Advances in Well and Reservoir Surveillance

Engineers are now connected to their reservoirs. Real-time measurements from permanent-monitoring sensors help them identify, diagnose and act to mitigate production problems. Constant surveillance also facilitates detailed analysis for production optimization and improves the accuracy of production allocation.

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Action is a response to knowledge; knowledge is derived from information. Accurate and timely information is essential to monitor and control complex and crucial operations successfully. Today's reservoir and production engineers have the challenging task of managing oil and gas assets. To do so requires a broad knowledge of the reservoir, advance project planning, fit-for-purpose integrated technologies and real-time access to relevant data. It is necessary to make the transition from large volumes of acquired data to those suitable for exploration and production (E&P) software tools. Proper data-validation and interpretation tools are then needed to analyze the data to direct action, if required. Modern hydrocarbon exploitation techniques, such as producing from multilateral wells or subsea installations, have changed the way the industry deals with well maintenance and production and recovery optimization. These sophisticated production scenarios, coupled with demanding economic hurdles, have made advanced well-completion systems more vital than ever before (next page).

Operating companies derive remarkable benefits from the steady progression of advanced completion technologies. Operators and service providers are working together to overcome challenges and to ensure that total production and reservoir management become a reality. To achieve the primary goal—improved recovery and accelerated production at a lower cost—the industry is developing permanent sensors and exploiting the uses of real-time data. This article highlights advances in continuous-surveillance technology, including downhole and surface production- and reservoir-monitoring techniques. Case studies illustrate the impact that permanent sensors and combined technologies have on the industry's production- and recovery-optimization efforts.

Evolution Through Revolution

Today's evolution in advanced completion technologies is all about economics: producing and managing fields more effectively and efficiently. It's about learning more, sooner, about the reservoir and its production behavior, facilitating faster and improved decision-making that enhances hydrocarbon production and recovery.

Commonly, information is acquired downhole by making occasional measurements using techniques such as production logging and well testing. This is joined by the industry standard permanent single-point pressure measurement. These methods are often reactive to an event or scheduled according to workover and well-intervention plans. Timing may not be optimal for

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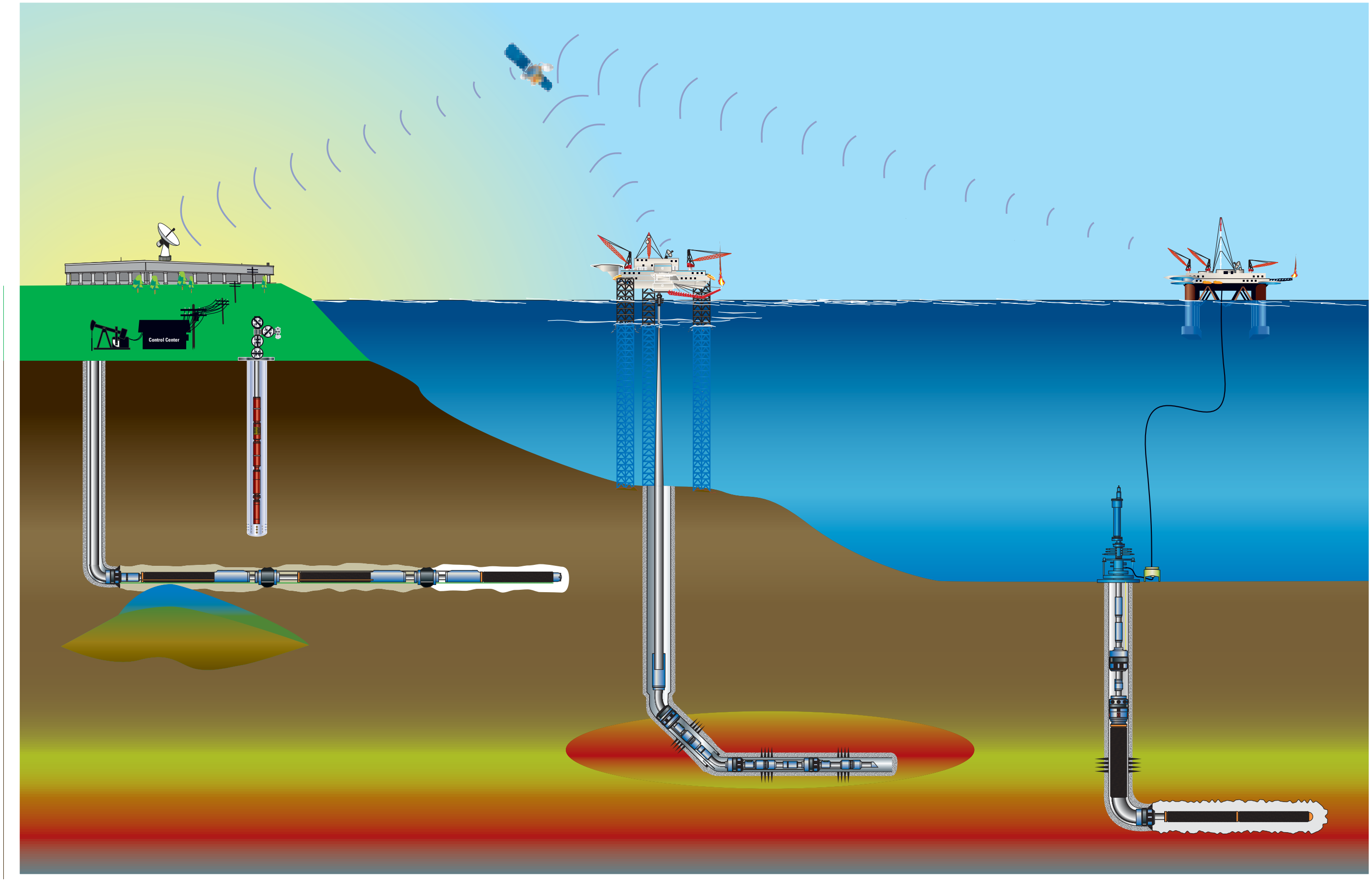


^ Advanced completion technologies. The need for advanced completion technologies continues to grow with the complexity of exploitation techniques. Longer horizontal wells *(left)*, multilateral wells and deepwater wells with subsea installations *(right)* have prompted the industry to carefully examine the deployment of permanent monitoring systems and the control that real-time information offers.

diagnosing production problems or reservoir changes. Occasional measurements in wells rarely detect production events as they occur and often fail to describe production behavior, or even define a trend, because of the low frequency at which they are collected. In addition, intervention costs and the loss of production revenues associated with periodic surveillance techniques can be extremely high and are especially daunting in operations involving subsea installations. Here, the simplest intervention can cost $2 million, and a single-well subsea intervention for wireline logging in more than 1500-m [4920-ft] water depth commonly exceeds $5 million. In subsea wells, production problems are often unidentified and unresolved because the risks and costs of intervention are too high. The number of subsea wells is expected to grow steadily in the coming years, prompting an industry search for solutions on multiple fronts.

Permanently installed sensors deliver data continuously or on-demand, greatly reducing or eliminating intervention costs to acquire data. Usually installed during the well-completion stage, permanent sensors can provide reservoir and completion experts with continuous data immediately—including pressure, both single-point and distributed temperature, flow rate, fluid phase and downhole-pump performance data. For decades, companies have collected daily surface-flow and pressure measurements that describe well-production behavior. However, these measurements do not adequately reflect trends and events in the reservoir, particularly in multizone or multilateral wells and in complex environments involving gas.

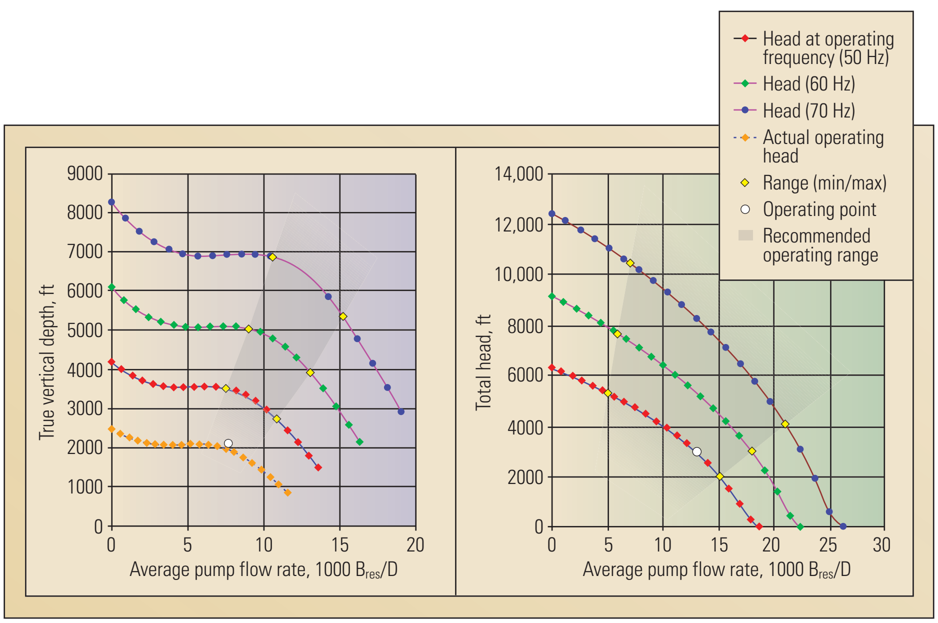
Critical events that occur during production can be planned—such as the initial flow period or shut-in of a well or zone—or they can be unexpected—such as premature water, gas or injection-fluid breakthrough. Detailed monitoring and interpretation of these events require connectivity and innovative methods to handle data streaming from permanent sensors. Asset teams can observe and interpret production disturbances in real time, enabling them to make informed and timely decisions. Action can take many forms—adjusting production rates at surface or downhole, or scheduling interventions or workovers. Early in field development, continuous surveillance also can provide valuable information to guide plans for subsequent wells, including target locations, completion methods and intervention plans.

Just as advances in drilling technology during the 1990s revolutionized the way exploration and production (E&P) companies contact oil and gas reserves, the evolution of completion technologies will enable companies to actively manage their producing reservoirs and fields. More and more downhole measurements are collected from an increasing number of sensor types. In many areas, permanent downhole measurements—such as pressure and temperature—now are considered routine and reliable (see "Reliability Testing," *page 18*).[1] New types of sensors are being installed, and new technologies currently being tested will be available soon.

Production Challenges in the Wellbore

Asset teams face a variety of production problems spanning a wide range of temporal and spatial scales. Downhole equipment failures often occur over a relatively short period and directly affect wellbore or near-wellbore regions. Complications in artificial-lift systems cause reduced or deferred production. The failure of a downhole pump affects production immediately, but the impact of inefficient pump operation is less obvious. Continuous monitoring of the environment in and around pumps will significantly improve production through an ongoing optimization of artificial-lift operations.

In October 2001, Schlumberger and Phoenix combined their expertise to provide comprehensive artificial-lift surveillance. Systems such as the Schlumberger PumpWatcher permanent downhole pressure and temperature gauge and the Phoenix MultiSensor well monitoring unit for submersible pump completions provide crucial data on the health and efficiency of pump operations. Several pump parameters are measured, including pump-motor temperature, vibration and current leakage. These measurements, along with reservoir and production data, enable production and completion experts, such as those at the Schlumberger Artificial Lift Center of Excellence in Inverurie, Scotland, to determine optimal system operation. For example, optimal pump operation can increase production, decrease water cut, ensure longer pump life and minimize intervention and pump-replacement costs (below).[2] Intake temperature, intake pressure and discharge pressure are also monitored to ensure that the drawdown pressure and fluid levels are within the designed operating conditions for the well. Previous methods—fluid shots and pressure-transfer systems—monitor only the fluid level above the pump intake and are significantly less accurate and less reliable. Monitoring the performance and effects of artificial-lift devices has helped operators optimize production on a field-wide basis.



^ Monitoring the performance of electrical submersible pumps. A snapshot of an electrical submersible pump's vital statistics, including intake and discharge temperatures and pressures, helps engineers optimize pump operation. At a given drawdown pressure, an examination of pump flow rates versus pump head at various operating frequencies defines the optimal pump operating range. In this case, pump performance at a 50-Hz operating frequency had degraded 41%, resulting in a loss of pump efficiency, and consequently, a loss of production *(left)*. This well's potential fluid-production rate was determined to be 12,850 B/D [2040 m^3/d], suggesting the pump was undersized to deliver the optimal rate. The Schlumberger Artificial Lift Center of Excellence recommended that the existing pump be replaced with a larger electrical submersible pump, resulting in about 5250 B/D [835 m^3/d] additional fluid flow, or 366 B/D [58 m^3/d] of added oil production *(right)*.

Not Just a Phase

Acquisition of standard surface flow rate and pressure data has been common practice for decades and is still used for assessing the total production of wells and fields, primarily for fiscal reasons. However, flow data obtained at the surface also enable an assessment of well performance. The fraction of each produced fluid phase is needed to accurately evaluate well performance during well tests. On exploration wells, test separators often are used to separate, meter and sample the well effluent. Test separators are extremely bulky, a distinct drawback in offshore environments where both topside and subsea space are limited. They are expensive to install and operate, and, if permanent, additional costs can be incurred with the installation and maintenance of associated equipment, such as test lines and manifolds. Even though test separators have been the industry standard for production allocation and well testing, their performance is often compromised when crude foams, when oil-water emulsions are produced or when slugging occurs.[3] In addition, conventional test separators often have limited capacity to process produced fluids, limiting the maximum flow rate and potentially impacting production revenues. Both surface and downhole multiphase flowmeters overcome many of these limitations, so their use has been increasing.

Schlumberger and Framo Engineering developed permanent and mobile surface systems—PhaseWatcher fixed multiphase well production monitoring equipment and PhaseTester portable multiphase periodic well-testing equipment, respectively—that utilize the Vx multiphase well testing technology to monitor wells in difficult environments.[4] These systems combine a venturi mass-flow measurement with a dual-energy gamma ray attenuation measurement. Pressure and temperature measurements indicate the pressure-volume-temperature (PVT) relationship within the flowline. These measurements provide accurate and continuous phase data, enabling the three phase fractions—oil, gas and water—to be calculated at 22-ms intervals (next page, top). The Vx systems are easier to install, safer and more efficient than test separators. In addition, Vx systems require no phase separation or upstream flow conditioning, can accommodate longer testing requirements and take up less space. Vx technology has been shown to be more accurate than test separators because measurements are made continuously at a high sample rate, even allowing accurate measurements of slugging flow to be made.

