture, and Production Characteristics, Proceedings of the Gulf of Mexico and International Gulf Coast Section, Society of Economic Paleontologists and Mineralogists Foundation 15th Research Conference* (1994): 23–34.

20. Johnson SD, Flint S, Hinds D and Wickens HdeV: "Anatomy of Basin Floor to Slope Turbidite Systems, Tanqua Karoo, South Africa: Sedimentology, Sequence Stratigraphy and Implications for Subsurface Prediction," *Sedimentology* 48 (2001): 987–1023.

The high-quality FMI images from the NOMAD project wellbores have identified and established the orientation of important sedimentological and structural features (below). For example, paleocurrent direction from borehole images will be input as trend maps to condition deepwater-fan reservoir models, facilitating the population of reservoir-feature geometry, porosity and permeability data. Sedimentary features observed on borehole images help geologists discern which portion of the fan has been penetrated and whether the well is in a confined channel or unconfined sheet-sand deposit—critical information when modeling deepwater fans. Seemingly insignificant features also can provide valuable clues about the sequence stratigraphy of deepwater systems. In the Tanqua fans, for example, concretions seen in outcrops and observed on the FMI images within some mudstone facies correlate with periodic flooding surfaces.[21]

Modeling and simulation tools allow geoscientists and engineers to exploit data from many different sources, including borehole images. The power of modern modeling and simulation software is exemplified in Petrel workflow tools, a PC-based platform that supports all disciplines of reservoir expertise. Petrel software handles two-dimensional (2D) and 3D seismic data interpretation and visualization; structural, stratigraphic and petrophysical modeling and mapping; well correlation; data analysis and model-volume population; reserve-volume calculation; and well design. Petrel software functionalities have enabled the visualization and modeling of the depositional zones of each of the Tanqua fan systems throughout the NOMAD project (next page, top). The ability to model deepwater-fan reservoir properties in detail offers multidisciplinary asset teams clear advantages in reservoir optimization during all stages of field development.

Borehole images are a small but important element within an enormous collection of data used in the modeling of reservoirs. However, specific data types change according to area, availability and the operating environment. While the FMI tool was used in the NOMAD wells drilled using conductive wellbore fluids, many deepwater wells are drilled with nonconductive drilling muds, thereby excluding the use of some formation-evaluation techniques. The OBMI tool, designed to run in oil-base and synthetic-base mud systems, provides high-resolution borehole images for sedimentological analysis.[22] For example, the OBMI tool can assist in the identification of slump features that reduce sand continuity and tend to reduce potential reservoir thickness and connectivity. Slumps observed at the wellbore should be considered when calculating total sand count or when estimating reservoir properties such as permeability. In addition, the examination of sedimentary features—such as crossbedding—on OBMI images has given geologists valuable insight into the orientation of sand bodies in a variety of depositional environments.



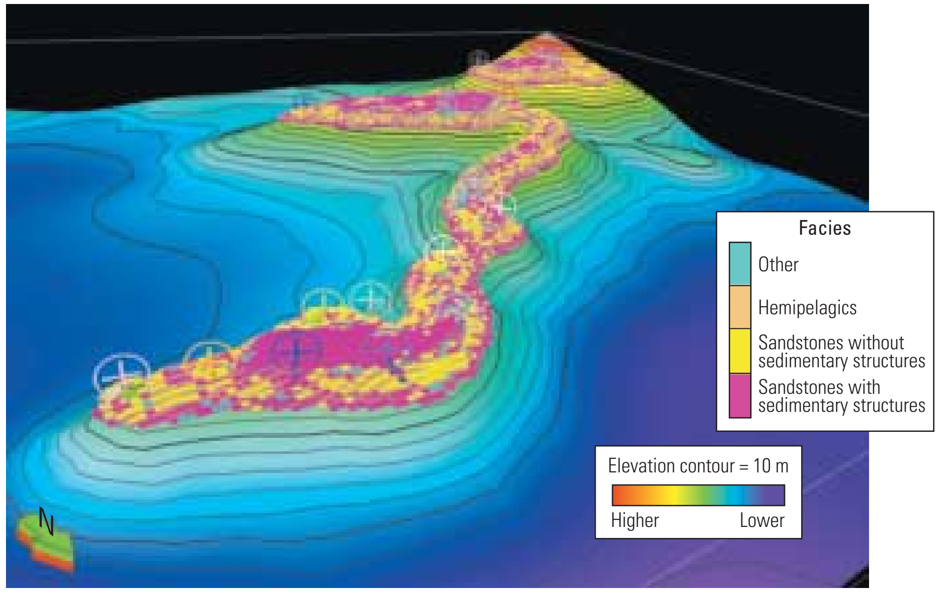
^ FMI images on NOMAD Well NB3. The FMI tool was run on the larger diameter wellbores to provide a high-resolution analysis of sedimentary and structural features. Track 1 contains gamma ray, caliper and borehole-deviation information. Track 2 shows the computed lithology from the ECS data. Track 3 displays a static image from the FMI tool, and Track 4 shows the computed true dips from the FMI data. Several key features are highlighted in this shallow wellbore. A significant thrust fault was identified at a depth of 203 m [666 ft] (*bottom right*). Contorted bedding was identified from 185 m to 190 m [607 to 623 ft] (*middle right*). Possible climbing ripple faces were identified at 80 m [262 ft] and show a south orientation, which is consistent with a northerly paleocurrent flow (*top right*). Fractures were also identified and oriented, although most are healed with quartz cement (*top right*).

Thin Beds in Deepwater Fans

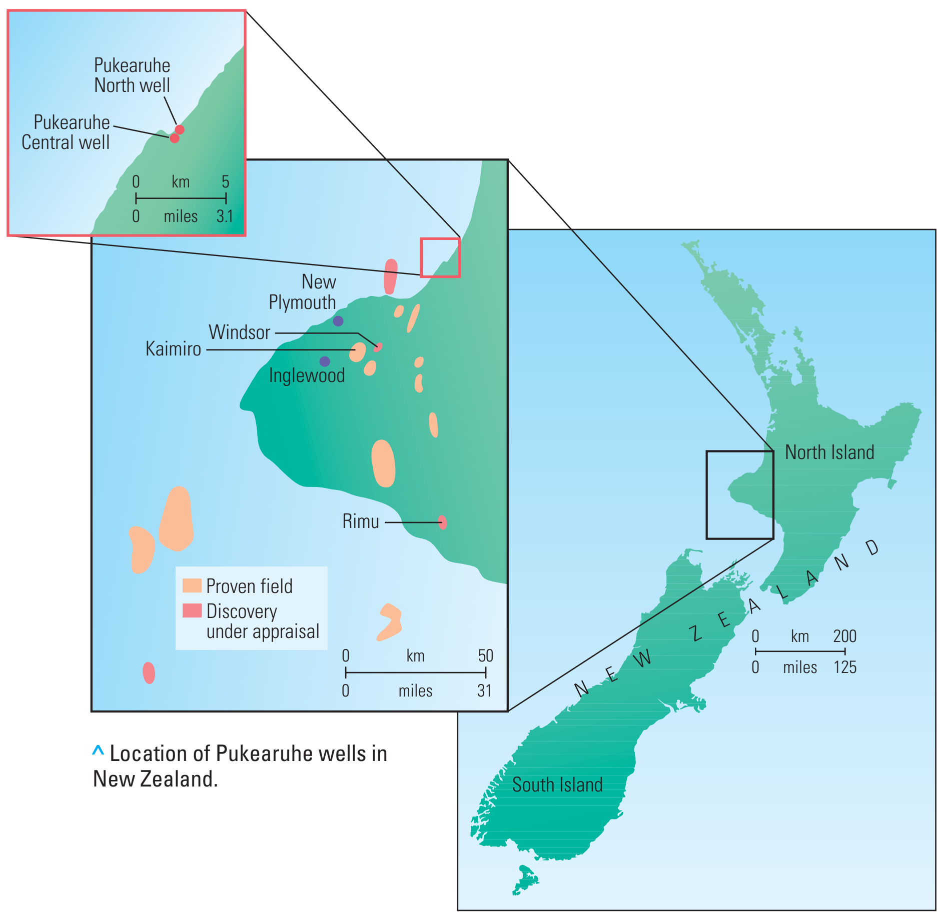
The Taranaki basin is one of the most explored and commercially successful hydrocarbon provinces of New Zealand. The main reservoir sands, of Miocene age and younger, were deposited in a deepwater slope and basin-floor fan setting. Oil was discovered in the Mt. Messenger formation in the Kaimiro field in 1991. Continued exploration led to oil discoveries in Rimu, South Taranaki, and a gas discovery in Windsor, North Taranaki. Thin-bedded sediments are the main reservoir facies, so identification of these sediments has been essential to successful exploration. The formation comprises predominantly very fine-grained sandstones, siltstones and mudstones, and geologists have interpreted this formation as deposited in a slope-fan setting.

