Wildlife and the E&P Industry
Reducing Drilling Uncertainty
Multiphase Flow Simulation
Reservoir Mapping While Drilling
Coiled Tubing Integrity
Oilfield Review Apps

Oilfield Review communicates advances in finding and producing hydrocarbons to oilfield professionals. Articles from the journal are augmented on the apps with animations and videos, which help explain concepts and theories beyond the capabilities of static images. The apps also offer access to several years of archived issues in a compact format that retains the high-quality images and content you’ve come to expect from the print version of Oilfield Review.

To download and install the app on your Android† or iPad‡ device, search for “Schlumberger Oilfield Review” in the App Store‡ or Google Play† online store or scan the QR code below, which will take you directly to the device-specific source.

†Android and Google Play are marks of Google Inc.
‡App Store and iPad are marks of Apple Inc., registered in the US and other countries.

Oilfield Glossary

Available in English and Spanish, the Oilfield Glossary is a rich accumulation of more than 5,800 definitions from 18 industry disciplines. Technical experts have reviewed each definition; photographs, videos and illustrations enhance many entries. See the Oilfield Glossary at http://www.glossary.oilfield.slb.com/.
Communications Across Time: Origins and Evolution of Oilfield Review

From the genesis of Schlumberger in 1926, communications on technologies and techniques have been critical to the company’s success and to its collaboration with customers to meet their challenges. I would like to chronicle some communications milestones from Schlumberger history and outline the future of Oilfield Review.

In 1930, Conrad Schlumberger asked his daughter Dominique to start a technical newsletter for the 30 or so field engineers located around the world. Named PROSELEC and based in Paris, this confidential, French-language communiqué ran until the start of World War II.

Conrad believed he had discovered how his rudimentary resistivity tool could be adapted to see deep into a reservoir to virgin oil-bearing rock and that this new technique could identify hydrocarbon-bearing formations. Wireline logs up to that time were used to determine well-to-well correlation. From his Paris office, he communicated the idea via telegraph to all 34 of his field engineers, spread like scattershot over the globe’s hydrocarbon provinces, urging them to experiment.

Marcel Jabiol, logging for Shell in Sumatra in 1930, was the first to try the innovation, and it worked. His logs, showing for the first time that a formation was hydrocarbon bearing rather than water bearing, arrived on Conrad’s desk three months after the initial communication. A new era in oilfield technology had begun.

In 1941, as head of research, Henri-Georges Doll set out on a single page one of the most famous communications in Schlumberger, titled Research program. Doll was there at the start of Schlumberger, initially performing field work. A graduate of Ecole Polytechnique, he had married Conrad’s daughter Annette. Several of the challenges on this handwritten list of 21 projects remain at the heart of Schlumberger research and engineering today. Among them were lateral investigation curves and apparatus to test pressure and permeability of porous beds. Of course, some more immediate operational challenges of the day also made the list—such as insulated weight and 5 galvanometer recorder.

Doll resurrected the technology newsletter in the 1950s, renaming it The Technical Review, to facilitate the exchange of ideas and technology development and solutions to field problems between research and engineering and the field. The Technical Review was based in Ridgefield, Connecticut, USA, home of the first Schlumberger center dedicated to research. This publication was highly confidential; named copies were distributed to engineers and technical managers around the world.

Schlumberger recognized that increasing collaboration with its customers was essential for the development of the technologies necessary to effectively understand and exploit increasingly challenging hydrocarbon reservoirs. As a result, in 1986, Schlumberger customers began to receive The Technical Review.

The first edition of Oilfield Review was published in 1989, a result of a merger of The Technical Review with journals previously published by Anadrill and Dowell, now parts of Schlumberger. The Oilfield Review staff of eight was split between the Schlumberger research centers in Ridgefield and Cambridge, England.

Oilfield Review today has a print distribution of 20,000, a reader-app and an increasingly important online presence on the Schlumberger website, slb.com. The ever-expanding Oilfield Glossary—also available as an app in both English and Spanish—and the series of Defining articles round out the online journal.

Over the next 12 to 18 months, Oilfield Review will strengthen its online presence and encourage deeper and broader engagement of the readership, which today far exceeds the print audience. You will continue to see three print issues per year as well as an increasing amount of content available online, organized in a contemporary and accessible format.

As oil and gas assets become more complex and working environments more challenging, communications and collaboration across the industry are more important than ever. Oilfield Review will continue in its role as an authoritative, objective and educational resource for E&P industry professionals around the world.

Charles Cosad
Executive Editor, Oilfield Review
Houston

Charlie Cosad joined Schlumberger in 1978 as a wireline field engineer in the Far East and then held a number of technical and managerial positions throughout that region and the Middle East. He then moved to the North Sea as a project manager in Oilfield Services and the IPM Segment and served as the BP Eastern Trough Area Project wells team leader. Subsequently, he moved to Houston as marketing manager for Camco International and the Well Completions and Productivity Segment and then served as technology manager for the IPM Segment based in the UK. He then became business development manager for real-time technologies and services and in 2010 director of marketing communications, based in Paris. Charlie has a BS degree in mechanical engineering from Syracuse University, New York, USA, and an MS degree in aerospace and mechanical engineering from Princeton University, New Jersey, USA.
Communications Across Time: Origins and Evolution of Oilfield Review

Editorial contributed by Charlie Cosad, Executive Editor, Oilfield Review

Marine Wildlife and E&P Activities—Working to Coexist

In the course of marine exploration and production activities, interactions with the environment and wildlife are inevitable. Research on seismic sources that are less invasive than those previously used is helping companies conduct surveys that have minimal impact on marine life. Additional activities that affect bird behavior are also under study.

Reducing Uncertainty Ahead of the Bit

A new drilling solution integrates surface seismic and well data and generates models to predict geologic conditions and formation pressures ahead of the bit. The models help geophysicists and engineers optimize reservoir contact and reduce the uncertainty of geohazards ahead of the bit.

Multiphase Flow Simulation—Optimizing Field Productivity

Operators are constantly on the search for innovative field development tools and techniques to help them balance optimal production with cost. One way in which service providers have met these needs is by developing multiphase flow simulators for wells and pipelines. These simulators help take the guesswork out of well construction and production optimization before operators begin drilling.
38 Reservoir Mapping While Drilling

Advances in LWD log acquisition and processing are helping to bridge the gap between surface seismic data obtained prior to drilling and well log data obtained after the bit has penetrated the formation. A new reservoir mapping-while-drilling service uses deep, directional electromagnetic measurements to provide data on reservoir geometry, lateral heterogeneities and fluid contacts. Using this real-time information, asset teams are able to maximize reservoir exposure and refine field development plans.

48 Monitoring and Managing Coiled Tubing Integrity

The pipe used in coiled tubing operations is subjected to various types of strain as it is run in and out of the wellbore. The resulting wear reduces the pipe’s service life. A wellsite pipe-monitoring system can alert coiled tubing operators to fatigue problems before they become unmanageable.

57 Contributors

60 Books of Note and Coming in Oilfield Review

63 Defining Coring:
Getting to the Core of the Matter

The Defining series informs and educates by presenting in two pages the fundamentals and latest techniques for a range of industry topics.
Marine Wildlife and E&P Activities—Working to Coexist

In its quest for oil and gas reserves, the E&P sector is concerned about the effects of exploration and production on the environment and wildlife. For decades, researchers have studied the environmental impacts of industry activities on various species of marine mammals, fish and migratory birds. Regulations and standards for conservation of the environment have been developed based in part on results of these studies, and the effectiveness of these various measures is continuously assessed by both the E&P industry and external organizations.

The geographic expansion of the pursuit for oil and gas reserves brings an increased potential for ecological side effects. Because exploration and production activities bring with them the potential for impacting wildlife and the environment, E&P operators and service companies are increasing their focus and efforts on minimizing the impact of industry activities.

In the early stages of exploration, seismic surveys play a vital role in helping scientists identify and determine the extent of subsurface prospects. Anthropogenic, or human-made, sound is a necessary component of such surveys and may be a stressor to fauna in some environments. For more than four decades, researchers have examined the effects of anthropogenic sound on marine life.

Marine seismic survey. An airgun array produces pulses of sound energy that penetrate the subsurface and are reflected back from rock interfaces toward the hydrophone sensors. (Adapted from API, reference 7.)
marine mammals as well as on various species of fish.\textsuperscript{1} Results from these studies have led operators and service companies to manage sound in an effort to protect marine fauna.\textsuperscript{1}

Birds, especially during migration, may also be affected by E&P and other industrial activities. Migrating birds frequently navigate by sight and are attracted to strong artificial light originating from structures such as lighthouses and offshore platforms. In the vicinity of these structures, birds may make navigational errors, potentially leading to their demise.\textsuperscript{2}

Effects of oil and gas E&P activities on the environment and wildlife depend on several factors; these include type of process, project size, project planning accuracy, pollution prevention and mitigation and the nature and sensitivity of the surrounding environment.\textsuperscript{3} This article focuses on the effects of seismic surveys on marine mammals and fish, discusses the influence of offshore platforms on migratory birds and reviews current mitigation strategies used by the oil and gas industry.

**Marine Seismic Surveys**

Seismic surveys have been used by the industry for more than 80 years. These surveys are essential tools for geophysicists investigating what lies hidden underground. Explorationists use data from seismic surveys to image the Earth’s subsurface and predict the distribution of hydrocarbons within rocks (previous page). Geophysicists and geologists interpret the survey data for input in developing exploration strategies, making drilling decisions and creating field management plans. Modern seismic imaging reduces risk by increasing the likelihood that exploratory wells will successfully encounter hydrocarbons, and also reduces the number of wells needed to optimally exploit a reservoir.\textsuperscript{4}

Marine seismic surveys rely on a strong acoustic source to generate sound waves that travel to the seafloor, penetrate and reflect from subsurface rock layers and return to the surface, where they are recorded by hydrophone sensors. The sensors are attached to multiple streamers,
which can contain up to 3,500 hydrophones each, and are towed behind a survey vessel (above). During the early days of marine seismic exploration, explosives such as dynamite were the only sources available for generating enough energy to produce the resolution desired for interpretation. These early marine seismic surveys typically used modified land exploration equipment. Explosive charges were detonated in water at depths ranging from a few to tens of meters; charge size and depth depended on the local geology, type of noise interference in the area and desired depth of seismic wave penetration into the subsurface.

Over the years, many types of marine sources have been developed; however, the airgun has proved to be the most effective. An airgun emits a sound as it releases compressed air into the water. This underwater air bubble oscillates and produces a complex source wavelet. The next advance in seismic sources was the introduction of the tuned airgun array—a collection of airguns activated at specified time intervals—which increased source strength and minimized the size of the bubble pulses relative to that of the primary pulse, creating a wavelet similar to that from an explosive source. By the mid-1970s, more than 50% of marine surveys used tuned airgun arrays as the source—a percentage that increased through the ensuing years. Today, airgun arrays typically have 20 to 30 individual guns arranged in an approximate square about 15 to 20 m [50 to 66 ft] on a side. By choosing the optimal gun size and determining the depth at which to deploy the array, a survey planner has some measure of control over the frequency characteristics of the seismic pulse produced by the array.

In the 1980s, 3D seismic surveys began to replace traditional 2D surveys. The 3D survey acquires data in a grid pattern that more accurately images the Earth compared with that of 2D surveys. Because seismic vessels towed only one streamer, acquiring the number of lines necessary for 3D coverage was extremely expensive. To reduce cost and boost efficiency, in the 1990s, contractors increased the number of streamers from one to two, then to three, four, six and eight. Today, this progression has continued, and vessels are capable of towing 10, 12 or even 18 streamers simultaneously.

Independent dual airgun sources that release the compressed air in a left-right-left pattern—known as flip-flop—were also introduced. The increased number of streamers and dual sources allow seismic survey vessels to record multiple subsurface lines by performing a single traverse of a survey area. This acquisition efficiency has made 3D marine surveys a practical and invaluable exploration tool.

Marine seismic survey acquisition programs are the least intrusive and most cost-effective option for pinpointing oil and gas traps beneath the ocean floor. Survey operations are conducted from vessels moving at a speed of approximately 4.5 to 5 knots [8.3 to 9.3 km/h; 5.2 to 5.8 mi/h]. The sound does not persist in any one location because the airgun arrays are typically activated every 10 to 15 seconds, and the vessel moves between pulses. The sound direction is vertically focused and has a normal peak-to-peak source level of around 220 to 260 decibels (dB), which is the same order of magnitude as sounds from some natural sources (next page, top). The duration of each survey depends on the area to be covered, operating parameters and source configuration.

Survey acquisition time can be affected by weather conditions and time of year. A large 3D exploration survey offshore West Africa typically achieves an average survey rate of 50 to 60 km²/d [19 to 23 mi²/d]. Because of different weather and sea conditions, the same type of survey conducted during summer in the North Sea might attain a rate of 25 to 30 km²/d [9.6 to 11.6 mi²/d].

Although the duration of marine surveys is important, the amplitude of underwater noise generated by the seismic source may have the greater impact on marine wildlife. Noise—essentially sound waves—has three main attributes: frequency, wavelength and amplitude (next page, bottom). The frequency, \( f \), represents the number of pressure waves passing a reference point per unit time, measured in cycles per second, or hertz (Hz). The wavelength, \( \lambda \), is the length of a sound wave measured between two peaks and is linked to the frequency through the sound velocity, \( v \), in a medium. Low frequencies correspond to long wavelengths; high-frequency sound waves have short wavelengths. The amplitude describes the intensity or loudness of a sound, commonly given in dB. Small amplitudes correspond to

---

\[ \text{Sound intensity (SI)} = \text{Sound pressure (SP)} \times \text{Sound velocity (SV)} \]

\[ \text{Sound level (SL)} = 20 \log_{10} \left( \frac{\text{Sound pressure (SP)}}{\text{Reference sound pressure}} \right) \]

\[ \text{Sound power (SW)} = \text{Sound pressure (SP)} \times \text{Sound velocity (SV)} \times \text{Source area (SA)} \]

\[ \text{Sound pressure (SP)} = \frac{\text{Sound power (SW)}}{\text{Source area (SA)}} \]

\[ \text{Sound velocity (SV)} = \frac{\text{Sound pressure (SP)}}{\text{Sound intensity (SI)}} \]
weak or quiet sounds, whereas large amplitudes correspond to strong or loud sounds.

Sounds in the sea can be characterized as intermittent, local or prevailing, and they are categorized by their source—natural or anthropogenic. Relative to sounds made by marine mammals, a typical airgun generates sound of slightly higher amplitude. However, other sources of high-amplitude noise exist in the open ocean, for example, echo sounders on ships and naturally occurring sound from sources such as lightning strikes, undersea earthquakes and volcanic eruptions.6

**Sound Effects**

Ocean water is a poor conductor of light but a good conductor of sound. Consequently, marine wildlife have evolved to rely mainly on their auditory systems for orientation, communication and foraging. Anthropogenic noise has the potential to interfere with all these functions. Effects from sound can be generally categorized as physical or behavioral. Researchers have studied the influences of seismic surveys on assorted species of fauna in the marine environment.7

The auditory systems of ocean fauna are the most susceptible to physical damage from sound pressure. As a result, mitigation measures that aim to prevent auditory damage should protect against physical impacts such as tissue damage. Physical auditory problems may occur from prolonged exposure to intense sound, resulting in loss of hearing sensitivity. The level of temporary threshold shift (TTS) depends on the level of exposure and may last from several minutes to hours.8

**Table:**

<table>
<thead>
<tr>
<th>Source</th>
<th>Source Level, dB re 1 μPa at 1 m</th>
<th>Frequency Band of Major Amplitude</th>
<th>Normal Duration</th>
<th>Directionality</th>
</tr>
</thead>
<tbody>
<tr>
<td>Marine Life Sounds</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sperm whale click</td>
<td>236 rms</td>
<td>5 to 40 kHz</td>
<td>Tens of μs</td>
<td>Focused</td>
</tr>
<tr>
<td>Bottlenose dolphin vocalization</td>
<td>225 peak to peak</td>
<td>Very broadband in kHz range</td>
<td>70 μs</td>
<td>Focused</td>
</tr>
<tr>
<td>Killer whale sounds</td>
<td>224 peak to peak</td>
<td>12 to 80 kHz</td>
<td>80 to 120 μs</td>
<td>Focused</td>
</tr>
<tr>
<td>Baleen whale moan</td>
<td>190 rms</td>
<td>10 to 25 Hz</td>
<td>Tens of s</td>
<td>Omnidirectional</td>
</tr>
<tr>
<td><strong>Anthropogenic Sounds</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Echosounders</td>
<td>235 peak</td>
<td>1.5 to 36 Hz</td>
<td>ms</td>
<td>Strongly vertically focused</td>
</tr>
<tr>
<td>7,900-in.³ airgun array</td>
<td>259 peak</td>
<td>5 to 500 Hz</td>
<td>30 ms</td>
<td>Vertically focused</td>
</tr>
<tr>
<td>Single 30-in.⁴ airgun</td>
<td>221 peak</td>
<td>10 to 600 Hz</td>
<td>60 ms</td>
<td>Omnidirectional</td>
</tr>
<tr>
<td>Naturally Occurring Sounds</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Volcanic eruptions</td>
<td>255 peak</td>
<td>Broadband</td>
<td>Seconds to hours</td>
<td>Omnidirectional</td>
</tr>
<tr>
<td>Lightning strike</td>
<td>260 peak</td>
<td>Very broadband</td>
<td>μs to s</td>
<td>Omnidirectional</td>
</tr>
</tbody>
</table>

^ Sounds in the marine environment. Underwater sound can have both natural and anthropogenic origin, and when these sounds overlap, anthropogenic sounds may mask marine-life sounds. Standard reference sound pressure in water is 1 μPa. In the chart above, all references are broadband-level values given in dB, standardized at 1 μPa at 1 m (dB re 1 μPa at 1 m) for source levels and dB re 1 μPa root mean squared (rms) for received levels, where “re” stands for reference value. [Adapted from “Appendix 1: Sounds in the Marine Environment,” Seismic Surveys and Marine Mammals, Joint OGP/IAGC position paper, http://www.ogp.org.uk/pubs/358.pdf (accessed February 24, 2015).]

9. The decibel (dB) is a unit of measurement to compare the relative intensity of acoustic signals and is equal to one-tenth of a bel. The dB equals 20 x log10 (measured value over reference value). Accordingly, each 20 dB corresponds to a power of 10 increase or decrease in amplitude relative to the reference amplitude: 200 dB = 10^2, 100 dB = 10^1, 40 dB = 10^0, 20 dB = 10^-1, 3 dB = 10^-2, −20 dB = 10^-1, −40 dB = 10^-2, −100 dB = 10^-5 and −200 dB = 10^-10.

^ Basic components of a sound wave. Period, frequency and amplitude constitute the basic components of a sound wave. The period of this sound wave is 0.5 s, and the frequency is 2 cycles per second, or 2 Hz. The amplitude scale is for reference and depends on the intensity of the source. The wavelength (not shown) is the distance sound travels in one period and depends on the speed of sound through the medium in which it is traveling. Sound travels at about 1,500 m/s through seawater so the wavelength is about 750 m.
threshold shift (TTS)—a measure of temporary hearing loss—and time to recover remain a subject of study. Experts have not yet come to a conclusion on what constitutes unacceptable risks to marine mammals.

Several factors may influence the effects of noise on marine wildlife, including the characteristics of the noise, the sound propagation in the environment and the animal that is exposed to the noise. Models of potential zones of impact around a noise source have been developed based on changes observed in species of marine mammals and fish. These models indicate the possible results of exposure to noise, including hearing loss, communication masking and various behavioral responses, and the severity depends on distance from the source (left).

Numerous studies conducted worldwide have attempted to determine whether sound produced by seismic surveys affect marine life behavior (next page). Many of these studies have focused on marine mammals, such as whales and dolphins, because they depend on sound for locating food as well as for socialization. Studies on the effects of seismic surveys on humpback whales offshore Angola have shown that their singing and vocalizing activity decreases when seismic surveys are conducted. Noise from seismic surveys has been found to cause avoidance behavior—wherein marine mammals vacate the survey area because of the noise—in several species of dolphins and whales (below left).

Although knowledge gaps still exist, during the last two decades, scientists’ understanding of potential impacts on marine wildlife, which include behavioral changes, masking of naturally significant and relevant sounds, physical injury, auditory injury and stranding, has expanded significantly.

Although little research is available on behavioral and ecological impact on fish as a result of long-term anthropogenic noise, scientists have ascertained that the survival and reproductive abilities of several species of fish may be affected by sounds originating from E&P activities. If human-made noise deters fish, or if noise has adverse effects on fish reproduction or survival, fish diversity and abundance in noisy environments would presumably decline. Currently, little conclusive data exist to indicate a negative link between fish abundance and noise levels. However, anecdotal reports indicate that fish catch rates decrease in areas of persistent anthropogenic noise because fish vacate the area. The seismic-associated reductions in catch rates appear to depend on species and fishing methods.
Regulating Noise

Many government and international agencies have developed guidelines and regulations to mitigate potentially adverse impacts of E&P sound on marine wildlife, but no common agreement has emerged. In 1995, the UK initiated the implementation of national regulatory guidelines for E&P activities. Today, the UK Joint Nature Conservation Committee (JNCC) is responsible for establishing guidelines to minimize the risk of injury and disturbance to marine mammals from seismic surveys. These guidelines form a basis for regulations and recommendations used by other countries and organizations.

To date, entities from Australia, Brazil, Canada, Ireland, New Zealand, the UK and the US have standardized regulations and guidelines. In much the same way as the JNCC operates in the UK, the International Association of Geophysical Contractors (IAGC) engages with international government agencies to develop E&P activity regulations. The IAGC Sound and Marine Life (SML) work group has developed guidelines and recommendations for mitigation measures and reporting forms for marine wildlife observers (MWOs) and marine mammal observers (MMOs). The SML was a founding partner of the International Association of Oil and Gas Producers (IOGP) Sound and Marine Life Joint Industry Program, as were several E&P companies.

14. Masking occurs when introduced noise interferes with a marine animal’s ability to hear a sound of interest. Stranding occurs when marine mammals become trapped on land or stuck in shallow water.
Although currently no country-specific regulations and no conclusive scientific evidence exist to support marine mammal injury as a result of seismic survey activities, IAGC members use basic minimum mitigation measures as outlined in IAGC guidance documents.17 These measures include planning presurveys, establishing various caution zones, developing soft start or ramp up procedures, enhancing visual observation and performing passive acoustic monitoring. Important factors in presurvey planning include source design and survey timing to avoid areas known to host biologically significant animal life functions. Survey planning is essential to ensure that the survey location is not conducted in areas where mammals are feeding or breeding.

