Viscoelastic Surfactants
Ocean Drilling for Science
Fault-Seal Analysis
Measuring Multiphase Flow
Rotary Steerable Technology: Pushing the Limit

In the oil and gas industry, economic and health, safety and environmental (HSE) realities force us to be objective in developing and deploying technology. The rapid development of individual technologies requires constant attention and objectivity from decision makers in exploration and production (E&P) companies. Among the most rapidly evolving technologies available to E&P companies are rotary steerable drilling systems.

Shell Exploration & Production in Europe (Shell) became interested in the potential of the earliest directional drilling systems to improve drilling efficiency—a key concern for well-delivery teams to fulfill the Drilling the Limit™ philosophy that is central to all of our projects. Although positive-displacement motors offered steering capability and directional control, the motors were not efficient. Steerable motors allowed rotation or sliding of the drillstring from surface, which improved directional control, but this technology was risky because the high torque and drag limited drilling capability in sliding and rotating modes. In addition, the wellbore tortuosity produced by steerable motors in the sliding mode often causes other problems: tortuosity makes future sliding more difficult and can impede critical operations for formation evaluation and running casing.

Rotary steerable technology eliminated most disadvantages of previous directional drilling methods. Because these systems drill directionally with continuous rotation from the surface, there is no need to slide the tool. Continuous rotation transfers weight to the bit more efficiently, which increases the rate of penetration (ROP). Rotation also improves hole cleaning by agitating drilling fluid and cuttings, allowing them to flow out of the borehole rather than accumulating as a cuttings bed. Efficient cuttings removal reduces the chance for the bottomhole assembly to become stuck or to pack off.

Service providers have developed a wide variety of fit-for-purpose rotary steerable systems to improve the economics of nearly any drilling project. These include tools that facilitate drilling long horizontal sections; systems for harsh, rugged environments, which support drilling with bicenter bits and drilling in soft formations; and even systems specifically designed to drill vertical wells.

Shell found that drilling from one casing shoe to the next with a rotary steerable system (RSS) provided more efficiency, better performance and improved safety than directional drilling with a downhole motor. The newest RSS, which includes an integrated downhole power section to achieve greater ROP, benefits drilling projects in inhabited areas (see “Powering Up to Drill Down,” page 4). In the Groningen field in The Netherlands, for example, use of this system allowed a topdrive to be run at 10 to 20 rpm to drill a water-injection well, greatly reducing the environmental impact of sound generated by the drilling rig. Nevertheless, the ROP increased 50% compared with other wells in the area.

Perhaps the biggest economic impact of rotary steerable drilling technology occurs in mature fields whose productive life can be extended by quickly drilling directional wells in a single bit run through highly depleted reservoirs. To this end, Shell pioneered use of a 6-in. powered RSS in mature fields to create smaller boreholes. Cost reductions of at least 25% are typical in our mature-field drilling projects because the performance of the 6-in. tool matches that of the 8.5-in. tool. In addition, the smaller hole sizes reduce the costs of drilling fluids, cuttings removal and disposal without constraining flow rates.

Within Shell, the value of using an RSS is well recognized. Our “shoe2shoe drilling” initiative reflects the optimal drilling process, and RSS technology is a key enabler. We have also instituted a Common Interest Network (CIN) on rotary steerable technology, whereby well engineers with RSS expertise in all Shell regions share RSS learning and practices to collectively advance the learning curve. The CIN also challenges industry providers to deliver additional RSS advancements, such as different tool sizes.

We expect the next important milestone, successful deployment of a superslim 3.125-in. through-tubing rotary drilling (TTRD) system for 3.875- to 4.5-in. holes, to be achieved in 2005, thanks to development by Shell, BP, Statoil and Schlumberger. Although TTRD work has already been completed through larger completions, the capability to drill sidetracks through 4.5-in. tubing will further reduce the cost of draining marginal accumulations in mature fields—a vital concern for companies large and small.

Chris Kuyken
Team Leader, Well Engineering and Well Services Technology
Shell Exploration & Production in Europe
Aberdeen, Scotland

Chris Kuyken has more than 22 years of experience in oil- and gas-well drilling with Shell and has worked onshore and offshore in many well engineering positions in Oman, Brunei and, since 1999, in Scotland. He is an energetic proponent of Shell’s Drilling the Limit™ philosophy, whereby people, HSE and technology are the keys to success. A European Engineer (EUR ING) registered with European Federation of National Engineering Associations (FEANI) and a Chartered Engineer (C Eng) through the British Engineering Council, Chris earned a BS degree in chemical engineering technology from Hogere Technische School (HTS), The Hague.

Drilling the Limit is a trademark of Shell.
4 Powering Up to Drill Down

A new rotary steerable drilling system includes an integrated power section that converts the hydraulic power of circulating fluid to rotational torque. This supplements rotational torque supplied by the drilling rig and produces unprecedented high rates of penetration, making it ideal for drilling hard formations. Like other advanced rotary steerable systems, this high-performance technology offers the advantages of continuous rotation at drillstring speed to minimize stick/slip phenomena and improve efficiency.

10 Expanding Applications for Viscoelastic Surfactants

Viscoelastic surfactants (VES) revolutionized fracture stimulations in the mid-1990s. Today, continued advances in VES chemistries allow engineers to apply these unique materials in new ways that dramatically improve and optimize well-completion techniques. Case studies from South America, North America, the North Sea and the Caspian Sea demonstrate the effectiveness of VES fluids in difficult gravel-packing, hydraulic fracturing and acidizing operations.

24 Scientific Deep-Ocean Drilling: Revealing the Earth’s Secrets

Drilling for science has contributed to an understanding of the dynamic processes that affect climate, natural disasters and the creation and distribution of resources on Earth. This article reviews the history of scientific deep-ocean drilling, technological developments and plans for the 21st Century.
Reducing Uncertainty with Fault-Seal Analysis

Faulting can have an enormous impact on oil and gas exploitation. Faults are often responsible for trapping hydrocarbons and compartmentalizing reservoirs. They can also introduce a high degree of uncertainty in both the exploration and development stages. This article describes how geoscientists and engineers are improving their understanding of faults in siliciclastic reservoirs, and how they analyze, model and simulate the effects of faults on subsurface fluid flow. Examples from Hibernia, Newfoundland, Canada, and Prudhoe Bay, Alaska, USA, illustrate the successful application of modern fault-seal analysis methods.

A New Horizon in Multiphase Flow Measurement

Measuring three-phase flow without separation increases the accuracy of gas, oil and water measurements. This technology helps engineers quantify changing fluid phases over time to better understand dynamic flow. Case studies from Australia, the Gulf of Mexico and Africa illustrate the benefits of advanced multiphase meters and show how they help enhance production, improve field operations and optimize reservoir management.

Contributors

New Books and Coming in Oilfield Review

Annual Index
Economics, efficiency, environmental protection and safety are the most important targets in the oil industry. New technology is often the key to hitting these targets, particularly for those involved in well drilling. Drillers pursue new technology as relentlessly as anyone in the oil field. Even though rotary steerable systems are evolving rapidly and delivering unprecedented rates of penetration, drillers nevertheless seek technology that speeds the drilling process even more. Their motivations are many, and include the obvious reductions in rig time and expense that result from using a rotary steerable system that provides more power to the bit.

Advanced drilling technology provides additional, more subtle advantages, such as reducing casing wear by preventing contact between drillpipe and the casing for long periods of time (next page, left). New technology also helps drillers decrease formation-exposure time—the time between drilling and formation evaluation. This minimizes invasion of drilling fluids and can simplify petrophysical evaluation. Less time between drilling and running casing means less time during which a borehole can degrade; beyond a certain point, running casing becomes difficult. Ultimately, in many cases, faster well construction means that wells produce oil and gas sooner.

Against these advantages, however, drilling engineers weigh the drawbacks of faster drilling, chief among them the potential for poor borehole quality if drilling operations are not performed carefully. In addition, the drilling rig’s mud system and pumps have an inherent capacity for hole cleaning that should not be exceeded. Using high flow rates to clean the borehole might cause hydraulic erosion. Mud properties and flow velocities must be balanced to ensure hole stability. Finally, directional control might sometimes be lost if speed overrides all other concerns.

Articles in recent issues of Oilfield Review described a rotary steerable system (RSS) that facilitates drilling long horizontal sections with excellent directional control; a system developed for harsh, rugged environments, which supports drilling with bicenter bits and drilling in soft formations; and a vertical drilling system. A common feature of all Schlumberger rotary steerable systems is the continuous rotation of all external components (next page, right). The latest RSS adds an integrated downhole motor to increase the rate of penetration (ROP). This system is ideal for quickly drilling long vertical or directional sections. In this article, we discuss the special technical demands on powered rotary steerable systems and the way...
tool developers satisfied those demands. Examples from the Caspian Sea, Egypt and Canada demonstrate the advantages now obtainable with an advanced rotary steerable system.

The Need for Speed

Early directional drilling systems paired downhole motors with an adjustable bent housing, a component of the drillstring that allowed drillers to change the well trajectory. These bottomhole assemblies (BHAs) tended to produce poor-quality or spiral boreholes as drilling alternated between sliding and rotating modes. In the sliding mode, the drillstring is not rotated by the drilling rig; instead, the drill bit is rotated downhole by the downhole motor. Frictional forces, known as drag, build as the nonrotating drillstring is pushed along the low side of the borehole. Drilling rates in sliding mode typically are slow, and both mechanical and differential sticking of the drillstring are ever-present concerns.

The earliest rotary steerable systems dramatically improved ROPs and borehole quality while limiting mechanical sticking. These observations led drilling engineers to consider joining a downhole motor to a rotary steerable tool. This combination is not trivial: the bearings and transmission of the downhole motor must be strong enough to support the additional weight of the rotary steerable tool below. In addition, the power section of the downhole motor must be configured to keep the rotation rate from exceeding the limits of the RSS. At excessive rates, steering control becomes difficult and the well path might be compromised.

Successful integration of a downhole motor and a rotary steerable system promised many advantages, from higher ROP to facilitating use of more aggressive drill bits. In areas of high environmental sensitivity, driving the RSS with only downhole power eliminates excess rig noise.

Given these myriad motivations, Schlumberger scientists and engineers began to tackle the challenges of building a powered rotary steerable drilling system. The PowerDrive vortex powered rotary steerable system is the result of their efforts.


Powerful Drilling Technology

The PowerDrive vortex system offers a unique set of capabilities for faster directional drilling (above). Its four main components are the power section; the filters, bearings and transmission; the control unit; and the steering section. The integration of the power section and the rotary steerable tool required engineers to develop bearings and a transmission for the downhole motor that support the additional weight of the rotary steerable tool and take the extra weight on bit (WOB), or load, from surface to drill more quickly. The other components of the PowerDrive vortex system incorporate proven technology from earlier systems.

The power section converts the hydraulic power of the drilling fluid to mechanical energy. The speed and torque output of the rotor can be changed by using a rotor with a different number of lobes. The rotor shown in this 5:6 power section has five lobes.

The control unit and steering section set the drilling trajectory. Various stabilization options allow engineers to tailor the BHA to the desired directional response.

Given these powerful adaptations, it is not surprising that approximately 90% of PowerDrive vortex system deployments to date involve performance-drilling applications in which engineers seek higher ROPs by using the exceptionally high power of the system. In about 5% of deployments, the PowerDrive vortex system is desirable because low torque, restricted rotation rate or small circulating pumps limit the capabilities of the drilling rig. The system is also useful for limiting casing wear by reducing the surface rotation rate of the drilling rig while allowing the downhole power section to rotate the bit. Minimal contact between the rotary steerable tool and the borehole wall also decreases casing wear.

The system also excels in shock-management applications, in which drillers strive to increase efficiency. For example, stick/slip effects might occur at the bit, causing it to become stuck momentarily before freeing itself. Minimizing these and other effects that tend to slow the drilling process and damage the BHA improves efficiency.

The problem of mechanical sticking involves the entire drillstring, not just the bit. Having a tool that makes minimal contact with borehole walls reduces the likelihood of mechanical sticking, but good borehole cleaning is key in avoiding mechanical sticking. Use of the PowerDrive vortex system reduces the risk of sticking because everything rotates at least as fast as the drillstring.

In addition to the typical performance attributes of an RSS—for example, high ROP, high efficiency and excellent directional control—the PowerDrive vortex system optimizes performance of polycrystalline diamond compact (PDC) bits. Higher torque output allows more aggressive PDC bits to be used, further increasing penetration rates.
Avoiding Differential Sticking in the Caspian Sea

Advanced rotary steerable systems are playing a key role for Dragon Oil Plc. in the redevelopment of the LAM field in the Cheleken block offshore Turkmenistan in the Caspian Sea. This field was initially developed using Russian drilling technology in the 1980s. Dragon Oil began redevelopment with infill drilling in 2001 and has recently drilled four wells as part of a continuous drilling program initiated in November 2003.

S-shaped wells are drilled from the LAM 21 production platform to access oil reserves in the Red Series reservoir, which comprises late Miocene to early Pliocene interbedded sandstones and claystones. Schlumberger was selected to provide directional drilling, measurement-while-drilling (MWD), logging-while-drilling (LWD) and wireline-logging services for the development wells. Drilling in the Cheleken block commonly requires high pressure overbalance in the upper part of each hole section when that section nears its total depth (TD). This is due largely to the overpressured nature and thickness of the reservoir. Problems with differential sticking are therefore common.

For the second of four development wells, LAM 21/107, Dragon Oil selected a conventional directional drilling assembly with a downhole motor. Directional drilling assemblies tend to build angle in the Red Series reservoir, so the rig crew reduced the weight on bit (WOB) to better control borehole trajectory. The reduction in WOB decreased ROP, which in turn increased the risk of differential sticking, especially when drilling in the sliding mode. Eventually, all sliding was stopped because of concerns about potential differential sticking. Furthermore, a natural tendency for the well to drift 3°/30 m [3°/100 ft] during drilling meant that the well trajectory was heading outside the original target tolerances.

Dragon Oil invited Schlumberger to optimize the drilling procedure for the next three wells. Schlumberger engineers proposed using the PowerDrive vortexX system to alleviate several problems. First, the powered RSS would maintain the high rotation rates Dragon Oil specified. Higher ROP and the resultant reduction in drilling days would limit casing wear in upper sections of the wellbores. Finally, using a fully rotating drilling system would greatly reduce the potential for differential sticking by eliminating drilling in the sliding mode.

In the third well, LAM 21/108, Dragon Oil drilled 772 m [2,533 ft] of 8.5-in. hole in 66 hours using the PowerDrive vortexX system. By comparison, a standard positive-displacement motor (PDM) assembly would have required approximately 10 days to drill this section (above).

In addition to the high ROP, the powered RSS maintained verticality in a 600-m [1,970-ft] borehole section through the reservoir, with 90% of the hole having less than 0.5° inclination. The wells are typically planned with a vertical or low-angle trajectory through the reservoir to minimize wellbore-stability problems. In the LAM 21/108 well, use of the PowerDrive vortexX system saved approximately seven days of rig time.

The PowerDrive vortexX system was also deployed in the fourth well drilled from the LAM platform, LAM 21/109. In this well, ROP in the 12.25-in. section was 204 m/d [669 ft/D] and 175 m/d [574 ft/D] in the 8.5-in. section. In this case, the powered RSS saved approximately nine days of rig time.

Dragon will continue its drilling program on the LAM 10 platform, and the company plans to build on the gains made while drilling the LAM 21 redevelopment wells. PowerDrive vortexX systems will be used in the 12.25-in. and 8.5-in. hole sections. Further upgrades to the rig and drillpipe might also allow the use of PowerDrive vortexX technology in 6-in. hole sections.

Developing a Mature Field in Egypt

Belayim Petroleum Company (Petrobel), a joint venture between Eni and Egyptian General Petroleum Corporation (EGPC), has been using PowerDrive vortexX technology to provide more energy and sufficient rotation rate to drill hard reservoirs.

3. Components of the bottomhole assembly below the power section rotate at the sum of drillstring and surface-rotary speed.
became evident during production. Construction, and formation damage that mud losses and differential sticking during well presented a variety of challenges, such as severe interbedded sands and shales that have pre-

This oil field, discovered in 1961, consists of Marine field, offshore Egypt in the Gulf of Suez. Anhydrite stringers in the mature Belayim formation. To meet the technical and financial objectives of the wells, Petrobel selected PowerDrive vorteX technology. Before drilling the wells, engineers simulated the performance of a conventional mud motor and the PowerDrive vorteX system, and they determined that the powered RSS would offer a boost of more than 123% in ROP compared with the mud motor. These operations, which began in January 2003, were the first deployment of PowerDrive vorteX technology in Egypt, and the powered RSS proved vital in avoiding stick/slip problems.

The operator recently drilled several new directional wells to drain the field more efficiently. Key to adding new wells is constructing them within the economic constraints of the field. To meet the technical and financial objectives of the wells, Petrobel selected PowerDrive vorteX technology. Before drilling the wells, engineers simulated the performance of a conventional mud motor and the PowerDrive vorteX system, and they determined that the powered RSS would offer a boost of more than 123% in ROP compared with the mud motor. These operations, which began in January 2003, were the first deployment of PowerDrive vorteX technology in Egypt, and the powered RSS proved vital in avoiding stick/slip problems.

In the 113M-86 well, which targeted oil in the Kareem formation, use of the PowerDrive vorteX system saved more than 10 days of rig time—a total of US$ 600,000. The ROP was 47% higher than the best previous performance in the field. In addition, the 12.25-in. section was drilled in a single trip, and the trajectory closely matched the plan. The powered RSS saved at least five rig-days per well in three other wells (left). Based on these results, Petrobel plans to use the PowerDrive vorteX system in the future.

Drilling Long Laterals in Steeply Dipping Beds

In a field in the foothills area of Alberta, Canada, an operator is drilling long horizontal wells that produce gas. The plan for one such well involved drilling out of the surface-casing shoe with an assembly capable of building inclination to 15° at a rate of 1.0°/30 m, and then drilling a 2,260-m [7,415-ft] tangent section through steeply dipping formations.

To drill the build and tangent section more efficiently, Schlumberger proposed using the PowerDrive vorteX system in combination with the SlimPulse third-generation slim MWD tool system. Although the higher penetration rates achieved with a powered RSS were an important consideration, the operating company also wanted a system capable of maintaining the desired trajectory through steeply dipping beds without drilling in the slipping mode as with a conventional PDM assembly. In addition, the company wanted to keep surface rotations between 30 and 60 rpm to minimize the casing wear caused by rotation.


6. An analytical tool used in forecasting the performance of the various elements comprising the completion and production system, NODAL analysis is used to optimize the completion design to suit the reservoir deliverability, identify restrictions or limits present in the production system and identify any means of improving production efficiency.


The PowerDrive vorteX system provided more efficient weight transfer to the drill bit and allowed the use of a much more aggressive bit design, increasing the ROP (left).

This powered RSS saved time and money in several ways. Higher penetration rates saved 12 days of rig time, valued at more than CAD 400,000. The powered RSS produced a smoother borehole than a downhole motor, and allowed casing to be run quickly and easily (below left). Compared with experience in offset wells, this borehole required 56 fewer hours of reaming.

As in many successful oilfield operations, use of a single tool is not the only contributing factor. In this case, careful planning, optimal BHA design and teamwork in the office were also factors in the positive outcome.

Driving Ahead

The PowerDrive vorteX system combines an integrated power section with a BHA that rotates at least as fast as the drillstring. The resulting increases in ROP are especially valuable in areas where rig rates are high, yet this technology also provides a vital performance boost in lower-cost operating arenas when rig capabilities limit drilling performance. The PowerDrive vorteX system augments the capabilities of other rotary steerable systems by drilling complicated wells in tightly defined targets within formations that are hard, unstable, or deep, or a combination of these.

Development of additional rotary steerable systems will likely continue at a rapid pace. As described in this article, the PowerDrive vorteX system, first deployed as a 9-in. tool for drilling 12.25-in. holes in 2001 and deployed with fully integrated components in 2003, is already available as a 6.75-in. system to drill 8.5-in. boreholes.

A high-output performance drilling motor, in development for integration with PowerDrive vorteX systems, features a thin layer of elastomer on metal to maintain a more consistent shape than elastomer alone, regardless of fluid pressure within the motor. This allows the new motor to effectively transmit even greater WOB from surface for faster, more efficient drilling. However, the new motor will require a rig rated to higher pressure and pumps capable of handling the cuttings volumes produced at higher ROPs.

In addition to Schlumberger research and development efforts, BP, Shell and Statoil are funding development of a superslim rotary steerable system based on PowerDrive vorteX technology (see “Rotary Steerable Technology: Pushing the Limit,” page 1). Technology developers are proving to be as relentless as drilling engineers when it comes to pushing the limits of technology.

—GMG
Expanding Applications for Viscoelastic Surfactants

Recent developments in viscoelastic surfactants have expanded application of these unique materials in new and challenging environments. From well completions to stimulations, viscoelastic surfactant systems are improving well productivity and hydrocarbon recovery.

Minute objects can have a disproportionate impact on large-scale endeavors. A drop of ink can darken a full glass of water, while splitting an atom causes a significant release of energy. Micelles—microscopic structures of water bound together by surfactant—are obscure to the naked eye, but only a few volume percent are needed to improve the efficiency and effectiveness of reservoir stimulation operations.¹

Surfactants are used in many oilfield operations, such as drilling and reservoir stimulation.² Before 1950, stimulation treatments relied on flammable mixtures of napalm and gasoline to create viscous fluids capable of initiating and propagating a hydraulic fracture.³ In the 1950s, engineers believed that introducing water into a reservoir during a fracturing treatment caused formation damage, so wells were stimulated with viscous, or gelled, oils.

Researchers later found that water-base fracturing fluids were not as damaging to production as they first thought. In the 1960s, engineers turned to viscous solutions of guar, or guar derivatives, in brine.⁴

In the 1970s, the exploration and production (E&P) industry experienced an increase in fracture stimulation as less permeable reservoirs were exploited. To stimulate deeper and hotter wells in these reservoirs, engineers needed fracturing fluids with higher viscosity and greater thermal stability. In response, scientists developed a new generation of polymer-base fracturing fluids. Most often, guar polymers were crosslinked with borate, zirconate or titanate ions to generate high levels of viscosity.⁵

The 1980s saw advancements in laboratory formation-damage evaluation techniques, along with a greater awareness of the fracture permeability damage caused by polymer-base fracturing fluids. To minimize polymer-induced conductivity impairment, engineers began using foamed fracturing fluids. This reduced the required polymer concentration by as much as 50%. Formation damage from polymer residue was reduced, and wells cleaned up faster and produced with greater efficiency.

The next step occurred in the 1990s, when scientists developed polymer-free aqueous fracturing fluids based on viscoelastic surfactant (VES) technology. Since the first generation of VES fluid systems, this technology has evolved considerably. New chemical adaptations enhance...
performance, and have been used to address a wide variety of well environments and to create entirely new applications.

In this article, we review the evolution of VES chemistry in the oil field over the last decade as it progressed from a relatively obscure technology to mainstream use. Case histories from South America, North America, the North Sea and the Caspian Sea demonstrate how these novel materials help engineers optimize oil and gas asset performance and improve hydrocarbon recovery.

From the Beginning
In 1983, the Dow Chemical Company introduced a family of surfactants later known as VES. They were used as thickeners in consumer products, such as bleach, liquid dishwashing detergent and cosmetics. Their intriguing performance led

1. Micelle structures refer to a colloidal aggregation of amphipathic molecules that occur at a well-defined critical micelle concentration.
4. Guar is a hydrophilic polysaccharide derived from seeds of the guar plant. Highly dispersible in water and brines of various types, it can be crosslinked by borax and other compounds to yield high gel strength for suspending solids, such as sand and other proppants. Guar is commonly used in fracturing fluids to generate the required viscosity. Guar has low thermal stability, is pH sensitive, and is subject to bacterial fermentation.
engineers at the Dowell Tulsa Technology Center, now Schlumberger, to explore ways of applying VES technology in the oil and gas industry.