The use of a venturi facilitates measuring mass flow rates because of its simplicity, phase-mixing efficiency and the fact that the pressure drop across a venturi can be converted to a mass flow rate, given that the fluid density is measured optimally (below right). Single-phase or well-mixed multiphase flow through a venturi can be described most simply as:

$$Q_{total} = K\,(\Delta p/\rho_{mix})^{1/2}$$

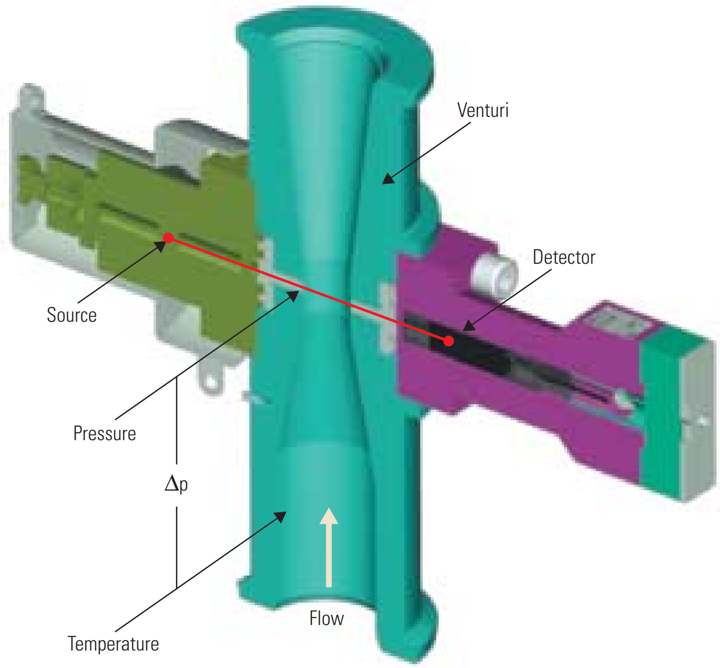
where Q_{total} is the total volumetric flow, K is the proportionality constant for the specific venturi, Δp is the pressure difference measured from either two absolute pressure gauges or a differential pressure gauge, and ρ_{mix} is the measured density of the fluid or combination of fluids.

When the phases are not well mixed, such as in stratified flow in horizontal wells, slip between the phases can be significant and leads to errors in phase flow-rate measurements. In horizontal well production logging, many holdup and phase-velocity measurements are combined with a slip model to avoid these errors, but this modeling is complicated in a permanent environment. However, in well-mixed flows, slip between the phases is small and the flow computation of a given phase can be expressed generally as:

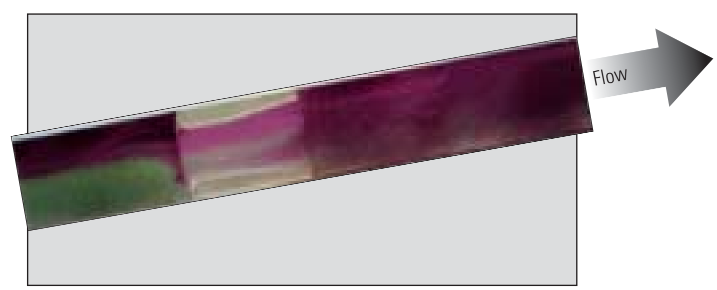
$$Q_f = \alpha_f Q_{total}$$

where Q_f is the volumetric flow rate of a given fluid phase and is the holdup of that given fluid phase. The holdup, or phase fraction, α_f, is equal to the phase cut when fluids are well mixed.

In the PhaseTester and PhaseWatcher multiphase surface meters, ρ_{mix} and α_f are derived from gamma ray attenuation measurements. The Litho-Density logging tool makes similar measurements downhole to determine formation density and lithology. In surface flowmeters, phase fraction is determined by measuring the attenuation of low- and high-energy gamma rays, produced from a small radioactive source, that interact with the producing fluids through Compton scattering. The attenuation of the gamma rays is measured by a scintillation detector and is proportional to the electron density of the fluid, or combined fluids, within the pipe.[5] The fluid's electron density is closely related to its density. In a two-phase system, with known fluid densities, the phase fractions can be determined, given that the total must sum to one. However, for surface multiphase flowmeters to yield three-phase information, another measurement is required. Much like determining lithology from a three-mineral model triangle using Litho-Density



^ Cross section of the multiphase flowmeter. The major components of a multiphase flowmeter include a venturi, which provides mixing so that an accurate total mass flow-rate measurement can be achieved using temperature and differential-pressure sensors. A dual-energy gamma ray detector and radioactive source are used to measure the oil, water and gas fractions.



^ Venturi in action. Flow simulators allow scientists to characterize the nature of multiphase fluid flow at various flow rates and well deviations. To the left of the venturi, laminar flow can be observed. Once the fluids have passed through the venturi, the fluids become well mixed *(right)*, enabling an accurate measurement of mixed fluid density using a source-detector configuration.

1. Eck J, Ewherido U, Mohammed J, Ogunlowo R, Ford J, Fry L, Hiron S, Osugo L, Simonian S, Oyewole T and Veneruso T: "Downhole Monitoring: The Story So Far," *Oilfield Review* 11, no. 4 (Winter 1999/2000): 20–33.
2. Williams AJ, Cudmore J and Beattie S: "ESP Monitoring—Where's Your Speedometer?," presented at the 7th European Electric Submersible Pump Roundtable, Society of Petroleum Engineers, Aberdeen, Scotland, February 6–7, 2002.

   Fleshman R, Harryson and Lekic HO: "Artificial Lift for High-Volume Production," *Oilfield Review* 11, no. 1 (Spring 1999): 49–63.
3. Kimminau S and Cosad C: "The Impact of Permanent, Downhole, Multiphase Flow Metering," presented at the 17th World Petroleum Congress, Rio de Janeiro, Brazil, September 1–5, 2002.

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   Atkinson I, Berard M, Hanssen BV and Ségéral G: "New Generation Multiphase Flowmeters from Schlumberger and Framo Engineering AS.," presented at the 17th International North Sea Flow Measurement Workshop, Oslo, Norway, October 25–28, 1999.
4. Oyewole AA: "Testing Conventionally Untestable High-Flow-Rate Wells with a Dual Energy Venturi Flowmeter," paper SPE 77406, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, September 29–October 2, 2002.
5. Compton scattering refers to a gamma ray interaction in which the gamma ray collides with an electron, transferring part of its energy to the electron, while itself being scattered at a reduced energy. When a beam of gamma rays traverses a material, the total attenuation due to Compton scattering depends on the electron density of the material. As density increases, there is more attenuation, forming the basis for the density log and the densitometer oilfield measurements.

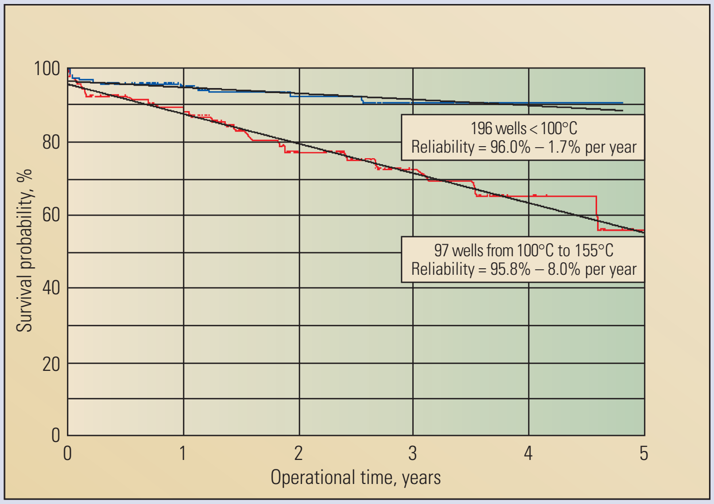
Reliability Testing

A structured approach to reliability testing is extremely important in the development of new permanent completion technologies. The unquestioned reliability of sensors and flow-control devices is the foundation on which this technology must be built. Schlumberger qualification testing (QT) is essential to that effort.[1] The need for an innovative and structured approach to QT becomes apparent when the technical and market challenges are considered. Reliability testing in the field is not ideal, because the cost of equipment failure in a producing well can be great. While the malfunction of a downhole sensor means loss of data, faltering downhole flow-control devices can negatively impact well performance, production revenues, operating costs, the environment and personnel safety. Analyzing equipment failure in the field is difficult because access to the failed components is limited—the devices are installed permanently and retrieval costs are high. Conversely, unnecessary tests conducted in the laboratory or test facility increase development costs, cause delays to the market and ultimately make the technology more expensive to deploy.

The QT approach first identifies the essential tests that satisfy the equipment's application requirements, including all factors involved in transporting, storing, installing and operating the equipment. The operating environment is examined in detail, for example temperature, pressure, flow rates, sand erosion, wellbore-fluid chemistry and environmental cycles. This means working closely with operating companies to ensure that all factors are considered when designing the testing program (above right). Qualification testing is divided into three basic categories:

- Environmental qualification tests verify that equipment conforms to its design specifications across a wide range of operating conditions, including applications that may not have been obvious from the outset.
- Failure-mode tests invoke equipment failure to define the extreme operating condition limits, confirm failure analysis and provide valuable data for accelerated testing.

^ **Reliability testing at completion test facilities. Testing facilities like this one at the Sugar Land Product Center in Texas, USA, help advance permanently installed completion equipment to new levels of reliability. This facility can test tools up to 10 m [33 ft] in length, subjecting them to 30,000 psi [200 MPa] and 500°F [260°C].**



^ **Using survival functions to tell the story. The survival functions for two different temperature ranges for 293 quartz pressure gauges. The blue data represent 196 wells operating below 100°C [212°F], and the red data represent 97 wells operating in temperatures from 100°C to 155°C [311°F]. At the lower temperature operating environment, the reliability is 96% with a 1.7% reduction per year of operation. At the higher range of operating temperature, the reliability is 95.8% with a reduction of 8% per year.**

- Accelerated tests ensure the equipment will perform properly over its intended design life. Accelerated stress tests are conducted beyond the specification limits, while accelerated life tests are within the specifications but at an increased operating frequency to match the cumulative equipment use throughout its design life.

It is common to track mean time between failures (MTBF) when assessing reliability, but studies have shown that the technique is not always valid. Commonly, MTBF rates are valid only when failure rates remain constant over the analysis period. Better analyses have resulted through the examination of survival probabilities.[2] Schlumberger uses survival curves because these curves are based on actual field history and allow the MTBF rate to be estimated under a given set of conditions (previous page, bottom).

With these techniques, along with fault-tree, cause-and-effect, root-cause analyses and other methods, the testing and analysis of monitoring and control device reliability are keeping pace with the advances in technology. Given the important demands placed on permanent downhole equipment, reliability testing is inextricably linked with the development, manufacturing and deployment of permanent monitoring and control systems.

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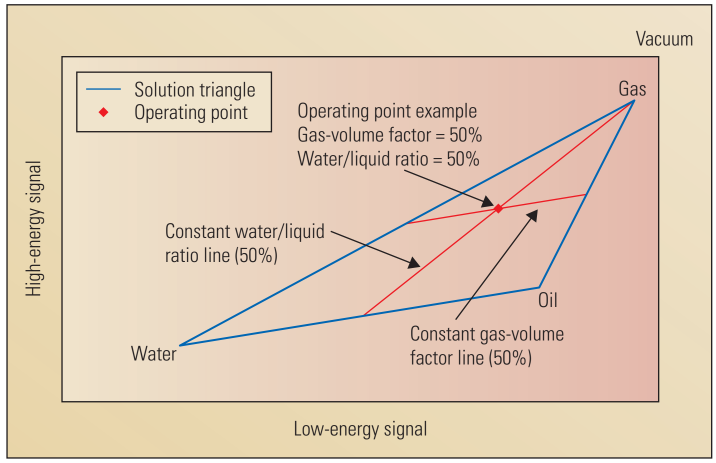
2. van Gisbergen SJCHM and Vandeweijer BV: "Reliability Analysis of Permanent Downhole Monitoring Systems," paper OTC 10945, presented at the Offshore Technology Conference, Houston, Texas, USA, May 3–6, 1999.



^ Determining relative phase percentages, or holdup. Gamma ray attenuations are plotted from both the high- and low-energy windows within a triangle defined by 100% water, 100% oil and 100% gas points. The phase fractions are determined by drawing a line through the measured point (red) and parallel to the line defined by the 100% water and the 100% oil points and then drawing a line from the 100% gas point through the measured point. In this example, the multiphase fluid is 50% gas, 25% water and 25% oil.

photoelectric effect (PE) data, the PE is measured in surface Vx flowmeters to determine the three phase fractions (above).[6]

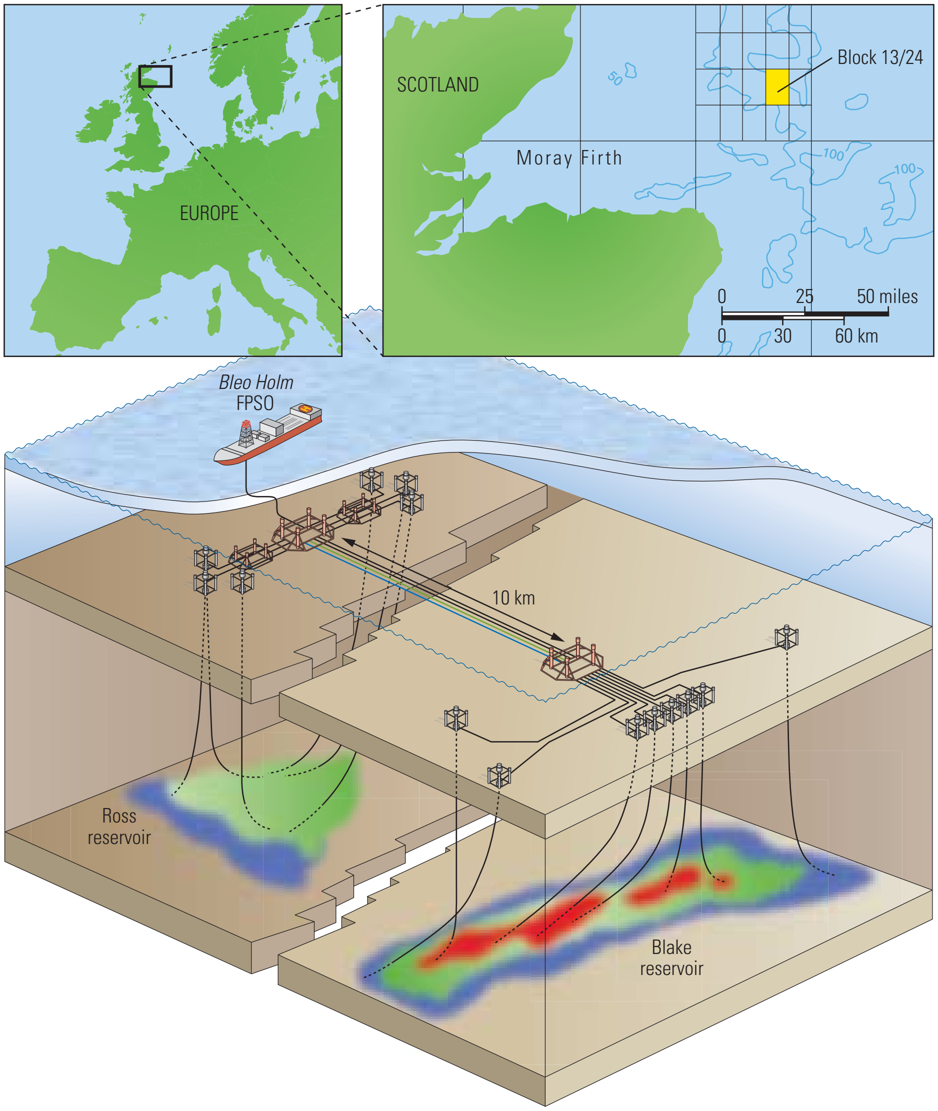
Hundreds of multiphase data sets have been analyzed to optimize well-test design when using new multiphase flowmeter technology. Ideally, properties of each phase, including density, attenuation and PVT properties, should be measured. Significantly, however, the sensitivity of the Vx measurements to input parameter accuracy is robust even if the individual phase properties are not well known. Surface multiphase flowmeters performed extremely well when compared with test-separator results on over 160 different well tests under various production test conditions.[7]

This technology also helps production engineers optimize artificial-lift well performance. The Schlumberger PowerLift artificial lift optimization service uses simultaneous acquisition of downhole pressure and temperature data and PhaseTester multiphase surface flowmeter data to provide real-time analysis and the construction of comprehensive artificial-lift solutions. The PowerLift solution involves expertise in system design, system fine-tuning and the selection of the most appropriate technology for long-term artificial-lift optimization.