Caution zones—identified prior to the commencement of operations—may be further classified as exclusion zones. Exclusion zones are typically defined as the area at and below the sea surface within a radius of about 500 to 2,000 m (1,640 to 6,600 ft) surrounding the source array center and normally dictate the location and type of sound source to be used.18 These zones are continuously monitored for the presence of marine mammals and other marine wildlife. In the event marine wildlife mammals are observed within the exclusion zone, the operating company activates mitigation measures such as delaying the start of or shutting down the sound source to reduce potential harmful effects on the nearby wildlife.19

A soft start, or ramp up, is defined as the time from when airguns commence shooting until they have full operational power. This procedure generally implies a slow buildup of energy, starting with the smallest airgun in the array and gradually adding others over at least 20 minutes to provide adequate time for marine mammals to vacate the specific area. The survey line typically commences immediately after the completion of the soft start.20

To conduct visual monitoring during the seismic survey operations, MMOs and MWOs coordinate monitoring efforts with survey operation teams and give advice on country- or area-specific guidelines, regulations and permits. In areas without specific regulations, the visual observers commonly consult the guidelines in IAGC Recommended Mitigation Measures for Cetaceans during Geophysical Operations and Guidance for Marine Life Visual Observers. The MMOs and MWOs are expected to be impartial, and they report animal sightings and monitoring efforts to the client company or geophysical contractor on a daily basis.

The MMO reporting forms were first introduced in 1998 for UK offshore activities and have been widely adopted by industry operations. In 2011, the IAGC board of directors formally adopted the Recommended Visual Observer Reporting Forms, which were reviewed and approved by the IAGC SML work group, Americas Offshore committee and Global HSE & Security Steering committee. These templates, recommended for use by all IAGC members, serve to improve quality and consistency of marine mammal observations and provide important data to increase scientists’ knowledge about how sound affects marine fauna.

If a specific species protected by guidelines or regulations is observed within the exclusion zone during operation, MMOs and MWOs have the authority to call for a shutdown or delay in operations. When visual observers give notification, the shutdown or delay must take place immediately, and neither the vessel captain nor client representatives may override this decision. After the MMOs have ensured that the species is no longer in the exclusion zone, operations may resume.21

Sometimes, visual observation can be an ineffective mitigation tool. During periods of darkness or when weather and sea conditions hinder visual observations, visually detecting marine mammals in and around the seismic survey area is difficult. Under such conditions, passive acoustic monitoring (PAM) is the only technique available for marine mammal detection. This technique uses hydrophones and software to detect the vocalizations of marine mammals.

A basic PAM system is composed of a hydrophone array, which detects the vocalization of marine mammals; a system to amplify and condition the signal; a signal acquisition device; and a computer to run the PAM software. The system is capable of locating, identifying and monitoring marine mammals within a survey area in real time. Regulatory agencies are increasingly requiring or encouraging the use of PAM systems, thereby reducing the potential environmental impacts from marine seismic operations.

Currently, standards requiring PAM are in place in Canada and New Zealand and are being developed in Trinidad and Tobago and Brazil. Because increases in E&P activities are imminent in the Arctic region, robust standards are expected to be implemented for this environmentally sensitive area.22 The industry is working toward adopting a worldwide set of guidelines and regulations.

The setup and employment of PAM equipment as well as the interpretation of detected sound data require trained PAM operators. Sometimes, the range or distance, as determined by a PAM array, can be inaccurate. For example, if a PAM system has an accuracy of about 300 m [1,000 ft], species detected and calculated to be within 500 m of the seismic source may actually be 800 m [2,625 ft] away. Nonetheless, the MMO must still instigate a stop or delay of the soft start.

In 2008, PAMGUARD, an open source software that processes and analyzes cetacean sounds, had its first industry field trial during a seismic survey in the Gulf of Mexico. Funded by the IOGP E&P Sound and Marine Life Joint Industry Program, PAMGUARD software was developed to correct the inaccuracies and imprecisions of the PAM system. PAMGUARD is becoming the standard software for acoustic detection, localization and classification for mitigation against harm to marine mammals and for research into marine mammal abundance, distribution and behavior.23

Leading Light

Bird-platform interactions are another observed side effect of the presence of oil and gas platforms. Seabirds and terrestrial birds are attracted to lights and gas flares and sometime collide with offshore installations.24 The occurrence of these incidents tends to increase in poor weather conditions such as fog, precipitation and low cloud cover, especially when such weather coincides with bird migrations.

The monitoring of birds at offshore platforms is traditionally observer based. The technique is time-consuming and has limited coverage. To be effective, observations should be performed by trained personnel.

Interactions between birds and offshore infrastructure, including platforms and windmills, may have both lethal and nonlethal direct effects. Interactions include collisions with infrastructure, incineration in gas flares and exposure to oil and drilling fluids. Birds may also experience exhaustion and starvation as a result of being diverted to the artificial light source. In some cases, interactions may not be necessarily harmful; platforms can provide roosting and resting sites. Little research and data are available on indirect impacts, which may include creation of foraging opportunities, exposure to predators, habitat alteration and changes to natural ecosystem functions.

The effects on population levels as a result of direct platform mortality may be regional, species specific and depend on the number of operational platforms encountered by migrating birds. Documented bird mortality numbers also vary greatly and may be incidental. Some reports are based solely on the number of dead birds found on platforms; hence, any birds that die and fall in the sea or go unnoticed will not be counted. Some
estimates of annual bird mortality at the more than 1,000 platforms in the North Sea are as high as 6 million, whereas in the Gulf of Mexico, which has nearly 4,000 platforms, reports estimate 200,000 collision deaths per year.\textsuperscript{15} Collisions involving large seabirds such as gulls have occurred, although numbers are small. In addition, geese and ducks have been known to alter their flight paths to avoid encounters with offshore structures. The risk of collision, stranding and incineration of seabirds is believed to be restricted mainly to smaller seabirds, such as storm petrels, that are attracted by rig and platform lights.\textsuperscript{21}

Artificial illumination on offshore oil and gas installations affect migratory and nonmigratory birds in different ways. At night, in overcast or foggy conditions, lights may interfere with the birds’ ability to orient themselves. Nocturnally migrating birds may divert from their migration route as a result of artificial light sources. Diversion of migrating birds has been documented in the North Sea, the Gulf of Mexico and offshore Australia.\textsuperscript{22} Nighttime light pollution comes not only from the E&P industry but also from other offshore facilities, including wind farms, ships, harbors and lighthouses.

Although the causes and consequences of birds’ attraction to light and flares from offshore installations have been studied, little data exist for quantifying these phenomena. Some mitigation measures have been tested, including shielding or reducing the light and changing the color of the light.\textsuperscript{26}

Birds use various tools for orientation and navigation, including visual cues and magnetic sensitivity, which are especially important in cloudy conditions and overcast nights. Research suggests birds respond to a magnetic “compass” effect, which depends on wavelengths of light. The studies indicate that migratory birds use light from the blue-green end of the spectrum for orientation; however, red light may be disruptive to their navigation systems.\textsuperscript{27} A field study conducted in the Dutch Wadden Sea aimed to determine whether a change in light color might influence nocturnally migrating birds. Preliminary conclusions drawn from this study include the hypothesis that the long wavelength part of the visible spectrum, including white and red light, causes significant disorientation, whereas shorter wavelengths, especially green and blue light, appear to have little or no disorienting effects on the birds.\textsuperscript{30}

Based on years of observations, studies conducted offshore the Netherlands have shown that conventional lights on offshore installations attract large numbers of migrating birds. In periods during which all lights were switched on, large numbers of birds assembled on and around the installations, but after the lights were switched off, the birds disappeared almost immediately. For operational reasons, switching off all lights is not a feasible option. However, further tests evaluating the effects of different color lights revealed that color is significant to the degree of disorientation. After modified lights were installed and conventional light was switched to light that had less red and more green spectrum light, visual disorientation impact on birds was significantly reduced. These results demonstrate the potential of reducing disorientation and attraction effects on birds from offshore installations can be achieved by introducing light that has increased green spectrum. Tests using these modified lights have not revealed any problems related to work safety for offshore personnel. This spectral-modified lighting may present a viable method for reducing bird attraction to offshore installations in the future.\textsuperscript{31}

In 2000, the Dutch E&P company Nederlandse Aardolie Maatschappij (NAM) conducted a series of tests in which lights at an offshore installation in the North Sea were switched on and off; the company also evaluated various illumination regimes (above). Results indicated that birds

![Table: Time After Light Remained on, Min | Observed Number of Birds](image)

18. The standard exclusion zone radius is 500 m, but it may be extended to 2,000 m in sensitive areas.
24. Seabirds are species that spend most of their life at sea and include gulls, petrels, auks and sea ducks. Land birds are terrestrial and include aquatic species such as passerines, waders and raptors.
react quickly to lights being turned off; no birds were observed 15 minutes after the lights were switched off. The NAM study also revealed that lights using the red part of the spectrum, the longer wavelengths, caused the most disorientation for the birds. Conventional lighting was replaced with platform illumination that had only 5% red in the spectrum; the gathering of birds surrounding the platform decreased by a factor of 2. These findings correspond with the observations from the field study in the Dutch Wadden Sea.

The attraction to platforms may also cause bird deaths as a result of exhaustion and starvation. In the event that birds are interrupted or disturbed during migration, their energy, which is reserved for often lengthy migrations, may be drained quickly, which can be lethal. Although platforms may, on the other hand, serve as resting sites, if the birds rest too long on platforms, they may not have sufficient energy to complete their migration, and as a consequence, they may die before reaching their destination. Some bird species deviate from their planned migration...
Birds such as gulls have been observed both resting and roosting on platforms, and for some birds, platforms serve as hunting grounds during migration. Platforms that have structures rising from the sea floor often act as artificial reefs, thereby potentially increasing marine food supply, which can be favorable to seabirds.  

Light from offshore platforms attracts not only birds but also other prey—plankton and small fish—potentially increasing the abundance of food for seabirds. Similarly, insects drawn to lights may increase the food availability for terrestrial birds that have become stranded on platforms, thereby enabling the birds to continue their migration.

**Neither Heard nor Seen**

Recent advances in technology and equipment have helped to mitigate the environmental impacts of E&P industry activities; one such example is the Q-Marine point-receiver marine seismic system, developed by WesternGeco. In addition to providing accurate and reliable seismic survey data, the Q-Marine sensors can be used to detect nearby marine mammals by deploying the WhaleWatcher system. This system represents a significant advantage to the traditional observer-based detection in that it allows cetacean detection below the sea surface.

The WhaleWatcher passive acoustic monitoring technology enables remote detection of marine mammals during seismic survey operations and can triangulate whale sounds to obtain the distance and bearing to the animal. The technique benefits from the fact that cetaceans use high-frequency clicks for echolocation and middle-to-low frequencies for communication. Because these sounds are in the sensitivity range of both the streamer hydrophones and the sensors in the IRMA intrinsic range modulated acoustic positioning system, the hydrophones and sensors are able to detect the distinctive calls from various species, which can be identified via frequency analysis (previous page).  

The single-sensor configuration of the Q-Marine system enables signal analysis to accurately determine an animal’s distance and azimuth relative to the seismic source. The technique provides seismic survey teams with a real-time presentation of marine mammal locations throughout the duration of the survey. In addition, it provides a continuous and reliable means of monitoring cetaceans in periods of limited visibility and does not rely on above-surface observations of the animals. The information provided by the WhaleWatcher system can be used to make operational decisions, including delaying startup or shutdown, in the event that marine mammals are detected within the exclusion zone.

Recent research efforts have focused on developing a marine airgun array that has a smaller frequency bandwidth with less dispersion; this array will further minimize environmental impact. Research indicates that marine wildlife is most sensitive to high- and midfrequency range sounds. The eSource airgun, the first bandwidth-controlled seismic source, has been engineered to enhance the low-frequency components essential to seismic exploration while reducing the high-frequency components, which may reduce the possible disturbance to marine life. The eSource airgun was developed by Teledyne Bolt, Inc., and the design is based on principles established through modeling work performed by WesternGeco scientists. This airgun reduces exposure levels and peak pressure and allows a gradual release of air at a predetermined rate. Users can tune the spectral content of the pressure signal based on the local marine mammal sensitivity. Reliability tests are currently being performed, and the eSource airgun is expected to be commercially available in 2015.

Studies have documented instances of both the presence and absence of marine wildlife behavioral responses to various anthropogenic sound signals; hence, researchers can, at present, draw no universal conclusions on the effects of sound on marine fauna. Although scientists realize that sound is important to life in the oceans, current knowledge on the impact of anthropogenic sound is incomplete. However, scientists generally agree that exposure to human-made sounds and offshore structures can produce a range of adverse effects on marine life and birds, including behavioral changes, marine mammal strandings and bird collision deaths.

Marine life can be protected by developing more sensitive receivers and adaptive seismic sources that have lower intensities and sound emissions than sources currently in use. Enhancing current systems such as PAMGUARD for locating, identifying and monitoring marine mammals also offers promise. Future work and research will focus on reducing the negative consequences of anthropogenic noise. The E&P industry’s ability to coexist with marine life will be a benefit to all.  

—IMF
Reducing Uncertainty Ahead of the Bit

Operators use seismic and offset well data to plan drilling trajectories. However, the actual geology encountered by the drill bit may differ significantly from what was anticipated. Reducing geologic uncertainty is a key to minimizing drilling risk and nonproductive time. A new service integrates surface seismic reflection and downhole data while drilling to generate structure and pore pressure models ahead of the bit.

Drilling is fraught with uncertainties arising from incomplete knowledge about the subsurface. To counter these uncertainties, operators assemble an earth model incorporating geology, formation mechanical properties, in situ stresses, pressures and temperatures. The information for the drilling prospect comes from seismic and nearby offset well data—well logs, cores, well tests and drilling reports. The earth model prepared by geoscientists is given to the drilling team, who plan the well, including its trajectory, casing points, drilling mud program and other specifications. Based on the drilling plan, the operator estimates the cost of drilling, assuming that the offset information is analogous to that of the well under construction. Engineers increasingly rely on real-time data to manage subsurface conditions and guide the drilling process.

Real-time data are often acquired with measurement-while-drilling (MWD) and logging-while-drilling (LWD) tools, which deliver an array of real-time measurements and allow geologists and engineers to assess properties of formations as the drill bit encounters them. Well conditions, which can change rapidly, may also be assessed and adjusted in near-real time. For instance, casing and mud-weight programs could be modified without interrupting drilling. The incidence and severity of well control actions in response to adverse events could be reduced.

Many real-time data come from tools that look primarily sideways from, or perpendicular to, the wellbore axis into the surrounding rock; therefore, they relate to conditions only behind the bit. Reflection seismic data, which are generally not available in real time, provide geoscientists the opportunity to look ahead of the bit.

As wells become more difficult to drill and are located in increasingly remote areas, the drilling nonproductive time (NPT) is often driven by geologic complexity and the uncertainty that accompanies it. Drillers continuously adjust parameters in response to subsurface conditions. If look-ahead seismic data were available in near-real time, the operator could anticipate future conditions and respond accordingly. For example, casing and mud-weight programs could be modified without interrupting drilling. The incidence and severity of well control actions in response to adverse events could be reduced.

The SGD Seismic Guided Drilling while-drilling integration of surface seismic and downhole measurements offers look-ahead predictive models in relevant drilling time. This article describes how the SGD solution provides geologists and drilling engineers knowledge of the subsurface conditions and an opportunity to drill with increased confidence; case histories from West Africa and China demonstrate its application.
Reducing Drilling Uncertainty and Risk

The Seismic Guided Drilling solution integrates surface seismic and downhole measurements while drilling. Before drilling begins, the method includes multidisciplinary integration of seismic processing and inversion, earth models, geology, geophysics, rock physics, petrophysics, geomechanics, formation pressure prediction and drilling engineering. During the drilling process, the method enables rapid refinement of formation pressure predictions several hundred meters ahead of the bit. It accommodates updates to depths of reservoir targets and models for identifying geohazards and casing points.

Although each project is tailored for specific job objectives, every one comprises three general phases: a feasibility study, predrilling model building and prediction, and while-drilling model updates and predictions (left). A team, consisting of Schlumberger geoscientists and experts from the operator, produces an SGD solution.

During the feasibility phase, the team investigates the drilling objectives, obstacles and risks; assesses various solutions and technologies; and studies seismic data and other relevant data such as previous earth and seismic velocity models, interpreted horizons and hazard predictions. The team then evaluates whether the data are suitable for the job. Finally, the team assesses the uncertainty inherent in using the seismic data for planning the well and monitoring its progress.

After the operator and team determine that it is feasible for the project to be accomplished using available data, they assemble data for building the predrill, or starting, earth model. In the context of the SGD technique, what constitutes an earth model depends on the application. If the intent is to place a well based on geology, then the earth model includes seismic velocities, structural seismic images and interpreted geologic horizons. If the purpose is to predict pore pressure, then the earth model contains a volume of pore pressure estimates. If borehole stability is the concern, then the earth model incorporates a mechanical earth model (MEM).

The earth model encompasses a seismic volume of data—the drilling volume of interest (DVI)—centered on the planned well trajectory and includes any nearby offset wells. The DVI is defined by an area that is laterally about 5 km by 5 km [3 mi by 3 mi] on a side and extends in time or depth to include the reservoir formations of interest. Earth models of this size facilitate rapid updating while drilling and the use of sophisticated processing and computational methods to ensure the model has the highest resolution possible for guiding drilling decisions.

The starting earth model uses surface seismic data as its primary input. To constrain the model further for planning the well, the model incorporates information from other seismic data sources, offset wells, basin models, rock physics models and area geology. Information from offset wells may include logs, borehole seismic data such as checkshots and vertical seismic profiles (VSPs), mud weights and drilling data. The model incorporates multiple parameters and their associated uncertainties. These parameters may include local anisotropic velocities, high-resolution depth-migrated seismic images,
The team developed a predrill velocity model (left, black line) for the well based on existing surface seismic and nearby offset well data. The team then incorporated checkshot velocity data (solid red line) obtained while drilling from the surface to a depth of 8,000 ft and created an updated velocity model (blue line) as if the well had been drilled to 8,000 ft. Afterward, the team incorporated checkshot velocity data (red dashed line) obtained from depths 8,000 to 11,500 ft. Over this depth interval, the updated velocity prediction compared favorably with the checkshot measurements.\(^1\)

In addition, the team used the updated velocities to forecast the pore pressure gradient (right, blue line) in the 8,000- to 11,500-ft interval. This forecast was in good agreement with measurements of the pore pressure gradient (red circles). An equivalent mud weight scale is provided for reference. The green and red curves are the hydrostatic and lithostatic pressure gradients; the lithostatic pressure gradient is the change in pressure resulting from the weight of overburden, or overlying rock, on a formation. (Adapted from Esmersoy et al, reference 9.)
well data to constrain the vertical velocities. The velocity models were used to constrain prestack depth migration (PSDM) and seismic images that showed the fault locations. The casing point was predicted to within 50 ft [15 m] at a distance of 1,500 ft [460 m] ahead of the bit.

Pore Pressure Ahead of the Bit

Abnormal formation pressure is a drilling risk and encountering it incurs nonproductive time and additional consequences, which cost the industry billions of dollars every year. To reduce these risks, drillers need a predrill model of expected formation pressures for determining many aspects of well construction such as casing points and mud weights. These estimates of formation pressure typically have large uncertainties.

The drilling team uses LWD tools to monitor formation pressure and determine formation properties while drilling. However, LWD pressure data are valid down to the current drilled depth and may not represent conditions beyond the bit. To mitigate uncertainty and foster timely decision making during drilling, looking ahead of the drill bit is important. Sonic LWD tools provide accurate and high-resolution elastic wave velocities, which in turn can be used to infer formation mechanical properties, but these tools also characterize the formations behind the bit. In addition to using LWD data, the drill team may rely on seismic reflections to illuminate regions ahead of the bit, but the predrill seismic velocities derived from them may have sizable uncertainties because they have not been constrained by the data from the well being drilled.

The SGD technique forecasts velocities from seismic reflections ahead of the bit and uses the constraints of known velocities along the wellbore behind the bit from LWD measurements to improve the accuracy and resolution of these velocities. At selected drilling depths such as important marker horizons and casing points, the geophysicists recalculate seismic velocities in the earth model based on LWD and drilling measurements and then remigrate the seismic data to produce an updated image of conditions ahead of the bit. The method yields velocities, traveltimes, depths to formation tops and values of formation pressure that match those that have been encountered since the well was spudded and then projects ahead of the bit to predict these values for the next increment of drilling. Reconciling the SGD solution with the well data and updating the earth model reduces the uncertainty of the look-ahead prediction.

The SGD technique was simulated to evaluate pore pressure prediction ahead of the bit in a well in deepwater offshore Nigeria that had been drilled by Total. Total signed a collaborative agreement with Schlumberger for a proof-of-concept study using data from the well, referred to as the test well. The study proceeded in three phases:

- build a starting model from data that existed before the test well was drilled
- simulate a while-drilling update using well data down to a predetermined depth to predict conditions ahead of the drill bit
- evaluate the prediction’s accuracy.

The study was a blind test of the SGD technique; to remove bias, Total concealed information about the test well until such information was necessary to move to each successive phase. To initiate the study, Total provided geologic and geophysical data from regional studies and from...
offset Wells A and B (previous page). The company revealed increasingly more data from the test well after the Schlumberger team completed the work for each phase.

Using these data, Schlumberger geoscientists constructed a predrill earth model of local drilling conditions within the DVI around the test well. The model included drilling, geologic, geophysical, well log and pore-pressure information from Wells A and B. The primary purpose of building a predrill model was to have a starting earth model for the while-drilling updates at subsequent stages. The geoscience team used what they learned about the geology, geophysics, geomechanics and petrophysics associated with the future well to build a new model; such model building, based on this newly acquired knowledge, is crucial for the success of the SGD solution.