Surfactants are compounds whose molecular structures contain both hydrophilic (water attracting) and hydrophobic (water repelling) groups. Most surfactants consist of a hydrophilic head group and a hydrophobic tail group (above left). When added to an aqueous fluid, surfactant molecules combine to form structures known as micelles. The hydrophobic tails of the micelles associate to form a core that is surrounded by the hydrophilic heads, isolating the tails from contact with water. Typically, micelles are spherical in shape.

In the case of VES surfactants, when certain salts are present in the aqueous fluid within a particular concentration range, the micelles assume a rod-like structure similar to polymer strands (above). These rod-like micelles become entangled, viscoelastic behavior develops, and fluid movement is hindered (left). A significant increase in viscosity occurs as does the development of pseudosolid elastic behavior.

\[\text{Chemomechanical effects and viscoelasticity. When blended with salt solutions at the correct concentration, VES materials form rod-shaped micelles that become entangled under static conditions (top), thus imparting fluid viscosity and pseudosolid elasticity. When exposed to even small amounts of shearing energy, such as that provided by pumping the fluids, micelles readily become disassociated (bottom). Elasticity and viscosity decrease.}\]

\[\text{Micrograph of micelles. Viewed through an environmental scanning electron microscope, VES molecules dispersed in an aqueous solution are shown to associate, form rod-like structures and entangle, ultimately generating viscosity.}\]

\[\text{The molecular level. Viscoelastic surfactants exhibit a well-defined, hydrophilic head structure (right) attached to an articulated tail section with a hydrophobic end (left). When dispersed in specific brine solutions, tail sections associate, ultimately forming a worm-like micellar structure.}\]
When micelles are disassociated by shear energy, the rheological behavior of VES fluids is similar to water, or nearly Newtonian; yet viscosity and elastic behavior recover when the disrupting energy is removed (right). The unique chemomechanical properties that create VES viscosity readily lend themselves to shear thinning, static suspension, low static to dynamic transition-energy requirements and high particle-transport efficiency. VES fluids require less energy to pump than more conventional polymer fluids, effectively reducing wells site pump-horsepower requirements.

The viscosity of VES fluids may decrease with temperature. However, increasing the surfactant concentration or adjusting the salt concentration can reduce this temperature-related thinning. Unlike conventional polymer systems, VES viscosity does not degrade with time, and is predictable and easily modeled, coupling operational simplicity with an efficient and effective fluid design (middle right).

Early laboratory experiments showed that the viscosity of VES fluids is easily broken by contact with hydrocarbons or dilution by formation water. Produced oil or condensate alters the electrical environment in the fluid causing the micelle shape to revert from rods to spheres (bottom right). Fluid viscosity falls because the now-spherical micelles cannot become entangled. Alternatively, when VES fluids are diluted by formation water, the surfactant concentration eventually falls to a level at which insufficient numbers of micelles are present to entangle, and viscosity is lost. Simple laboratory tests are often performed to confirm the compatibility of VES fluids with specific produced hydrocarbons.

In the early 1990s, Schlumberger first applied VES chemistry in PERMPAC viscoelastic surfactant gravel-packing fluid. New to the oilfield, this cationic surfactant was able to viscosify common completion brines—potassium chloride, ammonium chloride, calcium chloride or calcium bromide—to suspend and transport gravel. The VES concentration varied from 2.5 to 6% by volume, depending on the anticipated temperature in a well.

Unlike gravel-packing fluids based on polymer viscosifiers, such as guar or hydroxyethylcellulose (HEC), VES fluids leave little

7. Pseudosolid is a term describing materials that develop highly viscous gel structures, that may exhibit elastic behavior and that require little energy to reduce the gel to liquid.

8. Cationic surfactants are surface-active agents typically composed of fatty amine salts. They have a net positive charge, and they are stable over a range of pH levels and in various salt solutions.
residue, which significantly reduces gravel-pack damage.\footnote{1}

PERMPAC surfactant was eventually used in hydraulic fracturing applications, forming the basis for subsequent development of ClearFRAC polymer-free fracturing fluid. However, cost and temperature limitations—140°F [60°C]—precluded widespread use in fracture treatments.

Schlumberger introduced the original ClearFRAC surfactant system in 1997. Like PERMPAC fluids, the system was built on cationic surfactant chemistry. The ClearFRAC surfactant proved to be stable in low-density brines at temperatures up to 200°F [93°C]. With a high percentage of fracturing operations occurring at temperatures below 200°F, the market for VES fluids in fracturing was broad. In addition, the surfactant could be mixed continuously with brine, and the resulting fluid system could be foamed, or energized, with nitrogen [N₂].

The Challenge of Green Chemistry

From the beginning, VES fracturing and gravel-packing fluids improved well performance. Building on this early success, these fluids have continued to evolve. By the late 1990s, the quest for new oil and gas reserves led operators to drill and complete wells in more challenging and environmentally sensitive areas.

The VES fluids introduced in the early 1980s were based on cationic viscoelastic surfactants. Although effective from both an operational and cost perspective, and environmentally acceptable in most land-based locations, cationic surfactants are not always dischargeable in marine environments.

To address discharge concerns, Schlumberger engineers and scientists began the development of noncationic viscoelastic surfactants. By early 2000, researchers had discovered new anionic surfactants capable of meeting both environmental and functional demands.\footnote{10}

The result, ClearFRAC EF polymer-free fracturing fluid, improved performance in some situations, while providing a fluid that could be discharged in environmentally sensitive areas, such as the Lake Maracaibo region of Venezuela.

In South America, many wells have been drilled and completed in Lake Maracaibo, in north-central Venezuela. Today, discharges from oil and gas operations are limited to products and materials that meet strict environmental standards.

Wells in the Bachaquero field of Lake Maracaibo generally produce from unconsolidated, highly permeable, Miocene sandstones. In many cases, hydraulic fracturing stimulation has proven effective for improving well performance.

Engineers at the Schlumberger field support laboratory in Las Morochas, Venezuela, evaluated various ClearFRAC surfactants, ultimately selecting ClearFRAC EF for its environmental acceptability in marine environments, its low tendency to form emulsions with locally produced oil and its viscosity profile under predicted downhole conditions (top).

To improve well performance on steam injector Well BA-2233, engineers performed a fracturing operation generating a 0.6-in. [15.2-mm] fracture (above). Using a ClearFRAC EF carrier fluid, just under 60,000 lbm [27,215 kg] of fracturing proppant was placed in the BA-2233 well in the Lake Maracaibo area. Most regions of the fracture received over 14 pounds of proppant, producing an effective fracture conductivity of 19,746 mD/ft [6,019 mD/m].
NODAL production system analysis predicted that oil production after fracturing and prior to steam injection would be around 209 B/D [33 m³/d], Actual production after stimulation was 209 B/D [33 m³/d], in line with NODAL analysis predictions.

**Returning Thinner Fluids**

Fracturing fluids serve two primary purposes: first, to provide the hydraulic energy that generates and opens a fracture; and second, to place transported proppant materials in the open fracture to maintain a conductive pathway, or conduit, for linear flow into the wellbore. Once these tasks are performed, pressure in the wellbore falls and the fracturing fluid flows to the surface.

In field tests, engineers found that, compared with more conventional polymer fluids, significantly lower viscosity levels were required with VES fluids to efficiently transport and place fracturing proppant (left). However, in some cases, even minimal viscosity levels could slow fracturing-fluid flowback during well cleanup.

By shortening the time required to clean up a well, commercial production can be achieved sooner. With this in mind, developers began research on breaker chemistry for VES fluids that would provide in-situ viscosity reduction in a controllable and predictable manner.

Viscosity reduction in VES suspensions depends on various factors, including the ionic environment, the temperature and surfactant-packing parameters. Early experiments showed that, like produced hydrocarbons, chemical breakers cause the VES micelles to change shape from rods to spheres, collapsing the entangled micellular structure that generates viscosity.

By late 1999, developers discovered breakers that could be encapsulated and blended with proppant for delivery in a uniform and effective manner across the length of the fracture (below left). In a typical fracturing operation, once the proppant has been placed in the fracture, hydraulic pressure is removed and the fracture begins to close. Capsules containing the ClearFRAC breaker are crushed inside the closing fracture, releasing the breaker. The breaker alters surfactant-packing parameters of the fracturing fluid: the micelles collapse, and viscosity is reduced, effectively improving fracturing-fluid flowback.

In field applications, the use of VES breakers improves well cleanup and increases early gas production. Unwanted fluid foaming is reduced at surface, gas and liquid separation improves, and fracture conductivity is optimized. When comparing production curves from wells fractured with older polymer-base systems with wells fractured with VES incorporating breaker chemistry, production curves often become similar with time. However, in the first 60 days or so, quicker cleanup of VES fluids using encapsulated breakers cause the VES micelles to change shape from rods to spheres, collapsing the entangled micellular structure that generates viscosity.

10. Anionic surfactants are surface-active agents having a net negative charge.
11. Tip screenout fracturing involves deliberately causing proppant to bridge at the fracture tip through pad depletion. Further fracture propagation ceases and continued pumping increases the fracture width.
12. The surfactant-packing parameter is affected by solution conditions such as temperature and surfactant concentration. It may also be influenced by changes in micellar chain length and dissymmetry that cause an increase in the surfactant’s spontaneous curvature, ultimately determining whether surfactant’s molecules will form spherical or cylindrical micelles.
breakers produces substantial incremental gas—wells go online faster enhancing return on investment (top).

**Extending Thermal Limits**

Engineers, scientists and developers applying VES fluids achieved several milestones, including environmental acceptance and engineered viscosity control. Now, as drilling environments extend into more extreme conditions of temperature, depth and pressure, VES systems are also evolving to meet these challenges.

The versatility of viscoelastic surfactants makes possible the development of fluid systems for specific applications. In Canada, a new VES system was needed to address drilling challenges in the shallow-gas development areas in southern Alberta (below left). Marginal economics, stringent environmental regulations and cold wellbore temperatures made it necessary for operators to seek new fracturing-fluid technologies.

Schlumberger engineers responded by developing ClearFRAC LT polymer-free fracturing fluid, a VES-base fluid designed to meet several requirements including use in low-temperature environments. While performing in cold wellbores at temperatures below 100°F [38°C], the new fluid also proved economical in situations demanding low-cost hydraulic fracturing solutions. To meet Canadian environmental requirements, developers designed the ClearFRAC LT system to be compatible with nonchloride salt solutions, such as ammonium nitrate and nitrogen foam fracturing methods. ClearFRAC LT fluids can also be formulated with potassium chloride and ammonium chloride.

As with other ClearFRAC products, the ClearFRAC LT surfactant is mixed continuously, saving considerable time on location. Costs are reduced and more zones can be stimulated each day. Field tests conducted on multiple wells in Canada showed improved well economics and logistics, and the ability to stimulate marginal pay zones in low-temperature environments.

Modifications of the ClearFRAC LT VES chemistry have found application beyond low-temperature wellbores, for example in unconventional reservoirs such as coalbed methane (CBM) deposits and fractured carboniferous, or carbon-rich, shales, which can be difficult to produce. Globally these types of reservoirs represent as much as 3,500 to 9,500 Tcf [99 to 269 trillion m³] of natural gas.¹³

Permeability is one of the most critical factors in CBM recovery. Without intervention, fluid and pressure transmission is, for the most part, dependent on coal cleats and the associated natural coalbed fracture system (next page, top).¹⁴

Unlike gas in a conventional sandstone matrix, CBM gas is entrained in the coal system by adsorption onto the internal surfaces of coal. In sandstone systems, reducing pore pressure to 500 psi [3,447 kPa] often releases all entrained gas, while in a CBM deposit, pressures as low as 100 psi [689 kPa] are often required.

Whether fractures are natural or induced during drilling or completion, the combination of low permeability and low drawdown pressures...
makes CBM reservoirs sensitive to any restrictions in flow. Conventional horizontal completions have demonstrated some success in producing tight CBM reserves. However, producibility drops dramatically as natural permeability falls below 10 mD. Damage from drilling or fracturing fluids further reduces producibility.15

When a coal seam is exposed to drilling or fracturing fluids, swelling can result from sorption of water, gelled fluids or water containing low concentrations of friction-reducing agents such as partially hydrolyzed polyacrylamide (PHPA). This often leads to substantial reduction of cleat porosity and permeability (right). Five-to tenfold irreversible reductions have been reported.14 Further permeability damage can result from the failure to remove fracturing-fluid viscosifiers or gells from natural microfractures. The postfracturing removal of these materials is dependent on initiating a pressure drop and producing the fluid from the coal. At the low pressures inherent in CBM reservoirs, sufficient energy may not be available to efficiently clean up residual polymer-base fracturing fluids.

When preparing to hydraulically fracture a CBM deposit, engineers must also consider sensitive environmental issues. As much as one-third of US CBM reserves are located in areas where


14. A cleat is a breakage plane found in coal deposits that provides natural conductivity through the coalbed.


stringent environmental regulations control the composition of fluids that might come in contact with potable groundwater.

Engineers at the Schlumberger Sugar Land Product center (SPC) developed CoalFRAC nondonating fracturing fluids specifically for CBM fracturing. CoalFRAC fluids are most often nitrogen foamed and cause minimal sorptive damage to coal cleats. As with other VES-base fluids, CoalFRAC fluids readily return to surface after fracturing, avoiding potential permeability damage associated with polymer-base fracturing-fluid residue.

Field tests in central Wyoming, USA, demonstrated VES fluid performance in unconventional reservoirs. Initially, a six-stage fracture treatment placed 330,000 lbm [149,680 kg] of 16/30 mesh fracturing proppant in the coalbed using a combination of foamed and nonfoamed conventional, polymer-based fluids. CoalFRAC fluids readily return to surface after fracturing, avoiding potential permeability damage associated with polymer-base fracturing-fluid residue.

Since results were below expectations, Schlumberger and client engineers designed a refracturing program for the 600-ft [183-m] coalbed interval. Coalbed permeabilities ranged from 0.6 to 2 mD. Gas reserves were estimated at 350 to 450 scf/ton [11 to 14 m³/t] of coal. Pumping nine fracturing stages through coiled tubing using CoalIFRAC techniques, Schlumberger engineers placed 260,000 lbm [118,000 kg] of 16/30 fracturing proppant using a nitrogen-foamed CoalIFRAC fluid.

A combination of new fracturing techniques and CoalIFRAC VES fluid technology produced a fivefold increase in initial production. More than 100 CoalIFRAC treatments have now been performed in North America. When compared with the more common polymer-base fracturing-fluid treatments, on average, production rates using CoalIFRAC fluids have improved 30 to 60% in both CBM and carboniferous shale applications.

Operator interest in efficient fracturing fluids continued to expand from low-temperature applications to much deeper and higher temperature environments. Through 2002, VES stimulation fluids had proved effective at temperatures ranging from 40°F [4.5°C] to an upper limit of around 220°F [104°C].

To address the need for VES fluids that could work effectively in high-temperature environments, scientists at SPC developed ClearIFRAC HT polymer-free fracturing fluid, a zwitterionic-base VES fracturing fluid specifically for elevated temperature applications. The ClearIFRAC HT system extends the operating envelope of VES surfactants to 275°F [135°C] while maintaining other attributes common to other VES fluids, such as low friction pressure and excellent proppant-carrying capacity. ClearIFRAC HT fluids have low emulsion-forming tendencies, allowing them to be used in a broad range of oil reservoir applications.

As with other VES-base fracturing fluids, the viscosity of ClearIFRAC HT fluids is substantially reduced by dilution with formation brines, contact and mixing with hydrocarbons, or by the addition of chemical breakers.

Improving Gravel-Pack Performance
Sand production is a serious problem in many reservoirs, and operators go to great expense to minimize the effects of uncontrolled sand flow. Gravel packing, in its various forms, is commonly used to control sand flow into the production system.

Increases in thermal stability, improved breaker technology and expanded compatibility with a variety of salt solutions have extended the applications of VES fluids. Since their first introduction as a gravel-packing fluid, VES fluids are again receiving attention from both sand-control and gravel-packing specialists.

In openhole gravel-packing operations, a carrier fluid transports and places specifically sized gravel in the annular space between the reservoir rock and the production assembly, often a slotted liner or wire-wrapped screen (left). The gravel acts as a filter, allowing formation fluid to flow from the formation to the production string while filtering out sand grains and other formation fines. As with fracturing operations, the conductivity, or ability of fluids to flow through the gravel pack, is key to maximizing well productivity.

Gravel packs must also be designed to provide uniform flow across the production assembly. Poorly designed or implemented gravel packs may subject the production assembly to areas of concentrated flow, or hot spots. In the case of wire-wrapped screens, concentrated flow erodes the wire mesh, resulting in sand breakthrough and a shortened completion life that may lead to costly remedial workover or recompletion operations.

For prolonged gravel-pack life, engineers must achieve uniform gravel placement and produced-fluid flow across the entire completion. Conductivity through a gravel pack can be impaired by residual drilling or carrier-fluid
material left behind after flowback. Unlike many polymer fluids, VES carrier fluids optimize gravel transport while leaving no damaging residue to impair production.

During well construction, drillers attempt to minimize formation damage and drilling-related complications, such as stuck pipe, by reducing the amount of fluid lost to a formation. Drilling fluids have multiple phases, often described as continuous and discontinuous phases. The continuous phase consists of a carrier fluid, most often water or oil along with salts and other compounds soluble in the carrier fluids. The discontinuous phase contains insoluble materials, such as weighting agents, drilled solids, polymers and solid-particulate fluid-loss reducers such as calcium carbonate.

During drilling operations, the borehole is generally overbalanced—hydrostatic pressure is greater than pore pressure. As the drilling fluid pushes against permeable reservoir rock, the formation acts as a filter and the continuous phase is forced into the rock pore spaces. Depending on the permeability and the size of the pore throats within the formation being drilled, small amounts of the discontinuous phase are deposited in the near-wellbore area, forming a filtercake, both internal and external to the borehole face. As the fluid in the borehole circulates, this process continues in a dynamic cycle of erosion and deposition.

Once the borehole is drilled, engineers use mechanical tools and chemical sweeps to prepare the borehole for an openhole completion. Regardless of the cleanup method, some quantity of residual filtercake and pore-throat solids remains. If not removed, these materials migrate from the reservoir rock into the gravel pack, potentially plugging flow paths, reducing conductivity, impairing production and creating hot spots that shorten the life of the completion (above right).

To remove internal and external filtercake material, high drawdown pressures, greater than 200 psi [1.38 MPa], may be required to initiate flow when filtercake is trapped between gravel and formation. Industry data indicate that, without treatment, retained permeability after flowback may be extremely low, sometimes less than 1% of original reservoir permeability.17

In the past, treatments to remove filtercake were performed after the completion assembly and gravel packs were installed. This approach involved multiple trips into the hole to displace the gravel-pack carrier fluid and spot chemicals that attack filtercake and other residual compounds.18

Today, engineers combine VES gravel-pack carrier fluids such as the ClearPAC fluid system for gravel packing, with enzymes and chelating agent solutions (CAS) to attack the primary filtercake components—starches and calcium carbonate [CaCO3] bridging agents. Removing or degrading these compounds significantly reduces flowback-initiation pressure and allows degraded filtercake material to pass through the gravel pack, minimizing permeability impairment and improving well performance.

Implementation of a single-step gravel-packing and cleanup operation requires integration of well-construction and completion technologies. Through careful selection and engineering of the reservoir drilling-fluid design, engineers can reduce the time and cost associated with well construction and completion operations. 19

18. A zwitterionic, or dipolar, compound carries both a positive and negative charge.
laboratory evaluation of cleanup chemistries, and evaluation of potential borehole conditions, VES fluids are helping engineers to uniformly place gravel and obtain consistent filtercake removal, particularly across long horizontal-borehole sections.

Deepwater Openhole Gravel Packing

Reaching for deep oil reserves in the Foinaven field, about 190 km [118 miles] west of the Shetland Islands, in the UK sector of the North Sea, BP operates two blocks in 400 to 600 m [1,312 to 1,969 ft] of water. Development of the field began in late 1994. By 2003, BP had drilled and completed the world’s longest deepwater openhole shunt-tube gravel-pack completion, the first step in accessing oil reserves estimated at more than 250 million bbl [40 million m³].

Initial development of the T25 reservoir in the Foinaven field consisted of a single horizontal-wellbore completion. The P110 well reaches across 937 m [3,075 ft] of open hole, spans two sand bodies separated by a 162-m [532-ft] shale section, and accesses an estimated 42 million bbl [6.7 million m³] of oil.

Various types of openhole completion designs were available to BP engineers when field development began in 1997. However, no development had been as challenging as the P110 well. With the high cost of operations and the risk involved in deepwater operations, considerable resources were dedicated to the planning and design of the P110 completion.

Engineers first examined whether more than 900 m [2,952 ft] of horizontal borehole could be effectively gravel packed, and if so, how. Using numerical simulations and friction data from an earlier large-scale yard test, engineers determined that openhole shunt-tube gravel-packing technology could ensure effective gravel placement in wellbores exceeding 900 m and potentially as long as 1,524 m [5,000 ft]. However, to stay below friction-pressure limits, flow rates across gravel placement would need to be low, around 2.5 bbl/min [0.4 m³/min].

Effectively delivering gravel-pack sand at low flow rates across a long horizontal borehole requires a properly constructed borehole and a carrier fluid that is shear thinning, to minimize pressure loss while placing gravel across the sandface. Engineers determined that to minimize risk, and improve efficiency and production potential, a single-step gravel-pack and cleanup completion was required.

Limited reservoir information and a lack of core data presented a variety of challenges, from gravel and screen selection to developing synergistic, nondamaging drilling, gravel-packing and cleanup fluids.

The first challenge was to drill a high-quality borehole avoiding excessive washouts and deviation since these could interfere with proper sand placement during gravel-packing operations. Before drilling could begin, however, a detailed fluid-design program was initiated to select the correct reservoir drilling fluid (RDF).

This fluid-design program included a wellbore-stability study to determine zones of weakness and the mud-weight, fracture-gradient window. Sidewall core samples from offset wells were used to study shale characteristics and response to RDF exposure. Formation-damage potential was also evaluated along with cake quality and liftoff pressure requirements using standard laboratory return-permeameter evaluation techniques.

Compatibility with completion and cleanup-fluid chemistries was key to the RDF design. Engineers selected components of the drilling-fluid system based on drilling efficiency, wellbore stability and susceptibility to enzyme breakers and chelating agents.

Gravel selection was based on extensive offset-well sideline core studies and laboratory simulations. Dry-sieve, laser-particle-size analysis and scanning electron microscopy techniques were combined to estimate the gravel grain size in the Foinaven T25 sand. These results were then used to develop a laboratory-analog artificial core-pack material.

Technicians used the artificial core material for slurry injection and prepack testing. Slurry-injection tests simulated formation sand migration into the gravel pack during oil production. Prepack tests simulated the effects of borehole collapse that could cause significant amounts of formation sand to migrate onto the gravel-pack face. Based on these test results, a 30/50-mesh synthetic proppant was selected as the best material to effectively control sand production and optimize production efficiency.

Gravel placement across the two horizontal production intervals was the next challenge. A VES-base ClearPAC gravel-carrier fluid was selected for its shear-thinning, cleanup and proppant-transport characteristics, and its ability to incorporate and deliver filtercake cleanup chemicals uniformly across both gravel-packed sections.