The Mt. Messenger formation is found on the North Island of New Zealand, in both outcrop and subsurface. Borehole image data and wireline logs were collected from two adjacent wells, drilled about 450 ft [137 m] apart. The Pukearuhe North and Pukearuhe Central wells were drilled to depths of 236 ft [72 m] and 292 ft [89 m], respectively and were positioned approximately 300 ft [91 m] from the outcrop cliff. The boreholes were drilled into the Mt. Messenger formation in 1996, inland of Pukearuhe Beach, 50 km [31 miles] northeast of New Plymouth on the west coast of North Island (right). The outcrops have been interpreted as vertically stacked levee and overbank deposits comprising thin-bedded, typically planar-laminated sandstones and siltstones, and climbing ripple-laminated sandstones and siltstones.[23]

Detailed facies identified from the images were characteristic of a deep marine environment. A lithological log was defined from the gamma ray log and the SRES curve derived from stacking the 192 resistivity curves acquired by the FMI tool. The lithological log identified thin beds—minimum thickness of 2 in. [5.1 cm]—enabling a more accurate determination of sand count, mean bed thickness, lithological proportions, and thinning- and thickening-up cycles. Clearly identifiable dip domains defined these thinning- and thickening-up cycles. These dip



^ Modeling the Tanqua fans. A high-resolution lithofacies model constructed using Petrel software shows the variability of sheet-like sands in Fan 3. Grid cells represent 10 m by 10 m by 0.25 m [33 ft by 33 ft by 0.8 ft] volume—265 by 206 by 282 cells, equaling 15,394,380 cells in total—and are color-coded according to the mapped lithofacies type. The sinuous outcrop geometry is a result of erosion and is not related to sedimentation in a channel. The circled ‘plus’ symbols mark the top of each measured sedimentary section taken on the outcrop. Structureless sands are present in the areas of high amalgamation, or high energy, such as the center of a poorly confined channel, and structured sands are dominant in the less amalgamated areas, or lower energy areas. Hemipelagic sedimentation represents shutdown periods in the turbidite system. Hemipelagic sediments are deep-sea, muddy sediments formed close to continental margins, containing biogenic material and terrigenous silt.

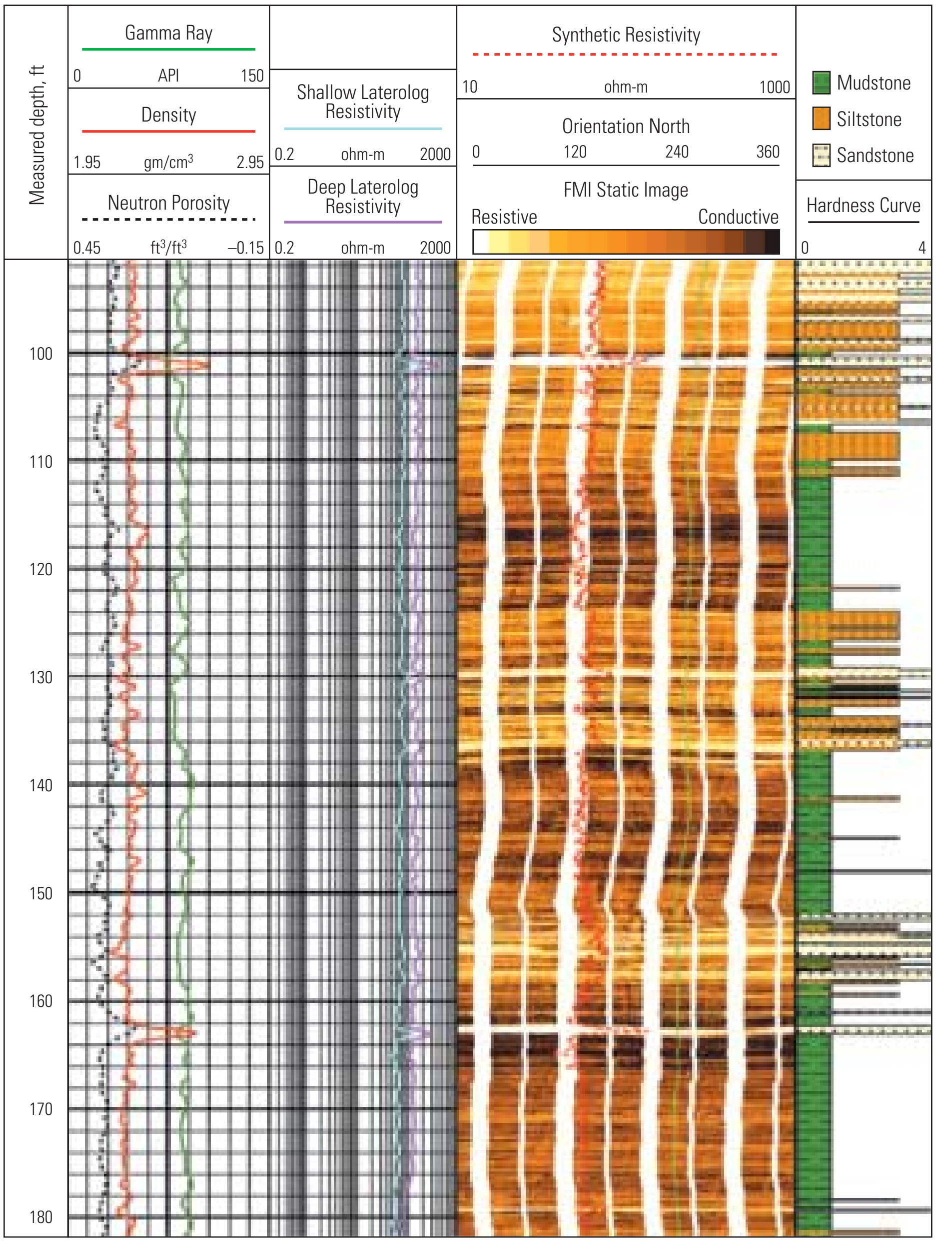


^ Location of Pukearuhe wells in New Zealand.

21. Johnson et al, reference 20.
22. Cheung et al, reference 5.
Cheung P, Pittman D, Hayman A, Laronga R, Vessereau P, Ounadjela A, Desport O, Hansen S, Kear R, Lamb M, Borbas T and Wendt B: “Field Test Results of a New Oil-Base Mud Formation Imager Tool,” *Transactions of the SPWLA 42nd Annual Logging Symposium*, Houston, Texas, USA, June 17–20, 2001, paper XX.
23. Browne GH and Slatt RM: “Outcrop and Behind-Outcrop Characterization of a Late Miocene Slope Fan System, Mt. Messenger Formation, New Zealand,” *AAPG Bulletin* 86, no. 5 (2002): 841–862.

domains were generally bounded at their base by a distinctive scour surface and overlain by a succession of dips that are similarly oriented but declining in magnitude upwards through the dip succession. Bed-to-bed correlation between the two wells proved difficult because of localized scouring and amalgamation of the sandstone beds. However, dip domains observed between wells suggested that facies packages could be correlated. These cycles were interpreted to represent individual lobes deposited on the basin plain.

Thin-bed analysis is critical to achieve accurate estimation of reserves, particularly during the early appraisal process. Although thin beds can now be identified from high-resolution openhole logs—2-in. resolution—sedimentological information from borehole images, with resolution as low as 0.2 in. [0.5 cm], helps assess reservoir continuity and reservoir potential.



^ Lithology log from the Pukearuhe North well. High-resolution lithology analysis helped resolve bed-thickness relationships in both the Pukearuhe North and Pukearuhe Central wells. Lithological logs, displaying beds as thin as 2 in., comprised three lithologies: sandstones, siltstones and mudstones (Track 4). Bed-thickness curves, derived from conductivity measurements, show thickening-up cycles in the Pukearuhe North well that coincided with the dip domains found in both wells.

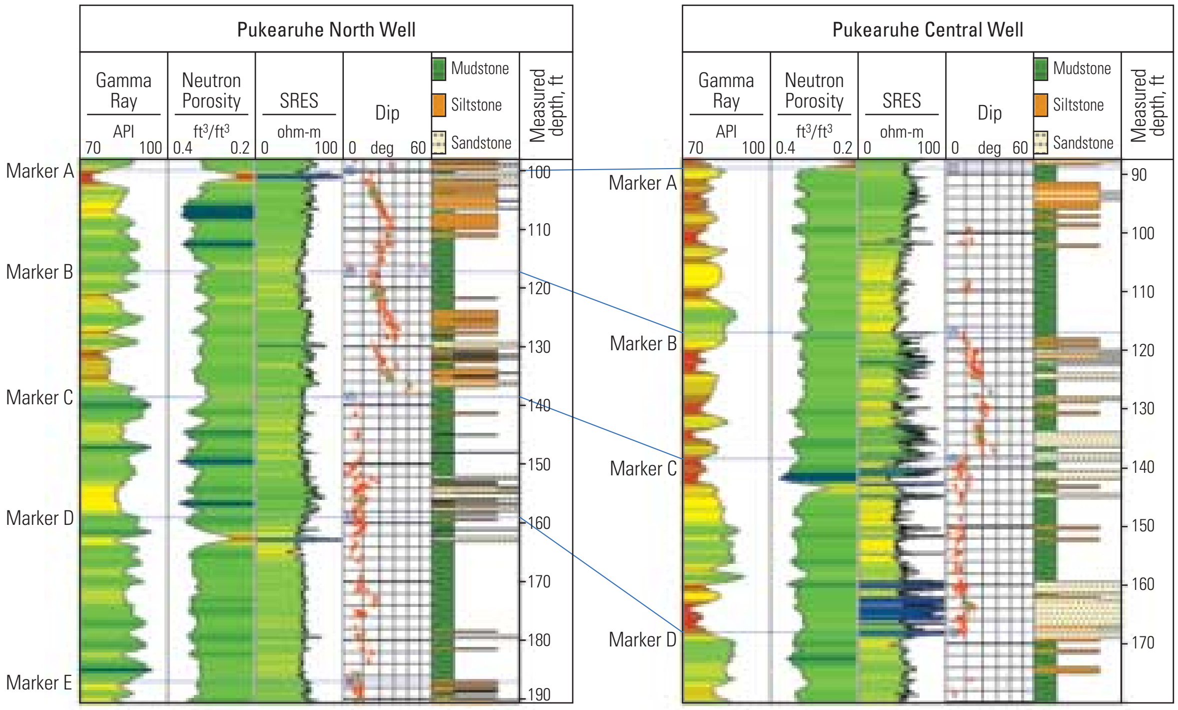
The FMI images showed the characteristics of a slope system, ranging from mudstone, then becoming interbedded with fine sands and growing increasingly sand-rich, and eventually forming thicker sandstones beds of approximately 2 ft [0.6 m] in thickness. Lithological logs comprised three lithologies: sandstones, siltstones and mudstones. The analysis displayed beds as thin as 2 in. (left). Bed-thickness block curves derived from conductivity measurements in the Pukearuhe North well exhibited thickening-up cycles that coincided with the dip domains. The dip domains were also observed in the Pukearuhe Central well, although the beds appeared much thinner and displayed much smaller cycles. The positions of the lithological markers were determined using the dip data and enabled a reasonably confident correlation across the two wells. The distinctive dip data within key zones allowed correlation between the two wells; without the dip data, correlation would have been difficult (next page, top). There were few other sedimentary features that could be correlated between the wells because of the repetitive nature of the sedimentation. As a result of the correlation, the proportion of sandstone was observed to increase towards the Pukearuhe Central well, indicating the greater potential for a channel margin towards the south.