The predrill earth model for the test well included a geologic model that identified major horizons. In addition, a rock physics model was developed using well logs from the offset wells. Geophysicists used tomographic velocity inversion and PSDM to create a seismic velocity model and image that were constrained by the geologic and rock physics models. A formation pressure model was also computed from the rock physics and seismic velocity models. To ensure consistency with the area’s structural geology, geologic horizons and velocities observed in the offset wells, the geoscientists input anisotropic velocities into the predrill model. The team completed the predrill model for the test well within 10 weeks of project initiation. In addition, the team prepared workflows for the while-drilling phase to simulate receiving and incorporating new data from the test well during its construction.

Next, the team simulated a rapid while-drilling update using well data down to the bit depth. Total provided VSP, checkshot, LWD and drilling data from the test well down to a specific depth. After these data were delivered, the clock started for predicting conditions ahead of the drill bit (above right). The team was given 48 hours to integrate the new data from the test well into the predrill earth model, rebuild the model, match it to what was known from the drilled section of the test well and predict seismic velocities, pore pressures, marker-bed depths and structures for 700 m [2,300 ft] ahead of the bit. The update was completed in 36 hours. The rapid while-drilling

Test well plan and while-drilling update. Total drilled and completed the test well using the casing plan shown on the left; the expected lithologies were sand (yellow) and shale (green and brown). The PSDM seismic sections, which are colored according to the seismic interval velocities, show the data evolution from legacy through predrill to update. The test well was drilled based on the legacy seismic data. After the Schlumberger team completed building the Phase 1 predrill model, total provided drilling, LWD, VSP and checkshot data from the test well to depth X m. During Phase 2, the team used these data to update the predrill model and predict conditions ahead of the bit for the next section of drilling (X + 700 m). (Adapted from Teebenny et al, reference 13.)

---


10. Abnormal formation pressure is a subsurface condition in which the pressure of the fluids within the pores of a geologic formation is greater than or less than the formation’s normal, or expected, hydrostatic pressure. When the pressure is greater than normal pressure, called overpressure or geopressure, it can cause a well to blow out or become uncontrollable during drilling. When the pressure is less than normal pressure, called underpressure, it can cause differential sticking, a condition in which the drillpipe cannot be moved and may cause the well to lose mud into the formation, referred to as losing circulation.

11. For more on subsurface pressures and drilling: Barriol et al, reference 7.


update produced a new earth model that differed significantly from the predrill model (above).

Accurate seismic interval velocities are fundamental for estimating pore pressures and determining depths of geologic structures, geologic markers and casing points. Within the look-ahead interval, the actual sonic and updated velocities were in good agreement (next page, top). Both profiles showed velocity decreases, which, in this geologic environment, are indicative of formation pressure increases.

The predicted formation pressures in the 700-m look-ahead interval below depth X were calculated from the updated velocities and indicated that below X + 350 m [X + 1,150 ft], pressure first decreased then increased. The update predicted an increase in formation pressure around X + 600 m [X + 1,970 ft]. After delivery of the update and its predictions for the next increment of drilling, Total revealed the actual data from the test well for comparison with the team's predictions. The trends were similar to the update predictions; the actual pressures in the test well decreased around X + 350 m and then increased at X + 650 m [X + 2,130 ft]. In contrast, the predrill pressure prediction, based on legacy seismic data, and made before incorporating drilling data from the test well, had predicted a pressure increase at around X + 850 m [X + 2,790 ft], 200 m [660 ft] below its actual occurrence.

In addition to predicting pore pressure accurately, the SGD solution had a positive effect on the resolution and clarity of seismic images (next page, bottom). After the update, a fault and other features near the test well became clearer than they were in the image produced from the legacy dataset before the test well was drilled.
Evaluating the SGD technique. The Schlumberger team submitted the Phase 2 SGD solution results from the test well to Total. The submittal simulated an update to the operator’s drilling team. Afterward, Total revealed data from the test well below depth X m. The updated velocities (left, red) compared favorably to sonic log velocities (black) from the test well. The pressure-gradient plot (right) shows how the formation pressure (brown) predicted from the SGD technique compared with the postdrilling formation pressure measurements (red circles) and calculation (red line). The update predicted an increase in formation pressure at about X + 600 m, whereas the actual increase began at X + 650 m. The test well was drilled based on the legacy dataset, and the legacy predrill pressure prediction (blue) placed the pressure increase at about X + 850 m, 200 m [660 ft] deeper than it actually occurred. (Adapted from Teebenny et al, reference 13.)

Increased resolution and clarity. The SGD technique positively affected seismic imaging. A depth slice at 2,100 m [6,900 ft] illustrates the improved resolution that occurs around the test well location. The depth slice after imaging the legacy seismic dataset (left) is compared with the same slice after the dataset has been updated with data from the test well (right). Faults, demarcated by red arrows, became more sharply delineated, and other features (yellow ovals) came into focus.
Drillers constantly adjust drilling parameters in reaction to changing conditions. The SGD solution and workflows use information about past and present conditions in a well to predict future drilling conditions. Drillers are given the option to modify casing and mud-weight programs without interrupting drilling.

**Paleokarst Reservoirs**

Ordovician carbonates host significant reservoirs in the Tarim basin of western China. The reservoirs are at depths that vary from 4,500 to 8,000 m [14,800 to 26,200 ft]; their matrix porosity is about 2%. Their principal storage is in secondary porosity composed of dissolution pores and fractures that developed into holes, fissures and caves during karstification. The reservoirs are in heterogeneous fractured cave systems that developed in a limestone karst environment.

The deep, fractured cave systems are difficult to image using surface seismic data. The Tarim basin is desert; its variable topography, sand dunes and sand thickness present challenges to seismic data acquisition, and the dry desert sand layer has low seismic velocity and produces multiples that mask primary reflections.

The paleokarst reservoir horizons lie beneath volcanic and gypsiferous salt layers, which vary laterally in thickness and velocity and generate complicated seismic wavefields, which are difficult to characterize because reflections are weak and accompanied by complicated scattered and diffracted wavefields. In seismic sections, these caves appear as bead-like reflections that echo off the caves, which vary from about 100 to 300 m [330 to 980 ft] wide. The complexity of seismic reflections and uncertainty of the seismic velocities in the area make accurate and precise location of individual caves difficult, especially as...
drilling targets; wells often graze the sides of caves or miss them altogether.

To improve its success drilling into the caves, PetroChina Tarim Oil Company contracted with Schlumberger to conduct a feasibility study to identify existing data and use the SGD technique to steer wells into the cave systems.  

The team gathered seismic data acquired in 2007, a legacy velocity model, offset well data and geologic information. The initial velocity model comprised a layer cake of horizontal stratigraphy. In this simple model, velocities did not vary in the horizontal direction but did vary in the vertical direction. Each layer was transversely isotropic with a vertical axis of symmetry, or possessed vertical transverse isotropy (VTI); seismic velocities were generally faster parallel to horizontal layers than perpendicular to them. The shallow part of the model to a depth of 1,000 m was based on refraction tomography. The deeper part, greater than 1,000 m, was based on a checkshot survey from one of the offset wells and was extrapolated laterally following geologic horizons. The transverse isotropy parameters epsilon, ε, and delta, δ—measures of P-wave velocity anisotropy—were zero to a depth of 200 m and then ε and δ steadily increased to constant values of 3% and 1.5%, respectively, below 1,200 m (3,940 ft).  

The geophysicists then used the initial velocity model as input to tomographic velocity inversion to generate the predrill velocity model for the DVI from the legacy seismic data, constrained by sonic logs from five nearby offset wells (previous page). The geophysicists used a layer stripping approach, working from the top down. The subsurface was divided into four layers from the surface to 10,000 m (32,800 ft); the Ordovician caves were in the deepest layer. The geophysicists minimized the traveltime errors and found the best-fit interval velocities for each layer before moving to the next deeper layer. The final predrill velocity model was consistent with well logs and VSPs and resulted in PSDM images that brought the caves into sharper focus (above right).

14. Primary porosity develops during sedimentary deposition and remains after lithification—the conversion of sediment to rock. Secondary porosity develops after primary porosity through alteration of rock, commonly by processes such as dolomitization, dissolution and fracturing.

Karstification is the process of dissolution and erosion of carbonate rocks. Sinkholes, caves, pockmarked surfaces, hills and pinnacles are typical features of karst landscapes. Paleokarst is karst that is preserved by burial and cessation of karstification.


19. Shi et al, reference 18. Epsilon (ε) and delta (δ) are P-wave parameters for a medium in which the elastic properties exhibit vertical transverse isotropy. Epsilon is the P-wave anisotropy parameter and the ratio of the difference between the horizontal and vertical P-wave velocities divided by the vertical P-wave velocity. Delta is a weak anisotropy parameter that describes near-vertical P-wave velocity anisotropy and the phase-angle dependence of the vertically polarized S-wave. For more on the transverse isotropy parameters: Thomsen L: “Weak Elastic Anisotropy,” Geophysics 51, no. 10 (October 1986): 1954–1968.

20. Layer stripping is a method for determining the velocity and depth structure of a layered earth model from surface seismic data. The method begins with inversion of the surface layer to determine its parameters. Then these parameters are used, together with seismic reflection data, to invert for the parameters of the next deeper layer. This procedure continues until the entire volume of interest has been inverted.
Vertical Well A was planned based on the predrill velocity model and PSDM images. While drilling Well A, the Tarim Oil Company acquired real-time checkshot measurements. The bottomhole assembly was equipped with the seismicVISION tool. After each pipe stand was drilled, while a new one was being added and no downhole drilling noise interfered, a seismic source on the surface was triggered, and the seismicVISION tool recorded the waveforms. The VSP from these data was used to update the predrill velocity model and seismic image of the caves at important decision points during drilling. Had Well A been drilled based on the 2007 seismic data alone, it would have missed its target cave by about 150 m (490 ft) laterally (left). The starting predrill model predicted the cave depth to within 16 m (52 ft) of the actual depth at which it was encountered. The updated model used to drill the well improved the accuracy of the cave location and predicted the cave depth to within 8 m (26 ft) (next page).

The driller had advanced warning and was better prepared to handle abnormal drilling conditions that developed upon approaching and drilling into the cave. As the drill bit nears one of these deep, fractured carbonate caves, lost circulation can occur as the bit encounters fracture systems associated with the caves. This may be followed by a kick—fluid entering the wellbore—should the lost circulation cause the bottomhole pressure to decrease below the formation pressure. There may also be incidents such as the drillstring dropping as the bit breaks through into the cave system; the drop may lead to loss of equipment.

Based on its success in Well A, the PetroChina Tarim Oil Company team drilled three more wells using the SGD solution. Each well hit its target and was drilled into caves.

**Illuminating the Way**

Operators strive to maximize production rate and overall recovery using the least number of wells. The challenge is to reduce the uncertainty and risk associated with these objectives. The locations of a reservoir’s sweet spots and the hazards to be encountered while reaching them create uncertainties that lead to exploration, drilling and production risks such as misidentifying the sweet spots, encountering unsafe drilling conditions and having to drill additional wells to augment uneconomic wells.
The Seismic Guided Drilling solution is a rapid well construction decision-making process that has developed through advances in computer power, integrative software technologies and collaborative multidisciplinary teams.

Rapid earth modeling techniques, such as the SGD solution, may evolve from being primarily an uncertainty and risk reduction tool for drilling to becoming an integral part of reservoir management. Upon entry into a new play, drilling engineers may use the SGD technique to drill the pilot well, geophysicists will then verify the presence of basin-scale sweet spots identified through regional mapping and petroleum system modeling, and geologists may be able to focus on geologic structures and strata within the DVI around the well. Well planning teams may also rely on similar methodologies to direct drilling of appraisal and development wells to assess the quality of the reservoir in the vicinity of productive sections. Eventually, the integration of multidisciplinary earth models during the development of a play could provide operators with a high-resolution model that enables efficient optimization of field development in complex geologic environments using a minimal number of wells. If this comes to fruition, operators will be guided toward greater efficiencies and find more effective drilling results in marginal plays. —RCNH

^While-drilling updates. From the predrill PSDM image (left), the top of the cave (blue diagonal line) was interpreted, based on picking the peak negative reflection amplitude (yellow), to be more than 16 m deeper than its actual depth (DO2y). In contrast, the update image (right) shows the predicted top of the cave (blue diagonal line) has moved up to within less than 8 m of the actual depth. The green horizontal line is a reference line for comparing the left and right images.
Multiphase Flow Simulation—Optimizing Field Productivity

As oil and gas well construction and field development become more complex, the need for more sophisticated flow simulation methods increases. New generations of multiphase flow simulation tools are helping operators construct wells, pipelines and processing facilities safely and efficiently and optimize long-term field production at minimal risk and maximal profit.

Increasingly sophisticated flow simulation models have been developed to meet the needs of operators as they open new frontiers. These models are vital for helping drilling engineers overcome well design challenges and production and facilities engineers to understand and anticipate flow conditions as they seek to extract hydrocarbons from deeper, more remote and geologically complex reservoirs.

Flow simulation is a well-established means by which engineers approximate the multiphase flow behavior in a well, production system or pipeline. Using mathematical models built into specialized software programs, flow simulations yield representations of the steady-state and transient flow of oil, gas and water that might be encountered in a real-world network of wells, flowlines, pipelines and process equipment. The output of these simulations guides operators’ field development decisions in determining the number of wells to drill, the location of such wells and how to complete each well to ensure optimal long-term production from the field.

Multiphase simulations predict flow behavior at all stages in the life of a well and field, from drilling to downhole production to network to processing facilities. For example, simulations may guide well control design and engineering decisions by helping understand the effects of gas influx in HP/HT wells. Another area is planning for reservoir sections prone to lost circulation or kick events where managed pressure drilling (MPD) may be the best option for development.

Flow simulation is also a useful tool in developing contingency plans in case of well blowouts, during which reservoir fluids flow into the wellbore in an uncontrolled manner and may reach the surface. Well control companies and operators have used flow simulations to understand the expected flow rates during a blowout, information that is then used to calculate the volumes and densities of well kill fluids as well as the

3. Managed pressure drilling uses flow control devices to precisely control the annular pressure profile throughout the wellbore. Managed pressure drilling techniques are commonly used to maintain wellbore control during drilling by managing kicks or preventing an ingress of drilling fluids into the reservoir.
Flow simulations help engineers optimize the design and operation of producing wells. Models provide insight into well completion designs, including choices about inflow control methods, well trajectory design, sand control and artificial lift. Production engineers use flow simulations to estimate how producing layers of the reservoir contribute to the total well production. They can then use this information to determine how to operate the wells for optimal recovery.

Simulation models are also used to optimize operations across an entire oil and gas field. Design engineers use flow simulations during the concept, front-end engineering and design and detailed design phases to guide decisions on sizing and materials selection for piping, valves, vessels and processing facilities. Models, which can also estimate the risks of hydrate and wax formation in the production system, guide the selection of optimal chemical inhibition methods as well as thermal control systems in the forms of insulation, bundling and heating. Flow simulations provide insight that systems designers use to counter corrosion and erosion in pipeline transmission and processing systems.

Production engineers implement flow simulation models to establish procedures for operational events such as pipeline startup, shut down and blowdown, production rate changes, optimal process equipment usage, pipeline pigging and network debottlenecking. Model output guides normal operational procedures for these events and highlights safe operating limits, which can be used to develop emergency procedures and contingency plans.

Flow simulations may play a role in operator training programs. Simulation models help operations personnel become familiar with initial startup procedures and flow assurance considerations for new production systems. Simulations also give less experienced personnel a means of practicing safe processing equipment operation and to run numerous “what-if” scenarios prior to working in real-world operations.

This article describes the evolution of flow simulation methodologies with emphasis on advances in the simulation of upstream and midstream transient multiphase flow in wells and pipeline networks. A brief history details how flow simulators evolved from those that modeled pumping rates required to bring the well back under control (left). In addition, capping operations can be reviewed because the flow simulation includes realistic pressures and temperatures for situations in which a capping stack is used to control a blowout.1

Flow simulation for well control. To regain control of a blowout, operators often use a dynamic kill operation. Well control specialists kill the well using a fluid density that will contain the well but not fracture the formation. While keeping the annulus and the drillstring of the relief well filled with fluid, the BHP—monitored through annular and tubing pressure gauges—is controlled through the fluid flow rate into the relief well. Flowing frictional pressure supplements the hydrostatic pressure of the kill fluid injected through the relief well (red arrows) and up the blowout well (blue arrows). Because these operations include produced fluids and kill fluids, they can be modeled with multiphase flow simulators. The $P_{ann}$ is annular pressure, $P_{hyd}$ is the hydrostatic pressure created by the kill fluid, $P_f$ is the frictional pressure drop caused by flow in the annulus of the blowout well, $P_{tbg}$ is the tubing pressure in the relief well drillstring and waterhead pressure is the pressure exerted by the weight of a column of water from surface to the relief point.
two-phase fluid systems under steady-state conditions to those able to model multiphase systems in which fluid and flow properties change over time. The article also discusses the derivation of mathematical models that represent a real-world flow system and includes a review of the numerical methods used to solve these models in a simulator.

Case studies highlight how the OLGA dynamic multiphase flow simulator has helped optimize well construction and production processes for operators working off the coasts of West Africa, the Middle East and Southeast Asia. An example of hydraulic well control simulation of an exploration well offshore Malaysia is also included.

A Brief History
The vast majority of produced fluids do not come to the surface in a steady, single-phase stream. Rather, production is a complex and ever-changing combination of hydrocarbon fluids and gases, water and solids flowing together at nonuniform rates.

The basis for multiphase flow design and operation is fluid dynamics. The driving force behind the earliest oil industry simulation tools was multiphase flow system designers' need for accurate estimates of the pressure, temperature and liquid fractions in wells and along pipelines. One fundamental approach to modeling flow behavior in oil and gas systems is the two-fluid model, in which designers assume only two fluid phases—typically a liquid and a gas—are present. Other models extend this treatment to include fluids that coexist in more than two phases such as a gas, oil and water phase. Separate phases can flow in a pipeline in three stratified, continuous layers—a gas layer on top, an oil layer in the middle and a water layer at the bottom of a pipeline. A phase can flow in each of the three layers. For example, some of the gas is transported through the pipeline in the upper gas layer, while the rest is transported as gas bubbles dispersed in the oil and water layers.

The multifluid model consists of mass, momentum and energy conservation equations. Often, mass conservation equations are written for each phase. Momentum conservation equations are written for each of the continuous layers, whereas energy equations can be written for the total fluid mixture or for each of the layers. In the case of a two-phase, two-layer flow model, a total of six differential equations are written.

Solving this set of equations requires development of closure laws, which are necessary relations that must be added to the conservation equations to allow their calculation (right). One basic closure law is the equation of state of the fluid, which is a thermodynamic equation that provides a mathematical relationship between fluid properties, such as density and viscosity; to two or more state functions; state functions include temperature, pressure, volume or internal energy associated with the fluid.

This relationship can be obtained by consulting precalculated tables of fluid properties as functions of pressure and temperature, assuming a constant total chemical composition at each pipe location and at each point in time. Functional relationships are also afforded through the study of black oil formulations, in which uniform fluid properties are used, or through full compositional analysis of reservoir fluid samples, in which individual fluid properties are used for each hydrocarbon component. Another set of basic closure laws includes laws or equations that relate the friction factors to velocities, pipe geometry and physical properties of the fluid.

The first simulations were performed in steady-state models in which fluid properties such as flow rate, density, temperature and composition were assumed to remain constant over time at a given point in the system. Steady-state models thus perform a mass, energy and momentum balance of a stationary process—one that is in a local equilibrium state. While flow parameters may change upstream or downstream of the particular point in the system, that point remains in a state of local equilibrium if the fluid always has the same properties, regardless of time.

Since their introduction into the oil and gas industry nearly 30 years ago, steady-state simulators have evolved significantly. For example, the PIPESIM steady-state multiphase flow simulator allows engineers to predict a range of flow challenges that hinder production optimization, from the occurrence or formation of asphaltenes, wax and hydrates to carbon dioxide [CO₂]-induced corrosion and flow-induced erosion.

Steady-state simulations provide system designers a method for quickly estimating flow results at a specific set of conditions and yield near-immediate insight into how changes in system conditions will impact production. However, because they operate on the fundamental principle that flow parameters do not vary with time, steady-state simulators are not applicable for transient flow phenomena simulation.

This missing time element prompted the development of dynamic multiphase flow simulations, which allow users to model the time-varying behavior of a system; as a result, predicting multiphase flow variations that occur regularly during normal oilfield operations is possible. As in steady-state simulations, dynamic simulations comprise equations for conservation of mass, momentum and energy. However, the local variables, including inlet and outlet conditions of the flow, are written.

4. A capping stack is used to control, divert flow and shut in a well during containment operations. It is not part of the standard drilling configuration and is deployed only as necessary.
5. Artificial lift refers to any system that adds energy to the fluid column in a wellbore; the objective is to initiate or improve production from the well. As wells mature and their natural reservoir pressure declines, most will need to use some form of artificial lift. For more on artificial lift: Fleshman R and Lekic O: "Artificial Lift for High-Volume Production," Dillifield Review 11, no. 1 (Spring 1999): 49–63.
9. A compositional tracking model may also be used to provide more accurate compositions for transient flow, particularly for networks that have different fluids and time-variable flow rates and thus time-dependent local compositions.
system being modeled—such as flow rates, inlet pressure and local gas volume fractions—are allowed to vary with time to more closely reflect real-world changes that occur in hydrocarbon production systems.12

Dynamic fluid models are used in a wide range of applications in the simulation of multiphase flow systems, including aircraft design, prediction of weather patterns and the analysis of steam and water flow in the core of nuclear reactors.12 In the early 1980s, fluid dynamics experts began to use such models to simulate oil, gas and water flow in pipelines.

Development of a Dynamic Flow Simulator
One of the earliest such attempts began in 1980 as a joint research project between the Norway state oil company, Statoil, and the Institutt for energiteknikk (IFE), or Institute for Energy Technology.12 The first version of the simulation tool, known as the OLGA dynamic multiphase flow simulator, was released in 1983 out of this research project.