Subsea Multiphase Flowmeters in the North Sea

The Blake field, operated by BG, is a northern North Sea subsea development of six producing and two water-injection wells tied back through a 10-km [6.2-mile] subsea manifold and pipeline infrastructure to the *Bleo Holm* floating production storage and offloading (FPSO) vessel. The subsea nature of the development significantly increases the complexity of well testing, production allocation and general field-management

6. The photoelectric effect involves gamma ray interactions in which the gamma ray is fully absorbed by a bound electron. If the energy transferred exceeds the binding energy to the atom, the electron will be ejected. Normally, the ejected electron will be replaced within the material, and a characteristic X-ray will be emitted with an energy that is dependent on the atomic number of the material. The highest probability for this effect occurs at low gamma ray energy and in a material of high atomic number.
7. Theuveny BC, Ségéral G and Pinguet B: "Multiphase Flowmeters in Well Testing Applications," paper SPE 71475, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, September 30–October 3, 2001.



^ The BG Blake field. Located in the northern North Sea *(inset)*, the Blake field is operated remotely using subsea equipment and a floating production storage and offloading vessel (FPSO). Produced fluids from six horizontal production wells must travel 10 km [6 miles] to the *Bleo Holm* FPSO. Numerous downhole sensors and two multiphase flowmeters at the Blake subsea manifold provide valuable production data for back-allocating production volumes and for production-optimization efforts.

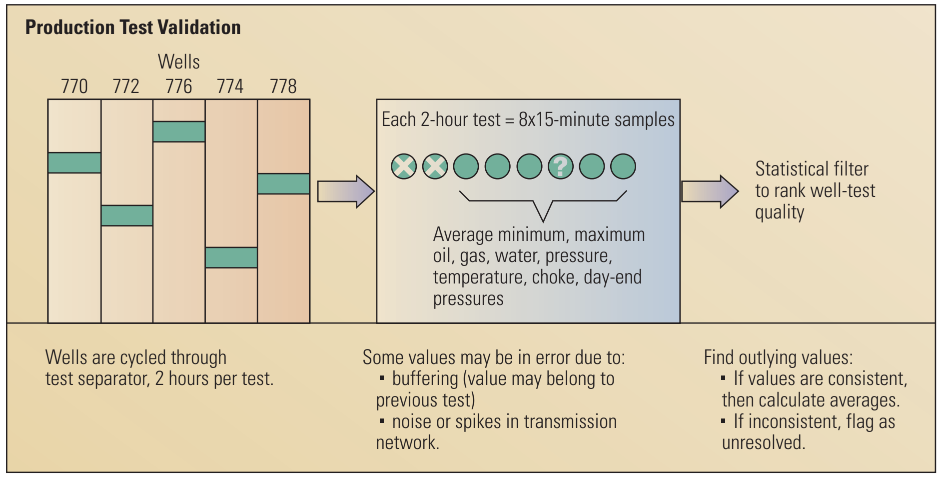
systems (above). Well testing must occur upstream of the FPSO, since no testing facilities are dedicated to Blake on the vessel. Prior to the introduction of Vx technology in 2001, BG installed two Framo multiphase flowmeters on the Blake field subsea manifold in 400 ft [120 m] of water to monitor six producing wells. These wells were completed using stand-alone sand screens and instrumented with permanent downhole and subsea sensors, including pressure and temperature gauges. Anticipating the need for artificial lift in the future, BG installed gas-lift systems in the production wells and has secured a limited supply of produced gas for future gas-lift operations. The field also has two water-injection wells for pressure maintenance.

Blake field oil production began in June 2001 from a 100-ft [30-m] oil rim within the Captain C sandstone. The relatively thin oil zone is underlain by water and overlain by gas, making precise well placement and optimal production management imperative to avoid water and gas breakthrough. Gas coning and water breakthrough must be managed to optimize production from these remote horizontal wells. Management of gas coning has required that flowing bottomhole pressure cannot drop below the bubblepoint inside the sand screen. Also, particular attention is given to the drawdown pressures within the horizontal section, resulting in maintenance of a maximum allowable drawdown pressure of 12 psi [83 kPa] to achieve optimal well flow performance. Operating under these constraints requires real-time surveillance to enable quick response to production changes, for example changing the choke setting on a well to control the downhole flowing pressure. Data from the downhole sensors allow BG to monitor the downhole production response, while the subsea Framo multiphase flowmeters are used to back-allocate production and assess well performance, including the determination of water cut and gas/oil ratio (GOR). Using the producing GOR, BG engineers can optimize gas-lift operations in the Blake field.

Downhole-sensor and subsea-meter data from the Blake field are transmitted every 15 minutes every day of the year. To convert this continuous stream of data into knowledge and effective action, data and results must be organized and managed. BG sought a solution that would reduce the data-processing burden on its engineers and provide an integrated approach to handle, visualize and analyze the Blake field data. BG worked with Schlumberger to maximize the surveillance data, making it available in the correct format at the right time. A detailed analysis of the engineering workflow conducted by BG and Schlumberger identified back-allocation and production-test validation as the most time-intensive processes.

To address these areas, Schlumberger worked with BG to automate the process by integrating Schlumberger commercial software, including the Finder data management system, FieldBA and Prodman applications, into the existing BG infrastructure. For example, a special functionality was developed within the Finder application to automate the process of statistically validating and averaging production-test data (next page, top). This software module is accessible through the BG network and eliminates the need for manual editing by automatically filtering the raw data. In a fraction of the time previously required, the FieldBA application can calculate allocated production volumes based on choke correlations, production-test results from flowmeters, or other data. The automated back-allocation process already saves BG 20 man-hours per month and compares favorably to hand calculations—with a correlation coefficient of 0.99 to 0.98. The Prodman application provides visualization and trending of the average production-test data, and can link multiple data sources for simulation in the PIPESIM total production system modeling software. The link to the PIPESIM application provides a variety of tools, including gas-lift diagnostics and optimization, and will become an important part of this data-management, field-optimization project in its second phase (below right).

As the Blake field moves through its production phase, water production will increase, necessitating artificial lift. The volume of lift gas available to Blake field is limited, so the allocation of lift-gas volumes to each well requires a system-wide solution. Real-time surveillance and interpretation of the data, including well-test analysis, production allocation, history matching, and well and system modeling, are critical to optimizing the total production. This continuous data-management and interpretation platform facilitates knowledge transfer and decisive actions, helping BG to address its primary goal of optimizing production through timely reservoir-management decisions.

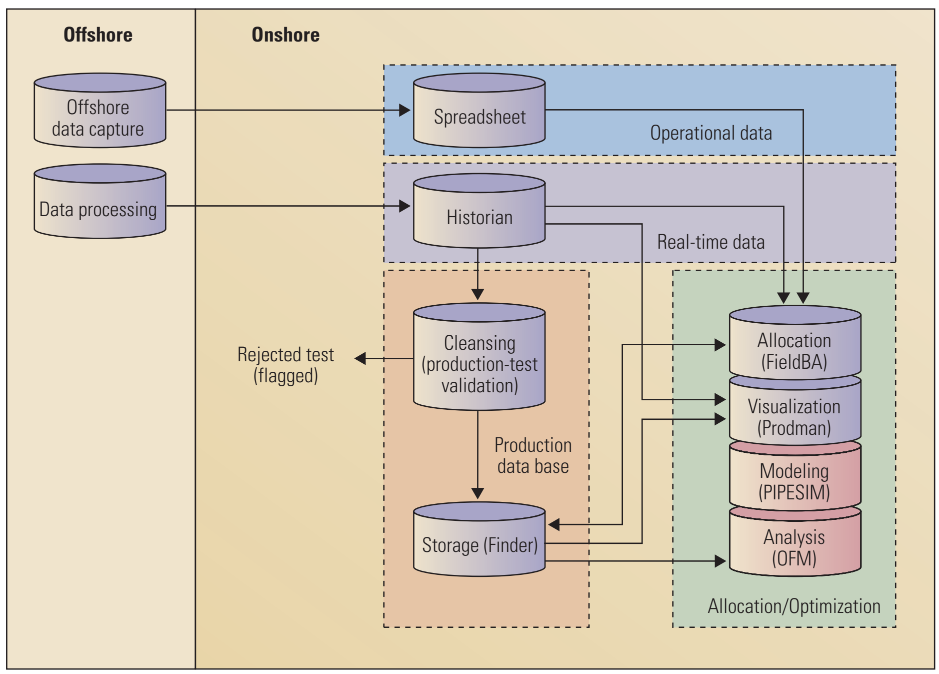


^ Automated production-test validation. A cost-effective solution was required to systematically process measured results from production tests. This required custom design of an integrated module within the Finder application to handle 80% of tests and flag the remainder for manual analysis. Each well is tested for two hours. Each two-hour well test consists of eight 15-minute averaged samples. Separation of data between wells, or buffering, may cause error, and noise in the data may render it uninterpretable. Automated processing filters the data and flags any unresolved errors, saving time.

Taking New Flowmeters to the Sandface

Surface-based measurements typically do not describe reservoir behavior, especially when the completions are complex. By moving sensors downhole and close to the sandface, reservoir engineers can directly observe real-time production response from the reservoir.[8] Downhole data can be used to more accurately diagnose production problems, predict future reservoir performance and enable production optimization from multizone and multilateral wells using downhole flow-control technology.[9] Understanding the different fluid-phase contributions is critical to extract maximum benefit from this information in the complex flow scenarios found in oil and gas wells.

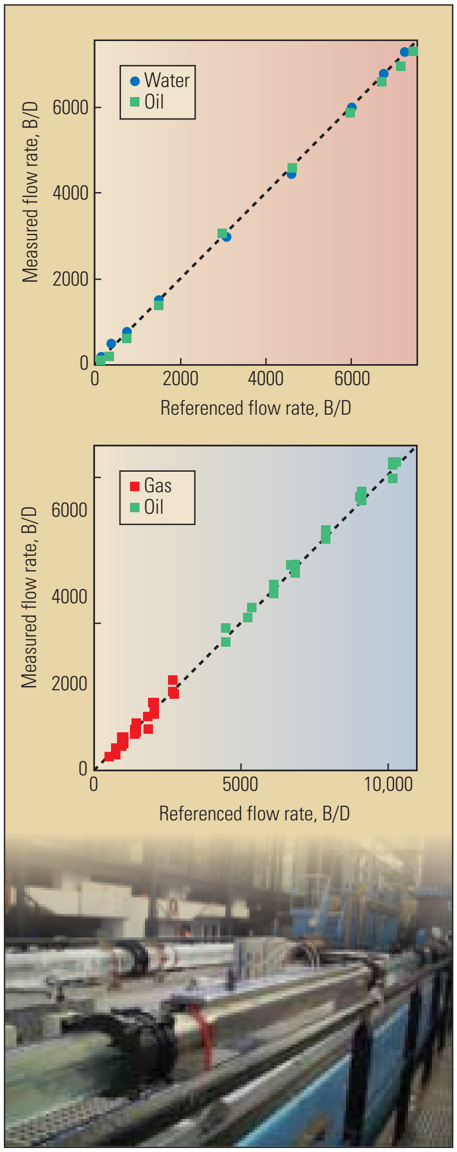
The FloWatcher integrated permanent production gradiomanometer is a downhole flowmeter for measuring two-phase flow.[10] It employs a venturi, two quartz pressure gauges—one at the venturi throat and one at the inlet of the venturi—and a third pressure gauge above the venturi. The third gauge is used in combination with one of the other gauges at the venturi to determine the average density, ρ_{mix}, of the fluid between the gauges. The holdup of the individual phases, α_f, can be determined if the densities of the two individual phases are known. This technology is commonly used in production logging and performs adequately where well deviation does not approach horizontal because gradiomanometers depend on gravitational forces. It is also applied successfully where flow rates are high enough to minimize the effects of phase slip and where the detection of small amounts of water is not required.



^ Data-flow diagram for Blake field. Real-time data from the downhole sensors and subsea multiphase flowmeters are routed through a data historian and then sent through a specially designed filtering program that automatically cleans up data before storing within the Finder production database. The Finder database interacts with the FieldBA application to perform back-allocation calculations, and with the Prodman application for data-visualization purposes. In Phase 2 of the project (pink), field-wide modeling with PIPESIM software will enable more timely actions to optimize gas-lift and production operations. OFM production management software will be utilized as a data-visualization and analysis tool.

8. Kimminau and Cosad, reference 3.
9. Lenn C, Kuchuk FJ, Rounce J and Hook P: "Horizontal Well Performance Evaluation and Fluid Entry Mechanisms," paper SPE 49089, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, September 27–30, 1998.
10. Eck et al, reference 1.

In horizontal wells, the measurement of α_f and ρ_{mix} must be achieved by different means. In 1999, scientists at the Schlumberger Cambridge Research (SCR) center in England developed the FloWatcher densitometer (FWD) multiphase flowmeter to measure downhole flow data in increasingly complex completions, from horizontal wells to multilateral wells with downhole flow control.[11] As with the Vx surface meters, the FWD flowmeter uses venturi technology and a gamma ray attenuation density measurement. However, the various flow regimes encountered in horizontal and highly deviated wells, including stratified, recirculating and slugging flows, are much different from those at surface. Fortunately, the simple approach based on the inherent mixing capability of the venturi is adequate, even for these flow regimes and at relatively low flow rates (below left). The density measurement is located where the phases are well mixed and free of slip.



^ Flow-loop testing of the FloWatcher densitometer (FWD). The FWD was tested extensively at Schlumberger Cambridge Research in England *(bottom)*. Different well deviations, flow rates and fluid cuts were used during testing to fully characterize meter performance. The graphs show FWD meter performance to be excellent at various water/oil *(top)* and gas/oil ratios *(middle)*. The water-oil data were acquired at 70 degrees well deviation, while the gas-oil data were acquired at a range of well deviations—0, 45, 70 and 90 degrees—with no effect on data quality.

For environmental safety reasons, the FWD uses an extremely low-activity gamma ray source, of the same order of magnitude as that used in smoke detectors. The low source strength means that it is difficult to implement the PE measurement used in Vx technology. This measurement would be affected by inorganic scales, such as barium sulfate, that form on the inside of production tubulars, just as barite affects the Litho-Density wireline logging tool's lithology measurement. Ultimately, the lack of full three-phase capability in downhole multiphase flowmeters is usually not a problem because many wells produce no more than two phases. Even when three phases are present, the continuous density measurement is able to flag abrupt changes in flow. For example, gas breakout will produce a dramatic decrease in density that is clearly evident on the density measurement.

The FWD flowmeter currently in field test in the North Sea has performed convincingly for more than a year, long beyond the original two-month trial period. It has helped characterize gas-coning problems by detecting the downhole change in flowing hydrocarbon density. The analysis of downhole flowmeter data can resolve bubblepoint pressure and density, and promptly identifies water breakthrough before it becomes visible at surface. The deployment of this technology can eliminate the need for test separators, avoiding potential production-rate limitations during testing. Proactive use of downhole phased-flow measurements includes the observation of phase changes to predict water- and gas-cut increases, offering significant production-management benefits.

