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Winter 2001/2002

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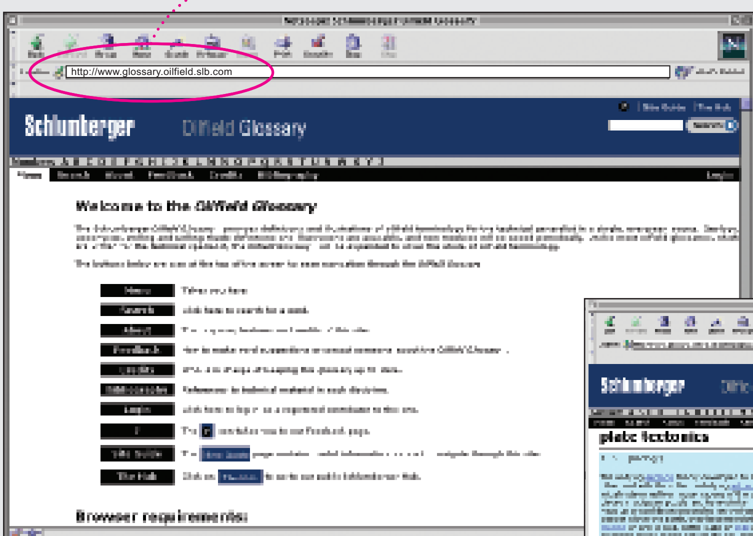

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Certain Technology in Uncertain Times

Our world and our industry are forever in a state of flux. Dynamic world economics and social and political unrest often disrupt the international community's efforts to coexist harmoniously. The geographic location of the world's largest hydrocarbon deposits, coupled with geopolitical volatility, present enormous supply and demand issues that hinder long-term stabilization of energy prices. What is certain, however, is that world demand for petroleum is expected to soar by 56%, or 43 million BOPD [6.8 million m^3/d], during the next two decades, due primarily to strong demand for power and transportation fuels. Predicting the future is impossible, so energy companies must continue to focus on efficient, cost-effective exploitation of their assets.

Our industry has always had a knack for adapting to global change and overcoming adversity by developing inventive new technologies. Over the last 10 to 15 years, creativity and technology have driven significant new exploration and production efforts. Advances in 3D seismic, drilling fluids, directional drilling, coiled tubing, logging and hydraulic fracturing—to name just a few—have had a monumental impact on the ability of both The El Paso Production Company and our industry to find, and economically optimize the production from, new reserves. Advances in one sector often lead to advances in others. Companies that adapt quickly to bring new technologies to the marketplace help themselves, spur industry success and deliver shareholder value.

In our quest for new reserves, we are drilling and fracturing in deeper and hotter environments. These stringent environments embody significant drilling and production challenges. Oil-base and synthetic-base muds help, but borehole evaluations can be daunting. In formation evaluation, borehole imaging has become an important part of the foundation that supports meaningful characterization of reservoirs, but the move to these nonconductive mud systems has undermined some of that foundation. Responding to our immediate needs, Schlumberger quickly developed an innovative tool to overcome the deficiencies of conventional imaging methods (see "A Clear Picture in Oil-Base Muds," *page 2*).

Coastal Oil & Gas, now El Paso, was the first company to use this new tool, and we have seen significant benefits in such areas as onshore South Texas, USA, and the Canadian Foothills. In these hostile environments, the device has already delivered greater structural detail and better fracture identification compared to previous methods, providing important information for petrophysical analyses and enhanced production techniques.

The use of elemental capture spectroscopy has also aided El Paso's efforts. This quantitative lithology interpretation is based on elemental concentrations available from logs. Along with elemental log analysis, it has led to improved evaluation of complex lithologies in most of our international wells, and in Texas as an integral part of fracturing treatment design. This technology has also been employed in our coal-bed methane ventures for more accurate, reliable measurement of coal content (thus total gas content), and for precise determination of coal-bed mineralogy, enabling an estimate of cleating—an important indicator of gas producibility.

Finally, all of these leading-edge, emerging technologies would be of diminished value if not delivered to an oil company in an expeditious manner. A real-time, seamless flow of data is critical. Many times, vital decisions are in the balance, and lost time means lost money. Unanticipated delays can adversely affect economics as daily spread rates in certain areas of our operations, such as offshore Gulf of Mexico, can approach $200,000. We live in an electronic world and rapid communications, information technology and the Internet are integral segments of our business (see "Lifelong Asset Management Using the Web," *page 42*). While we use remote communications software and the Web as a matter of routine, El Paso has gone one step further with the installation of a Schlumberger Dedicated Client Center, or DCC, three years ago. All of El Paso's data from more than 250 wells drilled annually are transmitted directly to the DCC for rapid distribution and petrophysical analyses.

Technology has enriched our industry. It is responsible for the influx of innovative exploration and production techniques, and contributes to improving exploration and development economics. Currently, we can do things in a matter of hours that previously would have taken days or weeks. What we are experiencing today was unimaginable five years ago. While we live and operate in fascinating times, we cannot rest on our technological laurels. Let us hope that our technological achievements thus far represent only the "tip of the iceberg" for the growth and future of our industry.

Rennie Décou

Rennie Décou
Manager of Geological Operations—Worldwide
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Rennie Décou is Manager of Geological Operations—Worldwide for The El Paso Production Company. He is from New Orleans, Louisiana, USA, where he received his geology degrees from Tulane University. He worked for The Louisiana Land & Exploration Company from 1969 to 1997, holding various management positions in exploration, acquisitions and operations during his career. Rennie joined the Coastal Corporation, now El Paso, in 1998 and directs their geological and geophysical operations worldwide.

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A Clear Picture in Oil-Base Muds

A new measurement device delivers high-quality borehole images in oil-base and synthetic-base drilling fluids. This unique technology fills a gap in formation-evaluation services and presents reservoir experts with a clear option to evaluate wells and fields more thoroughly.

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It is frustrating to be missing a single item or piece of information that might provide the key to accomplishing a task or solving a problem. That missing piece of the puzzle may seem small and insignificant, but often can make the difference between success and failure. Analogous to building a puzzle, but certainly more complex, are certain situations in hydrocarbon-reservoir characterization. Asset teams trying to build reservoir models often find that key information is missing. Geologists, geophysicists, petrophysicists and engineers may become frustrated when they are unable to extract the necessary detail from their formation-evaluation program, making difficult decisions more uncertain.

Today, microresistivity borehole-imaging tools are a common source of geologic and reservoir knowledge. However, in oil-base and synthetic-base drilling muds, a technical void prevented the industry from fully evaluating reservoirs using these tools. To address this growing need, imaging in nonconductive muds became a top priority of Schlumberger formation-evaluation research and development (R&D) in 1997.

Complicated reservoirs require detailed formation evaluation that is achievable only with borehole-imaging tools. In fields worldwide, data from these tools are analyzed routinely, and reservoir experts have come to depend on the information that imaging provides. While microresistivity-imaging technology has advanced over the past 15 years to include increased borehole coverage, improved resolution and more reliable measurement systems, the borehole environment in which these tools must operate also has changed.

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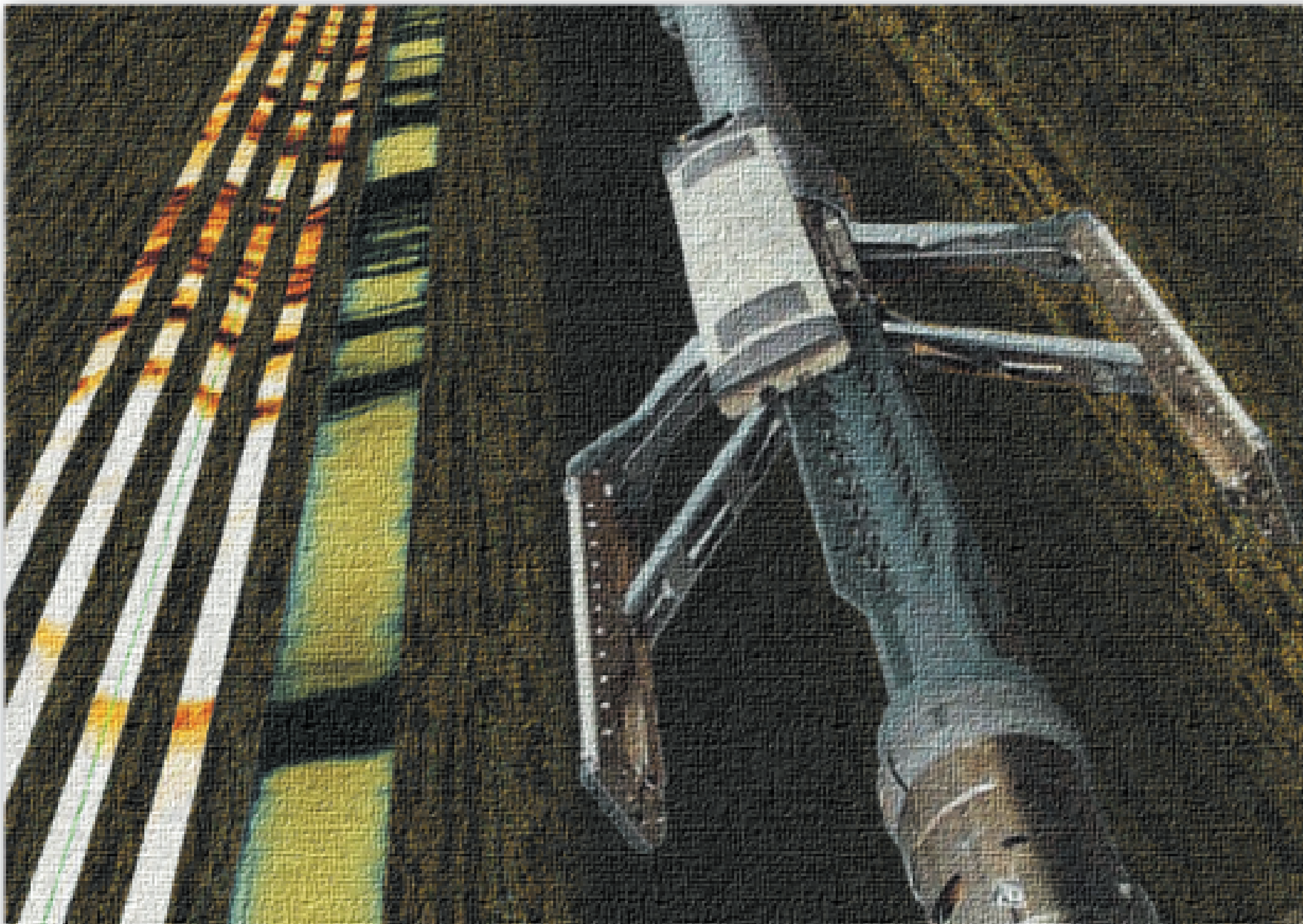
ADN (Azimuthal Density Neutron), ARI (Azimuthal Resistivity Imager), BorDip (automatic dip computation software), CMR (Combinable Magnetic Resonance), ECS (Elemental Capture Spectroscopy), ELAN (Elemental Log Analysis), Formation MicroScanner, FMI (Fullbore Formation MicroImager), GeoFrame (system software), GeoSteering (instrumented steerable positive displacement motor), GVR (GeoVISION Resistivity sub), MDT (Modular Formation Dynamics Tester), OBDT (Oil-Base Dipmeter Tool), OBMI (Oil-Base MicroImager), OFA (Optical Fluid Analyzer), RAB (Resistivity-at-the-Bit), StrucView (GeoFrame structural cross section software) and UBI (Ultrasonic Borehole Imager) are marks of Schlumberger. SIGMADRIL and SIGMADRIL II are marks of M-I L.L.C.. ELIAS is a mark of Bureau de Recherches Geologique et Minieres (BRGM) France. CAST and EMI are marks of Halliburton. CBIL and STAR are marks of Western Atlas.

1. 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.

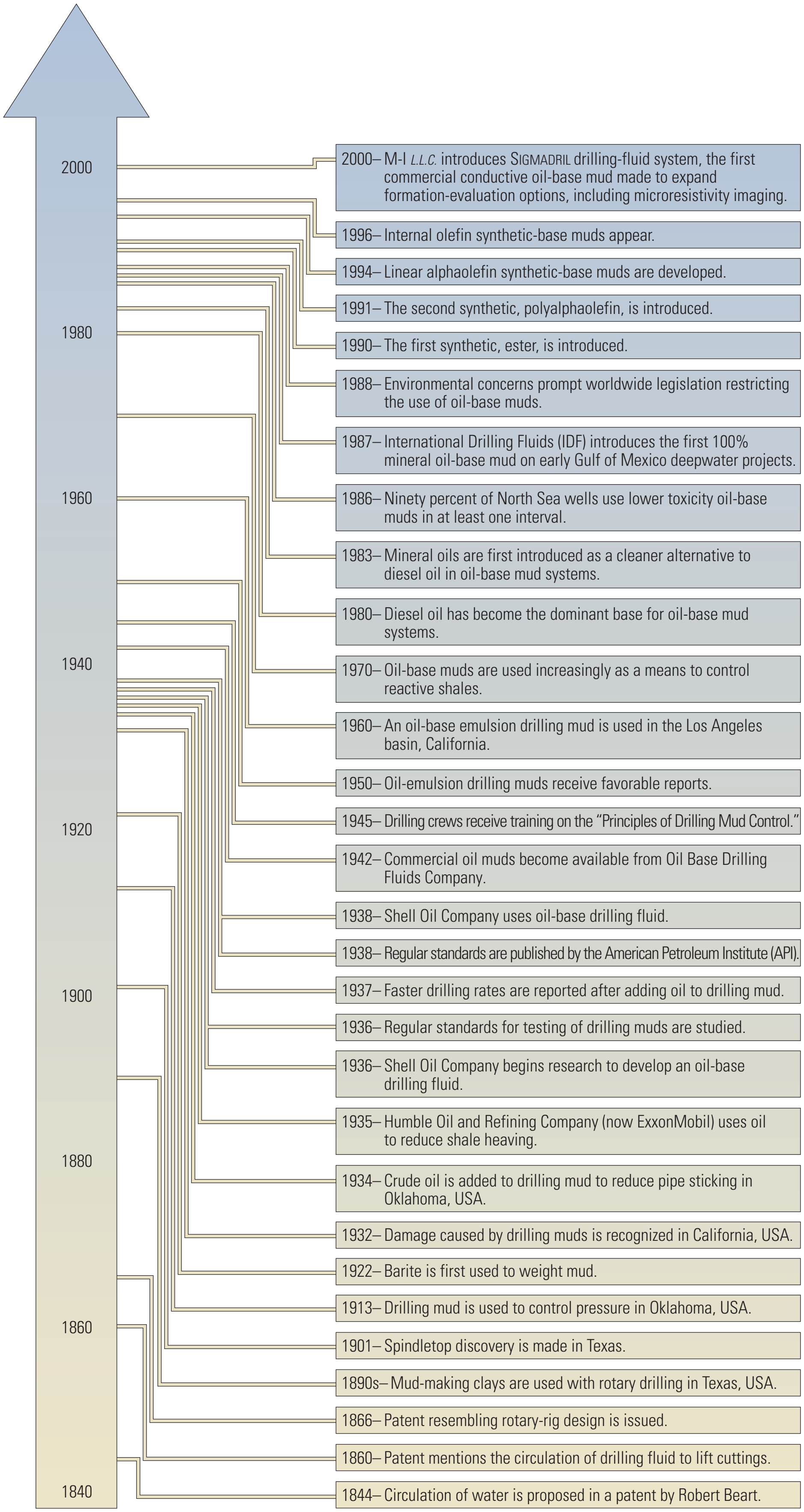


Advances in drilling-fluid technology have led to new and improved oil-base mud (OBM) and synthetic-base mud (SBM) formulations that are used in critical operations where costs and risks are high. This technological progression has decreased drilling risk and increased drilling efficiency, boosting the popularity of these mud systems.[1]

In many hydrocarbon basins, however, the evolution in drilling-fluid technology has complicated efforts to optimize logging programs and thereby obtain all the information needed to evaluate complex reservoirs. Nonconductive-borehole environments render conventional microresistivity-imaging devices ineffective, limiting wireline options for high-resolution geological measurements to ultrasonic devices and dipmeter tools. Unfortunately, the limitations of these tools restrict their usefulness.

A new wireline imaging device allows experts to see important details about reservoirs through nonconductive muds. The new device, the OBMI Oil-Base MicroImager tool, builds on proven methods in resistivity logging and incorporates a unique imaging pad to deliver the industry's first commercial microresistivity-imaging service for OBM- and SBM-filled boreholes.

In this article, we review factors leading to this recent breakthrough in borehole imaging, which are a combination of the timing of industry trends and the inventiveness and persistence of Schlumberger engineers, geologists and scientists. We explain how the new microresistivity tool operates in resistive-borehole environments and discuss tool limitations and interpretation considerations. Case histories demonstrate the usefulness of the new image data sets and interpretations, clarifying how this tool effectively provides crucial new information in formation evaluation.



^ Significant events in the development history of drilling fluids.

OBM and SBM History

Throughout the last half century, oil-base drilling fluids and borehole-imaging techniques have developed independently. The need for a more robust imaging tool in nonconductive mud environments grew from the advantages and increased use of such muds. Oil-base muds may have been used as early as the 1920s, much earlier than the first borehole-imaging tools.[2] By the next decade, the industry had begun to experiment more widely in the use of oil muds. In 1934, crude oil was added to drilling mud to reduce pipe sticking in Oklahoma (left). The following year, Humble Oil Company (now ExxonMobil) used oil in drilling mud to reduce shale sloughing and, in 1936, Shell Oil Company created a research program to develop an oil-base drilling fluid.[3] Reports of faster drilling rates attributed to the addition of oil to drilling muds surfaced in 1937.

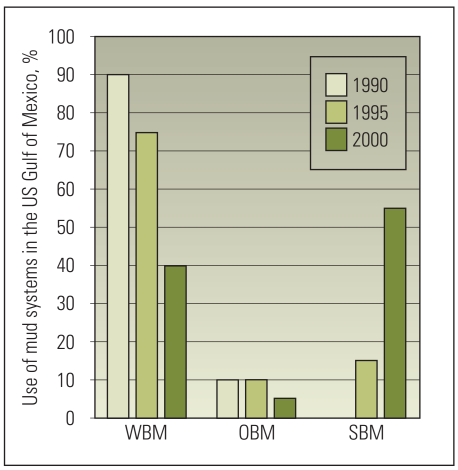
In 1950, OBMs were commercially available and by the 1960s, oil-base emulsion, or invert-emulsion, muds were used in the Los Angeles basin, California, USA.[4] The high water content of these muds—40% water emulsified in refined oil—made them less flammable and less expensive than more concentrated OBMs. Throughout the 1970s, use of OBMs became more extensive because they improved control while drilling in reactive shales. The unprecedented stability of oil muds allowed operators to push into extreme drilling environments—high-temperature, high-pressure and corrosive wellbores. For example, deep-gas drilling in the Canadian foothills encountered thick shale sections under tremendous stress. Water-base mud (WBM) systems reacted adversely with these shales, triggering hole cavings, but OBMs maintained borehole stability, allowing operators to advance the previous technical limits in this region.

Progress continued throughout the 1980s, as drilling-fluid additives were developed to address the industry's growing needs in increasingly demanding conditions. Widespread concern about the environmental impact of OBM spills and discharge of drill cuttings offshore prompted the introduction of low-toxicity mineral oils. By the late 1980s, the industry realized that the release of even mineral oil-base cuttings could have long-lasting environmental impact, leading to the first development of synthetic-base drilling fluids.[5] The first two synthetic fluids, esters and polyalphaolefins, were developed in 1990 and 1991, respectively. Linear alphaolefins appeared in 1994 and internal olefins in 1996. Since the first use of synthetic-base drilling fluids in the early 1990s, research has continued to focus on improving nontoxic systems.

This same decade also saw the dawn of deepwater drilling—prompted in the United States by the Deepwater Royalty Act of 1995.[6] As drilling advanced into deeper waters, the industry confronted new operational and environmental challenges. In some deepwater provinces, daily rig costs exceed $300,000 US, and total drilling costs eclipse $30 million for certain wells. Synthetic-base muds became crucial to drilling success because of their reduced environmental impact, decreased risks and improved efficiency. The last ten years have revealed a shift from water-base to oil- and synthetic-base drilling fluids in the Gulf of Mexico (below).

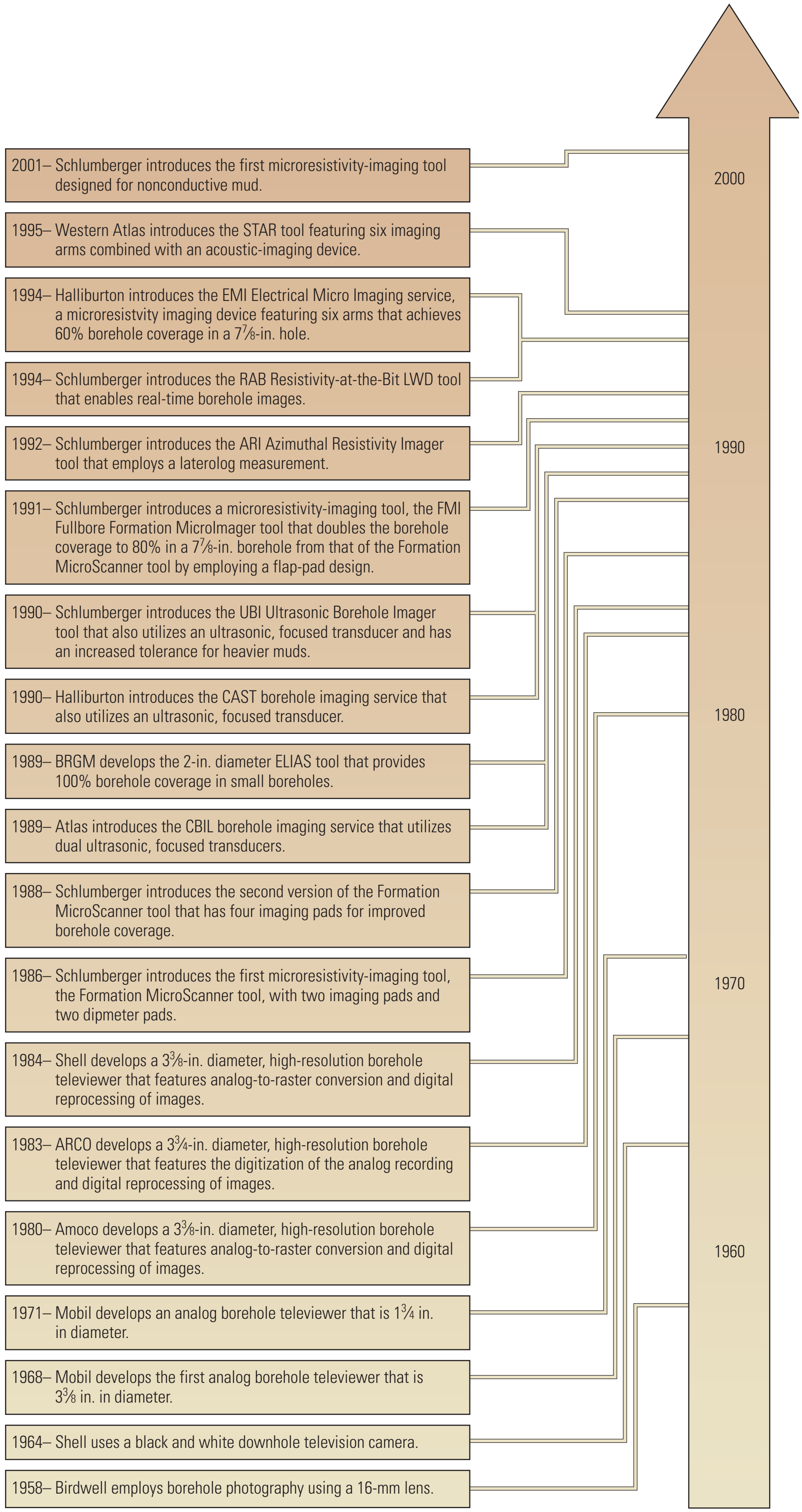
Borehole-Imaging History

Wireline borehole-imaging techniques were developed much later than the first OBMs. It was not until 1958 that photographic devices, deployed by Birdwell, were first used to get a glimpse of the rock within a wellbore (right).[7]



^ Growth of the US Gulf of Mexico synthetic-base mud (SBM) market in the last decade. Synthetic-base muds have replaced WBM and OBM systems in the US Gulf of Mexico after the use of oil-base mud systems waned in the late 1980s and because of the increased deepwater activity in the mid-1990s.

2. Lummus JL and Azar JJ: "Oil-Base Muds," in *Drilling Fluids Optimization, A Practical Field Approach*. Tulsa, Oklahoma, USA: PennWell Publishing Company (1986): 200–229.
3. Gray R and Darley HC: "Development of Drilling Fluids Technology," in *Composition and Properties of Oil Well Drilling Fluids*, 4th ed. Houston, Texas, USA: Gulf Publishing Company (1980): 63.
4. Gray and Darley, reference 3: 62–70.
5. Bloys et al, reference 1.
6. Baud R, Peterson R, Doyle C and Richardson GE: "Deepwater Gulf of Mexico: America's Emerging Frontier," *US Department of the Interior, Mineral Management Service, OCS Report MMS 2000-022*. (April 2000): 1–77.
7. For a comprehensive review of the evolution, methods, applications, limitations and guidelines of borehole imaging: Prensky SE: "Advances in Borehole Imaging Technology and Applications," in Lovell MA, Williamson G and Harvey PK (eds): *Borehole Imaging: Applications and Case Histories, Geological Society Special Publication No. 159*. London, England: Geological Society (1999): 1–43.

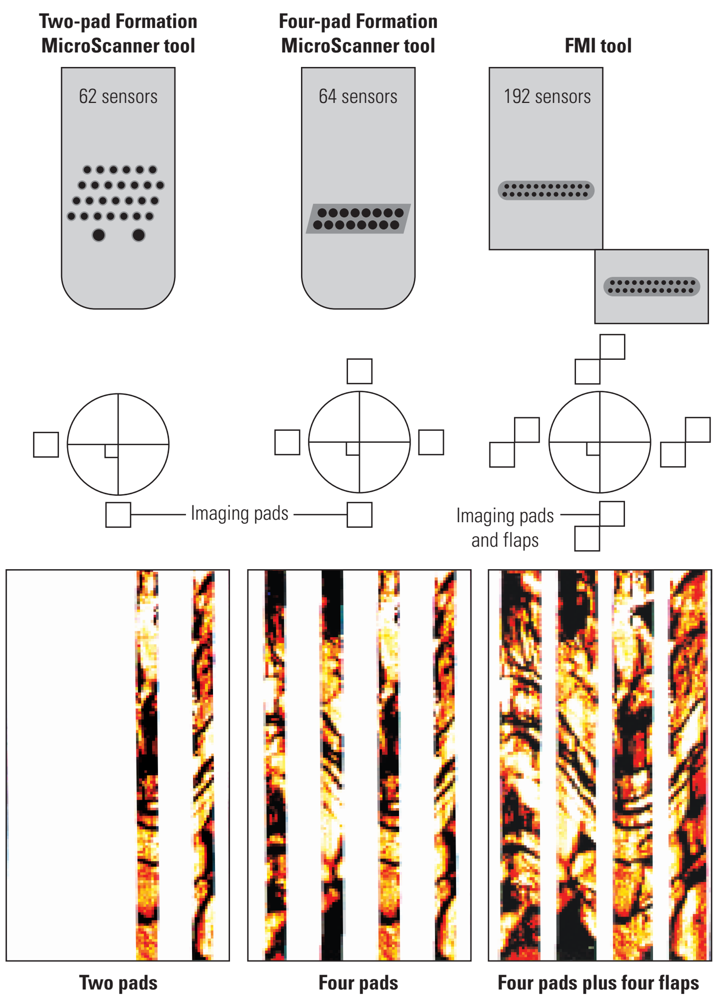


^ Significant events in the development of borehole imaging.

Later, in the 1960s, attempts to image the rock downhole shifted toward the use of television cameras. A significant breakthrough occurred in 1968, when Mobil developed the first high-frequency acoustic-imaging tool, the borehole televiewer. Unlike the optical devices before them, acoustic tools eliminated the need for transparent borehole fluid—clear water, gas or air—and greatly expanded the range of borehole-imaging applications. Efforts launched in the 1980s to make the data more usable resulted in improvements ranging from analog-to-digital conversion and reprocessing capability to digital tools with high-resolution, focused transducers—devices that function as both transmitter and receiver. However, acoustic-imaging devices are extremely sensitive to tool eccentering, borehole rugosity and mud density, and often are insensitive to formation bedding.

In 1986, Schlumberger broke new ground with the first microresistivity-imaging device, the Formation MicroScanner tool. This tool enabled geologists to observe and analyze formation bedding, fractures and secondary porosity on an image workstation and in greater detail than before. The initial tool included two imaging pads and two dipmeter pads, but could image only 20% of a 7⅞-in. borehole in one pass; multiple logging passes were necessary to achieve reasonable borehole coverage. In 1988, replacing the two dipmeter pads with two more imaging pads doubled the coverage of the original Formation MicroScanner tool.

The push for increased borehole coverage continued as operating companies wanted to see a larger percentage of the borehole in a single pass, especially when imaging high-risk wellbores, heterogeneous or fractured reservoirs or in complex carbonate rocks. The FMI Fullbore Formation MicroImager tool, equipped with four imaging pads and four imaging flaps, again doubled the coverage of a single logging pass in 1991. The FMI tool achieved 80% coverage in a 7⅞-in. borehole (below left).



^ Increased borehole coverage over time. As more image data are acquired from around the circumference of the borehole, a more comprehensive interpretation is possible. Schlumberger microresistivity-imaging devices have progressively added more sensors and pads to improve borehole coverage.

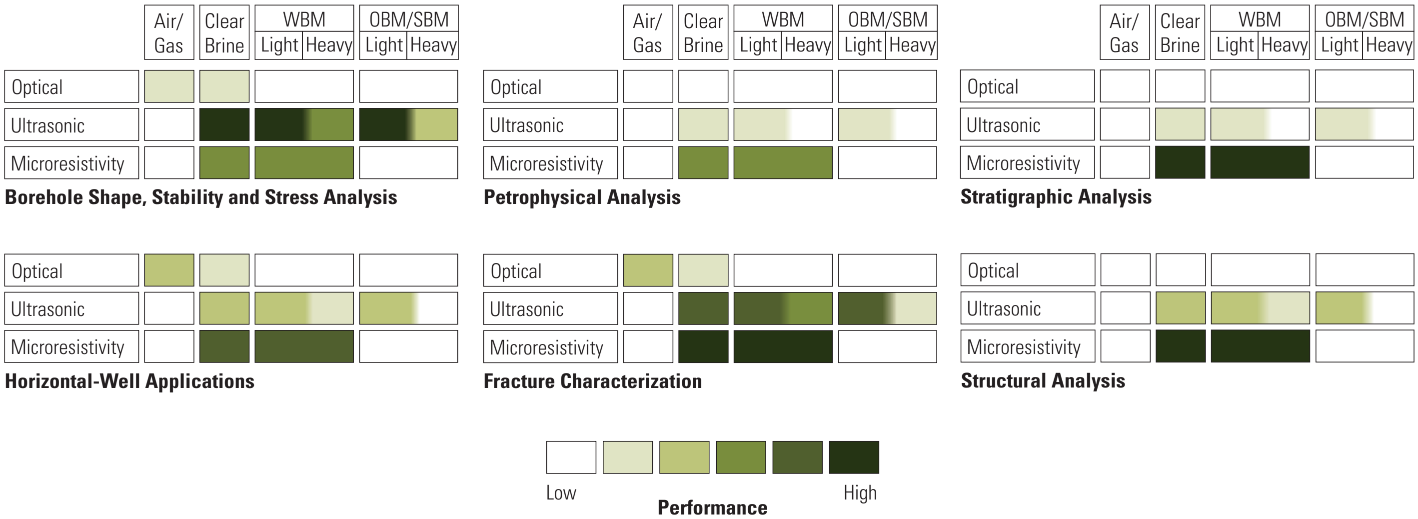
The quest for greater borehole coverage was not exclusive to Schlumberger. In 1989, Bureau de Recherches Geologique et Minieres (BRGM) developed the 2-in. diameter ELIAS, a 16-pad, microelectrical-imaging tool that achieved 100% borehole coverage in small boreholes. In the 1990s, both Halliburton and Western Atlas achieved 60% coverage in a 7⅞-in. borehole by employing six-arm designs—the Halliburton EMI Electrical Micro Imaging tool in 1994 and the Western Atlas STAR Simultaneous Acoustic and Resistivity imager tool in 1995. In addition to the microelectrical measurement, the Western Atlas tool included an acoustic-imaging sensor.

Other acoustic-imaging tools were introduced prior to 1995, including the Halliburton CAST Circumferential Acoustic Scanning Tool and the Schlumberger UBI Ultrasonic Borehole Imager tool. These acoustic tools have resolution specifications similar to some of the microresistivity devices, 100% borehole coverage and the potential to operate in OBM. Despite tremendous advancements, acoustic tools frequently do not assist in the analysis of formation bedding, which is critical to geologists trying to ascertain the structural dip or stratigraphy of a reservoir.

Borehole-Imaging Applications

The need to improve borehole-imaging capabilities in nonconductive muds came to the forefront in the mid-1990s. At that time, microresistivity-imaging services were employed worldwide in boreholes filled with conductive water-base muds. New geological and engineering applications for these wireline tools evolved with the industry's desire to more effectively find and exploit oil and gas reservoirs. The notable exception was wells drilled with OBM and SBM systems (next page, top).

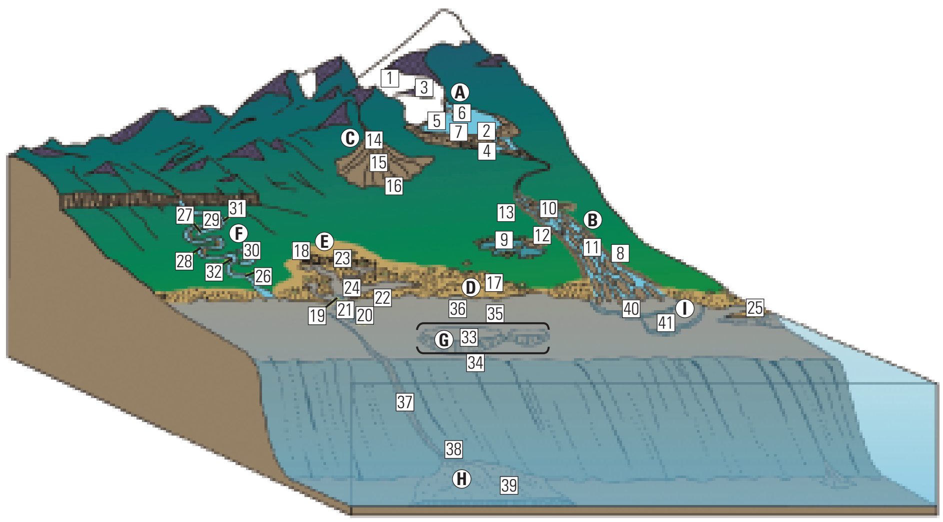
Microresistivity-imaging tools have become essential for geologists, helping them gain insight into the complexities of reservoirs that are stratigraphically controlled, structurally controlled or combinations of the two. At the largest spatial scale, borehole images help interpreters define the structural position of the reservoir and characterize features such as folds and faults. Geologists and geophysicists use formation dip and fault details to refine seismic interpretations for better understanding and mapping of the reservoir, more reliable reserve estimates and better development-well placement.



^ Wireline borehole-imaging techniques, applications and operating environments. Different borehole-imaging techniques demonstrate various levels of performance depending on the application and the operating environment. Microresistivity devices offer a wide range of applications in WBMs, while ultrasonic devices represent the only option for borehole imaging in OBMs and SBMs. A performance gap in OBM- and SBM-imaging technology exists, most notably in heavy muds.

Geologists assess vertical and lateral changes in the reservoir by identifying and characterizing large-scale depositional events and sequence-stratigraphic boundaries across fields. Using microresistivity-image data from devices like the FMI tool, they also define and determine the orientation of smaller depositional features to understand stratigraphically-controlled reservoirs.[8] A close examination of bedding reveals the depositional history in vertical successions of sediment types and grain sizes, helping to answer questions about the reservoir's origin (right). Was it deposited by the wind, in a freshwater system, a marine system or in a combination of environments? Was it deposited in deep or shallow water? In what direction was the depositional system prograding? In what direction should the reservoir thicken or thin? Answers to questions like these help geologists determine the potential size of the reservoir, the best drilling locations and whether additional wells are needed for efficient reservoir exploitation.

Frequently, there are reservoirs in which both stratigraphic and structural elements trap hydrocarbons. A common practice is to remove or delete the structural dip from the handpicked or computed dips to visualize the reservoir during sedimentation.[9] If the tectonic history of the



A. Glacial Environment
1. Ice sheet 2. End moraine 3. Nunatak 4. Delta 5. Medial moraine 6. Icebergs 7. Glaciomarine

B. Fluvial Environment–Braided System
8. Levee 9. Marsh 10. Longitudinal bar 11. Transverse bar 12. Crevasse splay 13. Flood plain

C. Alluvial Fan Environment
14. Proximal 15. Mid-fan 16. Distal

D. Eolian Environment
17. Beach ridge

E. Shallow Siliciclastic–Sea Environment
18. Tidal flats 19. Flood tidal delta 20. Ebb tidal delta 21. Main tidal channel 22. Barrier beach complex 23. Marsh 24. Lagoon 25. Barrier island

F. Fluvial Environment–Meandering System
26. Channel 27. Chute 28. Concave bank 29. Convex bank 30. Oxbow lake 31. Cut bank 32. Point bar

G. Shallow Water–Carbonate Environment
33. Reef 34. Fore reef 35. Back reef 36. Tidal channel

H. Deep-Sea Clastic Environment
37. Submarine canyon 38. Turbidity currents 39. Abyssal fan

I. Deltaic Environment
40. Actively prograding delta wedge 41. Abandoned wedge

^ Depositional environments. Microresistivity devices help define specific environments and identify their unique features. Understanding the relationship between wellbore-scale bedforms and the larger scale depositional environments is crucial when integrating the borehole-image interpretation into the reservoir-modeling process.

8. Depositional features observable on borehole images vary from current bedding to erosional surfaces and fill sequences.
   Serra O: "Information on Depositional Sedimentary Environments," in Serra O: *Sedimentary Environments from Wireline Logs*, 2nd ed. Sugar Land, Texas, USA: Schlumberger Educational Services (August 1989): 119–233.
9. Structural dips are usually taken from a constant and continuous section of deep-marine shale or low-energy bedding exhibiting planar laminations that were deposited horizontally.

rocks includes multiple episodes of deformation, an involved reconstruction may be necessary to determine the relative position of the reservoir at the time of its deposition.