The VES fluid allowed engineers to transport and place gravel across both production zones.
Engineers drilled each reservoir section with 10.5-bbl/gal [1,258-kg/m³] SOBM. As drilling progressed, technicians controlled filtratecake quality by maintaining the drilled solids concentration below 2% and performed tests to ensure that the RDP would flow through a 10-gauge completion screen, two sizes smaller than required.

Once the driller completed the reservoir section, a wire-wrap completion screen was attached on the outside of screens providing conduits for the gravel-pack slurry, allowing gravel packing to proceed past any blockage, or bridges, that may form around the screens. For more on shut-tube gravel packing: Acokk et al, reference 19.

The other two wells were put on production within 6 months of completion and ultimately resulted in a poor gravel-pack completion (previous page, top).

Working with service providers, BP engineers carried out extensive laboratory testing to develop a system of nondamaging RDFs and completion fluids capable of controlling the borehole during drilling and of providing a low skin factor during completion.

The reservoir consists of poor to moderately sorted, fine to very fine-grained sands with a median diameter of 85 to 200 microns requiring 20/40 gravel-pack sand and 12-gauge screens to control sand and fines migration.

Four reservoir sections were drilled with SOBM, ranging from 200 to 650 m [656 to 2,133 ft] thick and spanning two productive sands separated by a 120-m [394-ft] thick reactive shale section. Reservoir pressure averaged 32 MPa at 3,500-m [4,650 psi at 11,483-ft] true vertical depth (TVD).

When Oil-Base Mud Is Required
Even though water-base muds have improved substantially since the mid-1980s, engineers and scientists have struggled to design cost-effective WBM capable of emulating the inhibitive quality, lubricity and thermal stability performance of oil-base fluids.

Problematic openhole gravel-pack completions in Azerbaijan led BP to switch from water-base RDF to synthetic oil-base mud (SOBM). Prior to 2003, six wells had been drilled using water-base RDF, and then gravel-packed. In reservoir sections drilled with 6%-in. bits, washouts of up to 18 in. [45.7 cm] were observed. Ledges in the irregular hole made borehole cleaning difficult, and ultimately resulted in a poor gravel-pack completion (previous page, top).

Working with service providers, BP engineers carried out extensive laboratory testing to develop a system of nondamaging RDFs and completion fluids capable of controlling the borehole during drilling and of providing a low skin factor during completion.

The reservoir consists of poor to moderately sorted, fine to very fine-grained sands with a median diameter of 85 to 200 microns requiring 20/40 gravel-pack sand and 12-gauge screens to control sand and fines migration.

Four reservoir sections were drilled with SOBM, ranging from 200 to 650 m [656 to 2,133 ft] thick and spanning two productive sands separated by a 120-m [394-ft] thick reactive shale section. Reservoir pressure averaged 32 MPa at 3,500-m [4,650 psi at 11,483-ft] true vertical depth (TVD).

Less Water—More oil

Virtually every oil reservoir is swept at least partially by water, from either natural aquifer pressure or waterflooding. Water movement displaces oil and often determines the oil recovery efficiency in a field. Although critical to the oil-production process, water production sometimes becomes excessive.

Even the best field-management techniques have a limited ability to control excessive amounts of produced water. In mature fields, water production may increase to the point that it represents a majority of the liquid volume reaching the surface. Reports indicate that globally, at least three barrels of water are generated with every barrel of oil produced. Liquid-handling systems often become overloaded, impacting efficiency and productivity. Eventually, the cost of dealing with produced water precludes field profitability.

22. Shunt-tube, or Alternate Path technology, is used to ensure a complete gravel pack around screens. If the annular space packs off prematurely, the shunt tubes attached on the outside of screens provide conduits for the gravel-pack slurry, allowing gravel packing to proceed past any blockage, or bridges, that may form around the screens. For more on shut-tube gravel packing: Acokk et al, reference 19.


25. The skin factor is a numerical value used to define the difference between the pressure drop predicted by Darcy’s law and actual values. Skin factors typically range between negative 6 for stimulated high conductivity, such as that obtained by hydraulic fracturing, to 100 or more for extreme damage and poor conductivity.

26. The productivity index (PI) is a mathematical means of expressing the capacity of a reservoir to produce fluids. PI is usually expressed as the volume of fluid produced at a given drawdown pressure at the reservoir face.


In late 1999, engineers and scientists at Schlumberger discovered a new application for VES fluids, acid diversion. During standard acidizing treatments, stimulation fluids follow the path of least resistance, preferentially stimulating zones of higher permeability. These are often zones with higher water saturations where the relative permeability to water-base stimulation fluids, such as acids, is also higher. Hydrocarbon zones with lower permeabilities are stimulated to a lesser degree. Consequently, water production increases disproportionately compared with oil.

Frequently, the permeability contrast between water- and oil-bearing zones makes selective stimulation difficult. Earlier diverting techniques relied on polymers and solids to plug high-permeability zones. Unfortunately, both low- and high-permeability zones became plugged, doing more harm than good to production rates.

Research led to the development of OilSEEKER acid diverter, a VES-base system that can be engineered for either sandstone or carbonate reservoirs. In each case, OilSEEKER fluid selectively reduces injectivity in water-laden zones, forcing the acid to enter zones with high oil saturation (below).

During the development of OilSEEKER fluids, laboratory tests demonstrated effective diversion when the rheology of the diverting fluid is directly affected by the chemistry of formation fluids. In the case of OilSEEKER fluids, the acid diverter maintains a gelled state while in contact with water, but viscosity degrades when exposed to liquid hydrocarbon. Laboratory core-flood experiments have shown that VES-base diversion techniques can effectively divert acid from a 20,000-mD sandpack to a 200-mD core used to simulate a zone with lower permeability. After several treatment cycles, about 40% of the acid was injected into the low-permeability core.

In the Barinas field, located in southwest Venezuela, Petróleos de Venezuela S.A. (PDVSA) produces oil from low-permeability carbonate reservoirs containing a high percentage of sand and shale. High amounts of produced water, or water-cut, are common, and the wells have proved difficult to stimulate without increasing the amount of produced water. Completed in 1984, Well SMW9 initially produced 116 BOPD [18 m 3/d] with 25% basic sediment and water (BS&W). In 1997, a matrix stimulation treatment was performed, increasing oil production to 250 B/D [40 m 3/d], but also increasing water production.

PDVSA and Schlumberger engineers evaluated the well in early 2003. At that time, the well was producing about 51 B/D [8 m3/d] with a water/oil ratio (WOR) of about 75% (next page, top). As with many high water-cut wells, engineers believed that a reduction in WOR would substantially increase oil production.

The hydrocarbon-productive reservoir interval is a calcareous matrix with hard and compacted dolomites, streaks of glauconite and hard limestone. Because of this geology, engineers were concerned that the use of common acids, such as hydrochloric acid [HCl], could damage the remaining productive zones.

Stimulating oil zones. During acid stimulations, OilSEEKER acid diverter (left – yellow) is pumped ahead of the acid solution (red). On contact with water-bearing zones, the diverting fluid increases in viscosity, forming a plug that effectively blocks access to water zones. In contrast, on contact with hydrocarbon-bearing zones, the OilSEEKER diverter thins, allowing the subsequent acidizing step to preferentially treat oil-bearing zones not blocked by the diverting fluid (right – green oil zone).

30. For more on viscoelastic surfactant acid diversion:
Therefore, careful attention was paid to acid-stimulation design. Schlumberger engineers designed an HCl-free, organic-acid formulation composed of formic and acetic acids. Bottomhole static temperatures were estimated at 270°F [132°C], so engineers selected the high-temperature version of the OilSEEKER fluid to divert the acid treatment away from water-bearing zones.

In the field, engineers first pumped a solution of oil and solvents, followed by viscosified brine, to clean up the wellbore. Next, the OilSEEKER treatment was pumped into the formation, followed by organic acid. This process was repeated to assure adequate stimulation across the 30-ft [9.1-m] production zone. The pressure profile during pumping gave little indication of excessive fluid loss, suggesting that the acid was most likely being pumped into the oil-bearing zones of lower permeability.

During the first two months following simulation, engineers recorded a 253% increase in oil production coincident with a 24% decrease in BS&W production (above).

Whether used to simulate wells in new fields or in mature areas, selective acid stimulation can improve well performance. Today, engineers can treat only the oil-bearing zones by designing fluid treatments using VES-base diversion, such as the OilSEEKER system.

**A New Generation for VES**

Since their first use more than 20 years ago, VES surfactants have evolved significantly, finding new applications and benefits in the E&P industry. Today, engineers use VES fluids for hydraulic fracturing, gravel packing, acid diversion and a host of other applications.

New VES fluids are continually being developed. One area of interest is polymer-free liquid carbon dioxide [CO₂] fracturing. The future will include ClearFRAC products specifically designed to stimulate wells in which hydraulic fracturing with liquid CO₂ and the inherently low damage characteristics of VES fluids will significantly improve well productivity.

Engineers expect the intrinsically low friction pressure of CO₂ and VES systems to improve through-tubing stimulation by allowing higher pump rates at maximum treating pressure, particularly when compared with older polymer-base fracturing systems.

As oil and gas operations reach greater depths and increasingly treacherous environments, scientists and engineers are working to expand the performance limits of VES-base systems. Even though these materials have been used for a quarter of a century, they continue to promise the potential for new and exciting developments that will improve operational efficiency and enhance hydrocarbon recovery. —DW
Scientific Deep-Ocean Drilling: Revealing the Earth’s Secrets

The oceans and their underlying sediments and rocks act as natural laboratories that record the Earth’s dynamic processes from past to present. Scientific deep-ocean drilling, sampling and borehole measurements collected during the past 40 years are enhancing our knowledge of the Earth, giving clues to the distribution of mineral resources, to global climate change and to potential natural disasters. While some technologies used in the oil and gas industry are deployed for scientific research, other methods and tools developed specifically for deep-ocean drilling are also finding applications in the energy industry.

Understanding the past is critical to predicting the future. The ocean floors and their underlying sediments and rocks contain a high-resolution record of both the Earth’s history and its current conditions. Information locked within these strata has the potential to answer fundamental scientific questions. Scientific ocean-drilling programs provide keys to unlock this buried treasure trove of data, which leads to a better understanding of climatic changes, natural hazards such as earthquakes, volcanic eruptions and floods, and mineral and energy resources. Technologies commonly used in the oil and gas industry for drilling, borehole measurements and sampling play a major role in scientific ocean drilling.

Seafloor drilling during the past 40 years has led to exciting scientific discoveries. For example, in 1968, drilling confirmed that sediments and rocks flooring the south Atlantic became increasingly older with distance from the axis of the mid-Atlantic oceanic ridge, thereby verifying the plate tectonics hypothesis.1

Scientific deep-ocean drilling recovered evidence of massive marine gas hydrates in 1982, in deepwater sediments offshore Central America.2 Gas hydrates are crystallized water and gas, mostly methane \([\text{CH}_4]\), that form under...
conditions of high pressure and low temperatures (previous page). Hydrates have steadily gained recognition in the oil and gas industry because they are both a drilling hazard and a potential energy resource for the future.1

More recently, in 2004, drilling in the ice-covered Arctic Ocean at the crest of the Lomonosov Ridge has provided preliminary evidence that the Arctic was ice-free and warm about 56 million years ago.2 Scientists analyzing the cores and log data hope to determine when, why and how the Arctic climate changed from hot to cold, and to gain insight on current global warming trends. Scientists are also speculating about the possibility of oil and gas prospects in the Arctic Ocean.

Important facilitators to these discoveries have been advances in drilling, coring and logging technology. Borehole measurements, routinely collected in oil and gas wells, also play a major role in scientific ocean research by providing data in sections with poor or no core recovery, and in linking core measurements with larger scale seismic data. Schlumberger has been involved in scientific deep-ocean drilling programs since 1961, providing borehole measurements and working closely with scientists to develop technology to support their scientific objectives.4

While many tools and techniques developed for oilfield use are being applied in scientific research, technologies that advanced under scientific drilling programs are also useful in drilling for oil and gas, particularly deepwater drilling and in logging-while-drilling (LWD) applications.

In this article, we first review the historical context for scientific deep-ocean drilling and then examine current and emerging technologies, particularly for downhole measurements, that are essential to achieving the goals of scientific drilling. Finally, we describe the new Integrated Ocean Drilling Program (IODP), which will offer flexibility in its use of diverse drilling capabilities in all ocean basins regardless of water depth and geographic location.7
Historical Context

Several scientific deep-ocean drilling programs preceded the IODP. The earliest research program began with Project Mohole, followed by the Deep Sea Drilling Project (DSDP) and the Ocean Drilling Program (ODP), covering all the oceans with the exception of the ice-covered Arctic Ocean (next page, top). Seafloor sediments were sampled from 1,279 sites. Each of these programs achieved significant milestones (below and next page, bottom).

Project Mohole, conceived in 1958 and active from 1961 to 1966, utilized a converted US Navy barge, Glomar Challenger.¹ The objective was to sample the mantle by drilling through the Earth’s crust to reach the Mohorovičić discontinuity (Moho).² This ambitious goal would require a drillstring length of about 9,100 m [30,000 ft] to reach the Moho in water depths of 3,566 m [11,700 ft] between Guadeloupe Island, Mexico, and the coast of Baja California, Mexico.³ This target exceeded the deepest penetration achieved on land by 1,500 m [4,920 ft], and the water depths exceeded the capabilities of offshore drilling operations at that time. While the project did not come close to reaching the Moho, it did set the stage for scientific ocean drilling and led to development of deepwater drilling technology, dynamic ship-positioning and new ship designs that were later used in DSDP and ODP.

The DSDP began operations in 1968 with the Glomar Challenger drillship operated by Scripps Institution of Oceanography.⁴ The Glomar Challenger pioneered and refined the use of dynamic positioning with multipoint retractable thrusters to maintain ship position. This technology is still being used in oil and gas drillships today. Borehole measurements were not considered essential in those days—fewer than 90 boreholes were logged, and then only if core recovery was poor and if time permitted.

The first DSDP scientific cruise, called a leg, uncovered evidence of salt domes, through recovery of core and wireline data, which also contained evidence of hydrocarbons below salt at abyssal water depths of 2,927 to 5,361 m [9,603 to 17,590 ft] in the Gulf of Mexico.⁵ Discoveries of tectonically active salt and deep hydrocarbons encouraged oil and gas explorationists. Since the first commercial subsalt discovery by Phillips, Anadarko and Amoco in 1993, exploration and production (E&P) in the Gulf of Mexico continues to blossom.⁶

³. DSDP was funded by the National Science Foundation and managed by the Joint Oceanographic Institutions for Deep Earth Sampling (JOIDES), a consortium of US oceanographic institutions. In 1976, the program was expanded to include other countries—France, Japan, Soviet Union, UK and West Germany.
⁶. Project Mohole was funded by the US National Science Foundation and the US National Academy of Sciences.
⁷. The Mohorovičić discontinuity is the boundary between the Earth’s crust and mantle. Oceanic crustal thickness, interpreted from seismic refraction results, ranges from 3.6 to 5.5 km [11,600 to 18,045 ft].

^ Time line of scientific ocean-drilling milestones. Important scientific discoveries (blue) and technological advances (black) during the Mohole project, Deep Sea Drilling Project (DSDP) and Ocean Drilling program (ODP) are highlighted.
Scientific deep-ocean drill sites from 1961 to 2003. The Mohole project (green) initiated in 1958, used a converted naval barge Cuss I to drill at two sites near La Jolla, California, USA, and Guadeloupe, Mexico, from 1961 to 1966. The Deep Sea Drilling Project (black) used the drillship Glomar Challenger to drill at 624 sites, from 1968 to 1983. During the Ocean Drilling Program (red) between 1984 and 2003, the drillship JOIDES Resolution sailed as far north as 80° and as far south as 71° latitude, and drilled the next 653 sites.
Drillship JOIDES Resolution with seven floors of on-board laboratories. The 143-m (466-ft) drillship features a seven-story laboratory complex to analyze the wide variety of cores and logs collected worldwide. The ship is positioned over the drillsite by 12 computer-controlled thrusters that support the main propulsion system. Near the center of the ship is the moon pool, a 7-m (23-ft) opening in the bottom of the ship, through which the drillstring is lowered. The drillship is a virtual university that can house 50 scientists and technicians and 65 crew members, with a stack of laboratories on seven floors. The bottom two floors (not shown) have core-storage facilities. At the fantail of the ship, on the left, is a geophysics laboratory, which contains equipment that gathers ship position, water depth and magnetic information used in studying the seafloor topography.

A Schlumberger engineer acquiring real-time LWD data in the downhole measurements laboratory.

An ODP scientist working on core descriptions. (Photograph courtesy of Texas A&M University.)
The ODP, the next phase of the scientific deep-ocean drilling programs, used the JOIDES Resolution drillship operated by Texas A&M University in College Station (previous page). The ODP drilled 1,700 boreholes in water depths ranging from 91 to 1,283 m [300 to 4,200 ft] with more than 213,000 m [699,000 ft] of core recovery. With successful well-logging results, wireline acquisition became an integral part of the ODP, with more than 56% of the boreholes logged.

The past four decades of scientific ocean drilling have benefited from numerous technological advances in wireline logging, drilling and measurement technologies, coring and sampling techniques and long-term borehole-monitoring devices. The development of technologies to address challenges in scientific deep-ocean drilling was the result of close collaboration by the scientific community and the service industry.

Challenges in Scientific Deep-Ocean Drilling
There are many challenges associated with drilling in deepwater and ultradeepwater areas, where water depths exceed 183 m [600 ft] and 1,524 m [5,000 ft], respectively. The scientific objectives of the ocean-drilling programs required drilling in water depths far greater than those common in E&P operations. The program had to develop technology to drill without a riser—a large-diameter pipe that connects the subsea blowout preventer (BOP) stack to a floating surface rig—commonly used in offshore oil and gas drilling (right). When drilling with a riser, drilling fluid circulates down the pipe, through the bit, and returns back to the surface along with rock cuttings through the exterior of the drillpipe.

14. The Ocean Drilling Program was managed by Joint Oceanographic Institutions, Inc. (JOI)—a consortium of US oceanographic institutions. The operation and staffing of the drillship and core retrieval from sites around the world were managed by Texas A&M University (TAMU). The Lamont-Doherty Earth Observatory (LDEO) at Columbia University, New York, USA, managed the logging services and site survey data bank. The funding for ODP was initially provided by the US National Science Foundation (NSF) and later expanded to include other international partners including Australia, Belgium, Canada, China, Denmark, Finland, France, Germany, Iceland, Ireland, Italy, Japan, Korea, The Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Taiwan and UK.

15. ODP core repositories are located at Lamont-Doherty Earth Observatory, Palisades, New York, USA; Scripps Institution of Oceanography, California; Texas A&M University; and Bremen University, Germany.

Without a riser, the drilling fluid spills out of the top of the borehole onto the seafloor, and does not return to the surface (above left). This does not create a problem for the seafloor environment, because seawater is used as the drilling fluid. However, because no solids are added, no mudcake forms. Without mudcake, the borehole is less stable, which may lead to borehole collapse. Technology and solutions had to be developed to deal with problems of ship heave, wellbore stability, reentry of wells in more than 5,000-m [16,405-ft] water depth, along with other technical issues.

In conventional drilling for oil and gas, compensation devices treat the riser as the nonmoving reference to correct for depth uncertainties. A major improvement for logging in riserless wells was the development of a large-displacement heave compensator to reduce depth uncertainties arising from ship heave. The
wireline heave compensator (WHC) system measures the vertical motion of the ship with an accelerometer and automatically displaces the hydraulic piston and unspools logging cable by the required amount.  

The WHC can adequately compensate for heaves of up to 6 m [20 ft]. A new programmable rotary winch compensation system, developed by Schlumberger, is currently being tested on the JOIDES Resolution.

With flexible drillpipe more than 5,000 m long hanging in tension from the derrick, starting a borehole in bare rock is quite a challenge without a riser. In hard-rock settings such as the mid-oceanic ridges, spudding a hole and keeping it open becomes trickier due to the brittle, fractured nature of the rocks encountered. ODP developed the hard-rock reentry system to spud holes in difficult environments using a hydraulic hammer drill. The hammer drill is run inside the casing, and it simultaneously drills a hole and advances the casing. In the oil field today, technology using standard oilfield casing to drill the well and then leave it in place to case the well eliminates drillstring tripping and can increase drilling efficiency by 20 to 30%.

Another challenge in riserless drilling was reentry into preexisting boreholes. Reentry may be required for several reasons, such as replacing a bit, or when returning to the borehole on multiple legs. To replace the bit, for example, the drillstring must be raised, a new bit attached, and the string lowered back to the bottom into the same drill hole. The formidable task of reentering a borehole on the ocean floor was accomplished with the use of sonar scanning equipment and a reentry cone. The reentry cone assembly comprises a reentry funnel mounted on a support plate that rests on the seafloor and a housing to support multiple casing strings (previous page, right). The reentry system is wide at the top, above the seafloor, and narrows at the bottom near the base of the seafloor, thereby making it easy for the funnel to guide the drillpipe into the borehole.

The reentry cone allows a borehole to be reentered on multiple legs to deepen the hole or to install a borehole observatory for long-term downhole measurement and sampling.

ODP developed two primary types of borehole observatories. Downhole broadband seismometers with a bandwidth from 0.001 to 10 Hz and strainmeters were deployed at selected sites, primarily in seismogenic, or earthquake-prone, zones near Japan and in the eastern Pacific Ocean. The other type of borehole observatory consists of instrumentation to obtain in-situ recordings of formation temperature and pressure, and sampling of fluid geochemical properties. Similarly, permanent downhole gauges to monitor flow rate, pressure and temperature are routine in the oil field for real-time production optimization.  

However, effective utilization of boreholes as hydrogeological laboratories required sealing them from the overlying ocean water, and allowing the formation to return to a state of equilibrium. This was made possible by a circulation obviation retrofit kit (CORK) system, first deployed in 1991, which isolates boreholes from the ocean water above the seabed (above).
A new generation of advanced CORKs will incorporate multiple packers to isolate subsurface zones in the borehole to measure temperature, pressure, fluid chemistry and microbiology in each zone.

Although the water depths and borehole conditions are extreme, ODP and Schlumberger have engineered methods and tools for borehole measurements to satisfy scientific goals and to operate effectively in hostile environments.

**Advances in Borehole Measurements**

Borehole logging measurements are now considered as vital to the scientific goals of scientific deep-ocean drilling as they are to the E&P industry. They provide a continuous record of formation properties under in-situ conditions, and were to the E&P industry. They provide a continuous record of formation properties under in-situ conditions, a link between core data and larger scale regional seismic data, and are sometimes the only usable data when core recovery is poor or nonexistent.

The need for tools in slimhole, high-pressure, and high-temperature environments and the need for high-resolution tools to characterize thin beds have been the driving forces behind the customization and development of new borehole tools.

Sometimes logging sondes have to be conveyed through a pipe diameter as small as 3.8 in. [9.7 cm] to make measurements in hole sizes exceeding 11.5 in. [30 cm] in diameter. To overcome this difficulty, some oilfield tools have been made slimmer. In 1988, the Formation MicroScanner device, with an outside diameter (OD) of more than 4.5 in. [11.4 cm], was modified to 3.7-in. [9.4-cm] OD. Another tool, the slimhole WST Well Seismic Tool, was customized by addition of two horizontal geophones. This enabled determination of shear-wave velocity and anisotropy of underlying rocks from a vertical seismic profile survey.