The OLGA simulator models slow transients—time spans of flow fluctuations ranging from a few minutes to a few weeks—associated with mass transport in oil and gas systems.13 Production engineers use the simulator to model flow in networks of wells, flowlines, pipelines and process equipment (above).14

Starting in 1984, a joint research program between IFE and SINTEF further advanced the simulator.13 The program was supported by companies operating on the Norwegian Continental Shelf, including Statoil, Conoco Norway, Esso Norge, Mobil Exploration Norway, Norsk Hydro A/S, Petro Canada, Saga Petroleum and Texaco Exploration Norway. This research program aimed to extend the empirical basis of the model and to introduce new applications.15

Early attempts at modeling two-phase flow in single pipes used separate empirical correlations for volumetric gas fraction, pressure drop and flow regimes even though these entities are physically interrelated.14 In the OLGA simulator, flow regimes were treated as an integral part of the two-fluid system. In the late 1990s, the OLGA simulator was extended to model three-phase flow regimes, including the tracking of three-phase slugs, during which the flow stream is divided into intermittent segments of oil or water that are separated by gas pockets.

Mathematical Models in the OLGA Simulator
A mathematical model within the dynamic flow simulation space is a digital representation of a real-world phenomenon. Mathematical models tend to provide a macroscopic view of fluid flow in pipelines. This approach may simplify the flow regimes by assuming fluid composition within small sections of the pipeline are uniform, velocity fields at the inlet and exit surfaces are normal to these surfaces and that fluid properties such as density and pressure are uniform across the entrance and exit cross sections.

The first mathematical models within the OLGA simulator were based on data from low-pressure air and water and steam-water flows in pipes with an inside diameter range between 2.5 and 20 cm [1 and 8 in.]. The data from the SINTEF laboratory, which included the addition of hydrocarbon liquids flowing in 20-cm diameter pipes at a pressure of 20 to 90 bar [2 to 9 MPa; 290 to 1,300 psi]. Scientists used the data to make several modifications to the first version of the OLGA simulator. Further iterations of the simulator have included field data from pipe systems of up to 76 cm [30 in.] in diameter, which expanded the tool’s extrapolation capabilities.16

The transient simulation from the OLGA simulator also accounts for the flow regime within the modeled section of borehole or pipe.17 For two-phase gas-liquid flow, the structure of multiphase flow falls into four basic flow regimes:

- stratified flow, consisting of two separate and continuous fluid streams: a liquid stream flowing at the bottom of the pipe and a gas stream (usually with entrained liquid droplets) flowing above the lower stream
- annular flow, consisting of a regime in which a thin liquid film adheres to the pipe wall and a gas stream containing entrained liquid droplets flows internal to this film
- dispersed bubble flow, consisting of a continuous liquid flow with entrained gas bubbles
- hydrodynamic slug flow, consisting of stratified flow punctuated by intermittent slugs of highly turbulent liquid (next page).17

Initial testing of the mathematical model using data supplied by SINTEF showed that the simulator did an adequate job of describing bubble and slug regimes but was less accurate in predicting stratified and annular flows. In vertical annular flow, the simulator predicted pressure drops that were as much as 50% too high, whereas in horizontal flow, the predicted liquid holdups were too high by a factor of two in some cases.17

Scientists refined the model to account for the presence of a droplet field moving at approximately the same velocity as the gas phase, which describes the flow regime in stratified or annular mist flow. Mathematical models within the dynamic multiphase flow simulator also include continuum equations for three fluid phases: a gas phase; a liquid phase consisting of oil, condensate or water; and a liquid droplet phase consisting of hydrocarbon liquid—oil or condensate—dispersed in water. These continuity equations
are coupled through interfacial friction, interfacial mass transfer and dispersions such as oil in water. Modelers track dispersions by means of a slip relation, which is the dimensionless ratio of the velocity of the gas phase to the velocity of the liquid phase.\textsuperscript{22}

The conservation of mass equations can be written to account for several components and fluid types, including full chemical composition tracking, the presence of scale and corrosion inhibitors, drilling fluids, wax, isotopic tracers and solid particles. A model capable of simulating flow in particle beds was introduced in the 2014 release of the OLGA simulator.\textsuperscript{23}

The OLGA simulator also expresses the conservation of momentum for three continuous layers, yielding separate momentum equations for the gas layer, which may contain liquid droplets, and for oil and water layers. One conservation of energy equation in this model treats the energy of the system in terms of the combined mixture of the fluid phases and assumes that each phase is at the same temperature. An equation of state, one for each fluid layer, provides the functional relationship between the fluid volume and its pressure, temperature and composition.

The simulator selects the particular flow regime for the model based on the minimum slip criterion.\textsuperscript{24} For given superficial velocities, the simulator selects the flow regime that gives the lowest difference, or minimum slip, between the gas and liquid linear velocities. In the 2000s, the OLGA High Definition (HD) model was developed by starting with 3D models for frictional forces for stratified water, oil and gas flow in a circular pipe and deriving 1D wall friction models as well as 1D interfacial friction models that have 3D accuracy.\textsuperscript{25} These mathematical models, applied together, account for the real-world complexities of multiphase flow in production systems that may include multilateral wells, pipelines, artificial lift systems, processing facilities and flow control equipment such as chokes and sand control devices.

Analysts use mathematical models to compute solutions using numerical methods or algorithms. These methods take advantage of advances in computer processing power and speed to create digital solutions that simulate real-world flow phenomena at a fine level of detail.

Numerical methods begin by dividing the overall fluid stream in the pipe into small, discrete grids or cells. Each cell has its own values of pressure, temperatures, fluid compositions, densities, flow rates and fluxes.\textsuperscript{26} Solving the conservation equations for each cell begins by rewriting continuous equations into discrete counterparts by applying discretization concepts such as upwind weighting, which uses fluid properties of the upstream cells in flow calculations. This process results in a set of ordinary differential equations and algebraic equations that represent the model. However, since the equations may exhibit strong nonlinearity and have to be constrained—the total fluid volume must be equal to the pipe volume—the solution methods must be designed carefully.

Flow regimes as categorized by multiphase flow simulators. Separated flow regimes are broadly categorized as stratified or annular (top), whereas distributed flow regimes are either dispersed bubble flow or hydrodynamic slug flow (bottom). These categories can be further divided based on whether the fluid stream is two phase or three phase and whether the pipe sections are horizontal, vertical, straight or bent.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{flow_regimes.png}
\caption{Flow regimes as categorized by multiphase flow simulators.}
\end{figure}
The entire equation set is then grouped into subsets according to the characteristics or properties of the equations. The subsets are solved in stages, one stage followed by the next at the same time step. The stages are coupled together explicitly at the time step. The equations are solved numerically using iterative techniques until convergence is reached for the entire system. These methods can be applied to study flow in both steady-state and dynamic conditions (below).²⁷

**Principles in Action**

When applied to field operations, dynamic multiphase flow simulation plays an important role in scientists’ understanding the likelihood and severity of generating fluid-related by-products such as hydrates, wax, scale and emulsions in a production system. Design engineers use such simulations to predict the occurrence of these species in the actual field system and then test various design alternatives that are aimed at minimizing their impact. Ideally, such simulations are performed before the production system is built, thus allowing the operator to design and construct a production system—from the wellbore to the surface processing equipment—that will keep these flow assurance challenges to a minimum.

Chevron used dynamic multiphase flow simulation to help manage flow assurance and operational risks in its Lobito-Tomboco subsea field in Block 14, offshore Angola (next page).²⁸ The development comprises three subsea centers tied back to the Benguela Belize (BB) compliant tower.²⁹ Both the Lobito and Tomboco reservoirs contain light (31 to 32 degree API), low-sulfur and low-acid crude that has little asphaltene and naphtha content.

Chevron engineers were challenged to design a robust production system for this field that would economically transport the produced fluids from subsea wells to topside while sufficiently mitigating anticipated operational and flow assurance risks. To maximize production from each subsea center, water injection would be required to sweep and provide pressure support to each well. In addition, as water cut increased, the operator would have to implement gas lift. Additional challenges were expected in the form of flow assurance risks that included the formation of hydrates, scale, wax and corrosion by-products as well as the occurrence of sanding and slugging.

The operator first assessed its exposure to flow assurance risks by collecting and analyzing oil and water samples from the reservoirs. This analysis included fluid pressure-volume-temperature characterizations and a comprehensive assessment of the fluid compositions from each reservoir.³⁰ Using the OLGA flow simulator, modelers employed the resulting output of this analysis to develop various thermohydraulic models, which study hydraulic flow in thermal systems. The operator produced the following thermohydraulic models: individual wellbore and flowline, hydraulic models: individual wellbore and flowline, hydraulic models: individual wellbore and flowline.

---

Steps for solving two-phase flow models for stratified flow in a condensate-gas pipeline. Steady-state models (left) begin by dividing the pipe section into smaller sections (N) and inputting the boundary conditions for pressure (P), temperature (T), liquid velocity (vL) and gas velocity (vG) at the initial point of the pipeline. The model uses these initial conditions to solve the continuity equations in the first section (N = 0) and to calculate values for pressure, temperature and fluid velocities in that section. These values are used as inputs into the next section (N + 1), and the process repeats until the final section—the other end of the pipeline, Nmax—is reached. A similar process is followed in the dynamic model (right), but an additional iterative step accounts for changes to fluid properties and flow parameters and boundary conditions with time (t). Because the flow equations are nonlinear, performing iterations to reach a solution with acceptable accuracy is usually necessary.
Simulations were run under steady-state conditions, which the operator defined as any condition in which produced fluids were flowing in a fairly uniform and uninterrupted manner through the wellbore, flowlines and surface processing lines. A number of transient simulations were also run to determine how the production stream would react to dynamic situations that included system commissioning, startup, shutdown (planned-versus-unplanned and short-versus-long), initial well ramp up, pigging, dead-oil circulation and slugging.

This extensive modeling effort allowed Chevron to make informed decisions that lowered the company’s initial capital expenditures for the project while ensuring more reliable production with a low risk of upsets or unplanned shutdowns. For hydrate mitigation, the operator was able to design the optimal thermal insulation thickness for subsea flowlines and irregularly shaped components such as connectors and pipeline end terminations. The simulations also guided the optimal use and injection rate of treatment chemicals such as methanol for hydrate inhibition, corrosion inhibitor, biocide and oxygen scavenger to mitigate corrosive attacks.

To mitigate sanding risk, the simulation output guided the operator’s decision to complete all producing wells with robust gravel packs and limit maximum drawdown across the completion, which also minimized the risk of fines migration. The dynamic flow simulations suggested a slugging risk mitigation strategy that included proper well ramp up and ramp down procedures, minimum flow rates in each flowline to keep flow outside the slugging regime and ideal topside choke settings to control slugging during pigging and dead-oil circulation.

To further mitigate flow assurance and operational risks at the Lobito-Tomboco field, the operator used OLGA simulator training to help field personnel gain familiarity with how the subsea production system would interact with the topside processing system under various production conditions. The dynamic flow simulator was also implemented as part of the operator’s pipeline management system to model the real-time behavior of the multiphase flow in the subsea production system. The management system can be used in three different modes: an online real-time application to monitor the current state of the production system, an online look-ahead application to predict future operation based on planned changes to the production system and an offline what-if application for planning and engineering studies.

Once the system was built and production started flowing from the three subsea centers, the field data were compared with the simulated results obtained from the OLGA simulator. The actual and simulated datasets correlated in each instance, indicating that the thermohydraulic models used to develop the operations procedures for the field were accurate. The steady-state flowing pressures calculated using the OLGA simulator were within 90% of the field pressures, while the calculated temperatures were within 95% of those measured in the field. The actual and simulated tree and manifold cool down times also matched well. The systems were robust for operations and not over- or underdesigned for maintaining effective flow assurance.

---

29. A compliant tower is a fixed-rig structure used for deepwater oil and gas production. The tower consists of flexible (compliant) legs that reduce resonance and minimize forces caused by ocean waves. A deck sits atop the legs to accommodate drilling and production operations.
30. A pressure-volume-temperature characterization is a means of characterizing reservoir fluid systems through laboratory experiments and equation of state modeling. The resulting fluid parameters are then used as input for various reservoir, pipeline and process simulations.
31. An upset in a produced fluid stream occurs when physical conditions such as pressure, temperature or flow rates in the flow stream give rise to the formation of precipitates or emulsions.
Dynamic Production Management of a Gas Condensate Field

Today, it is common for operators to implement production management systems that incorporate dynamic flow simulation tools to optimize their field operations. Dolphin Energy used such a system on its Dolphin Gas Project, which comprises two offshore production platforms 80 km [50 mi] off the coast of Qatar (above). These platforms produce wet natural gas from the Khuff Formation; production flows to an onshore processing plant through two 91-cm [36-in.] subsea flowlines. The processing plant separates the hydrocarbon liquids—condensate and liquefied petroleum gas—for sale and processes the remaining natural gas for compression and transportation by pipeline to the UAE.

To meet the challenge of managing liquids production in a gas condensate field such as the Dolphin Gas Project, designers must properly size pipelines during the project planning phase. During operations, challenges include managing rate changes, pigging operations, shut-ins and restarts. Additionally, accurately predicting flow regimes and the onset of slugging in gas condensate fields is difficult; hydrate mitigation requires the operator to select the optimal type and thickness of insulation for subsea flowlines and the proper type and dosage of hydrate inhibitor to be deployed during production.

A pipeline management system was installed on the project to address these flow assurance concerns. The system included the OLGA Online dynamic production support system, which is an online simulator that generates real-time models designed to match field conditions and supports the reliable operation of the multiphase pipelines from the wellhead to the onshore receiving and processing plant.

The online simulator incorporates data from in-field monitoring and sensor systems, which measure fluid pressure, temperature, flow rate and liquid holdup in the pipeline. The simulator then runs real-time models to provide information that supports or adds to what is available from the existing control system. Such real-time simulation results help the operator detect leaks, calculate hydrate risks, understand the likelihood of pipeline slugging and track the progress of pigs during pigging operations (next page, top).

The dynamic online simulator can also be run in a mode that allows it to forecast future production or potential flow assurance problems. For example, an operator can simulate five hours into the future at regular intervals to gain an early warning of situations that might generate a shutdown alarm. The simulator may also be used in a planning mode, which allows the operator to understand the impact of any planned design changes to the operation of the pipeline and processing facility.

For the Dolphin Gas Project, the pipeline management system generated models for the two 85-km [53-mi] long, 91-cm diameter multiphase pipelines. It also modeled the operation of several offshore systems, including two platforms containing 15 production wells and pig launchers, and the injection and tracking of a hydrate inhibitor and a scale inhibitor. Onshore, the system provided real-time model updates on the operation of pig receivers and slug catchers.

The system has been used in daily pipeline operations since it was installed at the project at the end of 2007. Through continuous monitoring of the risk of hydrate formation, pipeline management has helped ensure optimal injection of hydrate inhibitor. The system is used for active liquid inventory management and tracking of pigging operations. Dolphin Energy pipeline integrity experts have also used the management system to track the use of corrosion inhibitor, providing input to calculate the viable operating life of the pipelines.

Well Cleanup and Startup in the Kitan Field

Dynamic simulations are also applied to well cleanup and startup operations. Eni Australia used multiphase, numerical transient simulation to guide decisions on well cleanup on the Kitan oil field (next page, bottom). Located approximately 200 km [124 mi] off the southern coast of Western Australia, the Kitan field was a small, deepwater field with complex geological and reservoir conditions.

The well cleanup process includes several stages: initial cleanup operations, followed by a period of controlled production during which the cleanup fluid returns from the formation, and finally the restart of the well. The duration of the cleanup typically follows a stimulation treatment, when the treatment fluids return from the formation and are produced to the surface. The duration of the cleanup generally depends on the complexity of the stimulation treatment; operations such as gravel packing and hydraulic fracturing require slower and more careful cleanup to avoid jeopardizing the long-term efficiency of the treatment.

Well cleanup operations typically involve the following steps:
1. Initial cleanup operations to remove debris and sludge from the wellbore.
2. Controlled production to allow the treatment fluids to return from the formation.
3. Restart of the well to resume normal production operations.

These steps are repeated until the well is deemed clean and ready for operation. The dynamic simulation models were used to optimize each step of the cleanup process, ensuring that the well was cleaned effectively while minimizing the impact on the production system.

In the Pig Tracking Advisor module of OLGA Online, the operator is able to see a display of a subsea production loop and the subsea template (top, yellow). The connection to the topside processing facility includes the pig launcher receiver. When a pig is launched into one of the legs of the production loop, its location is marked by an icon visible along the production loop. Operators are also able to monitor pipeline profiles (bottom left), including liquid holdups, elevation profiles and calculated variables (bottom right) such as estimated arrival time at the receiver and current location and velocity of the pig.

Kitan field. The Kitan field (left) is located about 200 km [124 mi] southeast of East Timor and 500 km [310 mi] northwest of Australia. Oil and gas flow from Kitan subsea Wells 5 and 3 and Well 2–sidetrack 1 to a floating production, storage and offloading (FPSO) vessel (right). Oil and gas flow from the seafloor to the FPSO (top right) via flexible production lines (black, bottom), whereas gas-lift gas is delivered through separate flowlines (red) from the FPSO to the wellheads (black). The control unit (yellow) distributes commands from the FPSO to the well centers via a main umbilical cable (yellow and black).
East Timor, the Kitan field consists of three subsea intelligent wells, subsea flowlines, risers and one floating production, storage and offloading (FPSO) vessel. Three wells were completed and cleaned up prior to the FPSO arrival on location.

Intelligent completions were installed at similar depths in three wells to control flow from an upper and lower zone. The upper zone for each well was perforated at a measured depth of between 3,344 and 3,367 m [10,971 and 11,047 ft]; the lower zone was perforated between 3,384 and 3,394 m [11,102 and 11,135 ft]. Downhole flow control valves with eight choke positions—fully open, fully closed and six intermediate—control flow from each zone. Downhole gauges were deployed to monitor pressure and temperature for each zone.

Because of the remoteness of the field location, the operator needed assurances that the cleaned up wells would perform as required prior to deploying the FPSO. The dynamic flow simulator was used to model the intelligent completion and several preselected well cleanup scenarios in which cleanup time, pressure and temperature at various points of interest and flow rates were altered to determine their impact on cleanup. The objectives of the study were to estimate the required flow rate and duration to unload the base oil and brine during well cleanup and to use these estimates as a guide for the actual cleanup program in the field. In addition, sensitivities to reservoir parameters such as permeability, pressure and temperature were simulated to estimate the effect on pressure, temperature and flow rate at the downhole gauges and upstream of the choke manifold. These simulations provided the rig engineers with the information they needed to predict flow conditions in the wells before conducting the cleanup operations and bringing the wells onto production.

The simulations defined well cleanup as complete when the amount of brine and base oil in the produced reservoir oil, measured at the surface, was less than 1% by mass. The optimal oil flow rate was estimated to be 7,000 bbl/d [1,100 m3/d], and the estimated flowing wellhead pressure and temperature were 1,200 to 1,400 psi [8.3 to 9.7 MPa] and 45°C [109°F]. Pressure and temperature were also predicted dynamically at locations of interest such as the downhole gauges and upstream of the choke manifold.

The operator used the values from the simulations as guideposts for the actual well cleanup and well test operations. A comparison of the model data with the actual well data after cleanup and testing found that matching was achieved at all downhole gauges with a maximum difference of less than 1% (below left). Matching, which was also achieved upstream of the choke manifold, had a maximum 1% error during the commingled flow period.

The validated well models were subsequently integrated with the operator’s flowline models, which were run to provide information to the field startup team. The team used the dynamic flowline simulation results to estimate the optimal position of the downhole flow control valves without exceeding the system’s production limitations. These simulations also helped the operator set the proposed ramp up schedule, estimate pressure and temperature at various places in the flowline and FPSO and estimate the production fluids arrival time at the FPSO. The production system model was validated with actual production data.

Drilling a Narrow-Margin Well Offshore Malaysia

Dynamic modeling methodologies also prove useful during drilling operations, particularly when an operator plans a drilling program in narrow-margin offshore wells. Petronas Carigali Sdn Bhd faced such a situation ahead of drilling an exploration well in the SB field, located in the PM block on the west side of the Malay basin, Malaysia. This basin is characterized by interbedded sand, coal and shale formations. These conditions, coupled with a high-pressure, high-temperature (HPHT) environment and a steeply rising pressure ramp presented numerous drilling challenges, including reduced kick tolerances, narrow drilling windows between the pore pressure and fracture gradient, high drilling fluid densities and equivalent circulating density (ECD) effects of the fluids.

An initial exploratory well was drilled in the area, and although the operator used MPD techniques, an influx of reservoir fluids into the wellbore exceeded kick tolerances and the fracture gradient of the reservoir, resulting in complete fluid losses and loss of the well. As a result, the drilling operation failed.

The operator planned a second exploratory well just 50 m [160 ft] from the first well, but with a more rigorous approach to wellbore pressure management that included the use of the Drillbench dynamic drilling simulator software (next page). This simulator uses a modeling methodology similar to that used by the OLGA flow simulator but focuses on predicting dynamic downhole conditions that pertain to maintaining well control while drilling. The Drillbench simulator provides profile plots simulating pressure

---

34. A base oil is the continuous phase in oil-base drilling fluids. In the case of well cleanup at Kitan, the base oil was pumped downhole to displace the brine that had been used during the well completions operation.


36. For more on drilling windows, pore pressure and fracture gradients: Cook et al, reference 2.
conditions for the entire wellbore at any time and has a particular focus on identifying potential weak zones in the formation and intervals of narrow drilling margins. The operator can then adjust the drilling program to minimize the risk of a kick or other well control event prior to reaching potential trouble zones.

Engineers began planning the second well by gathering offset data from the first well, which they used to validate data input to the simulator. Data inputs included the planned well geometry, pore and fracture pressure predictions, casing setting depths, predicted bottomhole-to-wellhead temperature profile, drilling mud weight and rheology parameters at various sections of the well.

Dynamic drilling simulations were then run for each hole section to determine ECDs for various mud flow rates and weights. Tripping simulations were performed to investigate the effects of changing wellbore temperatures and potential surge and swab pressure concerns, particularly in deeper sections of the well where the pore pressure–fracture pressure window was narrow. Kick tolerance calculations were also completed for each hole section; the dynamic simulations produced estimates of the impact of fluid circulation rates on the kick margin in the well.

The simulations allowed the driller to drill each section of the well using appropriate drillstring running and tripping speeds, mud circulation rates and surface back pressures to prevent well control events. Using these dynamic flow simulations and MPD techniques, the operator drilled the exploratory well within the narrow drilling margin to its target depth of 2,800 m [9,200 ft]. Petronas plans to use the workflow established by this hydraulic well control simulation effort as the blueprint for future appraisal and development wells in the region.