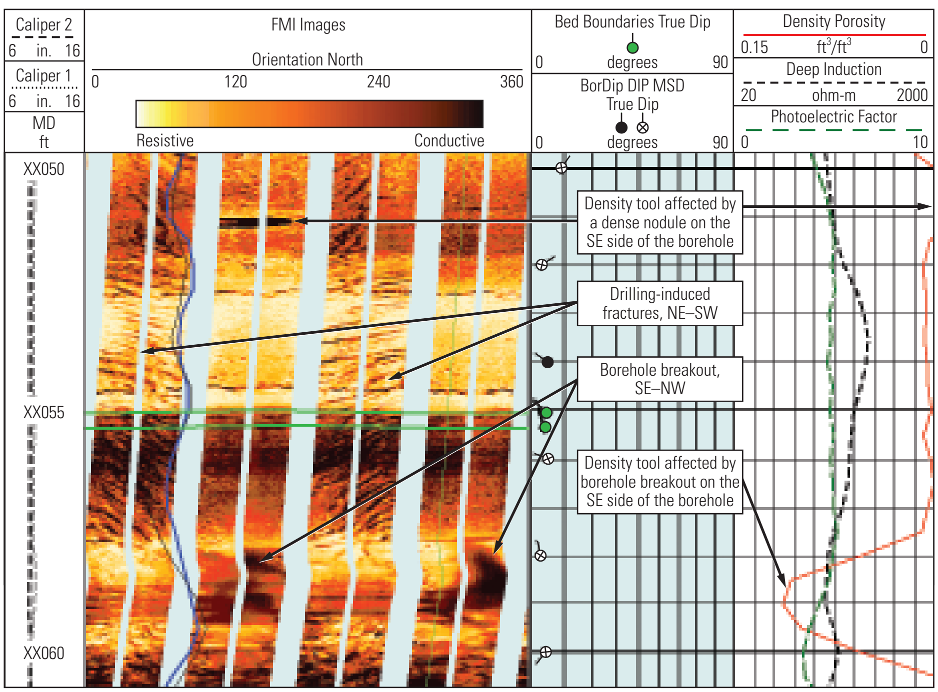
The superior vertical resolution of microresistivity-imaging tools helps petrophysicists answer difficult questions about porosity type and distribution, sand-clay distributions and the correlation and orientation of both fullbore and sidewall cores. In some cases, borehole images provide the details to resolve log-quality and log interpretation issues, such as the presence of drilling-induced fractures or laminated sands. In thin-bedded reservoirs, high-resolution borehole images enable petrophysicists and geologists to determine the distribution of high-quality, productive sand, also known as sand-count analysis. Sand-count accuracy is limited by the resolution of the measurement, but also is related to the thickness of the sand and shale layers. Thinner sand beds and shale laminations require higher resolution measurements to fully account for the amount of sand. This microresistivity technique has significantly improved the industry's ability to calculate total hydrocarbon reserves in thin-bedded reservoirs.

Borehole images give completion and reservoir engineers an opportunity to observe effects of in-situ stresses. Engineers frequently examine borehole breakout and mechanically-induced fractures created by the drilling process to determine stress directions (below). This analysis improves completion design and effectiveness—for example, orienting perforations before hydraulic fracturing.[10]

Induced fractures and borehole breakouts also indicate weak formation, potential lost-circulation zones and other wellbore-instability hazards that affect drilling and completion. Reservoir engineers model reservoir behavior more accurately when they know natural fracture trends, hydraulic fracture direction or a stratigraphic trend that may dictate a preferential permeability direction.[11] Reservoir engineers also need to know the structural details of a field because fluid contacts and reservoir compartmentalization directly affect field development.

Formation dip from borehole images allows the determination of true bed thickness, which is a critical input for field development and planning offset and kickoff wells.

Natural fractures commonly play a crucial role in oil and gas reservoirs. They can be the primary channeling mechanism allowing hydrocarbon or water migration to a wellbore and can be detected and characterized through borehole-imaging techniques. In many regions, microresistivity-imaging devices are used to assess whether natural fractures are open, allowing fluid flow, or healed by mineralization, thereby restricting fluid flow. Schlumberger developed a quantitative method to calculate the aperture or width of open fractures from FMI or Formation MicroScanner data.[12]



^ Using FMI images to determine stress directions and to help explain log response. The drilling-induced fractures are observed on the northeast and southwest side of the borehole and are oriented parallel to the maximum in-situ stress direction. The borehole-breakout direction confirms the stress direction and is oriented perpendicular to maximize in-situ stress direction. Frequently, borehole images provide the only means of determining why certain log responses occur. In this case, the density tool is responding to a high-density nodule at XX051 ft and borehole breakout at XX059 ft. Both are located on the southeast side of the wellbore.

Frequently, this fracture-aperture information is comparable to production results and offers an effective way to judge the productive potential of a fractured reservoir.

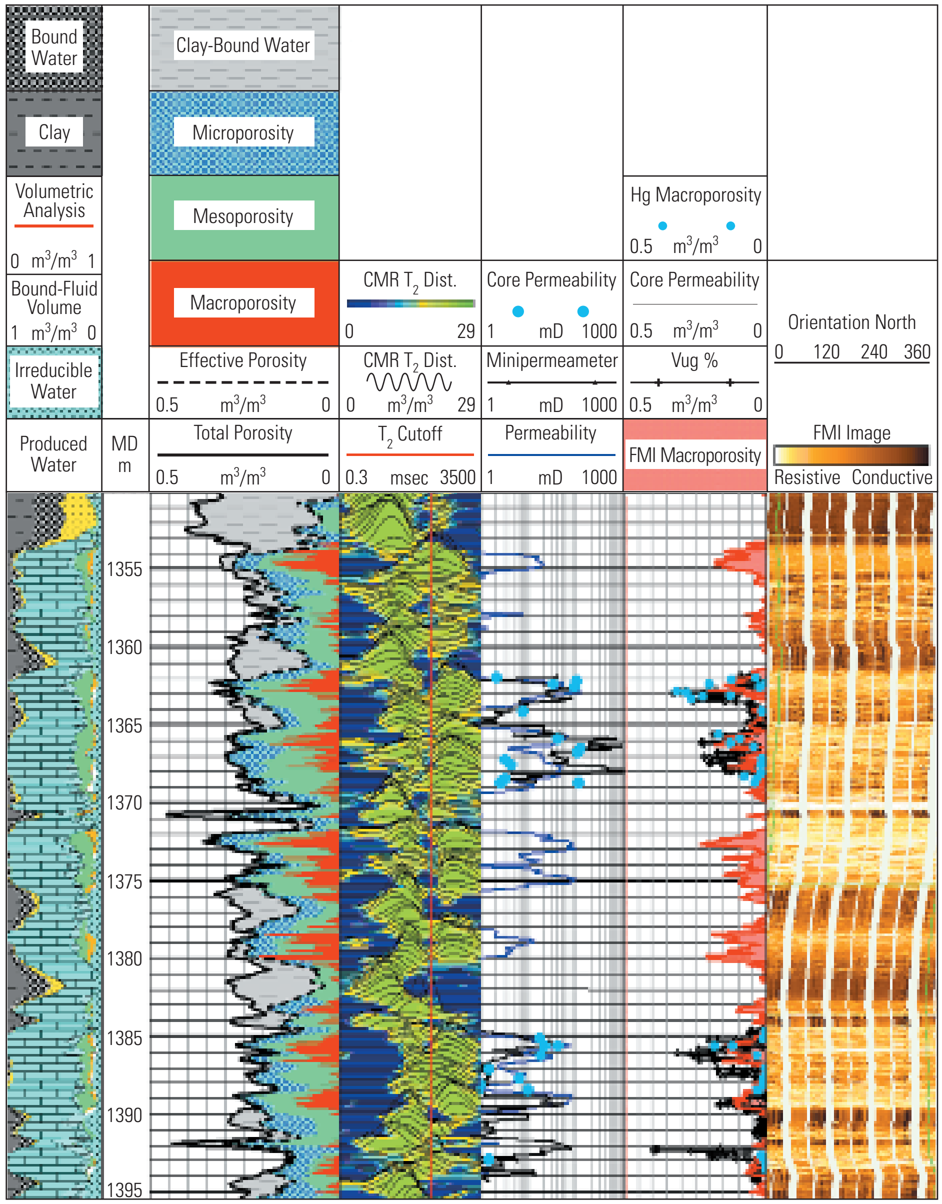
At a smaller scale, microresistivity-imaging tools reveal rock textures and porosity types, helping to identify and correlate both clastic and carbonate facies. These interpretations are most reliable when integrated with fullbore-core analysis. Borehole-imaging services include the highest resolution measurements that can be made on wireline today and are used frequently in combination with other tools—such as the Schlumberger CMR Combinable Magnetic Resonance and ECS Elemental Capture Spectroscopy tools and ELAN Elemental Log Analysis software—to evaluate reservoir complexities (right).[13] These complexities are challenging, especially in porosity systems of carbonate reservoirs because of the extensive diagenetic changes that occur after deposition.

Their tremendous versatility has made microresistivity-imaging devices a fundamental part of detailed formation evaluation in conductive borehole environments. Reservoir experts in many disciplines use microresistivity borehole images to better understand the behavior of a reservoir, from its largest to smallest scale, and from its distant past to its production future.

Borehole Imaging While Drilling

A discussion of modern borehole-imaging techniques would be incomplete without mentioning the impact of logging-while-drilling (LWD) imaging methods. Acquiring real-time image data has major advantages when combined with GeoSteering motor and real-time borehole-stability control. Timely access to information improves the quality of critical decisions made during drilling operations.

A great range of tool sizes and modular designs adds flexibility and reduces nonproductive rig time, making LWD tool use widespread today. LWD measurement sensors are placed close to the bit, providing immediate information to drillers and geologists. For example, in conductive muds, the RAB Resistivity-at-the-Bit tool allows operating companies to select casing and coring points immediately. The GVR GeoVISION Resistivity sub measures an azimuthal resistivity using 1-in. button sensors integrated into the tool collar. Borehole images are computed



^ A comprehensive analysis of a carbonate reservoir offshore western India. When FMI images are combined with CMR, ECS, core data and an ELAN analysis, a more accurate description of carbonate reservoirs is the result. ECS data are the main input to produce a detailed lithology description and a bound-water fraction (Track 1). CMR data are used to distinguish irreducible from mobile water that is associated with the smaller pore sizes (Track 2). Track 3 displays the T_2 distributions from the CMR log. Track 4 compares the ELAN-generated permeability (blue curve) with the measured core permeabilities, both from core-plugs (light blue dots) and a 1-cm sampling of the core-slab using a minipermeameter. The FMI data are used to assess the larger pore geometries. Track 5 shows a comparison of macroporosity computed from the FMI data (shown in Track 6) and core methods, including core plug mercury-injection and core slab vugular-porosity measurements.

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12. This method requires the image data to be calibrated to a shallow-resistivity measurement. For a more detailed review of this technique: Luthi S and Soulhaité P: "Fracture Apertures from Electrical Borehole Scans," *Geophysics* 55, no. 7 (July 1990): 821–833.
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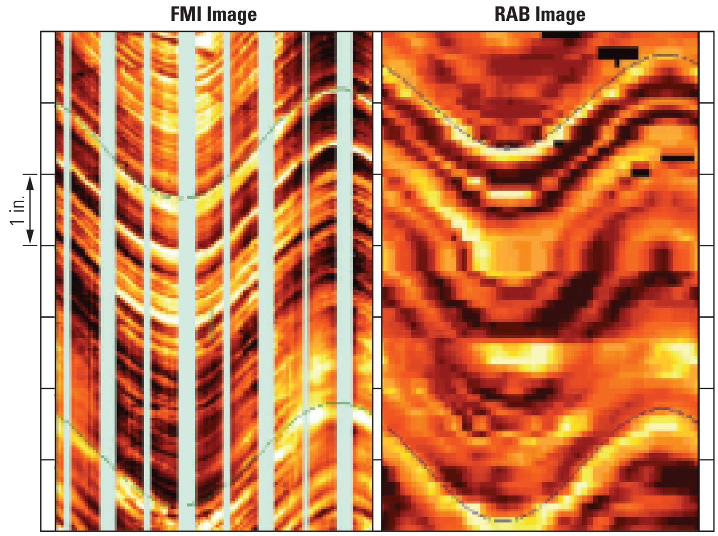


^ RAB images compared with FMI images. RAB images *(right)* identify formation bedding needed for the determination of structural dip. The FMI image *(left)* delineates the very fine bedding as well as fine fracturing (top of image).

and provide data on formation bedding and natural fracturing (above). Real-time knowledge of the geology and the location of the bit with respect to the reservoir allow precision steering of the bit, useful in highly deviated and horizontal wells. Imaging the formation through troublesome zones also gives drillers and engineers the opportunity to mitigate borehole-stability problems by examining geomechanical data and identifying failure modes.

Another LWD imaging device, the Schlumberger ADN Azimuthal Density Neutron tool, can be used in both conductive and nonconductive muds and assists in the examination of thin beds, formation porosity, lithologic heterogeneity, uneven filtrate invasion and fluid contacts. LWD imaging devices have proven beneficial to drillers as they negotiate complex drilling situations with increasingly aggressive well plans.

100% Coverage?

As oil- and synthetic-base drilling fluids developed and their uses spread, technical barriers to running microresistivity devices in these muds appeared insurmountable. In these muds, an insulating layer of resistive mud or mudcake separates the microresistivity electrodes from the formation wall, preventing the pads from imaging the formation. The complexity of deepwater drilling brought new focus to joining these technologies.

Deepwater drilling operations require stable, environmentally friendly drilling-mud systems—demands addressed by synthetic-base mud systems. Unable to image the formation using microresistivity devices, companies were forced to use alternative methods, including fullbore coring, acoustic-imaging devices and oil-base dipmeter tools to evaluate reservoirs. These alternative methods can increase costs and may still result in missing, marginal or unusable data.

Fullbore coring is time-consuming and expensive, and can significantly complicate drilling operations. High rig costs compound the effects in deepwater operations. Often, operators minimize the length of cored intervals, and partial core recovery is common. In highly fractured intervals, poor recovery and jammed core barrels are routine. When coring is successful, it is an excellent way to examine the reservoir rock's petrophysical and mineralogical properties. However, fullbore cores are rarely oriented and therefore have limited use for structural and stratigraphic dip determination.

High-frequency acoustic-imaging devices have been used successfully for natural fracture identification, borehole geometry information and in-situ stress analysis. Traveltime and amplitude are the key measurements derived from a high-frequency acoustic pulse fired from a transducer, reflected off the borehole wall and then received back at the transducer.[14] Traveltime and amplitude measurements are affected by drilling-fluid density and solids content, borehole size and tool eccentering.

Acoustic images are dominated by surface texture and rugosity effects, allowing observation of open fractures and vugs, breakouts and drilling-related features. Different textures or acoustic impedances can indicate bed boundaries. Formation bedding is most readily observable in smooth boreholes and hard rocks.

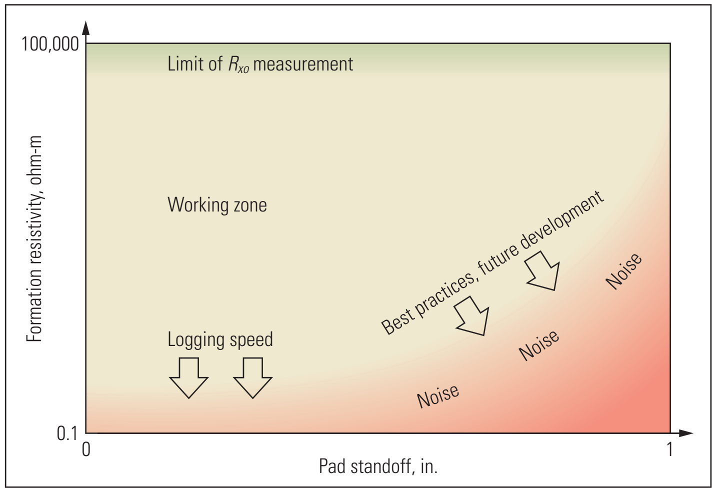
Today, the most common source of dip information in OBM- and SBM-filled boreholes is from oil-base dipmeter tools. The OBDT Oil-Base Dipmeter Tool sonde, for example, uses four microinduction sensors to measure variations in formation conductivity. Ideally, dipmeter processing provides computed dips for quick determination of structural dip and for locating and orienting significant structural events. OBDT processing often does not provide a sufficient number of accurate dips because the borehole environment adversely affects the measurement. Usually, visual examination and interpretation of the OBDT data are necessary to manually extract dip information from OBM-drilled wellbores in the Gulf of Mexico.

The practice of displacing OBMs and SBMs with conductive water-base muds prior to logging for microresistivity images has been used with limited success. However, because changing muds increases the risk of borehole instability, other solutions were required.

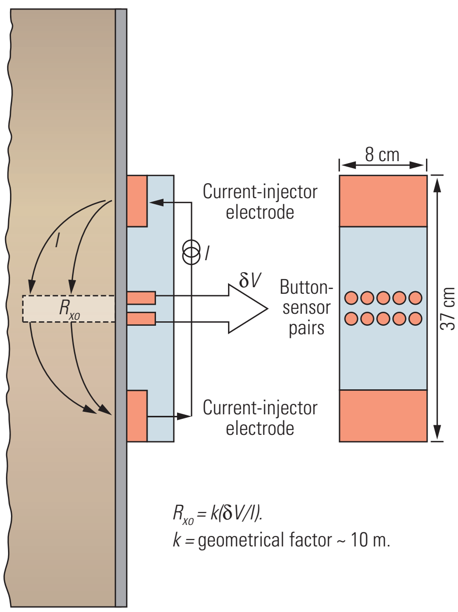
Seeing Through the Resistive Darkness

The capacity of a microresistivity-imaging device to electrically image features on a borehole wall is analogous to the ability of the eye to see. To function, the human eye needs some minimum transparency in the surrounding medium for light to reach it from an object. To operate effectively, microresistivity-imaging tools require some minimum conductivity—measured in siemens per meter (S/m)—in the surrounding medium so that current can flow in and out of the imaging sensors. In nonconductive boreholes, attempting to image using standard microresistivity devices is much like trying to see through darkened glass. Just as reduced light transmittance obscures vision, low conductivity makes microresistivity imaging difficult.

A typical water-base mud is one million times more conductive than an average OBM—10 S/m versus 10 microsiemens per meter (µS/m), respectively—making the task of measuring microresistivity in oil-base drilling fluids a daunting challenge.



^ OBMI tool operating envelope. The approximate OBMI operating envelope is described in terms of flushed-zone resistivity (R_{xo}) and standoff at the pad. At resistivities below 1 ohm-m, the measured signal is always small and therefore susceptible to noise, which may be reduced by logging in a slower mode (900 ft/hr or 1800 ft/hr [274 m/hr or 549 m/hr]). Pad standoff also diminishes the signal while simultaneously introducing systematic noise that cannot be helped by slower logging. The limit of accuracy for the R_{xo} measurement is found over 10,000 ohm-m, though the images are still useful for structural interpretation in this range. Ongoing engineering development and the application of a set of best practices during logging and drilling operations aim to increase the performance in marginal conditions.



^ Schematic diagram of the OBMI pad against the borehole wall in side-view *(left)* and in front-view *(right)*. An alternating current, I, is injected into the formation between two current-injector electrodes located above and below five pairs of small button sensors. A potential difference, δV, is measured between the button sensors in each pair. For each pair of sensor buttons, a flushed-zone resistivity, R_{xo}, is derived from the measured δV, a known I and the tool geometrical factor, k, and can be described in the equation $R_{xo}=k(\delta V/I)$.

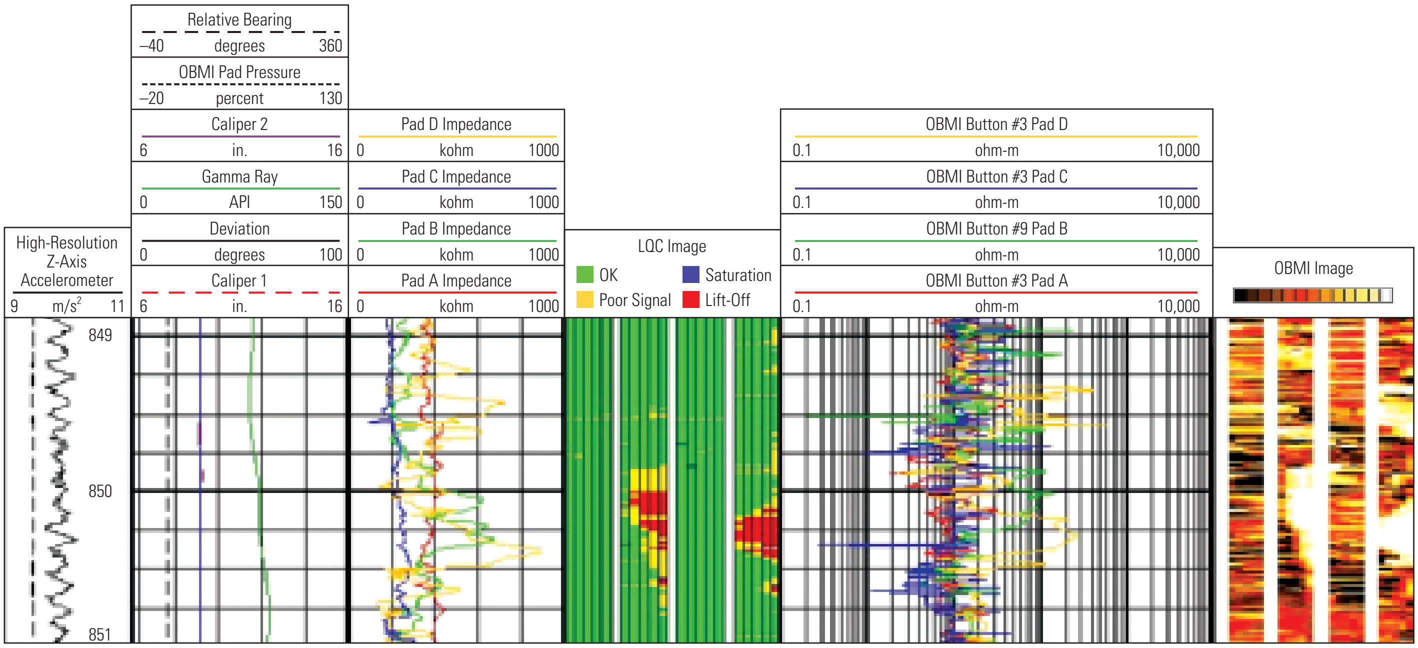
Just as advances in optical technology provide light amplification in diminished light to enable night vision, the solution to the OBM challenge also required a novel approach. Schlumberger scientists and engineers developed an innovative technique based on the proven principles of resistivity logging, producing the OBMI Oil-Base MicroImager tool.

The new tool employs the four-terminal method for measuring resistivity. On each of the tool's four imaging pads, an alternating current, I, is injected into the formation between two current-injector electrodes located above and below five pairs of small button sensors. A potential difference, δV, is measured between the button sensors in each pair. For each pair of sensor buttons, a flushed-zone resistivity, R_{xo}, is derived from the measured δV, a known I and the geometrical factor, k, and can be described by the equation $R_{xo}= k(\delta V/I)$ (left).

In nonconductive muds, the electrical-contact points between the imaging pads—specifically the current electrodes and button sensors—and the borehole wall are points of high impedance. This contact impedance originates at the thin layers of highly resistive mud and mudcake between the pad and the formation. What starts out as a potential difference of hundreds of volts at the injector electrode diminishes to only a fraction of a millivolt at the button sensors. Making this subtle measurement while simultaneously generating the required high voltages proved to be a difficult technical obstacle. The OBMI tool-development team successfully designed and implemented a unique imaging pad and associated electronics to clear this hurdle.

High-quality images are now acquired in nonconductive muds over a wide range of R_{xo} values—0.2 to over 10,000 ohm-m—when the standoff between the formation and the imaging pads remains within certain bounds.[15] Mathematical modeling, laboratory experiments and the OBMI tool field test helped define the tool's sensitivity to standoff (above). Sensitivity to standoff increases as R_{xo} decreases and secondarily as the resistivity of the mud, R_m, increases. In a typical nonconductive mud, for example,

14. The Schlumberger UBI tool operates on two frequencies: 250 kHz or 500 kHz. The lower frequency of 250 kHz has greater penetration through heavy muds, a lower resolution, and is used for imaging in heavy muds.
15. Standoff is defined as the distance between the external surface of a logging-tool sensor and the borehole wall.



^ OBMI log quality control. The OBMI log quality-control (LQC) display identifies intervals where the data may be compromised. From left to right: In the depth track, the accelerometer curve shows tool sticking. In Track 1, the caliper curve shows hole rugosity, and the pad-pressure curve indicates the logging engineer should reduce tool sticking by lowering pad pressure or improve pad contact by increasing pad pressure. In Track 2, the injector impedance indicates pad standoff from all four pads. In Track 3, a color-coded LQC shading is shown for each pad. Green coding indicates the proper amount of standoff, yellow coding for a small amount of standoff, resulting in a poor signal, and red coding for excessive standoff present or pad lift-off. Track 4 presents the resistivity from one button on each pad, and Track 5 displays the OBMI image.

where R_{xo} equals 10 ohm-m, a standoff of 0.5 in. [1.3 cm] may start to degrade image quality, but if R_{xo} is less than 1 ohm-m, degradation may occur at a standoff of 0.25 in. [0.64 cm].[16] Excessive pad standoff from rugose hole or poor pad contact appears on the images as areas of high resistivity and is displayed as white. Anomalous readings from too much standoff are detected by the tool's software and indicated on a log-quality display presented with the images (above).

The five button-sensor pairs on each of the four OBMI pads yield five pixels per imaging pad. The pixel size is equal to the spacing between button sensors in each pair, in this case, a 0.4-in. by 0.4-in. [1.0-cm^2] pixel. The vertical resolution of the tool is 1.2 in. [3.0 cm] and is defined as the thinnest bed whose thickness can be measured. The OBMI tool responds to beds and features smaller than 1.2 in. but cannot accurately determine their thickness (next page). The 1.2-in. vertical resolution of the OBMI tool falls between that of the FMI tool and that of the RAB tool resolution.[17] The OBMI tool, however, is the only microresistivity-imaging device available for nonconductive muds.

The new tool also provides high-resolution quantitative R_{xo} data with a maximum error of 20% in zones greater than 10 in. [25 cm] thick and where R_{xo} ranges from 1 ohm-m to 10,000 ohm-m. Beyond this resistivity range, the images can still be useful in showing the correct geometry and relative contrast of objects, but the resistivity measurement becomes less reliable.[18]

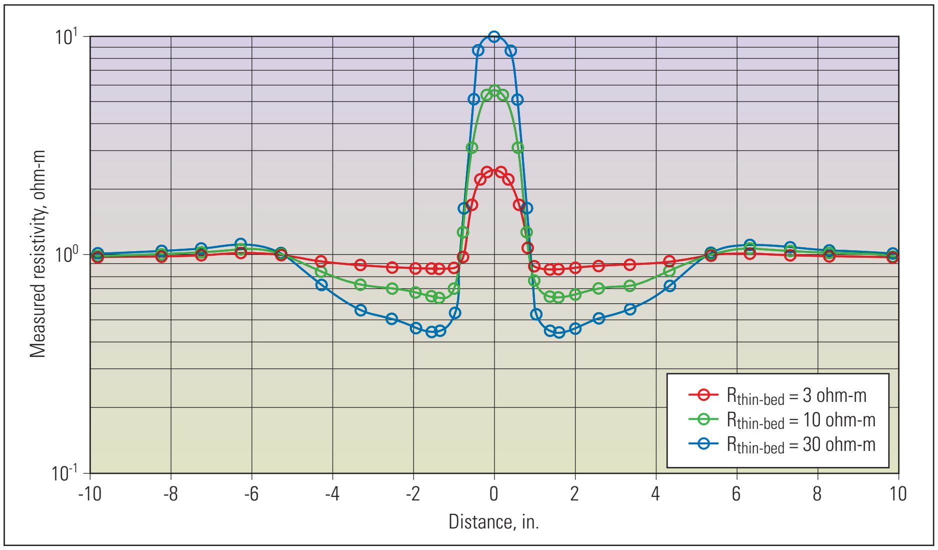
At sharp bed boundaries, OBMI results can suffer from shoulder-bed effects and distortions—as do laterologs and conventional microresistivity imagers, but for reasons arising from different measurement principles.[19] The severity of the distortion depends on the bed thickness, resistivity contrast between the imaged thin bed and the shoulder beds and on whether the thin bed is more resistive or more conductive than the shoulder beds. In the case of a 1.2-in. thin bed surrounded by two equivalent shoulder beds, a low thin-bed to shoulder-bed resistivity contrast of 3:1 or 1:3 produces an R_{xo} of good quality. At higher thin-bed to shoulder-bed resistivity contrasts—10:1 and above—distortions are observed, affecting the measured R_{xo} for both the thin bed and the shoulder beds. These effects occur up to 10 in. away from the thin bed because the injector-electrode spacing is 10 in. Where the thin bed is conductive and the shoulder beds are resistive, the higher contrasts generate less distortion than where the thin bed is more resistive than the shoulder beds (next page). Even though distortion can affect the measured thickness of thin beds and introduce small errors into thin-bed analysis, the OBMI tool has emerged as the most accurate wireline method to calculate a total sand count in nonconductive muds.

A Matter of Interpretation

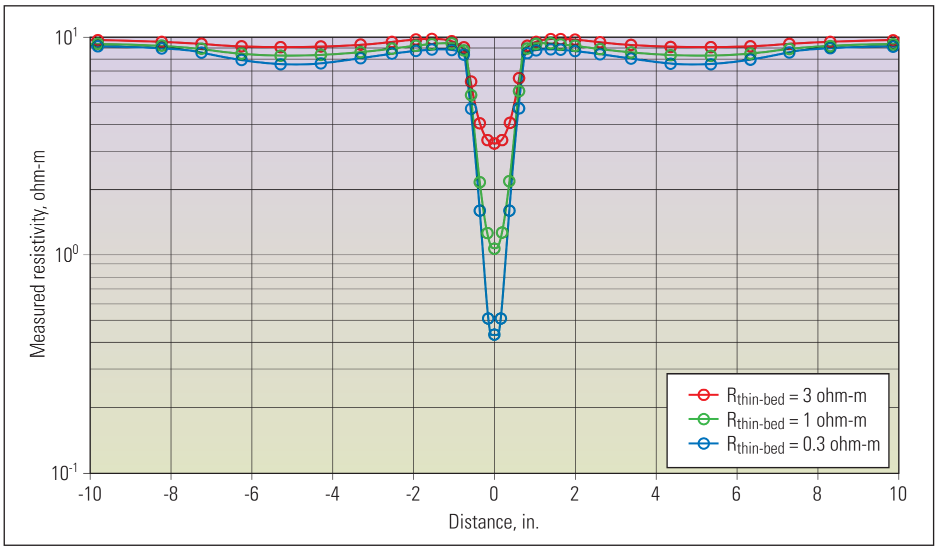
The OBMI tool produces the image resolution needed for detailed structural analysis. Large- to medium-scale stratigraphic analysis is also possible, characterizing thicker, more continuous bedding packages that represent deposition in a variety of environments.[20] However, the tool's ability to provide the detail required to fully interpret small features on or near the borehole wall depends on the size of the object. For example, a concretion imaged by an OBMI tool would have to be at least 1.2 in. in diameter for an accurate size assessment.[21] Smaller features, such as fine bedding and small-scale ripple laminations might be undetected.[22]

The OBMI tool sees fractures and allows their orientation to be determined. However, because the measurement is taken in nonconductive muds, several factors affect fracture analysis. As

Response to a 1.2-inch Bed—R_t Background = 1 ohm-m



Response to a 1.2-inch Bed—R_t Background = 10 ohm-m



^ Modeled response of the OBMI tool across a 1.2-in. thin bed. The OBMI tool response is shown for three different thin-bed resistivities when the shoulder-bed resistivity is 1 ohm-m *(top)*. The bottom graph shows the OBMI tool response for three different thin-bed resistivities when the shoulder-bed resistivity is 10 ohm-m. The graphs show some distortion in the OBMI tool response away from the thin bed. These shoulder-bed effects can be observed at a distance equal to the injector-electrode spacing, or 10 in. away from the thin bed.

with other microresistivity-imaging devices, the OBMI resistivity measurements are displayed as an image using lighter colors for higher resistivities and darker colors for lower resistivities. In conductive muds, an open, mud-filled fracture is conductive and appears dark while a healed fracture, more commonly filled with resistive mineral than conductive minerals, would appear light. However, an open fracture filled with nonconductive mud is resistive and appears white, making it difficult to differentiate open fractures from healed fractures. Although less common, fractures that appear dark on OBMI images indicate that conductive minerals—clays or pyrite for example—are present. Those fractures have been interpreted as inactive and lacking fluid flow. Additionally, standard microresistivity-imaging devices in conductive borehole fluids detect conductive fractures in resistive formations without difficulty. The opposite is true when imaging with the OBMI tool in nonconductive fluids, where fractures, both natural and induced, are identified more readily in conductive formations like shale.

Wells targeting the fractured carbonate reservoirs in the deep Anadarko basin of Oklahoma, USA, penetrate a harsh environment for acquiring even the most basic log data. Oil-base muds, used for the added drilling efficiency, made this location especially inhospitable for attempts to image the formation. The OBMI tool was run in a Hunton and Sycamore Limestone well to determine structural dip and identify structural features and natural fractures. An extensively fractured interval was identified in the Hunton section and the orientations of the main fracture trends were determined. Because both open and mineralized fractures are resistive in OBMs and SBMs, other methods, including other log data, helped interpret the Hunton fractures to be calcite-filled.

16. 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.
17. Cannon D and Kienitz C: "Interpretation of Asymmetrically Invaded Formations with Azimuthal and Radial LWD Data," *Transactions of the SPWLA 40th Annual Logging Symposium*, Oslo, Norway, May 30-June 3, 1999, paper G.

    Cryer J, Ford G, Grether B, Hartner J and Waters D: "Dip Interpretation from Resistivity at Bit Images (RAB) Provides a New and Efficient Method for Evaluating Structurally Complex Areas in the Cook Inlet, Alaska," paper SPE 54611, presented at the 1999 SPE Western Regional Meeting, Anchorage, Alaska, USA, May 26-28, 1999.

    Bonner S, Bagersh A, Clark B, Dajee G, Dennison M, Hall JS, Jundt J, Lovell J, Rosthal R and Allen D: "A New Generation of Electrode Resistivity Measurements for Formation Evaluation While Drilling," *Transactions of the SPWLA 35th Annual Logging Symposium*, Tulsa, Oklahoma, USA, June19-22, 1994, paper OO.
18. Cheung et al, reference 16.
19. A shoulder bed is a formation layer above or below the layer being measured by a logging tool. The term is used in resistivity logging to describe the layers above and below a reservoir. The term is more commonly used for vertical wells, and is derived from the typical picture of resistivity-log response across a reservoir—a high-resistivity reservoir (the head) with two low-resistivity shales above and below (the shoulders). The term also may be used in horizontal wells, although in that context the term surrounding bed is more common. The term adjacent bed is used in both cases.
20. For a general overview of sedimentary environments: Serra, reference 8.

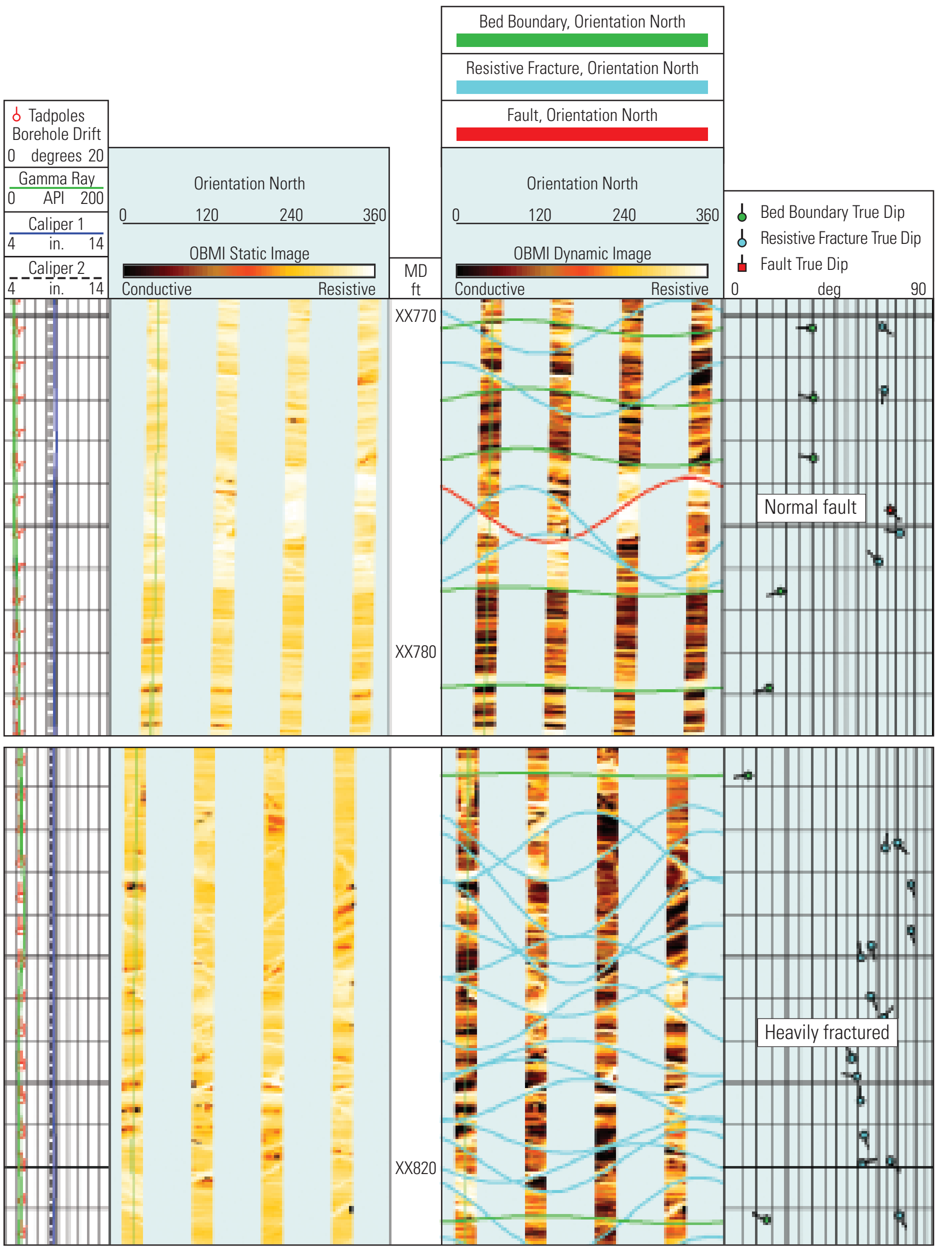
    For a more detailed examination of sedimentary environments: Scholle PA and Spearing D: *Sandstone Depositional Environments*. Tulsa, Oklahoma, USA: The American Association of Petroleum Geologists, 1982.
21. A concretion is a compact mass of mineral matter, usually spherical or disk-shaped and embedded in a host rock of a different composition. Concretions form by precipitation of mineral matter (commonly a carbonate mineral such as calcite, but sometimes an iron oxide or hydroxide, such as goethite, or an amorphous or microcrystalline form of silica) about a nucleus such as a leaf or a piece of shell or bone. Concretions range in size from a few centimeters up to 3 m [9.8 ft] in diameter. They form during diagenesis of a deposit, usually shortly after the enclosing sediment has been buried.
22. Ripple laminations are undulations on the sediment surface produced as wind or water moves across and deposits sand.

A short distance uphole, a normal fault, not observed on seismic images, also was identified and oriented and displayed a change of dip across the fault plane (below).