The goal of increasing vertical resolution of downhole measurements prompted scientists at Lamont-Doherty Earth Observatory in Palisades, New York, USA (LDEO) to develop the multi-sensor gamma ray tool (MGT) in 2001. This tool increases resolution by common-depth stacking and summing of the data received from an array of four gamma spectrometry sensors spaced 2 ft [61 cm] apart. The MGT increases the vertical resolution of natural gamma ray log data by a factor of three to four over conventional logging tools, improving characterization of thin layers and their correlation with core data.

Typically, a wireline-conveyed system cannot log the top interval just beneath the seafloor because the drillpipe has to be lowered about 50 to 100 m [164 to 328 ft] to ensure wellbore stability. Additionally, long tool strings often cannot log the bottom of the borehole. Also, in certain difficult environments, for example, alternating layers of hard and soft rock such as chert-chalk sequences, the rocks deteriorate after drilling, resulting in both poor core recovery and poor logs. In such cases, LWD tools are of critical importance and provide the only in-situ measurements.

For safety in unstable holes and to decrease drilling time, an innovative solution of logging-while-coring (LWC) was developed during the ODP. The RAB Resistivity-at-the-Bit tool was modified by incorporating annular batteries in the drill collar wall and a new resistivity button sleeve. This allows an existing ODP core barrel to pass through the RAB tool to carry out coring operations while making azimuthal resistivity and gamma ray measurements (left). The LWC system provides precise core-log depth calibration and core orientation without an additional trip, producing both time savings and unique scientific advantages.

**Obtaining Core Samples**

Improving core recovery and obtaining uncontaminated and unaltered samples are important scientific objectives. Contamination from the drilling process can affect studies of magnetic properties, fluid chemistry, microbiology, sediment structure and core-sample texture. As with E&P operations, drilling and sampling technologies in scientific ocean-drilling programs have been adapted to rock hardness and lithology. Specific innovations include advanced piston coring for sampling soft to medium-hardness rocks, and an extended core barrel or a diamond core barrel for coring medium to hard rocks.

Gas hydrate research, in particular, requires retrieving samples at in-situ conditions. During conventional coring of hydrates, substantial volumes of gas escape as sediments are brought to the surface. DSDP and ODP, respectively, developed the wireline pressure core barrel and

---

*Logging-while-coring system (LWC). The motor-driven core barrel (MDCB) passes through the modified RAB Resistivity-at-the-Bit tool to collect core samples while acquiring resistivity and gamma ray measurements. (Adapted from Goldberg et al, reference 22.)*
the pressure core sampler to recover samples at in-situ pressures up to 10,000 psi [70 MPa]. These tools are particularly useful for sampling gas hydrates and for measuring the volume of gas released from these samples. The need for pressurized sampling, which maintains the core at downhole pressure in an autoclave chamber, inspired a European consortium to develop a new suite of tools known as the hydrate autoclave coring equipment—the next generation of pressurized coring systems.

ODP Leg 204, conducted from July to August 2002, provided the opportunity to test a wide variety of new technologies and measurement techniques. The scientific objective of the mission was to understand the occurrence and distribution of gas hydrates offshore Oregon, USA. It marked the first use of simultaneous logging and coring with the LWC system and extensive tests of pressurized coring tools. Leg 204 also deployed a wide range of Schlumberger wireline tools and logging-while-drilling (LWD) tools, and included tools developed by ODP to measure in-situ pressure. Digital infrared cameras were used for the first time in an ODP operation to scan core samples. This is done as soon as they are retrieved from the gas hydrate interval to record the temperature anomalies.

Focus on Gas Hydrates

Gas hydrates have been known to exist in marine sediments since the early days of DSDP, but they were judiciously avoided in the past because of drilling safety issues. However, a growing interest in hydrates as a potential resource for energy and in their possible influence on climate change has made hydrates one of the focus areas in scientific ocean drilling.

Hydrates found in deepwater sediments at outer continental margins are usually stable. Gas hydrates become unstable when ocean temperature rises or depressurization occurs due to a reduction in confining pressure, caused for example by a decrease in sea level or a loss in sediment overburden. This triggers the release of methane—a powerful greenhouse gas—into the Earth’s oceans and atmosphere. Scientists have raised questions about the impact of gas hydrates on the carbon cycle and on global climate. However, there is great uncertainty about how much hydrate and free gas are actually contained in marine sediments. It is therefore important to know where and how hydrates accumulate, and to monitor conditions that could change their stability.

To reduce this uncertainty, 45 boreholes were drilled at nine sites on the bathymetric high known as Hydrate Ridge, in about 790 m [2,592 ft] of water, offshore Oregon, USA (top). Several geophysical measurements that can help quantify gas hydrates were performed during Leg 204. These include nuclear magnetic resonance, resistivity imaging, sonic logging and vertical seismic profiles (VSPs). Borehole seismic data were acquired with the VSI Vertical Seismic Imager tool, which can record simultaneously at multiple stations. With different source-receiver configurations, offset VSP and walkaway VSPs were acquired to image the subsurface away from the borehole.

The three-dimensional (3D) seismic data acquired over the nine drilled sites on the southern Hydrate Ridge provide a regional structural and stratigraphic setting (above). A
high-amplitude reflector referred to as the bottom-simulating reflector (BSR) results from a strong velocity contrast between the high-velocity sediments containing gas hydrates and deeper low-velocity sediments containing free gas. This reflector is interpreted as the base of the gas hydrate stability zone. Seismic velocities from the VSPs clearly resolve this velocity decrease, indicative of the presence of free gas beneath the BSR that occurs 129 to 134 m [423 to 440 ft] below the seafloor.

Because hydrates are nonconductive, the electrical resistivity of hydrate-saturated sediments is higher than that of water-saturated sediments. Resistivity images acquired by the RAB tool showed the azimuthal distribution of hydrates in the drilled sediments (below). The RAB data, in conjunction with 3D seismic data, guided subsequent coring, permitting an accurate sampling of zones rich in gas hydrate. Integrating cores with well logs and borehole seismic and surface seismic data, each with different spatial resolution and sensitivity to gas hydrate content, yields an estimate of the three-dimensional distribution of gas hydrate within an accretionary ridge system.

The percentage of gas hydrate was estimated using different methodologies. While borehole measurements provide continuous spatial sampling, there are assumptions involved in the estimation of gas hydrate. Assuming that only water and gas hydrate fill the pore space, the percentage of gas hydrate can be deduced by using Archie’s relation to determine water saturation; the remainder being gas hydrate. This technique does not distinguish between gas hydrate and free gas.

Another approach used a controlled release of pressure from the core sample to enable measurement of the volume of gas stored within an interval of sediment. This volume was then used with established gas equilibrium curves to estimate the amount of gas hydrate or free gas in the core.

Results showed that high gas hydrate content—30 to 40% of pore space—is restricted to the upper tens of meters below the seafloor at the crest of the Hydrate Ridge, while at the flanks of the ridge, the hydrates extend deeper. Understanding the heterogeneous distribution of gas hydrate is an important factor in modeling gas hydrate formation in marine sediments and the changes due to tectonics and environmental impact.

In 2000, the US Department of Energy (DOE), in consultation with other government agencies began an active effort to commence fundamental and applied research to identify, assess and develop methane hydrates as an energy resource. Many countries, including Japan, Canada and India, are also interested in the potential of gas hydrates as an energy source and have established large gas hydrate research and development projects, while China, Korea, Norway, Mexico and others are investigating the viability of forming government-sponsored gas hydrate research projects.

The US DOE gas hydrate joint industry project, led by ChevronTexaco, plans to drill two
sites in the deepwater Gulf of Mexico in 2005. Some of the techniques and lessons learned from Leg 204 will be applied. While the primary goal is to learn how to safely exploit conventional hydrocarbon reservoirs beneath hydrate, the results of the program will also allow a better assessment of the commercial viability of marine gas hydrates.

All these technological achievements will advance scientific ocean drilling studies in the 21st century, although specific technologies are needed in the next decade to address challenges such as measuring high temperatures and pressures in seismogenic zones, conducting in-situ sampling of fluids, retrieving uncontaminated sediments and microbial life at in-situ conditions, developing enhanced downhole measurements and installing long-term or permanent sensors.

As more data are acquired, data management is becoming another critical issue. In 1996, Schlumberger and ODP collaborated to test a stabilized mount for the antennae utilized for high-speed data transmission from the JOIDES Resolution to shore-based data centers. An advanced version of this very small aperture terminal (VSAT) system is now common in IODP operations, offering almost total global coverage for data transmission and electronic and voice communications.

Finally, the enormous volumes of data and information produced by the ocean drilling programs create the same issues that challenge E&P data management. These include legacy data gathered during the DSDP and ODP, and data from the newly launched IODP. In addition to raw measurements, the copious volume of digital information, such as drilling reports, mud logging data and cutting descriptions, must be managed properly and associated with the raw measured data to maintain contextual information and ensure integrity and validity of data managed by the system. Schlumberger has been collaborating closely with JAMSTEC—the Japan Agency for Marine-Earth Science and Technology—to design and build the prototype of such a data management system. Integrating data analysis capability into the data management system using GeoFrame integrated reservoir characterization system software allows users to directly access data from a remote site.

A New Era in Ocean Drilling

The Integrated Ocean Drilling Program (IODP), a new program that began in 2004, builds upon the experience and knowledge gained during previous scientific ocean drilling campaigns.

IODP is a global partnership of scientists, research institutions and government agencies that provides a more focused approach to explore at greater depths and in previously inaccessible areas. The scientific goals of IODP are outlined in the initial science plan. Like their predecessors, IODP expeditions are proposal-driven and are planned after extensive international scientific and safety reviews.

However, IODP differs significantly from any of the previous programs because it uses multiple ships with diverse drilling capabilities. The multiple platforms—riserless, mission-specific and riser—will enable drilling in areas that were previously inaccessible, such as on the continental margins, in shallow water less than 20 m [66 ft] deep, in ice-covered regions of the Arctic and in the ultradeep oceans.

The current US vessel, JOIDES Resolution, will be used in the first operational phase of riserless operations, which lasts through 2005. The mission-specific platforms (MSPs) operated by the European Consortium for Ocean Research Drilling will operate in shallow waters and ice-covered regions. As the name mission-specific suggests, these drilling platforms could be drilling barges, jackup rigs or seafloor drilling systems, depending on the drilling environment. The construction of the riser platform and development of related technologies were initiated in 1990 by MEXT (Ministry of Education, Culture, Sports, Science and Technology) in Japan. This program, called Ocean Drilling in Culture, Sports, Science and Technology, was integrated into the IODP. The Japanese vessel, the Chikyu, meaning “Earth” will be a state-of-the-art, riser-equipped, dynamically positioned drillship. Chikyu will initially reach a total depth of 10,000 m (32,800 ft), in water depths of up to 2,500 m (8,200 ft). In riserless operations, Chikyu will be able to drill in water depths of up to 7,000 m (22,970 ft).

In the future, Chikyu will be able to drill with a riser in 4,000-m (13,120-ft) water depth to reach a total depth of 12,000 m (39,370 ft), allowing access to regions where the presence of hydrocarbons or other fluids has previously prevented scientific drilling. Although riser drilling is commonly used for hydrocarbon exploration and development, it has never been used in such ultra-deep environments. It will be possible to drill boreholes that are more stable, and that can penetrate zones with different pressures. Seismogenic zones in particular are difficult to drill because of heavy fluid losses associated with fractured intervals. Using this vessel, researchers can drill and install permanent sensors in seismogenic zones. Chikyu is expected to be operational in late 2006 or early 2007.

The construction of the riser platform and development of related technologies were initiated in 1990 by MEXT (Ministry of Education, Culture, Sports, Science and Technology) in Japan. This program, called Ocean Drilling in Culture, Sports, Science and Technology, was integrated into the IODP. The Japanese vessel, the Chikyu, meaning “Earth” will be a state-of-the-art, riser-equipped, dynamically positioned drillship. Chikyu will initially reach a total depth of 10,000 m (32,800 ft), in water depths of up to 2,500 m (8,200 ft). In riserless operations, Chikyu will be able to drill in water depths of up to 7,000 m (22,970 ft).

In the future, Chikyu will be able to drill with a riser in 4,000-m (13,120-ft) water depth to reach a total depth of 12,000 m (39,370 ft), allowing access to regions where the presence of hydrocarbons or other fluids has previously prevented scientific drilling. Although riser drilling is commonly used for hydrocarbon exploration and development, it has never been used in such ultra-deep environments. It will be possible to drill boreholes that are more stable, and that can penetrate zones with different pressures. Seismogenic zones in particular are difficult to drill because of heavy fluid losses associated with fractured intervals. Using this vessel, researchers can drill and install permanent sensors in seismogenic zones. Chikyu is expected to be operational in late 2006 or early 2007.

The current US vessel, JOIDES Resolution, will be used in the first operational phase of riserless operations, which lasts through 2005. The mission-specific platforms (MSPs) operated by the European Consortium for Ocean Research Drilling will operate in shallow waters and ice-covered regions. As the name mission-specific suggests, these drilling platforms could be drilling barges, jackup rigs or seafloor drilling systems, depending on the drilling environment. The construction of the riser platform and development of related technologies were initiated in 1990 by MEXT (Ministry of Education, Culture, Sports, Science and Technology) in Japan. This program, called Ocean Drilling in Culture, Sports, Science and Technology, was integrated into the IODP. The Japanese vessel, the Chikyu, meaning “Earth” will be a state-of-the-art, riser-equipped, dynamically positioned drillship. Chikyu will initially reach a total depth of 10,000 m (32,800 ft), in water depths of up to 2,500 m (8,200 ft). In riserless operations, Chikyu will be able to drill in water depths of up to 7,000 m (22,970 ft).

In the future, Chikyu will be able to drill with a riser in 4,000-m (13,120-ft) water depth to reach a total depth of 12,000 m (39,370 ft), allowing access to regions where the presence of hydrocarbons or other fluids has previously prevented scientific drilling. Although riser drilling is commonly used for hydrocarbon exploration and development, it has never been used in such ultra-deep environments. It will be possible to drill boreholes that are more stable, and that can penetrate zones with different pressures. Seismogenic zones in particular are difficult to drill because of heavy fluid losses associated with fractured intervals. Using this vessel, researchers can drill and install permanent sensors in seismogenic zones. Chikyu is expected to be operational in late 2006 or early 2007.

IODP began its operations in 2004, with Expedition 301 using the riserless drillship and Expedition 302 using a mission-specific platform. The goal of Expedition 301 was to research the hydrogeology within the oceanic crust, determine fluid distribution pathways, establish linkages between fluid circulation, chemical alteration and microbial processes and to determine the relationship between seismic and hydrological properties. Expedition 301 was completed in August 2004, at the Juan de Fuca ridge, eastern Pacific Ocean. At this active hydrothermal system, molten lava from the Earth’s interior is released into colder ocean waters. Several hostile-environment wireline tools developed for the oil and gas industry to explore deeper reservoirs at extreme temperatures and pressures were used in Expedition 301. Expedition 301 also collected sediments, basalt, fluids and microbial samples. Two new borehole observatories were established as deep as 583 m (1,913 ft) beneath the seafloor. Hydrogeologic tests were conducted in these boreholes.

In the future, a network of such borehole observatories will enable the study of fluid movement. Water circulation through the oceanic crust has implications on land, particularly where oceanic plates sink beneath the continental plates. For example, the recent volcanic activity at Mount St. Helens, Washington, USA, in October 2004, is due to the combining of water with molten rock when the oceanic plate subducted into the Earth’s interior. Water in deep subduction zones is geochemically reactive with the surrounding rocks, and may also affect deep faulting.

Expedition 302, completed in September 2004, used multiple vessels in the Arctic (next page). The heavy ice-breaker, Sovetskiy Soyuz, provided upstream protection for the drilling vessel and ice testing for the expedition, while Oden provided close ice protection, communications and scientific staging. Both vessels accompanied the converted drilling vessel Vidar Viking.

Expedition 302 focused on short-term climate changes. The past 56 million years of Arctic climatic history has been recovered from 339 m [1,112 ft] of cores and about 150 m [492 ft] of wireline logs of marine sediments. Preliminary examination of the cores suggests that the ice-covered Arctic Ocean was once a warm place. Further research will provide clues to climate changes that occurred when the Earth changed from a hot planet to a cold one. Some scientists believe that a brief spike in temperature could have been due to a large release of methane from gas hydrate deposits. The exact cause of this possible massive release of greenhouse gas is yet to be understood.

Cores from Expedition 302 have provided the first evidence of extensive organic material created by plankton and other microorganisms in ocean floor sediments, suggesting a favorable environment for oil and gas deposits.

Challenges Ahead

In the coming decade, drilling and sampling technologies, borehole observatories and borehole measurements will play a pivotal role in answering questions about global climate change, natural disasters, and the occurrence and distribution of mineral and hydrocarbon resources.

The need for increased core recovery, while maintaining sample quality, is important for all IODP scientific objectives. Directional drilling and stress-orientation measurements may be required to optimize core recovery.

Contamination caused by drilling and sampling processes can jeopardize studies of
microbiology, fluid composition and paleomagnetism. The occurrence and distribution of microbial populations are a focus of future research. Samples will be collected from a range of tectonic and environmental settings that will utilize the multiple platforms in IODP. With riser drilling, for the first time, direct samples will be obtained from the area of coupling between the continental and oceanic plates. Contamination-free samples are crucial to the success of these studies. Finally, pressurized coring techniques will need to be developed further to retrieve samples at in-situ conditions, maintaining the pressure and temperature. This is particularly important in sediments containing hydrocarbons and gas hydrates.

Another prime goal of future expeditions will be to study seismogenic zones by drilling to the epicenter of earthquakes and placing permanent monitoring devices that track temporal changes in temperature, pore pressure, fluid chemistry, tilt, stress and strain. Temperatures can reach 250°C [482°F] in seismogenic zones and 400°C [752°F] in hydrothermal areas. However, current downhole sensors can withstand temperatures only up to 150°C [302°F] for long-term monitoring.

Schlumberger Kabushiki Kaisha (SKK) Technology Center in collaboration with JAMSTEC has performed a feasibility study on permanent monitoring technology and its applicability for long-term monitoring in scientific deep-ocean wells. Generally, the temperature and pressure ratings of the scientific instruments used in the past are not suitable. Another major problem is the amount of power required to monitor seismicity continuously, for periods longer than a year, and the reliability of the downhole monitoring system. Schlumberger has begun a new project to develop low-power telemetry and a power-delivery system for next-generation permanent monitoring sensors.

Scientific research on marine gas hydrates continues to be a focus area in the IODP program. Knowing the occurrence and distribution of gas hydrates, understanding their role in the global carbon cycle and evaluating their potential as an energy resource continue to be important objectives. The diverse drilling platforms will enable sampling and borehole measurements from different depths and environments. New technology will be needed, not only to directly measure gas hydrate properties, but also to monitor pressure, temperature and fluid flow over extended time periods. Borehole observatories will play a vital role in the future.

Finally, the enormous quantity of data gathered over the coming years—seismic surveys, logs, cored samples, data from borehole observatories, documents and reports—must be stored in databases for easy access by the global scientific community. A continuing close partnership between the scientific community and service providers is necessary to develop tools and processes to address these challenges in the years ahead.

—RG
Reducing Uncertainty with Fault-Seal Analysis

Oil and gas reservoirs in faulted siliciclastic formations are difficult to exploit. By integrating seismic data, detailed core information, and wellbore and production data, geoscientists can now model fault behavior and incorporate the results into reservoir fluid-flow simulators. This integrated process improves prediction of fault behavior, and reduces the uncertainty and risk associated with complex traps.

A fault can be a transmitter of or barrier to fluid flow and pressure communication. Categorizing fault behavior within these extremes is important for hydrocarbon drilling, exploration and development. Modern fault-seal analysis methods utilize seismic data, structural and microstructural information from high-resolution core analysis, and wellbore and production data to predict fault behavior and to reduce uncertainty and risk in faulted siliciclastic reservoir exploitation.

Sealing faults may be a primary control on the trap in many hydrocarbon reservoirs, but they may also transform a relatively large and continuous hydrocarbon reservoir into compartments that then behave as a collection of smaller reservoirs. Each compartment may have its own pressure and fluid characteristics, hampering efficient and effective field development and subsequent hydrocarbon recovery.

Faults that do not form a seal may prevent oil and gas from accumulating as hydrocarbons form and migrate through structures in the subsurface. Open and permeable faults within an established reservoir may also cause serious lost-circulation problems during drilling operations. The loss of drilling mud can be expensive and dangerous, and can result in the abandonment of wells. Whether detrimental or beneficial, faults and their behavior need to be understood by geologists and engineers to successfully explore and extract hydrocarbon reserves.

Recent developments in fault-seal prediction have focused on two separate but interrelated aspects of faulting: fault architecture and fault-rock properties. The fault architecture refers to the fault shape, size, orientation and interconnectivity. It also refers to the distribution of the overall fault displacement into multiple subfaults. Horizontal fault length may range from millimeters, in the case of microfaults, to hundreds of kilometers. For example, the San Andreas fault in California, USA, is more than 800 miles [1,290 km] long. Detailed studies in outcrops and in the subsurface have shown that longer faults usually comprise interconnected shorter faults. The fault clusters form a fault-damage zone or an interconnected halo of faults at a range of scales that may have a large cumulative impact on reservoir behavior. The displacement of the major and minor fault segments within the reservoir juxtaposes the reservoir across the fault against dissimilar lithologies, which may impact the fluid flow.

The rock properties that develop within the fault zones affect a fault's ability to seal. These properties are affected by the local facies, reservoir-fluid types and saturations, pressure differentials across faults, fault-zone architectures, burial and fault histories, and juxtaposition of the lithologies across faults. In addition, pressure and phase changes during reservoir development compound the complexity of analyzing fault-seal behavior.
Modern methods in fault-seal analysis improve the prediction of fault behavior in the subsurface and reduce the uncertainty in exploiting faulted siliciclastic reservoirs. This article summarizes methods of fault-seal prediction and the associated uncertainties. A brief introduction to basic fault theory helps define the fundamental causes, types and characteristics of faults before presenting a more detailed characterization of the process of fault-seal behavior and prediction. Also discussed are oilfield technologies that are used to measure and predict fault characteristics. Case studies from Hibernia, Newfoundland, Canada, and Prudhoe Bay, Alaska, USA, demonstrate how a better understanding of fault sealing improves clastic reservoir simulation and development, thereby reducing uncertainty and risk.

Basic Fault Mechanics, Architecture and Properties

When rocks or rock layers are subjected to tectonic stress, they bend, break, or do both. In its simplest form, a fault is a planar break, or failure surface, in rock across which there is observable displacement, or slip. Contraction

1. Facies designations represent the overall characteristics of a rock unit that reflect its origin and differentiate the unit from others around it. Mineralogy and sedimentary source, fossil content, sedimentary structures and texture distinguish one facies from another.


and extension induce shear failure in rocks. The direction of the principal stresses dictates the orientation of the failure plane, or fault. The strength of the rock controls the magnitude of the shear stress necessary to break the rock.

Although oversimplified, the Andersonian theory of faulting, developed by geologist E.M. Anderson in 1951, is still widely used as a basis to describe the fundamentals of fault orientation in failure. Anderson described the three basic fault types—normal, reverse and wrench, or strike-slip—relative to the maximum regional stress orientations. This theory assumes that one of the principal stresses—σ₁, σ₂ or σ₃ in order from greatest to least magnitude—or the lithostatic load, is always vertical, and that the others are orthogonal and horizontal. The theory predicts that faults will form as two conjugate planes with the following three relationships between fault orientation and principal stresses:

- faults form at ± 30° to the σ₁ direction
- faults form at ± 60° to the σ₃ direction
- the line formed by the intersection of conjugate fault planes will be parallel to σ₂.