The FMI tool was critical for proper thin-bed analysis. The identification and quantification of these thin beds would not have been possible with conventional wireline logs alone. The lithological log generated from the FMI data helped define the petrophysical parameters for each lithology and helped determine cutoffs, which could then be propagated throughout the field.

Improving Reservoir Models and Field Development

Continental-onshore and shallow-marine depositional environments may be more complex than submarine environments. Drilling in continental or transitional settings typically occurs at greater well densities, generating more subsurface data. Also, it is easier to observe active deposition in onshore environments. Transitional environments present special challenges because of the interplay of deposition and erosion under the combined and often opposing forces of land and sea, which leads to complex reservoir architecture.

Teikoku Oil de Sanvi-Güere has characterized the sedimentology of a complex series of reservoir sands in the Guarico 13 field of eastern



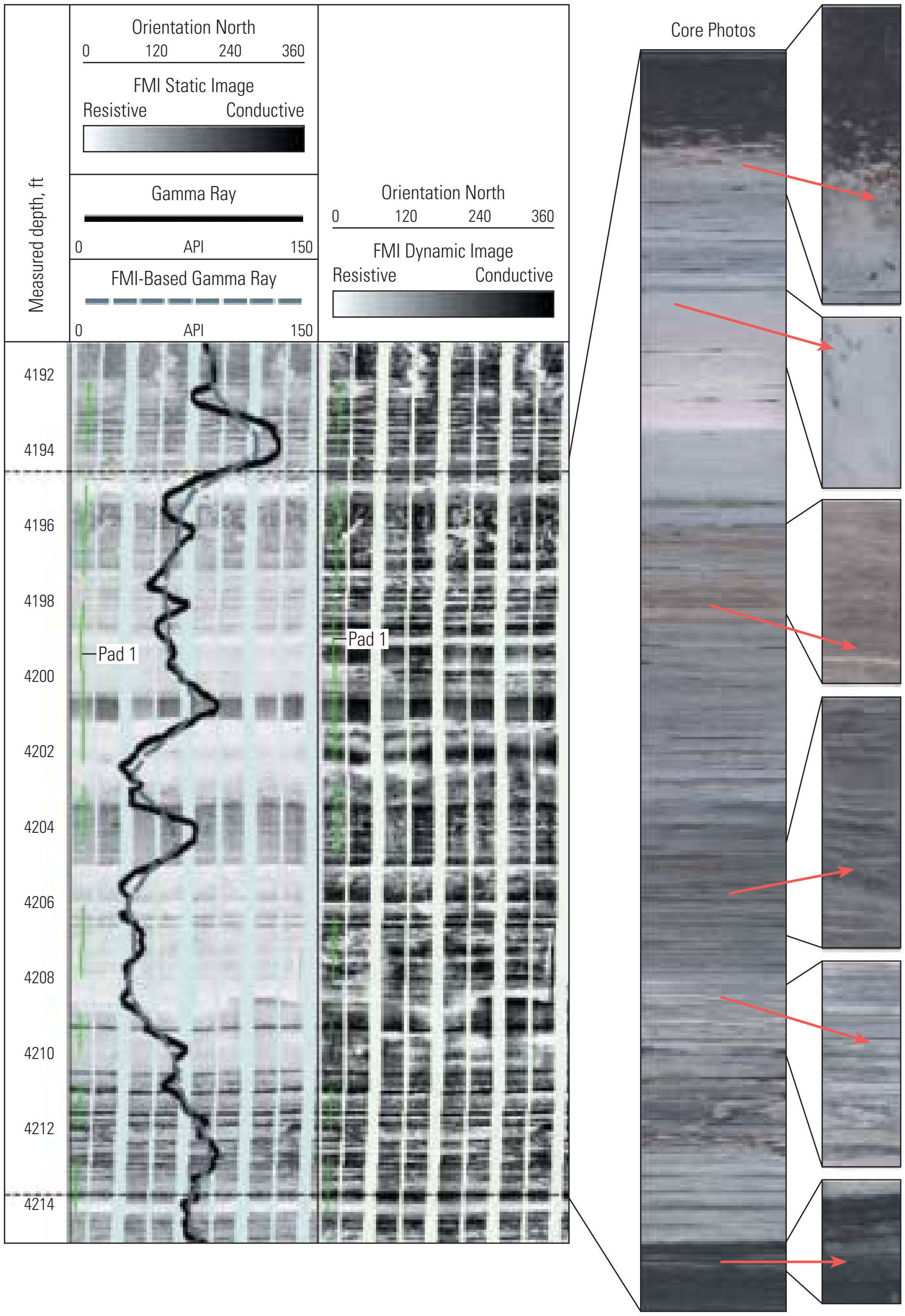
^ Correlation with dip data. The positions of the lithological markers were determined using the dip data from the FMI tool, enabling correlation across the two wells. A lack of sedimentary features and the repetitive nature of the sedimentation made correlation between the wells extremely difficult. This correlation allowed assessment of the relative proportions of sand in each zone. The Pukearuhe Central well contained the greater percentage of sand, suggesting the direction towards the channel and improved reservoir potential was south.

Venezuela (right). One of the main hydrocarbon-bearing intervals within this field, the upper Merecure formation, was deposited during the lower Miocene in a coastal-plain environment associated with a fluvial-deltaic system.[24] It is characterized by thin, very fine- to medium-grained sandstones, with typical gross-sand thicknesses of 10 to 30 ft [3 to 9 m]. Subenvironments include meander channels, floodplain channels, crevasse splays and channels, delta-front mouth bars, swamps and lakes.[25] Sediments within this environment are dominantly fine-grained but can be coarse- to medium-grained when deposited in higher energy channel subenvironments. Coal beds within the upper Merecure interval make laterally extensive correlation markers, but even with these markers, productive sand intervals can be elusive when drilling for maximum production and optimal recovery.

^ Location of the Guarico 13 field, eastern Venezuela.

24. Gamero H, Contreras C, Pestman P and Mizobe A: "Borehole Electrical Images as a Reservoir Characterization Tool in the Merecure Formation, Guarico 13 Field, Eastern Venezuela," *Memorias del VII Simposio Bolivariano*, Caracas, Venezuela, (September 10–13, 2000): 620–641.

25. For more on fluvial and deltaic depositional environments: Scholle PA and Spearing D: *Sandstone Depositional Environments, Memoir 31*. Tulsa, Oklahoma, USA: The American Association of Petroleum Geologists, 1982.