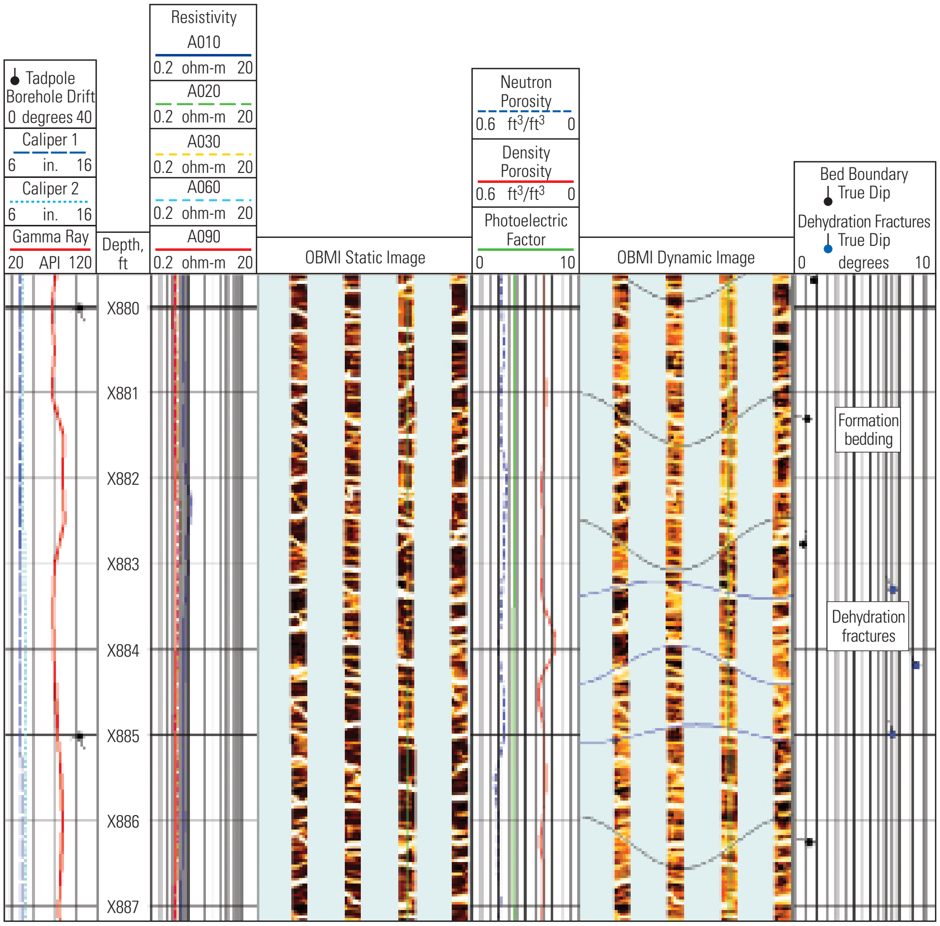
The OBMI tool injects currents into the formation that flow roughly parallel to the borehole. Voltage differences measured in this direction then allow the formation resistivity to be determined. Theoretically, if bed boundaries or fractures are oriented parallel to the borehole, the voltage drop in the direction of the borehole would be the same irrespective of the formation resistivity. Consequently, beds or fractures that maintain a high angle of dip relative to the borehole may be undetectable or difficult to observe. In practice, however, the new tool has had little difficulty imaging both fractures and bedding with apparent dips of up to 80 degrees relative to the borehole.

Fracture aperture, on the other hand, is not as easy to quantify. The vast majority of fractures observed downhole have apertures significantly less than the OBMI tool pixel width. For this reason, the fracture aperture cannot be observed directly. A method for the quantitative analysis of fracture aperture, similar to that in conductive muds using FMI and Formation MicroScanner data, has not been developed using OBMI data.

As more OBMI images become available, special interpretation challenges associated with OBMs become apparent. For example, the dehydration of shales by OBMs and SBMs leads to the



^ Natural fractures as seen by the OBMI tool. The OBMI tool clearly identifies and provides orientations of the natural fractures in this deep Anadarko basin well. The image on the left is the statically processed image to demonstrate gross changes across the section. The image on the right is the dynamically processed image to view small features within the section. Resistive fractures are more difficult to detect in the resistive Hunton Limestone. A normal fault was also identified uphole.



^ Dehydration fractures in shale on OBMI images. Dehydration fractures (sinusoids interpreted in the OBMI Dynamic Images Track) can mask formation bedding, making it difficult to automatically compute dips. In shales, the complexities of computing dips in SBMs and OBMs is readily apparent from OBMI images, underscoring the importance of having the option to handpick dips from clearer images.

fracturing or parting of shale laminations. These cracks are invaded by nonconductive mud so they appear as bright events on the OBMI images (above). Unlike stress-induced fractures, fractures caused by the dehydration of clay—most notably smectite—occur in high-density groupings and obscure the formation bedding on the images around the entire circumference of the wellbore. This can make geological interpretation of the image data extremely difficult. A dipmeter log run across such intervals might yield good quality but very misleading dips because of the presence of dehydration fractures.

These fractures have been noted on core and may explain the separation commonly observed between the shallow and deep induction logs. Until now, it has been difficult to know whether these fractures were on the borehole wall because they have not affected acoustic logs. For this reason, dehydration fractures are likely to be shallow and fine, and when filled with a very resistive fluid, become detectable by resistivity devices.

When operators cannot forego the use of SBM or OBM but still require a high-resolution imaging service, like the FMI tool, an alternative drilling fluid is available. The SIGMADRIL conductive OBM system, designed by M-I *L.L.C.*, provides the advantages of oil-base fluids and the electrical properties of conductive mud systems. Small-scale stratigraphic analysis, quantitative fracture analysis and other formation-evaluation techniques restricted to conductive boreholes are now possible with the use of this new mud (see "An Oil-Base Mud Designed for Imaging," *page 16*).

Imaging in Deepwater Wells

Given the immense cost of drilling, completing and producing wells at great ocean depths, the importance of making the right decision and getting it right the first time is unprecedented. Production testing and drillstem testing carry environmental risk and tremendous expense in the deepwater environment, making these practices undesirable. Operators want to maximize their initial look at the reservoir while minimizing their exposure to risk. The need for timely high-quality formation-evaluation data and accurate interpretations has never been greater than in today's deepwater operations.

The majority of wells in deepwater operations, including the US Gulf of Mexico and deepwater basins off the west coast of Africa, are drilled using synthetic-base muds, severely limiting the available options for borehole imaging. The OBMI tool has been used extensively in these areas, demonstrating significant applications to help geologists and engineers assess deepwater reservoirs.

More than half of the oil production in the US Gulf of Mexico now comes from deepwater projects. That figure is expected to rise to two-thirds, or nearly 2 million B/D [318,000 m^3/d], by the end of 2005.[23] Deepwater subsalt prospects have generated tremendous interest. Commonly, subsalt reservoirs are hard to detect and define through seismic imaging because much of the seismic energy is lost at the salt boundaries and does not penetrate and image subsalt strata.[24] Salt also disperses seismic energy, making seismic imaging more difficult when assuming straight raypath models.

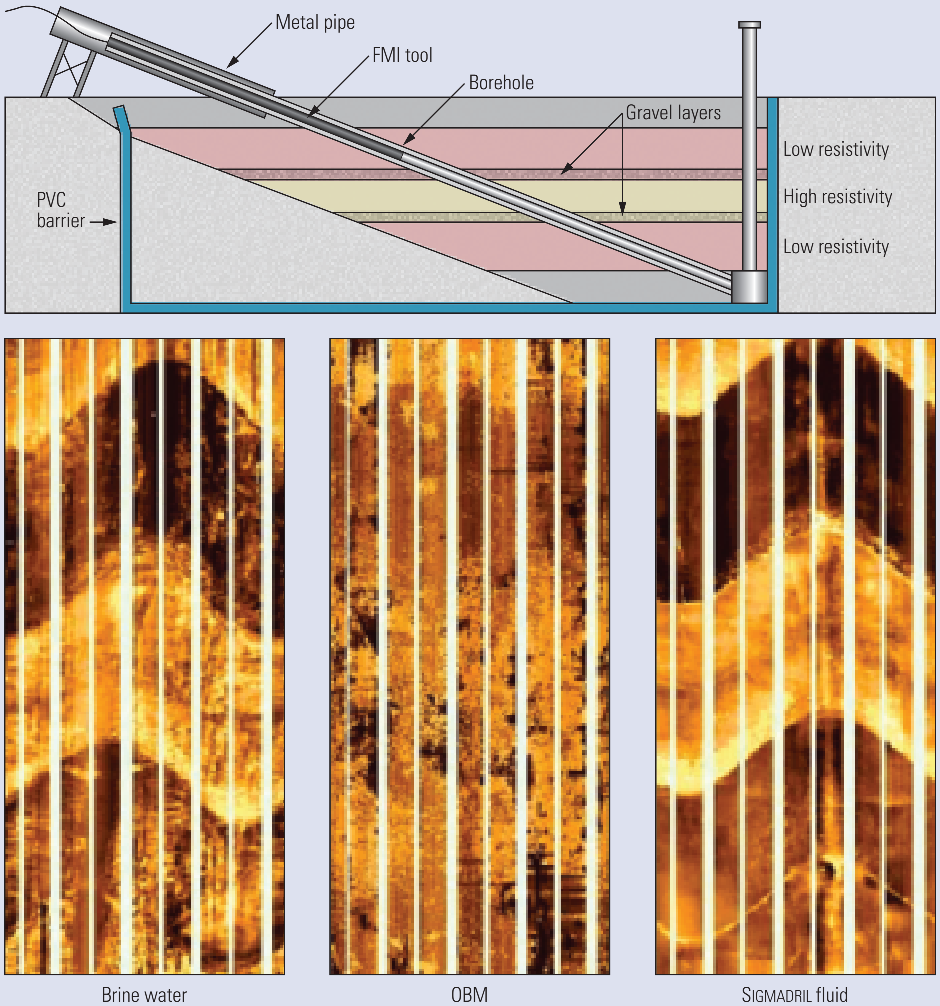
The OBMI tool allows deepwater geologists to pinpoint structural details and identify important features like faults and upturned beds, bringing more clarity to these complex sections where traditional seismic imaging can be ambiguous. Deepwater exploration targets in the Gulf of Mexico feature complex structures and faulting below salt in the folded strata of the Upper Jurassic through Miocene section. Using OBMI images, a deepwater operator confirmed the presence of a normal fault that was not detected previously in seismic images. The fault represented a significant structural feature with 500 ft [150 m] of throw. Faults like this hamper subsequent development efforts during the drilling of lateral production wells and can reduce the total recoverable reserves if the reservoir is highly compartmentalized. The improved structural picture derived from the OBMI interpretations can then be put into models used in seismic reprocessing, helping to define the reservoir extent and the future development strategy.

(continued on page 18)

23. Lyle D: "Deepwater Production Surges Higher," *Hart's E&P* 74, no. 8 (August 2001): 90.

24. Farmer P, Miller D, Pieprzak A, Rutledge J and Woods R: "Exploring the Subsalt," *Oilfield Review* 8, no. 1 (Spring 1996): 50–64.

An Oil-Base Mud Designed for Imaging



^ **Test borehole in Meaux, France. A 10-m [32.8-ft] long, 8-in. diameter hole constructed at 60° deviation was used to test the FMI tool response in three different borehole fluids, including brine water, OBM and SIGMADRIL conductive oil-base mud. To simulate formation layers, five layers of cement of different resistivities were used. The top and bottom layers were composed of high-resistivity construction concrete. Three middle cement layers were comprised of one high-resistivity center layer surrounded by two low-resistivity layers. Additionally, 5-cm [2-in.] layers of higher resistivity gravel were placed at the bases of the upper low-resistivity layer and the middle high-resistivity layer. The OBM prevented the acquisition of usable images by the FMI tool. The test showed that the SIGMADRIL mud produced high-quality images that identified both the thin resistive gravel layers and also subtle breaks observed both in the center of the resistive layer and in the center of the lower conductive layer, marking where those layers were laid in two different stages.**

Oil-base mud systems were developed to improve drilling performance relative to their water-base counterparts. With their associated higher rates of penetration and enhanced wellbore stability, shale inhibition and lubricity, oil-base drilling fluids often are the only viable technical and economic option for demanding applications such as extended-reach, deepwater and high-temperature, high-pressure wells.

Engineers and geoscientists often use microresistivity imaging to understand reservoir characteristics and to evaluate the productive capacity of a field. Historically, water-base drilling fluids were the only choice for acquiring high-quality formation-imaging logs using microresistivity techniques. The low resistivity of the mud, filter cake and filtrate of conductive water-base drilling fluids permits the return of a strong electrical-signal response from the formation, thereby generating logs of the highest clarity. On the other hand, the oil-wet fluid, filter cake and filtrate in conventional invert-emulsion fluids—water in an oil-continuous phase—create a resistive barrier that blocks electrical current, making image quality inadequate.

In response to that dilemma, M-I *L.L.C.* and Schlumberger embarked on a five-year research program that led to the joint development of the SIGMADRIL conductive oil-base drilling fluid system. SIGMADRIL mud employs an electrically conductive continuous phase that produces conductive mud, filter cake and filtrate. The result is a fluid delivering oil-base performance characteristics with the formation logging quality of a water-base drilling fluid. The conductive borehole environment produced by this new mud yields high-quality microresistivity images normally associated with water-base mud systems. Extensive testing at a Schlumberger test well in Meaux, France helped produce a mud system ideally suited for FMI Fullbore Formation MicroImager tool operations **(left)**.

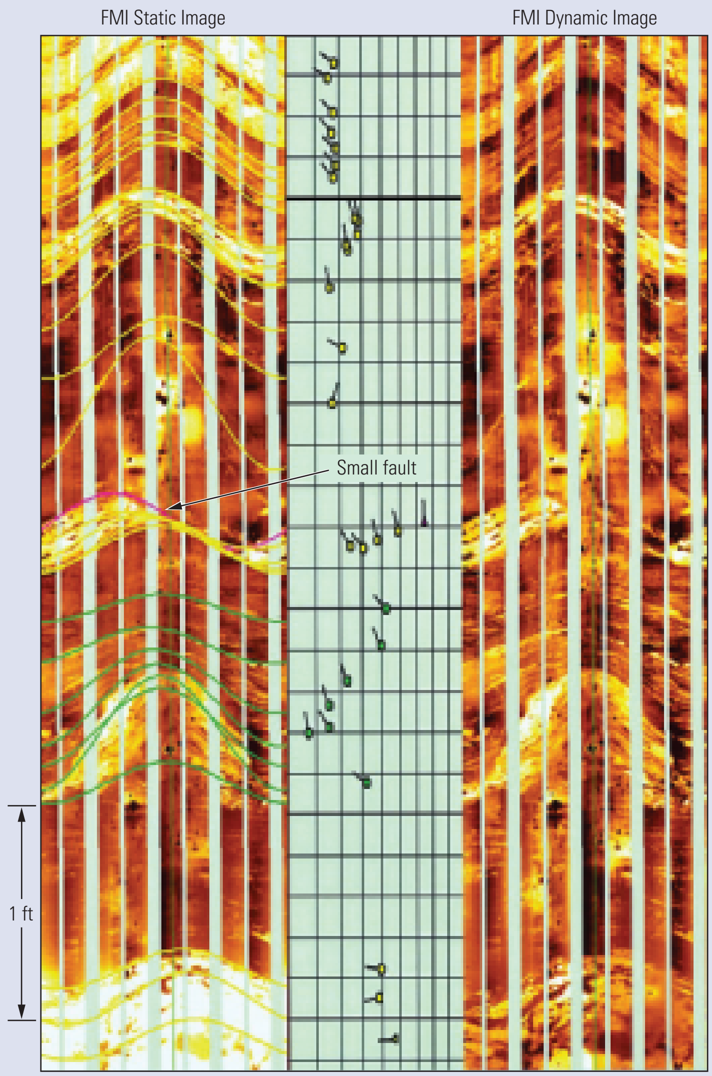
The system features a proprietary and patented chemical package that makes the continuous oil phase conductive without destabilizing the emulsion. The system is formulated for minimum filtration by incorporating a unique filtration-control package that contains a nonaqueous soluble polymeric additive and a liquid ester additive. The properties of Sigmadril drilling fluid are identical to those of a typical oil- or synthetic-base system, except for its electrical conductivity that permits the use of certain resistivity devices.

The system was first deployed in a highly deviated well in the Norwegian sector of the North Sea where the primary objective was to acquire detailed geologic data, including structural and sedimentary dip and information on faults and fractures. The FMI tool was selected as the only device capable of delivering the required resolution and borehole coverage results with minimal risk to data quality. The targeted section, however, contained highly reactive shales that made drilling with a water-base fluid system extremely risky, possibly resulting in loss of the well.

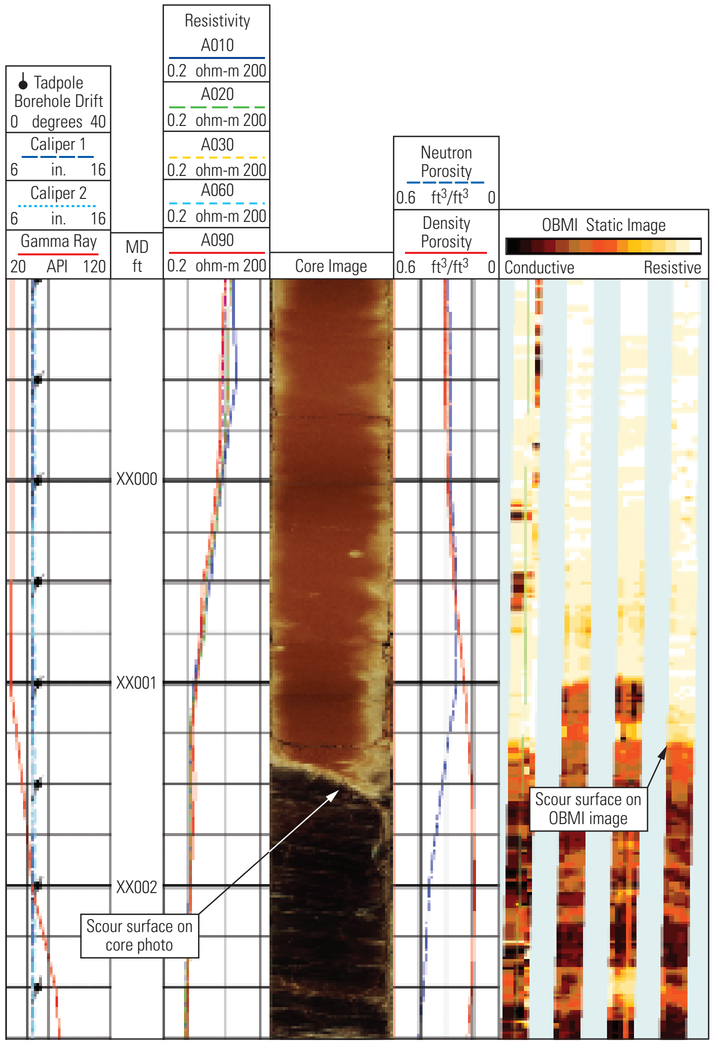
The operator displaced the original mud system with Sigmadril fluid in the targeted 8½-in. diameter section and used it to drill a total depth of 15,599 ft [4755 m]. Sigmadril mud proved to be a stable and easily maintained fluid system that behaved like any high-quality oil-base drilling fluid. The troublesome shales were drilled with no fluid-related downtime. The interval was drilled trouble-free, 4½ days ahead of schedule, resulting in a savings of US $1.5 million.

The quality of the formation imaging and detailed geologic interpretation was as good as, and in some instances better than, that achieved with water-base drilling fluids **(right)**. High-quality, interpretable images were obtained in formations with resistivity as low as 2 ohm-m. The resolution quality allowed the operator to define the reservoir clearly, reducing the cost of future development. Similar results were recorded in a second Norwegian North Sea well.

Presently, M-I *L.L.C.* is conducting a field trial for the second version of the oil-base system. The Sigmadril II conductive oil-base mud is designed to be 50% more conductive than its predecessor, further enhancing microresistivity-image quality while opening the door for LWD resistivity-imaging devices, such as the GVR GeoVISION Resistivity sub. In the initial and ongoing Sigmadril II mud field trial, the quality of the GVR images was excellent and the well experienced no mud-related drilling problems.



FMI images in Sigmadril conductive oil-base mud. The FMI images from this Norwegian North Sea well demonstrate the quality and detail of images in Sigmadril mud. In this case, the FMI data indicate a small fault and thin beds.



^ OBMI images of a basal-scour surface. OBMI images from an early field-test tool identified this abrupt erosional surface (arrows) in this deepwater well. The scour surface was confirmed by an examination of the core. The core photograph is shown in Track 3.

Just as earlier microresistivity-imaging devices revolutionized stratigraphic analysis in conductive WBMs, the OBMI tool allows deepwater operators to examine stratigraphic features and internal bedding in nonconductive muds. OBMI images assess laminated sequences, bedding character and abrupt changes in sedimentation. In one deepwater well, a Gulf of Mexico operator ran the OBMI tool and identified a basal-scour surface that was confirmed by fullbore core (above).

In deepwater operations, the cost of production systems exceeds the cost of drilling wells in the field. The selection and design of these production systems depend largely on the produced-fluid behavior. Wax and asphaltene solids that form during production and cause flow problems must be minimized. Fluid samples, collected downhole by wireline fluid-sampling tools, like the MDT Modular Formation Dynamics Tester tool, are analyzed to determine fluid properties. However, when the samples are more than 10% contaminated by SBM or OBM filtrate, extracting critical information about production-fluid properties becomes more difficult and puts at risk effective flow assurance.[25]

Images from the OBMI tool have been used in the selection of MDT fluid-sampling depths to minimize the percentage of SBM and OBM filtrate contamination in the samples. In the deepwater sands of the Gulf of Mexico, nonoptimal MDT tool placement can occur when selecting fluid-sampling depths using standard logs. With its 1.2-in. resolution, the OBMI tool can identify the location and nature of bed boundaries—sharp versus gradational—better than standard logs, facilitating optimal sample-depth determination. Combining the knowledge of bed contacts from the OBMI tool and producibility indicators from the CMR tool, higher permeability sands

25. Andrews J, Beck G, Castelijns K, Chen A, Fadness F, Irvine-Fortescue J, Williams S, Cribbs M, Hashem M, Jamaluddin A, Kurkjian A, Sass B, Mullins OC, Rylander E and Van Dusen A: "Quantifying Contamination Using Color of Crude and Condensate," *Oilfield Review* 13, no. 3 (Autumn 2001): 24–43.

Cuvillier G, Edwards S, Johnson G, Plumb D, Sayers C, Denyer G, Mendonça JE, Theuveny B and Vise C: "Solving Deepwater Well-Construction Problems," *Oilfield Review* 12, no. 1 (Spring 2000): 2–17.

Christie A, Kishino A, Cromb J, Hensley R, Kent E, McBeath B, Stewart H, Vidal A and Koot L: "Subsea Solutions," *Oilfield Review* 11, no. 4 (Winter 1999/2000): 2–19.

26. Cheung et al, reference 16.

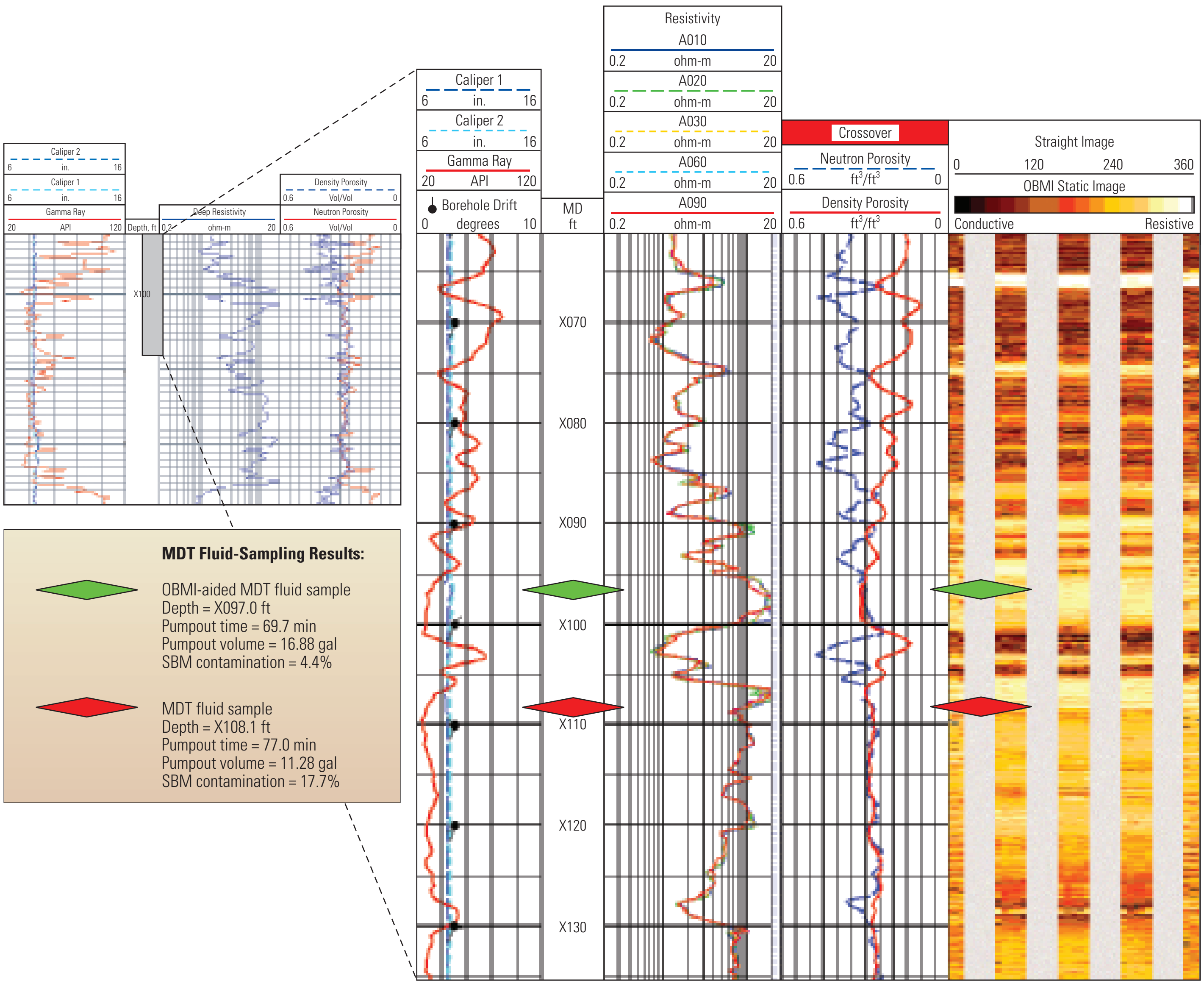
can be sampled closer to sharp bed boundaries, thereby reducing spherical-flow effects to the MDT probe.

Improved positioning of the MDT tool using OBMI and CMR logs, along with longer pumpout times and use of the OFA Optical Fluid Analyzer module, has helped one operator reduce sample contamination levels from 10 to 20% to less than 5% (below). These reduced contamination levels improve fluid-property characterization and help ensure the optimal design of deepwater production and treatment facilities.

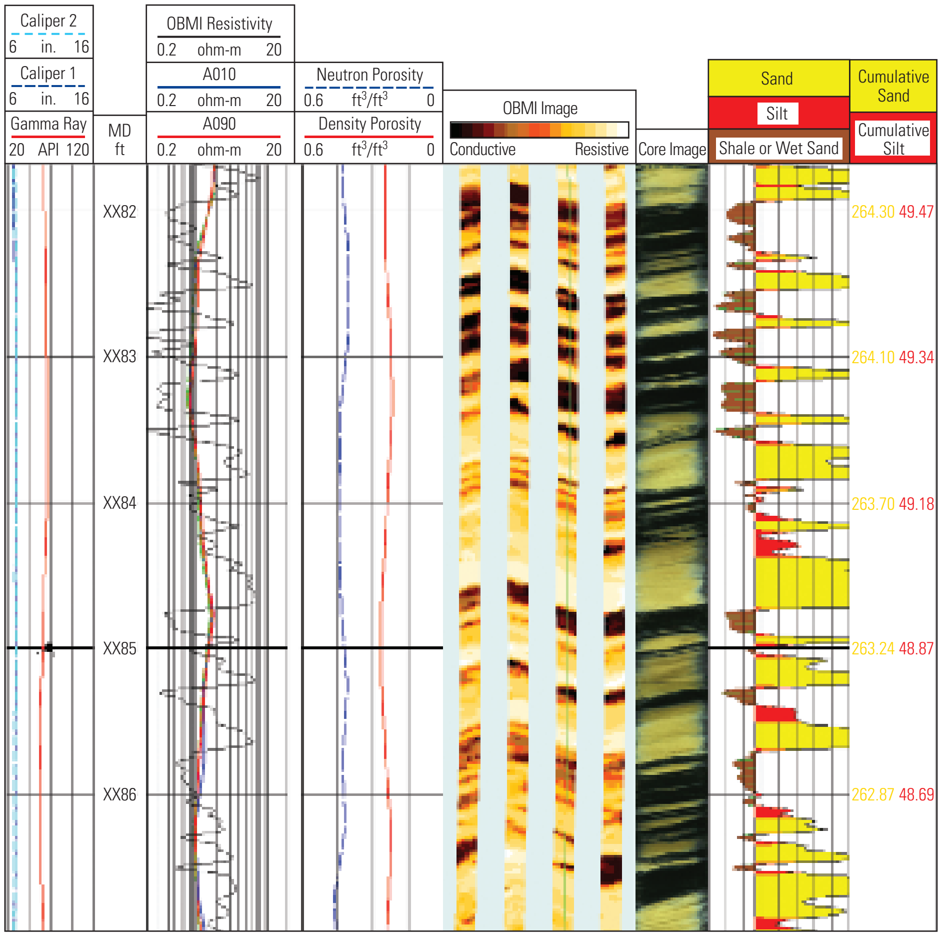
Images, Cores and Dips

Recent experience in the US Gulf of Mexico has shown the OBMI tool measurement to be robust. The new tool delivers high-quality results when compared with fullbore cores and provides more accurate sand-count numbers for reserve estimates compared to standard logs. Because it is an imaging tool, the OBMI tool provides more precise structural and stratigraphic dips compared with those obtained with previous methods. OBMI images eliminate much of the ambiguity of dip interpretations from processed dipmeter data in nonconductive mud-filled boreholes.

In the Gulf of Mexico, operators have successfully used OBMI images and resistivity measurements to characterize uncored intervals and to refine net-to-gross sand figures.[26] Fullbore cores and images were acquired across a section of Pleistocene-age sands to assess the level of detail provided by the OBMI tool. The correlation was excellent, and beds as thin as 0.5 in. [1.3 cm]



^ Fine-tuning MDT sampling depths. The OBMI images allow the differentiation of bed-boundary types for MDT sample-point selection. This improves the chances that higher quality rock will be sampled, thereby increasing the volume of the fluid samples and reducing the contamination of fluid samples. The lower MDT sample depth (red diamonds), X108.1 ft, was selected without the aid of the OBMI tool and suffered from a large percentage of SBM contamination. The upper sample depth (green diamonds), X097.0 ft, was selected from the OBMI images (Track 4) and was taken between laminations. It produced a larger, cleaner sample in less time than when the OBMI images were not used. Close proximity to the low-permeability laminations reduces spherical-flow effects, allowing quicker withdrawal of formation fluids from beyond the filtrate-invasion zone. MDT sample-contamination results have improved dramatically since new techniques and procedures have been introduced.

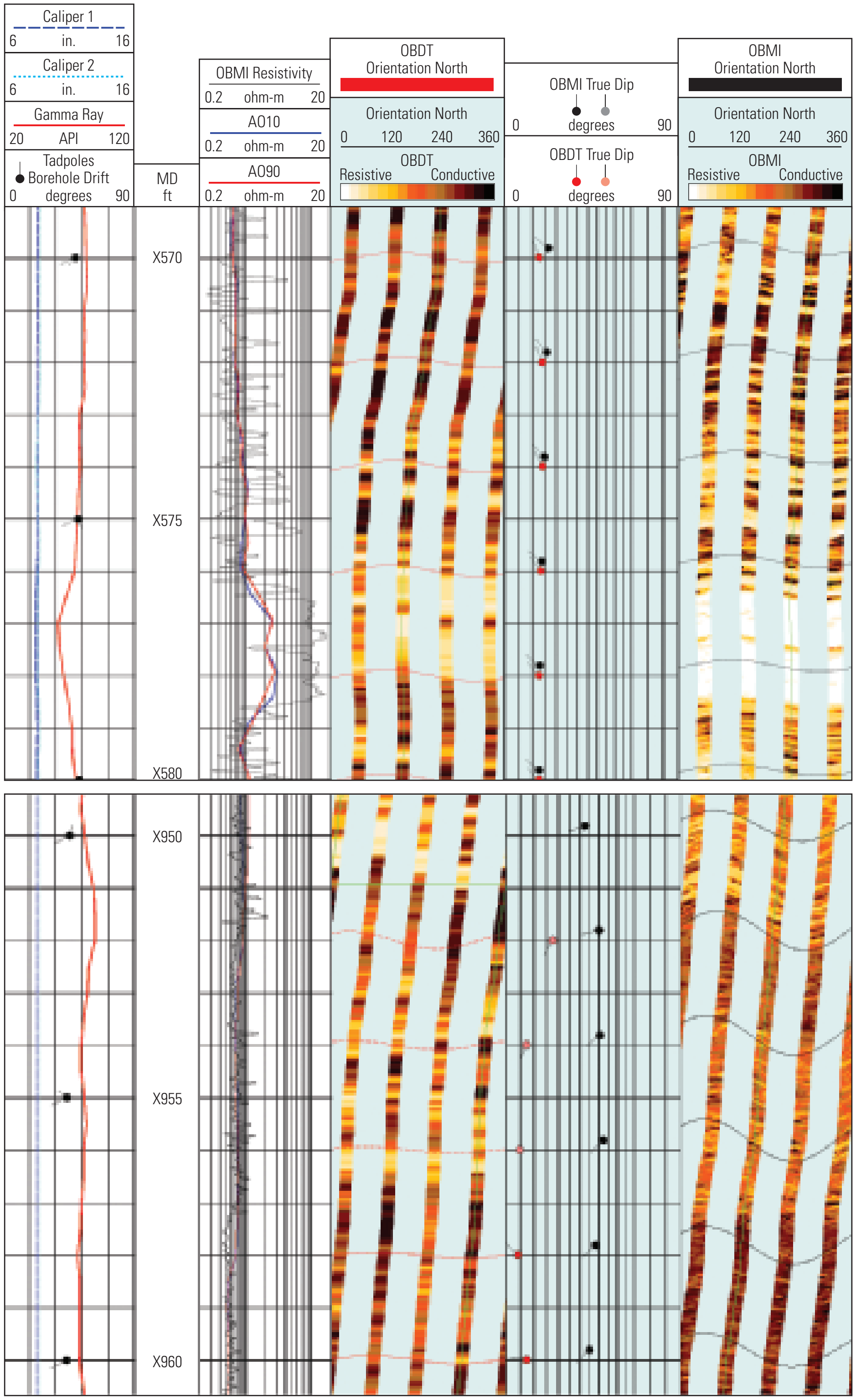


^ Imaging thin beds in nonconductive muds. OBMI images (Track 4) compare favorably to core (Track 5) and improve total sand-count estimates (Tracks 6 and 7) in nonconductive muds. Beds as thin as 0.5 in. [1.3 cm] can be identified but their thickness cannot be quantified until they reach 1.2 in. [3.0 cm], for example at XX84.0 ft. Additionally, planar and nonplanar bed boundaries can be identified, such as the nonplanar bed boundary at XX83.4 ft, on both the core and the OBMI image.

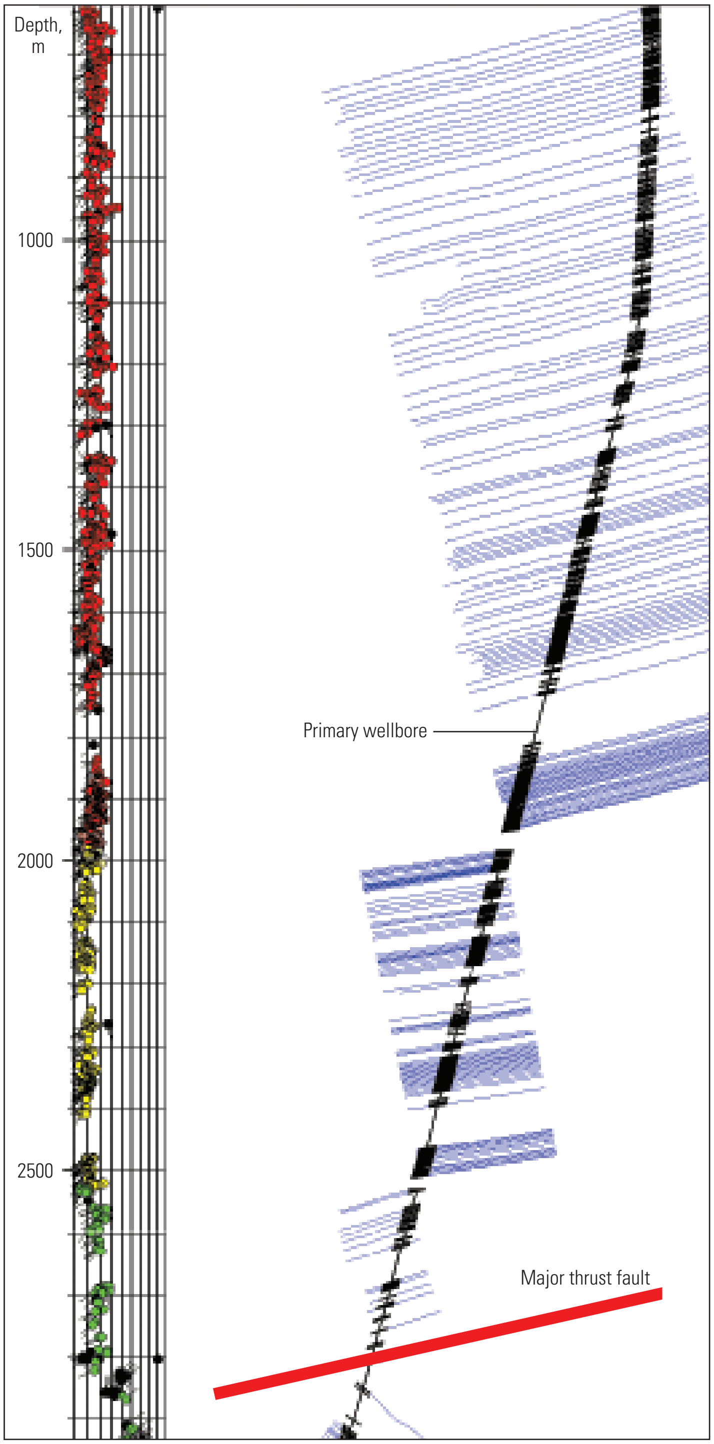
were identified (above). At a depth of XX84 ft, thin beds can be observed both on the core and on the OBMI image. The core clearly shows shale between the sand stringers. The OBMI tool, limited to a resolution of 1.2 in., suggests the shale is silty. This introduces small errors in the net-sand calculation that become more significant as the thin-bedded nature of the reservoir increases. In the Pleistocene sands of the Gulf of Mexico, the OBMI resistivity was used in combination with sidewall core data to improve the accuracy of the net-sand count. The calculated net-sand increase was 50 ft [15 m] greater than conventional log analysis indicated.