These relationships are significant because if geologists know the principal stress directions, they can predict fault orientations. If the relative magnitudes of the principal stresses are also known, geologists can predict fault types (above left).

At the seismic map scale, however, faults are rarely planar because of perturbations in the stress field caused by heterogeneities and anisotropy in the rocks. More commonly, faults are composed of separate segments with distinct tips defined by lines of zero displacement. The linkages may occur as hard links where the faults tips connect, or soft links where the fault-tip geometry is influenced by an adjacent fault that lacks a physical connection. The displacement of the stratigraphy across a fault varies in a systematic pattern from zero displacement at the fault tips to a maximum near the fault center. Anomalies in the systematic distribution in throw reflect the complexities in the lithology and adjacent fault segments. Fault complexities preclude a simple interpretation of the fault orientation, geometry and architecture.

A fundamental step in evaluating fault behavior and sealing properties is mapping the faults and constructing fault-plane throw and juxtaposition maps at the seismic scale (left). The limits of seismic resolution, however, introduce uncertainty in the throw mapped across the fault and do not allow the mapping

^ Relating fault types to stress orientation. The Andersonian theory explains the three main fault types relative to the principal stress orientation. These include the normal-fault style, in which σ₂, the largest in-situ stress, is vertical (top); the reverse-fault type, in which σ₁ is horizontal, and σ₃, the smallest in-situ stress, is vertical (middle); and the wrench, or strike-slip, fault type, in which both σ₁ and σ₃ are horizontal (bottom).

^ Interpreting faults from seismic data and modeling using software tools. Complex fault architecture in exploration and development scenarios can be made more understandable with the use of powerful mapping and imaging software such as the Petrel workflow tools application. In this example, color-coded stratigraphic intervals in the hanging wall and footwall are juxtaposed against the modeled fault surfaces in three dimensions.
of faults whose throw is less than the seismic resolution. The total mapped throw across a seismic-scale fault may also include the summed throws of numerous faults that are too small to be detected individually at the seismic scale. The volume of closely spaced fault segments is known as the fault-damage zone.

The mapped throw across a seismic-scale fault displaces the rock layers on a single fault or on a collection of multiple faults, each of which is below the seismic resolution. The offset influences the fault sealing and properties of the fault rocks within the fault zone. A sealing fault may result, for example, if a fault intersecting different lithologies places permeable, reservoir-quality rocks against less permeable rock, such as shale. This is known as a juxtaposition seal. A fault seal may also form if the reservoir is still juxtaposed against itself—where the throw is less than the reservoir thickness—or against another reservoir. This occurs because the rock within the fault zone may develop lower permeability.

Different fault rocks develop under different deformation conditions, and their sealing properties are related to the conditions of deformation and lithologic factors, such as clay content. Faults that cut porous sandstones with low clay content—less than 15%—may develop low-permeability seals from porosity reduction associated with the mechanical crushing of the quartz grains. These are called cataclastic or deformation bands. Disaggregation bands can also develop in clean sandstones, but without the associated reduction in porosity and grain crushing.

Faults in impure sandstones form phyllosilicate-framework fault rocks (PFFR), with higher clay contents—from 15 to 40%—that reduce the porosity and permeability by compacting and mixing the clay particles and quartz grains. Clay smear occurs along faults that cut rocks with greater than 40% clay. The clay layers or shales are dragged and deformed along the fault plane, forming a low-permeability barrier to fluid flow. Cementation may also occur along a fault plane, forming nearly impermeable barriers to flow. These cemented zones, however, are rarely continuous unless they are associated with a regional change, such as an increase in temperature above 90°C [194°F] at which the rate of quartz precipitation increases (above right).  

The most common faults found in oil and gas fields are normal faults, and most have some component of oblique movement. Complex, three-dimensional (3D) fault geometries stem from the nucleation, growth and linking of...
faults, and give rise to damage zones. An understanding of fault-damage zones is crucial in modeling fault behavior and its impact on reservoir performance.

**Fault-Zone Architecture Characteristics**

An appreciation of fault-damage zone complexity can be obtained through careful study of faults in outcrops. Surface exposures allow geoscientists to observe fault architecture in detail and in a 3D spatial context and scale not afforded by subsurface investigation. Importantly, much of what determines fault-sealing properties occurs at subseismic scales and within the fault-damage zone. Consequently, the study of damage zones in outcrops has become crucial in modeling fault seals and in predicting how they affect subsurface fluid flow.

The damage zone is the volume of deformed rocks around a major fault that has resulted from the initiation, propagation, interaction and buildup of slip along small faults between fault blocks. The deformed volume radiating away from a main fault segment can be divided into inner and outer damage zones. The inner damage zone typically consists of intensely deformed fault rocks that are difficult to map discretely, while the outer zone has a high density of small-throw faults that often maintain an orientation similar to the principal fault segment.

The damage-zone geometry can also be defined along the strike of a fault, or faults, as three distinct zones: (below left). The first zone is called the tip-damage zone and is associated with the stress concentration at the tip of the main fault segment, where the displacement goes to zero. The second zone is called the linking-damage zone, and refers to the volume affected by the interaction between two subparallel, noncoplanar fault segments. The wall-damage zone, the third zone, is located along the fault surface and is a result of damage from continued fault slip or from damage by previously abandoned fault tips as fault propagation continued through time. Secondary, subseismic-scale faults, natural fractures and cementation may occur in all three zones.

Intensive investigation of fault exposures, like the Moab fault in southeast Utah, USA, has allowed geoscientists to characterize fault-damage zones and make analogies to major faults in the subsurface. The Moab fault has been extensively studied by geoscientists, including scientists from Schlumberger-Doll Research (SDR), Ridgefield, Connecticut, USA, and Rock Deformation Research (RDR) Ltd, Leeds, England. Located in the northeast...
portion of the Paradox basin, the Moab fault is a normal fault approximately 28 miles [45 km] long with a northwest to southeast strike. The fault comprises several linked segments. The longest segment has a throw of 3,150 ft [960 m] to the south, as observed from surface displacement and erosion of Pennsylvanian to Cretaceous sedimentary rocks. The Moab fault was active from at least the Triassic period until at least the mid-Cretaceous period. The canyon landscape surrounding Moab is ideal for mapping the fault exposure in three dimensions (above).

SDR and RDR scientists set out to capture detailed outcrop data along a segment of the Moab fault-damage zone at Bartlett Wash as an analog to similar structures expected but not imaged in the subsurface. Within the study area, the throw along the main fault segment is 690 ft [210 m]. The older, Jurassic-age Slick Rock member of the Entrada sandstone is well exposed on the footwall and exhibits a dense network of small-throw faults within a narrow zone adjacent to the main fault segment. The geoscientists employed a sophisticated mapping technique, using a high-precision, differential global positioning system (GPS) and rover units to map discrete features to within 0.8 in. [2 cm] (previous page, right). Data coordinates were tagged with key geologic attributes at many stations to capture the complexity and scale of the fault-damage zone. The positions and geometries of major and secondary structural elements, such as faults and natural fractures, were also recorded. Scientists created a digital geologic model to use as an analog for subsurface fault interpretation to facilitate visualization through innovative techniques, such as virtual


^ The Bartlett Wash study area, Moab, Utah, USA. A photographic cross section along the Moab fault allows illuminating views of the complex fault-zone architecture within the detailed mapping area (top). An aerial view (bottom) from the footwall to the hanging wall shows another perspective of the sharp contact formed by the Moab fault.
field trips, and to use the fault population distribution as an input to flow models (top).

Although the static geometry and fault-rock properties are the principal controls on cross-fault flow in the subsurface, fault reactivation is another phenomenon that influences the flow properties along the fault. Changes in tectonic stress regimes over geological time, for example, may reactivate a fault, opening pathways that did not exist previously, and allowing hydrocarbons to leak. On a reservoir-production time scale, changes in pore-pressure regimes as a result of current production or injection in and around fault systems can initiate fault reactivation and cause loss of seal.

Local pressure increases near or within the fault plane resulting from injection decrease the effective normal stress, which may cause the fault to reactivate. Also, pressure changes in the rocks surrounding faults, for example from depleting a reservoir, alter the in-situ stresses acting on fault planes and, depending on fault alignment relative to the principal stresses, may lead to reactivation and subsequent seal failure. This behavior has been documented in such areas as the North Sea, the Gulf of Mexico and the Bight basin, Australia.

These pressure changes have major implications in production, enhanced oil recovery (EOR) and pressure maintenance, and in subsurface gas storage, including carbon dioxide [CO₂] storage for the reduction of greenhouse-gas emissions. The reactivation of reservoir-bounding faults compromises fault-sealing mechanisms, shears well casings, and causes compaction and subsidence. The integration of fault-rock strength properties, the fault geometry and in-situ stress conditions provides valuable input for modeling and assessing the reactivation risk. The in-situ stress orientations are interpreted with borehole imaging devices, like the FMI Fullbore Formation MicroImager or OBMI Oil-Base MicroImager tools, and from the acquisition of pore pressure data, using sampling tools such as the MDT Modular Formation Dynamics Tester or the RPT Repeat Formation Tester devices.

The Roles of Pressure and Timing in Fault Sealing
An important concept in estimating the sealing capacity of faults relates to the threshold pressure \( P_t \). In water-wet rocks, \( P_t \) is the lowest capillary pressure \( (P_c) \) at which hydrocarbons form a continuous path through the largest interconnected pore throats in the fault rock. Knowing the \( P_c \) of different fault rocks, generated under different conditions, allows geoscientists to calculate the maximum petroleum-column height \( (H_t) \) or sealing capacity of the fault rock that prevents hydrocarbon migration across the fault. The capillary pressure of hydrocarbons under hydrostatic conditions against a fault seal increases upward from zero at the free-water level (FWL), which is at the base of the hydrocarbon column. A capillary or membrane seal prevents hydrocarbon migration across the fault for a hydrocarbon column height measured from the FWL to where \( P_t \) equals \( P_c \). Membrane sealing occurs because of the surface tension between water and hydrocarbon, so the effective permeability to hydrocarbon is zero when \( P_t \) is less than \( P_c \) (next page, top).

A hydrocarbon column with \( P_t \) greater than \( P_t \) of the fault rock will migrate slowly across the fault. The flow is retarded by the hydraulic resistant sealing of the fault rock. Hydraulic resistant sealing occurs when the relative permeability to hydrocarbon is low because of the water-wet fault rock and low pressure potential across the fault for small hydrocarbon columns. The hydrocarbons may migrate at a slow rate, but hydraulic resistant sealing provides an effective seal over geological time. At the base of the hydraulic-resistance zone, \( P_t \) is equal to \( P_c \). Relative permeability to hydrocarbon at this elevation is zero, but increases above this point in a transition zone from membrane sealing up to geologically significant leakage because of an increase in the relative permeability. Geologists consider hydraulic-resistance seal failure significant once the leakage rate exceeds the hydrocarbon charge rate, at which point hydrocarbons stop accumulating.

Water-pressure differences in the reservoir across a fault or in fault fill influence the height of the resulting hydrocarbon column. Higher water pressure in the aquifer outside the trap, for example, leads to water flow into the reservoir if the hydrocarbon saturation in the fault zone is less than the irreducible water.
saturation, Swrr. These conditions improve the fault-seal potential and increase hydrocarbon-column height. Lower pressures in the aquifer outside the trap and in the fault fill at irreducible water saturation will lead to decreased hydrocarbon-column heights in the trap. These interrelationships between fluids, pressures and rock properties are important controls for predicting fault behavior and sealing capabilities.

Fault architecture, throw distributions, lithologies, fault-rock distributions and properties all impact the flow properties of faults. Fault history, however, is equally important when considering the sealing potential of fault traps in exploration and production. The burial history, deformation timing and hydrocarbon-charge history influence fault-rock properties and their impact on fault-seal capacity.

Successful reservoir-development strategies must incorporate the faulting and burial history to more accurately predict the fault-seal risk. For example, separate tectonic events create new faults and reactivate existing faults. Fractures may propagate, potentially changing the reservoir permeability characteristics. Fault-rock properties also change with burial and uplift. Permeability across faults and in surrounding rocks generally decreases with burial depth (below right). Increases in temperature boost the rate of quartz precipitation, which can significantly reduce the transmissibility across a fault.

Successful reservoir-development strategies must incorporate the faulting and burial history to more accurately predict the fault-seal risk. For example, separate tectonic events create new faults and reactivate existing faults. Fractures may propagate, potentially changing the reservoir permeability characteristics. Fault-rock properties also change with burial and uplift. Permeability across faults and in surrounding rocks generally decreases with burial depth (below right). Increases in temperature boost the rate of quartz precipitation, which can significantly reduce the transmissibility across a fault.


Capillary pressure diagram. The pressure-depth plot (left) shows the capillary pressure, Pc, as the difference between the pressures of water and hydrocarbon with depth. The hydrocarbon has a steeper pressure gradient than the water, so the capillary pressure increases above the free-water level (FWL) where the capillary pressure is zero. The plot on the right shows a typical mercury-injection capillary pressure curve as measured in the laboratory. The entry pressure, Pe, is the pressure at which the hydrocarbons first enter the sample. A hydrocarbon-column height, Hc, can be trapped below the threshold capillary pressure, Pc, and sealed by membrane sealing. Trap geometries may allow hydrocarbon columns to exceed this height. The hydrocarbon flow across the seal above Hc is possible at a rate dependent on the relative permeability of the seal.

Permeability reduction in a cataclastic fault zone with increased burial depth in three different basin examples. Permeability reductions occur in cataclastic fault zones primarily because of mechanical grain crushing and increased quartz cementation at greater depths. In basins having a high mean-effective-stress, strong cataclasis in fault zones (blue) would result, making permeability in those fault zones higher. In basins having lower mean-effective-stresses, moderate cataclasis in faults zones (red) would result, making permeability in those fault zones lower. In basins where quartz-cementation occurs in fault zones (green), fault-zone permeabilities would be higher at shallower burial depths but become very impermeable below 3 km (9,840 ft) of depth because of increased quartz cementation. Other factors, such as geologic history and host-rock lithology, play a significant role in determining which processes dictate fault-zone permeability.
Fault-activity maps that color-code the geological timing of structural development help asset teams quantify the risk of developing a prospect or of taking subsequent development steps, such as initiating an EOR process. Knowledge of the geologic history and its impact is also important when predicting fault-sealing properties.

Fault-Seal Analysis Methods
Successful fault-seal analysis methods integrate fundamental information on the fault-zone architecture, fault-rock properties and pressure data. An important tool for evaluating the flow potential across a fault is a strike view, or map of the fault plane with the hanging wall and footwall intersections superimposed on the modeled fault surface. Allan diagrams use this technique to show possible fluid-migration pathways, leak points or sealing areas across the fault, and have also helped explain the location of hydrocarbon/water contacts in various fields worldwide. Allan diagrams typically use the seismically interpreted horizons to define the hanging wall and footwall offset across the fault and lithology interpreted from well logs to identify the stratigraphic changes between the seismic horizons. Sophisticated mapping tools allow the development of Allan diagrams as 3D models. These models require significant amounts of data and can be time-consuming to develop, although new software tools, such as the Petrel workflow tools application, have reduced the processing time significantly.

An alternative to the complicated evaluation of the distribution of the stratigraphy across the fault plane, as used in Allan diagrams, is a simplified juxtaposition triangle diagram, which enables a quick initial examination and prediction of fault-seal capacity. This technique images the hanging wall and juxtapositions for varying throws and allows an evaluation of the juxtaposed stratigraphic intervals for a given throw (below left). These diagrams simplify the analysis of juxtaposition for a single fault plane. The effects of multiple small-throw faults may also be quickly evaluated using these diagrams. The juxtaposition is simply evaluated at the smaller throws for each fault.

In the initial analysis, triangle diagrams show the juxtaposition of the stratigraphy across the fault. Reservoirs juxtaposed against low-permeability rocks such as shales are expected to seal, whereas reservoir-to-reservoir juxtapositions across the fault are more likely to leak. Juxtaposition diagrams may also be used to evaluate the fault rocks present and their associated properties that develop within the fault zone. For instance, the distribution of clay smears from clay-rich layers in the fault zone can be determined and their effects on the seal quantified. Also, critical throws can be assessed when higher permeability cataclastic faults may represent a crossfault flow risk. This occurs where two permeable siliciclastic reservoirs are juxtaposed across the fault—one in the hanging wall (HW) and one in the footwall (FW) (next page).

Several methods have been developed to estimate the distribution of fault rocks within a fault zone. Two of the most commonly applied methods are shale-gouge ratio (SGR) and clay smear. Researchers at RDR have also recently introduced a modified SGR, or effective shale-gouge ratio (ESGR), that permits a greater control on the architecture and distribution of the fault rocks along the fault surface during the analysis.

The SGR method estimates the percentage of clay from the host lithology mixed within the fault zone. The algorithm calculates the net clay within the lithology that is displaced past each
point in the fault by taking the sum of the layer thickness times the clay percentage divided by the fault throw. This calculation is derived across a modeled fault surface with a calculated throw distribution and clay-percentage estimates from well logs. The ESGR uses a weighted SGR that allows a nonuniform distribution of the clays within the section dragged past each point on the fault surface to model a more complex fault-zone process.

Outcrop studies of fault zones have also revealed that clay smearing is a common fault-zone process in which clay is smeared along the fault zone from a local shale bed. The thickness of the clay smear along the fault increases with the thickness of the source shale bed and decreases with distance from the source shale. Multiple shale layers tend to combine to produce a continuous smear, enhancing fault sealing.

The basic method for modeling the fault-rock distributions involves calculating the throw distribution on a gridded fault surface from the horizon intersections on the fault, infilling the detailed stratigraphy with the estimated thicknesses and clay contents, and contouring the derived fault-seal properties onto the fault surface. Contours of capillary pressure measured along the fault provide a calibration to the sealing capacity for the estimated fault-rock properties. These pressure data are often acquired in open hole using formation-sampling tools, such as the MDT or RFT devices.

While the calculation of fault-seal potential across a fault seems straightforward, it may be an oversimplification. From outcrop and exhumed fault studies, geoscientists find that shale smears are not distributed evenly within fault zones; they may be interrupted, creating multiple gaps, which reduce the sealing effect over geologic time scales. One study of the Calabacillas normal fault in New Mexico, USA, 18.

---


Yielding et al, reference 2.
found that clay smears tend to be continuous for a distance of two to six times the clay source-bed thickness, but then thin significantly away from the base of the clay source-bed on the footwall.²⁰ Moreover, smears are frequently breached by small-throw faults. Consequently, smear-estimation and seal-calibration techniques can overestimate fault-seal potential, especially near the base of a clay source-bed.

The contours of capillary pressure and fault-rock property estimates over a fault surface are undercalibrated using the methods described. A more accurate analysis should include the calibration of fault-rock properties estimated from core measurements. Measured threshold pressure and permeability across small faults in core help predict the sealing capacity and flow properties of the estimated fault-rock distribution. Fault rocks in core also define the range of fault-rock types, created by processes such as cataclasis or grain crushing, and allow evaluation of the impact of the geologic history and fault timing.

Fault-rock databases from specific basins are key to the calibration of the fault-rock sealing potential. Fault-rock data are a crucial input to successful reservoir simulations, which also rely on field data, including seismic surveys, well logs, core logs and studies, and field pressure-data. These data are also important in reducing the risk in an exploration setting, where there may be significantly less data available.

**Increased Knowledge, Reduced Uncertainty**

Faults in core provide not only a calibration to fault-rock properties such as porosity, permeability and threshold pressures, but also fault distribution and density at a scale below that of seismic resolution. Recent advances in seismic interpretation methods, such as automatic fault-picking and attribute-mapping software, help geophysicists interpret large seismic volumes in less time and in greater detail than manual methods. However, much of the fault detail still exists at a scale below the seismic resolution, so detection of these small faults must rely on high-resolution borehole-imaging tools and the detailed study of fullbore cores.

The highly compartmentalized Hibernia field in the Jeanne d’Arc basin offshore Newfoundland, Canada, demonstrates the importance of detailed core examinations.²¹ The Hibernia field is situated in a sedimentary basin within the greater Jeanne d’Arc basin that has undergone multiple rifting events associated with the breakup of the supercontinent Pangea and the formation of the Atlantic Ocean from the late Triassic to the early Cretaceous period.

Since first production in 1997, geologists and engineers with the Hibernia Management and Development Company knew that the two main Hibernia reservoirs were compartmentalized by faults. An estimated 30 fault blocks were identified from observed variations in fluid-contact heights and in pressures. As development of the field continued, there were indications that the field might be even more compartmentalized than originally thought.²² However, the asset team was uncertain about the degree to which the faults were diminishing individual well production and injection performance.

Fullbore cores were taken from the lower reservoir in the hanging-wall section in two wells, the B-16 2 in Block Q and the B-16 4 in Block R, to characterize the deformation and the fault-zone architecture (above). The cores were examined for geologic structures, and samples were collected for analysis of microstructural and petrophysical properties. The fault rocks were classified according to clay content.

Fault rocks with less than 15% clay exhibited both disaggregation bands, which are localized zones of particulate flow with little grain fracturing, and deformation bands with cataclastic seams with variable amounts of grain-size reduction due to mechanical crushing of the grains. Despite the lack of clay, these fault rocks have an average permeability of 0.06 mD, which is almost five orders of magnitude lower than the host-rock permeability. Fault rocks containing an intermediate amount of clay—15 to 40%—are classified as phyllosilicate-framework fault rocks, and they exhibited even lower permeabilities than their low-clay counterparts. The high clay-content rocks, characterized by greater than 40% clay, formed clay smears. These fault rocks typically have permeabilities of less than 0.001 mD, equivalent to the host-rock properties. The analysis of the fault rocks in core showed that the fault-rock types are capable of significantly reducing the permeability across the faults in Hibernia field.

To evaluate the sealing potential of the faults compartmentalizing the reservoir, the fault-rock types and properties are integrated with the fault-rock distribution estimates from the juxtaposition diagrams. These diagrams show that where the fault throw is less than the individual layer thickness and the reservoir is juxtaposed against itself, the sealing properties are dictated by the cataclastic fault-rock properties. Conversely, where the fault throw exceeds the individual layer thickness, juxtaposition sealing of reservoir against nonreservoir rock is the principal seal.

A juxtaposition triangle diagram of the Hibernia formation at Well B-16 2 demonstrates the predicted fault-rock distributions and their interpreted effects on the fluid flow (next page).
Juxtaposition (top) and fault-seal (bottom) diagrams for Hibernia Well B-16 2. The juxtaposition diagram identifies a sand-against-sand juxtaposition at a 75-m [246-ft] throw. In this scenario, a Layer 2 sandstone in the hanging wall (HW) is dragged past other lithologies—impure sandstones and a medial shale—in the footwall (FW) and is juxtaposed against the basal sandstone in the upper Layer 3 interval. This represents a possible leak area. However, when clay smearing is taken into account, the predicted potential leak area is reduced significantly.

Lithofacies (volume-shale derived)
- Sandstone-dominated
- Mixed heterolithic
- Shale/mudstone dominated

Fault-Seal Types (using clay-smear factor 3.0)
- Cataclasites
- Phyllosilicate-rich fault rocks (PFFR)
- Phyllosilicate-rich fault rocks (clay smears)

Note: Reduction in window size due to smear potential of intervening impure sandstones and medial shale


This diagram shows that for throws less than 30 m [98 ft], fault rocks are predominantly cataclasites or zones of grain crushing. On the other hand, where throws are greater than 30 m, the lower permeability, clay-rich, phyllosilicate-rich fault rocks are present. These results show that fault rocks in the Hibernia field have the potential to degrade the performance of both production and injection wells.