**Future Directions in Flow Simulation**

To meet operator demands for models with greater accuracy and finer details, multiphase flow simulators must continually evolve. To that end, Schlumberger has gained experience through several joint industry projects (JIPs) that focused on extending the simulator’s physical and numerical models.

The OVIP OLGA verification and improvement project, for example, began in 1996 as a three-year study designed to verify the simulator’s output against field data provided by oil company participants, which included Statoil, Saga, Norsk Hydro, BP, Elf, Total, Agip, Exxon, Conoco and Chevron. The success of this initial project, which included fine-tuning the models to more closely match field realities, led to a series of subsequent OVIP project JIPs. The project has run continuously since its inception. The 2013 to 2015 OVIP members include BG Group, BP, ExxonMobil, Gassco, Eni, Repsol, Saudi Aramco, Shell, Statoil, Total, Woodside and PEMEX.

The OVIP project main objective is to serve as a platform for sharing knowledge about how OLGA simulator predictions compare with field and laboratory data. The project also serves as a means of sharing flow assurance expertise between its member oil companies. Members provide, from their OLGA Online systems, field-wide operational data that has been collected over long time spans. Last year, one member supplied the OVIP project group with detailed measurements from eight onshore and offshore pipelines. At present, another member is planning experiments covering the entire operational range of a 34-in. [86-cm] diameter offshore gas condensate pipeline.

Another JIP, known as HORIZON I, started in 2004 with industry participants including IFE, Chevron, Eni, ExxonMobil, Statoil and Shell. The project develops models to better simulate flow conditions in greater reservoir and water depths, longer flowlines and more challenging temperature and pressure environments. This project was followed by the HORIZON II JIP, which ran from 2008 to 2012. The original JIP participants were joined by Total and ConocoPhillips in Horizon II. HORIZON II was aimed at expanding the modeling capacity of the OLGA simulator for long distance gas condensate transport and long distance transport of oilwell streams. These projects resulted in new software modules that have expanded features for the OLGA simulator; these modules are in use today for longer and deeper pipelines and processing systems around the world.

Future developments promise to extend the reach of multiphase flow simulators even further by tying them into reservoir modeling, drilling and production optimization software systems. The ultimate objective of this work is to provide operators with a seamless, start-to-finish view of their production systems for better control of long-term field development costs and production potential.

—RvF/TM
Reservoir Mapping While Drilling

Breakthroughs in lateral drilling technology have paved the way to economic success of several new plays and the revitalization of many old fields. However, success in horizontal and extended-reach drilling is not defined in terms of the distance drilled but rather by the extent to which the driller stays in zone. A new deep-reading electromagnetic logging-while-drilling service is helping well placement teams maximize reservoir exposure by identifying fluid contacts, faults and formation changes far from the wellbore.
Advances in drillbit design, rotary steerable systems, downhole sensors and logging-while-drilling technology have helped drillers set new distance records for lateral drilling while increasing reservoir exposure. These achievements, in turn, have led to substantial gains in oil and gas production. However, the nature of the data used to map a target can pose a significant challenge for operators seeking to maximize lateral footage through a pay zone.

Limits to seismic resolution and logging tool depth of investigation (DOI) can create uncertainty with regard to reservoir position, orientation and overall structure. Initially, geoscientists map formations on the basis of surface seismic data and by offset well data if available. Surface seismic data are characterized by great DOI—on the order of hundreds of meters—and by relatively coarse resolution. By contrast, well log data are characterized by shallower DOI—typically on the order of several centimeters—and by much finer resolution. Given the relatively narrow diameter of a wellbore compared to a seismic wavelet, the imprecision of seismic resolution leaves plenty of room for the wellbore to miss its mark. It is usually while a well is being drilled or afterward that logs and other data become available for use in refining seismic prospect maps; seismic data sketch the broad outline of a reservoir, and log data must fill in the details.

The disparity in resolution and DOI between seismic and well log data may spur an operator to drill an initial vertical pilot hole for locating formation tops and fluid contacts and refining seismic models prior to drilling a horizontal well through the reservoir section. In this process, the operator drills a hole to penetrate the pay zone from top to base. Logging data from the pilot hole help the well placement team ascertain structural dips and depths of key geologic markers, which they use to refine the existing formation model and adjust targets for the extended-reach well. The hole is then plugged back to a shallower depth to establish a kickoff point that will permit a smooth landing into the target formation.

This approach, however, is not without uncertainty or risk. Perhaps the greatest risk stems from the fact that, at some scale, formations and their subordinate horizons tend to vary laterally (above right). Formation geometry, lithology or fluid saturation characteristics logged in the pilot hole may not extend for any appreciable distance beyond the pilot well. A formation model may differ dramatically from reality: Unconformities and pinchouts can change the thickness of a pay zone; grain size and water saturation often vary with depth or distance; and fractures, subseismic faults and changes in dip or other structural features can invalidate a model before it is verified by the bit.

Despite these geologic uncertainties, the operator must proceed on the assumption that the model based on pilot hole data also reflects formation characteristics at the landing point and beyond. In addition to their drilling costs, pilot holes carry the same risks as other drilling projects: lost circulation, stuck pipe and stuck tools, among others. High spread rates for deepwater drilling and challenging economics in shale plays also provide strong incentives to eliminate the cost of drilling pilot holes.

After extensive field testing, a new LWD service has been introduced to help map the subsurface and aid in precise placement of the wellbore within a target formation. This service helps bridge the gap between resolution and DOI that exists between the surface seismic data used to plan the reservoir development and the logging data used to steer and evaluate the wellbore. The GeoSphere reservoir mapping-while-drilling service uses deep-reading, directional electromagnetic measurements to detect fluid contacts and multiple formation boundaries more than 30 m [100 ft] from the wellbore. These reservoir-scale measurements provide timely data that operators need to guide real-time geosteering decisions. Well placement teams are using the GeoSphere service to accurately land wells, avoid unplanned exits from the reservoir, map multiple formation layers, develop interpretations of reservoir structure and reduce drilling risk while decreasing the need for pilot holes. GeoSphere mapping data are used to update and refine the operator’s reservoir models.

This article describes the architecture and operation of the GeoSphere service, which has been tested in more than 200 wells worldwide. Case studies from the North Sea and Australia demonstrate how data provided by this service guide operators in maximizing wellbore exposure to the pay zone.

The Landing and Beyond

Successful placement of a horizontal well requires the driller to land the bottomhole assembly (BHA) in a position that will then permit maximum wellbore exposure to the reservoir. After kicking off from vertical, the driller builds angle to increase inclination until the well path attains the trajectory needed to intercept the reservoir target. The driller then holds the inclination constant while drilling the tangent section.
As the bit nears the reservoir, the well placement team evaluates real-time well data to determine when to trigger the final inclination change needed to complete the landing. The team bases this decision primarily on information from near-bit gamma ray or at-bit laterolog LWD data, sometimes supplemented with mudlog data and biostratigraphic analysis.

However, most conventional LWD tools have a fairly shallow DOI, which limits acquisition of measurements to a few centimeters or meters into the formation. Shallow DOI may leave well placement teams with little time for geosteering adjustments. Depth of investigation may thereby impact the accuracy of a landing, which in turn can significantly affect the productivity of a horizontal or extended-reach well. A poor landing decreases the likelihood of optimal well placement within the reservoir section; by contrast, a good landing reduces the amount of steering required to keep the well in the sweet spot. Landing shallower or deeper than necessary reduces the amount of lateral reservoir exposed to the wellbore, which ultimately results in lost production (above). Once the LWD tools are in the reservoir, their shallow DOI may not be adequate to warn of approaching bed boundaries or important geologic features that could be detected.

While precise well placement is required to maximize pay zone exposure, a high-quality borehole is also necessary for maximizing production. To this end, the directional driller must not only hit the target and stay in zone, but also must deliver a smooth hole with minimum tortuosity. These objectives may not be entirely achievable, given the structural and stratigraphic complexities of the formations encountered. Regardless of their cause, necessary deviations from the well plan to maintain reservoir contact will force a driller to change azimuth or build or drop angle to get back on track to the target. Missing a target or straying beyond the pay zone may lead to course corrections that increase wellbore tortuosity.

By reducing tortuosity, operators avoid problems that compromise drilling, completion and production operations. During drilling, tortuosity can lead to poor hole cleaning and drillstring buckling; in severe cases, it can keep a well from reaching TD as increases in torque and drag prevent transfer of weight on bit required to drill ahead. Tortuosity also creates difficulty in running casing and cementing it in place and can interfere with the installation of downhole completion equipment. Even after a well is put on production, tortuosity can impede flow at sumps, or low spots, where fluid and debris may collect. These sumps can also cause slugging and holdup problems.

Wellbore placement and quality are impacted by an operator’s ability to ascertain the surrounding environment. Vertical wells are much simpler to drill in that regard: Once the bit enters a target formation, the next event usually involves exiting through the bottom of that formation. In contrast, horizontal or extended-reach wells offer the operator the prospect of weaving in and out of a changing reservoir section.

One of the early challenges in drilling lateral wells was the distance from the wellbore at which important geologic features could be detected. Reactions to changing scenarios detected at the last minute lead to insufficient trajectory corrections and less-than-optimal landings that adversely affect wellbore exposure to the reservoir. To avoid these problems, an operator needs the ability to detect formation and structural variations in time to provide effective course corrections.

**Toolstring Design**

To determine formation resistivity, many LWD and wireline services rely on multicomponent electromagnetic (EM) logging measurements. The GeoSphere reservoir mapping-while-drilling service exploits the directional sensitivity and deep-reading capability of EM signals to model formation geometry and characterize related properties in three dimensions. This LWD tool is designed to obtain multispacing, multi-frequency directional resistivity measurements. Geoscientists and drillers use these data to identify structural details and fluid contacts for optimum well placement within a reservoir and to refine the reservoir model. Although the GeoSphere service is not the first to provide this 3D visualization, the toolstring is designed to look much deeper into the formation than did earlier LWD tools.

The toolstring comprises one transmitter sub and two identical receiver subs—in some cases three receiver subs—located at six frequencies below 100 kHz. These frequencies:

1. **Tortuosity**, a measure of deviation from a straight line, may be used to describe wellbore trajectory. In a well, tortuosity can be quantified by the ratio of the actual distance drilled between two points, including any curves encountered, divided by the straight-line distance between those two points. Thus, as a wellbore deviates away from a straight trajectory, it becomes more tortuous.

2. **Properties that vary with direction are said to be anisotropic. Resistivity anisotropy, differences in horizontally measured resistivity versus vertically measured resistivity, is a common phenomenon in rock.**
cies are selected to provide optimal signal-to-noise ratio and measurement sensitivity. Each receiver sub has three antennae, which are tilted for azimuthal sensitivity.

The transmitter and receiver subs are available in two diameters—6$rac{3}{4}$ in. and 8$rac{1}{4}$ in.—allowing operations in hole diameters from 8$rac{1}{4}$ in. to 14$rac{3}{4}$ in. Each sub is 4 m [19.7 ft] long. To allay concerns regarding the effects of stabilizers on BHA performance, the collars are slick—they have no stabilizers.

The subs are configurable for placement at various locations within the BHA and may be separated by other LWD or MWD tools; receiver subs can be placed from 5 to 35 m [16 to 115 ft] away from the transmitter sub (below). Placement in the BHA sets the transmitter-receiver spacing, which is a critical factor affecting the EM signal’s DOI. In a resistive formation, the DOI is typically comparable to maximum antenna spacing; in a conductive setting, DOI is approximately half the antenna spacing. The DOI may be influenced by factors such as distance from the tool to a formation boundary, formation resistivity, thickness of formation layers and resistivity contrast between layers. The EM frequency also affects DOI; high-frequency measurements are typically used for short transmitter-receiver spacing and shallow DOI, whereas low-frequency measurements are used for long transmitter-receiver spacing and deeper DOI.

The deep-reading capability of the toolstring is enhanced by flexibility to configure transmitter output power and receiver gains to accommodate variable transmitter-receiver spacings and formation resistivity contrasts. Given the variability of formations to be drilled, prejob simulation is important for evaluating performance of various toolstring configurations. The transmitter-receiver spacing and the expected resistivity environment will affect the optimum frequency range used downhole. A prejob model helps the LWD engineer evaluate how spacing and frequency will affect DOI and the toolstring’s capability to resolve expected formation characteristics. The placement of the transmitter and receiver subs depends on client objectives and the formation characteristics that define transmitter-receiver spacing. In complex BHAs, power availability and telemetry bandwidth might influence BHA design. All of these factors must be considered during prejob modeling.

**Real-Time Multilayer Inversion**

For the wellbore to achieve maximum reservoir exposure, well placement team members must closely monitor formation structure and respond to changing lithology as they guide the wellbore laterally through a reservoir. GeoSphere EM measurements are directionally sensitive and thus provide valuable inputs for well placement and reservoir characterization. These data are processed using a real-time stochastic inversion algorithm to generate a multilayer formation resistivity model. The model is appended with continuous updates while drilling progresses, thus enabling well placement experts to track drilling progress while identifying fluid contacts or other boundaries within the reservoir.

The GeoSphere technology is capable of obtaining directional EM measurements at various frequencies and transmitter-receiver spacings. For a given frequency and transmitter-receiver spacing configuration, the toolstring measures a nine-component tensor between transmitter and receiver. These measurements are inverted in real time to provide multilayer model results, in which the number of layers and the layer thicknesses and resistivities fit the tool measurements and are consistent with frequency, spacing, sensitivity and DOI of each measurement. In addition, the resistivity anisotropy, dip and other structural aspects of the formations surrounding the wellbore can be estimated from the models.
The stochastic inversion algorithm employs few model constraints—overall bounds for resistivity, apparent dip and anisotropy values—along with a maximum parsimony criterion to calculate the simplest models that are consistent with the data. The algorithm iteratively adds or deletes layers as necessary to honor the constraints of tensor components, each of which has its own DOI and sensitivity. This process uses a probabilistic approach to estimate formation parameters; instead of requiring the inversion to develop only the most likely solution, a distribution of model solutions fitting the data is computed for each inversion station (below). The distribution consists of tens of thousands of formation models and quantifies the uncertainties for estimating the most likely formation model solution. Although the number of formation model solutions computed by the inversion is high, their distribution is computed in less than a minute to provide current inversion results—even at high drilling rates of penetration.

GeoSphere inversion of simulated data. The simulated formation consists of a 2-ohm.m upper shale (brown) above a 30-ohm.m reservoir (tan) with resistivity decreasing to a 1-ohm.m lower shale. Two resistivity profile distribution histograms are presented here for inversion stations (Points A and B). At each measured depth, a distribution of resistivity profiles is generated from the statistical inversion, with the P50 median value (inset, purple) shown as a color map over the entire length of the trajectory. Four other quantiles (inset, P05 to P95) provide information regarding the uncertainty of the distribution and thus show sensitivity limits of the measurements. The inversion also solves for relative dip of the formation.

At Point A, a 20-m DOI can be inferred from the spread of quantiles. At Point B, the inverted resistivity profile distribution indicates that the tool is within the reservoir, and the DOI is extended to 28 m, owing to an increase in resistivity of the volume investigated. At the same time, a declining resistivity ramp profile is delineated below the tool position. In both plots, the uncertainty in the position of the reservoir top, reservoir resistivity and reservoir thickness may be interpreted. This uncertainty decreases as quantiles converge when the toolstring gets closer to the reservoir. (Adapted from Seydoux et al, reference 5.)
This probabilistic inversion provides an unbiased estimate of the formation resistivity surrounding the wellbore. The inversion is suitable for complex geologic settings because it requires no user input, thereby reducing the risk of misinterpreting geologic structures, or the fluids contained therein, based on mistaken assumptions. By integrating results from the unbiased inversion with previously developed exploration and production models, operators can confidently update their interpretations in a timely manner. From these updated models, well placement teams can validate or modify drilling trajectories to account for changing conditions in the subsurface.

**Avoiding Water at Ekofisk**

The Ekofisk field, located on the Norwegian Continental Shelf, was discovered by Phillips Petroleum Company in 1969 and was put on production in 1971 (above). Operated by ConocoPhillips Skandinavia AS, this North Sea field consists of fractured chalks stacked in an elongated dome. The field produces from the Ekofisk formation and the underlying Tor formation. These chalk formations are characterized by high porosities of between 25% and 45% and low permeability between 1 and 10 mD. A tight zone—the EE unit—separates the lower Ekofisk from the Tor.

The field has undergone water injection since 1987. From its peak annual production rate of more than 20 million m³ [126 million bbl] oil equivalent in 1977, production from the field declined by more than half in eight years. Limited gas injection, combined with extensive water injection and several new installations at the field, helped to restore production to near peak levels during the late 1990s; but after 10 years, production started to decline again.

The chalks of Ekofisk field, despite their low matrix permeability, proved to have high matrix waterflood displacement efficiency. The fractured sections of the reservoir experience more rapid water flooding, while the remainder of the reservoir experience more rapid water flooding, while the remainder of the reservoir experience more rapid water flooding, while the remainder of the reservoir experience more rapid water flooding, while the remainder of

---


the reservoir floods later. Over time, this complex distribution of reservoir water and pore pressure has made it difficult to map remaining pay accumulations.

The well planning team at ConocoPhillips opted to use the GeoSphere service for landing and drilling a horizontal well. The team first sought to locate the tight EE horizon between the Ekofisk and Tor formations—a key marker used for landing the well. After landing, drilling would be conditional, based on formation water saturation. The goal was to geosteering within the upper Tor formation, but maintaining optimal position would involve more than simply steering along formation structure. Reservoir models indicated that the lateral section might encounter injected water within fractured intervals of the uppermost section of the upper Tor (TA) unit—which the operator wanted to avoid.

The well planning team targeted the oil-saturated part of the TA unit and needed the GeoSphere service to provide guidance in geosteering within the pay zone, identifying any water zones above and below the proposed lateral and locating the tighter middle Tor (TB) unit below the wellbore. The operator was also concerned that water breakthrough into the TA zone might compel an early decision to TD the well, thus a constant evaluation of the lateral section was needed to continue drilling. The tool’s capability for deep imaging around the wellbore would also be useful in observing faulting at a distance and revealing aspects of the reservoir pertinent to completion design such as determining the best intervals to perforate.

The GeoSphere service was utilized while drilling out of casing, allowing the operator to detect a resistive marker 50 ft [15 m] TVD below the wellbore. As the driller continued to build angle to 60°, the service located horizons within the Ekofisk formation some 60 ft [18 m] TVD (100 ft [30 m] MD) away from the wellbore. The top of the EE unit, the thin layer above the Tor formation, was detected 79 ft [24 m] below the wellbore. The service was used to resolve the contact between the EE unit and the upper Tor’s TA unit although it lay 50 ft MD ahead of the bit (above). As the wellbore intersected the middle of the Tor TA unit, the well planning team instructed the directional driller to increase inclination to 89.6° to land the well within the lower part of the TA unit.

While the lateral section was being drilled, the well intercepted a 40-ft [12-m] fault, and well planning geologists recommended increasing inclination to 94° to remain within the target reservoir. The GeoSphere inversion indicated that despite crossing the fault, the wellbore still remained in good quality reservoir within the TA unit. It also detected a low-resistivity zone below the wellbore, which was the water-filled TB unit of the Tor formation. As drilling of the lateral section proceeded, the GeoSphere toolstring continued to track the position of the TB unit some 40 ft TVD beneath the wellbore. Later, it detected a steeply dipping conductive boundary, interpreted as a fault, while the fault was still 90 ft [27 m] TVD above the BHA. Resistivity measurements indicated the zone beyond the fault would be wet, which was subsequently confirmed by conventional LWD measurements when the wellbore crossed the fault. Anticipating other conductive zones along with the potential for increasing pore pressure, the well planning team elected to TD the well after drilling more than 1,800 ft [550 m] MD of a hydrocarbon-filled lateral section (next page).
A matter of scale. The reservoir-scale mapping displays much finer resolution for navigating the reservoir than would be possible using seismic data alone. The deep-reading capabilities of the GeoSphere toolstring enabled early detection of the EE unit 79 ft below the wellbore, giving the operator advance notice to prepare for landing the well in the lower TA unit. Cold colors—blues and greens—indicate conductive or low resistivity layers such as shale or water-bearing sands. Warm colors—oranges and reds—indicate high resistivity typical of oil- or gas-bearing sands (top). In addition to mapping the structure and fluid content of the TA unit, the GeoSphere inversion also mapped the TB unit, even though the wellbore had not penetrated that interval. This information helped the operator extend the well horizontally through the TA reservoir while maintaining optimal standoff from the water-filled TB unit. The TB unit, as detected by the GeoSphere inversion (bottom, red line) compares favorably to that picked on the surface seismic display (yellow line).
Defining a reservoir. Even though data obtained from a pilot hole confirmed the presence of the reservoir and identified dip at the pilot hole entry point, the overall geometry of the reservoir top could not be estimated using the data obtained from the pilot hole and other offset wells. To reduce depth uncertainty inherent in seismic modeling of the reservoir, the Santos well placement team relied on directional, deep-reading measurements to define the upper and lower limits of the reservoir. As drilling continued, the operator was able to map the lateral extent of the reservoir. Gamma ray (top, green) and resistivity (red, blue, orange and black curves) readings from other LWD tools indicating clean sand and pay, compare favorably with the GeoSphere color map (middle). The lower panel highlights the discrepancy between the top of the reservoir and oil/water contact as determined by the seismic predrill model and those determined by the GeoSphere reservoir mapping-while-drilling service.
After providing early warning of the approaching landing zone, the service helped the well planning team map the oil-rich zones within a waterflooded reservoir and for up to 100 ft around the well. GeoSphere measurements also assured the operator that the wellbore trajectory had not bypassed the intended target. Furthermore, water saturation changes indicated by the LWD toolstring were used to assist in determining perforation intervals during the completion phase.

**Mapping Reservoir Boundaries Offshore Australia**

While drilling a prospect offshore northwest Australia, geoscientists with Santos Ltd had to contend with some 10 m [33 ft] of uncertainty in seismic depth control. The Santos well placement team sought to land the well as close as possible to the top of the reservoir, then steer the trajectory to achieve optimal positioning with respect to the oil/water contact (OWC). Logs from a pilot hole helped confirm the presence of a thick sand, showed the depth of the OWC and determined formation dip at the pilot hole. However, the orientation of the reservoir and geometry of its crest could not be inferred with accuracy. Despite suboptimal structural control, the Santos well placement team had to drill a landing that would position the well for maximum reservoir exposure.