Operating companies requiring structural analysis across thick sections of strata usually benefit from automatic dip computations. This method provides a quick structural picture so that critical decisions can be made rapidly. However, in nonconductive muds, dipmeter data must often be processed and interpreted by hand, taking too much time to provide timely answers to critical decisions.

With identical processing parameters, structural dips were computed from both OBDT data and OBMI data acquired across the same Pleistocene sand interval in a Gulf of Mexico well. A single button per pad was used in the OBDT processing, while three buttons per pad were used to process the OBMI data. The geologist received ten times more usable dip information from the OBMI tool than from the OBDT tool, and dip magnitudes and dip directions varied greatly from those of the OBDT tool in some sections. Comparison of the OBDT data and the OBMI images clearly demonstrates how the dip correlations differ between the two devices (next page). The computed sinusoid traces displayed on each image demonstrate the advantages of having the superior clarity of the OBMI images. Improved borehole images lead to more accurate dip computations and more rigorous structural interpretations.



^ Computed dips from OBDT and OBMI data. The upper section shows that, in some cases, OBDT computed dips are comparable to OBMI computed dips (Track 4). The lower section reveals significant differences. The OBDT data and the OBMI images demonstrate the considerable difference in clarity between the two data sets. Clarity is critical when handpicking dip sinusoids during the interpretation of the data.



^ StrucView plot of the upper section of the primary wellbore. The OBMI data *(left)* were instrumental in the identification of the major thrust fault at 2800 m. Wellbore trajectory and formation dips were plotted on a cross-sectional view *(right)*.

Complex Structures

Certain geologic provinces have experienced intense folding, faulting and uplifting throughout their tectonic history. Extensive thrust faulting along orogenic belts has created viable hydrocarbon traps, attracting operating companies looking to exploit these challenging reservoirs.

Companies operating in these fold-and-thrust belts often depend on nonconductive-mud systems to successfully drill exploratory- and development-well programs. In these structural settings, sloughing shales are especially troublesome during the drilling process, so every effort is made to minimize the shale-instability problems. OBMs and SBMs have successfully addressed those problems.

The use of nonconductive muds has made defining structure with conventional borehole-imaging and dipmeter tools a difficult task, and it is in these complicated tectonic settings that a clear picture is needed most. Critical to the success of these prospects is the understanding of structural geometries and features that are often steeply dipping, small and complicated and therefore a hindrance to the production of interpretable surface-seismic images. Adding to this complexity are deep subthrust reservoirs that lack a clear seismic response. The OBMI tool has made a positive impact in these areas by helping companies define and refine near-wellbore structural geometries. The new information from the OBMI tool is applied to geological models, improving the structural control and reducing the exploration risk of these prospects.

The OBMI tool has been used extensively by companies operating in the Canadian Foothills of Alberta, Canada. The Foothills are a part of the larger fold-and-thrust belt extending along the Rocky Mountains. Horizontal compression has deformed the sedimentary rock layers so that thrust sheets actually ride over each other, stacking to form complex and repeating or imbricate thrust-duplex geometries (next page, top).[27] Two-dimensional (2D) and three-dimensional (3D) seismic images are an important source of subsurface information, but the mountainous terrain often complicates the data-acquisition process. Additionally, seismic images of deep, intensely faulted and folded structures must be reinforced with the detailed structural knowledge that comes from accurate formation dip and fault data found at the wellbore. In WBMs, this would not be an issue, but this region requires the use of OBMs to mitigate problems associated with shale instability. For these reasons, the OBMI tool has become an essential part of formation-evaluation programs in the Canadian Foothills.

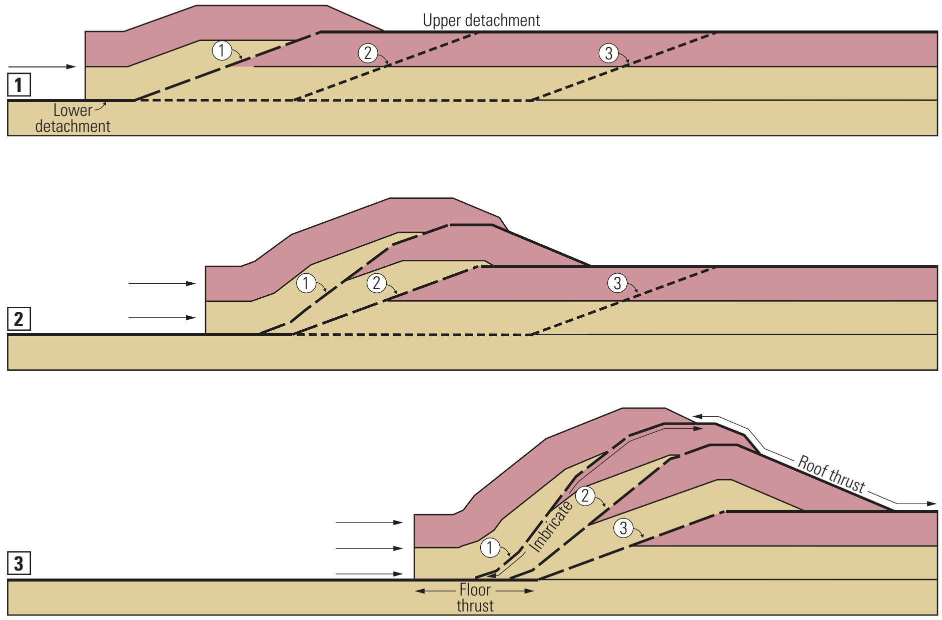
El Paso Oil and Gas Canada Incorporated, in conjunction with Suncor Energy, has targeted the fractured Turner Valley formation carbonate rocks in the northern portion of the Alberta foothills. Initially, a primary well was drilled vertically with OBM and logged with the OBMI tool in both the upper and lower sections. An upper OBMI logging pass produced formation dips and identified the presence of a major thrust fault at 2800 m [9186 ft]. The formation bedding was thoroughly examined using the OBMI tool, and the dips were used to generate a cross section in StrucView GeoFrame structural cross section software (previous page). This StrucView interpretation was generated across the upper portion of the primary wellbore and was in good agreement with the surface-seismic images.

Drilling was suspended temporarily to run the OBMI tool at 3582 m [11,750 ft] and again at 3665 m [12,020 ft] because formation tops were coming in 150 m below the predicted tops. Using the new dip information and sonic data, El Paso was able to correctly tie the log data to the 3D seismic image by moving the seismic data five traces in the up-dip direction.

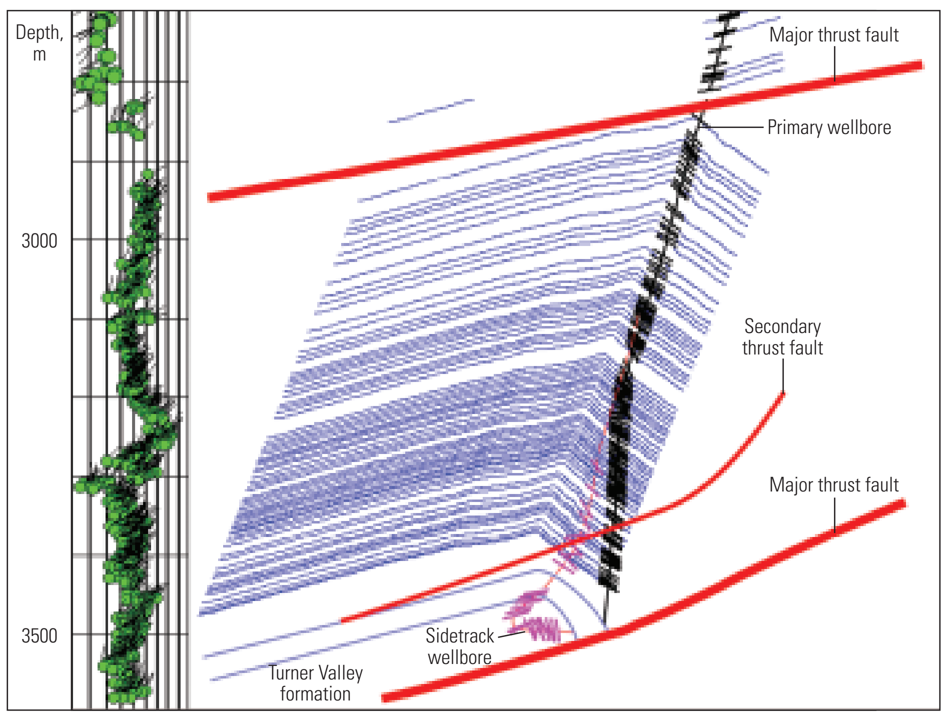
High-confidence dip data from directly above the Turner Valley reservoir indicated that the primary well actually missed the structural crest and was not in an ideal position to initiate the horizontal well through the reservoir. Commonly, fractured reservoirs maintain optimal productivity along the crest of these structures due to the presence of open tensional fractures. The OBMI data and the corrected seismic images were instrumental in the design of a sidetrack well, from which a more effective horizontal well could be drilled along the crest of the structure.

Across the upper section of the sidetrack well, the UBI tool was run in place of the OBMI tool because the OBMI tool was unavailable for that logging run. Sufficient dip information was acquired during this run to confirm El Paso's crestal position on the structure. These data were combined with those from the OBMI tool to construct another StrucView cross section, incorporating both the primary and sidetrack wellbores (right).

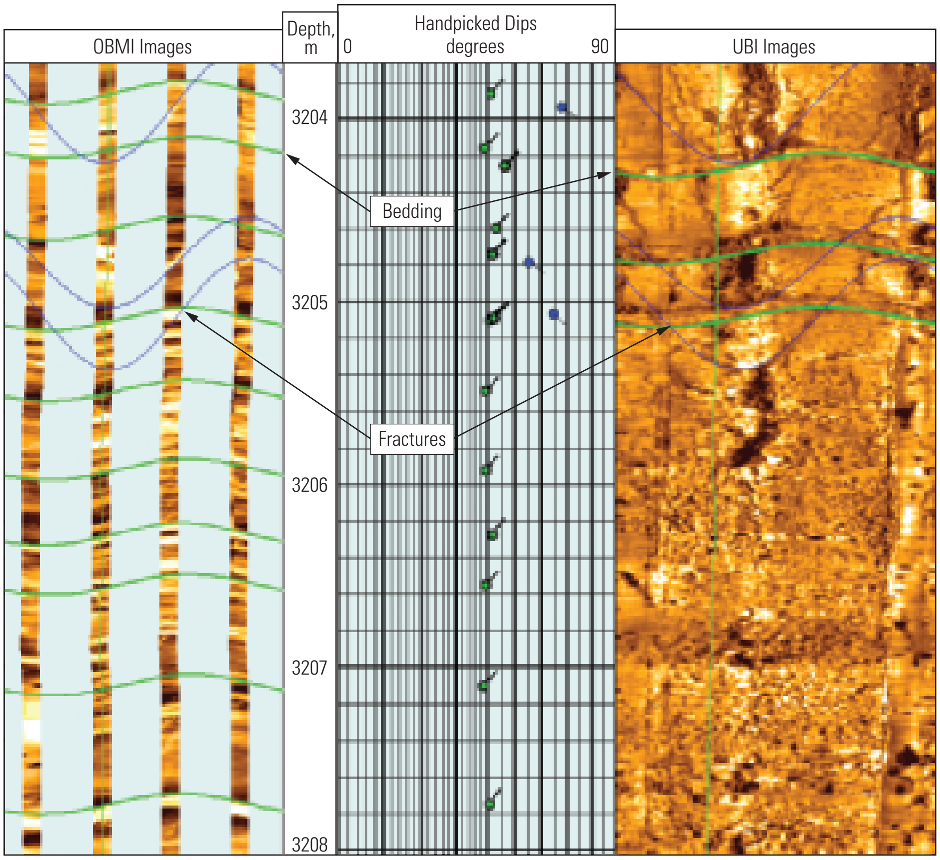
27. Mitra S: "Duplex Structures and Imbricate Thrust Systems: Geometry, Structural Position, and Hydrocarbon Potential," *The American Association of Petroleum Geologists Bulletin* 70, no. 9 (September 1986): 1087–1112.



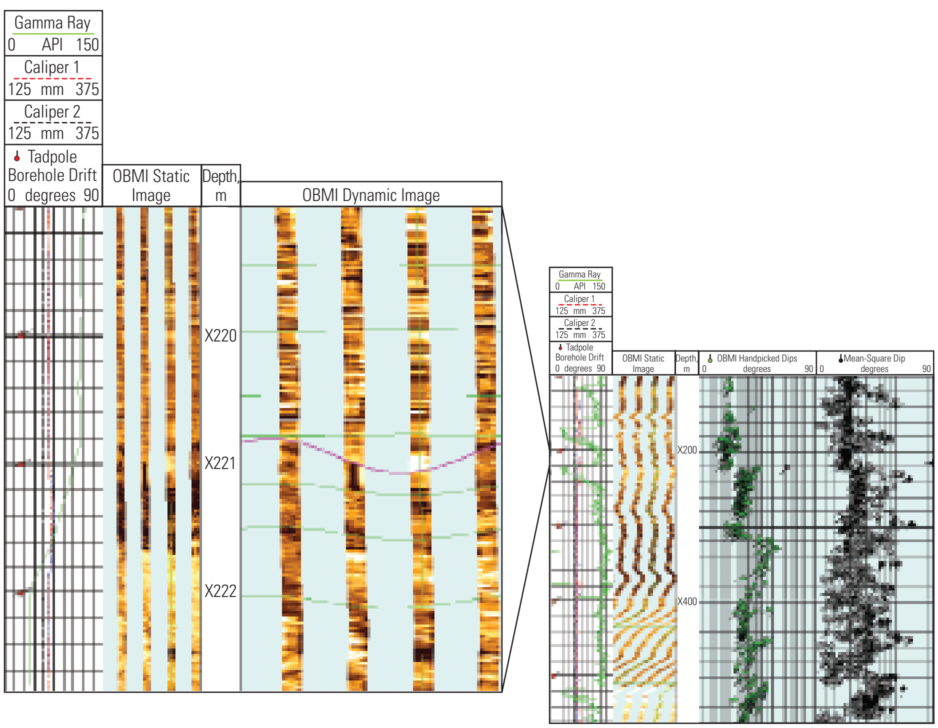
^ Evolution of a fold-and-thrust system. The formation of fold-and-thrust duplexes results in complex structures, high dips and repeated sections. The labels 1, 2 and 3 represent both the theoretical sequence timing and physical location of the thrust faults that form a duplex. The uppermost fault is oldest and the lowermost fault is youngest.



^ StrucView plot of the lower section of the primary and sidetrack wellbores. The OBMI data *(left)* identified the presence of the upper major thrust fault and confirmed the presence of the secondary thrust fault. The lowest thrust fault was below the well total depths and was identified from seismic images. The interpreted OBMI data sets show increasing dip into the major thrust fault below, with the steepest dips occurring near the major thrust fault (sidetrack well). With all available information, the sidetrack well was drilled into the crest and was in optimal position from which to drill the horizontal production well.



^ OBMI images compared with UBI images. OBMI images (Track 1) provide a detailed picture of formation bedding (arrows). The UBI images (Track 3) identify some bedding and indicate that the natural fractures are open.



^ Fault zone in the Canadian Foothills. A thrust fault runs through the upper sand occurrence at X221 m *(left)* and is responsible for the repeated section at X200 m *(right)*. En-echelon faulting is observed at X320 m. The OBMI images allow the handpicking of dips (Track 3) that are more accurate than the computed dips from dipmeter data (Track 4) and more clearly identify the faults in the section.

The close proximity between the upper portion of the sidetrack well and the primary well allowed comparison between UBI images and OBMI images. Both the UBI tool from the upper portion of the sidetrack and the OBMI device from the primary wellbore adjacent to the sidetrack identified natural fracturing. The UBI images showed the fractures were open but provided less information on formation bedding, while the OBMI images revealed abundant detail on bedding (left).

After examining all structural dip data in combination with the corrected seismic images, El Paso now was confident about proceeding with the horizontal production well. After intermediate casing was run, a 675-m [2215-ft] horizontal leg was drilled and successfully completed in highly fractured sections of the Turner Valley formation.

In another part of the Canadian Foothills, the OBMI tool helped an operating company gain insight about a complicated and repeating fold-and-thrust structure, enhancing the outlook for the field. Drilled with OBM, wells in this play typically penetrate two occurrences of Cretaceous sandstone reservoirs. The upper occurrence of the sand is productive when naturally fractured from folding and faulting processes that have enhanced the zone's permeability. The lower sand occurrence is less likely to produce because the lower thrusts have undergone less displacement and deformation, resulting in less permeability and porosity enhancement from natural fractures.

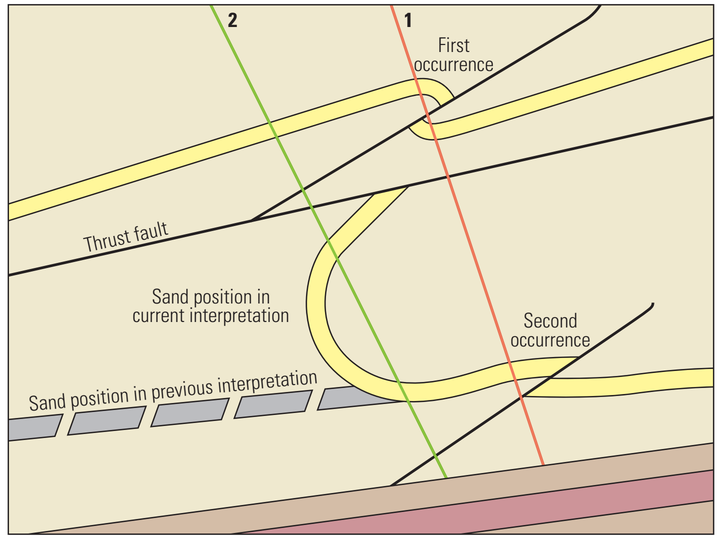
Accurate dips across these stacked thrust sheets clarify the true thickness of the sands and also the position of both the sands and the faults separating them. This information allows the geologist to determine if the entire repeated section is present from which a sidetrack well design, risk and economics can be reasonably assessed. Dipmeters have rarely provided this critical information in the Canadian Foothills (left).

The initial geologic model for the lower sand occurrence featured a simple overthrust scenario with minimal drag and reduced dip roughly equal to regional dip. Seismic images successfully characterized the low-dip strata but became unclear near the faults and folds. Below the upper fault, the overturned limb exhibits high formation dips and intense fracturing, precluding accurate interpretation of dipmeter and seismic data. Without a coherent picture, the second sand was assumed to be continuous, moderately dipping below the upper fault, and of poor reservoir quality.

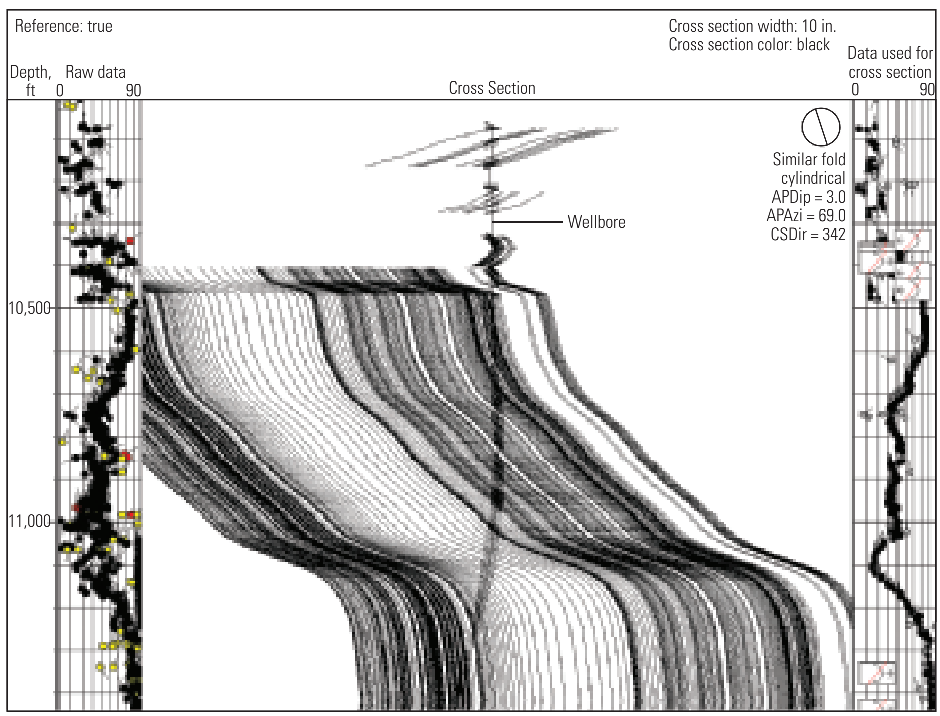
From work done with OBMI images, the operating company and Schlumberger recognized that a major fold extended to the upper thrust fault and that the second sand, now overturned, constituted a new production target (right). Unlike second-sand occurrences in typical wells, the highly fractured Cretaceous sand within the overturned limb makes an excellent reservoir, increasing field production and reserves estimates. The geologic model used in exploration and development has fundamentally changed from a simple overthrust structure to a complicated but more accurate model that involves an initial folding event followed by thrust-fault failure and associated faulting.

The Potato Hills field in the Arkoma basin of Oklahoma, USA exemplifies how thrust faulting, folding and fracturing combine to create an extremely prolific field. Owned by The GHK Company, the three-year-old field has produced a cumulative 92 Bcf [2.6 billion m^3] of gas from 34 wells. While the majority of this gas has been produced from the Pennsylvanian Ratcliff sand in the Jackfork Group, another deeper horizon, the Ordovician Bigfork chert, is now of great interest. The OBMI tool was instrumental in defining the near-wellbore structure in the Bigfork chert and surrounding formations in Potato Hills field. Oil-base muds are used in drilling the Ouachita Mountain portion of the Arkoma basin because of the unstable shales present throughout the section. These shales, the Stanley, Missouri Mountain and Polk Creek—overlying the Bigfork—and the Womble shale—underneath the Bigfork—have been stressed by the extensive thrust faulting and folding that took place during the Ouachita orogeny.

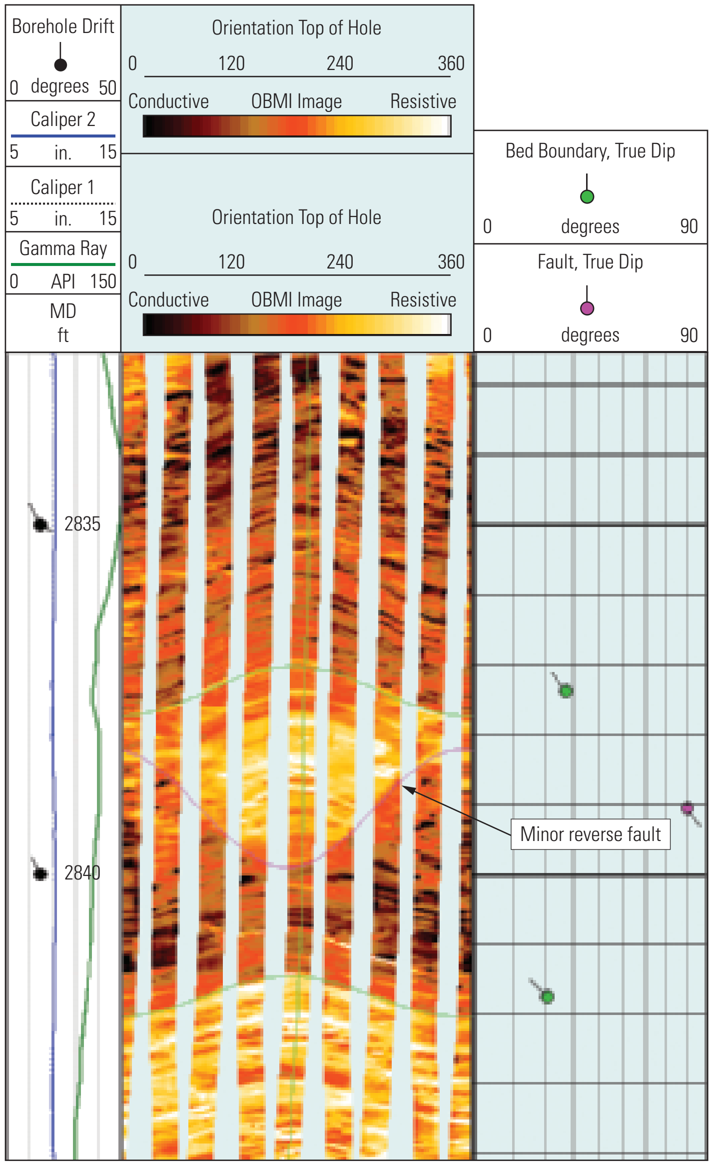
Knowledge of the local structural complexities in the field is extremely important for proper offset-well placement and for understanding the production behavior of wells. This information is often not provided by the existing 2D seismic images. In one particular well, the OBMI results, combined with conventional logs and a StrucView interpretation, helped define an overturned fold in the Bigfork chert section (right).



^ Structural scenario depicting two models and the resulting theoretical well paths. After primary folding from compression, major thrust faulting is initiated. A subsequent secondary, or en-echelon, fault occurs, furthering the complexity of the model. Sample Wellbore path 1 (red) represents the previous geologic model while sample Wellbore path 2 (green) represents the new model.



^ StrucView cross section of the upper limb of an overturned fold in Potato Hills field. The OBMI handpicked dips (Track 1) were input to the StrucView application and allowed visualization of this structure. The GHK Company now believes this reservoir is more extensive and less compartmentalized than previously thought.



^ Using OBMI images to characterize a fault in Potato Hills field. Two passes with the OBMI tool produced excellent borehole coverage and clearly pinpointed this minor reverse fault (arrow) located uphole from the main reservoirs.

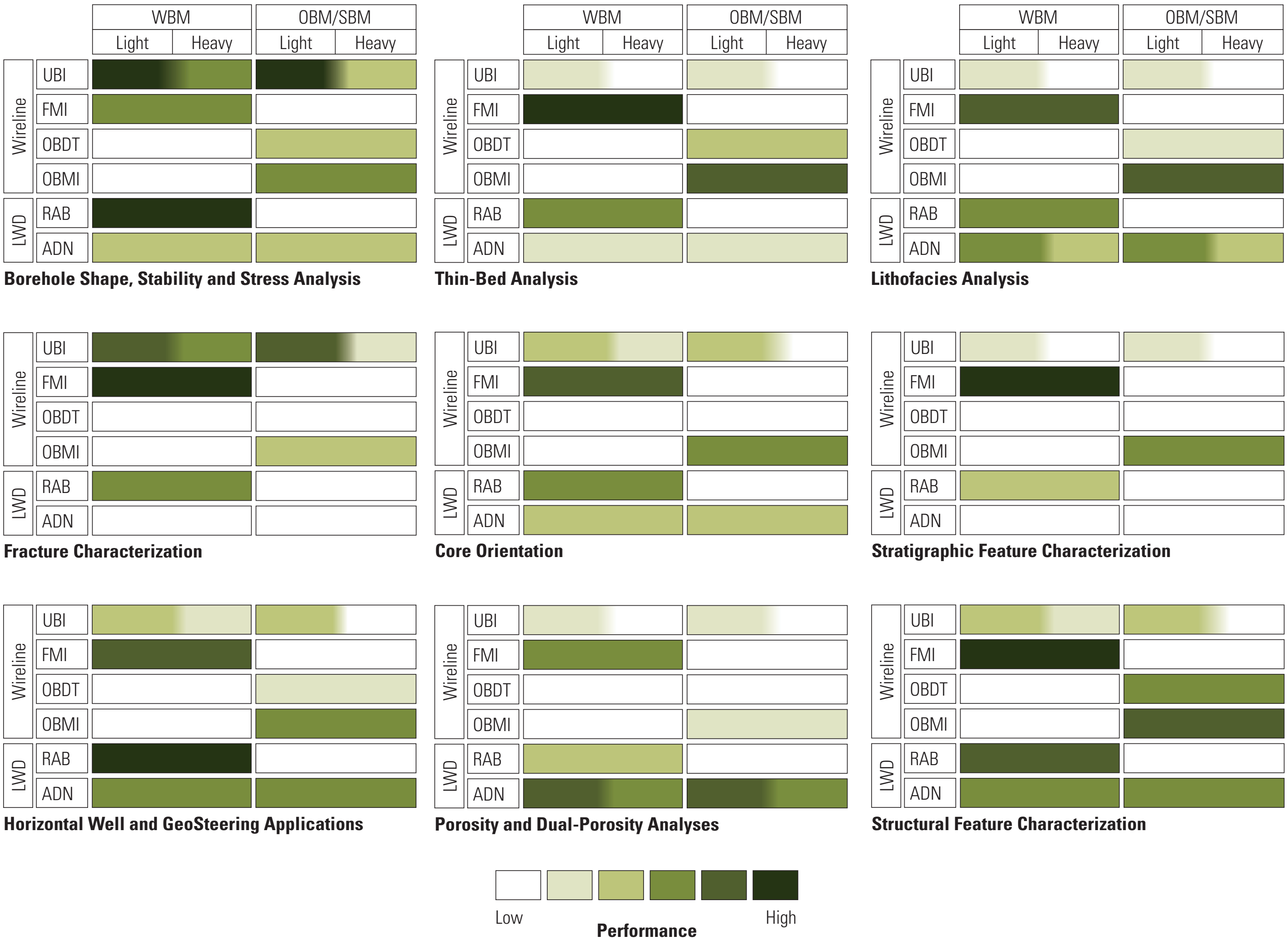
The clearer picture of the structural geometry has demonstrated to GHK that the reservoir is more extensive and less compartmentalized than was previously believed.

In the past, GHK used other methods to extract structural information from wells in this play with only moderate success. For example, conventional dipmeters have not produced repeatable dip information. Dips computed from different companies' wireline tools were significantly different in the same wellbore interval logged twice.

Ultrasonic-imaging tools used in the Potato Hills field also have yielded disappointing results. These acoustic devices delivered fair-quality images of natural fractures but generated only low-quality dip information, because of the ultrasonic tools' relative insensitivity to formation bedding.

Unlike dipmeter tools, the OBMI tool provided the data quality necessary for GHK to identify and differentiate lithology boundaries, faults, fractures and bedding planes (above). The static OBMI image helped in locating lithology changes and faults, while the dynamic image was used to calculate orientations of fractures, bedding planes and faults.[28] The ability to see the key features on the OBMI images allowed GHK to use only the meaningful data in their analyses, and provided the confidence to incorporate those data into their geologic and reservoir models.

28. In static image processing, colors are assigned to resistivity values across an entire data set, enabling the interpreter to observe gross changes across large intervals. In dynamic image processing, colors are reassigned at fixed intervals, normally one or two feet. Dynamic, or highlight, processing creates maximum contrast on the images, allowing the observation of fine details such as crossbedding.



^ Filling the borehole-imaging gap in nonconductive mud-filled boreholes. At 1.2-in. resolution, the OBMI tool permits the examination of stratigraphic bedding and features, improves the accuracy of sand-count analyses and the capacity to identify small structural features, even in heavy SBMs and OBMs. Acoustic-imaging devices, like the UBI tool, are important in nonconductive muds because they allow detailed examination of borehole shape, stress-related features and natural fractures. Their effectiveness diminishes when mud weights increase. LWD imaging tools maintain their importance in horizontal or highly deviated wells, especially when real-time answers are required for geosteering operations. However, RAB images cannot be acquired in nonconductive muds.

Imagine the Future

As information on hydrocarbon reservoirs becomes increasingly detailed, the industry has developed ways to harness improved measurements and convert them to knowledge for more profitable and less risky exploitation of assets. Although the physical obstacles to imaging reservoirs through nonconductive mud systems temporarily placed the numerous benefits of borehole imaging beyond the reach of reservoir experts, that is no longer the case.

Throughout the development and field testing of the OBMI tool, data quality improved continually with every design change. The image quality today is making possible intensive structural analyses, and the tool now is being used in an ever-expanding array of stratigraphic applications. As experience with OBMI data grows, geologists and engineers will develop even more applications to answer key questions about their reservoirs. The OBMI tool has effectively placed borehole imaging onto the OBM and SBM formation-evaluation palette (above). Combining OBMI information with existing knowledge and other new and emerging technologies will help companies find the missing pieces to complete a clear reservoir picture—a picture worth framing, even when imaged through oil-base muds. —MG

The Beginning of the End: A Review of Abandonment and Decommissioning Practices

The oil and gas industry anticipates growing activity in well-abandonment and platform-decommissioning operations. Technically sound well-abandonment practices are essential for long-term environmental protection, especially as regulations become more stringent and complex. Although advanced technologies and techniques bring new meaning to the "permanent" aspects of abandonment work, operators seek to minimize abandonment and decommissioning costs because these expenses are not recouped.

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The life of a well comprises numerous stages. The discovery of a new accumulation of oil or gas after months or years of exploration and drilling invigorates the responsible technical team. Achieving first production is another uplifting milestone. Successful enhanced-recovery operations can make the waning stages of production financially and technically rewarding. The stage that no one seems to enjoy facing is the final cessation of production and the abandonment of wells and production facilities. Although abandonment is supposed to mean permanent termination, the effects of some abandonment practices can be felt for many more years than the relatively brief producing life of the average well.

Well abandonments are becoming increasingly frequent as aging fields reach their productive and economic limits. The cost of decommissioning the world's 6500 offshore platforms is estimated at $29 to $40 billion over the next three decades.[1] Onshore, tens of thousands of wells must be abandoned someday.

Responsible operators now seek to balance environmental responsibilities with the profit demands of shareholders. Shoddy plugging and abandonment (P&A) operations are expensive to remediate and exact a toll on both the environment and the reputation of the company. Local P&A mishaps can affect the reputation of the entire oil and gas industry. With those issues in mind, many operators are upgrading their well- and field-abandonment procedures to ensure that abandoned reservoirs truly are permanently sealed and facilities properly decommissioned. In this article, we review P&A and decommissioning practices, explain how sound abandonment practices protect the environment and discuss new technologies that reinforce the meaning of the "permanent" part of abandonment work. We also discuss permanent-abandonment challenges and practices, and examine well- and platform-abandonment operations in Oman, Canada, the Gulf of Mexico and the North Sea.

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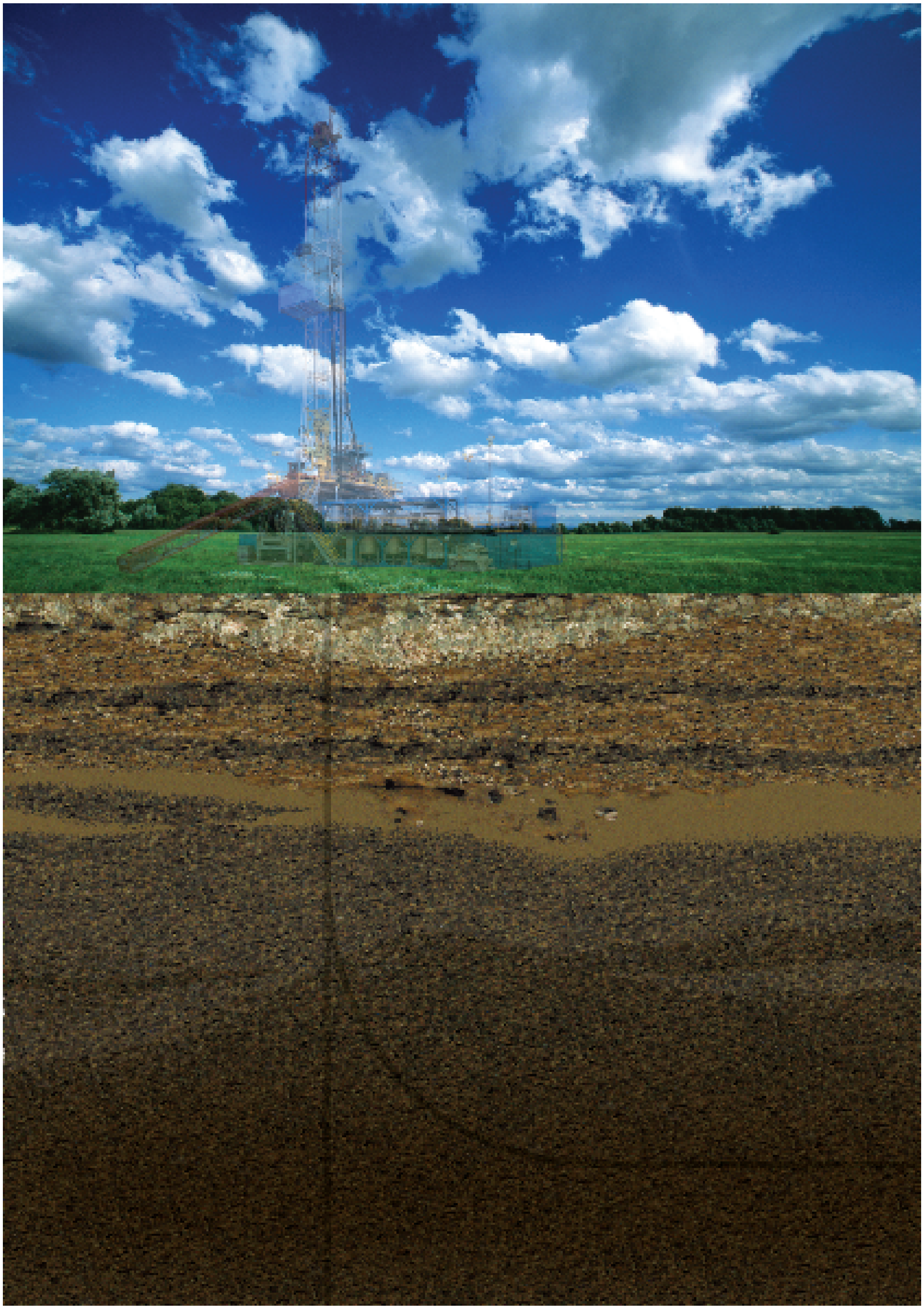
1. Pittard A: "Field Abandonment Costs Vary Widely Worldwide," *Oil & Gas Journal* 95, no. 11 (March 17, 1997): 84, 86–91.

   "Heavy Deck Removal Vessel Under Review for Frigg, Ekofisk," *Offshore* 61, no. 10 (October 2001): 88, 90.