When combined with production history-matching models, which yield nonunique solutions from many possible geologic scenarios, the fault-seal analysis calibrated to the fault data from core bolstered the interpretation of how faults affect fluid flow in the field. This led to the drilling of the injector well B-16 21, which was positioned to avoid dangerous fault-damage zones. The new injector well improved reservoir sweep and provided additional pressure support for nearby producing wells.

**Fault-Seal Analysis Aids Drilling**

Open, conductive fault systems may be as challenging as sealing faults in field development, especially where they pose a serious drilling hazard. Since development drilling began in 1970, the highly faulted Prudhoe Bay field, Alaska, USA, has produced more than 10 billion barrels [1.6 billion m³] of oil. Throughout the field’s history, lost-circulation problems have been commonplace and directly related to the number of faults crossed while drilling wells. With substantial remaining recoverable reserves, continued development by BP and ConocoPhillips requires drilling into smaller fault blocks and through more faults. As a result, lost-circulation problems have increased dramatically, even as total drilled footage has decreased in recent years (above).

Problems reached critical levels in 1998, when 66 out of 120 wells and sidetracks experienced lost-circulation problems, costing over US$10 million. Trouble-time costs added 50% to 100% to well costs. In some cases, loss rates exceeded 1,000 bbl/hr [159 m³/hr], raising serious safety concerns and risking the loss of wells. BP and ConocoPhillips, then Arco Alaska, considered several options to address the fault-related lost-circulation problems. The Prudhoe Bay asset team could choose not to drill risky targets, reducing development options and recoverable reserves, or could employ expensive drilling contingencies that may have mitigated the problem, but at the expense of understanding its cause.

The Prudhoe Bay partner companies, along with RDR, decided to investigate the cause of these lost-circulation problems—faults that act as conduits for drilling mud. In Prudhoe Bay field, more than 5,400 faults have been interpreted by seismic surveys. The faults range in strike length from 500 to 15,000 ft [152 to 4,570 m] with throws from 20 to 200 ft [6 to 60 m] (next page, top). First, the existing seismic data were reprocessed to improve the fault interpretation. The mapped faults were then added to a database, which included fault parameters such as orientation and length. Along with geologic data, drilling data for all wells in the field were compiled, including lost-circulation volumes and rates, and the location of losses. Wellbore data and production history-matching were also used to gain a more thorough understanding of fault, fluid and reservoir behavior. Although this analysis helped explain 80% of the lost-circulation problems, it showed that a more detailed exploration of fault-rock properties across the Prudhoe Bay field was warranted.

Analysis of the fault distributions and fault-rock properties from thousands of feet of core from 14 wells provided the necessary calibration to evaluate fault behavior. Open vuggy fractures in the core identified conductive zones that could pose potential drilling hazards. Full-field and local-stress modeling, integrated with the tectonic history, showed a preferential orientation of conductive faults parallel to the maximum in-situ stress direction. An integrated database of fault styles and architecture, fault-rock properties, and lost-circulation data facilitated the study of fault styles and the analysis of fault sealing.

The database properties calibrated to juxtaposition and fault-rock distributions from clay-content of individual faults helped reduce the risk of drilling development wells in Prudhoe Bay field. Predrill well planning now incorporates the data from the database to avoid hazardous drilling areas (next page, bottom).

In the year following this integrated fault-characterization project, 65 wells and sidetracks were drilled. The number of problematic wells, those losing more than 100 bbl [16 m³] of drilling fluid, dropped from 32 to 15% of the total wells. Lost-circulation zones were anticipated and accounted for, reducing trouble-time and decreasing drilling costs by US$2 to 5 million during that year. Only two wells had significant problems. A more thorough knowledge of faults in Prudhoe Bay field reduced drilling risk, improved well planning and increased asset team confidence in further development. The significant reduction in drilling risk has opened up more drillable targets that were once deemed too risky, while potentially increasing recoverable reserves.

**Complex Problem, Simple Answer**

Faults and their influences on fluid flow within reservoirs are complex. Technological advancements have improved our ability to measure these influences, both directly and indirectly. Well-testing techniques, production history-matching and the injection of tracers, for example, help assess whether reservoir compartments exist, and if they do, whether they are in communication or are isolated. Wellbore
measurements and sampling tools also are used to evaluate reservoir rocks, fluids and pressures to determine compartmentalization. Recently, engineers have successfully identified fluid compositional variances related to compartmentalization using the Schlumberger MDT device.^{23}

The evaluation, calibration and prediction of the faults that compartmentalize reservoirs require a systematic analysis that should include integrating datasets from properties measured in conventional core, to subsurface well and production data, seismic interpretation and outcrop and subsurface analogs.

Poorly resolved subsurface fault complexities may be incorporated into reservoir fluid-flow simulators using the results from detailed outcrop analog studies. In simulators, the effects of faults are represented as effective transmissibility factors across defined traverses. Fault-related transmissibility depends on the number of faults, the thickness of the associated damage zones and the fault properties, such as fault-rock permeability and pressure thresholds.

Incorporating the fault-rock properties from databases has improved history-matching and fluid-flow modeling across faults. These results still contain risk and uncertainty. In fault-seal analysis, there will always be uncertainties relating to the internal architecture of faults, the host-rock properties, the definition of stratigraphic units from seismic surveys, capillary pressure effects and how far to project the model given the limited amount of well data.

Fault-rock property databases provide the range and magnitude of the uncertainty that can be incorporated into risk modeling using Monte Carlo techniques, for example.

In fault-seal analysis, the complexity of faults must be captured and modeled, but the answer must be simple enough to be used effectively in reservoir simulations to reduce uncertainty when exploring and developing enigmatic, faulted siliciclastic reservoirs. —MGG


A New Horizon in Multiphase Flow Measurement

A quiet revolution has taken place in the technology for measuring three-phase fluids at the surface. Advanced multiphase meters provide production and reservoir specialists with the data required to understand and optimize well performance without separating a flowstream into individual gas, oil and water phases.

Ian Atkinson
Bertrand Theuveny
Cambridge, England

Michel Berard
Moscow, Russia

Gilbert Conort
Rosharon, Texas, USA

Joel Groves
Princeton, New Jersey, USA

Trey Lowe
Houston, Texas

Allan McDiarmid
Apache Energy Limited
West Perth, Western Australia, Australia

Parviz Mehdizadeh
Consultant
Scottsdale, Arizona, USA

Patrick Perciot
Clamart, France

Bruno Pinguet
Gerald Smith
Bergen, Norway

Kerry J. Williamson
Shell Exploration and Production Company
New Orleans, Louisiana, USA

For help in preparation of this article, thanks to Alain Chassagne, Luanda, Angola; Dan Dezman, Apache Energy Limited, Aberdeen, Scotland; Richard Kettle, Ahmadi, Kuwait; Donald Ross, Rosharon, Texas, USA; Jon Svaeren, Framo Engineering AS, Bergen, Norway; Eric Toskey, Bergen, Norway; and Laurent Yvon, Douala, Cameroon.

3-Phase, LiftPRO, NODAL, PhaseTester, PhaseWatcher, Platform Express and Vx are marks of Schlumberger.
A new surface flowmeter is fundamentally changing the way we measure complex flow from producing wells. This transformation is driven by new technology that accurately measures rapid variations in three-phase fluids, including slug flow, foams and stable emulsions that previously were difficult to quantify. The capability to meter multiphase fluid in real time increases operational efficiency, saving both time and money.

It is now possible to allocate production without conventional phase separation and to overcome processing constraints, or bottlenecks, in existing surface facilities. Accurately quantifying individual fluid phases in a production stream allows operators to make more informed decisions about well performance. Engineers can now better identify, understand and remediate multiwell flow problems, optimize artificial lift operations and build dynamic reservoir models.

This article discusses recent advances in multiphase metering and examines the use of this technology for permanent-measurement, artificial lift and mobile well-testing applications, both onshore and offshore. Case histories from Australia, the Gulf of Mexico and Africa highlight the benefits of advanced measurement technology.

Conventional Separation and Well Testing
Conventional test separators are scaled-down versions of the large production separators that segregate and measure gas, oil and water at surface processing facilities. In established field operations, test separators are permanent installations. For exploratory and field-delineation wells, companies must deploy modular test separators. Several test separators in series or parallel are sometimes needed to handle high-rate wells, heavy oils or condensate-rich—wet—gas.

Typically, test separators are cylindrical vessels that are deployed horizontally. These vessels vary from 15 to 30 ft [4.6 to 9.1 m] in length, 8 to 13 ft [2.4 to 4 m] in height and weigh up to 10 tons [9,072 kg]. Separators receive produced effluent from individual wells and segregate the different fluid phases through a gravity-based process (above).

Two-phase vessels separate gas from liquids, and three-phase vessels further separate the liquids into oil and water. These systems meter the separate fluid phases individually as they leave the vessel before commingling and returning the fluids to a flowline. Normal operating conditions for a test separator are limited to pressures between 200 and 1,000 psi [1.4 and 6.9 MPa] with maximum working pressures up to 1,440 psi [9.9 MPa].

Test separators are not designed for specific wells, but instead must handle a wide range of flow rates. At the time of installation, test separators are often intentionally oversized to serve as backup or supplemental production separators and to accommodate future increases in field output.

Obtaining reliable measurements from a test separator requires relatively stable conditions within the vessel, which can take several hours. Well-test protocols associated with these units generally emphasize operational efficiency—a one-size-fits-all approach—rather than setting the measurement instruments and controlling flow rates based on individual well conditions. Time constraints and personnel limitations often preclude optimization of the separation process.

In addition, operating conditions sometimes prevent complete separation of the fluid phases. Some oil remains in the water, some water in the oil, some gas in the liquids and some liquids in the gas. These conditions cause errors in separator instruments, which are designed to measure streams of single-phase gas, oil or water. Test separators also have difficulty measuring certain anomalous flow regimes because of the need for stable processing conditions and the fact that response to dynamic flow conditions is always delayed.

Problematic flow regimes include fluid slugs, in which one phase is interrupted by another phase; foams, which conventional separators cannot handle; and stable emulsions that require additional heat or chemical treatment to separate the one phase that is suspended in another. In addition, viscous fluids, such as heavy oil, make separation and accurate test measurements extremely difficult.
Multiphase Measurements

Unlike conventional separators, multiphase meters continuously measure gas, oil and water flow without physically separating the flowstream into individual fluid phases. Multiphase flowmeters accept three-phase fluids directly from a flowline, make measurements and immediately return fluids to the flowline (left). These meters yield measurement results within minutes of being placed in operation.¹

Pressure drop across multiphase flowmeters is significantly less than for conventional separators, which allows wells to be tested close to actual producing conditions. In permanent metering applications, these devices have minimal footprints at surface locations or on offshore platforms. At this time, there are more than 1,300 multiphase meter installations worldwide, reflecting sharp increases during the past six years (below left).²

Third-party testing and joint-industry projects have helped prove multiphase measurement technology. Developers of three-phase flowmeters have also demonstrated the effectiveness of these systems through extensive flow-loop testing. A flow-loop test consists of accurately measuring single-phase fluids—gas, oil and water—in a controlled environment, mixing them to create a multiphase stream and then flowing them through a multiphase meter.

Flow-loop measurement results are compared with the individual volumes of constituent fluids that formed the test flow.³ These tests assess meter performance over a wide range of fluid mixtures and flow conditions. Meter performance under anticipated field conditions can be extrapolated from flow-loop test data.

Users conduct extensive testing of multiphase flowmeters to qualify the systems for specific field applications. Qualification is frequently necessary because various metering systems react differently to changes in process conditions, such as flow rates, fluid properties, the presence of scale or paraffin, and sand or gas volumes in a flowstream.⁴

To date, there is no commonly accepted test procedure. Project partners, government entities and other joint-interest owners must agree on appropriate qualification procedures each time a metering system is used to allocate, or apportion, commingled production according to ownership. However, several industry and regulatory bodies—the American Petroleum Institute (API),
American Society of Mechanical Engineers (ASME), Oil & Gas Conservation Commission (OGCC), International Organization for Standardization (ISO), United Kingdom Department of Trade and Industry (DTI) and Norwegian Society for Oil and Gas Measurement (NSOGM)—are developing guidelines for the application and qualification of multiphase flowmeters.

In addition to flow-loop tests, testing under field conditions is another means of qualifying multiphase flowmeter systems for specific applications. Flowmeter performance is compared with measurements from test separators in a field where fluid composition, line pressure and flow rates closely approximate those of an intended application. Testing under actual field conditions often establishes a higher level of acceptance for multiphase meter performance.

However, field tests consume more time than typical flow-loop tests and tend to be more costly. It is also essential that operators pay close attention to the calibration and operation of test separators to ensure high-quality reference data.

For subsea developments with wellheads, or trees, and production-control equipment located on the seabed, field tests are often impractical.

In addition, flow-loop procedures may not be capable of replicating the extreme pressures and temperatures prevalent in some projects, such as deepwater and ultra-deepwater developments. Often, the best option in these cases is to compare data from an accelerated program of postinstallation monitoring with conventional single-phase process-stream data at export points during monthly production testing.

A New Flowmeter Design

Because of the limitations inherent in conventional test separators, Schlumberger and Framo Engineering AS developed the Vx multiphase well testing technology through the joint-venture company 3-Phase Measurements AS. This multiphase flowmeter system is applicable for permanent installations, mobile testing and artificial lift optimization.

Vx technology has been qualified in more than 1,500 flow-loop tests conducted by third parties at five independent facilities that generated about 5,000 flow-regime test points.

The principal components of the Vx multiphase flowmeter are a venturi meter equipped with absolute- and differential-pressure sensors, and a dual-energy spectral gamma ray detector paired with a single, low-strength, radioactive chemical source to measure total mass flow rate and the holdups, or fractions, of gas, oil and water.

Vx technology functions without the need for an upstream flow-mixing device, which minimizes the size and weight of the unit. These systems have no moving parts and are essentially maintenance-free. In-line flow passes through an inlet into a short, straight length of horizontal pipe leading to an inverted tee with one horizontal end closed. This blind tee preconditions and directs the flow upward through a venturi section in the Vx meter. Pressure is measured just before fluids enter the venturi and as the flowstream passes through the narrow venturi throat.


The dual-energy spectral gamma ray detector is mounted on one side of the venturi section, directly across from a barium source, which emits gamma rays at various energy levels—approximately 32, 81 and 356 keV. The detector measures radioactive count rates, which are related to gamma ray attenuation through the fluid mixture at the 32- and 81-keV energy levels. The higher energy level chiefly measures mixture density, which is affected by the gas/liquid ratio; the lower energy level corresponds to fluid composition, which is influenced by the water/liquid ratio (below left).

Because total mass flow rate and holdup are measured at the same time and same place—the venturi throat—the dual-measurement systems in Vx meters evaluate the same flow. This configuration and stringent equations for the fluid dynamics associated with flow conditioned by a venturi throat provide a robust measurement capability unaffected by upstream flow regimes. The detector makes complete calculations of gas, oil and water fractions every 22 milliseconds, or slightly more than 45 measurements of fluid-mixture density and three-phase holdup per second. The rapid sampling and measurement speed allow the flowmeter to derive the velocity of liquid and gas phases in a flowstream and to compensate for high-frequency instabilities in the venturi throat. As a result, the Vx meter can measure flow conditions caused by downhole conditions and surface piping, including slug flow, foams and emulsions (next page, top).

The PhaseWatcher fixed multiphase well production monitoring service is the main permanent monitoring application of Vx technology. This system is available with venturi throat sizes of 29 mm [1.1 in.], 52 mm [2 in.] and 88 mm [3.5 in.], depending on flow rate. For mobile well-testing applications, the PhaseTester portable multiphase periodic well testing equipment is available in 29-mm or 52-mm throats. This compact system weighs about 3,750 lbm [1,700 kg] and can be transported easily on a truck, trailer or modular skid (next page, bottom). A gas-testing module also is available for permanent-monitoring and mobile-testing applications.

Continuous Measurement Opportunities
Multiphase flow measurements help allocate production among working- and royalty-interest owners or record volumes for custodial transfer at pipeline stations or port terminals. This information is essential for project partners and also for governments, which have testing requirements for accurate computation of taxes and royalty payments. For example, measurements might be made on a given well during a one-week period so the results can be extrapolated to allocate production over a longer time.

---

\(^{\text{\footnotesize 11}}\) Gamma ray attenuation. Different fluids attenuate gamma rays to varying degrees. The high-speed detector produces a signature count rate over the higher and lower energy bands that are a function of the measured medium (top). These count rates permit a triangular solution of phase holdup (bottom). For each phase, the ratio of high-energy count rate versus source strength, or empty pipe count rate, is plotted against the ratio of low-energy count rate versus source strength on an x-y chart. These points become the apexes of a triangle. Phase holdup is determined by the intersection of two lines inside the triangle. The first line represents the gas/liquid ratio (green); the second connects the 100% gas point to the oil/water ratio point (red).
14. Maximum flow rates:
- 29-mm [1.1-in.] venturi: liquid, 12,000 B/D [2,051 m³/d]; gas, 0.17 MMcf/D [48,086 m³/d];
- 52-mm [2-in.] venturi: liquid, 39,500 B/D [6,281 m³/d];
- 88-mm [3.5-in.] venturi: liquid, 112,000 B/D [17,808 m³/d]; gas, 1.6 MMcf/D [452,271 m³/d].

^ Periodic well testing. The PhaseTester portable multiphase periodic well testing system can be skid-mounted for transport to onshore well sites on the back of a small truck or as a modular package for crane lifts onto offshore platforms. The PhaseTester unit is significantly smaller and more compact than temporary conventional test separators.
Multiphase measurements also identify phase flow regimes (next page, bottom). Since test separators cannot be deployed in this setting, surface measurement of production from subsea wells requires the installation of expensive subsea test lines. In addition, platform-based facilities often have insufficient capacity for subsea wells to be tied into existing topside test separators that were initially designed to accommodate only the production from platform wellheads.

Multiphase metering systems increase well-testing frequency, but also enhance measurement quality. Flow from some wells is so unstable that it cannot be measured accurately with a conventional test separator. Multiphase flowmeters are more accurate than conventional test separators and are less affected by complex flow regimes (next page, bottom).

Multiphase measurements also identify phase conditions that might not be detectable by the exclusively volumetric measurements of conventional test separators. Furthermore, unlike test separators, multiphase flowmeters have no moving parts and associated maintenance requirements to maintain measurement accuracy. Multiphase flowmeters enhance operational safety by eliminating the need for high-pressure valves and relief lines. Also avoided is storage of substantial volumes of hydrocarbons under potentially unstable conditions in test separators. This is an important issue if well testing takes place in environmentally sensitive areas.
Moreover, there are no fluid-disposal problems associated with multiphase flowmeters, which enhances safety and environmental protection.

Multiphase flowmeters not only eliminate obstacles to greater measurement consistency, reliability and quality, but the measurement process itself essentially becomes a continuous monitoring function. Even when wells are not metered all the time, measurements are typically more frequent and conducted over longer time periods.

Because of this, operators are now obtaining dynamic multiphase flow data. This ability to observe in-line multiphase flows over an extended period in real time affords a step-change improvement in the quantity and quality of data available for production-optimization decisions. The PhaseWatcher unit can interface securely with the Internet to allow monitoring and remote decision-making about well and field operations from anywhere in the world.

Multiphase flowmeter data allow operators to determine whether wells are flowing as expected and whether to schedule remedial workovers based on individual gas, oil and water production rates. If field production is limited by bottlenecks in surface gas- and water-handling facilities, multiphase flowmeters help identify which wells to optimize and which to choke back.

Another significant optimization opportunity involves artificial lift operations, typically where electrical submersible pump (ESP) or gas-injection systems lift fluids to the surface. The Schlumberger LiftPRO service for improving underperforming artificially lifted wells addresses this need, with applications for both permanent measurement and periodic mobile testing. Individual wells can be monitored with multiphase flowmeters, while pump or gas-injection rates are separately monitored by different instrumentation to identify optimal levels.

Optimizing Artificial Lift Operations

Apache Energy Limited used the PhaseWatcher system to optimize artificial lift operations while developing offshore fields in Australia. The Vx system achieved several important objectives, including reduced capital and operating expenditures, and improved production allocation and field management.
A key element of these development efforts was the installation of five unmanned platforms with minimal facilities with no processing capacity, and therefore no topside separation (below). Production from each platform was commingled into a single production flowline, which required accurate measurement of each component fluid in the flowstream. Wells in each field are produced using a common gas lift system.

Web-enabled PhaseWatcher metering at each wellhead allowed Apache to quickly optimize gas lift and production systems, and make immediate operational adjustments in response to changes in choke settings or well productivity.

This eliminated the waiting period for inventory tank flows to stabilize, which is necessary with a test separator.

The optimization process began during well cleanup, so the Vx systems provided continuous production monitoring. Wells reached their target rates within hours of startup. Multiphase monitoring also helped eliminate production interruptions by immediately identifying rising water cuts and slug flows, which enhanced the ability to maintain a stable production process. Rapid identification of dynamic flow factors by the PhaseWatcher meters improved well diagnostics on a continuing basis.

By equipping each flowline with a multiphase meter, Apache eliminated the need for a test separator in the field production systems. At about 815 lbm [370 kg], the PhaseWatcher systems represented nearly a 90% weight savings compared with the alternative of conventional test separators that weigh about 3.5 tons [3,175 kg] each, excluding structural support and utility components.

This weight reduction helped minimize capital expenditures, which were further reduced by limiting the size of platform structures and the extent of piping. Still other capital savings in logistics resulted from this structure minimization. The reduced size, weight and complexity of the topsides for each platform allowed transport to the loadout site by road in a single trip.

Elimination of test separators and minimal multiphase flowmeter maintenance also reduce operating costs. Remote operating capabilities achieved by integrating metering and telemetry systems further minimized the need for intrusive maintenance and personnel visits. Installation of multiphase meter systems played an important role in optimizing gas lift operations and reducing capital and operating expenses, critical objectives in the development of these fields.

Improving the Allocation Process

Regulatory and petroleum industry bodies, including the United States Minerals Management Service (MMS), API, ASME, Norwegian Petroleum Directorate (NPD) and United Kingdom DTI, recognize the role of high-quality data from multiphase meters for well testing and are developing standards for this equipment. As a result, multiphase flowmeter technology is increasingly used for allocating oil and gas production.

New deepwater projects increasingly reflect development strategies with a processing hub that receives production from one or more satellite reservoirs with subsea completions. The number of outlying fields often increases as new discoveries are developed and tied directly or indirectly into the host facility (left).
For these types of developments, allocation is often more complex because ownership may be different for each field or reservoir. The use of hub-based test separation for multiphase flow measurements can become increasingly problematic. First, there is the issue of test separator size and weight, which affects host-facility cost and operating parameters, such as number of platform wellhead slots and operational safety. In addition, expansion of production through satellite tie-ins can cause well-testing demands to exceed test-separator capacity and availability, resulting in less frequent testing of individual wells. Adding separation capacity at a hub is often impractical or impossible. Furthermore, as distance from the wells to a hub increases, metering and measurements with test separators become more difficult.

Stabilization time for test separators increases when test lines are longer. Long subsea test lines can mask well-flow dynamics and contribute to slug flow as water accumulates in low points along their path. As the availability and effectiveness of test-separation facilities decline, so does the quality of data obtained for allocation and production optimization. By contrast, multiphase flowmeter systems eliminate concerns about measurement quality and well-test frequency.

The number of multiphase flowmeters currently deployed in deepwater developments is small, but their effectiveness for improving production allocation creates potential deepwater applications. Multiphase meters can be economically designed into new production facilities as satellite fields are developed. In light of these factors, Vx technology becomes a practical necessity in many offshore developments and essentially an enabling technology for some deepwater projects.