Monitoring with Light and Fiber

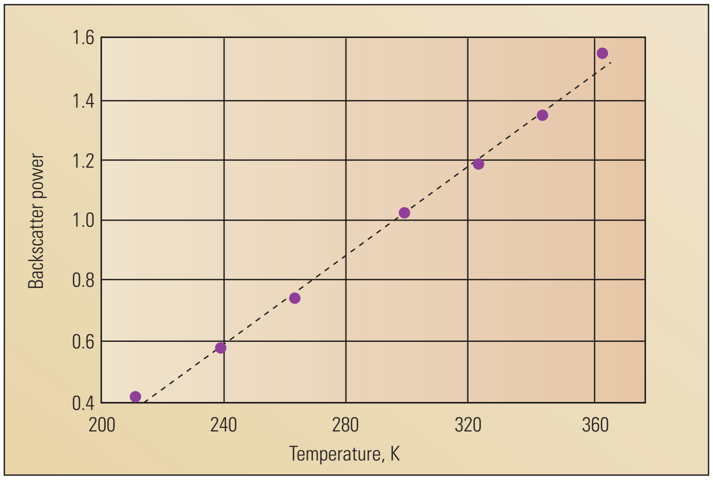
In December 1926, Clarence W. Hansell proposed the use of fiber-optic bundles for transmitting optical images.[12] Fiber-optic technology has been exploited in numerous industries, particularly telecommunications. Permanent downhole fiber-optic sensors were introduced in the oil and gas industry in the early 1990s, but their use has become widely accepted only within the last two years. Scientists and engineers at Schlumberger have been involved in the application of fiber-optic technology since its introduction into the oil and gas industry.

SENSA optical fibers offer the industry detailed information about production wells, injection wells and production systems using a passive technique. In addition, SENSA fiber-optic monitoring systems are small and relatively easy to install, even after the completion has been run. The adaptation of this technology to one of the most challenging environments encountered so far—oil and gas wells—has meant production teams can now add continuous, real-time measurements from fiber-optic sensors to a growing list of reservoir-management tools.

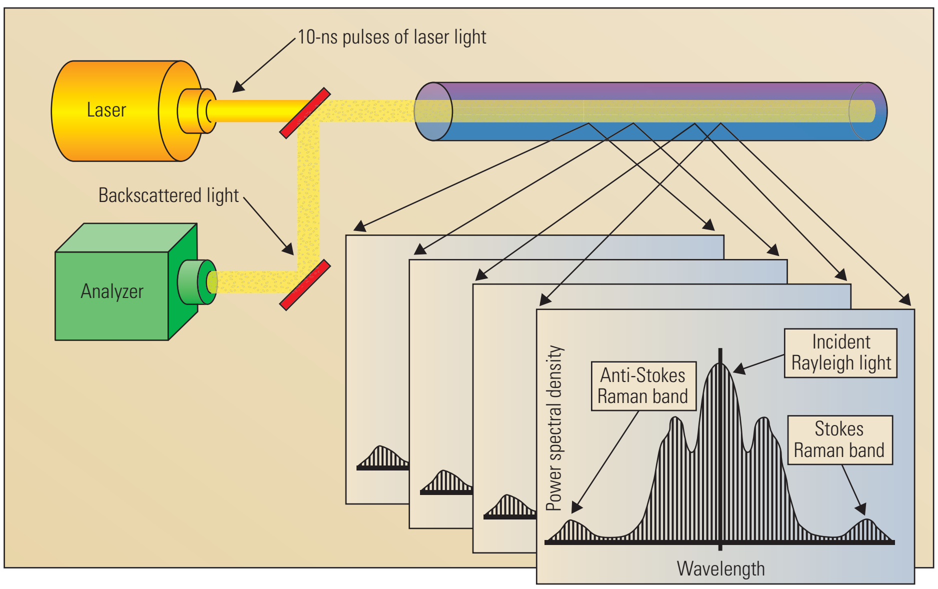
Today, the most widely used fiber-optic sensors measure distributed temperature over the wellbore length. Downhole temperature data have been acquired since the early 1930s by wireline logging in both open and cased boreholes. However, some of the more advanced completion designs make the running of conventional production logging tools extremely challenging. Cased-hole temperature measurements are an important element of modern production logging (PL) measurements and are extremely useful when combined with other data, such as pressure, flow rate from a spinner and gradiomanometer data. However, temperature surveys are logged only occasionally and provide a temperature profile across the well, at a single point in time. Today's complex well and completion designs make occasional surveys complicated and expensive to run, often swaying the decision to preclude logging to the detriment of gaining knowledge.

Schlumberger has developed several fiber-optic sensors, most prominently the SENSA distributed temperature system (DTS). The DTS measures continuously in both time and space, supplying engineers with continuous temperature data—as often as every seven seconds—or on-demand over the life of the well. Temperature data can be collected every meter [3.3 ft] along the length of the well. This continuous measurement allows precise identification of when and where production events occur, making near real-time diagnosis and control steps possible.

The DTS measurement employs a pulsed laser, an optical fiber and an opto-electronics unit for signal processing and display. The laser sends 10-nanosecond (ns) bursts of light down the optical fiber. Typically, optical fibers are made up of a central core of silica 5 to 50 µm [0.0002 to 0.002 in.] in diameter and are surrounded by another layer of silica of a slightly lower refractive index.[13] The pure silica in the core and



^ Anti-Stokes backscatter power versus temperature. The intensity of backscattered light at the anti-Stokes wavelength increases as temperature increases. The temperature range shown is from 200 K to 368 K [–100°F to 203°F]. This relationship remains robust throughout the range of temperatures in oil and gas production environments.



^ The principles of DTS operation. Pulses of laser light are sent into an optical fiber. Immediately, some of the light scatters. Retained within the core of the fiber, the scattered light is transmitted back to the source where it is captured and redirected to a highly sensitive receiver. The returning light from the scattered light pulses shows an exponential decay with time. The constant speed of light allows the determination of the exact location of the source of the scattered light. The analyzer determines the intensity of the Raman backscatter component at both the Stokes and anti-Stokes wavelengths, which is used to calculate the temperature of the fiber where the backscatter occurred.

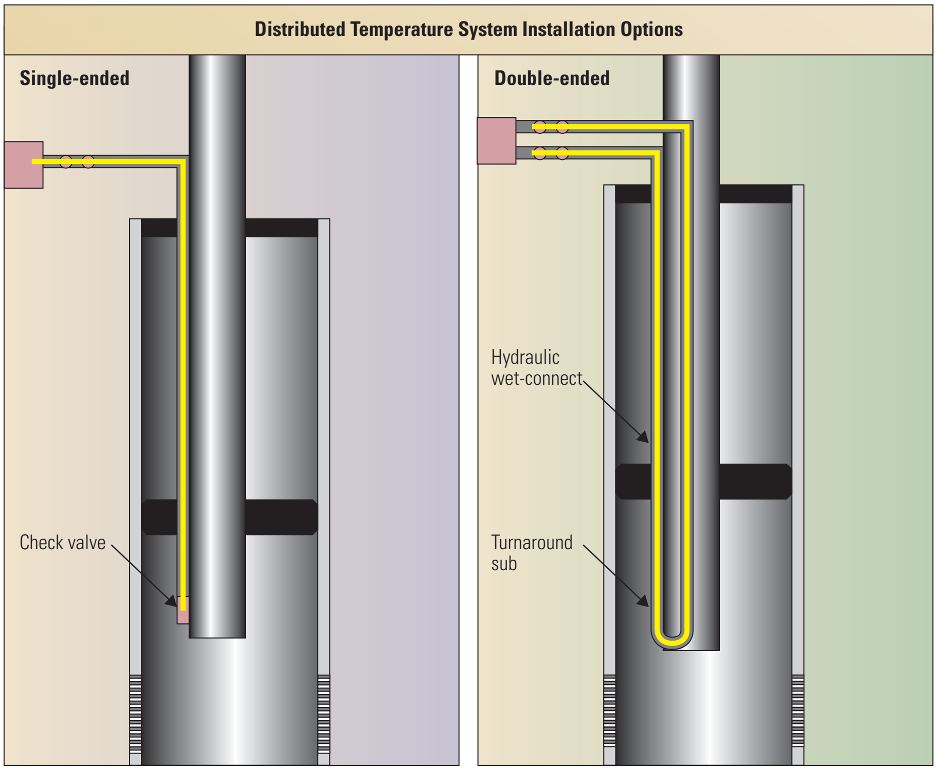
surrounding layers is altered, or doped, with the addition of other materials—such as germanium or fluorine—to achieve the desired refractive-index profiles and dispersion properties. The lower refractive index of the outer layer helps minimize the optical attenuation through long spans of fiber by guiding the light in or near the fiber core. Currently, attenuation at the most transparent wavelength reduces the signal by only a factor of 10 for every 50 km [31 miles] of fiber. A coating applied to the fiber protects it from scratching and micro-bending which can potentially cause signal loss. Because of high temperatures, high pressures, corrosive chemicals, and risk of abrasion and crushing in downhole environments, special coating materials have been developed to provide added protection. Finally, the completed fiber—typically 250 µm [0.01 in.] in diameter—is further protected by a ¼-in. [0.63-cm] metal control line in which it is housed.

When light is transmitted through an optical fiber, small amounts of light are returned back, or backscattered. In the DTS measurement, an "analyzer," or opto-electronics unit, at surface captures spectra of the backscattered light. One of the backscatter components, called the Raman signal, comes from an inelastic collision of photons with molecules in the medium, interacting through molecular vibrational energy states. The backscattered photon can either lose energy to the molecule and raise it to a higher vibrational energy state, called Stokes scattering, or gain energy by moving the molecule to a lower state, called anti-Stokes scattering. In a hot medium, more molecules are in a higher, excited energy state. Since anti-Stokes scattering is dependent on the number of molecules in the excited state when the photon collides, the intensity of the anti-Stokes response is strongly temperature dependent (above left). Stokes scattering is weakly temperature-dependent. Since the scattering process occurs at the molecular level, the backscatter signal is a continuous function of time, unlike the reflections that would be observed at an abrupt change in refractive index, such as at the end of the fiber.

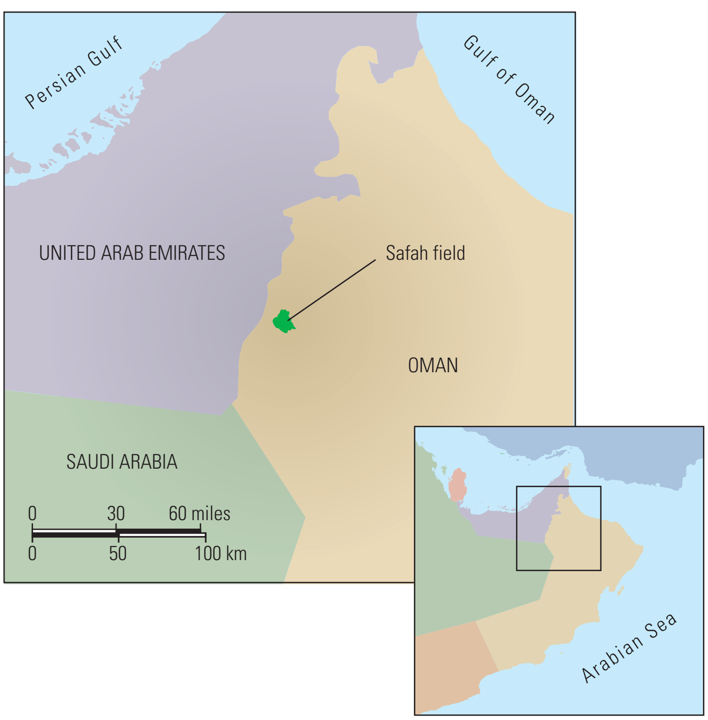
Observed intensity changes within the spectra at the Stokes and anti-Stokes lines relate directly to changes in downhole temperature. The analyzer separates the forward and backward light and selects, from the backscattered light, the two Raman components. These are detected by a photodiode and the amplified electrical current is sampled by a fast analog-to-digital converter. The samples resulting from each laser pulse are accumulated in a digital memory and then converted into temperature by a processor.

Determining the temperature at a given depth is made possible by the efficient transmission characteristics of fiber and by the constant speed of light in the fiber. The backscattered light can be split up into light packets, with each packet representing a certain interval along the entire fiber, typically 1 m, which corresponds to a sample interval of 10 ns in the time domain (left). The spectrum of each backscattered light

11. A significant engineering contribution was provided by the Schlumberger Princeton Technology Center (SPTC) in New Jersey, USA, formerly EMR Photoelectric.
12. For more on the history of fiber optics: Hecht J: *City of Light: The Story of Fiber Optics*. New York, New York, USA: Oxford University Press, 1999.
13. Brown G and Hartog A: "Optical Fiber Sensors in Upstream Oil & Gas," paper SPE 79080, *Journal of Petroleum Technology* 54, no. 11 (November 2002): 63–65.



^ Single-ended and double-ended distributed temperature system (DTS) installation options. Single-ended *(left)* installation usually occurs after a well has been completed and is less advantageous than the double-ended installation *(right)*. In double-ended installation, the fiber is hydraulically pumped down a ¼-in. control line, around a U-tube and back up to the surface. Ideally, the optical fiber should be probed from two ends. The laser sends a light pulse down one side and then switches to the other side. The double-ended measurement provides more accuracy and resiliency.



^ The Safah field in Oman.

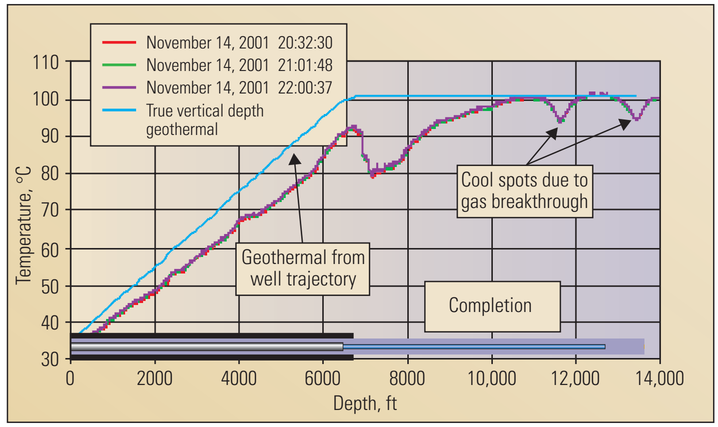
packet is analyzed for each sampling interval. Temperature is determined by computing the ratio of anti-Stokes Raman band intensity to the Stokes Raman band intensity and applying the following relationship:

$$\frac{1}{T_z} = \frac{1}{T_{Ref}} - \frac{1}{S}\left[ln\left(\frac{I_{as(z)}}{I_{s(z)}}\right) - ln\left(\frac{I_{as(Ref)}}{I_{s(Ref)}}\right)\right]$$

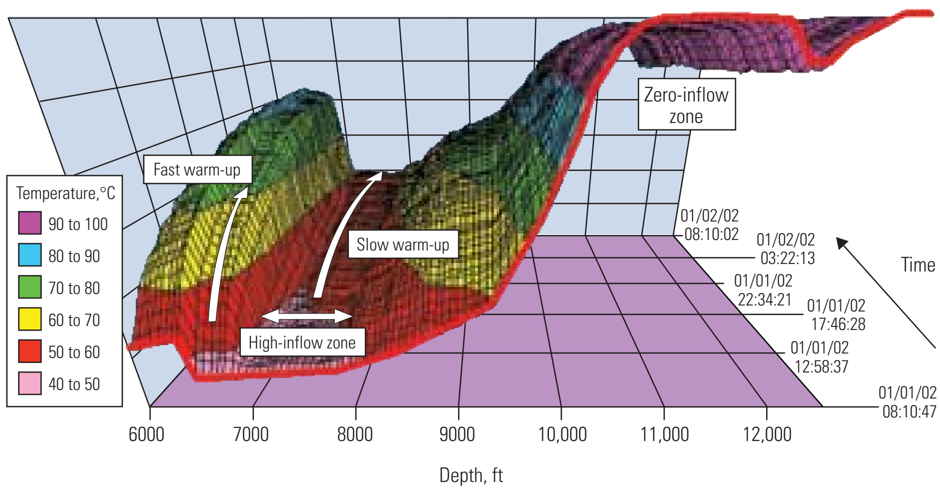
where T_z is the temperature in Kelvin, I_{as} and I_s represent the intensity of the anti-Stokes and Stokes signals, respectively—corrected for propagation losses—and ln is the natural logarithm function. The coordinates z and Ref represent the position of the point of interest and the reference coil, respectively, where T_{Ref} is the known temperature from a reference fiber. The sensitivity term S is dependent on Planck's constant, Boltzmann's constant and the frequency difference between the incident and Raman-shifted light.[14] The band intensities are normalized to those measured in the reference coil.