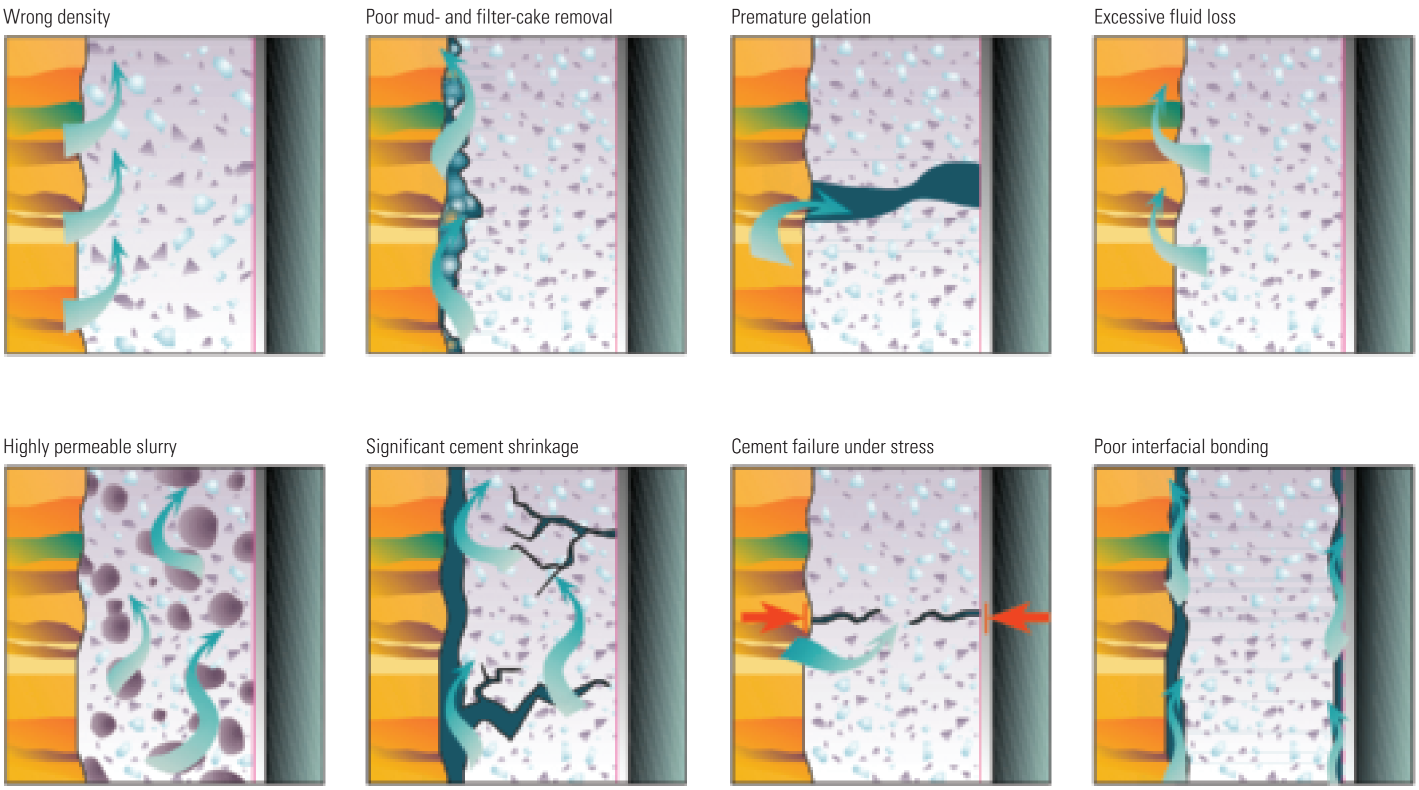
Wellbore-Abandonment Challenges and Solutions

The key goal of any well abandonment is the permanent isolation of all subsurface formations penetrated by the well. Although sealing depleted reservoirs is an important concern in P&A procedures, ideal abandonment operations isolate both producing reservoirs and other fluid-bearing formations. Complete isolation prevents gas, oil or water from migrating to surface or flowing from one subsurface formation to another. Experts estimate that a high proportion of seals placed in wells may be faulty.[2]

Leaking seals pose risks to the environment—groundwater resources and the overlying land or sea—and must be repaired, but remedial plugging operations are difficult and expensive. Sealing a well correctly at the outset is far easier, even if the initial financial outlay appears high. Considering well abandonment at the earliest stages of the well design makes sense because the quality of the primary cement between the casing and formations is a key factor in successful well abandonment years later (below).[3] For decades, oilfield engineers have recognized that Portland cement is the best material to seal abandoned wells. It is durable, reliable, available worldwide and relatively inexpensive. Complete removal of drilling mud and filter cake during primary-cementing operations decreases the risk of forming a microannulus or channel in the cement sheath, and improves bonding between rock formations, cement and casing. Bulk shrinkage of ordinary Portland cement slurry as it sets can create small cracks and gaps that can become flow paths.

Any deficiencies in primary cementing tend to affect long-term isolation performance. Wide fluctuations in downhole pressure and temperature can negatively affect cement integrity or cause debonding. Tectonic stresses also can fracture set cement. Regardless of the cause, loss of cement integrity can result in fluid migration, impairment of zonal isolation or casing collapse, even when high-quality cement is placed properly and initially provides a good seal.

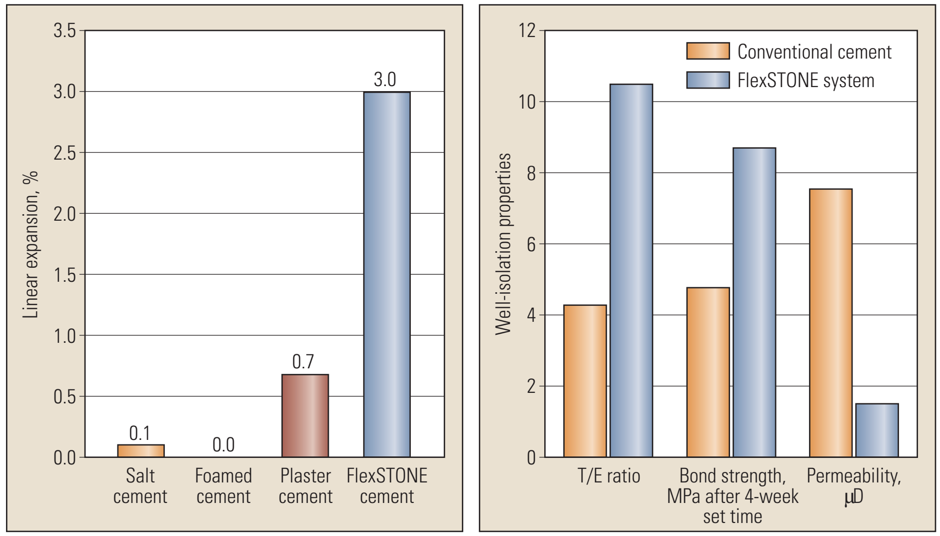
Advanced, flexible cement provides greater long-term cement integrity than ordinary Portland



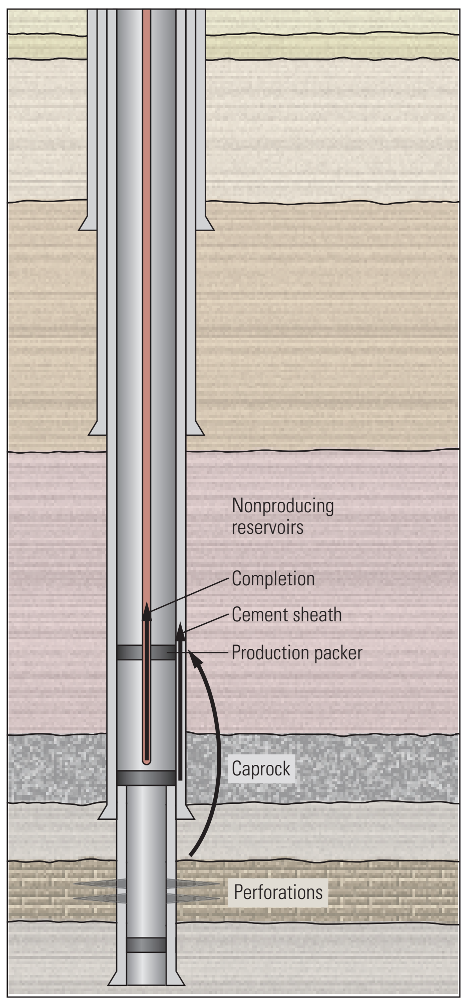
^ Primary cementing parameters that affect sealing. Incorrect cement density can result in hydrostatic imbalance. Poor mud- and filter-cake removal allows gas to flow up the annulus. Premature gelation leads to loss of hydrostatic pressure control. Excessive fluid loss allows gas to enter the slurry column. Highly permeable slurries provide poor zonal isolation and resistance to gas flow. Significant cement shrinkage and cement failure under stress create fractures and microannuli that transmit fluids. Poor bonding at cement-casing or cement-formation interfaces also can cause failure.

cement because it resists stress cracking and microannulus formation. Introduced in 2000, FlexSTONE cementing technology incorporates an optimized distribution of flexible particles into the cement matrix to adapt to temperature and pressure variation, providing zonal isolation for the life of the well and beyond.[4] The corrosion resistance, low permeability, flexibility and posthydration linear-expansion capabilities of FlexSTONE systems make them ideal primary cements and abandonment-quality cements (right).

If fluids are migrating from a well that must be abandoned, then the first challenge is to locate the fluid-migration path. Typically, subsurface fluids migrate through completion components, leaky plugs, deficient cement squeezes, or flaws in the primary cement sheath or the caprock—the relatively impermeable formation that encloses the reservoir. The caprock might be compromised by natural fracturing or by fracture-stimulation treatments. When multiple reservoirs exist, identifying which one is leaking enables targeted remediation.[5] Knowing the condition of primary and secondary cement is vitally important. Personnel involved in abandonment must understand the geology, wellbore geometry and accessibility, downhole equipment and its condition, reservoir pressure and potential fluid-migration paths to abandon a well successfully (right).



^ Properties of isolation-quality cement. New, flexible cement systems offer higher linear expansion than other expanding cement systems *(left)*. FlexSTONE systems also offer improved critical well-isolation properties, including tensile strength-to-Young's modulus ratio (T/E), bond strength and low permeability *(right)*.



< Well-abandonment considerations. Abandonment designs should address geological considerations, such as the type and condition of reservoir and caprock formations. The design also should address the condition and configuration of cement, perforations, tubulars and downhole equipment. Caprocks, cement and completion equipment are common fluid-migration paths that must be identified and sealed for effective long-term isolation.

2. While the estimates of the proportion of leaky seals vary widely from one region to another, in a survey initiated in 1993 in the Lloydminster area, western Canada, Husky Oil reported that 45% of surveyed wells suffer from gas-migration problems. On the basis of their research, the company estimated that remediation of these wells might cost $15,000 to $150,000. For more information: Schmitz RA, Cook TE, Ericson GMJ, Klebek MM, Robinson RS and Van Stempvoort DR: "A Risk Based Management Approach to the Problem of Gas Migration," paper SPE 35849, presented at the International Conference on Health, Safety & Environment, New Orleans, Louisiana, USA, June 9-12, 1996.
3. Primary cement is the initial cement sheath placed around a casing or liner string. The main objectives of primary cementing operations include zonal isolation to prevent migration of fluids in the annulus, support for the casing or liner string, and protection of the casing string from corrosive formation fluids.

   For more on primary cementing: Bonett A and Pafitis D: "Getting to the Root of Gas Migration," *Oilfield Review* 8, no. 1 (Spring 1996): 36–49.
4. For more on flexible cements: Le Roy-Delage S, Baumgarte C, Thiercelin M and Vidick B: "New Cement Systems for Durable Zonal Isolation," paper IADC/SPE 59132, presented at the IADC/SPE Drilling Conference, New Orleans, Louisiana, USA, February 23-25, 2000.

   Thiercelin MJ, Dargaud B, Baret JF and Rodriguez WJ: "Cement Design Based on Cement Mechanical Response," paper SPE 38598, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, October 5-8, 1997.
5. Isotope analysis of gas from two formations in the Lloydminster area demonstrated that the shallower formation was more prone to gas-migration problems. For more information about this example: Schmitz et al, reference 2.

Another challenge in P&A procedures is that relevant documents detailing the life of the well, such as well logs and schematic diagrams, might not be accessible. Information about the geology might be lost or unavailable because of the time that elapses between first production and well abandonment. This time frame can be decades. Also, it is common for wells to change ownership.

Operators also must strictly adhere to local well-abandonment regulations (below). In some regions, regulators grant permits for specific abandonment procedures and observe key stages of the operations. Compliance requires careful planning and coordination, which, for some operators, may be facilitated by specialized databases and software.[6] Regulations have changed considerably over the years, and keeping track of them requires engineering, environmental, legal and safety expertise.

In many regions, there are rules and regulations in place that constitute the requirements for well abandonment. In areas where the regulatory authorities do not supply minimum standards, operators tend to follow their own internal standards. Most of these standards are similar because many originated in the North Sea, where environmental-protection goals significantly influence operations.

Rigless Wellbore Abandonment

Preparation is a key ingredient in well abandonment, including a thorough assessment of the near-wellbore geology and the unique mechanical condition of the well. In a straightforward case, well abandonment begins with cleaning the production tubing and cementing, or squeezing, the production perforations. After the tubing above the production packer is perforated, cement is circulated between the tubing and casing. At shallower casing-shoe levels, multiwall perforations are shot and cement is circulated in all open annuli to achieve a wall-to-wall cement barrier. Finally, the tubing is perforated at a shallow depth—perhaps 150 m [490 ft]—and a surface cement plug is placed. When all cement plugs have been placed and tested, the wellhead and casing stump are removed.

In reality, most abandonment operations are much more complicated. Multiwell onshore-abandonment programs demonstrate both the complexity of the operations and the gains in efficiency and cost savings achieved when using a coiled tubing unit instead of a workover or drilling rig.[7]

Although pioneered on land in 1983 in the Prudhoe Bay field, Alaska, USA, rigless well-workover procedures using coiled tubing units have been adapted for abandonment operations worldwide.[8] Rigless abandonment operations also have been performed offshore for more than a decade, but removing production facilities generally requires mobilizing heavy lifting equipment (see "Field Abandonment and Platform Decommissioning," *page 37*).[9]

There are clear advantages to rigless abandonment using a coiled tubing unit for a multiwell abandonment program. The equipment costs less offshore and often is much easier to mobilize; onshore, its value lies in time savings over a comparable hoist operation. Coiled tubing allows precise placement of cement plugs, even in deviated wellbores. Also, coiled tubing operations can be performed without killing the well or removing the production tubing or wellhead.

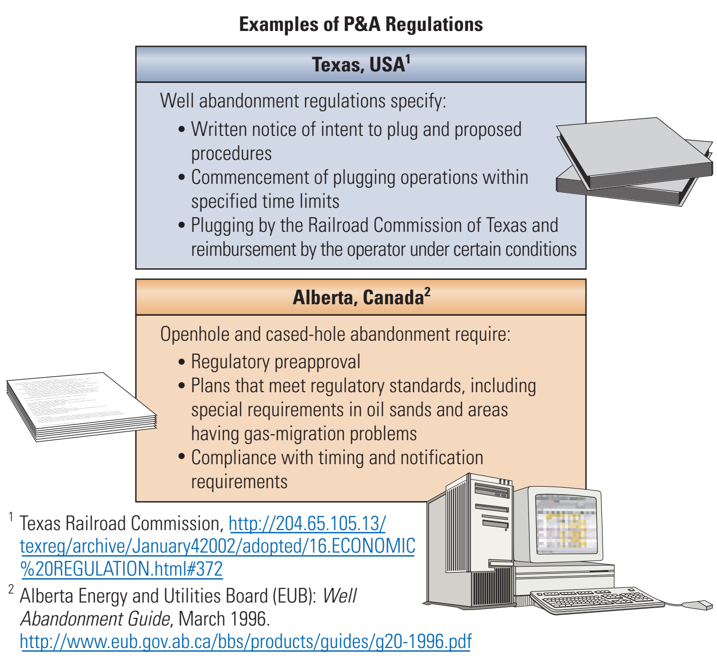
In several depleted oil and gas fields onshore Oman, Petroleum Development Oman LLC (PDO) initiated a multiwell abandonment program with Schlumberger (next page). The primary concern was to properly abandon all producing zones and protect aquifers while minimizing cost and risk.

PDO began its rigless abandonment project in November 2000 following a research report on permanent plugging materials and rigless applications. After an initial literature study, a review of the PDO well inventory revealed 60 redundant exploration wells located throughout their concessions. PDO decided to begin the 60-well abandonment project in southern Oman, where formation pressure regimes are mainly at or below hydrostatic levels.

PDO prepared the scope of work and equipment requirements for the contract tender, and soon realized that the complexity and variety of the abandonment activities required an integrated services approach. A key element of this rigless abandonment program would be coordinating all well services to maximize efficiency. Ideally, the lead contractor would perform at least 80% of the work, and preferably could perform the two most critical activities, perforating and cementing.

PDO developed five main criteria for optimal rigless abandonment performance:

- *Supermobile equipment*—All equipment, including a mobile camp, would be mounted on wheels to allow faster relocation, given the fact that the units must move every four to six days.
- *Self-supported operations*—The contractor takes care of nearly all activities, such as supplying materials, transport and subcontractor services, with minimal operator involvement. PDO supplies only programming, air transport, communication facilities, some mud chemicals and a site representative.



^ Examples of well-abandonment regulations. Designed to protect water and hydrocarbon resources, some regulations include standards for the type of cement used and the locations of cement plugs in the well, how deeply below surface the casing must be cut, and how the well location should be marked. Returning the surface to a pristine condition also is part of the job. In areas not subject to regulation, operators generally follow their own guidelines.

^ Location of Jisr field, Sultanate of Oman.

- *Dry location concept, also known as zero discharge*—No fluids are drained on or near the wellsite. This eliminates the possibility of repairing or rebuilding waste pits at abandonment locations. Although fluid circulation and dumping are inevitable during the job, all fluids are stored in tanks. Dry locations speed up the abandonment and restoration job by approximately ten days per well because no time is spent cleaning a waste pit or waiting for the location to dry. Previously, this required as much as several months.
- *One-stop job*—Each wellsite is visited only once and the entire abandonment job must be completed at that time. Any return to the site substantially delays the next operation.
- *Minimum mileage*—Equipment moves are optimized to reduce move time and optimize transport. With the PDO concessions covering approximately 41,000 square miles [110,000 square kilometers], executing the moves in accordance with health, safety and environment (HSE) guidelines is a crucial requirement.

From September through December 2001, 18 wells were abandoned, with typical savings of 30% over previous abandonment procedures. The wells were up to 25 years old and produced from sandstone and carbonate reservoirs of various geologic ages, so the abandonment of each well had to be planned and executed according to its unique attributes.

Although the lessons learned from each well were incorporated into subsequent operations, procedures could change significantly from one well to the next. Typically, the need for these changes became clear only after the first entry into a well. Thus, abandonment work differs greatly from new-well engineering, where forward planning is possible. Abandoning old wells requires an initial plan plus constant communication between field and base once the job commences, since the status of the well at surface and downhole differs for each well. For these reasons, seasoned site representatives and experienced, dedicated contractor staff are required to cope with the constant changes dictated by well conditions.

Challenges encountered to date included heavy, thick crude oil in the production tubing and "A" annulus—the space between the tubing and the first string of casing—that made it impossible to run wireline. Corrosion of the outer casing of some wells required additional plugging through the outer annulus of each well. Some wells had more than one annulus, requiring perforations through overlapping, concentric casing strings. On the other hand, some wells had good injectivity, which simplified downhole discharge by bullheading the cleaning slugs into the formation.[10] Bullheading saved time and effort compared with handling the cleaning slugs at surface. All these situations created a need for detailed programming for each individual well.

Common to all abandonments, however, is the requirement to perform the operation flawlessly the first time and to protect the environment at all stages of the operation. Accordingly, all locations are kept "dry" to speed restoration to their natural state. All waste fluids must be removed for safe disposal at PDO-designated areas, except for excess cement, which is nonhazardous. Fluids used on site are stored in tanks. Since there are no rigid governmental abandonment directives in place, the applicable PDO abandonment policy and standards are developed in line with the United Kingdom Offshore Operators Association (UKOOA) standards set for North Sea operations and similar Dutch government-accepted standards.

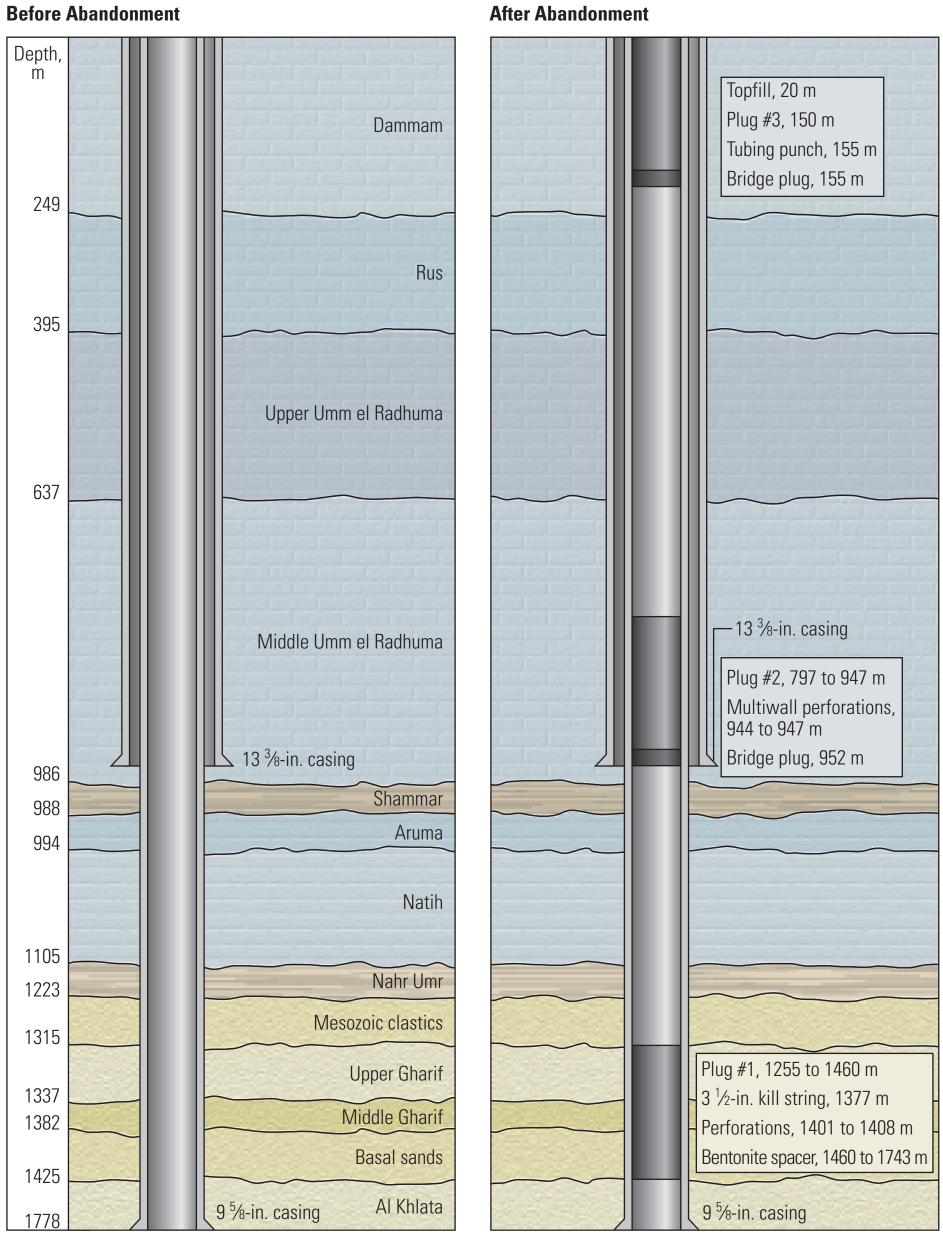
6. Woody F: "Streamlining Abandonments for Cost Reduction," paper SPE 66497, presented at the SPE/EPA/DOE Exploration and Production Environmental Conference, San Antonio, Texas, USA, February 26-28, 2001.
7. Bigio D, Rike A, Christensen A, Collins J, Hardman D, Doremus D, Tracy P, Glass G, Joergensen NB and Stephens D: "Coiled Tubing Takes Center Stage," *Oilfield Review* 6, no. 2 (October 1994): 9–23.
8. Harrison T and Blount CG: "Coiled Tubing Cement Squeeze Technique at Prudhoe Bay, Alaska," paper SPE 15104, presented at the 56th California Regional Meeting, Oakland, California, USA, April 2-4, 1986.
9. Hoyer CWJ, Chassagne A, Vidick B and Hartley IP: "A Platform Abandonment Program in the North Sea Using Coiled Tubing," paper SPE 23110, presented at the SPE Offshore Europe Conference, Aberdeen, Scotland, September 3-6, 1991.
10. Bullheading refers to the technique of forcibly pumping fluids into a formation. In addition to fluid-disposal operations, bullheading may be performed when formation fluids have entered the wellbore during a well-control event or when normal circulation cannot occur, such as after a borehole collapse. During bullheading operations, the fluid usually enters the weakest formation.

Abandonment of the Jisr-1 well, located in southern Oman, represents an average degree of difficulty for the PDO well-abandonment program (right). The operation began as a coiled tubing rig was moved on location (next page, top). Because the well was 12 years old, all valves on the Christmas tree were backed up with new valves, and coiled tubing blowout preventers were rigged up to ensure well control. Gas-detection and other safety equipment was installed before entering the cellar.[11]

Next, the tubing-hanger plug, used for temporary well suspension, was removed. The production tubing and "A" annulus were cleaned by jetting cleaning fluids down the tubing and up the annulus. The cleaning fluid contains surfactants and acids that remove sludge, oil and paraffin. Cleaning is critically important because seals within the wellbore can shift if sludge or other material moves after setting cement plugs. Also, cement will not form a perfect hydraulic seal with materials that are coated with hydrocarbon.

The production tubing and 9⅝-in. casing sump were cleaned with a high-pressure jetting tool run on coiled tubing. The tubing and the "A" annulus were then displaced with 11.4-kPa/m [0.5-psi/ft] salt brine. High-pressure jetting has proved to be an effective, environmentally friendly method for cleaning the tubing and sump, as waste generation is kept to a minimum. In cases of heavy-oil contamination, light crude and TubeCLEAN slugs are pumped and bullheaded through the perforations where possible. These were not required on Well Jisr-1, where a 2-m^3 [13-bbl] surfactant wash, with a 10-minute contact time, was considered sufficient to clean the "A" annulus.

With coiled tubing, the operations team set a bentonite spacer on bottom to serve as a base for the cement plug. On Jisr-1, the perforations were shot 342 m [1122 ft] above the base cement plug. The PDO requirement is to set the reservoir-isolation plug from 50 m [164 ft] below the lower perforation to 50 m above the top reservoir. To comply with this requirement at minimum cost, a 280-m [920-ft] bentonite spacer was spotted on bottom as a filler. The first cement plug was set through coiled tubing across the perforations. A second plug was set higher in the wellbore, opposite the 13⅜-in. casing shoe, after a bridge plug was set inside the 3½-in. production tubing using coiled tubing. The 3½-in. tubing and 9⅝-in. casing were perforated and a wall-to-wall cement plug was placed. Next, a bridge plug was set at 155 m [508 ft], and the tubing was perforated at 150 m. Finally, the surface cement



^ Jisr-1 wellbore schematic before *(left)* and after abandonment *(right)*.

plug was pumped. In contrast to procedures for the previous cement plugs, PDO abandonment standards do not require pressure-testing of the surface plug.

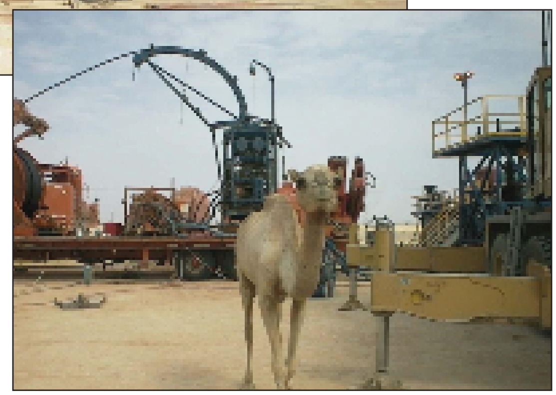
In most of the wells in this abandonment program, the cellars are about 2.6 m [8.5 ft] deep. Once the wellhead was cut 50 cm [1.6 ft] above the cellar floor, a 10-mm [0.4-in] thick steel plate was welded to the stump, and a small pole with the well number was installed to mark the location above the surface. Then, the cellar was temporarily filled with sand until final site restoration. The operation concluded with rigging down the coiled tubing unit, and removing the severed wellhead assembly and all junk from the location (next page, bottom). This operation took five days, including a two-day rig move. Placing cement plugs consumed much of the remaining time. Rig moves for closely spaced wells typically require 6 to 10 hours. Moves greater than 15 km [9.3 miles] require relocating the work camp.

This multiwell abandonment program will continue through much of 2002. The most complicated abandonment operations are scheduled late in the program to capitalize on the experiences of the previous operations. Other challenges continue to be addressed by the operations teams. Because unit moves consume a substantial part of the operational time, achieving the "supermobile" equipment goal and using multifunctional, fit-for-purpose equipment will increase efficiency. In addition, the major, daily activity is placing cement plugs in the wellbore, so there is considerable interest in developing short but safe cement-setting times.

In an operation such as rigless abandonment, where the benefits are in the time saved, long waiting-on-cement (WOC) times are a major hurdle. Slurry recipes are modified frequently to reduce pumping and thickening times as field experience increases. Current conventional through-coil slurries have 3-hour pump times and have been tagged, or contacted, in 11 hours. UniSLURRY formulations are being considered to reduce this time even more. UniSLURRY systems can be used for all cementing operations over a wide temperature and density range, addressing most oilfield cementing requirements. The UniSLURRY family consists of solid and liquid fluid-loss additives and liquid retarders. Their versatility simplifies the logistics of cementing operations by reducing the number and quantity of additives that have to be transported and, eventually, stored at the wellsite. The additives synergistically reduce overall additive concentrations while maintaining slurry quality.

As the operation teams prepare to abandon the most challenging wells, PDO is considering the use of flexible systems from the CemSTONE family. FlexSTONE long-term zonal isolation technology is expected to increase resistance to cracking under changing field conditions and provide an abandonment-quality plug that will last longer than ordinary cement plugs. Another advantage of the FlexSTONE slurry system is that it can be designed to expand, which eliminates any possible bulk shrinkage that might lead to loss of isolation. The expansion and flexibility will ensure excellent bonding with the casing and prevent the development of a microannulus between casing and cement plug so the well remains properly abandoned over time. An added improvement is faster compressive-strength development for slurries based on optimized particle-size distributions, such as FlexSTONE systems, than for conventional slurries, reducing the WOC time for pressure-testing the plugs. Laboratory tests have confirmed the faster compressive-strength development. The FlexSTONE system is one of many new systems that will be employed over the course of the PDO abandonment project.

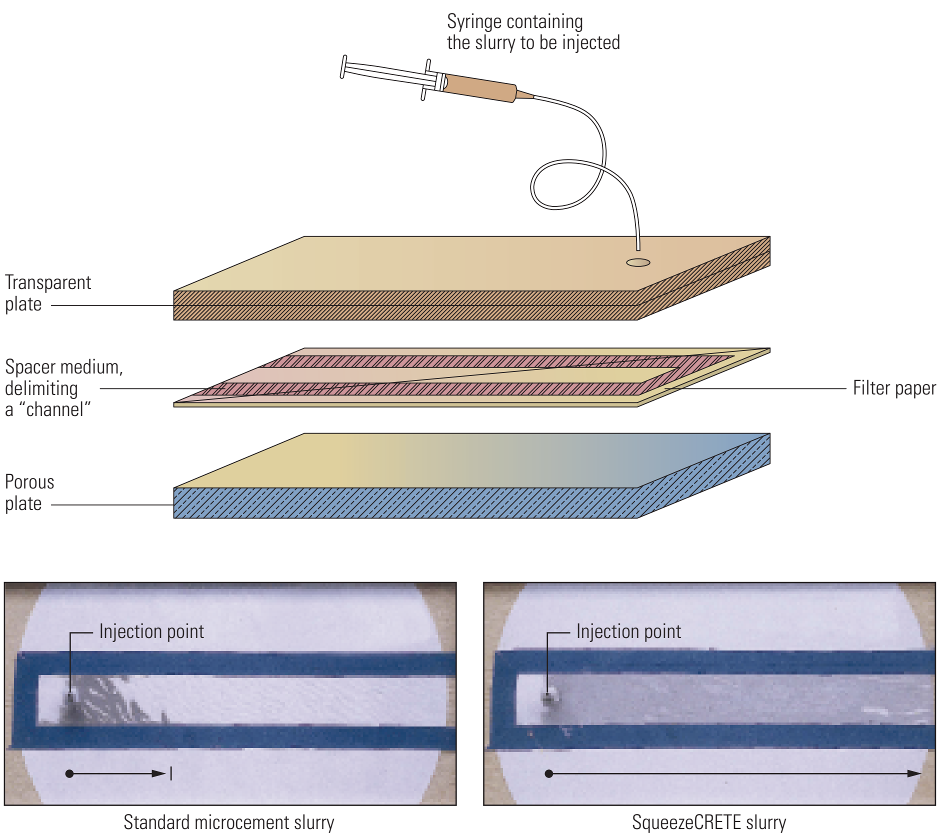
11. The cellar is a pit located below the drilling rig that holds the casinghead and casing spools. The depth of the cellar allows access to the master valves of the Christmas tree from ground level.



^ Typical P&A site in Oman. Mobile equipment, such as the coiled tubing rig (orange), allows P&A jobs to be completed in about five days *(top)*. Camels visit the sites from time to time *(bottom)*.

^ Typical restored desert location in Oman after well abandonment.

^ Bantry and Killam North fields, Alberta, Canada.



^ Slurry testing apparatus and results. Cement slurries are injected into one end of a test apparatus *(top)*. The slot between two plates represents a channel or imperfection to be repaired. Standard microcement slurry *(bottom left)* formed a bridge 30 mm [1.2 in.] into the narrow slot. SqueezeCRETE slurry *(bottom right)* penetrated the entire 225-mm [8.9-in.] length of the 120-µm slot to provide a complete seal.

Reduced-density LiteCRETE slurries are a possible solution for interaquifer isolation, where heavy fluid losses make the use of conventional slurries impractical.[12] The use of dropped proppant and pelletized bentonite to isolate well sections that are below the reach of conventional coiled tubing, either because of borehole restrictions or depth, is also being investigated. The use of resins to seal ⅛-in. pressure-transmitting systems and control lines has been successfully yard-tested and is awaiting a suitable candidate well for a full field test.[13] This procedure will permit wells with control lines to be abandoned without a rig, rather than using a rig to pull the completion. The development of resins also may lead to short, low-volume plugs with quick setting times that will replace expensive inflatable packers and mechanical bridge plugs.

Remediation of Imperfect Abandonments

In some cases, the initial well-abandonment procedures fail to seal the reservoir completely or permanently, and remedial operations must be undertaken.[14] This is particularly troublesome in gas wells because gas can pass through micron-scale leaks easily. Even high-quality primary cements sometimes fail to seal microannuli at pipe-cement or cement-formation interfaces. Remediation is essential for protection of groundwater resources.

Perhaps the most persistent efforts to seal small gas vents in onshore wells are occurring in western Canada.[15] PanCanadian Energy Corporation, for example, is working steadily to improve all aspects of its well-cementing operations; recently, it has focused on optimizing remedial cementing for permanent well abandonment. Working with Schlumberger, PanCanadian has sealed vent flows in abandoned gas wells in Alberta using an ultralow-rate squeeze-cementing technique.[16]

In a well in the Killam North field, two squeeze attempts failed to stop gas migration to surface. Another well in Bantry field also had been squeezed twice without success (above left). Both wells were permanently abandoned after successful ultralow-rate squeeze operations with advanced cementing technology.

A key ingredient in sealing the gas vents was the SqueezeCRETE remedial cementing solution, which uses optimized particle-size distributions to penetrate and fill minute gaps.[17] The extremely low set-cement permeability and resistance to cracking enhance the performance of SqueezeCRETE technology.

Prior to use of new cementing technology in the field, laboratory testing of ordinary microcement and SqueezeCRETE systems demonstrated that the ordinary microcement lost water rapidly and penetrated only a short distance in the narrow slot before forming a bridge in the testing apparatus.[18] In contrast, the SqueezeCRETE system evenly penetrated the full 225-mm [8.9-in.] length of the apparatus without fingering or bridging (previous page, bottom).

The ultralow-rate squeeze process required pumping rates as low as 5 L/min [0.03 bbl/min] to limit friction pressure and place as much slurry in the gap as possible. The SqueezeCRETE water content is much lower than typical Portland cement slurries, so the solid particles fill the voids readily without having to apply moderately high pressure to force water from the slurry. Maintaining a relatively low pressure reduces the potential for casing or tubing to expand as slurry is pumped through and then to relax as pressure is released. Even minor casing-shape changes during cementing operations can form a microannulus. Pumping continued as the cement set so that gas could not migrate into the cement.

Subsequent gas-migration tests of the Killam North and Bantry field wells confirmed that the gas vents had been sealed and that the wells met regulatory requirements for abandonment. Because tens of thousands of gas wells must be abandoned in western Canada alone, and many others worldwide, innovative cement-remediation technology and techniques may become increasingly important for successful permanent abandonment of wells with gas leaks.

Field Abandonment and Platform Decommissioning

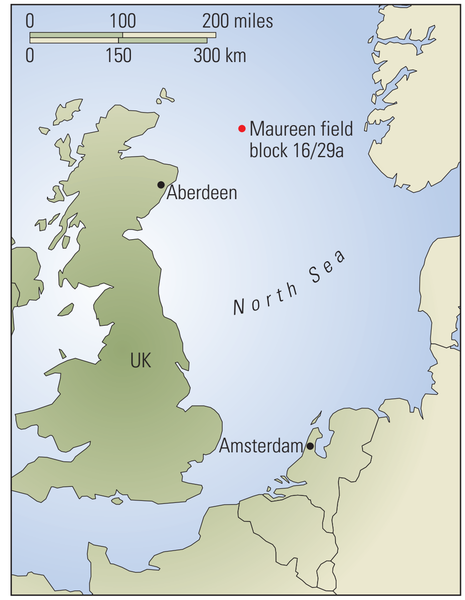
Once individual wellbores have been plugged and abandoned, the pipelines, facilities and other structures in the field must be decommissioned and removed. The surface site must be returned to a pristine condition. These operations can be challenging onshore; in offshore environments, especially in deep water, P&A and decommissioning procedures can become monumental endeavors that require careful coordination of several specialized crews.

Offshore production-platform decommissioning is subject to extensive regulation worldwide.[19] Decisions about when and how to decommission platforms involve complicated issues of environmental protection, safety and cost. Limited availability of heavy-lift equipment necessitates significant advance planning to remove platforms. Operations typically are scheduled to avoid rough weather.

Offshore field abandonment and platform decommissioning encompass abandonment of each well in the field. Permeable subsurface formations are isolated permanently from each other and the surface. Each well is plugged and the casing is cut at some depth below the seabed, as specified by local regulations. Pipelines also must be decommissioned and removed. The pipelines may be reused, sold as scrap or treated as waste.

Next, surface facilities and other structures are decommissioned, which may involve partial or complete removal or toppling in place. This may begin with removing the platform deck or topsides, followed by removing the supporting structure, known as the jacket, or the entire structure may be removed in one piece. Depending on the method selected, extensive diving operations may be necessary to cut the structure into pieces. Finally, the seabed must be remediated.

Typically, platform removal is the most expensive part of decommissioning operations because of the expensive lifting equipment that must be mobilized.[20] Ongoing advancements in lifting technology should make platform removal safer, quicker and easier.[21] Most offshore platforms are customized, so decommissioning operations are tailored for the specific configuration and conditions.



^ Location of Maureen field, North Sea.