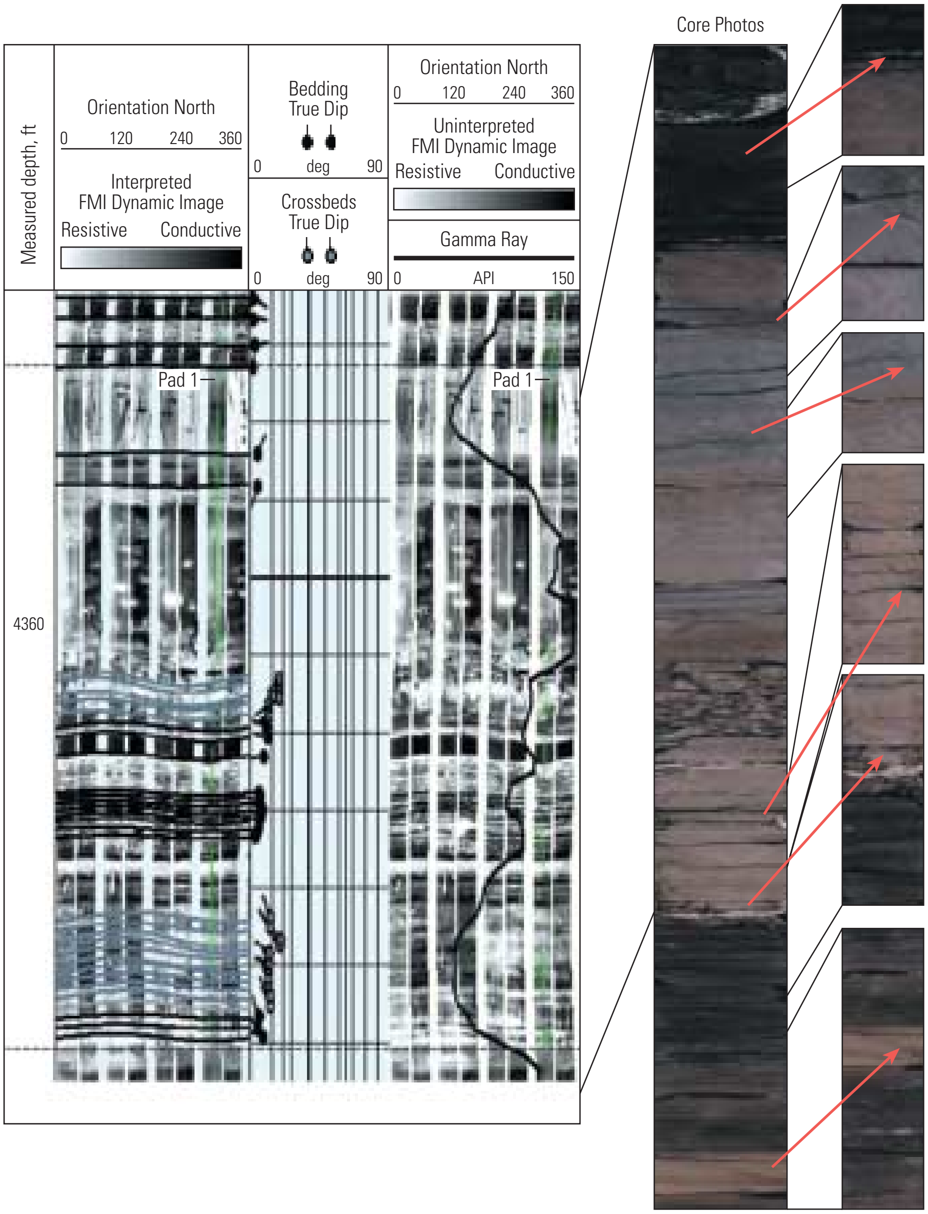


^ Crevasse-splay and lacustrine-sand facies. The core photographs show thinly laminated shales and siltstones, followed by sharp-based, parallel to crosslaminated sandstone that grades upward into a massive sandstone with plant-root traces (*right*). This is capped by a coal bed less than 1 ft thick. The FMI images match the core data over the crevasse-splay succession (*left*).

Borehole imaging tools, such as the FMI tool, have been invaluable to Teikoku Oil geologists. They have used the FMI data to develop sedimentological models for each reservoir sand within the Merecure formation. Using BorView tools in GeoFrame system software, Schlumberger and Teikoku geologists characterized the different sands by analyzing the sedimentary features on FMI images, thereby improving sedimentological models.

The determination of reservoir trends, continuity and connectivity could not have been accomplished using the available seismic data in the Guarico 13 field. In this area, most of the sand thicknesses and structural features—like faults—fall below the limits of the seismic data resolution. Borehole images help resolve the orientation of both productive and nonproductive lithofacies used in model and field development.

Extensive core and image analysis led to the recognition of eight facies within the Merecure formation. All eight facies are distinguishable on the FMI images and are verifiable by modern

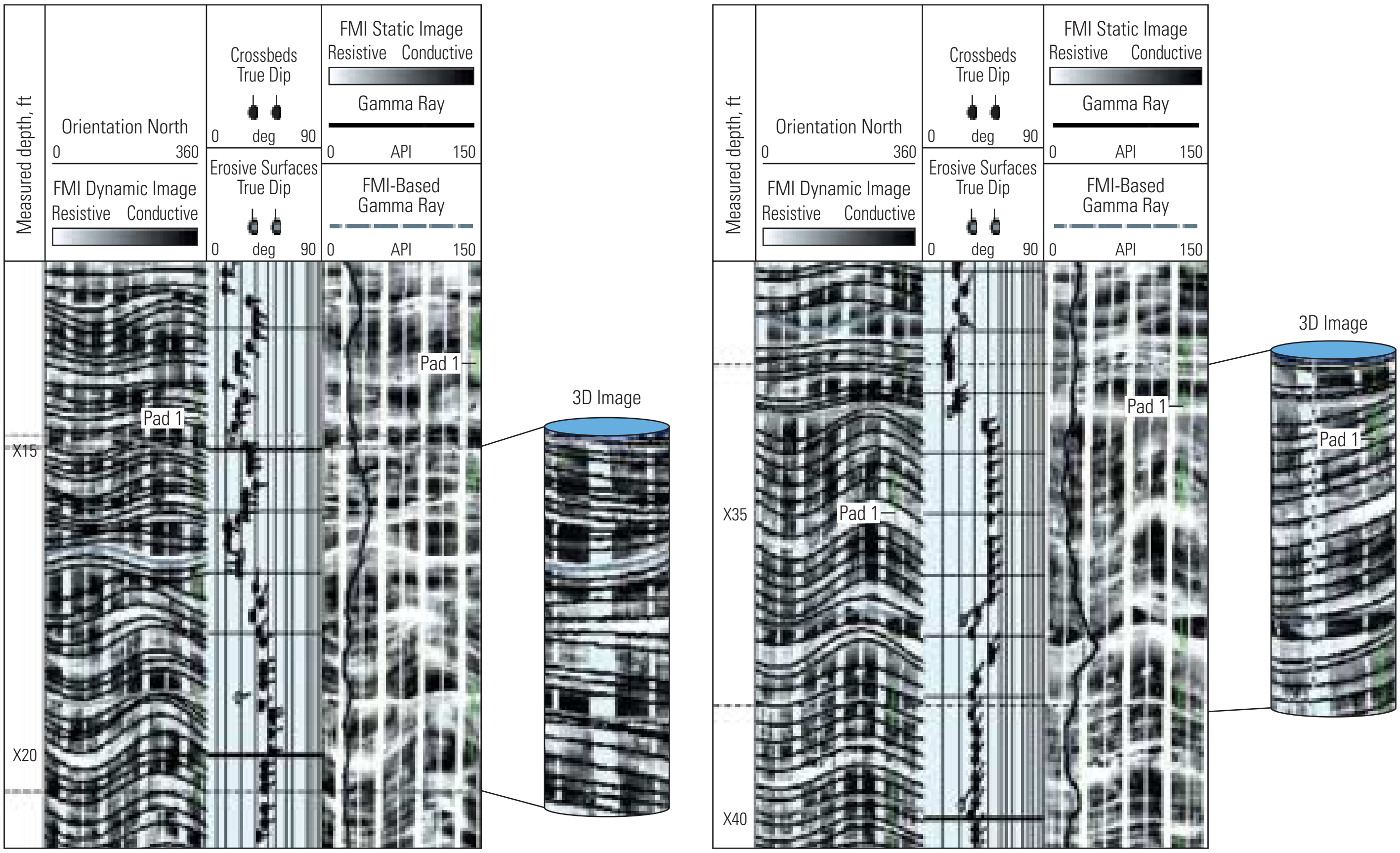


^ Crevasse-channel facies. The core data show sharp- or erosive-based, fine- to medium-grained sandstone (*right*). In some cases, the sandstones are crosslaminated or cross-stratified, but usually the facies appear massive. This interval is capped by abandoned channel facies. The FMI images match the core data over the crevasse channel-fill succession, and show sharp-based crosslaminated sandstone, overlain by fine-grained river-floodplain facies (*left*).

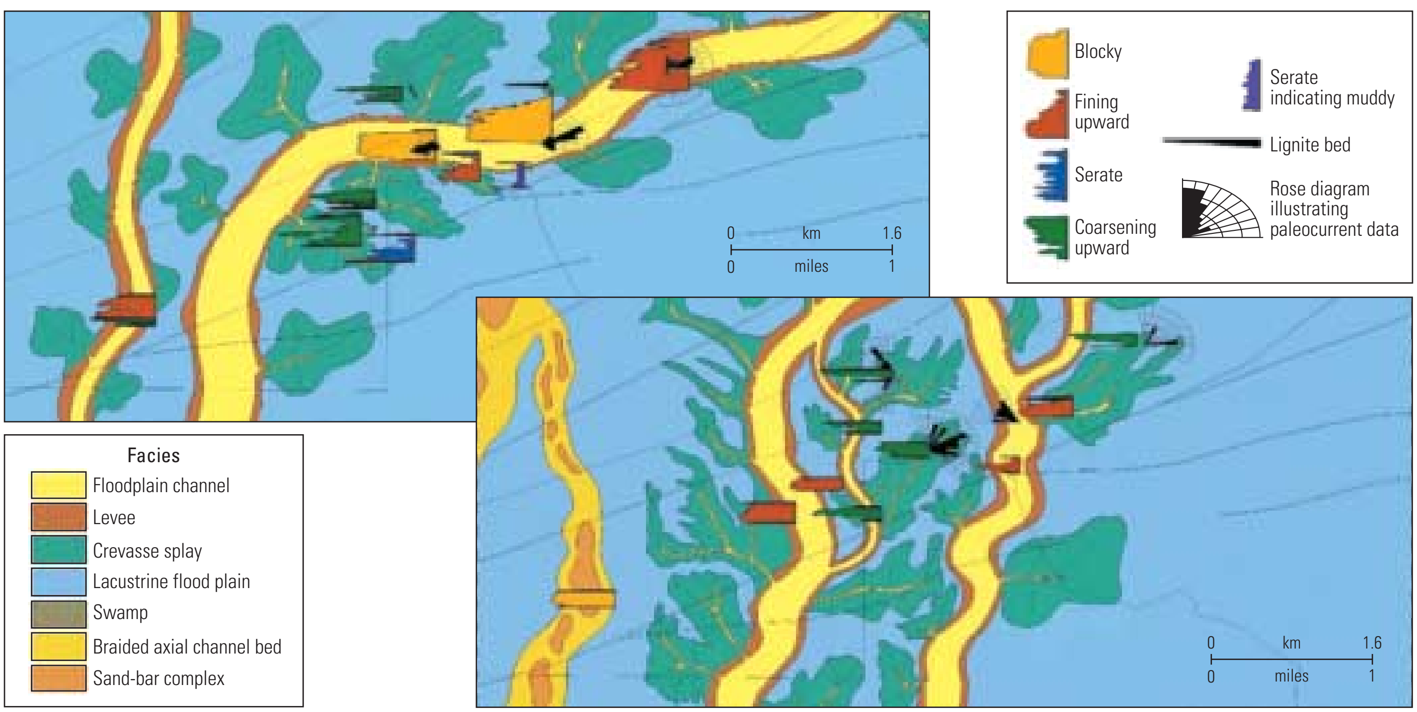
depositional analogs.[26] Crevasse channels and crevasse splays are important facies in the upper Merecure formation because of their high-quality reservoir characteristics. Crevasse splays are very fine- to medium-grained sand bodies that generally coarsen upward. They display abrupt lower contacts, parallel to crosslaminations and often show root traces in the top portion of the sand (previous page). This facies overlies thinly laminated shales and siltstones and is overlain by a thin coal bed. Characteristically, crevasse channels have sharp erosive bases, are fine- to medium-grained fining-upward successions, and can exhibit crossbedding but usually have a more massive internal structure. Both crevasse splays and crevasse channels display crossbedding that indicates paleocurrent direction, often representative of reservoir trends (above).