Naturally occurring temperature changes with depth, called geothermal gradients, have been studied extensively in most oil- and gas-producing regions. Typical gradients range from 0.6 to 1.6°F per 100 ft [1.0 to 3.0°C per 100 m] of depth, with the average gradient of around 1.0°F per 100 ft [1.7°C per 100 m] of depth. The effects of the geothermal gradient can be observed once a shut-in well reaches thermal stability. The temperature profile of a well changes as fluids are produced or injected. Additionally, the Joule-Thomson effect, which explains the temperature change of an expanding fluid in a steady flow process, should be taken into account.[15] This change in temperature occurs both in flow into the wellbore where a large pressure drop can occur, and flow up the wellbore where a more gradual pressure drop occurs. Because of this phenomenon, it is common to see warming with oil and water entry, and cooling with gas entry into the wellbore. Both the geothermal gradient and the Joule-Thomson effects are taken into account when interpreting DTS data using sophisticated nodal thermal modeling tools.

Installing the subsurface portion of the DTS is quite straightforward. First, a ¼-in. diameter control line, or conduit, is designed into the completion. It is commonly attached to the production tubing and can extend beyond that—across the sandface along sand-control screen completions. The fiber is then pumped into the control line using a hydraulic deployment system. There are two measurement techniques, single- or double-ended. While a single-ended technique may be the only option because of limitations related to the completion configuration, the best method is the double-ended installation, involving a U-tube configuration (previous page, top). This provides a closed system for simple fiber installation and replacement, and it ensures data quality by increasing both measurement accuracy and resiliency. The fiber is alternately probed from each end by the laser pulses, and the geometric mean of the two return signals is used. Measuring from both ends and taking the average improves the accuracy by eliminating the effects of signal loss, including micro-bends and connector losses. This accuracy becomes especially important in applications requiring analysis of small temperature changes. If a fiber breaks, the temperature profile of the well can be acquired using the single-ended technique. The temperature profile can be recorded from each end to the break, so that no data are lost. However, more than one break in the fiber results in the loss of data between the breaks. Fortunately, a replacement fiber can easily be pumped into the control line during the next planned intervention.



^ The Safah 179 temperature profile after workover. The DTS, installed during workover, identified the exact locations of gas breakthrough, shown in three overlaying curves. The source of the gas is from a nearby gas-injection well. The completion diagram *(bottom)* shows the location of the casing (black), production tubing (gray) and the smaller diameter stinger (blue) on which the DTS was installed.



^ Safah 179 water-injection profile. After 39 hours of water injection, the Safah 179 was shut in. The temperature profiles start as injection stopped *(front)* and show how the interval warmed over time *(front to back)*. The amount a particular zone cooled during injection and the rate at which a zone warms up after injection are an indication of a zone's injectivity. Zones taking more injection water start warming from a cooler temperature and warm more slowly than low-injectivity zones.

Warming Up in Oman

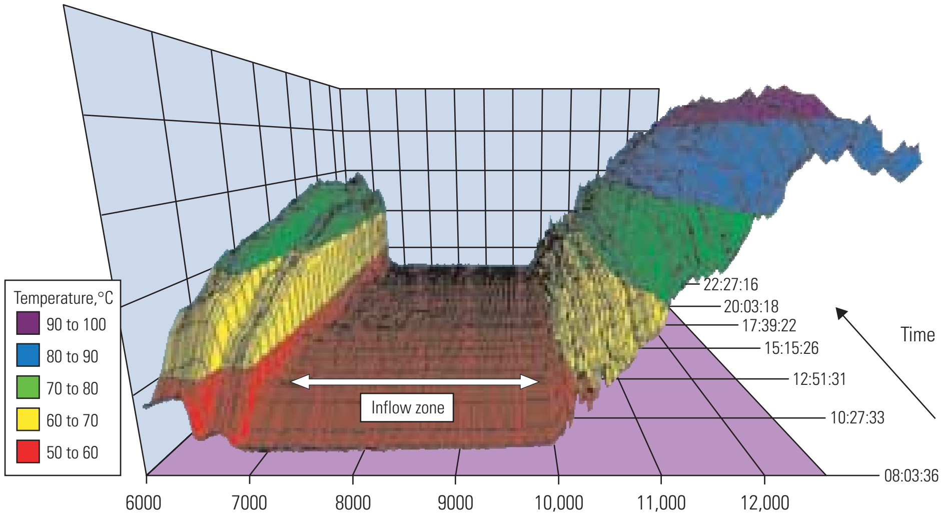
Occidental Petroleum Corporation (Oxy) recently installed the SENSA DTS in wells within its 300 million-barrel [47 million-m^3] Safah field in Oman (previous page, bottom). Discovered in 1983, this field produces from the micritic lime mudstone Shuaiba formation.[16] Initially, gas injection from vertical wells was selected for enhanced oil recovery (EOR). However, producing wells were commonly experiencing gas breakthrough, gas flaring was undesirable and surface compression constraints were encountered. Oxy decided to phase out gas injection and move to an enhanced recovery method using water injection from horizontal wells. Production wells also were drilled horizontally, but their effectiveness varied. The ample high-pressure gas supply available in the field also facilitates the use of gas-lift techniques.

The DTS system has supplied valuable data to Oxy on both production and injection wells. One well, the Safah 179, was drilled and completed with a long openhole horizontal section across the reservoir and was being produced temporarily in preparation for water injection. The temporary production phase of the water-injection wells helped clean up the wells prior to injecting water. During this production phase, the well experienced gas breakthrough because of its proximity to a gas-injection well 146 m [480 ft] away, effectively diminishing oil production. The DTS fiber was installed during a workover, before the well was converted into an injector, into a ¼-in. diameter control line attached to a stinger positioned across the reservoir section and hung below the production tubing. The DTS identified the exact locations where gas breakthrough was occurring because the thermal effects of breakthrough take time to dissipate and were still present after the workover (top).

The Safah 179 underwent 39 hours of water injection and was then shut in (above). At this time, the DTS identified a single 1000-ft [305-m] interval taking the cooler injection water from 7000 to 8000 ft [2130 m to 2440 m] measured

14. For more information on fiber optics and their applications: Kao CK: *Optical Fibre*. London, England: Peter Peregrinus Ltd., 1988.
    Grattan KTV and Meggitt BT: *Optical Fiber Sensor Technology Advanced Applications—Bragg Gratings and Distributed Sensors*. Dordrecht, The Netherlands: Kluwer Academic Publishers, 2000.
15. The Joule-Thomson effect is the change in temperature of a fluid upon expansion in a steady flow process involving no heat transfer or at constant enthalpy. This occurs in "throttling" type processes such as adiabatic flow through a porous plug or an expansion valve.
16. Vadgama U and Ellison RE: "Safah Field: A Case History of Field Development," paper SPE 21355, presented at the SPE Middle East Oil Show, Bahrain, November 16–19, 1991.

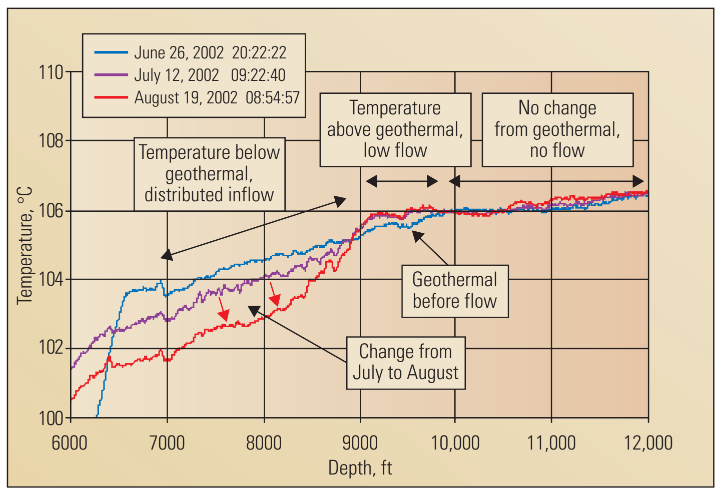
depth. Not surprisingly, the same interval had shown gas breakthrough during the initial production phase. While this interval displayed the highest injectivity, it represented only a small percentage of the intended injection zone needed to achieve optimal flooding. Injection was then resumed for 81 days, at which time another shut-in period was initiated and the well was allowed to warm up (right). The DTS data showed that the injection interval had expanded toward the toe of the well and was now more than 3000 ft [914 m] long from 6800 ft to 10,200 ft [2070 m to 3109 m] measured depth—but still left the bottom half of the Shuaiba unflooded. An analysis comparing DTS temperature data from the first shut-in period with data from the second shut-in period suggested that an expected reduction in effective permeability had occurred in the highest-injectivity zone.



^ **Increase in Safah injection zone. After 81 days of injection, the effective injection zone increased to more than 3000 ft [914 m] in length. However, the bottom half of the Shuaiba interval was still not flooded from 10,200 ft [3109 m] to the toe of the horizontal well.**

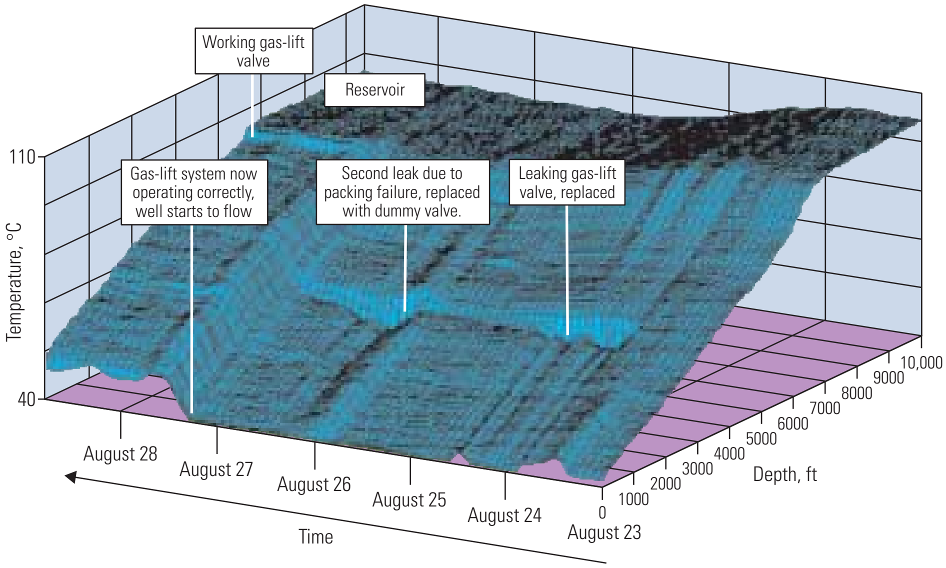
The information provided Oxy with a greater understanding of the Safah water-injection program. The injection profile across the horizontal section allows Oxy to optimize its injection design and procedures, and indicates which portions of the Shuaiba reservoir are being left unswept.

Subsequently, DTS data from another well, the Safah 203, showed that only two-thirds of the horizontal section was contributing to production, while the bottom one-third towards the toe of the well was not (right). A large portion of this nonproductive interval was good-quality reservoir that was expected to contribute more significantly. Oxy reservoir engineers suspected that the interval might not have been adequately stimulated at the time of this survey, as suggested by their experience with the Safah 179 well. The contribution from the remainder of the horizontal section is expected to increase over time. The production profile from the DTS led to a stimulation-design change to accelerate early production. This new design was used on another new well in which DTS fiber was installed, the Safah 217.



^ **The Safah 203 production-temperature profile. DTS data from the Safah 203 during production indicated that only two-thirds of the horizontal section is contributing to production, while the bottom one-third towards the toe of the well is not. The temperature profiles from two different time snapshots in July and August (purple and red) are compared with the well's geothermal profile (blue). The profiles overlay towards the toe of the well *(right)*, indicating no flow, and separate towards the heel of the well *(left)*, indicating flow into the well from that interval. A large portion of the nonproductive interval was deemed good-quality reservoir and was expected to contribute more significantly. Oxy reservoir engineers suspected that the interval might not have been adequately stimulated.**

Data from the DTS had an immediate impact on Safah 217 operations. The completion of this horizontal production well included the installation of DTS technology and a gas-lift system to assist in well startup and production.[17] Initially, the well did not flow oil or water and was circulating only injected gas. The scenario was consistent with a potential gas-lift problem, so DTS data were acquired and analyzed to diagnose the fault and formulate an action plan. The DTS data identified a retrievable gas-lift valve at a measured depth of 3500 ft [1070 m] that was stuck open (next page, top). The faulty gas-lift valve was retrieved and replaced. Unfortunately, the replacement valve experienced a packing failure, continuing the unwanted gas flow. This valve problem also was identified immediately by the DTS, and the valve was replaced with a dummy valve that allowed no gas entry at 3500 ft. The lower gas-lift valve at the measured depth of 6200 ft [1890 m] operated correctly and helped kick off the well. The use of DTS continuous surveillance during the gas-lift startup on Safah 217 immediately identified the problematic gas-lift valves, facilitating the timely replacement of valves and allowing hydrocarbon production to begin sooner. Traditional diagnosis



^ Faulty gas-lift valves on the Safah 217. The DTS fiber identified the presence of a leaking gas-lift valve at 3500 ft [1067 m]. The valve was replaced, but the second valve experienced a packing failure on August 26, 2002. Once again, the DTS pinpointed the problem and the second valve was replaced with a dummy valve. The lower gas-lift valve at 6200 ft [1890 m] operated correctly and kicked the well off on August 27, 2002.

^ Petrozuata production area in Zuata field, Venezuela. Venezuela's Orinoco belt is known for its heavy oil that ranges from 8 to 11°API gravity.

and intervention methods would have resulted in significant lost production.

After the treatment, the DTS data from the Safah 217 well showed that the entire horizontal section contributed to production. The ability to observe production behavior across the entire horizontal leg and at critical moments in the life of these wells enabled Oxy to detect a problem and to take action to improve the process with positive results.