Maureen Platform Refloating

The Maureen platform, installed in the UK sector of the North Sea in 1983 by operator Phillips Petroleum Company United Kingdom Limited and partners, was designed with recycling in mind. Because of the marginal reserves of the Maureen field, the platform was built to be refloated, moved and installed to produce oil from another field after depleting the Maureen field (above). In 2001, after eight years of planning and

12. For more on ultralightweight cementing: Al Suwaidi A, Hun C, Bustillos JL, Guillot D, Rondeau J, Vigneaux P, Helou H, Martínez Ramírez JA and Reséndiz Robles JL: "Light as a Feather, Hard as a Rock," *Oilfield Review* 13, no. 2 (Summer 2001): 2–15.
13. A yard test involves simulation of an oilfield operation using actual field equipment rather than laboratory equipment. For example, yard testing of cementing systems typically entails mixing and pumping a small batch to assess slurry characteristics before mixing and pumping into a wellbore.
14. For more on remedial cementing: Marca C: "Remedial Cementing," in Nelson EB: *Well Cementing*. Sugar Land, Texas, USA: Schlumberger Dowell (1990): 13-1 – 13-28.
15. For more on well abandonment in Alberta, Canada: http://www.eub.gov.ab.ca/bbs/products/catalog/g1-pubs.htm#guides.
16. For more on the ultralow-rate squeeze technique: Slater HJ, Stiles DA and Chmilowski W: "Successful Sealing of Vent Flows with Ultra-Low-Rate Cement Squeeze Technique," paper SPE/IADC 67775, presented at the SPE/IADC Drilling Conference, Amsterdam, The Netherlands, February 27-March 1, 2001.
17. For more on SqueezeCRETE technology: Boisnault JM, Guillot D, Bourahla A, Tirlia T, Dahl T, Holmes C, Raiturkar AM, Maroy P, Moffett C, Pérez Mejía G, Ramírez Martínez I, Revil P and Roemer R: "Concrete Developments in Cementing Technology," *Oilfield Review* 11, no. 1 (Spring 1999): 16–29.
    Farkas RF, England KW, Roy ML, Dickinson M, Samuel M and Hart RE: "New Cementing Technology Cures 40-Year-Old Squeeze Problems," paper SPE 56537, presented at the 1999 SPE Annual Technical Conference and Exhibition, Houston, Texas, USA, October 3-6, 1999.
18. The laboratory testing and apparatus are described fully in Slater et al, reference 16: 2.
19. For more on offshore platform decommissioning: Anthony NR, Ronalds BF and Fakas E: "Platform Decommissioning Trends," paper SPE 64446, presented at the SPE Asia Pacific Oil and Gas Conference and Exhibition, Brisbane, Australia, October 16-18, 2000.
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    Bradbury J: "Find the Right Solution for Cessation," *Hart's E&P* 74, no. 11 (November 2001): 45.

^ Refloated Maureen platform.

preparation, the platform was refloated and relocated successfully to Norway, where it awaits reuse or dismantling.[22]

Unique among North Sea production platforms, the Maureen platform rested on a steel-gravity structure rather than the more common concrete-gravity structure; its three storage tanks served as legs for the platform.[23] The storage tanks double as ballast tanks when the platform is towed. Its facilities integrate all equipment necessary to drill, produce and store oil while also accommodating personnel. The main platform components—the steel-gravity structure and the deck—were constructed onshore and mated near the shore before being towed to the field. An articulated loading column (ALC) was installed to move oil into tankers because a pipeline to shore was uneconomic.

The platform supported 13 production wells and seven water-injection wells in the Maureen field, which produced 223 million bbl [3.5 million m^3] of oil between 1983 and 1999.[24] In addition, a single subsea well in the Moira field was tied back to the Maureen platform. As production declined, Phillips began to study decommissioning options.

Platform decommissioning typically involves multiple operations.[25] Before any operations begin, regulatory agencies require proof that the abandonment plans will meet environmental and safety standards. The first step is to cease production and abandon each well. Next, the platform is decommissioned, after which it may be dismantled and removed. The size, water depth and structural condition of the platform strongly influence dismantling and removal plans. The most common options for offshore platform decommissioning include total or partial removal, toppling in place or reuse. As in most offshore operations, equipment availability and weather are critical factors. Following decommissioning operations, the site must be surveyed to ensure navigational safety and environmental protection.

Total removal of offshore facilities leaves the seabed free of debris, which is desirable for fishing but tends to be expensive. Partial removal reduces cost, but necessitates careful surveying of the remaining structure to ensure navigational safety. This option currently is open only to structures greater than 10,000 metric tonnes [11,000 tons] in the OSPAR Commission area.[26] Toppling a platform in place, which will be discussed later, is considerably less expensive than removal, but is illegal in North Sea and northeast Atlantic Ocean areas under OSPAR regulations. The operation would have to ensure that the platform is devoid of environmental hazards and falls as intended. Some well-maintained platforms are left in place or moved to another location for possible reuse.

Studies of the Maureen platform revealed more than 60 possible removal options. Of these, six were considered achievable, and each of those required refloating the platform before subsequent disposal operations. Computer simulations of refloating operations, including issues such as metal fatigue, confirmed that the operations could be performed safely.[27] The studies confirmed that reusing the platform was feasible, even after more than 18 years of production, because of the excellent maintenance of the facilities.[28]

All the wells were abandoned and the conductors and risers cut before refloating the platform. Seawater in the storage tanks was pumped out to provide buoyancy. Refloating operations began with water injection below the platform to lift the structure from the seabed. Aker Offshore Partner performed the refloating operation in about 60 hours without incident (previous page). Operational arrangements included preparing extensive contingency plans—particularly to provide additional buoyancy if necessary—and constant monitoring of ascent rate and tank pressures to achieve the desired draft for towing.

Despite marketing the platform worldwide for several years, Phillips has been unable to identify a full reuse option for Maureen that satisfies its five criteria—regulatory, technical, commercial, environmental and scheduling. Partial reuse options also have been evaluated, with the most viable being a proposal from Aker to turn the bases of the platform and parts of the ALC into a deepwater quay at Stord, Norway.

Toppling an Offshore Platform

In some regions, platforms may be abandoned in place to form an "artificial reef." Toppling a platform in place requires significant preparatory work to ensure safety and care for the environment. In the Main Pass area, Block 254, in the Gulf of Mexico, the production platform was toppled in place in August 2000 (above right). The

^ Location of Main Pass 254 platform, Gulf of Mexico.

22. Bradbury J: "Majestic Maureen Makes It," *Hart's E&P* 74, no. 8 (August 2001): 75, 76, 78, 80.
For more on the Maureen field: http://www.phillips66.com/maureen/.
23. Tilling G: "Refloating Maureen Oil Platform (110,000 Tonnes) for Re-Use in Waters Away From the North Sea," paper SPE 29938, presented at the SPE International Meeting on Petroleum Engineering, Beijing, China, November 14-17, 1995.
24. The production proved to be substantially higher than that predicted at the time of discovery. See Tilling, reference 23: 6.
25. For more on facility removal: Della Greca A: "Offshore Facility Removal: How to Save Cost and Marine Resources," paper SPE 36936, presented at the SPE European Petroleum Conference, Milan, Italy, October 22-24, 1996.
26. The OSPAR Commission for the Protection of the Marine Environment of the North-East Atlantic, formerly the Oslo and Paris Commissions, works to prevent and eliminate marine pollution. For more information: http://www.ospar.org/.
27. Denise J-P and Tilling GM: "Interactive Hydrodynamic/Structural Analysis for Refloating a Very Large North Sea Structure: Maureen Alpha Platform," paper SPE 36937, presented at the SPE European Petroleum Conference, Milan, Italy, October 22-24, 1996.
28. Tilling, reference 23: 2.

^ Toppling a platform in place. These time-lapse photographs show the controlled sinking of the platform, which took 37 seconds from first motion to complete submergence.

operations, which took several months of planning and coordination by operator Unocal, involved contractors for marine operations, engineering and diving services.

From the start, Unocal worked with several agencies to be sure that all operations would comply with existing regulations. The company also decided at an early stage not to use explosives to topple the platform because of the abundant marine life in the area. Next, the team had to prepare for all aspects of decommissioning and toppling operations.

The platform, which sat in 280 ft [85 m] of water, was installed in 1975. Six wells produced to tanks mounted on the decks, so there was no pipeline to abandon. However, the company sought to topple the deck and jacket together, an operation not attempted previously in the area.

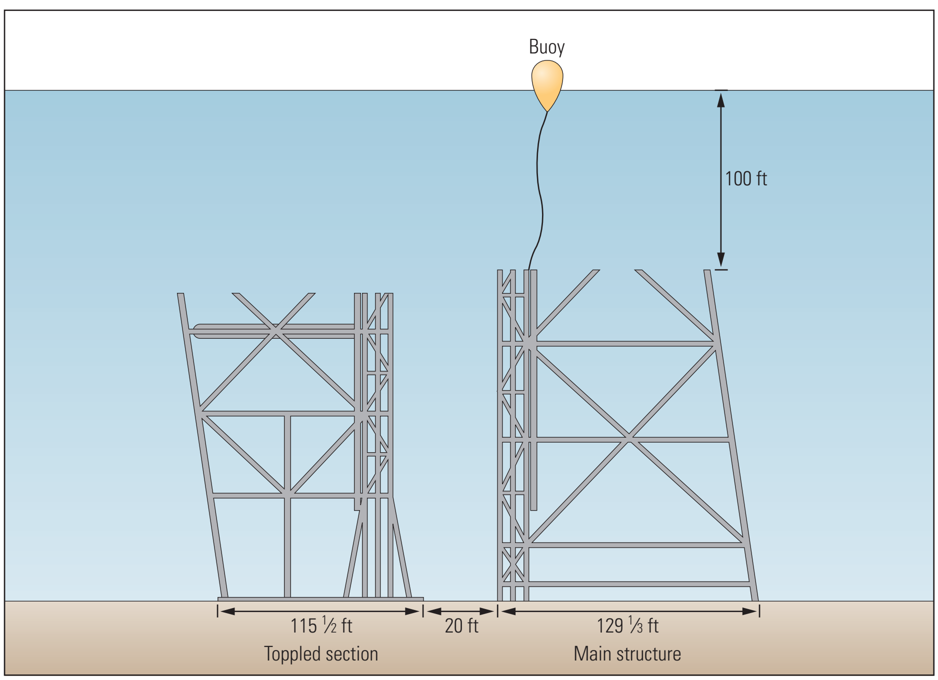
29. For more on the Main Pass 254 abandonment: Whitney CD: "Toppled Platform In-Place Creates Reef in US Gulf," *Oil & Gas Journal* 98, no. 45 (November 6, 2000): 53, 54, 56, 58, 59.

30. El Laithy WF and Ghzaly SM: "Sidki Well Abandonment and Platform Removal Case History in the Gulf of Suez," paper SPE 46589, presented at the SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, Caracas, Venezuela, June 7-10, 1998.

The abandonment operations began with decommissioning and removal of production equipment and piping, including recovery and proper disposal of all fluids. Next, each of the production wells was abandoned according to rules of the US Minerals Management Service (MMS). During well abandonment, divers cut each well and leg of the platform. Cutting the abandoned wells eliminated the possibility of damaging cement plugs below the mudline by transmitting stresses along the casing during toppling. Cuts in the legs created weak points to facilitate toppling. Before completely severing the pilings, the crews installed rigging to provide the force necessary to topple the platform. Personnel stayed on the platform throughout the operations to ensure safety once navigational aids were removed. Divers worked for 205 hours, completing their work in 26 days.[29]

At that point, the platform was ready for toppling with horizontal force provided by an anchor-handling vessel equipped with two 500-ton [181-tonne] winches. The initial attempts failed because of problems with the rigging system, so the crew deballasted subsea drill-water tanks to reduce the horizontal toppling force required. The third attempt succeeded in toppling the platform, which submerged completely within 37 seconds (previous page). Divers surveyed and videotaped the toppled platform to confirm its location and a buoy was installed to mark its location (below left).

There has been at least one case in which wells and a platform were abandoned after a cargo ship collided with a platform. In an accident in the Gulf of Suez in 1989, the wellheads and the platform were damaged to the degree that they were declared a total loss.[30] The operator's key objectives were to control the wells, minimize pollution and decommission the damaged structures safely. Scaffolding erected over the mangled platform allowed workers to safely access valves, so oil spills were halted within one week of the accident. After the top deck of the platform was removed, a drilling rig was mobilized to support well-abandonment operations. Finally, two and a half years later, the rest of the platform was decommissioned. This exceptional event underscores the need for contingency planning in case wells or platforms must be abandoned prematurely.



^ Toppled platform. This diagram, prepared after a post-topple survey, shows the stable resting positions of the main structure and toppled section more than 100 feet [30 m] below the sea.

Abandonments Ahead

The conceptual "life of a well" clearly extends beyond the production phase. Ideally, modern well-abandonment procedures isolate subsurface formations forever. Oil and gas producers recognize the importance of true permanent abandonment, which begins with well design, continues through primary cementing and concludes with fit-for-purpose well-abandonment procedures. Creating a common budget for each of these operations at the beginning of a project helps ensure that they are carried out properly.

Field abandonment, which typically involves more than one well, requires close coordination of many different operations to ensure subsurface isolation of each well, removal of surface equipment and facilities, and restoration of the surface to a pristine condition. With new technologies for primary and remedial cementing, perforating, and cement evaluation in addition to coiled tubing and slickline intervention, Schlumberger and E&P companies are ready to tackle the many well- and field-abandonment projects ahead. —GMG

Lifelong Asset Management Using the Web

Lost time means lost opportunity and reduced cash flows. Using the World Wide Web to communicate and collaborate shortens cycle time, while increasing the amount of information immediately available from a company's knowledge bank. A new system of information solutions provides secure, reliable interaction tools for all stages of the exploration and production cycle.

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The exploration and production industry faces mounting pressures to reduce finding and production costs, increase recoverable reserves and maximize asset value. The industry must discover and develop new reservoirs and improve recovery percentages for existing reservoirs from the traditional average of 35%, to 60% or better, while controlling costs. Yet, new prospects tend to be in deep waters and remote areas where costs and risks are high and field developments increasingly are more complex.

Efficiency and productivity improvements are essential. Each 1% increase in recovery equals one year's consumption at current demand. As operators focus on their core business of exploration and production (E&P), they are outsourcing other activities, redefining the traditional roles between operators and the service industry.

This focus on core activities has led many E&P companies to develop less technology in-house. Instead, they establish a competitive advantage through joint developments or by using available technologies in innovative ways. High-definition seismic interpretations, new logging measurements and improved reservoir modeling and simulation provide tools to optimize reservoir performance. Monitoring production and reservoir data from permanent sensors linked to control equipment is changing production management.[1]

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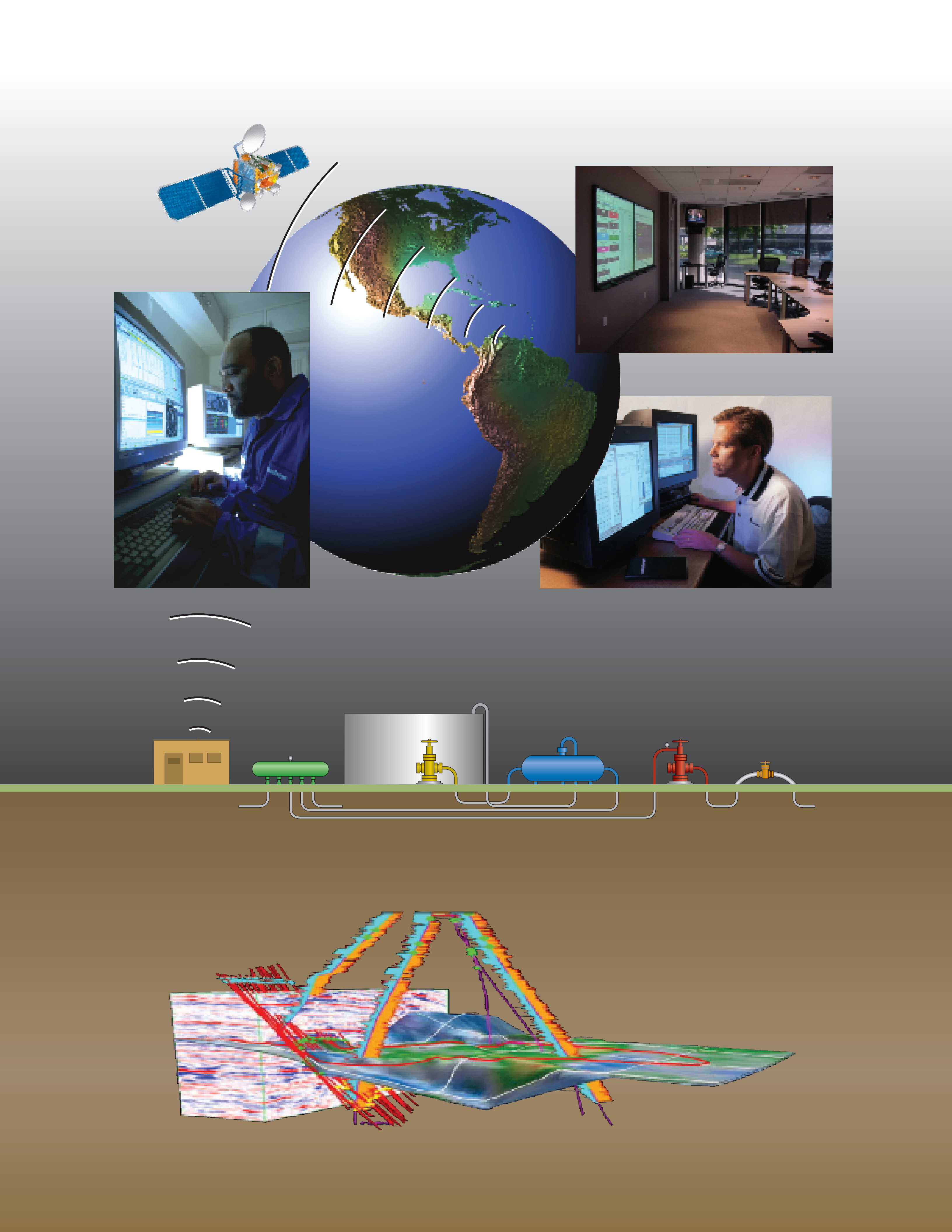
1. Algeroy J, Morris AJ, Stracke M, Auzerais F, Bryant I, Raghuraman B, Rathnasingham R, Davies J, Gai H, Johannessen O, Malde O, Toekje J and Newberry P: "Controlling Reservoirs from Afar," *Oilfield Review* 11, no. 3 (Autumn 1999): 18-29.
   Bratton T, Edwards S, Fuller J, Murphy L, Goraya S, Harrold T, Holt J, Lechner J, Nicholson H, Standifird W and Wright B: "Avoiding Drilling Problems," *Oilfield Review* 13, no. 2 (Summer 2001): 32–51.



At the heart of this transformation in the E&P business is creating the ability for anyone, anywhere to immediately access reliable, validated data and knowledge required to make informed decisions. This requires new information technology (IT), new workflows and highly skilled individuals. The service sector must provide more than traditional products and services; information is key to the future. New solutions are based on real-time data and technical collaboration within and between companies.

Much of the E&P industry lacks the infrastructure to classify, verify, interpret and translate the current profusion of data into information, knowledge and, ultimately, well-founded decisions. Operational and financial success hinges on a company's ability to make effective decisions and take corrective actions. Knowledge-management systems based on best practices help to reduce error repetition and enhance quality consistently in global operations.[2]

Web-based tools have matured to the point that many parts of reservoir management can be effected over the World Wide Web. The Web enables collaboration and access to real-time and archived data. Knowledge-management tools can mine information that a company already has on hand, providing a competitive advantage.

The recent demise of so many "dot.com" companies illustrates the importance of understanding an industry's fundamental business processes for success on the Internet. Schlumberger has years of experience providing service to the E&P industry, giving it a profound understanding of industry business processes. Its worldwide presence means it has connectivity where hydrocarbons are found and produced. Schlumberger was the first company in the industry to use an Internet-based client data-delivery system.[3] Schlumberger Information Solutions (SIS), an operating unit of Schlumberger Oilfield Services, provides a unique combination of elements to produce an effective, integrated, global information solution for the oil and gas industry:

- information technology to connect users to data
- information management for handling and manipulating massive quantities of data
- decision-making software tools to transform data into useful information for analysis
- expert consulting services to help oil companies focus on core activities.

This article describes these SIS tools for improving lifelong management of a reservoir. Starting with licensing rounds and acquisitions and continuing through prospect evaluation, drilling and reservoir management, interactive Web-based collaboration tools are streamlining the way the E&P industry works.

Acquiring a Property: Virtual Data Rooms

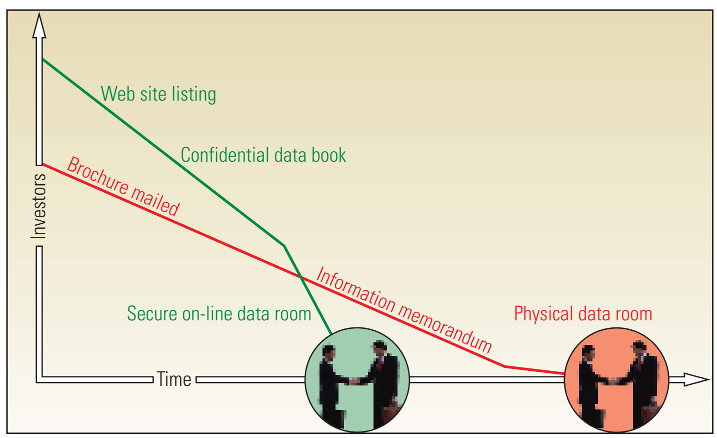
The life cycle of a reservoir often begins when an owner of mineral rights in an area grants E&P companies permission to explore. In most parts of the world, companies compete for exploration rights in government-managed licensing rounds. Licensing agencies typically provide technical and economic information about the blocks or leases to qualified companies. E&P companies analyze opportunities and submit proposals to the government agency, which, in turn, awards exploration licenses to the successful bidders.

Instead of obtaining properties through government licensing rounds, a company may buy directly from another company wishing to sell properties. The acquisition and divestiture (A&D) process traditionally has been slow and cumbersome. When an oil company had properties to divest, either they or a broker gathered the information necessary for bidders to evaluate the technical and economic condition of a property. A limited amount of information about the property was compiled in a brochure and mailed to an audience selected by the company or broker. Interested parties signed a confidentiality agreement to gain access to a set of binders, termed a data book, often containing hundreds of pages of technical and economic information about the property.

Those still interested after examining the data book were given access—one company at a time—to a data room containing boxes or file cabinets full of detailed technical and financial information. These parties submitted bids and, after negotiations, the offering company signed a contract with the winning bidder. Often, further due diligence preceded closing the deal. This whole process could be lengthy (below).

If deals are completed faster, cash is generated faster. The Web introduces possibilities for new efficiencies to speed this process. IndigoPool, a Schlumberger company, publishes information on licensing rounds and A&D deals throughout the world. The IndigoPool.com Web site serves as a platform for buyers and sellers to communicate large volumes of complex technical information and provides a secure, neutral workspace for oil- and gas-property A&D or licensing, data sales and service.

Authorized users can evaluate potential opportunities on-line from anywhere in the world. Using either graphical or search-based navigation, a buyer can immediately see the coverage of speculative seismic and other exploration data from the vendors—currently about 20—that publish this information on the IndigoPool.com site. The Web site takes the place of the brochure, physical data book and



^ Shortening the acquisition and divestiture (A&D) process with on-line transactions. The traditional A&D process (red) requires time to prepare and send materials to prospective investors. Access to the physical data room is limited to one investor at a time. In the new process (green), the IndigoPool.com Web site is secure, yet more widely accessible. Multiple investors can view the confidential data simultaneously. Deals can be completed more quickly using the Web site.

data room. The information is available to many more interested investors worldwide (right).

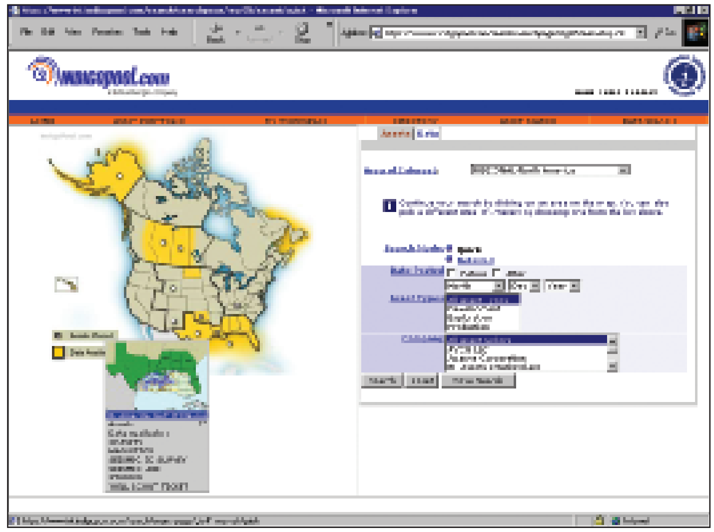
As part of the evaluation process, the buyer has the opportunity to acquire additional data as appropriate to the evaluation. The IndigoPool on-line A&D data book and data room are powerful means for exposing these opportunities to a global audience (below right). The on-line data book provides summary asset information—similar to the set of binders submitted in the traditional A&D process—such as production reports, key logs and structure maps.

The physical data room containing boxes of technical information has been replaced with an on-line data room. This part of the site contains extensive well data, production and operational data, financial reports, geologic and geophysical interpretations, and land and legal agreements. Superior data organization and wider data access give a large pool of potential buyers a clearer picture of the value of the asset. Multiple prospective investors can access this information simultaneously using IndigoPool, significantly reducing the time from offering to signing the deal.

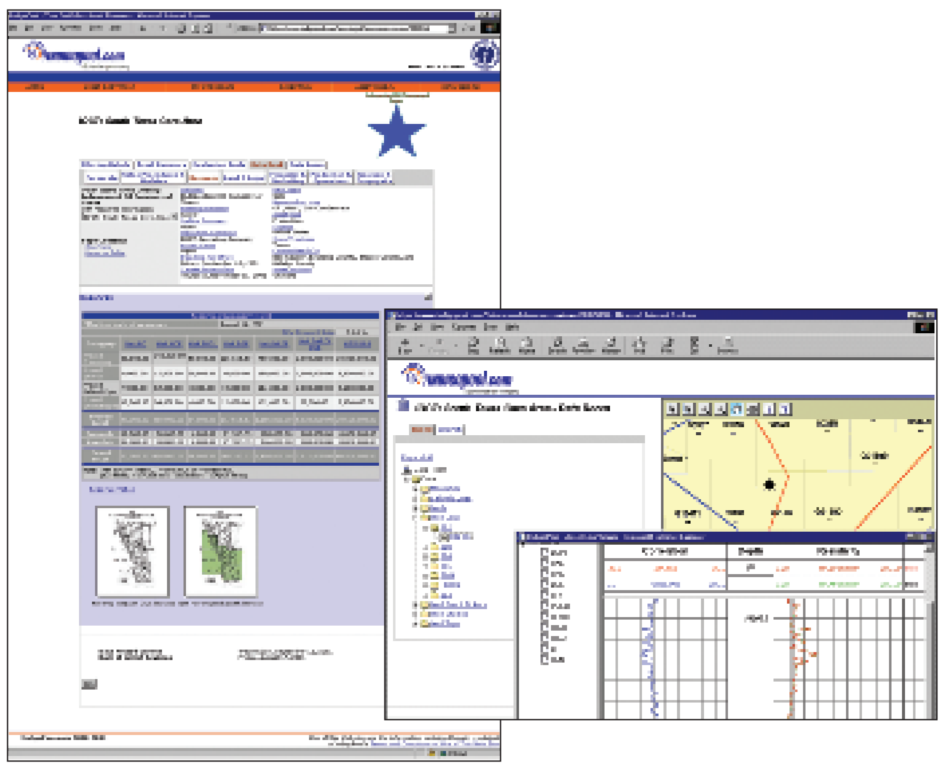
IndigoPool can provide direct marketing of assets through targeted e-mail messages. For example, an announcement about offerings by a major E&P company for properties in Australia, Egypt, Trinidad and France generated traffic from 600 different recipients the same day it was distributed. Broadcasting offerings through the IndigoPool service helps reach more prospective investors than a company's internal marketing organization normally can contact.

Since IndigoPool.com began operations in April of 2000, daily user traffic has steadily increased. At the end of 2001, between 600 and 900 users were accessing the site daily.

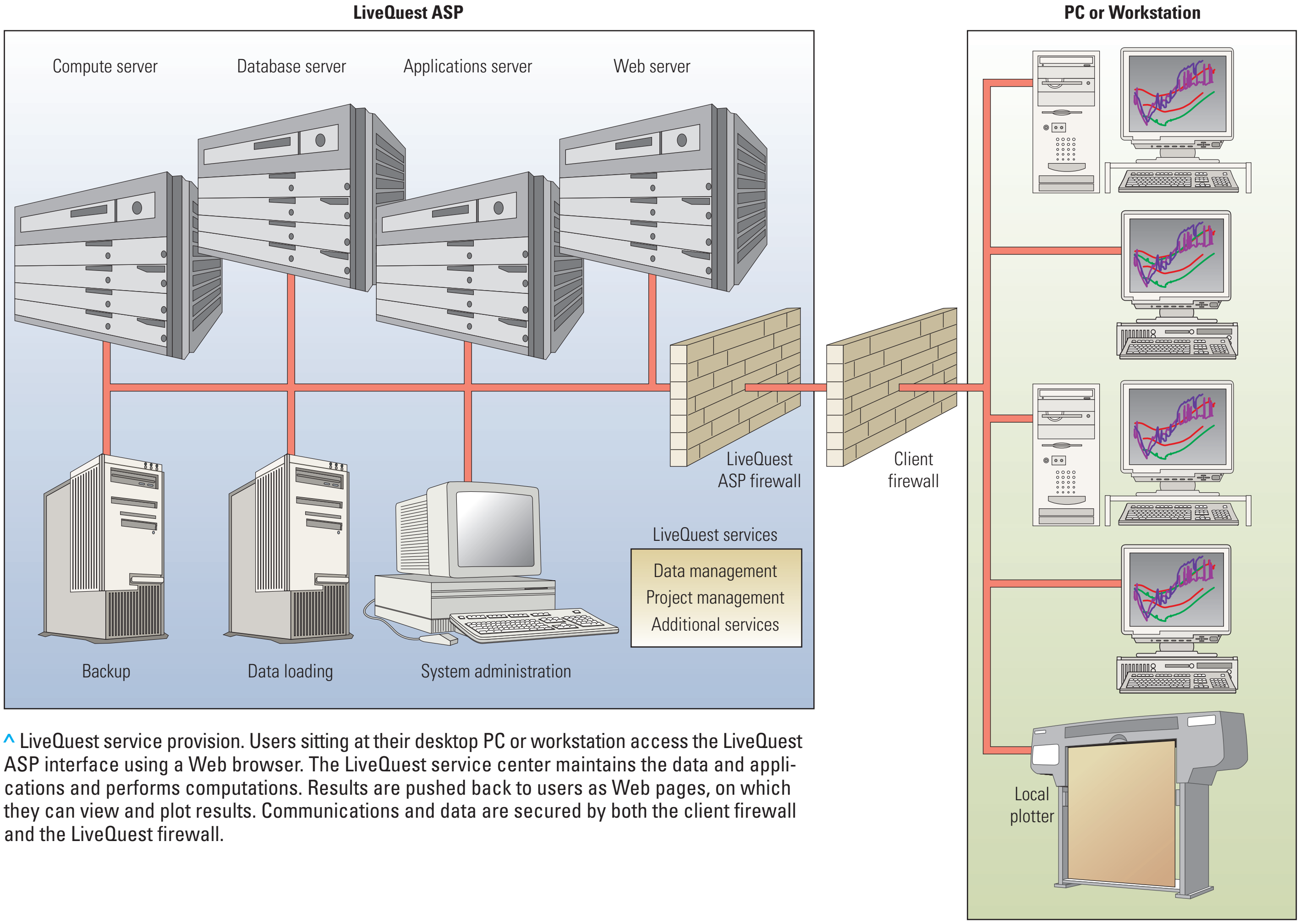
2. Amin A, Bargach S, Donegan J, Martin C, Smith R, Burgoyne M, Censi P, Day P and Kornberg R: "Building a Knowledge-Sharing Culture," *Oilfield Review* 13, no. 1 (Spring 2001): 48-65.
   Brown T, Burke T, Kletzky A, Haarstad I, Hensley J, Murchie S, Purdy C and Ramasamy A: "In-Time Data Delivery," *Oilfield Review* 11, no. 4 (Winter 1999/2000): 34–55.
3. "Schlumberger Data Management," in *Outsourcing: Creating Value, a supplement to Oil and Gas Investor* (April 2001): 16–17.



^ Navigation on the IndigoPool.com site. Users can access information either by selecting locations from a map or by searching text fields.



^ Data book and data room. High-level information is provided in the data book *(left)*. Interested investors can obtain access to property details, such as this well log *(right)*, in the on-line data room.



^ LiveQuest service provision. Users sitting at their desktop PC or workstation access the LiveQuest ASP interface using a Web browser. The LiveQuest service center maintains the data and applications and performs computations. Results are pushed back to users as Web pages, on which they can view and plot results. Communications and data are secured by both the client firewall and the LiveQuest firewall.

Prospecting Alternatives

After its merger with Amoco and takeovers of ARCO and Vastar, BP had a strong concentration of acreage in the US Gulf of Mexico continental shelf, but insufficient exploration staff to fully evaluate these holdings. BP feared some of the leases could expire untested. The potential problem was solved with the VirtualProspect on-line system, a joint development of BP and IndigoPool, that exposes the data to a broad audience of external consultants. The VirtualProspect program was initiated in late 2000. Consultants examined the on-line information and submitted proposals for developing prospects. BP awarded contracts on 42 prospects in five Gulf of Mexico properties based on these proposals.

Following the interpretation work by the selected consultants, BP bought the rights to 10 of the prospects for about $300,000 US. BP estimates that collectively they could contain over 1 Tcf [28 billion m^3] of gas. This represents 200 Bcf [5.7 billion m^3] of risk-weighted resources. The net present value of the risked reserves is between $50 and $100 million US, assuming standard terms and prevailing costs for Gulf of Mexico development. If the prospects are successful, the consultants stand to receive additional bonuses. Prospectors whose proposals were not accepted by BP may obtain additional compensation by farming out the prospects on behalf of BP.

BP has conducted two additional VirtualProspect rounds. Many of the consultants who were involved in the first round also participated in subsequent rounds. The VirtualProspect system allowed BP to fully evaluate these properties in less than one year—a dramatic acceleration over what might have been achieved internally.

Another Path to Evaluation Tools

Companies perform extensive evaluations on properties and prospects, requiring a variety of hardware and software components. Some applications, particularly seismic interpretation software, are designed to run on high-end workstations using the UNIX operating system. Many economic-analysis and production-engineering applications run only on a desktop or laptop PC. An engineer or geoscientist may need two computers to run the software required for a job.

If software applications are used infrequently or are available only on a computing platform not used by a company, they may be prohibitively expensive to acquire. Even when purchase is justifiable, maintaining a company's software and updating to the latest releases can be daunting.

The evolution of the Web as an interactive workspace has introduced a new kind of business, the application service provider (ASP). Essentially, an ASP leases software use to clients on a periodic-payment or a pay-per-use plan. The Schlumberger ASP is called the LiveQuest service. A client may choose to connect to a LiveQuest center on a dedicated line or through the Internet, needing only a browser such as Netscape Navigator or Microsoft Internet Explorer software.

The LiveQuest ASP solution gives easy access to oilfield software, including the following:

- geophysical and geologic software, including most of the GeoFrame suite
- reservoir-management tools, including ECLIPSE software
- Merak economics and risk-analysis software
- production-management tools, including FieldView and OFM software
- data-management tools, including the Finder system
- Drilling Office integrated drilling software.

The LiveQuest offering is continually updated to the latest version of supported applications.

The data used in LiveQuest projects are kept secure in the same location as the application, eliminating the need to transfer large data sets to run applications. The applications run on state-of-the-art hardware at Schlumberger Data Centers in Calgary, Alberta, Canada; Houston, Texas, USA and Aberdeen, Scotland, with other locations planned. Schlumberger experts around the world provide interpretation support and assist with the use of LiveQuest applications.

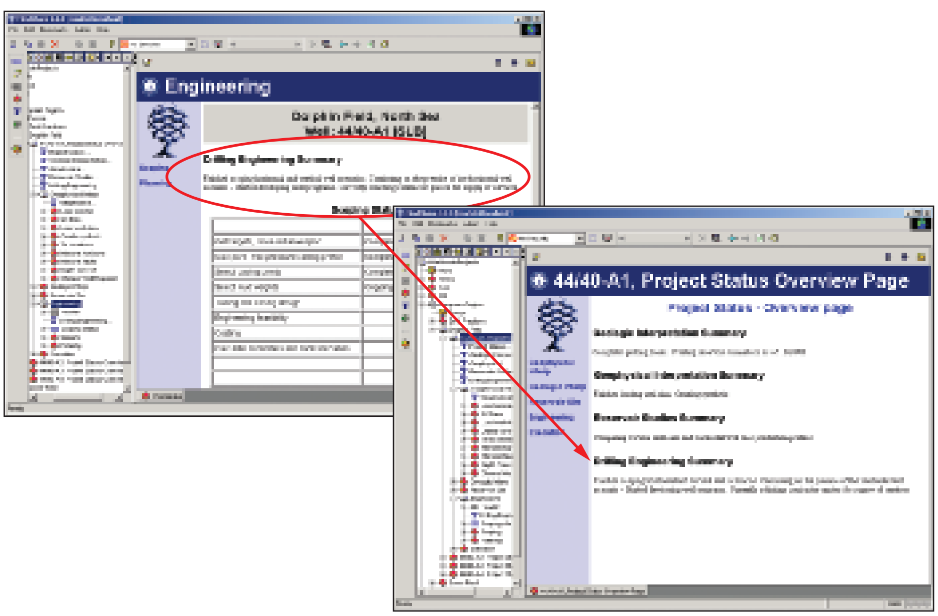
The LiveQuest secure interface pushes information to a user's desktop computer (previous page). Users see the same displays through the ASP interface as they do when using a local version of the software. Since the application results are rendered on a standard desktop computer, screen images easily can be cut and pasted into word-processing or presentation software.

Companies buying the LiveQuest service have the flexibility to quickly increase or decrease the number of authorized users and the software accessed as business opportunities arise. Users can be in any location that has an Internet connection, simplifying project collaboration. Even locations with slow modem access can set up and start jobs or check the results from many applications.

Some companies want to maintain close control over their data, or companies may not be allowed to take data outside of some countries. In such instances, an alternative to multiple desktop computers is the LiveQuest Inside application, with servers, applications and data storage maintained within the company intranet.

LiveQuest ASP services are available through IndigoPool. Waterous & Co., a global, independent investment bank, recently divested several producing properties in the Middle East for a client, using the IndigoPool.com site. The bank provided a link to the LiveQuest service, allowing potential bidders to analyze information in the on-line data room using the OFM suite of production-management software.

Waterous specializes in financial-advisory and agency services for the energy industry. The company has a technology joint venture with IndigoPool to develop comprehensive Web-based access to key technical information, data and a variety of evaluation tools to fully support the on-line buying and selling of oil and gas assets.



^ Sharing MindShare project information. When a user, such as a drilling engineer, changes information in the MindShare system *(top)*, all linked pages are instantly updated. In this case, the driller's summary information is linked to a project status page. The new information refreshes automatically, even for viewers who are currently connected *(bottom)*.

Knowledge Capture and Collaboration

Not long ago, the first stage of any field-development project involved finding old paper reports and data. Even then, much work was redone, many times almost from scratch. Knowledge management in the industry has matured to the point that results from one study often can be put into later ones. Company or service company data centers and tools, such as the Schlumberger Finder system, help operators manage information, archiving the final version of data and interpretations.