Four other significant facies that were identified are the meander-belt/braided-channel facies, which is found in the lower and middle

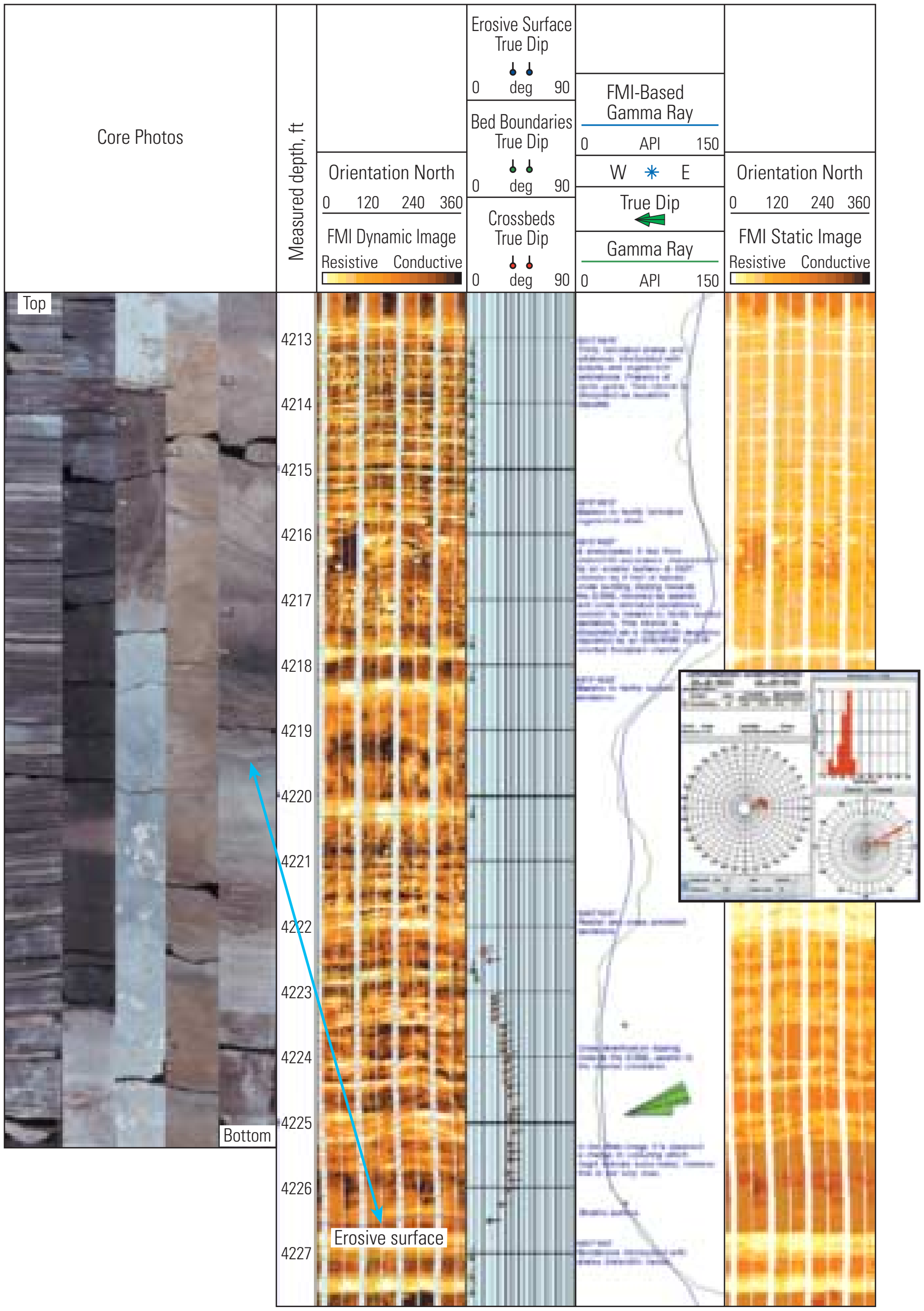
26. Gamero et al, reference 24.



^ Meander-belt/braided-channel facies. The FMI images show multiple erosive surfaces, separating units of 1-ft to 1.5-ft [0.3-m to 0.5-m] thick planar-crossbed sets dipping towards the north-northeast, east-northeast and northeast. This facies was not cored.



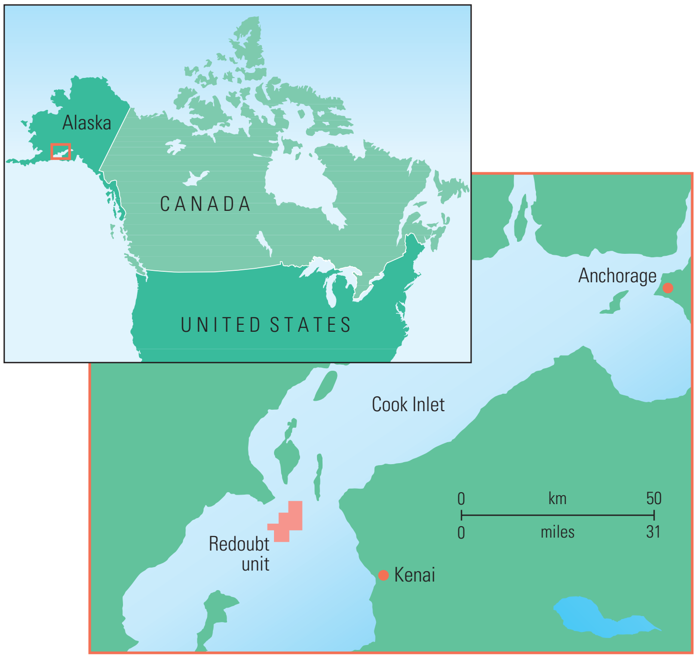
^ Sedimentological models incorporating the information derived from log, borehole image and fullbore core data. Models of two of the reservoir sands in the Guarico 13 field are displayed along with paleocurrent direction from the FMI analysis. Productive facies include the floodplain-channel facies (yellow), crevasse-splay (green), and the braided-channel facies (gold and orange). [Adapted from Hamilton DS, Ambrose WA, Barba RE, De Angelo M, Tyler N, Yeh JS, Dunlap DB and Laubach SE: "Hydrocarbon Production Opportunities Defined by Integrated Reservoir Characterization, Guarico 13/10 Area, Eastern Venezuela," Internal Teikoku Oil de Sanvi-Güere Report (1999).]



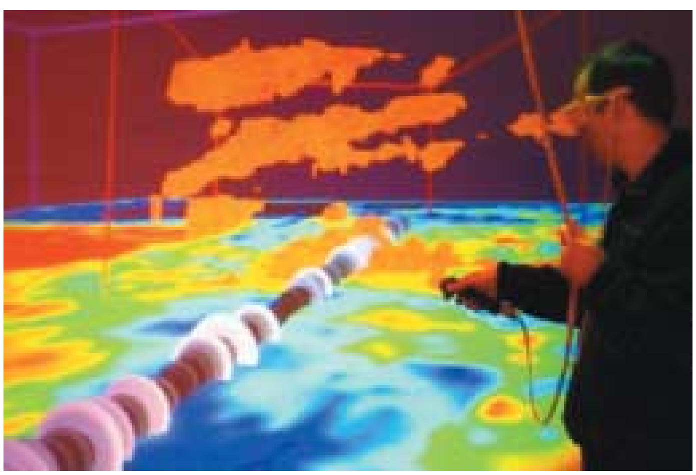
< Floodplain-channel facies. The borehole electrical images, integrated with the core data (4214.5 to 4222.6 ft, core depth), over the fining-upward succession (4219 to 4227 ft) show, from base to top, an erosive surface at 4227 ft (4222.6 ft, core depth) with an associated coarse-grained channel lag, overlain by a medium-grained sandstone with high-angle cross-stratification dipping towards the east and east-northeast. The cross-bedded sets are bounded by truncation surfaces, are inches thick and indicate an east-northeast sediment-transport direction. This interval is interpreted as a channel-fill succession deposited by a fluvial channel oriented east-northeast to west-southwest.

Merecure formation; the floodplain-channel facies in the lower part of the upper Merecure formation; and the shallow-marine shale and marine-bar facies, both at the top of the upper Merecure formation. The channel facies exhibit higher energy sedimentary structures such as planar and trough crossbedding as well as basal scour surfaces (previous page, top).