Santos selected GeoSphere technology to reduce geologic uncertainties and map structure, dip, fluid contacts and reservoir boundaries. The BHA included a rotary steerable system, GeoSphere transmitter and receivers, PeriScope LWD tool, TeleScope high-speed telemetry service and adnVISION azimuthal density neutron tool. Upon exiting the casing shoe, the toolstring detected the top of the reservoir 6 m [20 ft] TVD below the proposed well path and identified the OWC 19-m [62-ft] TVD beneath the reservoir top. As a consequence, the well placement team was able to ascertain the structural geometry and assess the drilling trajectory prior to landing the well (previous page).

Real-time mapping of the reservoir and OWC proved crucial in optimizing and maintaining structural positioning within the reservoir. Interpretations of the reservoir structure and fluid contacts from the GeoSphere service were later integrated into the operator’s 3D geologic model to update drilling and field development plans.

**The Big Picture**

The spacing between a transmitter and receiver affects a logging tool’s depth of investigation, and the GeoSphere toolstring uses this relationship to attain greater DOI than that of conventional LWD tools. Its deep-reading directionally sensitive measurements drive a continuous real-time automatic multilayer inversion that gives well placement teams a broader perspective on the geology surrounding a wellbore. This expanded view of the subsurface helps geoscientists and drillers bridge the gap between conventional LWD data and surface seismic data to identify fluid contacts, subseismic faults and other geologic details not defined through surface seismic data.

By presenting mapping-while-drilling information in real time, the GeoSphere service can have a significant impact on well placement decisions that ultimately influence production. A well can be steered along a path defined by boundaries observed above and below the wellbore—most commonly, the top of the reservoir and the water contact at its base. This broader view of the reservoir helps the driller to drill a longer productive interval with a smooth well path, resulting in increased recovery through the pay zone.

At the office, mapping-while-drilling data can subsequently serve as a basis for developing strategies to optimize production in complex or marginal fields. These data are also used to identify new targets in neighboring sands. GeoSphere reservoir scale measurements provide higher resolution than do surface seismic data, leading to a tighter integration with other reservoir information. Complementary information from surface seismic data, along with conventional LWD or wireline logging data, can be integrated with GeoSphere inversion results to create or refine structural models for increased understanding of the reservoirs and the fluids they contain. —MV
Monitoring and Managing Coiled Tubing Integrity

Coiled tubing is subject to wear and fatigue during each trip in and out of a wellbore. A new wellsite scanning system helps operators minimize premature tubing failures through continuous monitoring of tubing anomalies as they evolve.

Advances in drilling and stimulation technologies are opening new plays for development of unconventional resources. The success of these plays hinges largely on an operator’s ability to maximize wellbore exposure to the reservoir and then open that reservoir to production. These strategies rely on horizontal or extended-reach drilling followed by hydraulic stimulation. To convey tools and stimulation treatments downhole in high-angle wells, operators increasingly call on the capabilities provided by coiled tubing.

Coiled tubing (CT) is designed to be flexible and ductile enough to withstand winding and unwinding from its storage reel while remaining strong enough to convey and retrieve tools downhole. The tubing is made of low-carbon alloy steel...
in diameters ranging from 0.75 to 3.5 in. and may exceed 9,100 m [30,000 ft] in length. From onshore to offshore and from drilling and completions to workovers, coiled tubing has proved its versatility. Coiled tubing is used for reentry drilling, logging, fishing, perforating, fracturing, acidizing, wellbore cleanouts, unloading of wells, electric submersible pump installations and other applications. A typical CT job will subject the tubing to numerous and varied types of stresses, which, over time, subtly weaken the pipe and ultimately lead to its withdrawal from service.

During each CT deployment, diverse forces act in concert to degrade the service life of the coiled tubing string. On its way into the wellbore, the string is led off its storage reel, bent over a guide arch then straightened as it is pulled through the injector head to enter the wellbore; downhole, the tubing must bend to extend beyond the heel of a lateral wellbore (right). Bending stresses tend to be highest at the guide arch and on the reel, where they can exceed the steel tubing’s elastic yield strength, thus subjecting the CT string to plastic deformation.

Once the downhole tasks are completed, the process is reversed as the tubing is extracted from the wellbore and spooled back onto the reel. Repeated bending, unbending and tensile stresses exert cyclic loads on the pipe. The resulting strains impart low-cycle fatigue, cumulative damage that leads to the formation of microcracks and ultimately forces the tubing string to be removed from service. In addition to low-cycle fatigue, certain operating conditions exacerbate the typical stress loads: a tight bending radius, high temperature or high internal pressure can cause a tubing string to be retired after only a few hundred cycles.

Numerous other factors affect CT fatigue life. Metallurgical composition dictates the tensile strength of the pipe and the types of environments in which it can operate. Defects may be caused by inclusions or poor welds. Fluids pumped downhole, such as those for acid treatments or brine completions, can cause corrosion, as can residual moisture left in the pipe during storage. Corrosion causes pitting and degrades tubing wall thickness. Mechanical damage—a result of routine CT operations caused by contact with the reel, injector head, blowout preventers, wellhead internals and downhole well completion equipment—manifests itself in the form of surface flaws such as scratches, gouges or dents. Chrome production tubulars are particularly abrasive to carbon steel tubing.

To prevent problems associated with tubing wear and fatigue, the CT industry has instituted pipe management practices for the handling and treatment of coiled tubing. Most pipe management systems estimate the progression of CT fatigue over time by tracking the number of bending cycles imposed by the reel and the guide arch, or gooseneck, in addition to tracking various operating parameters. Industry standards set limits on the size of external mechanical damage that is acceptable for CT operations; most ratings are based on damage depth, expressed as a percentage of nominal wall thickness. The tubing is typically retired when metal loss exceeds 10% of the wall thickness.

Damage and imperfections are typically identified during periodic pipe inspections when non-destructive evaluation (NDE) techniques can be

---

5. If metal loss occurs within a small section of tubing, that section may be cut out, and the rest of the tubing is welded together before it is returned to service; if metal loss is extensive along the tubing string, the entire string may be retired.
used to measure the geometry of surface-breaking defects. Various NDE methods, including liquid dye penetrant, radiographic, magnetic particle, eddy current and magnetic flux leakage testing, have been adapted for identifying damage and flaws in CT. Depending on the technique employed, CT inspectors can measure outside diameter (OD), ovality and wall thickness of the pipe; identify welds, external scratches, gouges and cracks; and detect internal pitting and welding flaws.

Regular inspections are part of the CT string scheduled maintenance plan and are typically performed offline at a pipe service facility. As such, these inspections obtain only a snapshot of the pipe condition before or after deployment. Such snapshots are intermittent and may not be sufficient for evaluating the severity of defects, assessing the serviceability of a CT string or determining the cause of damage. At the wellsite, conditions that affect CT integrity and fatigue life can change rapidly. If problems are discovered early, operating parameters may in some cases be altered, thus prolonging the life of the CT string.

This article reviews a CT inspection system that operates at the wellsite in real time. Mounted near the storage reel, the CoiIScan RT real-time pipe inspection system incorporates a series of sensors that allow the operator to monitor the condition of the CT string as it is spooled in and out of the well. The inspection system establishes the location and extent of internal and external anomalies that point to pipe defects and damage. This technology enables CT crews to identify flaws and monitor how they evolve over the working life of the pipe.

Problems in the Making

Under the stress and strain of wellsite operations, minor tubing defects and imperfections may develop into major problems that can undermine the integrity of the CT string and compromise operations. These flaws can be attributed to three primary sources: manufacturing defects, corrosion and service-induced mechanical damage.

Manufacturing of coiled tubing starts at the mill, where rolls of sheet steel are laid flat and cut into strips, known as skelps. Each skelp is cut on a bias, typically at 45°. The bias edges of several skelps are welded together to form a continuous strip of sheet steel, and the mechanical properties of the bias weld nearly match those of the skelp. Next, the strip of sheet steel is rolled formed into a tubular shape while a high-frequency induction welding machine fuses its two edges together to form a continuous longitudinal seam. When the sheet steel is formed into a tube, the 45° bias weld winds helically around the tubing and is evenly distributed over a greater length of the tubing than would be the case for a butt weld (above). The mill removes the bead of welding flash from the external side of the seam to obtain a smooth OD on the tubing. The inside of the tubing is flushed to remove scale or other loose material; in some cases, excess welding flash inside the tubing must also be removed.1

Although tubing companies take measures to prevent their occurrence, two types of problems have been encountered during the manufacturing process. Nonmetallic inclusions, such as calcium oxide, may sometimes be introduced into the steel strip at the steel mill.1 Such impurities and inclusions can lead to delamination of the tubing wall, degradation of the mechanical properties of the steel and an increase in the risk of corrosion. The other type of problem is caused by any interruption to the welding process. Welding interruptions produce a partial or complete lack of fusion that can result in porosity, underfilling of the weld area and open gaps along the bias and seam welds.

Corrosion can pose a significant problem throughout the life of a CT string. Through deployment in the wellbore, the tubing may be exposed to acid treatments, brine completion fluids, water, hydrogen sulfide [H2S] and carbon dioxide [CO2]. Such exposure promotes corrosion, which results in pitting and reduction in tubing wall thickness.1 To combat these problems, tubing manufacturers and end users have instituted a variety of measures. While running hydrostatic pressure tests, tubing companies maintain the testing fluid at slightly alkaline pH levels between 8 and 9. After testing, they drain and wipe the inside of the tubing to remove any fluids. Some companies pump nitrogen into the tubing and maintain a slight pressure to eliminate as much oxygen as possible during storage and transport. Corrosion inhibitors may also be used to coat the inner and outer surfaces of the pipe.

---

^ Welding of coiled tubing. Early manufacturing processes used a butt weld (left) to join lengths of tubing together. After a number of tubing failures were found at the heat-affected zone adjacent to the weld bead, tubing makers developed a new approach to manufacturing. Flat strips of sheet steel are joined end to end before being curled into tubular form. These strips are cut on an angle and joined by a bias weld (right). This weld forms a helix when the strip is rolled into a tube (middle). The bias weld distributes stresses in the weld zone over the length of the helix rather than concentrating it within a narrow band as would a butt weld.
Perhaps the most common threats to tubing integrity arise from damage incurred during routine wellsite operations (above). Normal handling at the wellsite subjects the CT to mechanical damage—scratches, abrasions, dents or gouges—through contact with the injector, wellhead, casing and completion equipment as well as through contact with abrasive formations in openhole settings. Other operational damage may take many forms (previous page bottom). These include the following:

- **ballooning**: localized expansion of the tubing caused by high pressures while tripping
- **necking**: stretching and thinning caused by application of excessive tensile force
- **erosion**: wearing away of the inner or outer tubing surface as a result of high flow rates or abrasion
- **injector damage**: transverse gripper marks or longitudinal gouges created as the CT is injected downhole may be caused by improper operation of the injector, misalignment of injector gripper blocks or foreign objects between the gripper blocks and the coiled tubing.

Manufacturing defects, corrosion and service-related damage result in surface flaws that affect the tubing’s capability to handle cyclic stress loads: They concentrate stress. Ideally, when a load is applied to a piece of tubing, the resulting stress will be distributed uniformly. However, scratches, gouges, pits or pinholes produce voids in the surface of the metal tubing, and these voids are incapable of bearing loads. The stress must then be redistributed over the remaining metal. This creates an uneven distribution of stress that is highest at the edges of the void, which causes stress concentration. Furthermore, these stress risers accelerate the formation of fatigue cracks.

When tubing has been subjected to stress cycles, fatigue cracks may form where stress is concentrated. Fatigue cracks usually initiate at the surface of the tubing; therefore, surface flaws such as abrasion, pitting or scratches can decrease fatigue life. Conversely, smooth surfaces increase the time required for fatigue cracks to form.

Because CT is ductile, such defects do not normally cause failure at their onset and do not

---

7. Calcium oxide helps remove impurities such as phosphorus and sulfur from the steel. When calcium oxide is added, these impurities form a slag on the surface of the molten metal, which can then be skimmed for removal.

---

### Damage Indicators and Mitigation

<table>
<thead>
<tr>
<th>Indicators</th>
<th>Damage Type</th>
<th>Damage Mechanisms</th>
<th>Mitigation Steps</th>
</tr>
</thead>
<tbody>
<tr>
<td>Used on wells with chrome tubulars</td>
<td>Mechanical damage</td>
<td>Surface abrasion</td>
<td>Avoid cycling the defect</td>
</tr>
<tr>
<td>Visible, isolated, external defects</td>
<td>Mechanical damage</td>
<td>Dents, gouges and plow marks</td>
<td>Move pipe slowly through chrome tubulars</td>
</tr>
<tr>
<td>Visible extended wear</td>
<td>Mechanical damage</td>
<td>Storage corrosion</td>
<td>Use metal friction reducer</td>
</tr>
<tr>
<td>Wall loss with outer diameter loss</td>
<td>Fluid damage</td>
<td>Acid corrosion</td>
<td>Adjust surface equipment</td>
</tr>
<tr>
<td>Wall loss without outer diameter loss</td>
<td>Fluid damage</td>
<td>H₂S corrosion</td>
<td></td>
</tr>
<tr>
<td>Periodic internal magnetic flux leakage (MFL) anomalies</td>
<td>Reactive damage</td>
<td>Increase corrosion inhibitor</td>
<td></td>
</tr>
<tr>
<td>Used on H₂S wells</td>
<td>Reactive damage</td>
<td>Improve blowdown procedures</td>
<td></td>
</tr>
<tr>
<td>Used on acid pumping jobs</td>
<td>Reactive damage</td>
<td>Avoid acid and H₂S downhole</td>
<td></td>
</tr>
<tr>
<td>High level of fatigue</td>
<td>Metallurgical damage</td>
<td>Increase volume of acid or H₂S inhibitor</td>
<td></td>
</tr>
<tr>
<td>Wrinkles or stress marks on pipe</td>
<td>Metallurgical damage</td>
<td>Trim pipe to avoid high fatigue</td>
<td></td>
</tr>
<tr>
<td>Invisible, isolated, MFL defects</td>
<td>Metallurgical damage</td>
<td>Operate below yield point</td>
<td></td>
</tr>
<tr>
<td>Isolated necking (outer diameter loss)</td>
<td>Metallurgical damage</td>
<td>Avoid cycling damaged sections</td>
<td></td>
</tr>
</tbody>
</table>

Damage from coiled tubing operations can often be diagnosed and mitigated at the wellsite.
necessarily result in condemnation of the entire CT string. Minor surface blemishes can be dressed with a grinding tool and brush. Sometimes, whole sections must be cut out of the pipe, leaving the undamaged sections on either side of the cut to be rejoined by welding. Over time, however, even minor blemishes can evolve into major flaws that threaten the structural integrity of the pipe.

The CT Scanning System
The CoiIScan real-time pipe inspection system consists of an inspection head, a data acquisition system and monitoring software. This system employs two proven nondestructive evaluation techniques for detecting flaws in the tubing: magnetic flux leakage (MFL) and eddy current testing. These techniques are well suited for oilfield operations, requiring neither a clean tubing surface nor any type of coupling agent between the sensors and the tubing. Because the CoilScan RT system uses noncontact sensors, it can accommodate CT strings with rough, dirty, wet or muddy tubing surfaces. The only parts that touch the tubing during normal operations are the stainless steel guide rollers and the odometer wheels. The MFL sensors locate defects and determine wall thickness; eddy current sensors measure the OD and ovality of the tubing string. This system provides continuous real-time monitoring at an operational speed up to 40 m/min [130 ft/min].

Magnetic flux leakage is the basis for detecting magnetic anomalies in the tubing string. The anomalies typically originate from gouges, pitting, metal loss or other imperfections, including material damage or manufacturing defects. The MFL device employs strong magnets to induce a magnetic field in the steel wall of the coiled tubing. This magnetic field flows from its south, or negative, pole—where it enters the steel—to its north, or positive, pole, where it exits. Any break or void in the magnetized tubing will have a similar polar orientation; when the magnetic field encounters a break—a crack, for example—the field will exit the north pole of the crack and reenter at its south pole. The air gap between edges of the crack cannot support as much magnetic flux as steel can, so the magnetic field will spread out, or leak (above left). This flux leakage is detected by Hall effect sensors in the inspection head. Measurements of the intensity and distribution of magnetic flux leakage infer an underlying defect in the steel. This method can also be used to determine CT wall thickness.

\[ \text{Magnetic flux leakage. The magnetic flux in a piece of tubing may be interrupted by any type of break or discontinuity along the inner or outer surfaces of the tubing. The air gap at the surface discontinuity cannot support the same flux magnitude as can steel. This causes the magnetic field to leak out of the metal and spread outward from the defect.} \]

\[ \text{Eddy currents. An eddy current probe is used to measure outside diameter and ovality of a CT string. Current flows through the primary coil of the probe, generating a magnetic field. This field creates eddy currents in the conductive tubing. The eddy currents generate their own magnetic fields, which are out of phase with the original primary coil’s magnetic field.} \]
Eddy currents are circular electric currents induced within a conductor by changing magnetic fields in that conductor. In an eddy current probe, alternating electric current flows through a wire coil and generates an oscillating magnetic field (previous page, bottom). When the probe nears the CT, eddy currents are generated on the tubing surface. The eddy currents generate their own magnetic field, which opposes the magnetic field originating from the wire coil. As a result, the electrical impedance of the wire coil will be altered. From measurements of the change of electrical impedance in the coil, the distance between the coil eddy current probe and the conductive CT surface can be determined. Using these measurements, the CoilScan RT system determines the tubing OD and the ovality of the CT string.

The two halves of the CT inspection head form a clamshell that is placed around the tubing, and measurements are obtained as the CT is spooled off and on the reel (above). The head consists of an MFL subsystem, an OD-ovality subsystem and an odometer subsystem.

The MFL subsystem is located at the center of the inspection head. It employs permanent magnets and Hall effect sensors to screen for CT wall thickness and detect anomalies on the inner and outer tubing walls. The MFL sensor data are processed through digital filters specially designed for detecting fatigue cracks, corrosion, holes, notches, gouges and pitting, and the processed data are also used to quantify metal loss over time.

The OD-ovality subsystem measures the outside diameter of the tubing. These measurements are used to calculate ovality. The OD measurements are obtained from eddy current displacement probes arranged in opposing pairs over the circumference of the tubing. 


11. A Hall effect sensor is a transducer that varies its output voltage in response to the strength of a magnetic field.
High-definition 3D magnetic flux leakage (MFL) signature plot for a typical bias weld anomaly. Bias welds are used extensively during the manufacturing process and are found in nearly every coiled tubing string. An anomaly associated with such welds is caused primarily by localized changes in material properties, particularly changes in steel permeability between two skelps. On some CT strings, bias welds join skelps of differing thickness, and this change in thickness may play a role in causing magnetic flux leakage as well. This display shows an aggregation of MFL amplitude readings from all Hall effect sensors (top). The same anomaly is mapped in 2D and 3D (bottom). Colors correspond to MFL values in gauss from low (blue) to high (red). The map view can be rotated for better visualization of the data.

The odometer subsystem measures the depth, length and position of the tubing as it is being inspected. Two odometer subassemblies provide redundancy and reliability in distance measurement. Each subassembly has a measuring wheel and a high-resolution rotary encoder to convert wheel rotation into linear distance.

A data acquisition subsystem interfaces with the inspection head, processes and interprets the MFL and eddy current sensor data and depth encoder counts then outputs the results to the monitor for display. This independent data acquisition and processing subsystem can be placed up to 30 m [100 ft] from the inspection head. Essential capabilities under normal operating conditions include the following:

- measurement of wall thickness to an accuracy of ±0.127 mm [±0.005 in.]
- measurement of outside diameter to an accuracy of ±0.254 mm [±0.01 in.]
- detection of through-hole defects as small as 0.79 mm [0.031 in.]
- detection of wall thinning, blind holes, transverse notches and longitudinal notches on the outer and inner surfaces of the tubing string
- calculation of ovality and measurements of MFL amplitude, wall thickness and outside diameter obtained every 1.2 cm [0.5 in.] along the CT axis.

All measurements are integrated with 3D modeling and interpretation software that helps the operator detect, identify, visualize over 360° and track anomalies over time.

Wellsite Data Processing and Display
Signals from the MFL sensor encode a complex combination of measurements related to the geometry and severity of surface tubing defects as well as anomalies within the wall of the tubing. In the CT unit, CoilScan AP characterization technology processes the MFL, eddy current and depth encoder signals to help the CT crew interpret changing pipe conditions. From the CT unit graphical interface, the CT engineer and operator can set up the parameters of the job, set anomaly detection alarm levels and carry out postjob reporting functions.

When anomalies reach a user-specified threshold, the CoilScan AP technology sends visual and audible alarms to the CT unit operator. Alarms are triggered when the following occur:

- MFL amplitude exceeds the specified threshold
- wall thickness drops below the threshold
- ovality computations exceed the threshold.

Pipe damage identification and the defect library. The red curve is derived from the upper boundary of the measurements from all MFL sensors; the blue curve is derived from their lower boundary. The red and blue curves together constitute the MFL defect signature. The MFL plots from a CoilScan RT system inspection of a 2-in. OD string reveal severe pipe damage. The software correctly identified the defect as a gouge on the pipe surface and also provided severity information. This identification was accomplished without having to stop the CT operation to prove up the defect. The CT defect (top left) can be compared with a similar defect from the predefined library (top right). Corresponding MFL amplitude signatures from the defect and library also showed a good match (bottom).
The CoilScan AP technology software retains a record of all alarm-triggering events in its alarms record table. During a job, the CT operator may enter notes into the comments field of that table. All comments are saved with the main data to become a permanent attachment to the inspection data. Selecting any row in the table will pull up an MFL amplitude display of the associated anomaly (previous page, top). The CT engineer can evaluate the MFL signatures at the wellsite and archive the data for further review after the job.

As the tubing is spooled in and out of the hole, the CT crew monitors MFL amplitude and various job parameters using the log plot. For used tubing, tens or even hundreds of spikes are not uncommon on the amplitude chart of a typical string. Each spike corresponds to a magnetic anomaly and thus a potential defect (above). To address the high number of spikes and the difficulties associated with stopping the CT operation to perform prove up—physically locating the defect that caused the MFL alarm then investigating it further using various nondestructive evaluations—Schlumberger researchers developed a program to automatically identify and track the recorded anomalies.