The new MindShare tool improves knowledge capture and streamlines information sharing and reporting. The unique database-driven architecture enables secure, global, multiuser access to project content. Almost any kind of project information can be stored, including word-processing documents and spreadsheets, images, presentations, e-mail messages, seismic-section snapshots, drilling plans and simulation results. The information is available on user desktops with hyperlinks to project information details. All authorized users can view and edit the same sources, which are stored in a common location.

Designed specifically to support E&P multiplatform interpretation workflows, the MindShare application has the same interface and level of user friendliness on a UNIX platform as it does on Windows systems. The MindShare tool allows drag-and-drop functionality for all platforms—common on PCs but not in the UNIX environment. Images on user screens can be captured and dropped into the project easily. Changes to the stored information are reflected immediately on other users' computer screens (left). With certain options enabled, multiple copies of a data set can be maintained and personalized to different users without affecting the original version.

Since the MindShare tool is database-driven, and users can organize data during a project, progress and summary reports can be created easily. These reports automatically update themselves as information is added or changed elsewhere in the project. Report templates can be customized for special purposes. With the high mobility of E&P personnel, the MindShare tool provides an essential evergreen repository for project work.

Today, members of a project team often work in different locations and for different E&P or service companies. Firewalls maintain security but hinder sharing information between companies. In the MindShare application, access to each stored item is designated independently for each user or group of users, secured by their login names and passwords. This system provides an ideal balance between accessibility and security. There is no need to maintain multiple copies of a project record tailored to different purposes because the same source can feed multiple uses.

The information also is available to registered users through a Web-browser interface. They can view any information for which they have clearance from any computer connected to their network.

Schlumberger used the system in Luanda, Angola, to provide support for a major international E&P company. The MindShare system replaced paper files containing seismic loading parameters and scaling plots, allowing rapid retrieval of digital images and monthly reports. A contact information page for each member of the support staff was accessible from the same interface.

A separate MindShare archive records information for a production data-management solution currently being developed for the same E&P company. This archive captures the knowledge gained by the implementation team for transferal to the client.

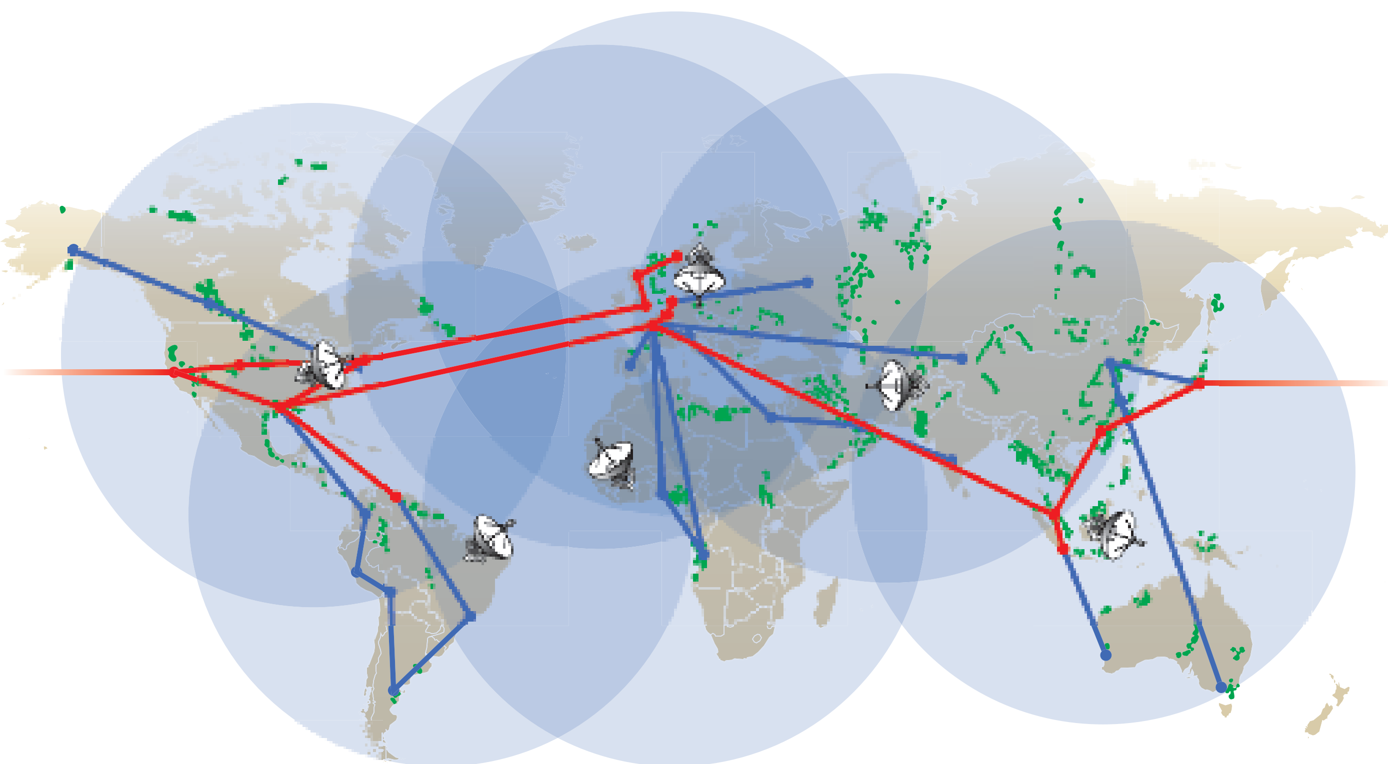
The Luanda office also implemented a MindShare application to track data for Schlumberger use. The system has important details about the quality, health, safety and environment programs, including tracking physical examinations for the staff, driving policies, local policies and organization charts.

Personalized Portals

The information environment within the E&P business has become both rich and complex. A vast array of asset data is stored in a company's knowledge bank. Real-time data and updated project information, perhaps organized using MindShare software, flow in continually. Data can be analyzed using either local or remote LiveQuest ASP applications.

Specialized data formats exist for seismic surveys in two and three dimensions, drilling reports, well logs, reservoir-characterization studies, production data, reports to governments and economic data. The same data may be used in slightly different formats for different purposes. Similar information can be stored at various times, but are the most recently stored data always the most accurate? Combining Web connectivity and a specialized suite of data-management tools helps capture, store and distribute validated data to users.

Information is an asset. Proper management of this asset can have a positive impact on a company's operational efficiency and financial results. A petrotechnical IT staff with experience loading and managing data sets for the E&P industry is critical to maintaining data quality and validity. Schlumberger has many years of experience converting data between formats and controlling the quality of geophysical and engineering data. Schlumberger Data Management Centers, located in every region of the world, provide data-management services ranging from contract assistance for a company's internal systems, through service-alliance projects, to complete outsourcing solutions. These centers make up the backbone of the Schlumberger intranet joining 75,000 users at 800 sites in 100 countries (below).



^ Schlumberger intranet connectivity. The original (red) network has been augmented by additional connections (blue) and enhanced bandwidth to cover oil- and gas-producing regions around the world (green dots). Satellite dishes indicate locations of Earth stations for satellite communication.

Schlumberger designed the Finder integrated data-management system to capture, store, archive, access and deliver corporate E&P information. The system reflects years of software development and practical data-management expertise. This system makes the best available data accessible for studies and reports. The next step in the evolution of information-management solutions is coming in a joint development by SIS and Statoil. The new technology provides scaleable systems that are Web-enabled, integrate with interpretation workflows and interface seamlessly with software from a variety of vendors. This conduit for quality, real-time data will help ensure that the right information is available to the right people at the right time.

Storing data intelligently is only the first step in data management. Geoscientists and engineers must know information exists, and be able to find it, in order for it to be useful. Good search facilities must be combined with logical arrangement to optimize accessibility. A library patron may use an electronic card catalog to find a specific book, but while browsing the stacks containing that book, may find a related, unexpected treasure shelved nearby.

This same concept applies for properly organized and indexed petrotechnical data. Users should be able to quickly find all relevant data, even if they were unaware of the information before accessing the database. The technical difficulty is creating a system that is flexible enough to gather the information needed for a variety of end users, regardless of data format, without making something so cumbersome that it is impossible to maintain.

One solution, the enterprise information portal (EIP), goes beyond the features contained in Web portals or home pages offered by many companies to the general public. When users go to a standard Web portal for information on such items as stocks, television shows, weather and travel conditions, the information flows in one direction to the users. In contrast, the EIP extends bidirectional access between users and sources of information, applications and knowledge.

Schlumberger combined the EIP technology with data-management services, software and E&P industry expertise and created the new Web-based DecisionPoint solution. This digital workspace enables faster, more successful decisions at all operational levels and provides personalized access to the following:

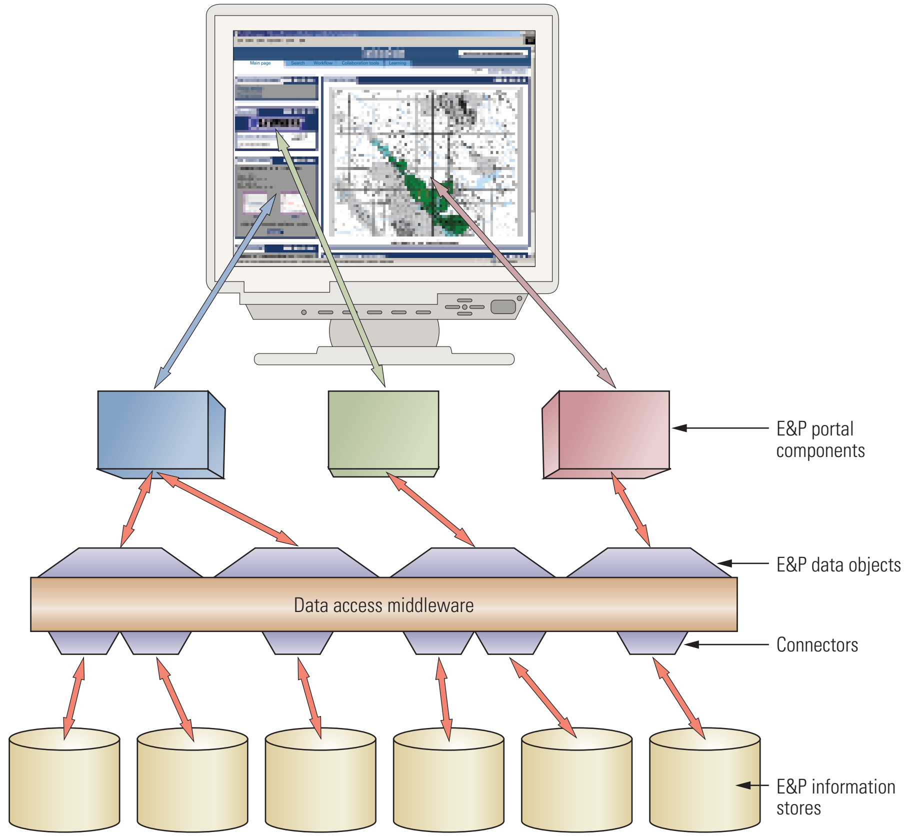
- information in structured formats, such as financial, operational, logistics and production information, seismic surveys, and well data
- information in unstructured formats—e-mail messages, presentations, desktop files and special reports—categorized and cataloged for efficient searching
- information and services from the Internet, including industry portals, public and governmental Web sites, and regulatory resources
- applications through on-demand use of LiveQuest ASP software
- knowledge banks, including corporate directories providing searchable access to personnel, repositories of best practices and lessons learned, and learning resources, mentors and discussion groups.

Much of this information can be categorized and cataloged for efficient searching.

MindShare information can be accessed as another component on a DecisionPoint portal. If a manager is monitoring several projects, each can have a hyperlink from the portal directly into project working files, or a tailored status report can be pulled from those files.

Both standard and EIP portals share one important attribute: personalization. Each user can decide what information will be displayed on a personal portal. Providing users with tens of individual components means they can create millions of combinations for personalized portal pages, which makes for essentially unlimited choice in design.[4] Unfortunately, that could also mean that converting data from their native formats to any possible user's format could require millions of data translations.

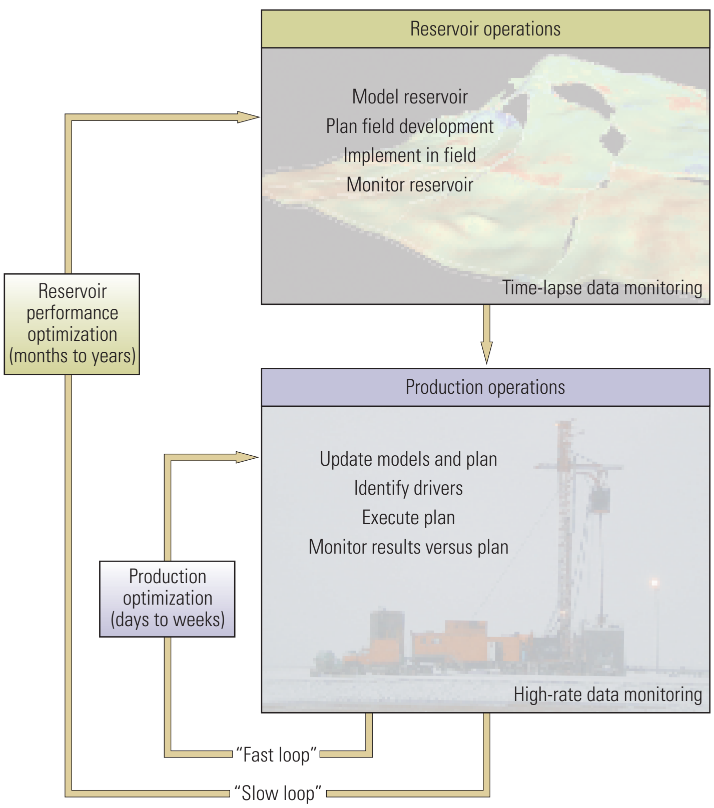
A portal is simply a doorway. The data side and the user side of the doorway can be handled independently. This simplifies the problem of translating the native format of every possible component into a personalized Web site. On one side of the door, data are converted from their native format into a format common for the portal (above). On the other side, an information request is translated from that common format into the one needed by the user for display, visualization or analysis. By treating the portal as a translation device, the millions of design choices can be provided with relatively few conversion routines.



^ Web-portal middleware. Connectors convert data from E&P information stores into a common format used by the portal's middleware software. Users configure individualized screens using E&P portal components. User-side connectors convert the data objects—production and well-test data, well information and drilling reports—from the middleware format into the format necessary for display or analysis.

4. Personalization permits many variations with a set of reusable components. For a case in which users can choose from 60 portal components, and are allowed six components per page, the number of combinations is given by the binomial coefficient, 60! / (6! (60-6)!) = 50,063,860.

^ Types of portals. An asset manager's portal (*left*) provides high-level summary information about ongoing projects. A technical portal, in this case for a production engineer *(right)*, provides a graphical link to a production unit. Portals can also provide information such as crude oil prices and links to the InterACT server. The tabs at the top provide access to other DecisionPoint pages with search engines and workflow-management, collaboration and learning tools.



^ Reservoir and production optimization. Production operations are optimized continually, with day- to week-long cycle times. This impacts the reservoir model, but major optimization projects are done less frequently, often only every few years. Maintaining an optimal condition requires both high-rate data monitoring and longer time-lapse data monitoring in the reservoir.

Personalization allows each individual to emphasize specific, critical information tailored to each job and workflow. Everyone in the organization can collaborate on the same validated information and data analysis. Information is available to everyone as soon as it is posted, decreasing cycle time on virtually any process in the E&P workflow.

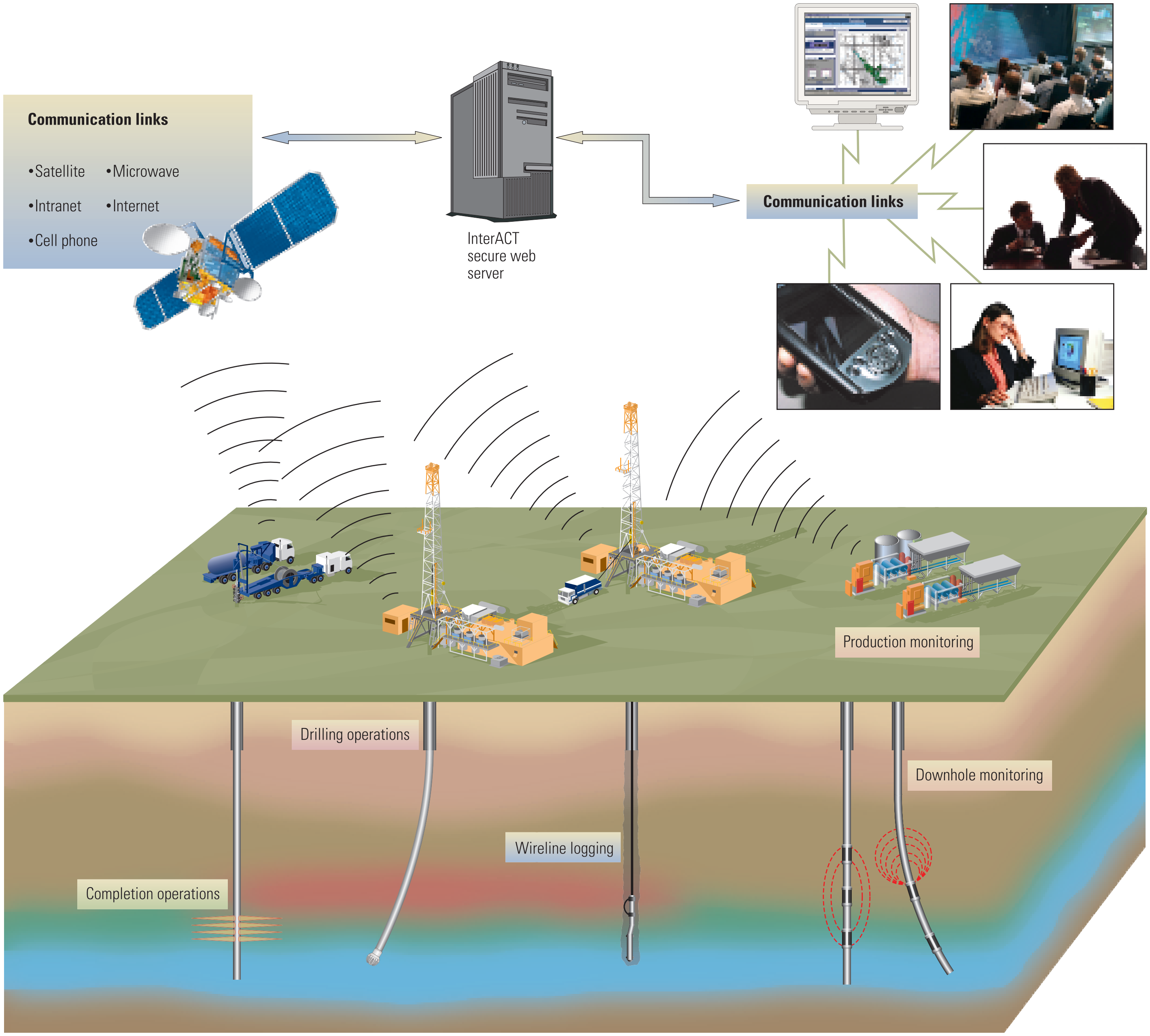
A company in South America had a complex field with an aggressive drilling schedule. The general manager wanted to track key performance indicators for drilling and business-unit finances. The solution included optimizing production planning using the Finder database and a DecisionPoint portal, with links to the key indicators (left). The system optimized information flows needed to determine those indicators. The DecisionPoint service reduced bottlenecks in information flow and availability, allowing more effective decisions.

An exploration manager's portal would contain some of the same indicators as the one used by a general manager, but would focus more closely on the goals of the exploration department. Each group of geoscientists, engineers or financial analysts in the company can have a portal that focuses on different items. The DecisionPoint process gives all users the most current validated information. Communication among groups involved in drilling a well, for example, can be optimized. The nonproductive time between one group completing a task and another group receiving the information needed to begin the next task is decreased. By keeping validated information in a databank, delays in transmitting reports from rigsite to office are eliminated. Regulatory requirements can be tracked easily and made available to the project team.

A DecisionPoint portal explicitly links to processes that drive business performance, reducing or eliminating information bottlenecks. Immediate access to data, information, applications, people and marketplaces empowers everyone to make important decisions any time, anywhere.

Performance Optimization

Optimizing field operations has a direct influence on a company's cash flow. The process can be viewed as comprising a long-term, reservoir-recovery optimization loop and a short-term, production optimization loop (left). After field discovery, the outer, long-term loop starts with initial reservoir evaluation and development. After producing for a while, reservoirs are often reevaluated, including large-scale



^ Real-time InterACT data transfer. Information from field operations—including completions operations such as fracturing, drilling, permanent downhole sensors and surface facilities—is transmitted in real time to a secure InterACT server. Communication links include satellite or microwave links, intranets or the Internet, or cellular phones. These same communication links connect from the InterACT server to users at home or in their offices, iCenter meeting rooms or personal digital assistants.

surveillance such as time-lapse 4D and multicomponent-seismic studies and new reservoir modeling. Cycle time for a major model update ranges from months to years, but reservoir and production data are used continually to revise reservoir models and guide decisions on corrective steps to improve production.

The outer loop includes a production loop representing daily decisions and actions to keep the asset operating at peak performance. Ideally, feedback time is hours or days. Surveillance data, like bottomhole pressures and flow rates, can be obtained frequently and should be analyzed, interpreted and acted upon quickly. Unfortunately, quick evaluation is often difficult to achieve because data may not be accessible in a timely fashion. In such cases, opportunities and money are lost.

The process can be divided into four distinct, but related elements. First, hydrocarbon reservoirs provide a primary source for generating value. Second are the wellbores, constructed to optimally access hydrocarbons and placed to ensure efficient, cost-effective recovery. Third are the production systems and handling facilities for process and transport to a point of sale. Finally, but not least important, are the monitoring and data-transmission systems. The entire domain must be seen as a single system, with each link vital to success.

In the past, data transmission has been a bottleneck for getting information to engineers. Now, the Schlumberger InterACT remote-communications service provides secure, real-time, bidirectional access to oilfield data (above). This on-line collaborative workspace grants access to project information via the Internet or an intranet to authorized personnel, promoting teamwork in the decision-making process. The system delivers all types of data in any format, such as drilling reports, directional-drilling information, mud records, wireline and logging-while-drilling logs, well-stimulation data, processed log data, electronic photographs and a vast array of production data. The InterACT data-cataloging architecture allows companies to access and manage data from both local and remote operations.

InterACT data-delivery service is a user-friendly, intuitive system that does not require installation of specialized software. Data can be streamed from the rig, wellhead, boat or truck to a secure Web site hub using the InterACT system.

Wellsite data can be transmitted through any existing connectivity channel, even over a cellular telephone. State-of-the-art digital technology and unique transfer protocols enable the InterACT system to reliably complete transfers, even with poor connections typical of remote locations. Flexible update options refresh data at predetermined intervals—as frequently as every second. User-configurable thresholds can be set for specific operating conditions or events. When a prespecified condition occurs, a flag is generated and stored in an individual's profile.

Using an InterACT connection, a team of experts can access information and collaborate in the decision-making process from practically anywhere, improving efficiency while reducing travel and rig costs. Data access in offices or homes requires no modifications or changes in a company's firewall settings. After logging into the InterACT Web site through a browser, users locate data by browsing a well or by searching the site. Data security is maintained by best-in-class encryption, robust user authentication and tight access controls. Reports, logs and real-time production rates can be streamed live and viewed on a desktop or a hand-held personal digital assistant (PDA). Data files also can be produced for import to other local applications for further manipulation.

The InterACT service provides real-time drilling and measurement information. WITS (Wellsite Information Transfer Specification) or WITSML (Wellsite Information Transfer Standard XML) data, which are industry standards for well-data formatting, are loaded through a secure link to a database on the server. The InterACT system supports more than real-time drilling decisions. Any WITS or WITSML data can be loaded to the database and viewed at a later time; experts do not have to be on-site or on-line at all times.

^ Houston iCenter complex. The central iVision theater contains state-of-the-art visualization equipment and software for meetings of about 35 people. Satellite rooms also contain modern visualization equipment outfitted especially for tasks in the E&P workflow.

Interactive displays allow users to view real-time and historical data in graphical and numeric displays. Logs can be viewed using a time or depth basis. Well trajectories or directional plots and a representation of a driller's console track drilling progress. The InterACT system was the first in the industry to remotely display a logging-while-drilling resistivity or nuclear image log in real time.

A wellsite wireline engineer can upload graphical or digital logging data to the InterACT space. Remote users can analyze or manipulate logging-while-drilling and wireline data in real time, or later, using the embedded log graphic viewer. During operations such as reservoir sampling, experts at different locations using the real-time data can make immediate decisions on critical issues.

The InterACT system is integrated with the Schlumberger FracCAT wellsite acquisition system to monitor well-stimulation jobs remotely. Stimulation data published to the server become available for display in real time on an embedded graphical and numeric display.

During the production phase, well problems can be flagged by looking for changes in tubing-head pressure, bottomhole pressure, and production-manifold pressures and temperatures, for example. Normally, this information is transmitted every few hours, as specified by the operator. However, if there is an out-of-tolerance reading, the system can be set to increase the frequency of transmission to capture important data. The InterACT system can send alarms through an Internet connection or to a preset telephone number, a useful feature in remote locations without a fast data connection.

Collaborative Visualization Environment

When the first high-powered 3D graphics workstations appeared in the early 1990s, geoscientists would gather around a computer monitor in someone's office to rotate and translate displays of seismic sections. The power of data visualization made it an important tool for exploration and later for reservoir development. By the late 1990s, rooms specially designed for visualizing complex data had been developed by several major E&P companies and service companies. Within the past couple of years, the ability to link remote visualization rooms has improved opportunities for collaboration.

As facilities improved, the uses for visualization expanded from seismic interpretation to almost any aspect of the E&P business. Schlumberger developed several locations for visualization, called iCenter collaborative environments. The center in Houston is a hub for interactive field management (previous page). This fit-for-purpose facility includes a large theater, the iVision room, capable of accommodating up to 35 people. It was created for 3D visualization and collaboration sessions and videoconferences with other Schlumberger and client locations.

Screens that use bright light-output projectors are easy to see in a lighted room; participants can take notes or use other materials while viewing displays. A rear-projected flat screen allows discussions to take place next to the screen without disrupting projection.

The display can be configured for viewing stereo images using glasses with left and right lenses polarized in different directions (right). This "passive" stereo system is less fatiguing for the viewer, and unlike an "active" display does not require interaction between each set of glasses and a control unit.

Flexibility is an essential component of iCenter connectivity. Real-time communication and collaboration between rig-based or remote personnel and the iCenter facility are available through an intranet, the Internet, by cable or satellite. The room is wired to the Schlumberger intranet, and participants can log in to their own company systems through the Web. No longer do critical decisions have to wait until someone returns to a remote office to obtain information; information retrieval and decision-making can be immediate. The Houston center is available 24 hours a day, seven days a week.

Additionally, the Houston facility contains satellite rooms around the iVision theater designed specifically to accommodate the domain expertise of client teams and Schlumberger. The rooms are configured to access real-time data streams through the InterACT system and then process, format and display information critical for making decisions. Some of the workflows include the following:

- seismic reconnaissance
- reservoir simulation
- mechanical earth model construction
- well planning
- well construction
- well completion and production optimization.

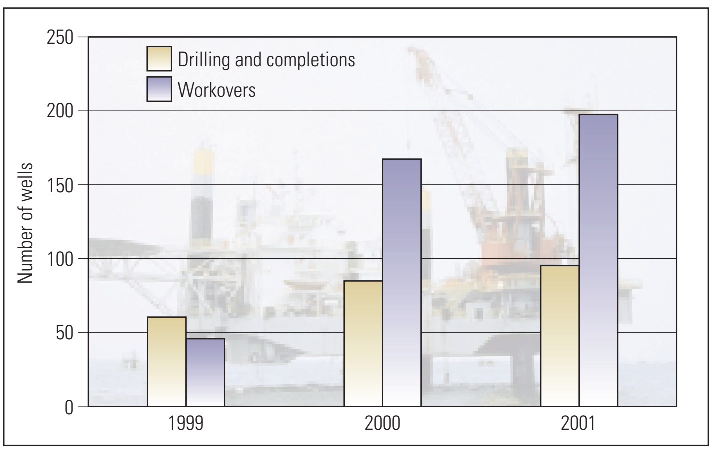
In the iWitness room, personnel can communicate with a rig, deliver and receive real-time data, and develop fracture-analysis recommendations using CADE Office software for well construction, well production and well intervention. Since its inception in August 2001, the iWitness room has been used for 55 jobs that required InterACT data transfers. The room has been popular for offshore completions, because it eliminates the need for engineers to travel to remote locations to monitor critical treatments.

Drilling teams plan wells and interface with No Drilling Surprises operations in the iDrilling room.[5] Engineers monitor real-time well

5. Bratton et al, reference 1.

^ Stereo viewing in Stavanger. A geologic model is viewed using special polarized glasses, which convert the passive stereo image into a three-dimensional representation. The console *(foreground)* controls the video-conference display on the main screen.

^ The Costanero Bolívar field in Lake Maracaibo, Venezuela.



^ Drilling and workover activity on Lake Maracaibo for PRISA in Costanero Bolívar field.

and field data in the iProduction room, controlling operations from the room to optimize performance. The iGeology area is set up to interpret borehole-image data from devices like the OBMI Oil-Base MicroImager (see "A Clear Picture in Oil-Base Muds," *page 2*) and FMI Fullbore Formation MicroImager tools on a large projected image, making interaction with clients easier than when using a small computer screen. The iProject room provides a large workspace for multidisciplinary teams to work together and make joint decisions as they integrate workflows on complicated oilfield projects. Reservoir simulation tools, such as ECLIPSE software, are available in the iProject room.

The iCenter facility contains the latest hardware and software technology coupled with the expertise of in-house personnel. When combined with real-time data transferred from wellsites using InterACT remote-communications software, these visualization and collaboration tools help clients make more informed decisions. Multidisciplinary teams can communicate through a common visual language, cutting through many of the complexities of the E&P business.

The iCenter environments can be scaled to different sizes and uses. Collaborative iCenter facilities are designed for geophysical interpretation, reservoir management and project planning. Facilities similar to the Houston iVision room are presently available in Stavanger, Norway; Ridgefield, Connecticut, USA; and Cambridge, England.

With ergonomics, usability and collaboration the prime requirements, Schlumberger Industrial Design developed a communications iCenter videoconference concept that uses multiwindow screens to facilitate information sharing and remote collaboration. These centers can be linked with client videoconference rooms to exchange real-time data and information. They have been installed in the Schlumberger corporate offices in New York, New York, USA, and Paris, France, and in the Oilfield Services facility in Sugar Land, Texas.

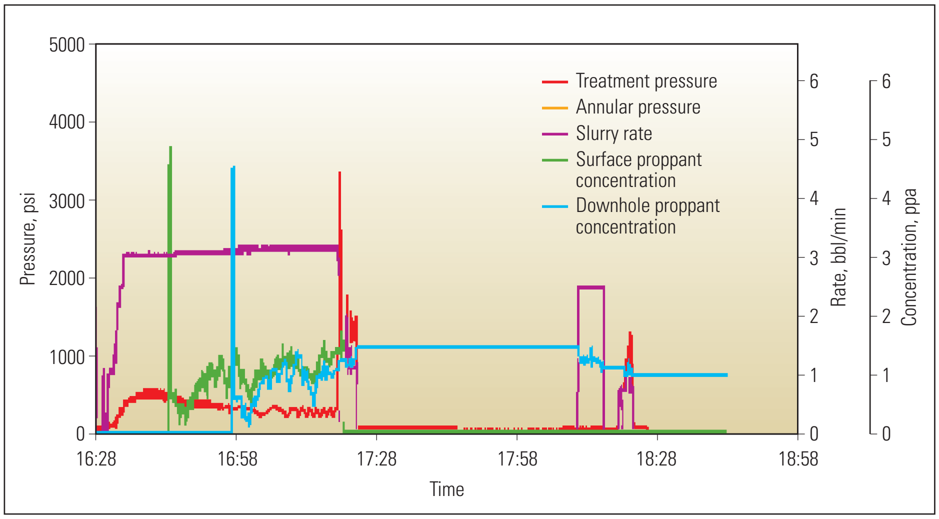
With a collaborative iCenter installation recently completed for Amerada Hess in Aberdeen, Scotland, Schlumberger Industrial Design currently is working on collaborative iCenter facilities for Schlumberger in Port Harcourt, Nigeria, and Gatwick, England, and for Sonatrach in Hassi Messaoud, Algeria.

Innovations in Venezuela

Petróleos de Venezuela S.A. (PDVSA) is a pioneer in using information management to improve operations. In the late 1990s, PDVSA formed alliances with Schlumberger to effect several changes in its IT operations.

PDVSA recognized opportunities to improve operational efficiency by organizing and archiving exploration and exploitation data. Schlumberger and PDVSA worked together to successfully preserve a large volume of new data and to transfer both old and new information to the Finder database-management system and a newly designed archival databases, known within PDVSA as the Ambiente Integrado, or Integrated Environment. This is the largest outsourced E&P data-management project in the world. Using this system, PDVSA estimates its savings in time and in lost data amounts to $314 million US per year. This data-management alliance is discussed in "Integrated Data Environment," *page 56*.

PDVSA formed a separate alliance with Schlumberger called PRISA (Perforación y Rehabilitación Integral con Servicios en Alianza, or Alliance for Integrated Services in Drilling and Workover) to improve production from the Costanero Bolívar field in Lake Maracaibo (top left). The contract called for Schlumberger to drill 90 wells per year and perform workovers on 250 wells during the 10 years of the agreement. Within PRISA, PDVSA supervises all operations while Schlumberger designs and executes them. Schlumberger focuses on reducing operations



^ Real-time monitoring of a PRISA gravel-packing job. Conditions at the rigsite were monitored from the PRISA office as the job was performed. The slurry pump treating pressure (red) indicated a screenout at about 17:20 so slurry pumping stopped (magenta). The rig pumps (parameters not shown) backflushed to remove excess sand; the test at about 18:20 indicated a good gravel pack had been achieved. Annular pressure (gold) was zero throughout this job, confirming the packer maintained its seal. There is a time lag between surface (green) and bottomhole (blue) proppant concentration.

time, while PDVSA concentrates on increasing production. Teamwork between operator and contractor has been important to the alliance's success.

The Costanero Bolívar field has undergone intensive exploitation both offshore and inland over the past 70 years. This highly complex field comprises depressurized reservoirs that still contain significant amounts of oil; remaining reserves are estimated at 2.5 billion barrels [397 million m^3]. Because of the field complexity and low formation pressures, state-of-the-art technologies are needed to produce these remaining reserves profitably.

PDVSA had five goals for the Schlumberger alliance in the Costanero Bolívar field:

- 30% reduction in operations times
- 20% decrease in well-operations costs
- constant and strict environmental-conservation measures, including zero discharge into Lake Maracaibo
- maximum hydrocarbon recovery in low-pressure reservoirs
- implementation of technological innovations to achieve the desired goals.

The field has a large number of planned and existing wells requiring drilling and workover units that can be easily moved between wells. Specially commissioned, multipurpose rigs designed by Schlumberger first arrived in Venezuela in 1999.[6] The units, which are light and modular, can incorporate leading-edge technology to address the specific field needs. Currently, the PRISA project operates six multipurpose units on Lake Maracaibo, which have added production of about 125,000 barrels [19,870 m^3] of oil per day through new wells and workovers (previous page, middle).

Within the PRISA agreement, new technologies may be introduced only when they are expected to increase reservoir productivity. One hundred new technologies have been applied, many for the first time in Venezuela, and some for the first time anywhere in the world. These include the following applications:

- gravel packing in horizontal wells[7]
- reentry in short-radius wells in the Lagunillas Lake area
- mud containing stabilized air microbubbles—aphrons—for prevention and mitigation of lost circulation
- single-trip perforating and packing using PERFPAC sand control[8]
- CoilFRAC, ISO-AllPAC and screenless completions.[9]

The alliance has shown quantifiable improvements in production—more than 6000 barrels per day [950 m^3/d] beyond the forecast made by PDVSA before the project began. Synergy between Schlumberger and PDVSA improved steadily as the strengths and responsibilities of each team were established. During the project, PRISA reduced operations times far beyond the 30% target. In some wells, the 10-year objectives were met in just two years.

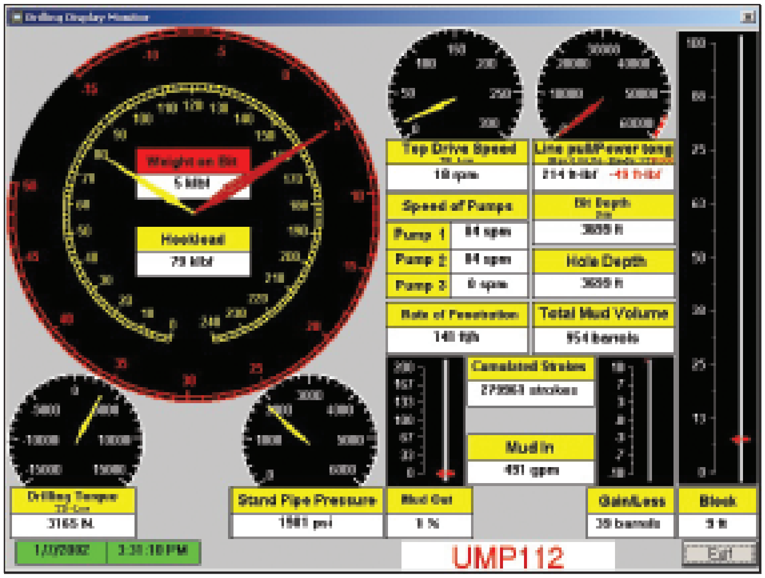
Some of the improvement in operational efficiency came from communications and information technologies. Schlumberger created a Web site for PRISA that is based on the Knowledge Hub, which is the browsable index of the Schlumberger intranet. This secure interface allows access by PRISA personnel to selected PDVSA and Schlumberger proprietary sites. Project data are available, including well-construction programs, final well reports, drilling reports, completion and stimulation programs, technical papers developed during execution of the project, and presentations from PRISA technology forums. A daily report also is published on the site.

At the heart of the system is the Schlumberger InterACT interface connecting wellsites and offices. This technology makes the PRISA Hub a source of real-time operational data and a true knowledge-management system. The goal of the PRISA Hub is integrating 3D reservoir seismic and geology data with well-drilling and workover operational data.

PDVSA and Schlumberger presented operational results from the PRISA project at an internal technology forum in March 2001. A prototype of a PRISA Virtual Room was unveiled at this meeting. Similar to an iCenter facility, this room combines access to information from several technical domains in one environment. It will provide 3D visualization of reservoir, seismic and well data and real-time data during operations. With this system, geologists and engineers can observe key operations without traveling to the field.

The prototype demonstration included real-time monitoring of a gravel-packing operation as it was conducted on the PRISA-112 workover rig. During this operation, the InterACT system transmitted pressures and flow rates to a workstation in the office about 2 miles [3.3 km] away (above left). Ongoing operations from all wells being

6. Adamson S, Cupello F, Hicks J, Keenleyside M, Formas D, Gabillard C, Gamarra F and Sanchez A: "Multipurpose Service Vessels: Versatile Toolkits for Well Intervention," *Oilfield Review* 8, no. 3 (Autumn 1996): 34–43.
7. Foxenberg B, Troncoso J, Tiffin D, Steven B, Ripa G, Pitoni E, McPike T, Godwin K, Cooper S, Price-Smith C, Parlar M, Bixenman P, Bennett C, Dickerson R, Ali S and Desroches L: "High-Productivity Horizontal Gravel Packs," *Oilfield Review* 13, no. 2 (Summer 2001): 52–73.
8. 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.
9. 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.