High-energy environments produce particularly strong directional indicators and typically represent the most productive reservoir section—highest porosity and permeability. In many cases, consistent paleocurrent indicators represent the channel-sand orientation. One of the main reservoirs in the Guarico 13 field, the U2M sand, is interpreted as a floodplain-channel facies. These facies are fining-upward successions of medium- to coarse-grained sandstones between 7 and 35 feet [2 and 11 m] thick, with tabular and trough cross-stratification and characterized by erosive basal contacts (above). This sedimentological information benefits the asset team's reservoir-modeling and field-development efforts (previous page, bottom).



^ The Redoubt Shoal field, Cook Inlet, Alaska, USA.



^ Understanding reservoir geometry using immersive visualization. In many fields, development economics dictates drilling of a minimum number of wells, each having maximum contact with the reservoir. Knowing more about reservoir sedimentology helps reduce the risk of failure or problems in these important wells, improving project economics. Using Inside Reality immersive technology, well-planning teams may be able to plan more complex wells that take detailed sedimentology into account, leading to greater success during drilling and geosteering operations.

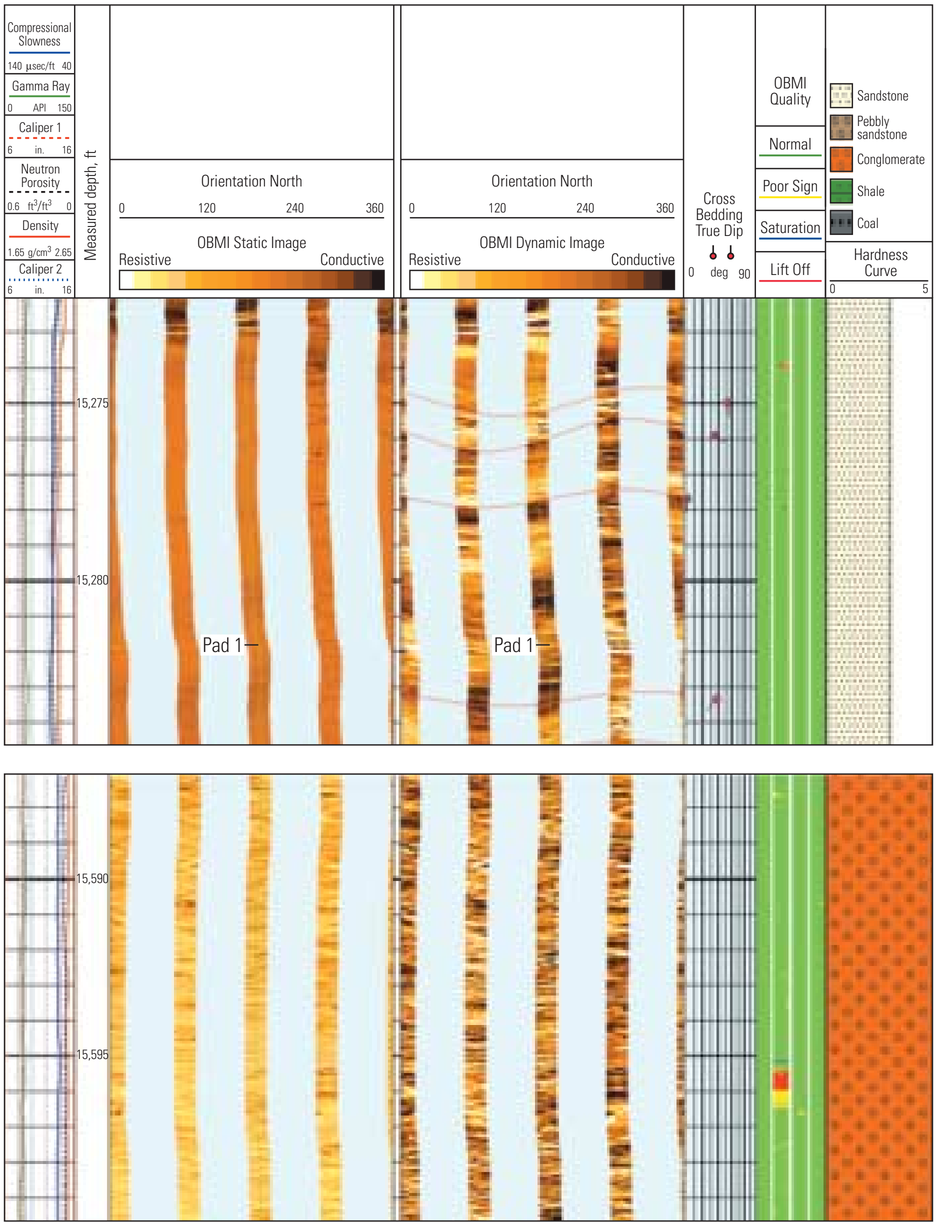
Facies Determination in Complex Rocks

Forest Oil Corporation is a key operator in the Cook Inlet, Alaska, USA, and has maintained an aggressive exploration program in the Redoubt Shoal field by using advanced technology to improve reservoir characterization. OBMI images acquired in March 2003 marked the first use of the tool by Forest in Alaska. There is substantial evidence from early results that the OBMI tool will have a considerable positive impact on facies determination and correlation in this area.

The Cook Inlet is a major oil and gas province located south-southwest of Anchorage, Alaska (left). It is located in a forearc-basin setting, which developed as a result of the subduction of the Pacific Plate margin. The hydrocarbon is trapped in compressional structures related to the convergent tectonics. Complex borehole-stress regimes create difficult drilling conditions that require the use of oil-base muds. Until the arrival of the OBMI tool in Alaska, acquisition of resistivity image data had not been feasible in the Hemlock formation within Redoubt Shoal field.

The central part of the Cook Inlet is filled in with 26,000 ft [7925 m] of nonmarine Tertiary rocks. The Hemlock conglomerates are upper Oligocene in age and consist of interbedded conglomeratic sandstone and conglomerates. They have been classified as lithic feldarenites, feldspathic litharenites, or lithoarenites. From core results, the Hemlock formation at Redoubt Shoal has been interpreted as low-sinuosity braided-stream deposits. The sandstones and conglomerate beds are often stacked to form large, homogeneous, sedimentary units that can reach thicknesses of greater than 50 ft [15 m]. OBMI images now provide important stratigraphic information that was previously unavailable, and a more robust structural-dip calculation than previously derived from the UBI Ultrasonic Borehole Imager tool.[27] Also, because of complex lithologies, the log character of these conglomeratic sediments makes facies determination and correlation difficult. However, OBMI images show clear differences between productive sandstone facies and less productive conglomerate and nonproductive mudstone facies (next page).

27. Johansson M and Saltmarsh A: "The Geological Application of Acoustic Images in Homogeneous Clastic Sediments; Examples from the Tertiary Hemlock Formation, Cook Inlet, Alaska," paper SPE 77995, presented at the SPE Western Regional/AAPG Pacific Section Joint Meeting, Anchorage, Alaska, USA, May 20–22, 2002.



< Facies determination with OBMI images. The use of oil-base mud systems in the Redoubt Shoal field has limited Forest Oil Corporation's ability to differentiate facies. There is now good evidence that the sandstone facies (*top*) can be distinguished from conglomeratic facies (*bottom*) within the Hemlock conglomerates using textural differences in the OBMI image data. The OBMI data were first acquired in the Cook Inlet in March 2003.

Knowing the Reservoir

To understand sedimentology is to understand the foundation on which a reservoir was built. Different depositional environments give rise to a variety of facies that influence reservoir characteristics. Reservoir models that incorporate detailed aspects of depositional processes often are more useful for predicting reservoir performance because of this relationship between environments, facies and the reservoir. Today, high-resolution seismic images and reservoir-visualization and immersion tools give asset teams the ability to more fully account for complexities, such as discontinuous or unconnected reservoirs. The GeoViz 3D visualization tool within GeoFrame software and the Inside Reality 3D virtual-reality system, a technology acquired by Schlumberger from Norsk Hydro, bring interactive well and field planning to the next level (previous page, bottom). As the industry moves ahead, borehole images will join a growing list of functional data types for these reservoir-visualization tools. Real-time and detailed visualization of LWD borehole images for geosteering holds significant promise.

The industry will continue to see the capabilities and applications of borehole imaging tools expand in both wireline and LWD systems. For example, in oil-base and synthetic-base muds, the new OBMI2 Integrated Dual Oil-Base MicroImager tool offers twice the borehole coverage of the original OBMI tool. As technologies advance and improve, the capacity of asset teams to assess, quantify, model and predict the sedimentological effects on reservoir development and performance will continue to multiply. Consequently, the value of borehole imaging in geology and asset management will be more fully realized. —MG

Contributors

Andrew Acock, Schlumberger Sandface Business Development Manager, is based in Aberdeen, Scotland. His primary focus is developing sand-management and PowerSTIM* solutions for the offshore environment. He joined Schlumberger in 1984 as a field engineer in Africa. From 1987 to 1990, he was cementing field service manager in Aberdeen. Subsequently, he directed the cementing laboratory and provided field support for Europe and Africa. From 1993 to 1998, he was assigned to Shell Offshore in New Orleans, Louisiana, USA, working with multidisciplinary teams that identified production-enhancement opportunities. His next assignment was matrix-stimulation engineering manager for North and South America. Before taking his current position, he was solutions coordinator for the Gulf of Mexico, working for the Data and Consulting Services group in Houston, Texas, USA. Andrew has a BS degree in engineering science from University of Aberdeen, a postgraduate degree in management studies from Newcastle-upon-Tyne Polytechnic in England, and an MS degree in petroleum engineering from University of Texas at Austin.

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Scott Dingwall, Senior Geophysicist for Schlumberger Data and Consulting Services (DCS), is based in Stavanger, Norway. Among his responsibilities are borehole seismic acquisition support, data processing and business development. He began his career working in offshore surface seismic processing before joining Schlumberger in 1996. He started as a geophysicist in the borehole seismic processing group in Aberdeen, Scotland, and later transferred to the borehole seismic group in London, England. He assumed his current position in 2002. Scott is a graduate of Imperial College in London and holds an MS degree in exploration geophysics.