Cooling Down in Venezuela

Petrozuata C.A., a joint venture between Conoco de Venezuela C.A. and Petróleos de Venezuela S.A. (PDVSA), tapped the latest drilling and completion technologies to address the complexities associated with developing the heavy-oil reservoirs in eastern Venezuela's Orinoco belt (bottom left). In 1997, construction commenced on the Petrozuata property within the Orinoco belt, including the drilling of the first production well on the property. Single horizontal production wells were drilled until 1999, when multilateral-well design was introduced.[18] Recovery of the heavy oil—8 to 11°API gravity—is further exacerbated by the geologic complexity of the producing horizon, the Oficina formation.[19] The Oficina formation is a series of Miocene sandstones whose stacked fluvial-marine deposition was primarily responsible for production variations from well to well. Solutions addressing the cold production of heavy oil at low bottomhole pressures through long horizontal wellbores did not exist, prompting Petrozuata and service providers to develop effective ways to monitor and manage production, including downhole surveillance techniques.

Through innovative drilling and completion technologies, multilateral wells have enabled operating companies, like Petrozuata, to contact more reservoir.[20] However, complicated wellbores with artificial-lift systems—such as electrical submersible pumps and progressing cavity

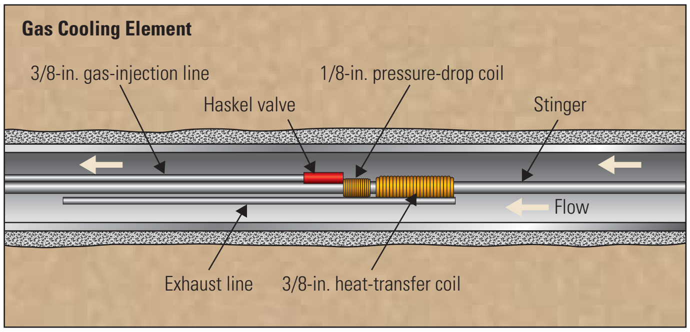
17. Gas-lift systems typically use several gas-lift valves installed in gas-lift mandrels at different depths to assist in well startup. To facilitate liquid unloading, the shallowest valve is opened first, injecting gas into the production string, thereby lifting the fluid column above the valve and reducing the hydrostatic head on the zones below. Each valve, from shallowest to deepest, is opened to provide lift and then closed. This continues until the lowest valve is opened and remains open to assist continued production.
18. Clancy TF, Balcacer J, Scalabre S, Brown G, O'Shaughnnessy P, Tirado R and Davie G: "A Case History on the Use of Down-Hole Sensors in a Field Producing from Long Horizontal/Multilateral Wells," paper SPE 77521, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, September 29–October 2, 2002.
19. For more on heavy-oil reservoirs: Curtis C, Kopper R, Decoster E, Guzmán-Garcia A, Huggins C, Knauer L, Minner M, Kupsch N, Linares LM, Rough H and Waite M: "Heavy-Oil Reservoirs," *Oilfield Review* 14, no. 3 (Autumn 2002): 30–51.
20. Stalder JL, York GD, Kopper RJ, Curtis CM, Cole TL and Copley JH: "Multilateral-Horizontal Wells Increase Rate and Lower Cost Per Barrel in the Zuata Field, Faja, Venezuela," paper SPE 69700, presented at the SPE International Thermal Operations and Heavy Oil Symposium, Porlamar, Margarita Island, Venezuela, March 12–14, 2001.

    Smith KM, Rohleder SA and Redrup JP: "Use of a Fullbore-Access Level 3 Multilateral Junction in the Orinoco Heavy Oil Belt, Venezuela," paper SPE 69712, presented at the the SPE International Thermal Operations and Heavy Oil Symposium, Porlamar, Margarita Island, Venezuela, March 12–14, 2001.

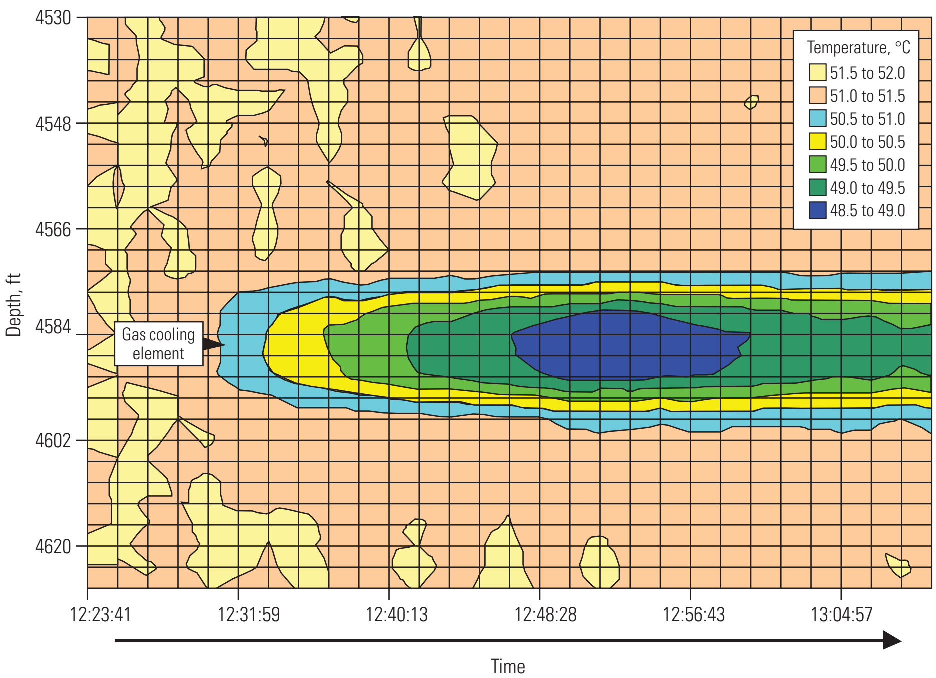
    Fraija J, Ohmer H, Pulick T, Jardon M, Kaja M, Paez R, Sotomayor GPG and Umudjoro K: "New Aspects of Multilateral Well Construction," *Oilfield Review* 14, no. 3 (Autumn 2002): 52–69.

pumps—make it more difficult to completely understand the production behavior of these low-pressure, heavy-oil reservoirs. To improve understanding in real time, Petrozuata has installed downhole sensors on numerous wells, even on complex dual horizontal lateral wells.

Phoenix MultiSensor well monitoring units measure vital statistics of electrical submersible pumps, including intake pressure and temperature, motor-winding temperature, vibration and current leakage. Pump-intake pressure measurements track bottomhole flowing pressures, preventing excess drawdown, and have also been used to perform buildup tests during shutdowns. Pump-head reduction problems caused by viscous crude oil are readily identified by monitoring pump-discharge pressures, while the detrimental presence of sand or gas is detected by the pump-vibration measurement. Vigilant pump surveillance has already identified overheating motors downhole, and allowed rapid remedial action to ensure that the well continues to produce optimally. Pump failure also can be predicted by monitoring pump-current leakage, a reflection of the degradation of the pump's electrical system. This permits better rig scheduling in replacing an underperforming pump.



^ Monitoring low flow rates in Venezuela using gas cooling elements (GCE). The system tracks a slug of cooled production fluids as it moves up the wellbore. The flowing fluid, in this case, oil, is cooled by the Joule-Thomson effect of expanding nitrogen gas. Nitrogen gas is pumped down a ⅜-in. [0.95-cm] diameter control line to a Haskel valve that opens at a predetermined pressure of 6500 psi [44.8 MPa]. This releases the gas into a pressure-drop coil, causing the gas to expand and cool. The cold nitrogen gas then goes through a coil of ⅜-in. control line, which acts as a counterflow heat exchanger and cools the surrounding oil flowing in the opposite direction past the GCE. The small volume of nitrogen gas is then released into the production stream through the exhaust line.

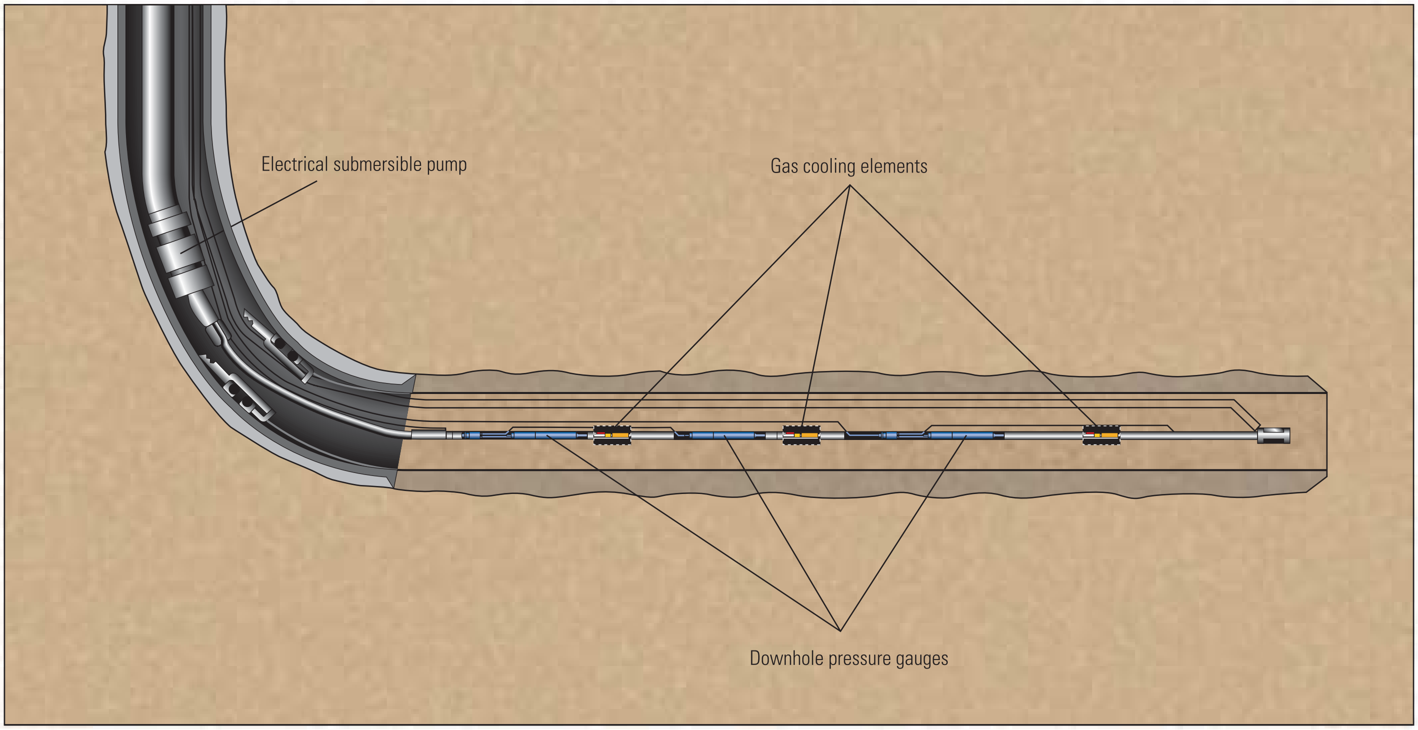


^ No flow from the lower lateral wellbore in Petrozuata Well A. The flattened plot of DTS cooling data in a time-depth plot indicates no flow from the lower lateral in Well A. The cooling effect remains at the GCE depth and does not proceed up the wellbore.

With the construction of more complex and expensive wellbores, Petrozuata wanted to determine the production contribution from horizontal lateral wells. Periodic production logging (PL) was not practical because it required the removal and reinstallation of the completion, which is not an economical solution. Adding to expenses, a rig and tubing would be needed to acquire PL data to the toe of the 10,000-ft [3050-m] laterals since field experience showed that even 2-in. coiled tubing had failed to go past 7000 ft [2130 m] in these wells. Petrozuata attempted to assess production behavior above each lateral by using a series of high-resolution pressure gauges. However, the pump-placement requirements for optimal well performance limited the available distance between the tandem gauges and made the recorded pressure data more reflective of pump operations—vibrations and surges—than of reservoir response. This, along with high pump-intake pressures, made meaningful flow characterization difficult. An alternative method was needed to evaluate flow contribution from the different multilateral wellbore sections.

Petrozuata turned to SENSA optical fibers for a cost-effective solution to measure single-phase flow velocity in low production-rate wells. An expanded use of the SENSA DTS provides downhole flow information by utilizing the Joule-Thomson cooling effect of expanding nitrogen gas in a counterflow heat exchanger to cool a slug of the flowing fluid at a point in the well. As the slug of cooled fluid moves in the wellbore, the DTS tracks its movement, allowing measurement of flow velocity. The system's measurement principle is much like a wireline tracer log, except the DTS method uses temperature changes instead of radioactivity.[21]

The nitrogen gas is pumped from the surface through a ⅜-in. [0.95-cm] diameter control line that is rated to 10,000 psi [69 MPa] and attached to the production tubing down to a valve (above left). When the pressure reaches 6500 psi [44.8 MPa], this valve opens, releasing nitrogen gas into a ⅛-in. [0.32-cm] line. As the nitrogen gas pressure lowers to the wellbore pressure, it expands and cools. The cold nitrogen gas is then

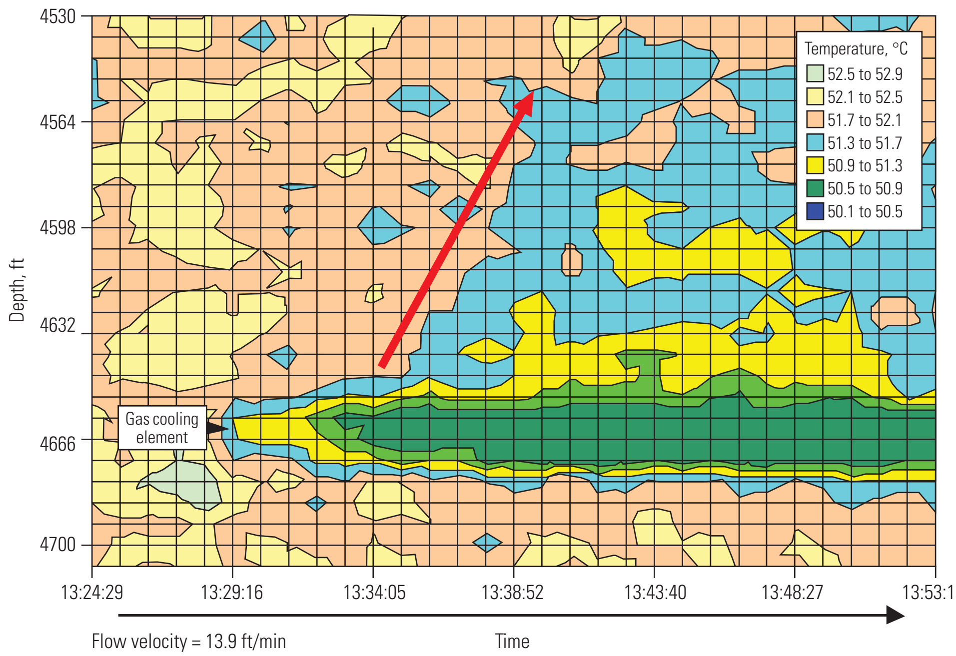


^ Completion diagram for Well B showing the location of the three GCEs. Other key elements include the electrical submersible pump and the three low-resolution downhole pressure gauges and their control line (blue). Low-resolution pressure sensors were not helpful in the horizontal section.