Using advanced pattern identification, recognition and matching algorithms, the program identifies the underlying defect type and provides useful information regarding severity of the flaw. Just as important, the program tracks defect initiation and growth at various times in the life of the tubing. Automatic defect identification is based on a library of defects that has been preloaded into the program. This library pairs MFL signatures with photographs of numerous defects collected from yard and field inspections. The software can identify newly discovered defects by matching their MFL signatures with patterns in the predefined benchmark library (previous page, bottom).

This process of automatic defect tracking enables CT crews to maintain a history of important defects for each string, characterized by their similarity to catalogued MFL signatures, depths and wall thicknesses. The tracking of MFL signatures as they evolve can shed light on
Defect tracking. An MFL defect signature (pink shading) is tracked from initial development of the defect (top left) to its final signature before the CT is retired (bottom right). By tracking signal changes over time and across jobs, the CT crew can monitor how quickly a defect deteriorates. The MFL ratio, calculated by dividing the evolving defect’s MFL amplitude during each job by that of the initial defect, is a normalized measure of defect severity. Within the one-foot [30-cm] sample window shown, the minor lateral shifting in the defect position results from tubing stretch and reactions to strain.

Each defect’s severity and its impact on pipe integrity (above).

On subsequent jobs, the CoilScan AP technology enables the CT engineer to identify and track defects over time. By compiling all the matching defects recorded within individual inspection jobs, the entire evolution of a particular defect can then be reconstructed (below).

Continuous Inspection
Through continuous MFL monitoring of pipe—from first use to the end of its service life—defects can be identified, isolated, and tracked, leading to improved evaluations of a CT string’s condition and future serviceability. By integrating these features into a small portable device suitable for real-time inspection, the CoilScan RT system significantly improves the ability to monitor overall pipe integrity.

Once the sensors locate a defect, the next priority is to evaluate the severity of the defect in relation to its effect on CT integrity. Defect severity can be determined by obtaining its length, width, and depth. Schlumberger researchers are using finite element analysis (FEA) to model magnetic flux leakage for specific mechanical defects in CT. The FEA models, followed up by laboratory tests of MFL responses on actual pipe, indicate that defect geometry can be accurately measured using MFL.

Researchers continue to make progress in defining the relationships between MFL measurement profiles and the corresponding geometric characteristics of defects. Researchers are also making progress in evaluating the impact of defects on pipe fatigue. By identifying and grouping defects into different types—transverse or longitudinal dents, notches or gouges—researchers are able to establish a correlation between the MFL signals of the defects and the fatigue life of the pipe.

Pipe management can now be based on job-to-job, continuous, physical measurements with an object-oriented tracking system that allows CT operators to monitor defects over time with minimal interruption to normal wellsite operations. Coiled tubing crews will be able to understand the circumstances that cause defects and that promote further tubing degradation as well as devise mitigation techniques. Defects will be tracked and recorded simultaneously with CT characteristics and critical job parameters. The integration of the CoilScan RT real-time pipe inspection system into CT operations promises to redefine pipe management practices. —MV
Contributors

Intan Arian Binti Abd Aziz is Head of Well Malaysia Development for Petronas Carigali Sdn Bhd in Kuala Lumpur. He joined the company in 2011 and has since served on the Malaysia Peninsula as well as the IPM Segment and served as the BP Eastern North Sea as a project manager in Oilfield Services region and the Middle East. He then moved to the Oilfield Services region and the Middle East. He then moved to the Oilfield Services region and then served as technology manager for the IPM Segment based in the UK. He then became business development manager for real-time technologies and services and in 2010 director of marketing communications, based in Paris. Charlie earned a BS degree in mechanical engineering from Syracuse University, New York, USA, and an MS degree in aerospace and mechanical engineering from Princeton University, New Jersey, USA.

Jean-Michel Denichou is Well Placement Domain Head for Schlumberger in Sugar Land, Texas. During 19 years in well placement, he has taken assignments in Nigeria, Algeria, Tunisia, Norway, the US and China. His role in the Drilling & Measurements Segment includes advising clients in the planning and execution of well placement operations and overseeing Schlumberger well placement operations globally. Jean-Michel has an MS degree in sedimentology from Institut Géologique Albert-de-Lapparent, Paris.

James Donley is a Field Evaluation Geologist at Santos Ltd. in Adelaide, South Australia, Australia, with the asset evaluation and development team. He began his career at Origin Energy in 1984. After an initial stint in exploration, he moved into the development group as production geologist. For the next seven years, he worked on a variety of gas fields in the Cooper and Otway basins in central and southern Australia. He moved to Shell in New Zealand in 2002 to work on the giant Maui oil and gas field. In 2006, he moved to Aberdeen for a cross-posting with Shell and worked the Gannet and Nelson fields in the UK Central North Sea. James joined Santos in 2010 and moved to Perth to lead a geoscience team through the development of the Fletcher–Finucane fields.

Christophe Dupuis, based in Stavanger, is the Well Placement Domain Champion for Schlumberger in the North Sea, where he works in geosteering and reservoir mapping. Since joining the company in 2006, he has held positions in LWD tool and inversion development, research, well placement operations and technical sales. His current interests focus on multi-disciplinary integration of reservoir mapping GeoSphere® data with seismic data, geomodeling and reservoir engineering. Christophe received a master's degree in applied mathematics engineering from the University of Louvain, Belgium.

Cengiz Esmersoy is a Technology Advisor in the PetroTechnical Services (PTS) Segment at the Geosolutions Center in Houston, working on integrated solutions of seismic and well data, including the Seismic Guided Drilling® technique. He began his career in 1985 at Schlumberger-Doll Research in Ridgefield, Connecticut, USA, where he worked on seismic imaging and multicomponent borehole-seismic techniques and became the leader of the sonic logging program and then the deep formation characterization program. In 1997, he became manager of the Deep Measurements group, where he launched the seismicVISION® and sonicVISION® services and worked on the PeriScope® service. He next managed Measurement Integration for Reservoir Seismic Services and Data and Consulting Services and was technology advisor for the Deep Reading Theme until he joined WesternGeco and later PTS. He has published numerous papers and is the recipient of multiple awards; he is currently Chair of the SEG Research Committee. Cengiz obtained a PhD degree in electrical engineering from the Massachusetts Institute of Technology, Cambridge, USA.

Dayal Gunasekera is a ConocoPhillips Senior Manager for Schlumberger in Abingdon, England. He has more than 25 years of industry experience and has held his current position since 2014. Previously, he was a manager for various sectors and technologies for Scandpower Petroleum Technology and was also a petroleum engineering software application developer. He is a member of the scientific committee of the European Association of Geoscientists and Engineers European Conference on the Mathematics of Oil Recovery and a former technical committee member of the SPE Reservoir Simulation Symposium. Dayal received BS and MS degrees in general engineering from the University of Cambridge, England, and has a PhD degree in electronic and electrical engineering from the University of Wales Swansea.

Bjarte Hatviet has been the Schlumberger Scandpower Petroleum Technology Center Manager in Kjeller, Norway, since 2013. He began his career as a researcher at SINTEF in Trondheim, Norway, in 1992 and the next year became a consultant for Scandpower AS in Kjeller. In 2008, Bjarte became Scandpower senior vice president before joining Schlumberger as a senior vice president of its OLGA® multiphase flow simulator group. He obtained a MS degree in mechanical engineering from the Norwegian University of Science and Technology in Trondheim.

Kjetil Havre is Schlumberger Advisor for OGLA asset optimization. He began his career as a research scientist with ABB before joining Scandpower Petroleum Technology in Kjeller, Norway, where he became senior vice president and then senior principal consultant for OGLA online. Kjetil holds a BS degree in cybernetics from Oslo Engineering College, Norway, an MS degree in process automation from Sivilingeniørutdanningen i Telemark, Oslo, and a PhD degree in process control from the Norwegian Institute of Technology, Trondheim.
Andy Hawthorn, who managed the Schlumberger Seismic Guided Drilling® solution program at the Geosolutions Center in Houston, worked on integrated solutions for drilling. He began his career with Schlumberger 25 years ago and has served in positions worldwide on a diverse range of projects, including in field operations, for LWD sonic and seismic tool development and in unconventional and deepwater geomechanics. Andy earned a BS degree in geology and an MS degree in geological engineering from Durham University in England.

Hui Li is Engineering Supervisor in the Exploration and Development Department of North Tarim Basin, PetroChina Tarim Oil Company in Korla, People's Republic of China. He has nine years of experience in field geology, production and well logging. Hui holds a master's degree in mineral prospecting and exploration from China University of Petroleum, Qingdao, People's Republic of China.

Xiao Liu has been a Geophysicist with the Schlumberger PetroTechnical Services Segment for two years; he works in the Geosciences and Petroleum Engineering subsegment in Beijing. Previously, he was a geophysicist and project manager with LandOcean Energy Services Company, Ltd. in Beijing. Xiao (Shawn) obtained a bachelor's degree in petroleum engineering from China University of Geosciences, Beijing, and an MS degree in geology from Peking University, Beijing.

Zhanke Liu is a Senior Mechanical Engineer at the Schlumberger Houston Conveyance & Surface Equipment Center in Sugar Land, Texas. He joined Schlumberger in 2008 after receiving a PhD degree in mechanics, materials and structures from Princeton University, New Jersey, USA. He has since worked in various product areas, including coiled tubing, slickline and well services, and on new product development projects. Recently, Zhanke has focused on the hardware and answer product software development of the CQuipScan® real-time coiled tubing pipe integrity inspection service.

Ettore Mirto is Project Manager for Well Placement Answer Products at the Schlumberger Houston Formation Evaluation Center in Sugar Land, Texas. He joined Schlumberger in 2007 after receiving a master’s degree in geology from the University of Palermo, Italy. Ettore previously held various operations and technical positions, ranging from wireline field engineer, log analyst and petrophysicist to well placement domain champion in Africa, Europe and the Middle East.

Steve Nas is a Schlumberger Drilling Software Advisor based in Kuala Lumpur and a NEXT® well engineering training modules instructor. He began his career in 1977 as a mud logger with Geoservices and became a wellsite drilling engineer in 1980. He joined Shell in 1988 as a wellsite engineer and then became an operations engineer in the southern North Sea. In 1995, he joined Smedvig ASA. Steve joined Weatherford in the Asia Pacific region in 2004 as regional engineering manager for managed pressure drilling operations. In 2011, he joined Scandpower Petroleum Technology and served as head of the company’s well engineering group; he specialized in well control and hydraulic flow modeling technology. Steve has an MS degree in drilling engineering from Robert Gordon University in Aberdeen.

Andre Metzler is HSE Compliance Manager for WesternGeco in Gatwick, England, where he supports marine technical and environmental regulatory compliance. Andre began his career with WesternGeco in 2007 as a junior seismic engineer. He received a BSc degree in electrical and electronics engineering from Universidade Federal de Santa Catarina, Florianópolis, Brazil, and is pursuing an MSc degree in management of oil and gas industry at Heriot-Watt University, Edinburgh, Scotland.

Laura Pontarelli is a Senior Well Placement Geologist for Schlumberger Australasia in Perth, Western Australia, Australia. She joined Schlumberger in 2007 as a field engineer in Doha, and in 2011 moved to the PetroTechnical Services Segment as well placement geologist in Australia. Laura has an MSc degree in structural geology from the University of Chieti-Pescara, Italy.

Miguel Rivas is a Global HSE Advisor for WesternGeco in Gatwick, England. He is responsible for numerous HSE functions, including advisory and monitoring, site-specific environmental assessments and fleet audits. Miguel started his career with WesternGeco in 1993 as an emergency medical doctor. He graduated from Universidad de San Francisco Xavier, Sucre, Bolivia, as a general practice physician.

Ian Sealy is an Environmental Engineer for Schlumberger in Sugar Land, Texas. He started his career with the company in 1979 as a field engineer in Edinburgh, Scotland. Ian obtained a BSc degree in engineering from University College London.

Jean Seydoux is the Schlumberger Well Placement and Reservoir Positioning Program Manager at the Brazil Research and Geoenvironmenting Center in Rio de Janeiro. He joined the company in 1990 as a tool physicist in Houston. Since then, he has been involved in the development of various LWD resistivity tools, including an inclination-at-the-bit tool and an experimental ultradepth resistivity tool. By 2004, he was assigned as physicist and project manager to lead the development of the GeoSphere LWD service. In 2011, he moved to Brazil as a well placement domain champion and since 2014 has been investigating the next generation of answer products for well placement and reservoir characterization. Jean holds a diplôme ingénieur physicien from Ecole Polytechnique Fédérale de Lausanne, Switzerland, and a PhD degree in particle physics from Carnegie Mellon University, Pittsburgh, Pennsylvania, USA.

Hongxiang Shi, based in Korla, People’s Republic of China, is Deputy Manager of the Exploration and Development Department of North Tarim Basin, PetroChina Tarim Oil Company. He has 26 years of experience in well drilling, construction, production and reservoir dynamics. Hongxiang earned a PhD degree in mineral prospecting and exploration from China Southwest Petroleum University, Chengdu, People’s Republic of China.

Grant Skinner is a Senior Well Placement Geologist for Schlumberger in Perth, Western Australia, Australia. He was previously Well Placement Domain Champion for the Australasia region and has been working in well placement for 12 years. He began his career with Schlumberger Wireline in Western Canada in 1999, after which he was involved with seismicVISION® while drilling and LWD in Trinidad and Norway. Grant has a BSc degree in geology from the University of Saskatchewan, Saskatoon, Canada.

Rebecca Snyder is a Passive Acoustic Monitoring (PAM) Manager for Seiche Measurements Ltd in Bradworthy, England, where she supports PAM field operations and training. Before joining Seiche in 2014, she was a PAM program manager for the RPS Group, where she worked on seismic survey vessels and exploration drilling platforms and was responsible for supporting field observers in protected species observation and PAM equipment maintenance, inventory and project management. Rebecca received a BS degree in biology from Northwestern Michigan College, Traverse City, USA, and BSc and MS degrees in marine biology from the Florida Institute of Technology, Melbourne, USA.

Shanhong Song is the Chevron Project Resources Company Project Manager for the Chevron Oronite China Technical Solutions business. Before joining Chevron, he worked as a senior consultant for Western Atlas in Houston and for the Scandpower Petroleum Technology Group, both in Houston. Shanhong joined Chevron in 1989 and was a staff research scientist specializing in flow assurance issues and providing consulting services for Chevron operations worldwide. In 2003, he joined the Chevron Southern Africa Business Unit; two years later, he moved to Luanda as the senior production advisor. In 2008, he was engineering manager on a sour gas processing project in Chengdu, China. He obtained a BE degree in mechanical engineering from the Southwestern Petroleum University, Chengdu, China, and MS and PhD degrees in petroleum engineering from The University of Texas at Austin.

Knut Erik Spilling is Schlumberger Business Development and Consulting Manager—Asset Optimization in Sandvika, Norway. Before joining Schlumberger, he was vice president of Fautoll Process Technologies, head of sales and marketing. Before joining Chevron, he worked as a senior consultant for Western Atlas in Houston and for the Scandpower Petroleum Technology Group, both in Houston. Shanhong joined Chevron in 1989 and was a staff research scientist specializing in flow assurance issues and providing consulting services for Chevron operations worldwide. In 2003, he joined the Chevron Southern Africa Business Unit; two years later, he moved to Luanda as the senior production advisor. In 2008, he was engineering manager on a sour gas processing project in Chengdu, China. He obtained a BE degree in mechanical engineering from the Southwestern Petroleum University, Chengdu, China, and MS and PhD degrees in petroleum engineering from The University of Texas at Austin.

Matthew Spotkaeff is a Schlumberger Product Champion for Drilling Interpretation in Grabels, France. He has 20 years of experience working for Schlumberger, 16 of which have been in the field of geosteering. Currently employed in the Software Integrated Solutions Segment, Matthew is developing drilling software for the Techlog® software platform.

Roderic Stanley has worked in tubing inspection for Baker Hughes, Lone Star Steel, Quality Tubing and iRobotics and is now a Director of Coiled Tubing Resources Management in Houston and Cochair of the API Resources group for coiled tubulars. He has worked on five tubular inspections patents and is active in promoting increased levels of nondestructive evaluation for both the manufacturing and in-service use of coiled tubing. Roderic earned a PhD degree in physics from Florida State University, Tallahassee.
James Telford is a Reservoir Engineer and Team Leader for Asia-Pacific Development at Santos in Adelaide, South Australia, Australia. He began his career with Santos in 2002, working in field and facilities engineering roles before moving to a subsurface engineer position in the Cooper and Amadeus basins. James joined Marathon Oil UK in Aberdeen in 2007 as senior reservoir engineer, working fields in Ireland and the Norwegian Sector of the North Sea. In 2009, he moved to Perth, South Australia, Australia, joining Santos as senior reservoir engineer and then as team leader for reservoir engineering for the Western Australia and Northern Territory Business Unit before returning to Adelaide in 2013. He is currently focused on providing appraisal and development support to assets and opportunities within the Asia Pacific region, including Vietnam, Papua New Guinea, Malaysia and Bangladesh. James has a BEng degree (Hons) from the University of Adelaide.

Michelle Torregrossa is a Coiled Tubing Services Technical Sales Support Engineer in Houston. Michelle started her career as a coiled tubing services field engineer in 2010 on the North Slope of Alaska, USA. She is an active member of the American Society of Mechanical Engineers and the SPE. Michelle received a BS degree in mechanical engineering and business from The University of Texas at Austin.

Mauro Viandante is the Well Placement Domain Champion for Schlumberger Australasia. He has eight years of experience in the oil and gas industry. In 2008, Mauro was involved in geosteering operations in the North Sea and Continental Europe, and by 2012, he was in charge of geosteering operations in Australia and New Zealand. He has authored several papers on geosteering technology and its application in geologic scenarios. Mauro obtained an MS degree in geology and a PhD degree in structural geology from the University of Chieti-Pescara, Italy.

Petter Vikhamar, based in Houston, is a Geological Operations Supervisor for the Bakken field for ConocoPhillips. He joined ConocoPhillips Norway in 2005, where he held various positions in the well planning team for the Ekofisk and Eldfisk fields before transferring to Houston in 2014. Petter holds an MS degree in petroleum geology from the Norwegian University of Science and Technology, Trondheim.

Gjermund Weisz is Schlumberger Portfolio Manager for dynamic flow simulators in Kjeller, Norway. Before joining Schlumberger in 2008 as a senior account manager, Gjermund worked in Oslo, Norway, as a sales engineer for Fly & Industri-Instrumenter AS and was CEO and founder of a computer-based sports training company, Sportsim. Gjermund earned an MS degree in geophysics from the Norwegian University of Science and Technology in Trondheim and an MBA degree from BI Norwegian School of Management in Oslo.

Zheng Gang Xu, based in Kjeller, Norway, is a Schlumberger OLGA Multiphase Flow Simulator Advisor. Zheng joined Schlumberger as a senior consultant in 1990 and became chief scientist in 2007. He has a BS degree in petroleum engineering from the China University of Petroleum (East China), Qingdao and Dongying, China, and a PhD degree in petroleum engineering from the Norwegian University of Science and Technology in Trondheim.

Fangjian Xue, as the Manager of Seismic Reservoir Characterization with the Schlumberger PetroTechnical Services Segment, led the team that conducts integrated analysis of the carbonates that host reservoirs in cave systems and defines drilling targets for the Seismic Guided Drilling technique. Fangjian (Jack) has 20 years of experience in the industry, providing geology and geophysics solutions to E&P challenges. He gained his expertise in karst reservoirs through his work on various carbonate projects in China and Southeast Asia. He began his career at China National Offshore Oil Corporation and joined Schlumberger in Houston two years later. Jack received bachelor’s and master’s degrees in geology from Ocean University, Qingdao, People’s Republic of China, and a PhD degree in geophysics from Texas A&M University, College Station.

Sherman Yang has worked for WesternGeco and its associated companies for more than 20 years. Located in Beijing, he is currently the Chief Geophysicist in the Schlumberger Geosolutions Center. He has held several technical positions during his 21 years with WesternGeco and Schlumberger. Previous assignments with the company included senior research positions at the Houston Research and Engineering Center, a senior geophysicist position in integrated application for subbasalt exploration in the Mumbai Regional Technology Center, principal geophysicist for earth model building and the Seismic Guided Drilling solution in Houston. Sherman, who is a member of the SEG, obtained a BS degree in geophysics from University of Science and Technology of China, Heifei, and master’s and PhD degrees in geophysics from the University of California, Los Angeles, USA.

Ryosuke Yokote is a Senior Petroleum Engineer at Eni Australia, in Perth, Western Australia. Before joining Eni, he was a petroleum engineer and then senior project engineer for INPEX Corporation in Jakarta, Perth and Tokyo. He also worked for Conoco Indonesia and Total Indonesia as an offshore engineer. Ryosuke, who has coauthored numerous professional papers on the application of dynamic simulation applications and techniques, holds BS and MS degrees in resource engineering from Tohoku University, Sendai, Japan.

Hui Zhang is Processing Supervisor with Schlumberger Geosolutions in Beijing. He has six years of experience in seismic data processing, velocity model building, depth imaging and project management. Hui earned a bachelor’s degree in geology and a master’s degree in geophysics from China University of Mining and Technology, Beijing.

Andrew Zheng is a Surface and Subsurface Integration Architect at the Schlumberger High Efficiency Center of Excellence in Katy, Texas. He began his career in 1996 as a development engineer and has since worked on various projects ranging from coiled tubing and downhole technologies to surface automation and control. In 2007, he moved to Schlumberger Information Solutions to manage the development of the Perform Toolkit® software for drilling, the ProSource® Seismic management system, and Petrel® Studio software. His next assignment bought him back in 2011 to coiled tubing engineering, where he managed the development of a downhole coiled tubing extended-reach tool and the CoiScan coiled tubing inspection device. He is an active member of the SPE and has served as a technical editor for SPE Drilling & Completion since 2003. He serves on the board of Intervention and Coiled Tubing Association. Andrew has a PhD degree in aeronautics and astronautics from Purdue University in West Lafayette, Indiana, USA, and MS and BS degrees in engineering mechanics from Tsinghua University in Beijing.