Nick Drinkwater is a senior research scientist in the Geophysics department at Schlumberger Cambridge Research (SCR) in England. One of his main responsibilities is to serve as project coordinator for the project NOMAD (Novel Modeled Analogue Data for more efficient exploitation of deepwater hydrocarbon reservoirs). He worked at BP Exploration Sunbury Research Centre in 1995 on the collection and integration of outcrop-derived data for use in reservoir characterization, description and production. From 1997 to 1998, he was at Schlumberger-Doll Research in Ridgefield, Connecticut, USA, working on development of new software for object-modeling of subsurface reservoirs. He joined the Seismic Reservoir Characterization team at SCR in 1999. Before assuming his current position in 2002, he was a member of the Geology and Geophysics group, involved in developing new software and workflows for use in reservoir characterization and modeling of deep-marine reservoirs. Nick has a BS degree (Hons) in geology from University of Birmingham, an MS degree in industrial mineralogy from University of Leicester, and a PhD degree from University College in London, all in England.

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Cees Geel is an assistant professor at the Department of Applied Geosciences, Delft University of Technology, The Netherlands. After earning an MS degree in geology from University of Utrecht in The Netherlands in 1985, he spent two years as a researcher in turbidites at the same university. After a year with SedCon (now Enres International BV), and a year with the Geological Survey, he joined The Netherlands Institute of Applied Geoscience TNO-National Geological Survey in 1989, where he worked as a log analyst and production geologist. Cees has been with Delft University since 1993, first as a research associate, and since 1997, as an assistant professor. His main interests are integration of log analysis, petroleum engineering and production geology.

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David Hodgetts is a postdoctoral research associate in the Department of Earth Sciences, University of Liverpool, England. He is currently working on the NOMAD project. His research interests are reservoir and numerical modeling in shallow-marine and deepwater environments, along with digital mapping and geological surveying techniques, and applying new technologies to field geology. He has been with the STRAT group since 1997 and is scheduled to take a lectureship in reservoir modeling and petroleum geology at the University of Manchester, England, in September 2003. David earned a BS degree in geology from University of Durham, and MS and PhD degrees from the University of Keele in Newcastle-under-Lyme, England.

Steven Hoover has been a Schlumberger sand-control sales engineer in Houston, Texas, since 2000. He began his career in 1976 as a Dowell service supervisor in Louisiana. His subsequent assignments in Louisiana involved tool service, supervision and sales, and management of gravel-pack pumping services. In 1996, he became sand-control manager in Stavanger, Norway, and then assumed the same position in Aberdeen, Scotland, from 1997 to 2000. Steven studied business at Mississippi State University in Starkville, USA.

Rune Hope is team leader for operational geophysics assistance at TotalFinaElf in Paris, France. This group works closely with the company's new ventures and field-development teams and with subsidiaries around the world within the areas of lithoseismic, imaging, seismic processing and feasibility studies. He began with Petrofina in 1985 as an exploration geophysicist working in the North Sea. Two years later he joined TOTAL Norway in Bergen as an exploration interpretation geophysicist. His subsequent assignments included senior production geophysicist for TOTAL Norway in Stavanger (1990 to 1991); senior staff geophysicist for TOTAL Indonesia (1991 to 1995); chief geophysicist for TOTAL Thailand (1995 to 1998); chief geophysicist for TOTAL Upstream in Nigeria (1998 to 2000); and senior geophysics manager in Nigeria (2000 to 2002). Rune has a BS degree in geology and an MS degree in geophysics from the University of Bergen in Norway.

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Erik P. Johannessen is a senior staff geologist with Statoil and has had 23 years of experience in exploration, research and technology development in clastic depositional systems, and in prospect generation in deltaic and deep-marine environments. A specialist in sequence stratigraphy and deep-marine deposits, he currently is an explorationist on the Statoil Angola team. A key component of his daily work is interpreting integrated subsurface data and comparing the data and interpretations with outcrop analogs. For the past 10 years, he has been a company-wide supervisor in sequence stratigraphy and a supervising area geologist in the northern North Sea. Erik joined Statoil in 1980, after earning an MS degree from the University of Bergen in Norway.

Melissa Johansson is a Schlumberger Alaska GeoMarket* interpretation and development geologist. Based in Anchorage, Alaska, USA, she is responsible for imaging-tool sales, support and interpretation, for both the logging-while-drilling (LWD) and wireline market segments. She joined Schlumberger in 1998 as a geoscientist in Kuala Lumpur, Malaysia, before being assigned as geologist to a field development-planning project for the Petronas Bayan field in Sarawak, Malaysia. Melissa earned a BS degree (Hons) in physical geography and geology at University of Liverpool, and a PhD degree in deep-marine sediments at University of Southampton, both in England.

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Henry Menkiti, Schlumberger wireline field service manager for special services in Belle-Chasse, Louisiana, oversees the borehole seismic business in the northern Gulf coast. He also serves as geophysical domain champion for this area. He spent five years as a field engineer in Venezuela, Nigeria, Canada and Brazil. In 1997, he transferred to the Land Technical Support group in Hannover, Germany, and later became a geophysical and data processing instructor in Gatwick, England. Before accepting his current position, he was responsible for Schlumberger Oilfield Services training within North and South America. Henry received an MS degree in petroleum geology from Imperial College, University of London, England.

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Art Saltmarsh is a geologist for Forest Oil Corporation in Anchorage, Alaska. There he is involved in exploration projects in Cook Inlet, including the exploration and development of the Redoubt field. After earning a BS degree and completing work on an MS degree in geology from the University of Florida at Gainesville, USA, he joined Phillips Petroleum in 1980. He spent the next four years in London and Houston working on exploration prospects in Europe, Africa and Texas. In 1984, he joined Marathon International to work on petrophysical analysis of the company's exploration wells worldwide. From 1990 to 1994, Art was responsible for Marathon Oil's development projects at MacArthur River field in Anchorage. After several years of consulting, he accepted his current position in 1997.

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Sergei Tcherkashnev is a Schlumberger borehole seismic geophysicist based in Gatwick, England. He is currently working on integration of borehole seismic and log data for borehole-calibrated surface seismic processing, advanced borehole seismic processing, and modeling, inversion and pore-pressure prediction. Previously, he was a geophysicist with GeoQuest in Melbourne, Australia, a field geophysicist with Zonge Engineering in Adelaide, Australia and a field and processing geophysicist with Trust Dalmorneftegeofizika (DMNG) in Yuzhno-Sakhalinsk, Russia. Sergei has an MS degree in geophysics from The Moscow State University, Russia.

Ted Ter Burg is a Schlumberger senior geophysicist in The Hague, The Netherlands, who is seismic coordinator and GeoMarket geophysicist for continental and eastern Europe. Responsible for all borehole seismic activities in the area, he oversees quality assurance of data acquisition and processing, interpretation support, marketing and sales, and serves as seismic team leader of the European Borehole Seismic group. After earning a degree in technical physics, he joined Schlumberger as a petrophysicist in 1979. He has been active in all aspects of design, planning and field acquisition of borehole seismic surveys and has had 18 years of experience in seismic data processing and interpretation. Ted became GeoMarket geophysicist in 1992.

Ian Tribe, Schlumberger Logging-While-Drilling (LWD) and Well-Placement Business Development Manager, is based in Aberdeen, Scotland. He began his oilfield career in 1995 with a UK-based geological consultancy and, since joining Schlumberger in 1997, has held technical, operations, sales and management positions related to wireline and LWD formation-evaluation and geosteering services. He has a BS degree in geology and computer science from University of Reading, and a PhD degree in structural geology from Oxford Brookes University, both in England.

John Tulett, Schlumberger KK Technical Manager, is based in Fuchinobe, Japan. He joined Schlumberger in 1977 as a field engineer in the Middle East. He remained in the region as field-test coordinator for induced gamma spectroscopy logging until 1984, when he became technical operations engineer and then location manager in China. He moved to Schlumberger Japan as section manager in manufacturing two years later. From 1991 to 1994, he was Geco-Prakla technical manager in Canada, Alaska and the Middle East, and then became technical manager for seismic land operations worldwide. Before assuming his current position, he was surface seismic systems product champion. John holds a BS degree (Hons) in electrical engineering from Queen's University in Kingston, Ontario, Canada.

Michel Verliac, Geophysics Domain Advisor for Schlumberger Data and Consulting Services, is based in Clamart, France, where he is involved in product development, borehole seismic training and new technologies. After several student projects for the Institut Français du Pétrole, the French Atomic Energy Agency and Petrofina, he joined Schlumberger Wireline in 1991 as a borehole seismic geophysicist in West and South Africa. From 1996 to 1997, he was special project leader for Schlumberger in Kazakhstan and Russia. He spent the next two years as geophysicist for south Latin America and then became Argentina Computing and Interpretation Center manager. Before taking his current post in 2002, he spent three years in Mexico and Central America developing borehole seismic services. Michel holds an MS degree in geophysics and geochemistry from University of Science Louis Pasteur in Strasbourg; an engineering degree, also in geophysics and geochemistry, from Institute of Earth Physics in Strasbourg; and an engineering degree in exploration geophysics from Ecole Nationale Supérieure du Pétrole et des Moteurs in Rueil-Malmaison, France.