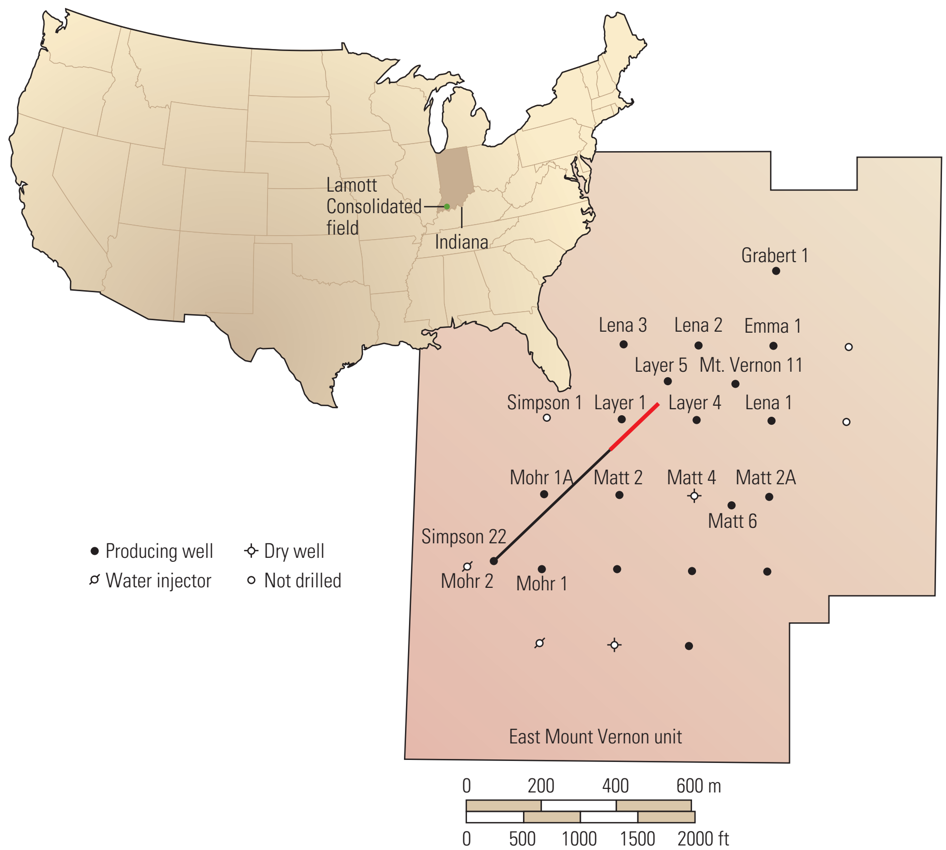
run through a coil of ⅜-in. control line, which acts as a counterflow heat exchanger and cools the surrounding produced fluid that is flowing in the opposite direction past the gas cooling element (GCE). The rate at which the produced fluid cools depends on its velocity as it passes the GCE. As the cooled section of fluid moves up or down the wellbore, it is tracked by the DTS, which measures the temperature at every meter, every 25 seconds. A fluid velocity can then be calculated for lower flow rates from 0 to 1000 B/D [160 m^3/d] in 7-in. casing.

In January 2001, two gas cooling elements were installed, along with the associated control lines and DTS fiber, in the lower lateral wellbore of Well A. In February 2001, engineers determined that no contribution from the lower lateral section was evident (previous page, bottom). Also in January 2001, three GCEs were installed in another well, Well B, to assess the flow contribution from its lower lateral wellbore (above). Initially, as with Well A, no flow was evident, but after four months of production, both wells showed lower lateral wellbore flow contribution at normal production rates (right).

21. Wireline tracer logging involves the downhole release of a weak radioactive fluid, or tracer fluid, typically iodine, into the flow stream. The tracer is then monitored as it moves up or down the wellbore by detectors in the production logging tool string to determine the direction and velocity of flow.



^ Flowing oil in the lower lateral in Petrozuata Well B. The results from the analysis of DTS data, using the GCE configuration, show the lower lateral in Well B is contributing to production. With time, cooled produced fluids travel up the wellbore at a calculated velocity of 13.9 ft/min [4.2 m/min] (red arrow).



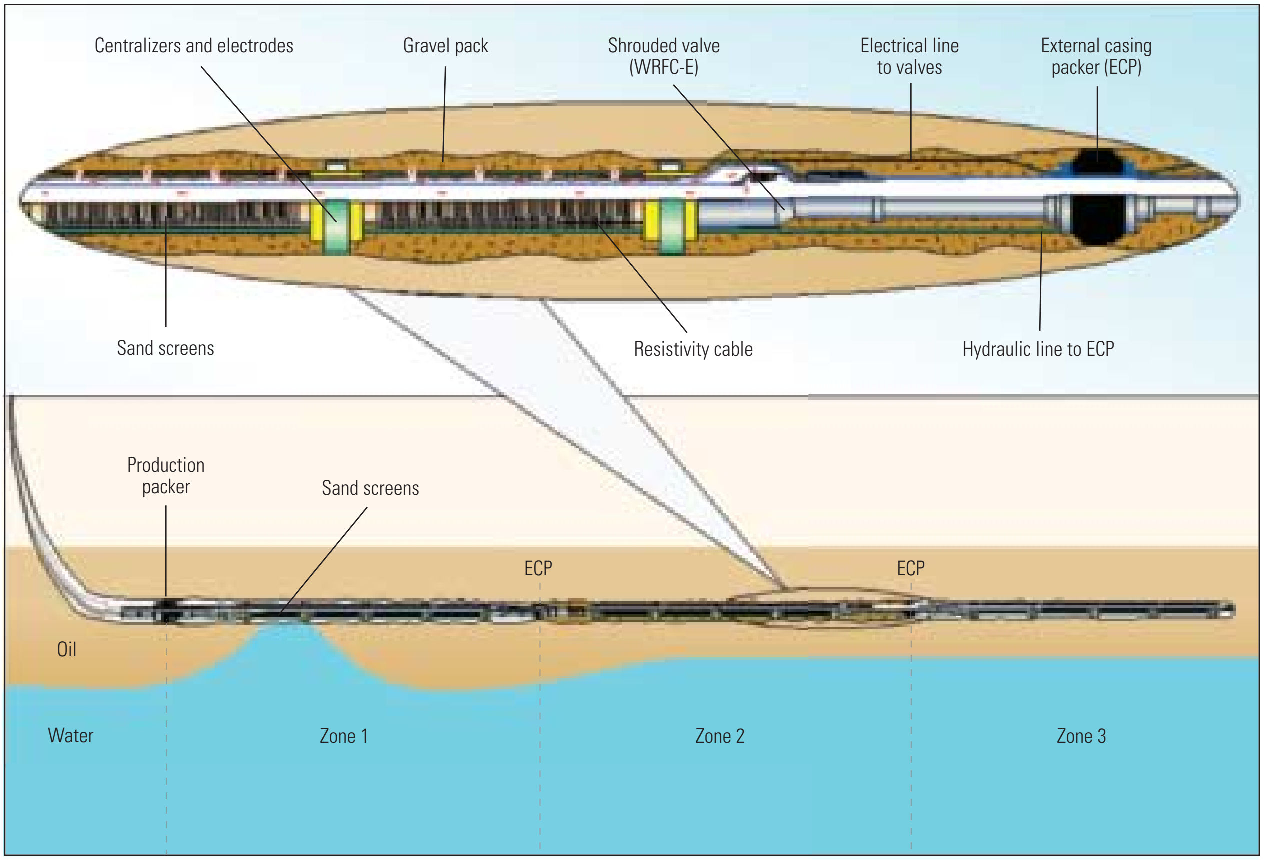
^ Map of the East Mount Vernon Unit of the Lamott Consolidated field, Indiana, USA. The Simpson No. 22 horizontal well was drilled in the northeast direction. The 808-ft [246-m] horizontal section is shown as a thicker line (red).

This innovative, cost-effective and real-time approach was smoothly integrated into complicated well-construction and completion designs in a difficult production environment. During 2001, the SENSA DTS flow-monitoring technique was applied in four wells in the Zuata field; one well had two GCEs, one well had three GCEs and two wells had six GCEs installed.[22] This technology provides valuable insight into the production behavior of Petrozuata's dual horizontal lateral wells. Eight GCEs also were installed in each of two fishbone multilateral wells for another operator in the area in 2002.

Combining Technologies to Monitor, Analyze and Control

Innovative reservoir-monitoring technologies focus on large-scale, far-field changes. Reservoir-monitoring techniques such as resistivity arrays and time-lapse (4D) seismic surveys allow asset teams to observe changes in the reservoir around their production and injection wells to anticipate and then mitigate detrimental effects on production. The value of seismic reservoir monitoring has been demonstrated repeatedly in the North Sea, where 4D surveys are used extensively to observe the changes in producing reservoirs.[23] Data from these surveys help asset teams build field-wide production-development and enhanced-recovery strategies based on reservoir simulation. Increased water or gas production from injection-fluid breakthrough associated with enhanced recovery techniques or fluid-contact changes can now be predicted before they occur, allowing proactive reservoir management. By integrating downhole and surface real-time monitoring capabilities with the rapidly advancing reservoir-monitoring techniques, the real power of comprehensive reservoir management will be realized.

Industry opinions on "intelligent" wells vary. Most believe it comprises surface control of a downhole device where ongoing measurements direct control. While there is a general agreement on a definition, the value and application of intelligent well technologies in a field-wide context are still taking form. Advances in well-construction and completions technologies, coupled with those in data transmission, management and processing, bring this vision closer to reality. Engineers and scientists at Schlumberger believe intelligent wells must include not only the elements of real-time monitoring and control, but also the capacity to move, store, process and interpret vast amounts of data quickly and accurately, converting surveillance into effective action in real time. A few years ago, Schlumberger researchers examined the feasibility of constructing a truly "intelligent"



^ The Simpson No. 22 well completion comprising a production packer, two external-casing packers (ECP), sand screens, electric flow-control valves (WRFC-E), a resistivity array, a DTS fiber, and pressure and temperature sensors. The horizontal completion interval was separated into Zones 1, 2 and 3. A thin shale layer, splitting the thin oil column, and a fault crossing Zone 2 complicate the production behavior of the well. An expanded view shows completion hardware in greater detail *(top)*.

well. This research effort culminated in an installation as part of the RES2000 project in Posey County, Indiana, USA.

In June 2001, the Simpson No. 22 well was spudded in the East Mount Vernon Unit of the Lamott Consolidated field (previous page). The field is operated by Team Energy, which worked closely with Schlumberger throughout the project. A horizontal well plan was based on extensive three-dimensional (3D) modeling derived from field, pilot-hole and real-time logging-while-drilling (LWD) data and designed to stay within a 6-ft [1.8-m] layer for 808 ft [246 m] of oil-bearing Cypress sandstone reservoir using state-of-the-art geosteering techniques.[24] The Lamott Consolidated field produces oil at a high water cut—approximately 95%—from the Tar Springs and Cypress sandstones. Logs across this interval identified a high-permeability layer in the middle of the oil column that had previously been flooded with injected produced water. A shale layer and a low-displacement fault also were identified, adding complexity and making precise well placement crucial. The 3D earth model was updated in real time using LWD data. In addition to the well-placement benefits, detailed information from logs assisted in accurate placement of the gravel-pack completion in the openhole section, made up of three zones separated by two strategically placed external casing packers (ECPs) (above).

Numerous sensors, including a DTS, a resistivity array and flow-control valves, were installed during completion of the Simpson No. 22 well and performed a variety of functions essential to the project. Three electric flow-control valves along the horizontal section allow independent control of production from each of the three isolated zones. Power and

22. Clancy et al, reference 18.

23. Alsos T, Eide A, Astratti D, Pickering S, Benabentos M, Dutta N, Mallick S, Schultz G, den Boer L, Livingstone M, Nickel M, Sønneland L, Schlaf J, Schoepfer P, Sigismondi M, Soldo JC and Strønen LK: "Seismic Applications Throughout the Life of the Reservoir," *Oilfield Review* 14, no. 3 (Summer 2002): 48–65.

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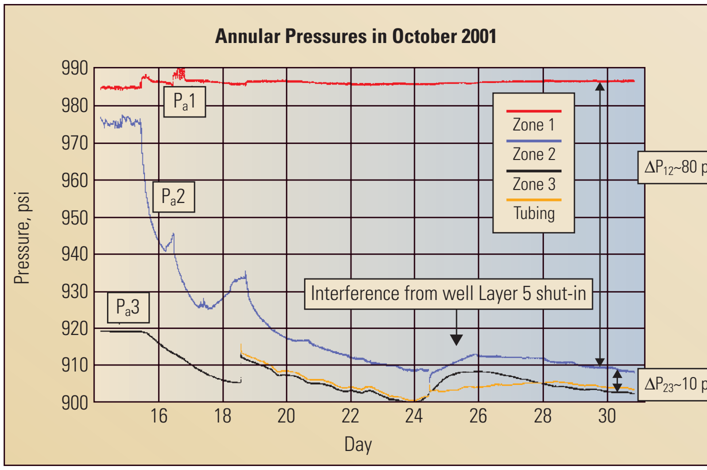
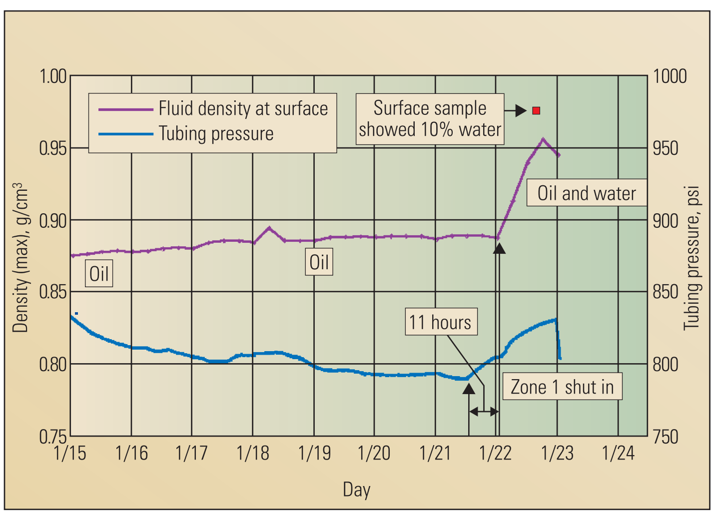
24. Bryant I, Chen M-Y, Raghuraman B, Schroeder R, Supp M, Navarro J, Raw I, Smith J and Scaggs M: "Real-Time Monitoring and Control of Water Influx to a Horizontal Well Using Advanced Completion Equipped with Permanent Sensors," paper SPE 77522, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, September 29–October 2, 2002.

Bryant I, Malinverno A, Prange M, Gonfalini M, Moffat J, Swager D, Theys P and Verga F: "Understanding Uncertainty," *Oilfield Review* 14, no. 3 (Autumn 2002): 2–15.



^ Preproduction analysis. Before the Simpson No. 22 well was produced, annular pressure data from the downhole pressure sensors demonstrated the drawdown effects from producing the Cypress sandstone in a nearby well. The nearby well was shut in three times while pressure data were recorded continuously from the permanent pressure sensors in the Simpson No. 22 well. Analysis of the data showed good communication between Zones 2 and 3, and poor or no communication between Zones 1 and 2.