Allocation Measurements at Offshore Hubs

Shell installed the PhaseWatcher system at the Gulf of Mexico Auger complex to overcome test-separation bottlenecks and related allocation difficulties resulting from production growth. Several subsea fields in the area had been tied into the Auger complex for production processing. The Auger field produces from a tension-leg platform (TLP) that began operation in 1994 with the capacity to process 50,000 B/D [7,950 m³/d] of oil and 140 MMcf/D [39.6 million m³/d] of gas from direct-vertical-access (DVA) wells. As development activities progressed, production soon exceeded expectations. The Auger TLP facilities were upgraded and expanded.

In addition, the development of several nearby subsea fields led to a series of tiebacks at the Auger platform in 2000, 2001 and 2004. This transformed the Auger facilities into a production processing and export hub that today handles production from six different fields (above). Through the various tiebacks and expansions, processing capacity more than doubled, and the facilities network became more complex. Because of limited test-separator capacity and the complexity of measurement and allocation needs, well testing began to require production deferment and downtime on some wells. This further increased susceptibility to a system shutdown. With platform space at a premium, adding separation capacity was both difficult and expensive.

By installing four multiphase flowmeters, Shell reduced both flow interruptions and the need to divert and defer production because of well testing. Utilizing Vx technology in a continuous processing environment provided a simpler concept for new subsea production wells. Shell installed six additional PhaseWatcher metering devices on incoming production flowline tiebacks and the DVA production manifold. This allows continuous flow-rate monitoring of subsea flows without the need for individual separators.

The use of multiphase flowmeter technology at the Auger complex led to MMS approval of this technology in combination with NODAL production system analysis for measurement and allocation applications. Multiple metering solved important problems at the Auger hub, enabling Shell to economically meet complex measurement and allocation needs.

Improving Onshore Development Planning

In North Africa, surface facilities for five satellite oilfields are located on 12 onshore well pads spread throughout the development area. Production is allocated among various partners based on the ownership and royalty percentages of each company.

The operator faced difficulties planning for future development because of increasing complications associated with integrating new wells into the existing test-separation system and the high costs of expanding that system. Test-separator operation periodically caused significant pressure losses in the surface gathering system that required the use of field compressors to compensate for these losses. Gas flaring was occasionally necessary to control the resulting pressure increases.

Allocation Measurements at Offshore Hubs

Subsea field-development strategies. Higher-than-anticipated production at the Shell Auger platform in the Gulf of Mexico led to facility expansions, followed by a series of tiebacks from nearby subsea fields that required additional facilities. This transformed the Auger facility into a high-volume processing and export hub. Multiphase flowmeters helped eliminate costly bottlenecks at the Auger hub, enabling Shell to economically meet complex measurement and allocation needs.
The operator installed a series of 12 PhaseWatcher multiphase metering systems, including 52- and 88-mm meter sizes, throughout the field. Seven of the meters were dedicated to fiscal allocation and five to well testing for reservoir management. Key specifications for the new meters included internal data storage, direct linkage to a service computer and compatibility with the existing supervisory control and data acquisition (SCADA) systems. The operator implemented the Vx Fluid ID module with a set of field-specific fluid property data loaded into the meter setup parameters. The deployment of Vx meters simplified field development plans considerably.

The first four PhaseWatcher systems were delivered and commissioned in October 2004. The site-acceptance process incorporated several field tests to evaluate meter performance. To date, the Vx systems have proved highly accurate with demonstrated measurement repeatability. By using these meters, the operator avoids production pumping and flaring. Delivery and commissioning of the remaining Vx multiphase flowmeter systems were slated for the end of 2004 and early 2005.

Streamlining Field Infrastructure

At another North Africa location, several partners hold working interests in three satellite fields, which are being developed and tied back to a centralized host production facility. Installation of PhaseWatcher 52-mm multiphase well production monitoring systems achieved considerable cost savings by eliminating the need for remote separation and metering stations (above).

To address a growing need to improve multiphase flow measurement for production and fiscal allocation, and for field optimization, the operating company commissioned the first PhaseWatcher metering system in August 2003. This meter initially allocated production between the partners in Well 1 during development of the first field. Six months later, the operator brought Well 2 on stream through the same meter. The two wells are about 7.5 miles [12 km] from the main gathering station.

The PhaseWatcher monitoring system saved an estimated US$10 million by eliminating the need for an intermediate field station. Numerous field tests compared meter performance against conventional measurements made by third-party test separators and associated gauge tanks. Results indicated a maximum difference of less than 1.7% with daily oil production rates that ranged from 4,500 to 6,000 B/D [715 to 954 m³/d].

Based on this record, a second, identical PhaseWatcher device was installed in January 2004 to meter two wells in the second field. Performance has been comparable to the initial system. A third PhaseWatcher 52-mm flowmeter was commissioned in November 2004 to monitor production from the third field. Data from this metering system facilitate operation of a well equipped with an intelligent completion that incorporates four downhole flow-control valves. The second well in this field is scheduled to come on stream in 2005 and flow through the same meter.

Mobile Testing Opportunities

Multiphase flowmeters have transformed permanent flow measurement and are also creating new opportunities in mobile and periodic well testing. In many instances, it is uneconomic to retrofit existing production wells with permanent multiphase flowmeters. The PhaseTester mobile system acquires the same high-quality, dynamic data as the permanent PhaseWatcher system. Measurements can be obtained relatively frequently, which is an ideal solution in locations where multiphase flow data were previously obtained infrequently or not at all.

For the first time, there is no overriding logistical or technical obstacle to testing any production well an operator needs to evaluate. Production wells can be tested at any time, but a potentially advantageous time for mobile testing is during the cleanup stage just after drilling. In this way, testing can be integrated into the larger package of well services to establish optimized production from the very beginning.

Additionally, by combining a full complement of downhole production-logging measurements with the surface measurements of a multiphase flowmeter, it is possible for the first time to obtain a complete well diagnosis. The mobile PhaseTester flowmeter plays an essential role in diagnosing the source of water encroachment in commingled producing wells.

---


21. A floating production, storage and offloading (FPSO) system is an offshore facility, typically ship-shaped, that stores crude oil in tanks located within the vessel hull. The oil is periodically offloaded to shuttle tankers or ocean-going barges for transport to receiving and processing facilities. An FPSO can be used to develop and produce marginal reservoirs and fields in deep water or remote from existing pipelines.
Cleanup Well Testing

Total used the PhaseTester system to perform cleanup tests on subsea development wells in the deepwater Girassol field, Angola. The Vx system obtained complete flow data coverage that was more accurate than with a conventional separator (right). Data obtained by multiphase metering were instrumental in helping the operator bring these wells on stream economically at planned levels of production.

This approach ensured that the wells would flow as projected on a sustained basis, enhanced operational efficiency, safety and environmental protection in well-testing operations, and avoided the need for a conventional test separator. In addition, multiphase flow data established a valuable foundation for ongoing field and reservoir management decisions.20

All wells had to reach optimal production levels as they came on stream to ensure that the projected plateau for field production could be attained with the number of planned wells. Additionally, flow-assurance considerations imposed elaborate startup procedures for these wells.

Each well needed to reach an immediate oil production level of 10,000 to 15,000 B/D [1,590 to 2,385 m³/d] to create a slug-free, stabilized flow in the subsea flowlines. At the same time, it was necessary to maintain sand-control integrity through a graduated startup that was not possible from the floating production, storage and offloading (FPSO) system because of equipment constraints and flowline-stability concerns.21

To perform these startups without risk to the wells required execution from the drilling rig. That meant setting strict limits on budgeted rig time to control this considerable expense and identifying any additional rig interventions quickly. After the first two wells were thoroughly tested, all subsequent wells were allotted minimal cleanup time, and performance evaluations had to be completed during the cleanup stage.

The mobile PhaseTester system provided continuous flow-measurement data during well cleanup that were unobtainable with conventional measurements. Dynamic flow-rate data allowed the operator to optimize the cleanup period and avoid unnecessary rig time. The multiphase data confirmed the precise point at which fluids and debris were completely removed and unimpeded production was flowing from all wells.

The multiphase meter data formed the basis for pressure-buildup interpretations that would not have been possible with only test-separator data. These interpretations led to key analyses of well and completion performance. Permeability and skin measurements derived from these pressure-transient data confirmed the selection of sand-control completion designs in a number of wells and facilitated the choice of tool-running procedures.

The data were also valuable for formation-evaluation and dynamic reservoir modeling, which, in turn, increased confidence in well-behavior predictions. In one case, using dynamic multiphase flow measurements to track the estimated transient productivity index (PI) of a horizontal well led to a timely decision to suspend and reenter the well, which had responded poorly to cleanup. After the intervention, the PI improved dramatically to meet expectations, and production logging confirmed that the entire horizontal section was producing.

Complete coverage of cleanup rates made an important contribution to interference testing conducted prior to first oil in key areas of the field. Monitoring production from one well during cleanup of a nearby offset well provided valuable data about pressure and fluid transmissibility through formation layers and geologic faults (see “Reducing Uncertainty with Fault- Seal Analysis,” page 38).

These data led Total to revise the drilling pattern and eliminate one of the proposed development wells. Data from a multiphase flowmeter and downhole gauges also expedited decision-making that led to slickline and coiled-tubing intervention on another well, which opened a partially closed completion valve and allowed the well to flow normally.

The multiphase flowmeter system improved personnel safety by eliminating the test separator with its safety valves and relief lines. In addition, multiphase metering reduced cleanup flow periods and hydrocarbon flaring, which helped protect the environment.

Future Multiphase Technology

As utilization increases, multiphase flowmeters will replace conventional separators in many well-testing applications and eliminate the need for costly, space-consuming facilities at some production sites. Future demand for conventional test separators will increasingly be driven by fluid-sampling requirements. Some sampling, however, particularly for pressure-volume-temperature (PVT) analysis, will be performed with multiphase flowmeters.

Technological innovations are likely to push multiphase flowmeters into higher pressure and temperature environments. This could significantly expand subsea applications for Vx technology, while spawning additional applications onshore in heavy-oil thermal recovery and in natural gas markets.

Another possibility for future growth is intelligent multiphase flowmeter systems that, in addition to providing flow-rate information, diagnose meter health and measurement quality. In all, growing demand and new insights into potential applications for multiphase flowmeters are virtually certain to spur continuing, competitive innovations and enhancements to meet new challenges.

—JP/MET
Ian Atkinson is Engineering Advisor, Schlumberger Cambridge Research (SCR), England, where he works on multiphase flow research. He joined the company in 1984 in Farnborough, England, where he designed and developed single-phase fluid pressure, density and flowmeters. In 1990, he transferred to SCR to work on multiphase flowmetering and later to Schlumberger Riboud Product Center (SRPC) in Paris, where he worked on developing Vx multiphase well testing technology, which later led to PhaseWatcher® fixed multiphase well production monitoring equipment and PhaseTester® portable multiphase periodic well testing equipment. Ian holds a BS degree in physics from the University of Bristol, and a PhD degree in materials science from the University of Warwick, both in England.

Michael Berard, Scientific Advisor for Schlumberger Moscow Research, earned a Droit Grand in physics from Ecole Normale Superieure de Paris, a doctoral degree in physics from Universite Pierre et Marie Curie, Paris, and a PhD degree in molecular physics from University of Paris. He joined the company in 1984 as head of the sensor physics lab at Schlumberger Montrouge Research, France, after spending 13 years in academia. Since then, he has worked as head of the flow measurement and telemetry department at Flopetrol in Melun, France, and at the Schlumberger Riboud Product Center in Clamart, France, where he was head of flow measurement and physics metier manager. Prior to transferring to Moscow, he was scientific advisor at Schlumberger Dhahran Carbonate Research in Saudi Arabia. A prolific author, Michel also holds 6 patents.

Tim Brewer is Senior Lecturer in the Department of Geology, University of Leicester, England, and Director of the University of Leicester Borehole Research Group. Before assuming his current post, he worked as a geochemist for the British Antarctic Survey, as a consultant geologist and geochemist for Midland Earth Science Associates, and as a geology lecturer at the University of Nottingham in England. Tim has a BS degree from Portsmouth Polytechnic in England, and a PhD degree from the University of Nottingham, England, both in geology.

Kip Cerveny is Development Lead, Greater Prudhoe Bay Satellites Team, for BP Alaska, based in Anchorage. Prior to joining the company as a geologist in 2000, he began his career with ARCO as a research geologist in Plano, Texas, USA, and later worked as an Alaska-based geoscience consultant on projects in Alaska, Russia and Kazakhstan. Kip received BA and MS degrees from Dartmouth College, Hanover, New Hampshire, USA; and a PhD degree from the University of Wyoming in Laramie, USA.

Gilbert Consort is Well Testing Marketing Manager for Schlumberger Well Completions and Productivity headquarters in Roxanor, Texas. He is responsible for developing strategies and launching new products and services for well testing, tubing-conveyed perforating and slickline businesses. He joined the company as an electronics engineer in Clamart, France, and subsequently transferred to Flopetrol Engineering in Melun, France, as pressure gauges program manager and later as early production systems pressure measurements engineering manager. After various management positions in France and the USA, he assumed his current position in 2004. He is a co-founder of 3-Phase® Measurements AS, a joint venture between Schlumberger and Framo Engineering AS, to develop Vx technology. Gilbert earned a diploma in electronics engineering from Ecole Superieure d’Informatique-Electronique-Automatique in Paris.

Pierantonio Coperetti, Deputy Drilling and Workover General Manager, Belayim Petroleum Company (Petroleum), an Eni operating company, is based in Cairo. He manages all activity of the company’s drilling and workover rigs. He began his career with Agip as an onshore drilling supervisor and worked in several positions including drilling engineer, drilling manager and well operations manager, before taking his current assignment. Pierantonio has a technical school diploma in mechanics issued in Milan, Italy.

Russell Davies, who is based in Dallas, is the US Operations Manager and consulting geologist for Rock Deformation Research (RDR) USA Inc. He holds a PhD degree in structural geology from Texas A&M University in College Station, and has worked in the oil and gas industry for more than 14 years. At RDR, he manages projects at the regional and prospect scale from basins worldwide, develops and teaches training courses, and participates in applied research. He is also an adjunct professor at the University of Texas in Dallas. Prior to working for RDR, Russell spent three years with Shell Oil Company on exploration and development projects in the Gulf of Mexico before joining the structural geology research group at ARCO. There, he was responsible for research and consulting on structural interpretation and validation, fault and fracture analysis and fault-seal analysis. He worked on fault-related problems in basins throughout the world and recently edited a special issue of the Aapg Bulletin on fault seals.

Graham Dudley is North Sea Technology Manager for BP in Aberdeen. Since joining the company in 1985, he worked from exploration to production as a geologist and later as a team leader and field development manager of E&P business throughout the North Sea, UK, Norway, Alaska, Ukraine and other project locations. Graham earned a BS degree in geology from University of Liverpool, England.

Mohamed El Gamal, Sales Manager for the Schlumberger Libya GeoMarket®, is responsible for introducing new technology including AIM® A-Bit Inclination Measurement tool, VISION® Formation Evaluation and Imaging While Drilling tools and PowerDrive® rotary steerable systems. Previously, he was Drilling and Measurements (D&M) sales manager for the Schlumberger East Africa & East Mediterranean GeoMarket, based in Cairo. He joined the company in 1997 as a sales and applications engineer and later worked as a D&M account manager. He has also worked as a petroleum geologist, pressure evaluation geologist, wellsite geologist and technical sales representative for EXLOG and Milpark throughout the Middle East and the North Sea. Mohamed holds a PhD degree in petroleum geology from Cairo University in Egypt.

Tatsuki Endo, Marketing Manager for Schlumberger KK Technology center, Fukushima, Japan, is responsible for coordination of all client collaboration projects. He joined the company in 1981 as a field engineer in Indonesia. He later worked in Norway and in Brazil as a log analyst before returning to Japan, where he joined the field support staff and managed several projects. Prior to his current position, Tatsuki worked as a project manager of VSP® Versatile Seismic Imager tool development. He received a BS degree in physics from Sophia University in Tokyo.

Paul Jeffrey Fox is Director of Science Operations, US Implementing Organization, Integrated Ocean Drilling Program at Texas A&M University, College Station, and a Professor in the Geology, Geophysics and Oceanography Departments. He has participated in 36 oceanographic expeditions and has served as chief scientist on 26 of those. His primary research interests include investigation of the volcanic and structural processes that create oceanic lithosphere along the mid-oceanic ridge system. A prolific author, Paul has served on advisory committees for the National Science Foundation, University National Oceanographic Laboratory System and other major US oceanic research programs. He obtained a BA degree in geology from Ohio Wesleyan University in Delaware, Ohio, USA; and a PhD degree in marine geology/geophysics from Columbia University in New York City.

Richard Fox, based in Aberdeen, is Lead Geologist, North Sea Portfolio Quality Team for BP. He joined the company in 1991 as a research geologist and helped develop BP’s fault, fracture and stress analysis capabilities. He later worked around the world—Alaska, Gulf of Mexico, Colombia, Venezuela, North Sea, Norway and the Middle East—as part of BP’s structural geology team and as structural network leader. Prior to taking his current post, he worked as subsurface team leader for BP Appraisal and Development. Richard earned a BS degree from Kingston Polytechnic, London; and a PhD degree from University College, Cork, Ireland, both in geology.
Dave Goldberg is a Doherty Senior Scientist at the Lamont-Doherty Earth Observatory of Columbia University in Palisades, New York. He is also director of its Borehole Research Group, which managed logging services for the Ocean Drilling Program and now for the US component of the Integrated Ocean Drilling Program. Dave received BS and MS degrees in marine geophysics from Massachusetts Institute of Technology, Cambridge, USA; and a PhD degree in borehole geophysics from Columbia University, New York City. He has written more than 100 scientific publications on topical research in borehole and marine geophysics.

Shaheddine Kefi, Senior Research Scientist at Schlumberger Cambridge Research, England, is responsible for the development of new formulations in oilfield stimulation and cementing. Since taking this position in 2004, he has researched the development of new oil-base muds and worked on matrix acidizing in mature-field conditions. He joined the company in 1998 as a development engineer for Dowell in Clamart, France, and has also worked in Sugar Land, Texas, on a variety of projects including OilSEEKER® acid diverter, CemCRETE® concretes-based oilwell cementing technology and LiteCRETE® slurry systems. Shaheddine holds MS and PhD degrees from l’Université Paris Sud, Orsay, France; and an MS degree from Ecole Supérieure de Physique et de Chimie Industrielles, Paris, all in chemistry.

Steve Kitteredge is a General Field Engineer for the Houston Offshore District Ocean Drilling Program (ODP) of Schlumberger Well Services, based in Webster, Texas. He is currently working on Expedition 304 of the Mid-Atlantic Ridge. Previously, he was the senior engineer for ODP, responsible for providing logging services and maintaining all logging equipment for Lamont-Doherty Earth Observatory and its projects. Steve has a BS degree in mechanical engineering from the Georgia Institute of Technology, Atlanta, USA.

Rob Knipe is Professor of Structural Geology and Director of Rock Deformation Research (RDR), a research/consultancy spin-out company, at University of Leeds in England. He formed this group of geoscientists in 1992, to provide specialist structural geology services to the oil and mining industries, including new methods to evaluate the impact of fault structures on the flow processes associated with hydrocarbon exploration and production. He has led research into the physical and chemical behavior of rocks during deformation, and has focused on evaluating the dual role of faults as enhanced permeability zones for concentrated fluid migration and as low-permeability barriers to fluid flow. The author of more than 70 research papers, Rob frequently presents keynote lectures at international conferences and has won awards from the Geological Society of London and the AAPG for his research. He is a member of the steering committee for the National Environment Research Council (NERC) Micro to Macro Fluid Flow in Rocks research program and has been chairperson of the AAPG Reservoir Deformation Research Group. Rob was recently awarded the William Smith Medal of the Geological Society of London.

Bob Krantz is a Structural Geologist, Upstream Technology, for ConocoPhillips in Houston. There he focuses on the impact of faults and fractures on reservoir performance, and trap effectiveness and the relationships of small structures to regional deformation. Previously, he worked in Alaska for ConocoPhillips, ARCO Exploration Research, ARCO International Exploration and ARCO Alaska. He holds a BS degree in geology from the University of Utah, Salt Lake City, USA; and MS and PhD degrees in geology from the University of Arizona, Tucson, USA. Bob has also done postdoctoral research at the University of Arizona and at the University of Rennes, France. He is chairman of the AAPG Reservoir Deformation Research Group.

Shin’ichi Kuramoto is the Science Service and Information Service Group Leader at the Japan Agency for Marine-Earth Science and Technology (JAMSTEC). Before this, he worked as a senior researcher for the Geological Survey of Japan in the Advanced Industrial Science and Technology group. Shin’ichi has a PhD degree in marine geology and geophysics from Tokyo University, Japan.

Chris Kuyken, Team Leader, Well Engineering and Well Services Technology for Shell Exploration & Production in Europe, has more than 22 years of experience in oil- and gas-well drilling with Shell. He has worked onshore and offshore in many well engineering positions in Oman, Brunei and, since 1999, in Scotland. He is an energetic proponent of Shell’s Drilling the Limit® philosophy, whereby people, HSE and technology are the keys to success. A European Engineer (EUR ING) registered with European Federation of National Engineering Associations (FEANI) and a Chartered Engineer (C Eng) through the British Engineering Council, Chris earned a BS degree in chemical engineering technology from Hogere Technische School (HTS), The Hague.

Jesse Lee, Schlumberger Program Manager for oilfield chemical products in Sugar Land, Texas, is responsible for ClearFRAC® polymer-free fracturing fluid, coalbed methane fluid projects and high-value polymer fracturing fluids. He joined the company in 1997 as a development engineer for Dowell in Sugar Land, and became senior development engineer for surfactant-based viscoelastic fracturing fluids before taking his current post. Jesse has a BS degree in natural products chemistry and analytical chemistry from National Taiwan University, Taipei; and PhD degrees in inorganic chemistry from Yale University, New Haven, Connecticut; and in polymer/organometallic chemistry from Massachusetts Institute of Technology, Cambridge.

Wayne Longstreet is Drilling Advisor for Dragon Oil Plc., based in Dubai, UAE. He has worked for the company for four years.

Trey Lowe, International Account Manager for Schlumberger Well Completions and Productivity (WCP), is based in Houston. He is responsible for supporting international testing and multiphase metering operations for Houston-based customers. Since joining the company in 1998, Trey has worked in various field management and sales positions including product champion for PhaseWatcher products and services. He holds a BS degree in chemical engineering from Oklahoma State University in Stillwater, USA.
Iain McCourt, Drilling and Engineering Manager for the Schlumberger Caspian GeoMarket in Baku, Azerbaijan, is responsible for all drilling and engineering design work performed for clients in the Caspian Sea area. He joined the company after earning a BS degree in geology from Queen’s University in Belfast, Northern Ireland. He began his career as a mud logger in the North Sea and worked throughout Asia, the Middle East, Australia and New Zealand in positions of varying responsibility including measurements-while-drilling (MWD) and logging-while-drilling (LWD) engineering, directional driller, product champion, field service manager, instructor for drilling engineering and rotary steerable systems and knowledge manager for measurements training. Before taking his current position, Iain was based in Midland, Texas, as operations manager for West Texas.

Allan McDiarmid is Senior Petroleum Engineer for Apache Energy Ltd in Perth, Western Australia, Australia. He was graduated from the University of Strathclyde, Glasgow, Scotland, in 1985, with an MS degree (Hons) in mining and petroleum engineering. Allan has held various reservoir and petroleum engineering positions at Soekor in South Africa, and at Santos and Helix Well Technologies in Australia.