Liam Zoolt is a Schlumberger CoilTOOLs® solutions General Field Engineer in Prudhoe Bay, Alaska. There he serves as the local CoilScan lead. Liam received his bachelor’s degree in chemical engineering from McGill University, Montreal, Quebec, Canada.

An asterisk (*) denotes a mark of Schlumberger.


**Imaging Tools.** Image logs, introduced in the 1980s, are one of the tools geologists and petrophysicists have at their disposal to analyze in situ rock and formation properties. This article reviews the evolution of these devices—from dipmeter tools to newly introduced tools that can image formations drilled with oil-based mud (OBM). Case studies demonstrate the use of imaging tools for geologic characterization and fracture analysis and include examples of image logs run using a newly introduced tool designed for acquisition in OBM environments.

**Carbon Dioxide.** Carbon dioxide presents challenges and opportunities in the oilfield. Early on, operators saw its corrosive effects on well internals while, later, operators used it to enhance oil recovery. Public interest centers on carbon dioxide’s role in climate change. Industry projects underway reflect these priorities—storing carbon dioxide to mitigate climate change—as well as priorities in the oil field, which include managing corrosive effects and using carbon dioxide to recover additional oil after waterflood.

**Sand Control.** For decades, engineers have chosen sand control solutions based on “rules of thumb” and laboratory tests. Recently, experts have reassessed the validity of the assumptions embedded in those practices. Their findings suggest that sand management efforts are better served by a method that uses mathematical models validated by experiment, particularly when choosing from among the vast array of standalone screens available.

**Books of Note**

**Light: The Physics of the Photon**
Ole Keller
CRC Press
Taylor & Francis Group
6000 NW Broken Sound Parkway, Suite 300
Boca Raton, Florida 33487 USA
2014. 484 pages. US$ 99.95
ISBN: 978-1-4398-4043-6

Author Keller examines, from various perspectives, the photon and what constitutes light, including the models and physical and mathematical descriptions of light as well as the behavior of light and its interaction with matter. The book covers classical and quantum optics and explores quantum electrodynamics and various photon states.

Contents:
- Classical Optics in Global Vacuum
- Light Rays and Geodesics. Maxwell Theory in General Relativity
- Photon Wave Mechanics
- Single-Photon Quantum Optics in Minkowskian Space
- Photon Embryo States
- Photon Source Domain and Propagators
- Photon Vacuum and Quanta in Minkowskian Space
- Two-Photon Entanglement in Space-Time
- Index

... a remarkably comprehensive look at the photon . . . from all possible theoretical angles . . . a delightful book for theoretically inclined advanced students and scientists specializing in optical science. . . . This is an excellent survey of our theoretical state of understanding the photon. Roychoudhuri C. “Book Review,” American Journal of Physics 83, no. 3 (March 2015): 286–287.

**Practical Seismic Data Analysis**
Hua-Wei Zhou
Cambridge University Press
32 Avenue of the Americas
New York, New York 10013 USA
2014. 496 pages. US$ 75.00
ISBN: 978-0-521-19910-0

Intended as a textbook for those studying exploration geophysics and seismology, this introduction to seismic processing uses real-world data and case studies to help students understand how to create subsurface models. The author explains the underlying physics and mathematics of the various seismic analysis methods for models for hydrocarbon and mineral resource exploration. Additional case studies are online.

Contents:
- Introduction to Seismic Data and Processing
- Preliminary Analysis of Seismic Data
- Discrete Spectral Analysis
- Seismic Resolution and Fidelity
- Digital Filters
- Deconvolution
- Practical Seismic Migration
- Practical Seismic Velocity Analysis
- Data Fitting and Model Inversion
- Special Topics in Seismic Processing
- Index

... a practical, detailed, and well-explained introduction to modern methods of seismic data processing . . . the mathematical content is clear and readable for readers with a basic knowledge of calculus and linear algebra. It is an excellent textbook for senior undergraduates and graduates in seismology and exploration geophysics; nevertheless, it can also serve as a reference for researchers in all fields of solid earth geophysics. Bogiatzis P. “Book Review,” Pure and Applied Geophysics 172, no. 2 (February 2015): 593–594.

**The Art of Insight in Science and Engineering: Mastering Complexity**
Sanjoy Mahajan
The MIT Press
55 Hayward Street
Cambridge, Massachusetts 02142 USA
2014. 408 pages. US$ 30.00
ISBN: 978-0-262-52654-8

According to author Mahajan, insight, rather than precision, should be the guiding principle to connect seemingly disparate bits of information into the bigger picture and solve problems in science and engineering. The book, whose tenets are based on Mahajan’s 15 years of teaching at the Massachusetts Institute of Technology, Cambridge, USA, is also available as a free download from The MIT Press.

Contents:
- Organizing Complexity: Divide and Conquer; Abstraction
- Discarding Complexity Without Losing Information: Symmetry and Conservation; Proportional Reasoning; Dimensions
- Discarding Complexity with Loss of Information: Lumping; Probabilistic Reasoning; Easy Cases; Spring Models
- Bon Voyage: Long-Lasting Learning
- Index

[The book] acts as a step-by-step guide that enables the reader to tackle fundamental scientific problems through simple back-of-the-envelope calculations. The main objective . . . is not to promote a thorough understanding of an underlying theory or to allow us to come to an exact solution but rather to encourage us to use our instincts and knowledge of the fundamental concepts to come to an approximate and reasonable solution.

As multinationalism and global cooperation increase in science and technology endeavors, English has become emerging as the lingua franca. Montgomery explores, through a broad range of perspectives in linguistics, history, education and geopolitics, why this phenomenon is occurring and the forms in which it appears. He examines the advantages and disadvantages, the consequences and what the future of a global language for science may be.

Contents:
• A New Era
• Global English: Realities, Geopolitics, Issues
• English and Science: The Current Landscape
• Impacts: A Discussion of Limitations and Issues for a Global Language
• Past and Future: What Do Former Lingua Francas of Science Tell Us?
• Does Science Need a Global Language?
• Notes, Index

Because both educators and researchers at all levels encounter increasing levels of globalization, this book is highly recommended for all.

The book makes a timely contribution to the emerging literature on English as (global) lingua franca . . . a debate that has been taking place mostly in the humanities and the social sciences rather than in the STEM (science, technology, engineering, and mathematics) subjects.

One hopes that the important questions Montgomery raises and the nuanced discussion he presents will be followed by further work on the complex interplay among science, power, and language.


With an enjoyable blend of hard science and good storytelling, Hofstadter . . . and French psychologist Sander tackle these most elusive of philosophical matters. . . . [It’s] worth sticking with [Hofstadter’s] long argument, full of up-to-date cognitive science and, at the end, a beguiling look at what the theory of relativity owes to analogy. . . . [First-rate popular science: difficult but rewarding.


Surfaces and Essences: Analog as the Fuel and Fire of Thinking
Douglas Hofstadter and Emmanuel Sander
Basic Books, a member of The Perseus Books Group
250 West 57th Street, 15th Floor
New York, New York 10107 USA
2013. 592 pages. US$ 35.00

Through descriptions of situations that use language, thought and memory, the authors put forth a vision of the act of cognition. Hofstadter, a Pulitzer Prize–winning author, and Sander, a psychologist, believe that analogy is the core of all thinking and that we are always making analogies, from instances of fleeting daily thoughts to creative scientific insights.

Contents:
• Analogy as the Core of Cognition
• The Evocation of Words
• The Evocation of Phrases
• A Vast Ocean of Invisible Analogies
• Abstraction and Inter-Category Sliding
• How Analogies Manipulate Us
• How We Manipulate Analogies
• Naïve Analogies
• Analogies That Shook the World
• Katy and Anna Debate the Core of Cognition
• Notes, Bibliography, Index

Surfaces and Essences warrants a place alongside [Hofstadter’s Pulitzer Prize–winning book] Gödel, Escher, Bach and major recent treatments of human cognition. Analogy is not the endpoint of understanding, but its indispensable beginning.


Magnificent Principia: Exploring Isaac Newton’s Masterpiece
Colin Pask
Prometheus Books
59 Glenn Drive
Amherst, New York 14228 USA
2013. 528 pages. US$ 26.00
ISBN: 978-1-61614-745-7

Mathematical Colin Pask’s Magnificent “Principia”: Exploring Isaac Newton’s Masterpiece belongs to a respectable tradition: books that attempt to translate the abstruse Principia for the common reader.

Pask gives only a sketchy description of the historical context, and he doesn’t address at all a number of relevant and thorny philosophical issues. The reader who wants to understand Newton the man will need to supplement Pask’s portrait with other writings.

That said, Magnificent “Principia” certainly provides a useful introduction to Newton.


. . . an insightful and expansive look into Isaac Newton’s complex and illuminating 1687 publication on classical mechanics. . . . Breaking the Principia down into easily digestible portions and suffusing his narrative with modern insights, Pask reveals the genius that built modern physics.

Falling Behind? Boom, Bust, and the Global Race for Scientific Talent
Michael S. Teitelbaum
Princeton University Press
41 William Street
Princeton, New Jersey 08540 USA
2014. 280 pages. US$ 29.95
ISBN: 978-0-691-15466-4

The author examines five episodes since World War II in which the US feared it was falling behind in its scientific and engineering talent and how each episode led to a boom and a bust. After exploring these repeated cycles, Teitelbaum contends that the science and engineering workforce is adequate for the current and future needs of the US.

Contents:
• Recent Alarms
• No Shortage of Shortages
• Beliefs, Interests, Effects
• The Influence of Employer and Other Interest Groups
• What Is the Market Really Like?
• Surplus—and Disequilibria
• Supply, Demand, Shortage, Other Interest Groups
• Making Things Work Better
• Appendix A: Controversy About the Meaning of Sputnik
• Appendix B: Evolution of the National Institutes of Health
• Appendix C: “A Nation at Risk” and the Sandia Critique
• Notes, Index

[Teitelbaum’s] discussion usefully pulls together previous work by him and others that shows that the existing funding model and practices of universities have uncoupled the supply of new scientists from the need for new scientists, particularly in the life sciences. . . . Falling Behind? also illuminates a bigger picture: Scientists must recognize that the solution to low grant acceptance rates and poor job prospects for new scientists is not increased public funding for research.


Seismic Reflections of Rock Properties
Jack Dvorkin, Mario Gutierrez and Dario Grana
Cambridge University Press
32 Avenue of the Americas
New York, New York 10013 USA
2014. 338 pages. US$ 75.00

An introduction to the application of rock physics in seismic interpretation for hydrocarbon reservoirs, this book, for researchers and petroleum geologists, offers practical workflows, catalogs various cases, discusses the effect of attenuation on seismic reflections, shows how to build earth models and includes case studies based on real-world well data. The authors provide sample catalogs of synthetic seismic reflections from a variety of reservoir models.

Contents:
• The Basics: Forward Modeling of Seismic Reflections for Rock Characterization; Rock Physics Models and Transforms; Rock Physics Diagnostics
• Synthetic Seismic Amplitude: Modeling at an Interface: Quick-Look Approach: Pseudo-Wells: Principles and Examples; Pseudo-Wells: Statistics-Based Generation
• From Well Data and Geology to Earth Models and Reflections: Clastic Sequences: Diagnostics and V, Prediction; Log Shapes at the Well Scale and Seismic Reflections in Clastic Sequences; Synthetic Modeling in Carbonates; Time Lapse (4D) Reservoir Monitoring
• Frontier Exploration: Rock Physics Workflow in Oil and Gas Exploration: DHI Validation and Prospect Risking
• Advanced Rock Physics: Diagenetic Trends, Self-Similarity, Permeability, Poisson’s Ratio in Gas Sand, Seismic Wave Attenuation, Gas Hydrates: Rock Physics Case Studies; Poisson’s Ratio and Seismic Reflections: Seismic Wave Attenuation; Gas Hydrates
• Rock Physics Operations: Directly Applied to Seismic Amplitude and Impedance: Fluid Substitution on Seismic Amplitude: Rock Physics and Seismically Derived Impedance
• Evolving Methods: Computational Rock Physics
• Appendix: Direct Hydrocarbon Indicator Checklist
• Index

In their new book, [the authors] fill a gap in the rock-physics literature: linking rock properties directly to reflection characteristics. . . . I found the book engaging and informative. . . . The first few chapters provide a solid overview of the concepts that underlie the remainder of the book, such that an extensive knowledge of this background material is not required for comprehension.


The Quantum Moment: How Planck, Bohr, Einstein, and Heisenberg Taught Us to Love Uncertainty
Robert P. Crease and Alfred Scharff Goldhaber
WW Norton & Company, Inc.
500 Fifth Avenue
New York, New York 10110 USA
2014. 352 pages. US$ 29.95
ISBN: 978-0-393-06792-7

The authors, a philosopher and a physicist, explore the path of the concept of “quantum” from scientific theory to its use in many forms of popular culture. Crease and Goldhaber look at the use of the term as metaphor and in intellectual exchange and the contemporary world, from cartoons and movies to fiction and coffee mug quotes. The authors illustrate how understanding and recognizing the misuse of the language of the quantum theory helps define the matrix between science and contemporary culture.

Contents:
• The Newtonian Moment
• A Pixelated World
• Quantum Leaps
• Randomness
• The Matter of Identity: A Quantum Shoe that Hasn’t Dropped
• Sharks and Tigers: Schizophrenia
• Uncertainty
• Reality Fractured: Cubism and Complementarity
• No Dice!
• Schrödinger’s Cat
• Rabbit Hole: The Thirst for Parallel Worlds
• Saving Physics
• Notes, Index

The Quantum Moment is a good introduction to concepts in quantum theory and will help us better understand how science is bound up with human culture.


. . . [The Quantum Moment] is an introduction to the brave new world we inhabit.


. . . the authors are at their most entertaining when they expose the hollow understanding of physics that many who use its terms possess.

Getting to the Core of the Matter

Matt Varhaug and Tony Smithson
Senior Editors

Rock cores provide essential data for the exploration, evaluation and production of oil and gas reservoirs. Physical rock samples allow geoscientists to examine firsthand the depositional sequences penetrated by a bit and offer direct evidence of the presence, distribution and deliverability of hydrocarbons. Cores provide ground truth for calibration of well logs and can reveal variations in reservoir properties that might be undetectable through downhole logging measurements alone. Operators are better able to characterize pore systems in the rock and model reservoir behavior to optimize production based on the analysis of core porosity, permeability, fluid saturation, grain density, lithology and texture. These analyses are carried out in core laboratories around the world.

Before the samples reach the laboratory, they must first be extracted from formations below the Earth’s surface. The process of coring—obtaining representative samples of the formation—is undertaken in either of two ways. Conventional coring is performed as the zone of interest is being drilled; sidewall coring is carried out after that zone has been drilled. Each method yields distinctly different rock samples, and each requires its own coring strategy, procedures and equipment.

Conventional Coring

Conventional cores, also known as whole cores are continuous sections of rock extracted from the formation in a process similar to conventional drilling. The two operations differ chiefly in the type of bit used: Instead of a conventional drill bit, coring uses a hollow bit and core barrel in the bottomhole assembly (BHA) (above right).

During conventional coring operations, the operator first drills the well down to a zone of interest using a conventional drill bit and drillstring. A wellsite geologist closely monitors drilling progress to decide when to begin coring operations. The timing of this decision is critical because if the coring begins too soon, the operator will waste rig time obtaining unneeded core above the zone of interest; if coring begins too late, the drill will have already penetrated the zone and possibly miss the most crucial section of the formation.

Correlations with offset well logs usually provide the first indication that the drill bit is nearing the coring point. By charting the formation type, drilling rate and amount of gas extracted from the mud during drilling, the geologist can create a mud log that may be compared with logs from offset wells. Some zones have been cored simply on the basis of a drilling break—an increase in drilling rate, which is often accompanied by an increase in gas or evidence of oil in the formation cuttings. Modern logging-while-drilling technology, however, can deliver resistivity-at-the-bit measurements in real time to help operators determine when the bit is approaching the zone of interest.

Once the geologist gives the order to begin coring, the driller pulls the drill bit out of the hole, and the drilling crew exchanges the drilling BHA for a coring bit and core barrel. The hollow coring bit grinds away the rock, leaving a cylindrical core of rock at its center. This core is retained inside the core barrel, which is mounted just above the bit. The core barrel consists of an inner and outer barrel and a core catcher. These barrels are attached to a swivel that enables the inner barrel to remain stationary while the outer barrel rotates with the coring bit. Drilling fluid can circulate between the inner and outer barrels. The catcher keeps the core from slipping out through the hollow bit when the coring BHA is retrieved to the surface. Cores typically range in diameter from 4.45 to 13.34 cm [1.75 to 5.25 in.] and are usually cut in 9-m [30-ft] increments, corresponding to the length of the core barrel or its liner, which in turn, is consistent with the length of standard drillpipe.

When the core barrel is full, the drilling crew pulls the drillstring to the surface and retrieves the core barrels. A core recovery specialist lays the barrel liner on the pipe rack. The liner, with core inside, is then scribed with depth markings and orientation lines. The metal liner is usually cut into segments and sealed at each end for shipping to a core analysis laboratory.

Conventional coring operations often provide the best rock samples for testing, analyzing and evaluating reservoirs. However, the time required to cut and recover whole cores can impact drilling efficiency. Depending on coring objectives and cost limitations, some E&P ventures may deem conventional coring nonessential. In such cases, the operator may turn to an alternate method for sampling downhole formations.

Sidewall Coring

Sidewall cores (SWCs), plugs of rock taken from the wellbore wall, may offer a cost-effective alternative to conventional cores. The SWCs are usually acquired by wireline tools, and a single wireline descent can recover SWCs from multiple zones of interest.

After the driller reaches a casing point or drils to total depth (TD), the drillpipe is pulled out of the hole and the well is logged before casing is set. Sidewall cores typically are obtained after logs have been run, usually near the conclusion of an openhole wireline logging job. This gives geologists time to pick core depths after consulting the logs to identify zones that...
merit sampling. Wireline gamma ray or spontaneous potential logs are used to correlate between openhole log depths and core depths. Sidewall coring devices are controlled from the surface logging unit and can extract samples from the side of a wellbore at up to 90 selected depths.

Petrophysicists use SWCs to validate log responses and obtain empirical petrophysical and geophysical properties. Sidewall cores also offer an alternative means for petrophysicists to acquire core data should conventional coring operations fail. However, because of their small size relative to conventional cores, SWCs taken from a heterogeneous formation may not have properties that are representative of the formation at a reservoir scale. The rock from which the SWC is taken may also lack crucial features that geologists need to analyze the reservoir, especially in laminated sand-shale sequences, organic shales and fractured reservoirs.

Two types of wireline sidewall coring devices—percussion and rotary—are available. A percussion coring tool, or core gun, has bullet-shaped core barrels mounted on a carrier (above). The core gun uses small explosive charges to propel individual core barrels into the side of the wellbore to capture samples of the formation. In contrast, a rotary coring tool uses a small, horizontally oriented coring bit to cut plugs from the side of the borehole (below). Of the two methods, percussion coring has been the most common; however, in some environments, especially hard rock reservoirs, deepwater exploration and unconventional resource plays, petrophysicists may prefer to work with rock samples obtained by rotary coring tools.

Core guns obtain SWCs measuring from about 2.86 to 4.45 cm [1.125 to 1.75 in.] in length by 1.75 to 2.54 cm [0.688 to 1 in.] in diameter. Each core barrel, or bullet, is fired sequentially by command from the surface after the tool is positioned at the desired sample depth. Bullets are attached to the gun body by means of flexible steel cables, which facilitate extraction of cores from the sidewall. After a bullet embeds in the formation, the wireline operator uses the weight of the gun and the force applied by the wireline logging unit to work the bullet and its core free from the side of the wellbore. After the cores are shot, the gun is pulled to the surface, where logging specialists use a plunger to push each sample from its barrel into a sample bottle. The bottles are sealed and marked with the sample depth then boxed and transported to a laboratory for analysis.

Rotary sidewall coring tools employ diamond-tipped drill bits, which are miniature versions of those used for conventional coring operations. At each core point, the core bit assembly pivots from its recessed transport position in the tool to a position perpendicular to the tool body. The bit cuts a round plug of formation material directly from the borehole wall. The tool then snaps off the core and pulls it into a holding area inside the tool body. This process is repeated until the core-catching apparatus is full. Cores from older-generation rotary coring tools are typically less than 2.54 cm [1 in.] in diameter; however, some large-volume rotary sidewall coring tools are capable of drilling up to 50 cores, each 6.4 cm [2.5 in.] long by 3.8 cm [1.5 in.] in diameter. This device produces core samples that have more than three times the volume of percussion SWCs.

Planning for Success
The process of coring requires planning, attention to formation characteristics and specialized equipment. Prior to drilling a well, the operator must factor the expense of the coring operation into the formation evaluation budget, including the cost of rig time, coring equipment, laboratory evaluations and logistics. The information extracted from cores depends in part on their size and quality, which in turn, control the types of analyses that may be performed. For some wells, routine analysis of porosity, permeability, saturation and petrology are sufficient to guide operators towards a future course of action. Frequently, additional analyses are required. These include evaluations of multiphase saturation and flow properties such as capillary pressure and relative permeability, log-tuning measurements such as electrical properties for determining porosity and saturation from logs, geomechanical measurements or enhanced oil recovery evaluations. Core analysis, in its many forms, informs operator decisions to drill ahead, abandon or complete their wells. These analyses add tremendous value to reservoir evaluation, and they all begin with the coring process.
Oilfield Review Apps

Oilfield Review communicates advances in finding and producing hydrocarbons to oilfield professionals. Articles from the journal are augmented on the apps with animations and videos, which help explain concepts and theories beyond the capabilities of static images. The apps also offer access to several years of archived issues in a compact format that retains the high-quality images and content you’ve come to expect from the print version of Oilfield Review.

To download and install the app on your Android™ or iPad® device, search for “Schlumberger Oilfield Review” in the App Store® or Google Play™ online store or scan the QR code below, which will take you directly to the device-specific source.

1Android and Google Play are marks of Google Inc.
2App Store and iPad are marks of Apple Inc., registered in the US and other countries.

Oilfield Glossary

Available in English and Spanish, the Oilfield Glossary is a rich accumulation of more than 5,800 definitions from 18 industry disciplines. Technical experts have reviewed each definition; photographs, videos and illustrations enhance many entries. See the Oilfield Glossary at http://www.glossary.oilfield.slb.com/.