^ Comparing tubing pressure data to surface fluid-density measurements from Zone 1 in the Simpson No. 22 well. After staying constant for one week, tubing pressure (blue) from a downhole sensor measured an increase in pressure due to water entry into the wellbore. This was followed, 11 hours later, by a notable increase in produced fluid density at surface (purple).

communication—commands sent downhole and data sent uphole—to the valves were supplied through a single permanent downhole cable. Each valve was equipped with two pressure gauges, one measuring the annular pressure and the other measuring the tubing pressure at one-second time intervals. Annulus and tubing temperature and the degree of valve opening also were measured and recorded. Separate from the temperature measurements at the valves, a single-ended DTS fiber provided continuous temperature information at 1- to 20-minute integration intervals every 1 m along the entire wellbore. All these systems required the installation of cables and control lines through ports across production and isolation packers.

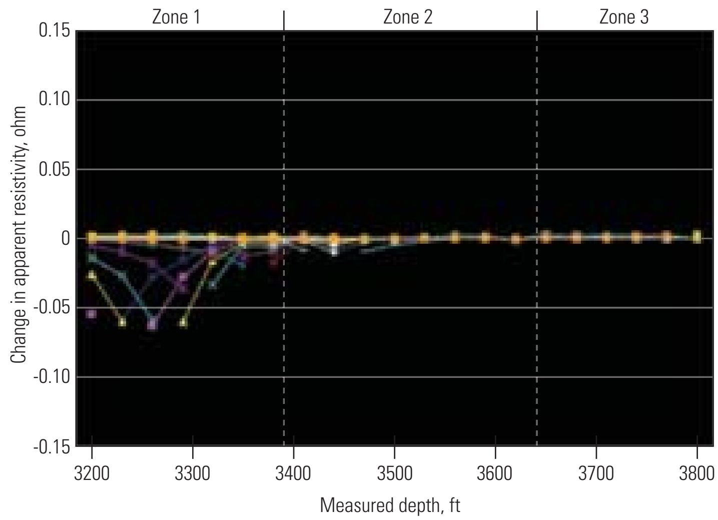
A 21-electrode resistivity array, covering the entire 694-ft [212-m] completion interval, was installed to detect far-field water movement towards the well. Electrodes also served as centralizers for the completion. Seven electrodes in each zone were mounted on an insulated section on each sand screen at a spacing of 20 ft [6 m]. Current injected from one electrode returns to an electrode at surface, while the voltage at the other 20 electrodes is measured relative to a reference voltage at the surface. The voltages are measured on either side of the injector electrode and normalized by the injector current. The data are displayed as voltage differences from one acquisition cycle—typically every 3 hours—to the next. Each injector cycle is represented by two curve segments with points corresponding to the voltage differences at the measurement electrodes along the length of the completion interval to either side of the injector electrode. The strength of the measured signal is high when measuring within the same zone as the assigned injector electrode. Based on this observation, Schlumberger scientists estimated the depth of investigation of the resistivity array to be 300 ft [91 m].

High-frequency pressure measurements on the Simpson No. 22 well helped characterize near-well formation heterogeneity. Zonal well tests, combined with interference testing between zones and wells, improved the understanding of communication between zones and provided estimates of the productivity index (PI) of each zone. Before the well was produced, annular pressure data captured the drawdown effects from the Cypress Sandstone in a nearby well (top left). The nearby well was shut in three times while pressure data were recorded continuously from permanent pressure sensors in the Simpson No. 22 well. Analysis showed good communication between Zones 2 and 3, and poor or no communication between Zones 1 and 2. Further analysis estimated the horizontal permeability in the formation above the shale layer to be 100 to 500 mD.

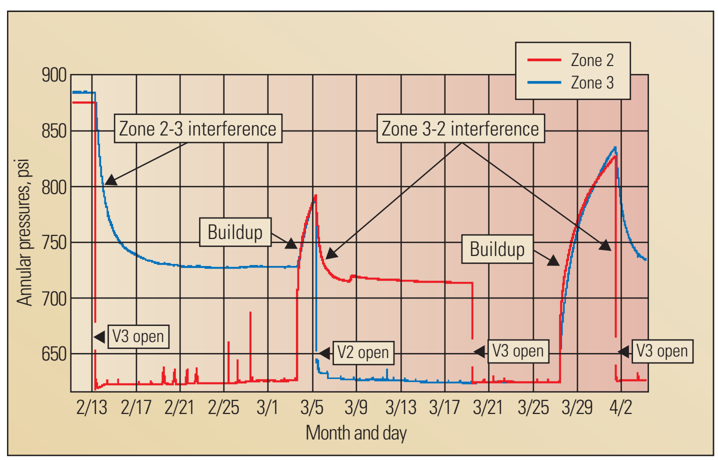
After production began in November 2001, small-volume tests in each zone showed the PI of Zone 1 was an order of magnitude higher than that of Zones 2 and 3. Also, the communication between Zones 2 and 3, and the lack of communication between Zones 1 and 2 were confirmed subsequently by interference testing. Combined with log and field data, this information was essential for deciding how best to produce the well for the purpose of the project. For example, because Zone 1 was isolated, appeared most productive and was proximal to the oil/water contact, it was produced first at a low rate. Using a low-capacity pump and a downhole valve set at 9.3% open, scientists monitored water migration inside and at a distance from the wellbore using the various technologies. While Zone 1 was produced for one week, the annular pressure stayed fairly constant, indicating good pressure support in this portion of the reservoir.

The resistivity array captured the water movement in Zone 1. Data acquired by the array during the first five days of production indicated clear effects of water movement in Zone 1 many hours before downhole pressure sensors noted water production at the wellbore. Shortly after this period, downhole tubing pressure increased, indicating significant water arrival at the wellbore followed by an increase in produced fluid density at surface 11 hours later (previous page, bottom). No effects were observed in the other production intervals during the Zone 1 production phase, once again confirming Zone 1 isolation (above right).

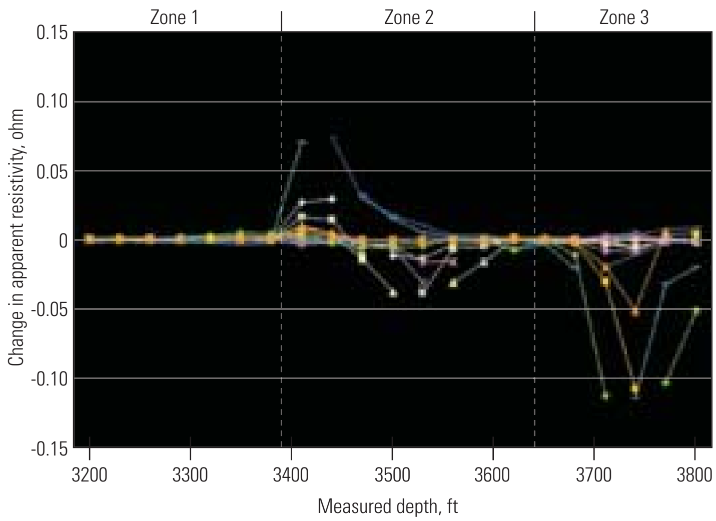
Interference testing was performed on Zones 2 and 3. After a shut-in period, the downhole valve controlling production from Zone 3 was opened 100% and the interference effects on Zone 2 were observed in the annular pressure data (right). The analysis showed that the zones communicated, and the slow buildup rates indicated that pressure support across these intervals was poor. Derivative plots clearly demonstrated a 14-minute communication delay between Zones 2 and 3, and showed no response in Zone 1. Zone 2 interference on Zone 3 was then tested by monitoring annular pressures while the



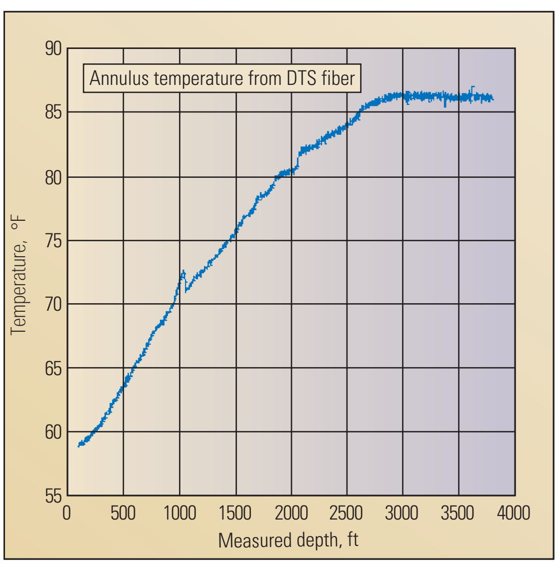
^ Identifying far-field water migration using a 21-electrode resistivity array. Many hours before downhole pressure sensors noted water production at the wellbore, the resistivity array identified water movement in the formation as a result of producing Zone 1. The formation adjacent to the Zone 1 completion interval showed changes, but the other completion intervals—Zones 2 and 3—did not, confirming that Zone 1 was not communicating. The data are displayed as voltage differences from acquisition cycles 10 hours apart. They are represented by two curve segments with points corresponding to the change in voltage at the measurement electrodes along the length of the completion interval to either side of the injector electrode.



^ Interference testing between completion intervals Zone 2 and Zone 3. After a shut-in period, the downhole valve controlling production from Zone 3 was opened 100% and the interference effects on Zone 2 were observed from annular pressure data *(left)*. The analysis showed that the zones communicated. Zone 2 was then opened to measure the interference on Zone 3 *(center)*. This test showed a greater response in Zone 3 to Zone 2 production than in Zone 2 to Zone 3 production. Buildup data from these tests were also used to determine the horizontal permeability of the Cypress sand adjacent to those intervals.



^ Identifying far-field water migration in the formation at Zones 2 and 3. While Zone 3 produced for a period of four days, the resistivity array clearly identified water movement in both Zones 2 and 3 but showed no water movement in Zone 1.



^ Temperature profile from the Simpson No. 22 well. The temperature profile is a snapshot during Zone 3 production and shows the geothermal gradient in the vertical section *(left)* and the flattened temperature profile in the horizontal section *(right)*. The small increase in temperature at 1037 ft [316 m] is from the heat of a running pump.

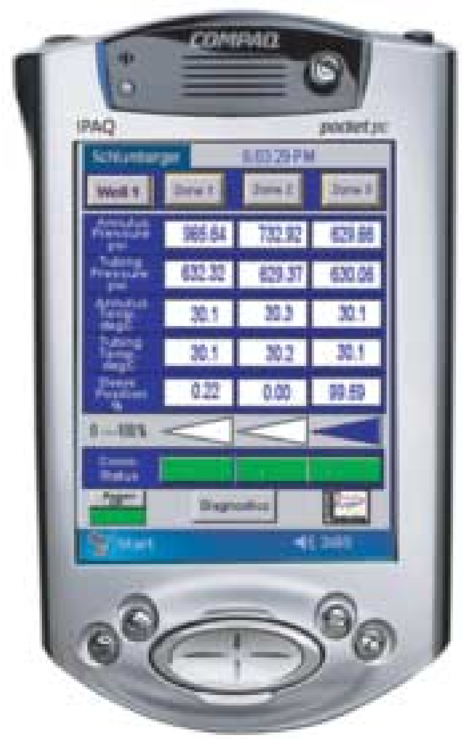
downhole valve controlling Zone 2 production was opened. This test showed a greater response in Zone 3 to Zone 2 production than in Zone 2 to Zone 3 production. This, coupled with buildup-test data from both zones and production-test data with both zones open, established that both zones exhibit good horizontal permeability—100 to 500 mD—but display heterogeneous characteristics. Zone 3, however, displayed higher vertical permeability because of its greater response to Zone 2 production. During the four-day production period for the Zone 3 completion interval, the resistivity array clearly identified water movement in both Zones 2 and 3 but showed no water movement in Zone 1 (left).

The DTS fiber installation in the Simpson No. 22 well provided valuable temperature information across the entire completion interval and validated the deployment and splicing techniques used during the project. Downhole pressure and temperature gauges alongside the DTS fiber confirmed the proper calibration of the DTS measurement and ensured that the data being acquired were accurate. The DTS data during well flow show the geothermal gradient and the relatively flat temperature profile across the horizontal completion interval (below left).

Connecting to the Reservoir from Anywhere

The RES2000 installation of permanent completion systems in Indiana showed that wells could be optimally placed, monitored and operated intelligently using downhole electrical valves to adjust zonal inflow. Data accessibility was paramount to success. The unmanned wellsite also had to be protected from intermittent power losses and software failures. Five computer acquisition systems were used at the Indiana wellsite and were incorporated into the data-management structure. Data management included preprocessing steps, such as the activation and issuing of local and remote event alarms, creation of data summaries to facilitate monitoring, and data transfer to separate locations for backup, analysis and interpretation. This required moving vast amounts of data—100 MB per day—to distant sites for decision-making and then from the decision-makers back to the valves for precise control measures. Sites included Schlumberger facilities in Houston, Texas, USA; Clamart, France; and Cambridge, England. Remote monitoring and control were made possible through the Schlumberger Secure Connectivity Center (SCC) in Houston. Using firewall-protected servers and secure connections, reservoir experts did, in real time, use their desktop or laptop PCs to monitor crucial data and access a wellsite computer to control the downhole valves as if the personnel were actually at the wellsite.

The ultimate freedom in accessibility and control now has been achieved. Schlumberger has extended these capabilities to personal digital assistant (PDA) devices, an evolutionary step in mobile computing, and has tested and demonstrated this capability throughout 2002 (right).



^ Connecting remotely to the reservoir. The use of personal digital assistant (PDA) technology was demonstrated during the RES2000 project, allowing asset-team members to monitor and control wells remotely.

Monitoring the Future

Permanent monitoring and control technology must work the first time, every time and deliver years of dependable service thereafter because there are few opportunities to intervene, recover, repair and determine the source of problems should they develop. In 1972, Schlumberger first installed permanent downhole gauges in West Africa, and since then, the operating environments in which they must function have become increasingly demanding. There are misconceptions about reliability today. Ninety percent of the downhole permanent quartz gauges (PQGs) installed since 1994 are still operating reliably. To date, Schlumberger surface-controlled multiposition downhole valves have achieved 75 valve-years of operation with only one failure worldwide.

The proper evaluation of complex design and installation procedures continues to add value to field developments when considering the cost benefits of integrated reservoir monitoring and control. Schlumberger designs customized solutions based on the time demands of E&P customers. Implementation can be placed on a fast track through a process called RapidResponse client-driven product development to assist customers with their aggressive asset-development schedules.

Advanced permanent monitoring and control equipment will continue to become more reliable though the use of rigorous new testing and full system assembly qualification testing (QT) procedures. A clear balance is needed between QT, for controlling development costs, and environmental qualifications to cover the demands of today's operating environments.

Higher levels of automation will help asset teams concentrate on more complex problems and more forward-looking endeavors. Today's well-by-well introductory approach to intelligent completions will be replaced with a field-wide, or systems, approach to optimization. This change will have a tremendous impact on field management, especially in the optimization of reservoir-sweep and artificial-lift systems.

Significant hydrocarbon reserves are trapped in reservoirs previously not considered exploitable without further technological developments, for example deepwater fields with subsea installations (see "High Expectations from Deepwater Wells" *page 36*). Technological breakthroughs in exploration, well construction, formation evaluation and well completions have enabled oil and gas companies to move ahead, tapping increasingly complex and inaccessible reservoirs at economic finding and lifting costs. Advanced completion systems, involving permanent surveillance techniques, streaming data, real-time information, data management, interpretation, efficient use of information technology and timely action through remote well- and field-control methods, are the next step. Operating companies have already seen the potential of this technology to help them increase hydrocarbon recovery, accelerate production, improve production strategies and optimize surface facilities. While the paths that companies choose to take may vary, the convergence of technologies and economics has already set the direction. —MG