Mark Williams, Atlantis Senior Development Geophysicist, works for the BP Deepwater Development Business Unit in Houston, Texas. His responsibilities include 3D VSP planning, acquisition and interpretation, and 3D depth imaging and interpretation for appraisal and development-well placement and reservoir mapping for reserves calculation. He has had 19 years of experience with Sohio, BPAmoco and BP working as an appraisal and exploration geophysicist in a variety of locations. His prior experience includes appraisal and development roles in the Cusiana and Cupiagua fields of Colombia, South America and the Harding field in the UK, and six years in deepwater Gulf of Mexico exploration with BP Houston. Mark has a BS degree in geology from Florida State University in Tallahassee, and an MS degree in geophysics from Colorado School of Mines in Golden, USA.

An asterisk (*) is used to denote a mark of Schlumberger.

Coming in *Oilfield Review*

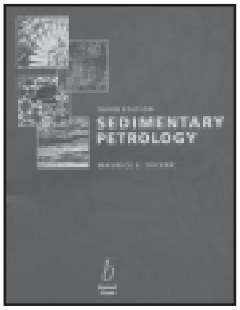
Cased-Hole Formation Evaluation. Novel formation-evaluation services accurately determine porosity, resistivity, lithology, shale content, fluid saturations and pressure, and recover formation-fluid samples in cased holes. Innovative tool designs and processing software make formation evaluation behind casing a viable option to evaluate bypassed zones, intervals that must be cased before openhole logs are run or the effects of time on producing zones. Exploration and production companies now are able to obtain cost-effective, useful data in difficult operating environments.

Mechanical Earth Modeling. Well construction has become technically and economically challenging in many areas of the world. A mechanical earth model (MEM) provides a framework for understanding and mitigating many of the risks associated with drilling. This article describes building an MEM for drilling and illustrates its use in life-of-the-field applications.

Magnetic Resonance in Real Time. Petrophysical characterization of reservoir rock can be challenging. Magnetic resonance (MR) logging has proved to be an effective means for determination of free fluid, bound fluid and permeability, even in difficult carbonate sections. This article explores new applications of real-time logging-while-drilling (LWD) MR technology for geosteering and optimal wellbore placement.

Environmental Responsibility in Seismic Operations. WesternGeco has put into worldwide practice a methodology to ensure that land seismic survey operations promote stewardship of the environment and respect for local culture. This new environmental performance monitoring process starts in the planning phase, runs through survey acquisition, and reviews postproject analysis to help plan future work. Examples come from North and South America, Australia and the Middle East.

NEW BOOKS



Sedimentary Petrology, 3rd Edition
Maurice E. Tucker
Blackwell Science
350 Main Street
Malden, Massachusetts 02148 USA
2001. 262 pages. $59.95 (paperback)
ISBN 0-632-05735-1

The third edition of this textbook provides a description of the composition, mineralogy, textures, structures, diagenesis and depositional environments of sedimentary rock. The book also includes many color and black and white photographs and photomicrographs of sedimentary rock in thin section.

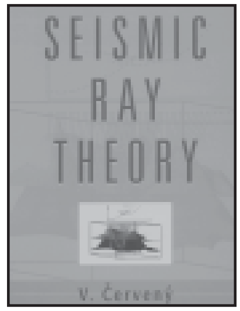
Contents:

- Introduction: Basic Concepts and Methodology
- Siliclastic Sediments I: Sandstones, Conglomerates, and Breccias
- Siliclastic Sediments II: Mudrocks
- Limestones
- Evaporites
- Sedimentary Iron Deposits
- Sedimentary Phosphate Deposits
- Coal, Oil Shale and Petroleum
- Cherts and Siliceous Sediments
- Volcaniclastic Sediments
- References, Index

It offers a comprehensive treatment of sedimentary petrology, is very lucid and well illustrated, showing the obvious enthusiasm and knowledge of the author, and has been tried and tested over two decades.

If I were still teaching, I would prescribe this book. I believe that it is still one of the best introductory texts available.

Tankard AJ: *Sedimentary Geology* 152, no. 1-2 (September 2002): 159-160.



Seismic Ray Theory
V. Červený
Cambridge University Press
40 West 20th Street
New York, New York 10011 USA
2001. 697 pages. $130.00
ISBN 0-521-36671-2

This book presents a comprehensive treatment of the seismic ray method, which plays an important role in seismology, seismic exploration and in the interpretation of seismic measurements. In tutorial style, derivations start with a relatively simple problem, in which the main ideas are easier to explain, and then advance to more complex problems.

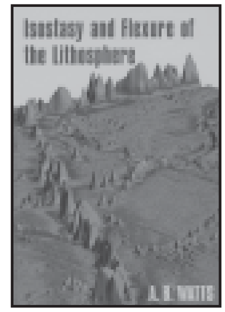
Contents:

- The Elastodynamic Equation and Its Simple Solutions
- Seismic Rays and Travel Times
- Dynamic Ray Tracing. Paraxial Ray Methods
- Ray Amplitudes
- Ray Synthetic Seismograms
- Appendix, References, Index

I was impressed with how well written, thorough, and readable this book is. I like its broad scope and completeness, and believe that Červený has made a great achievement in presenting such a large amount of material so clearly.

The tutorial nature of this book will appeal to those who want to learn isotropic or anisotropic wave theory or to those who just want a reference volume that will be easy to use.

Schneider WA Jr: *The Leading Edge* 21, no. 9 (September 2002): 939-940.



Isostasy and Flexure of the Lithosphere
A.B. Watts
Cambridge University Press
40 West 20th Street
New York, New York 10011 USA
2001. 478 pages. $110.00 (hardcover); $44.95 (softcover)
ISBN 0-521-62272-7

This book presents an overview of isostasy using a simplified mathematical treatment, numerous geological examples and an extensive bibliography. Tracing the ideas behind local and regional models of isostasy, the book describes the theoretical background and the observational evidence of flexure, and the constraints it has placed on the physical properties of the lithosphere. Also included is a discussion of flexure's role in understanding the evolution of the Earth's surface features and those of its neighboring planets.

Contents:

- The Development of the Concept of Isostasy
- Isostasy and Flexure of the Lithosphere
- Theory of Elastic Plates
- Geological Examples of the Flexure Model of Isostasy
- Isostatic Response Functions
- Isostasy and the Physical Nature of the Lithosphere
- Isostasy and the Origin of Geological Features in the Continents and Oceans
- Isostasy and the Terrestrial Planets
- References, Index

[The book] provides an excellent guide for those applying flexural isostasy to practical problems. It is also a starting point for those wishing to learn more about the actual physics of the Earth's lithosphere.

Sleep NH: *Physics Today* 55, no. 10 (October 2002): 57-59.

The Schlumberger *Oilfield Glossary*

Do you know what the Udden-Wentworth scale is? Or what a blowout preventer does? It's easy to find the answer on the Schlumberger Web site.

The Schlumberger *Oilfield Glossary* is a unique, multidisciplinary reference that defines hydrocarbon exploration, development and production terms for the technical generalist and expert alike. Technical experts review all definitions, from "abnormal events" to "Zoeppritz equations." High-quality, full-color photographs and illustrations clarify many definitions.

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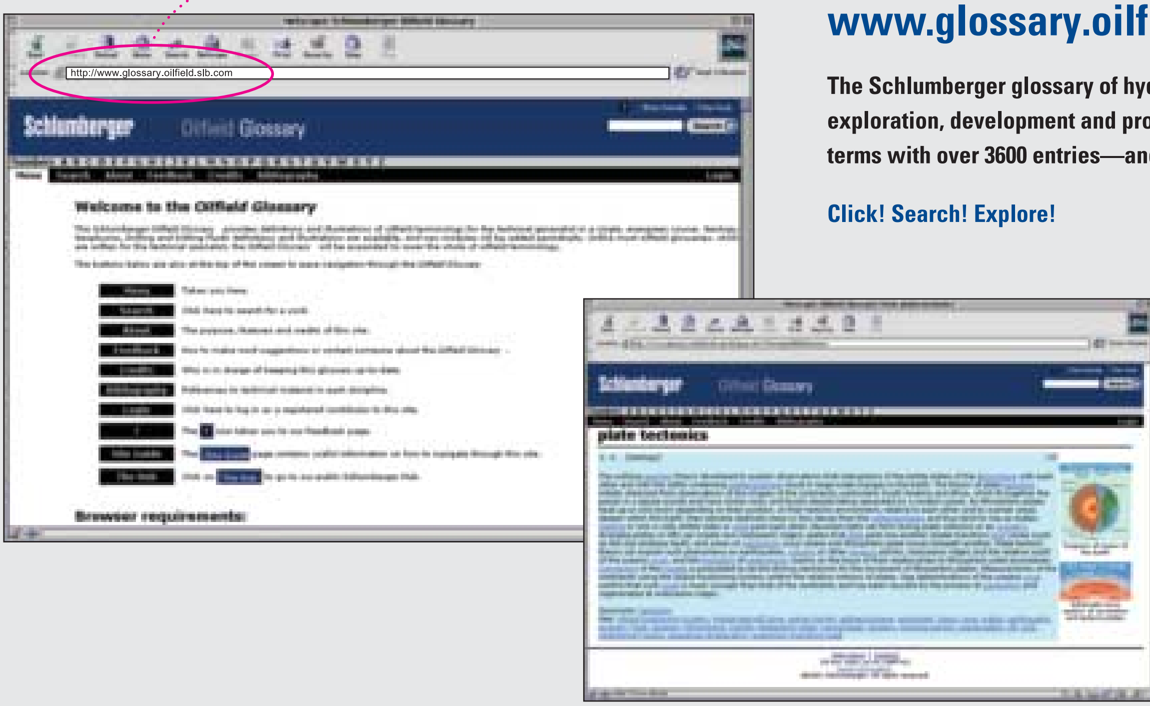

On the Web, go to:

www.glossary.oilfield.slb.com

The Schlumberger glossary of hydrocarbon exploration, development and production terms with over 3600 entries—and growing.

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