Parviz Mehdizadeh, Consultant, Production Technology Inc., in Scottsdale, Arizona, began his career in 1962 with Conoco Inc. During his 30 years with the company, he worked on technology development programs and production development application projects, including those dealing with the processing and measurement of fluids offshore. He also directed the construction of the Conoco multiphase field test facility in Lafayette, Louisiana, USA. From 1983 to 1996, he worked as a consultant for the Agar Corporation, directing the development, marketing and field installation of multiphase meters for well testing. Since then, as a consultant, he has provided technical advice on selection and specification of multiphase meters to operating companies. He cochaired the Texas A&M University Multiphase Metering Users Roundtable and is currently working with the American Petroleum Institute Committee on Petroleum Measurements on development of specifications for multiphase metering systems. Parviz received a BS degree in physics, an MS degree in metallurgical engineering, and a PhD degree in chemical engineering and material science, all from the University of Oklahoma in Norman.

Stefan Mrzezowski is a Schlumberger Drilling and Measurements DESC® design and evaluation services for clients in-house sales and support engineer for BP in Houston. He coordinates MWD and LWD operations for BP’s Gulf of Mexico (GOM) shelf and deepwater development groups. He joined Schlumberger in 2000 as a field engineer in Youngsville, Louisiana. He sailed as lead LWD engineer on Ocean Drilling Program Legs 204 and 209, drilling for gas hydrates and testing RAB® Resistivity-at-the-Bit logging-while-coring technology. Stefan earned his BS degree in geophysics from the University of Waterloo, Ontario, Canada.

Greg Myers is Manager of Engineering and Technical Services for the Borehole Research Group at the Lamont-Doherty Earth Observatory in Palisades, New York. Since graduating from Rutgers, The State University of New Jersey, New Brunswick, USA, in 1991, he has been involved in many aspects of borehole geophysics such as field service, data analysis, tool research and development, new technology integration and program management. His areas of engineering focus are new measurements, heave compensation, logging while coring, and new core-collection techniques. In addition to his shore-based management and design responsibilities, Greg has participated in many scientific ocean drilling expeditions.

Erik Nelson retired from Schlumberger in 2004 after 37 years of service, and is now an independent consultant in Houston. Before his retirement he was an engineering advisor with Schlumberger in Sugar Land, Texas, where he worked on the development of new chemical products for cementing, fracturing and sand control. Erik has a BS degree in chemistry and an MS degree in geochemistry, both from the Colorado School of Mines in Golden. He is chief editor of the textbook Well Cementing, currently in its third printing.

Angel Nuñez Hernandez is Technical Manager, South Central District for Petróleos de Venezuela SA (PDVSA), located in Barinas, Venezuela. He began his career in 1987 at Corpoven, a PDVSA subsidiary, in the San Tomé District and specialized in production operations, production engineering, chemical stimulations, perforation operations and workover wells. In 1997, Angel was transferred to the Barinas District as reservoir leader and later supervised reservoir development in the production management unit for PDVSA. He holds a BS degree in petroleum engineering from the University of Zulia, Maracaibo, Venezuela.

Tom Olsen, Schlumberger US Land Unconventional Gas Business Development Manager, is based in Denver. He has been with Schlumberger since joining Dowell in 1980. His first assignments involving wellbore stimulation, production enhancement and project engineering took him to postings in the North Sea, the former Soviet Union (CIS), Canada, and, in the USA, Alaska, Texas, Oklahoma and Colorado. He then served as technical manager of production enhancement for Europe and the CIS. After serving as Dowell well production services manager for Europe and the CIS, he moved to Sugar Land, Texas, as marketing manager for the Well Services Product Center. Before taking his current assignment, he managed the Schlumberger Consulting Services Group. Tom has a BS degree in geology from the University of Connecticut in Storrs.

Mehmet Parlar, Business Development Manager Sandface Completions-Fluid Systems with the Schlumberger Sand Control Business Development team in Rosharon, Texas, provides technical and marketing input to sand-control product development and sand control and stimulation fluids support. After receiving BS and PhD degrees in petroleum engineering from the University of Southern California at Los Angeles, he joined Dowell in Tulsa, as a development engineer. From 1996 to 1999, he was a reservoir engineer with the Dowell Sand Control Business Development team in Lafayette, Louisiana. Before his current posting, Mehmet was principal engineer, horizontal completion solutions in Rosharon and well production specialist and technical coordinator in Sugar Land, Texas. Author of many publications, he also holds a BS degree in petroleum engineering from Istanbul Technical University in Turkey.

Barry Persad, based in Sugar Land, Texas, is Product Champion, Motors and Drilling Tools, for Schlumberger Drilling and Measurements. He works as liaison for the introduction of PowerEdge® high-performance drilling motors as well as the implementation of new thin-wall stator technology to other powered rotary steerable drilling tools. After earning a BS degree in environmental science from the University of Guelph, Ontario, Canada, he began his career with Baker Hughes InTeq in Trinidad, West Indies, as a mud-logging specialist. Barry joined Schlumberger Anadrrill of Canada in 1997 as an MWD specialist and also worked as a directional driller and as field service manager, directional drilling, in Canada before taking his current position.

Bruno Pinguest, Technical Advisor Multiphase Flow Metering for Schlumberger International Oilphase DBR, is located in Aberdeen, Scotland, and Bergen, Norway. He is charged with defining and developing the business and the technical transfer of knowledge. He also represents Schlumberger in the Wet Gas Joint Industrial Project with other companies including Saudi Aramco, BP, Shell, Total, BG Group and ConocoPhillips. He began his career with Schlumberger Research & Engineering Flopetrol in England and France, designing a new sensor to measure flow structure in diphasic flows. He transferred to the Schlumberger Riboud Product Center engineering department where he worked on production logging and modeling measurement in multiphase flows. He also worked in Kuwait, Indonesia and Malaysia as a field engineer and in Norway as a new product development manager for 3-Phase Measurements AS. Bruno has a PhD degree (Highest Hons) in fluid mechanics from Ecole Normale Supérieure de Paris, and a postgraduate degree (Hons) in physics of liquids from Université Pierre et Marie Curie, Paris.

Timothy L. Pope, Schlumberger Product Champion for ClearPressure fracturing fluids in Sugar Land, Texas, works with product development teams on testing, product evaluation and field support. He joined the company in Vernal, Utah, after earning a BS degree in petroleum engineering from the University of Wyoming in Laramie. He will also obtain an MS degree in petroleum engineering, pending defense of his thesis, from the University of Wyoming. Prior to taking his current position in 2003, he worked as a DESC engineer at Talisman Energy in Calgary.

Brian Powers is a Senior Completions Engineer responsible for completion design and execution in the Azeri-Chirag-Guneshli (ACG) fields offshore Baku, Azerbaijan, for BP. He joined Amoco in 1982, and subsequently worked for BP after the 1998 merger of the two companies, in various production engineering and completions engineering assignments in the USA, Egypt and the UAE before transferring to Baku in 2001. Brian received a BS degree in geological engineering from South Dakota School of Mines and Technology, Rapid City, USA.
Frank R. Rack is Director, Ocean Drilling Programs (ODP) and Director, Department of Energy/National Energy Technology Laboratory (DOE/NETL) programs at the Joint Oceanographic Institutions (JOI), Inc. based in Washington, DC. He is responsible for program management and oversight of JOI contracts with the US National Science Foundation for preserving the legacy of the ODP and systems integration activities of the US Implementing Organization for the Integrated Ocean Drilling Program. Frank is also responsible for management and oversight of the DOE/NETL projects related to gas hydrates and provides project management for new ventures related to scientific ocean drilling. Frank has participated in more than 12 research cruises as staff scientist, physical properties specialist and marine specialist. He holds a BS degree in natural resources from the University of Rhode Island, Kingston, USA; and a PhD degree in geological/geophysical oceanography from Texas A&M University, College Station.

Jon Rodd, Petroleum Development Manager for Dragon Oil Plc. in Dubai, UAE, oversees all field development, drilling and workover operations, 3D seismic operations, production management and subsurface reservoir geology and geophysics. Before joining Dragon Oil more than 20 years ago, he worked in the UK North Sea, The Netherlands, Syria, Oman, Fiji, Qatar and Pakistan for several major operators. Jon has a BS degree from University of Wales, Swansea, and a PhD degree from the University of Reading, England, both in geology.

Alistair Roy, BP Senior Completion Engineer for the Rhum gas field in the North Sea, is based in Aberdeen. He is responsible for the design and installation of three high-pressure, high-temperature subsea completions in early 2005. Prior to joining BP in 2000, he worked as a petroleum engineer for several companies including Marathon Oil, Monument Oil and British Gas. Alistair obtained a BS degree (Hons) in applied geology from University of Strathclyde, Glasgow, Scotland; and an ME degree in petroleum engineering from Heriot-Watt University in Edinburgh, Scotland.

Mark Sarsam is Head of Reservoir Development and Production for Dragon Oil Plc. in Dubai, UAE. Before joining the company this year, he worked for Shell Oman, Shell Brunei, Fina and Amerada Hess. Mark received an MS degree in petroleum engineering from Imperial College in London.

Gerald Smith is Schlumberger Business Development Manager—Multiphase Well Testing, in Bergen, Norway. He is responsible for the creative development of the multiphase well testing field including metering and reservoir monitoring. He joined Flopetrol Schlumberger in 1979 after earning a BE degree (Hons) in engineering from the University of Bradford, England. Gerald worked throughout Europe and Africa as an engineer, product manager, account manager and business development manager before moving to Houston as marketing manager for wireline and testing production and completion. Prior to taking his current position, he was international account manager, multiphase well testing marketing in Houston.

Farag Soliman, Drilling and Workover General Manager for Belayim Petroleum Company (Petroleb), is based in Cairo. He holds a BS degree in petroleum engineering from Cairo University.

Phil Sullivan, Principal Engineer for Schlumberger in Sugar Land, Texas, is currently developing fluid-loss additives to improve the efficiency of fracturing fluids, and collaborating with researchers at Schlumberger Cambridge Research, England, and at Princeton University, New Jersey. Since joining the company in 1984 as a development engineer for Dowell, he has worked on fluid systems, fiber-assisted transport fluids, ClearFRAC fracturing fluids and coiled tubing cleanout operations. Phil has a BS degree from the University of Virginia, Charlottesville, USA; and MS and PhD degrees, all in mechanical engineering, from Purdue University, West Lafayette, Indiana, USA. A prolific author, he also holds several patents.

Bertrand Theuveny, Production Real-Time Product Champion/Production Development Manager based at Schlumberger Cambridge Research, England, is responsible for the rationalization of production and reservoir collection of answer products and for supporting the Real Time infrastructure. He has been involved in well testing since joining Flopetrol in 1985. He has worked in various wireline and testing positions including testing engineer, field service manager, country manager and testing marketing coordinator in Brazil, Algeria and Libya. He transferred to Norway as support manager for 3-Phase Measurements AS, and before taking his current post in 2002, worked as worldwide business development manager for multiphase well testing. Bertrand earned a BS degree in ocean engineering from Ecole Centrale Paris, and MS degrees in petroleum engineering and geophysics from the University of Alaska in Fairbanks.

Allan Twynam, BP Senior Drilling Engineer (Fluids), is based in Sunbury, England, in the Exploration and Production Technology Group. There he manages the fluid laboratories and is responsible for technical support and development projects in all aspects of reservoir drilling and completion fluids and formation damage mitigation. He joined the drilling and completions branch at the BP Research Centre in 1990 after serving as a wellsite drilling fluid engineer and base manager in Great Yarmouth for BW Mud, UK. He subsequently worked as fluids technical support engineer for BP International operations and managed fluids, cement and waste-management contracts for BP Venezuela. He returned to Sunbury in 1998 to lead technology development projects in drilling waste management. Following the BP-Amoco merger, he managed fluids and formation-damage projects for BP. Allan received a BS degree (Hons) in geology and geography from University College, Cardiff, Wales.

Mike Williams, Schlumberger Global Sales Manager for Drilling and Measurements in Sugar Land, Texas, helps ensure that client partners employ the most cost-effective drilling, well placement and formation evaluation technology. He began his career with Schlumberger in 1987 as a mud logger in the southern North Sea. He has worked as a directional drilling supervisor on many projects for various clients in the North Sea and on the record-breaking extended-reach drilling program at Wytch Farm, and as business development manager for drilling-related services in the UK North Sea. The author of several papers, Mike has a BS degree (Hons) in earth sciences from the University of Birmingham, England.

Kerry J. Williamson, Senior Process Engineer for Shell Exploration and Production Company (SEPCo) EP Americas region, is based in New Orleans, where he provides process-engineering support to the Shell Gulf of Mexico (GOM) assets and projects. He joined the company in New Zealand in 1997 and has worked in the GOM since 2001. He was the facilities engineer for the Auger tension leg platform where he managed the installation of multiphase measurement for well testing of onboard subsea flowlines using Vx multiphase well testing technology. Kerry obtained a BS degree in engineering from the University of Auckland, New Zealand.

Allan Wilson is a BP Senior Completions Engineer, based in Aberdeen, where he works in the Deepwater Production Unit, covering the Foinaven, Schiehallion and Loyal fields, West of Shetlands. He is responsible for completions delivery in those areas and is the technical authority for completion issues. Allan joined BP in 2000 after working five years for Wellserv plc in various positions from engineer to project manager. Allan earned a BE degree (Hons) in mechanical engineering from The Robert Gordon University, Aberdeen.

An asterisk (*) is used to denote a mark of Schlumberger. Drilling the Limit is a trademark of Shell.
Carbone Reservoirs. For all their hydrocarbon wealth, carbonate reservoirs are notoriously difficult to produce. To recover these hydrocarbons as safely and efficiently as possible, scientists and engineers perform formation evaluation, reservoir characterization and completion optimization at the wellbore scale. At the reservoir scale, operating companies strive to optimize production and the placement of new wells. Field examples will demonstrate how new technology enhances carbonate evaluation; simpler rock classification schemes facilitate reliable interpretations of pore-size distributions and serve as useful frameworks for reservoir-management decisions.

Subsea Production Assurance. Subsea completions are often tied back to production facilities through miles of flowline and riser. Temperature, pressure and chemistry of the produced fluids must be regulated in these subsea production lines to prevent formation of deposits that could impede flow between the reservoir and the host facility. This article describes the roles that fluid testing, flow boosting and monitoring systems play in managing the flow of oil, gas and water from one end of the production system to the other.

Managing Gas-Condensate Reservoirs. A retrograde gas-condensate fluid drops out liquid hydrocarbon when the fluid drops below its dewpoint pressure. The condensation can occur in the formation and create a condensate bank that decreases production; or it can happen in the wellbore, loading up the well with the heavier phase and often requiring intervention to maintain production. This article describes efforts to maintain well productivity despite declining reservoir pressure.

NEW BOOKS

Corrosion and Protection
Einar Bardal
Springer-Verlag
175 Fifth Avenue
New York, New York 10010 USA
2004. 336 pages. $89.95
ISBN 1-85233-758-3

Intended as a guide for mechanical, marine and civil engineering students and also as a reference for practicing engineers, the book combines a practical description of corrosion problems with a theoretical explanation of the various types and forms of corrosion. Exercises for each of the 10 chapters emphasize the relationship between practical problems and basic scientific principles.

Contents:
• Introduction
• Wet Corrosion: Characteristics, Prevention and Corrosion Rate
• Thermodynamics—Equilibrium Potentials
• Electrode Kinetics
• Passivity
• Corrosion Types with Different Cathodic Reactions
• Different Forms of Corrosion Classified on the Basis of Appearance
• Corrosion in Different Environments
• Corrosion Testing, Monitoring and Inspection
• Corrosion Prevention
• Index

Although the book was originally written in Norwegian, the style is direct and the explanations easily followed. The theoretical material is not overwhelming but is adequate for a strong foundation. Many clear and effective figures and diagrams are included.

The book is recommended for introductory courses in corrosion and as a practical reference for practicing engineers and technicians who want a clear description of basic principles and applications.

Darby R. Choice 41, no.10 (June 2004): 1911-1912.

Development of Petroleum Reservoirs
József Pópáy
Akadémiai Kiadó
P.O. Box 245
H-1519 Budapest, Hungary
(Also available from International Specialized Book Services, Inc. 920 NE 58th Avenue Suite 300 Portland, Oregon 97213 USA) 2003. 939 pages. $89.00
ISBN 693-05-7927-8

This book deals with both conventional and enhanced recovery methods of crude oil and natural gas, including discussion of geological principles and such topics as reservoir classification, numerical simulation and temperature management. Also featured are underground gas-storage processes in porous rocks, reservoir-model construction, and planning and analysis methods.

Contents:
• Basic Geology for Petroleum Recovery
• Conventional Recovery Processes: Methods of Planning and Analysis
• Enhanced Petroleum Recovery Processes
• Classification of Petroleum Reserves and Resources
• Index

The author does provide a valuable service in bringing together literature from Western, Eastern European (mainly Hungarian), Russian, and other former Soviet Union sources. Reservoir engineering is not my field, but this book does seem to provide a good reference book to many aspects of reservoir engineering. Many simple relevant equations can be found within.

Most geophysicists would get little use out of this book. Someone working heavily in development geology/geophysics or reservoir modeling may find it useful as a reference.


Power to the People: How the Coming Energy Revolution Will Transform an Industry, Change Our Lives and Maybe Even Save the Planet
Vijay V. Vaitheeswaran
Farrar, Straus and Giroux
19 Union Square West
New York, New York 10003 USA
2003. 358 pages. $25.00

To produce his assessment of the economic, political and technological forces that are reshaping the world’s management of energy resources, Vaitheeswaran, an energy reporter for The Economist, interviewed executives of oil and utility companies, regulators, chiefs of environmental groups and advocates of alternative fuels.

Contents:
• Introduction
• Market Forces: The Invisible Hand
• Ascendant: Micropower—Thomas Edison’s Dream Revived; Exxon vs. Enron—or, The Sleeping Giants Awaken; Why California Went B.A.N.A.N.A.s; Oil—The Most Dangerous Addiction
• Environmental Pressures: The Green Dilemma: Welcome to Global Weirding; Clearing the Air; Adam Smith Meets Rachel Carson
• Energy Technology: Bigger than the Internet: The Future of Fuel Cells; Rocket Science Saves the Oil Industry; A Renaissance for Nuclear Power? Micropower Meets Village Power
• Epilogue: The Future’s a Gas
• Notes, Bibliography, Index

Vaitheeswaran (energy and environment correspondent. The Economist) has prepared the best review of the world’s energy situation that this reviewer has read.

Comer JC. Choice 41, no. 9 (May 2004): 1696.

The book is entertaining (another quality that is unusual in a book about energy policy).

Blair PD. American Scientist 92, no. 3 (May-June 2004): 271.
Fuzzy Logic in Geology
Robert V. Demicco and George J. Klir (eds)
Academic Press
525 B Street, Suite 1900
San Diego, California 92101 USA
2004. 347 pages. $95.00
ISBN 0-12-415146-9

Aimed at geoscientists, this book outlines the role of fuzzy logic, a system of concepts and methods for exploring modes of reasoning that are approximate rather than exact. The authors introduce the use of fuzzy set theory with individual chapters on topics relevant to earth scientists: sediment modeling, fracture detection, reservoir characterization, clustering in geophysical data analysis, groundwater movement and time series analysis.

Contents:
- Introduction
- Fuzzy Logic: A Specialized Tutorial
- Fuzzy Logic and Earth Science: An Overview
- Fuzzy Logic in Geological Sciences: A Literature Review
- Applications of Fuzzy Logic to Stratigraphic Modeling
- Fuzzy Logic in Hydrology and Water Resources
- Formal Concept Analysis in Geology
- Fuzzy Logic and Earthquake Research
- Fuzzy Transform: Application to the Reef Growth Problem
- Ancient Sea Level Estimation
- Acknowledgments, Index

The book serves as an excellent starting point for any geophysicist interested in learning about soft computing techniques, and applying them to seismic processing and interpretation. I soon hope to see some applications of this technology in our industry, and be able to review a volume on fuzzy logic in geophysics in the not too distant future.

McCormack M: The Leading Edge 23, no. 6 (June 2004): 606-607.

Petroleum Geoscience
Jon Gluyas and Richard Swarbrick
Blackwell Publishing Company
350 Main Street
Malden, Massachusetts 02148 USA
2004. 288 pages. $83.95

Intended as a comprehensive introduction to the application of geology and geophysics to the search for, and production of, oil and gas, this textbook is structured to reflect the sequential and cyclical processes of exploration, appraisal, development and production. Case histories of wells drilled around the world and examples from petroleum systems ranging in age from late Precambrian to Pliocene are provided at the end of each chapter.

Contents:
- Introduction
- Tools
- Frontier Exploration
- Exploration and Exploitation
- Appraisal
- Development and Production
- References, Index

A very nice feature of the book is the extensive case histories—including more than 15 at the end of each chapter.... The book is well illustrated, with over 300 illustrations. The quality of reproduction of many of the figures and half-tone photographs is really good... Nevertheless, the book is warmly recommended, at a very competitive price, to its target market—and, indeed, to all petroleum geoscientists.


The Travels and Adventures of Serendipity: A Study in Sociological Semantics and the Sociology of Science
Robert K. Merton and Elinor Barber
Princeton University Press
41 William Street
Princeton, New Jersey 08540 USA
2004. 328 pages. $29.95
ISBN 0-691-11754-3

The book traces the history of the word serendipity—that happy combination of knowledge and luck by which a discovery is made that is not quite accidental. Tracing the word from its mid-18th century coinage into the 20th century, the authors chronicle much of what is now the natural and social sciences. The book also presents the argument against the rhetoric of pure science that defines discovery as only the result of rigid research planning.

Contents:
- Introduction
- The Origins of Serendipity
- Early Diffusion of Serendipity
- Accidental Discovery in Science: Victorian Opinion
- Stock Responses to Serendipity
- The Qualities of Serendipity
- Dictionaries and “Serendipity”
- The Social History of Serendipity
- Moral Implications of Serendipity
- The Diverse Significance of Serendipity in Science
- Serendipity as Ideology and Politics of Science
- A Note on Serendipity as a Political Metaphor
- A Note on Serendipity in the Humanities
- Afterword, References, Index

...and this biography of serendipity is a humane, learned and very wise book.

It is a pity that we had to wait so long for it, since [the book is] Merton’s greatest achievement.


The Isaac Newton School of Driving: Physics and Your Car
Barry Parker
The Johns Hopkins University Press
2715 North Charles Street
Baltimore, Maryland 21218 USA
2003. 250 pages. $26.95
ISBN 0-8018-7417-3

Written by a physics professor, the book describes nearly every aspect of physics in terms of its relationship to automobiles—from basic mechanics including velocity, acceleration, momentum and torque, to more advanced concepts such as heat transfer and efficiency, electricity and magnetism, and aerodynamics. The generously illustrated book is intended to appeal to both car enthusiasts and aficionados of science.

Contents:
- Introduction
- The Open Road: Basic Physics of Driving
- All Revved Up: The Internal Combustion Engine
- When Sparks Fly: The Electrical System
- Give ’Em a Brake: Slowing Down
- Springs and Gears: The Suspension System and the Transmission
- What a Drag: Aerodynamic Design
- A Crash Course: The Physics of Collisions
- Checkered Flags: The Physics of Auto Racing
- Rush Hour: Traffic and Chaos
- The Road Ahead: Cars of the Future
- Epilogue: The Final Flag
- Bibliography, Index

The book has a definite flair and keeps the reader interested. Despite a few minor flaws, the book should have broad appeal and could provide a good resource for those who teach elementary physics.