^ Virtual Room display of rig operation. Current operating parameters can be called up from the PRISA office for any drilling and workover rig in the Costanero Bolívar field.

drilled and repaired also were shown using the drilling and workover consoles. The real-time data were compressed and sent via satellite. Once the data arrived at the Virtual Room, the information was decoded, processed and displayed (above).

The PRISA alliance used the proprietary Schlumberger InTouch repository of best practices, lessons learned and other knowledge to obtain answers to operational problems. In addition to the on-line database, the InTouch system is supported 24 hours a day, 365 days a year, by a Schlumberger center in Houston. The center uses a global community of experts to answer questions raised in Schlumberger projects anywhere in the world. For urgent problems, solution-response times can be as short as one hour.

The InTouch system helped PRISA overcome the low productivity of Well LL-648, Reservoir LGINF-05, in the Lagunillas Lake area. An assessment of root causes for poor well performance used field-wide well information. Prior formation damage likely was due to extensive workovers over the past 30 years, including five squeeze stimulations using sand in an oil-base slurry, seven gravel packs and use of lake water during well-control operations. Poor-quality sands, and, in some cases the wrong zones, had been perforated. The worldwide database of best practices of the InTouch system provided several recommendations for these problems:

- Recover gravel-pack completion hardware and clean out with 2- to 3-micron filtered fluid.
- Run new gamma ray and resistivity logs and redefine perforating intervals.
- Identify the oil-water contact using the new gamma ray and resistivity logs.
- Analyze the possibility of performing a stimulation job before gravel packing.

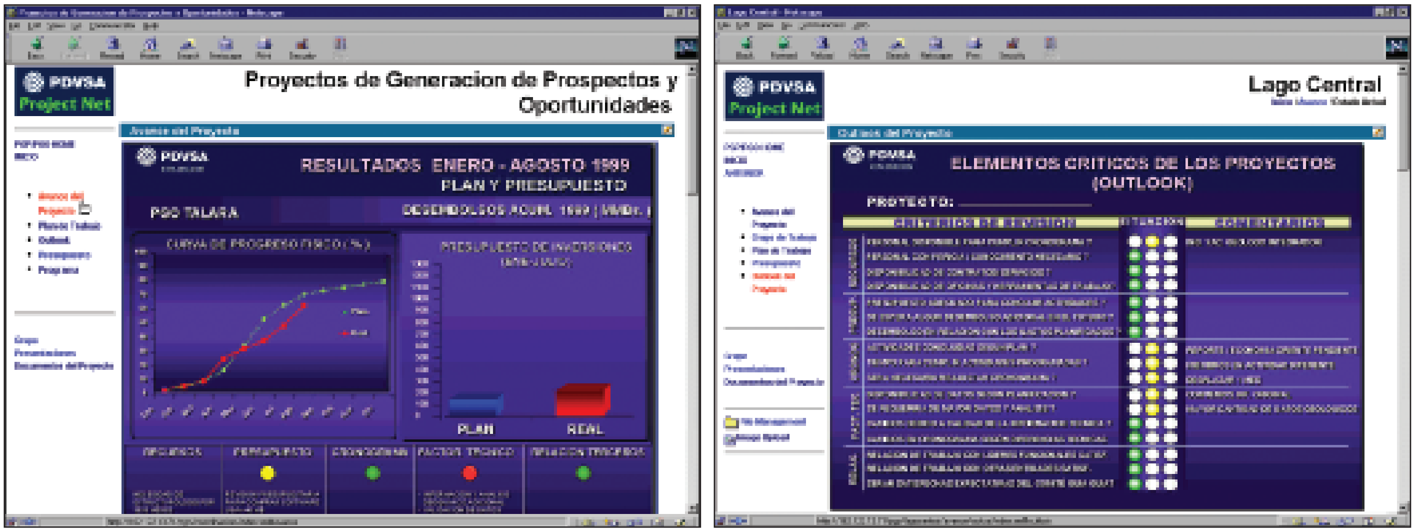
This project provided three new lessons to include in the knowledge-management database. First, when the original resistivity and gamma ray or spontaneous-potential logs are old, consider them unreliable for correlating with perforation depth. If there is not a reliable correlation log, analyze whether to run a new log before perforating. The second lesson was to check intervals to be perforated with correlation logs, and report any differences to the workover engineer in charge. Finally, remediate formation damage before any gravel-pack job.

Integrated Data Environment

Prior to the creation of the Ambiente Integrado, PDVSA had data spread over a large number of unlinked databases. Ambiente Integrado created a unified source for a wide variety of data types: well data, seismic data, geochemistry and fluid-properties data, map and environment data, technical reports, and project data from integrated studies.

Schlumberger staffs the PDVSA Data Management (PDM) organization, which created the Ambiente Integrado system. PDM supports more than 2800 users in PDVSA and a portfolio of more than 100 specialized applications, with customer service and support desks in 16 PDVSA offices in 14 cities. The organization supports daily operations and includes a special-projects group to develop applications, extend and integrate data models and provide technical leadership.

PDM ensures that PDVSA has access to the latest technologies available within the industry. Several technologies have been developed in this Schlumberger and PDVSA alliance:



^ PDVSA project management. Schlumberger developed Project Net software to help PDVSA manage projects such as this "Project for Generation of Prospects and Opportunities." The left side of each screen is a navigation bar. The top-level screen *(left)* tracks the physical progress of the project and the budget from January to August in 1999. The traffic lights at the bottom indicate status of key indicators for the project. One detail-level screen *(right)* breaks the critical elements for one of the prospects, Lago Central, into finer points, including the traffic-light warning system and space for comments.

- a system for visualization, query and management of satellite images
- an integrated system to manage surface-facilities data for oil and gas fields
- a Web interface to provide direct access to data in the Ambiente Integrado system
- a custom-built reserves system for estimating, accounting, reporting and managing all types of company reserve data (oil, gas and bitumen)
- a Web-based system for sharing project information called Project Net.

The success of Project Net led Schlumberger to develop the MindShare collaborative environment. This tool allowed PDVSA to manage large, complex projects while sharing the information among the project staff and company management using a Web browser across the company's intranet.

In its first test, Project Net was used in a program to examine 24 opportunities in Venezuela, which led to eight prospect areas. Project Net organized all information related to this project, including maps, interpretations and final reports. Participants documented best practices and lessons learned for future projects. The project staff could access relevant information from a centralized digital archive.

Summary data screens helped management track the key performance indicators of the project, such as planned and actual expenditures (above). More complete details were available on a second level of screens. For example, progress of each element of the project was tracked and managed. Team members quickly could see the status of important items using a system of green, yellow or red "traffic" lights. Project Net helped foster a cooperative environment throughout the project execution.

Transforming Workflows

The Schlumberger Information Systems toolkit provides many new options for managing the E&P business. Changes already are under way throughout the industry to accommodate the new information-centric paradigm, but there are clear needs to be fulfilled before the industry can realize the benefits of this new way of working. Many locations lack a powerful IT infrastructure. Broadband connectivity to remote locations is still a rarity. Getting more information, more quickly, from wellhead to decision-makers is key to optimizing performance. Although bringing old data sets into a powerful database such as the Finder system may be an enormous task, the information and lessons from the past contained within those data must be made accessible.

Dealing with the conflicting problems of data security and data accessibility is an ongoing job. Efficient collaboration requires accessibility, but without the proper software, corporate firewalls make sharing difficult. Systems must have robust authentication for security to assure confidentiality. Smart-card technology is a solution that is already available.

New Web-based technologies and applications soon will be an integral part of everyday business. They will permeate every aspect of exploration and production, eventually becoming so essential and obvious that no one notices them. Then the transformation to the digital enterprise will be complete. —MAA

Contributors

Ian Barclay is a fluids and cement engineer working on the Petroleum Development Oman LLC (PDO) Well Abandonments Project in Muscat, Sultanate of Oman. There he is involved in sourcing and approval of innovative well-plugging materials. He began his career in 1978 with Baroid Ltd. and spent the next 11 years in various drilling-fluid-related field and office positions in Libya, Italy, West Africa and the North Sea. From 1989 to 1996, he held several drilling-fluid consultant positions in the North Sea. In 1996 he joined Total Oil Marine as a mud and cement supervisor and oversaw North Sea drilling fluids and cementing operations. Before joining PDO he was a mud-cement-environmental engineer for Shell Expro (UK) Ltd. (1998 to 2000). Ian received a BS degree in pure science from University of Aberdeen in Scotland.

Mike Bosco, Technical Marketing Manager at IndigoPool, supports sales efforts, manages key projects, and serves as the first point of contact for clients. He joined GeoQuest in 1999 as a geoscientist and moved to IndigoPool in 2000 to support the implementation of the IndigoPool.com Web site. Since then he has participated in development and testing of all site releases and enhancements. Prior to joining GeoQuest, Mike was a geologist with Union Pacific Resources and BHP Petroleum. Author of many papers, Mike holds a BS degree in geology from George Mason University in Fairfax, Virginia, USA, and an MS degree in geology from Texas A&M University in College Station, USA.

Mark Burgoyne works in software marketing for GeoQuest in Houston, Texas, USA. He joined Schlumberger in 1990 and previously served as engineer in charge of Dowell China field operations (1996 to 1997). Mark has a BS degree in chemical engineering from University of Adelaide, South Australia, Australia.

Philip Cheung is based at Schlumberger Riboud Product Center in Clamart, France, where he is currently a member of the Modular Imaging Platform team as physicist and technical consultant. Since joining Schlumberger in 1982, he has worked in London, England on seismic and sonic processing software, and at Schlumberger-Doll Research in Ridgefield, Connecticut, USA on permeability from Stoneley waves. Since 1988 he has been based at Clamart, where he has been section head and technical consultant responsible for borehole-imager and dipmeter-tool interpretation products. Philip received a BA degree in physics from University of Oxford, and a PhD degree in theoretical physics from University of Warwick, both in England.

Gregory Cook, Exploration Manager for The GHK Company, is based in Oklahoma City, Oklahoma, USA. After obtaining BS and MS degrees in geology from Oklahoma State University, he became a staff exploration geologist with the Cities Service Oil Company in 1972. His duties included exploration in the midcontinent area and the Appalachian basin. In 1974 he worked as an independent petroleum geologist establishing a partnership from 1974 to 1997; this involved exploration and developmental drilling primarily in the Anadarko basin. Greg joined GHK in 1998 as exploration manager but also supervises drilling, completion and production operations.

Michael Davidson is a management consultant who is currently working at IndigoPool in Houston, Texas. He joined Schlumberger in 1999 as director of strategy and business development for IndigoPool. He previously worked for BP, where he had been worldwide director for information technology (IT) with responsibility for planning IT integration between BP and Amoco. Since beginning his career with BP Exploration in 1975, he has had many assignments as exploration manager, resource development manager and development geology manager in the North Sea, the USA, France, Latin America and England. Michael holds a BS degree (Hons) in geology from University of Edinburgh, Scotland.

Steve Decatur, Director of Subsurface Staffing and Development at BP, is based in Houston, Texas. He has held a variety of positions within the company since he joined Amoco in 1979. Steve received a BA degree in psychology from Westminster College in New Wilmington, Pennsylvania, USA in 1971, and an MS degree in geology from Kent State University in Ohio, USA in 1979.

Michael Donovan, Schlumberger Data & Consulting Services Solutions Manager in Houston, has been responsible for solutions management for Houston-based clients since 2000. He joined the company as a wireline field engineer in 1980 in Fairmont, West Virginia, USA and became a sales engineer four years later. He moved to Bakersfield, California, USA as a sales engineer in 1990 and subsequently became district manager, Gulf Coast Special Services and then served as wireline sales manager, Dallas-Fort Worth. From 1997 to 1998, he was wireline business development leader, Texaco North America, and the following year oversaw wireline alliance business development. Prior to his current position, he was reservoir evaluation technology applications manager and formation evaluation marketing manager for North America. Mike has a BS degree in mechanical engineering from Rensselaer Polytechnic Institute, Troy, New York, USA.

Shane Dufaur is product champion for Schlumberger Oilfield Services data delivery and communications projects at the Austin Technology Center in Texas. He acts as user advocate, marketing contact and link between engineering, operations and clients. He joined the company in 1991 as junior field engineer in Japan and Sumatra, and then served as field engineer in Kalimantan and offshore Vietnam. From 1996 to 1998, he was a field service manager in Australia. After a stint as a senior instructor at the training center in Indonesia, he spent two years with Schlumberger Oilfield Services training and development in Paris and Houston. Shane earned a BS degree in engineering (Hons) from University of Auckland in New Zealand.

Greg Flournoy is a Schlumberger geologist and interpreter for the midcontinent region. He is responsible for interpreting dipmeter, FMI* Fullbore MicroImager, Formation MicroScanner*, UBI* Ultrasonic Borehole Imager and OBMI* Oil-Base MicroImager images for clients in the region. From 1982 to 1988, he was a consulting geologist for many oil and gas companies in the eastern shelf of the Permian Basin and north Texas. After completing graduate school in 1991, he joined Oryx Energy Co. in Dallas, Texas as an exploration geologist. From 1994 to 1998, he was a geologist with GeoMarine, Inc. in Plano, Texas. He joined Schlumberger in 1999 as a geologist and FMI interpreter in Midland, Texas. Greg holds a BS degree in geology from Hardin-Simmons University, Abilene, Texas, and an MS degree in geology from Baylor University in Waco, Texas.

Peter Goetz is currently principal geologist with the Southern Foothills team at El Paso Oil and Gas Canada in Calgary, Alberta, Canada. He began his career at Hudson's Bay Oil and Gas Co. Ltd. in 1979 and since then has worked for many major and intermediate-size companies, most significantly Bow Valley Energy Inc., in various Canadian basins. Currently he is focused on exploration and development for structured plays within the Alberta Foothills of the Western Canadian basin. Peter has a BS degree (Hons) from University of Waterloo in Ontario, Canada and a PhD degree from Carleton University in Ottawa, Canada.

Steve Hansen is currently lead geologist with Schlumberger Applied Interpretation & Development in Houston, Texas. Since joining Schlumberger, he has worked on dipmeter and image interpretation for more than 20 years while stationed in Texas and the Far East. Trained as a field engineer in both open- and cased-hole services, he has also had field and sales assignments in both evaluation and production services with a focus on interpretation of dipmeter and imaging tools. Steve obtained a BS degree in geological engineering from the University of Arizona in Tucson, USA and an MS degree in geology from the University of Texas of the Permian Basin at Odessa.

Andrew Hayman, Principal Physicist in the Formation Evaluation department at Schlumberger Riboud Product Center (SRPC) in Clamart, France, helped develop the OBMI Oil-Base MicroImager tool. He is currently working on next-generation borehole imaging and continuing to support cement-evaluation projects and interpretation of ultrasonic imaging tools. Before this, he was a physicist at SRPC working on development of wireline imaging tools for cement and corrosion evaluation and formation imaging. He has also been a physicist for British Steel Corp. in Corby, England (1980 to 1985). Holder of several patents and author of many publications, Andrew has a BS degree in physics from Bristol University in England, an MS degree in medical physics from University of Aberdeen in Scotland, and a PhD degree from The City University in London, England.

Jon Ingham, Schlumberger Information Solutions UK Business Development Manager, Production Solutions, is responsible for promoting production solutions (including real-time production optimization and economics) to the UK client base. He joined Schlumberger Wireline in 1982, working in west and north Africa, Morocco and the North Sea. He rejoined GeoQuest in 1996 as UK GeoFrame* Product Champion. From 1997 to 1998, he managed the European Training Center. In 1999 he became GeoQuest UK software support manager before taking his current post in 2001. Jon holds a BS degree (Hons) in civil engineering from University of Leeds, in addition to an MBA degree from Manchester Business School, both in England.

Malcolm Lamb, Senior Interpretation and Development Geologist for Schlumberger in Canada, is based in Calgary, Alberta, Canada. He is currently focusing on interpretation and borehole geology in western Canada. He began his career in 1993 as an openhole field engineer in Canada, becoming a senior field engineer in 1995 and then a general field engineer and district cased-hole specialist in 1996. From 1997 to 1999, he was in a technical sales position in reservoir evaluation, working on account development and client training. He also served as a DESC* Design and Evaluation Services for Clients engineer for major Canadian oil companies. Before assuming his current position in 2000, he was involved in sales and account management for several clients. Malcolm received a BS degree in geology from University of Alberta in Edmonton, Canada.

Ken Landgren, Planning Director for Web Solutions at Schlumberger Information Solutions in Houston, is responsible for designing new web-based product and service offerings, including the DecisionPoint* E&P information solution. From 1978 to 1982, he held various positions in field operations and management in Gulf of Mexico wireline operations, and was unit geophysicist for Schlumberger Offshore in New Orleans, Louisiana, USA (1982 to 1986). He spent the next two years as section manager for seismic engineering at Schlumberger in Clamart, France. In 1988 he moved to Schlumberger Austin Product Center as workstation coordinator and then Geoshare project manager. In 1993, he served as marketing manager for data management, and three years later became manager for information technology and data management for GeoQuest North America. From 1998 to 2000, he was product development manager for data management at GeoQuest in Houston. Ken holds BS and MS degrees in physics from the University of Tennessee at Knoxville, USA.

Robert Laronga, OBMI Product Champion for Schlumberger, is based in Clamart, France. There he oversees the global deployment of the OBMI service including training, technical support, marketing, public representation and introduction to clients. Previously, he worked for Schlumberger as a wireline field engineer for seven years in West Texas, the Gulf of Mexico and aboard the drillship of the Ocean Drilling Program. He served as the field-test engineer for the first experimental prototype of the OBMI tool before assuming his current role in 2001. Rob received a BA degree in archaeology and geology from Cornell University in Ithaca, New York.

Mark Larsen has been principal geologist for Schlumberger based in Shreveport, Louisiana, since 2000. He performs interactive workstation interpretation of resistivity and acoustic-imaging data to provide borehole geology interpretation for clients. He had similar responsibilities in his previous position as interpretation geologist with Schlumberger of Canada in Calgary (1996 to 2000). He began his career in 1980 with Tenneco Oil of Canada. In 1985 he joined Canadian Occidental Petroleum Ltd., where he served as a senior geologist in western Canada and as international staff geologist. Mark holds a BE degree in engineering science from University of Saskatchewan in Saskatoon, a management development certificate and a MEc degree in economics from University of Calgary, both in Canada.

Bingjian Li is a senior geologist with Schlumberger Data & Consulting Services in Calgary, Alberta, Canada. He has been with Schlumberger for four years, working primarily in the area of borehole image interpretation. Prior to joining Schlumberger, he spent one year with a consulting firm in Canada, three years in geological research in the UK North Sea and eight years as a geologist with CNPC (Chinese National Petroleum Corp.) in China. Bingjian obtained a BS degree in petroleum geology from Daqing Petroleum Institute in China and a PhD degree in reservoir geology and sedimentology from University of Aberdeen in Scotland.

Gilberto Lopez, Drilling and Workover Manager, PRISA (Alliance for Integrated Services in Drilling and Workover) project, for Petróleos de Venezuela S.A. (PDVSA) West Venezuela, has held this position since 2001. He began his career in 1974 as a drilling engineering trainee with Shell Oil Company. Four years later he became drilling and workover supervisor with Maraven SA. (PDVSA). After an assignment in The Hague, The Netherlands with Shell Oil in 1982, he became a wellsite rig supervisor for Maraven in West Venezuela. Subsequent assignments in Venezuela included drilling and workover rig superintendent, drilling and workover superintendent and drilling and workover leader. Gilberto became a petroleum technician after attending the Industrial Technical School in Cabimas, Venezuela, and received a BS degree in petroleum engineering from University of Oklahoma.

Alessandro Madrussa, who works in GeoQuest Geology & Geophysics (G&G) Software Support, is based in Luanda, Angola. He joined the company in 1996 as a geophysicist for GeoQuest in Milan, Italy. Before taking his current position, he was responsible for support of GeoQuest G&G software products in Montrouge, France. Alessandro holds an MS degree in geophysics from the University of Trieste, Italy.

Mel Marshall, Manager, Alberta Foothills with El Paso Oil and Gas Canada, is based in Calgary. He began his career in 1985 with Dome Petroleum working on exploration plays in the Devonian carbonates. In 1989 he joined Encor Energy, where he worked on the Devonian and Triassic plays in Alberta and British Columbia. He then joined Crestar Energy and spent another five years in exploration of northeastern British Columbia. In 1998, he joined the newly formed El Paso Oil and Gas Canada as the staff geophysicist and explored in Alberta, British Columbia and the Northwest Territories. Mel obtained a BS degree in geophysics from the University of Calgary.

Hugo Morán, Schlumberger IPM Project Manager of the PRISA Project, West Venezuela, is based in Ojeda, Venezuela. There, under the PRISA contract with PDVSA, he is responsible for commercial and operative management of six drilling rigs in Lake Maracaibo. In that role, he was team leader for the drilling and workover process optimization that reduced nonproductive time by 70% and resulted in the best operational performance in Lake Maracaibo during 2000 and 2001. Since joining Schlumberger in 1998, he also has served as senior drilling engineer and drilling and completions manager. In his 26 years in the oil industry he has worked for many oil companies, mainly in drilling and completions operations in Argentina, Iraq, South America and Canada. Hugo earned a degree in civil engineering at J.A. Mazza Private University in Mendoza, Argentina.

Romer Morillo, who is based in Caracas, Venezuela, is Schlumberger account manager for PDVSA Data Management (PDM) Services, which is an exclusive service for Petróleos de Venezuela S.A. (PDVSA) to provide data administration, IT projects and specialized applications support for the E&P community. His main responsibilities are to conduct the relationship between the two companies and identify common opportunities for improvement and new projects. He joined Schlumberger in 1997, after working 15 years for the PDVSA Information Technology organization as project analyst, project leader and information systems supervisor in the areas of gas management, oil domestic market, refining, exploration and production. Romer obtained a degree in information technology from Simon Rodríguez University in Venezuela.

Mark Orgren is an owner of Alliance Energy Corporation in Jones, Oklahoma, a geological consulting firm he co-founded in 1995. He specializes in the creative use of digital data to find new hydrocarbon reserves. For the past two years, he has worked with The GHK Company to help develop the firm's prolific discovery in the Ouachita Mountains of southeastern Oklahoma. Prior to 1995, Mark was an exploration geologist and geological manager, working for Exxon, Chevron and other companies. He holds a BS degree in geology from State University of New York (SUNY) in Fredonia and an MS degree in geology from the University of Oklahoma.

Jan Pellenbarg works for Petroleum Development Oman LLC (PDO) in Muscat, Sultanate of Oman, on their rigless abandonment project. There he supervises the operations of Schlumberger Coiled Tubing Unit 20. Before this (1994 to 2000), he was a senior drilling supervisor and senior well engineer with PDO. From 1986 to 1990, he served as a drilling supervisor for Shell in North America. He also spent four years with Shell PDC Nigeria Ltd. as a senior drilling supervisor. Jan earned a degree in mechanical engineering in The Netherlands.

Jochen Pfeiffer, who is based in Oklahoma City, Oklahoma, is involved in cementing within the Schlumberger US land eastern area. He joined Schlumberger Dowell after receiving a degree in geology at Ludwig-Maximilians University in Munich, Germany in 1981. His early assignments were as cementing specialist in Turkey and Libya, offshore manager of cementing in Libya, manager of a stimulation vessel in Italy, station manager in Libya and then Norway. From 1993 to 1997, he managed coiled tubing stimulation in Germany and then became district manager there. From 1997 to 1999, he was Dowell marketing manager for central and eastern Europe. Prior to taking his current position, Jochen was project manager, well services marketing for Schlumberger in France.

Paul Pickavance, Business Development Manager for LiveQuest* application service provider solution in the US-Land GeoMarket* region, is based in Houston, Texas. He joined Seismograph Service Ltd. in 1981 and worked first on land seismic-acquisition crews in Pakistan, Libya and Peru, and then in marine seismic processing and interpretation. He moved to the Research Division, studying marine seismic sources, anisotropy and three-component recording. He joined GeoQuest Systems in 1991, working in software support and training. After Schlumberger acquired GeoQuest Systems in 1992, he worked in support, training and marketing in Italy and France, covering southern Europe and Africa. He was with the Product Marketing group in Houston from 1998 to 2001. Paul is a graduate of University of Cambridge in England with BA and MA degrees in natural sciences.

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Jim Redden has been communications supervisor for M-I L.L.C. Drilling Fluids in Houston, Texas since 1997. His primary responsibilities include writing and photography for a quarterly external magazine, quarterly internal technical newsletter, trade journal articles, professional association papers, news releases and brochures. He began his career in 1973 as a reporter for the *Fort Lauderdale Sun-Sentinel* in Florida, USA. Four years later he became energy editor for the *Amarillo Globe-News* in Texas. In 1979 he joined Fairchild Publications as southern US bureau chief, and a year later became senior technical writer for Halliburton in Houston. From 1983 to 1990, he was with Pennwell Publications first as news editor for *Offshore Magazine* and then as editor for *Ocean Oil Weekly Report*. Prior to his current position, he was a technical writer with Hughes Christensen Co./Baker Hughes. Jim earned a BA degree in journalism at Marshall University, Huntington, West Virginia.

David Seabrook, Geology & Geophysics (G&G) Business Development Manager for Schlumberger Information Solutions, is based in Luanda, Angola. There he is responsible for managing the sales and support team with regards to G&G, reservoir, knowledge management, iCenter* environments and Merak products and services. He joined GeoQuest in 1997 as data management geoscientist and engineer in charge of the GeoQuest office for South Africa. David obtained an MS degree in geophysics from the University of the Witwatersrand, Johannesburg, South Africa.

Gilberto Segovia, Schlumberger Engineering and Technologies Development Manager based in Ojeda, Venezuela, works in the PRISA project. He is involved in drilling design for shallow, deep, reentry, directional and horizontal wells in the Lake Maracaibo area. He began his career in 1987 as a junior drilling engineer with Petróleos de Venezuela S.A. (PDVSA) in the Lake Maracaibo area. His 15 years of experience in the industry have been mainly in drilling, workover and completion engineering of deviated, shallow and deep wells in Venezuelan fields. Gilberto earned a degree in mechanical engineering from Zulia State University in Maracaibo, Venezuela.

Harold Slater, Senior Staff Completion Engineer for PanCanadian Energy Corporation, is based in Calgary, Alberta, Canada. There he is responsible for well-abandonment operations as well as completion design for oil-producing, steam-injection and disposal wells associated with the company's steam-assisted gravity drainage projects. In 1968, after graduation from the University of Saskatchewan, Saskatoon, Canada with a BS degree in mechanical engineering, he joined Hudson's Bay Oil and Gas Co. Ltd. in their drilling and completions department in Edmonton, Alberta, Canada. He moved to Calgary in 1972 to pursue opportunities in the gaswell testing area. He continued his work in the drilling, completion and production engineering sector. Harold joined PanCanadian in 1998 after 10-year period of independent consulting, with assignments in drilling, completions, well workover, oil-processing facility and pipeline installation.

Timo Staal, Schlumberger Dowell Manager in Muscat, Sultanate of Oman, is currently responsible for the 60-well plugging and abandonment (P&A) project for Petroleum Development Oman LLC in Oman. He joined Dowell in Turkey in 1992 as an operator trainee then became a field engineer in Denmark. His next assignment was with Sedco Forex in France as an assistant driller and rig engineer. In 1995 he trained crews in coiled tubing drilling and wrote the operations manual for the first successful underbalanced coiled tubing drilling well extension in Norway. Later his responsibilities included coiled tubing drilling in Nigeria, Norway and Denmark, where he worked on more than 15 coiled tubing drilling projects. Before assuming his current position, he was worldwide business development manager for Schlumberger Coiled Tubing Drilling. Timo earned an MS degree in industrial engineering and management from Eindhoven Technical University in The Netherlands.

David Stiles, Technical Manager, Well Construction Services for Schlumberger Dowell in Calgary, Alberta, Canada, has been responsible for management of all cementing technology within the Canadian region since 1999. He began his career in 1984 as a field engineer with The Western Company of North America in Sidney, Montana, USA. From 1986 to 1987, he was a laboratory supervisor with Tracer Laboratory in Midland, Texas. In 1987 he joined Schlumberger Dowell in Midland, as division chemist and laboratory supervisor. In 1989 he became a field engineer in Midland and Alice, Texas. He has also been Southwest Division laboratory manager in Houston (1990 to 1991), Dowell North American Technology Center senior staff engineer (1991 to 1993), Gulf Coast area engineer for well-construction services in New Orleans, Louisiana (1993 to 1997), and product center marketing manager at Schlumberger Riboud Product Center in Clamart, France (1997 to 1998). Prior to his current position, he was cementing engineer manager for North America. Author of many technical papers and holder of a patent for foamed right-angle-set cement, he is a member of the API subcommittee on well cements. David received a BS degree in geology from Kansas State University in Manhattan, USA.

Frans Tettero, Senior Well Engineer for exploration and deep gas development, Petroleum Development Oman LLC (PDO), is based in Muscat, Sultanate of Oman. His responsibilities include abandonment of redundant exploration wells, and drilling of high-pressure oil wells and high-temperature gas wells. He began his career with Shell Internationale Petroleum Maatschappij BV (SIPM) as a trainee driller in 1981. From 1984 to 1992, he was an assistant driller, driller, drilling supervisor and drilling contracts engineer for Shell Brunei Petroleum Co. He spent the next four years as a drilling support engineer and a drilling operations engineer for Shell Gabon. After serving as senior drilling engineer for offshore operations, he joined PDO in 1997. Frans earned a degree in mechanical engineering from Hogere Technische School, Apeldoorn, The Netherlands.

Geoff Tilling, Decommissioning Manager for Phillips Petroleum Company United Kingdom Limited, is based in Woking, England. His 35-year career in oil and petrochemicals has included refining, chemical manufacture, offshore and onshore terminals and production with Shell Chemicals, Esso, Rohm and Haas. He has been with Phillips for 27 years. Geoff has been chairman of the United Kingdom Offshore Operators Association (UKOOA) Decommissioning Committee since 1998, previously serving as its vice chair; he has also chaired the UKOOA Engineering and Development Committee. A chartered chemical engineer, he is a graduate of the University of Newcastle-Upon-Tyne in England.

Keith Tushingham, Senior Geoscientist with Schlumberger Information Solutions in Houston, Texas, is currently the iCenter Product Champion. He joined Geco-Prakla in 1985 in the mapping department and then moved into Charisma* product support. In 1990 he became a support geoscientist in Norway. Four years later he moved to Jakarta as marketing support manager for Indonesia. Keith holds a BS degree (Hons) in geology from the University of Portsmouth in England.

Chris Whitney is superintendent for engineering and construction for Unocal Corporation in Sugar Land, Texas. He joined Unocal in 1982 after college graduation. A registered professional engineer in Louisiana, Chris earned a BS degree in civil engineering from Louisiana State University in Baton Rouge.

Jon Wine, Schlumberger Oilfield Services Account Manager for Kerr McGee Oil & Gas Corporation, coordinates sales and service delivery for all Kerr McGee's offshore Gulf of Mexico operations. He began work with Schlumberger Dowell as a field engineer trainee in 1985 at Glenville, West Virginia. Since then he has held various positions within Dowell in marketing, sales and operations while working in the eastern and midcontinental US, south Texas and the Gulf of Mexico. Before his current assignment he was GeoMarket technical engineer for stimulation and sand control in Houston, Texas. Jon has a BS degree in petroleum engineering from Marietta College in Ohio.

Seismic Depth Imaging. In many of today's hot exploration areas, especially where faulting and salt structures lead to complex seismic velocities, traditional time-domain processing gives misleading results; only depth imaging reveals the true location and shape of subsurface features. This article explains depth imaging and presents examples showing how oil and gas companies use it to improve their success rates.

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NEW BOOKS

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E.C. Pielou
University of Chicago Press
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2001. 244 pages. $25.00.
ISBN 0-226-66806-1

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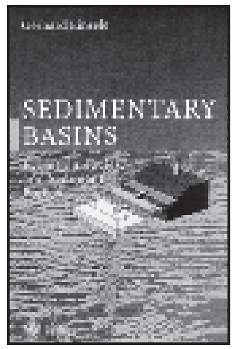
Buy this book. It is a lively read for anyone interested in how physics underpins the natural world, and for instilling a sense of proportion.

You'll have to concentrate as [the author] draws comparisons between the diverse components of the atmosphere, biosphere, lithosphere and all the other "spheres," but the reward is a much clearer picture of how the world works.

Bowler S: *New Scientist* 170, no. 2288 (April 28, 2001): 49.



Sedimentary Basins: Evolution, Facies, and Sediment Budget, 2nd Edition
Gerhard Einsele
Springer-Verlag
175 Fifth Avenue
New York, New York 10010 USA
2000.792 pages. $84.95
ISBN 3-540-66193-X

In addition to discussion of depositional systems, facies models, basins and plate tectonics, the book includes a novel section with detailed treatment of subsidence, sediment flux and the sediment budget.

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- Types of Sedimentary Basins: *Basin Classification and Depositional Environments*
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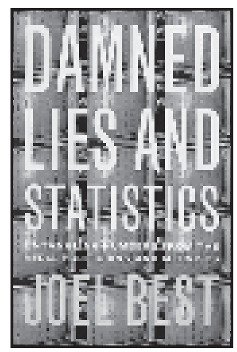
- Diagenesis and Fluid Flow: *Mechanical and Chemical Diagenesis; Hydrocarbons and Coal*
- References, Index

The material on depositional systems and facies models is up to date and very thorough, and is characterized by Einsele's stylish diagrams.

This book is an impressive tour-de-force. There is no other modern text that deals with subsidence, sediment flux and the sediment budget, in the thorough manner presented here. Much of the treatment appears to represent an entirely original synthesis, and the book is worth purchasing for this section alone.

Graduate students and professionals will be the main readers of this book, and I can certainly recommend its purchase for this group….

Miall AD: *Sedimentary Geology* 143, no. 1-2 (August 15, 2001): 185-186.



Damned Lies and Statistics: Untangling Numbers from the Media, Politicians, and Activists
Joel Best
University of California Press
2120 Berkeley Way
Berkeley, California 94720 USA
2001. 190 pages. $19.95
ISBN 0-520-21978-3

This book outlines the uses of social statistics and describes how to interpret apparently contradictory conclusions. Avoiding the use of complicated mathematics, the author also shows how to detect bad statistics, those with questionable or inappropriate origins.

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- The Importance of Social Statistics
- Soft Facts: Sources of Bad Statistics

- Mutant Statistics: Methods for Mangling Numbers
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- Stat Wars: Conflicts over Social Statistics
- Thinking About Social Statistics: The Critical Approach
- Notes, Index

Definitely a must for politicians, activists and others who generate or use statistics, but especially for those who want to think for themselves rather than take as gospel every statistic presented to them.

Anderson A: *New Scientist* 170, no. 2296 (June 23, 2001): 50-51.

Handbook of Exploration Geochemistry Volume 7, Geochemical Remote Sensing of the Sub-Surface
M. Hale (ed)
Elsevier Science B.V.
Sara Burgerhartstraat 25
P.O. Box 211
1000 AE Amsterdam, The Netherlands
2000. 549 pages. $196.50
ISBN 0-444-50439-7

Written by 21 expert contributors from different fields, the book covers genetic models of remote dispersion patterns and the genesis, behavior and detection of different gases in the Earth's crust. Included is discussion of new approaches for deciphering not only subsurface structure, but also near-surface and geochemical expressions of both hydrocarbon and mineral deposits.

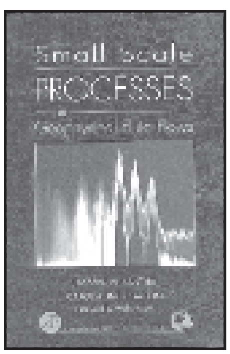
Contents:

- Genesis, Behaviour and Detection of Gases in the Crust
- Geoelectrochemistry and Stream Dispersion
- Spontaneous Potentials and Electrochemical Cells
- Carbon Dioxide Dispersion Halos Around Mineral Deposits
- Light Hydrocarbons for Petroleum and Gas Prospecting
- Gas Geochemistry Surveys for Petroleum
- Aerospace Detection of Hydrocarbon-Induced Alteration
- Sulphur Gases
- Sulphide Anions and Compounds
- Helium
- Radon
- Mercury
- Discrimination of Mercury Anomalies
- Oxygen and Carbon Dioxide in Soil Air
- References, Indexes

The illustrations and equations are well presented and explained throughout the book. About 30 pages of references are given at the end in case more details are needed.

The book emphasizes these new approaches of geochemical remote sensing and is a must read for any person involved in petroleum or mineral exploration.

Michael F: *AAPG Bulletin* 85, no. 7 (July 2001): 1277.



Small Scale Processes in Geophysical Fluid Flows
Lakshmi H. Kantha and
Carol Anne Clayson
Academic Press
525 B Street, Suite 1900
San Diego, California 92101 USA
2000. 888 pages. $115.00
ISBN 0-12-434070-9

The authors discuss a range of phemonena involving small-scale processes in geophysical flows. These include three-dimensional turbulence and the various instability mechanisms leading to turbulence. Each chapter begins with a presentation of the key observational results relating to particular processes along with a brief history of the field's development and discussion of the basic physics involved.

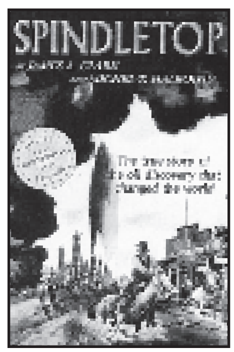
Contents:

- Turbulence
- Oceanic Mixed Layer
- Atmospheric Boundary Layer
- Surface Exchange Processes
- Surface Waves
- Internal Waves
- Double-Diffusive Processes
- Lakes and Reservoirs
- Appendices, References, Index

Its authors have done an exhaustive job of reviewing the important developments in the field, even to the extent of presenting all of the recent estimates of various phenomenological constants.

The authors have done a valuable service to the community. I expect this text to be the starting point for many researchers new to a specific aspect of the field.

Moum J: *Physics Today* 54, no. 10 (October 2001): 74-75.



Spindletop: The True Story of the Oil Discovery That Changed the World
James A. Clark and Michel T. Halbouty
Gulf Publishing Company
P.O. Box 2608
Houston, Texas 77252 USA
2000. 306 pages. $26.95.
ISBN 0-88415-813-6

This centennial edition of the history of the first great oil gusher in Spindletop, Texas, in 1901 describes the people and events that formed the nucleus of the modern oil industry.

Contents:

- The Prophet
- Three Holes in the Hill
- The Captain
- Geyser of Oil
- Birth of a Boom Town
- Pandemonium
- Hell on the Hill
- The Onion Patch
- Guffey Goes Gulf
- A Star is Born
- The Rising Sun
- Standard Steps In
- Humble Beginnings
- The Second Prophet
- Master of the Mound
- Accent on Success
- Suits and Countersuits
- Commemoration
- Appendices

Clark and Halbouty combined their eyewitness experience and technical expertise to produce an unparalleled account of the colorful and exciting story of the most significant petroleum discovery in the world.

Barfoot L: *Journal of Canadian Petroleum Technology* 39, no. 4 (April 2000): 22.

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