The Future of CCS

Widely recognized in some quarters as a means to reduce carbon dioxide \( \text{CO}_2 \) emissions to the atmosphere, the practice of carbon capture, utilization and storage remains largely unfamiliar to the general public. The utilization component of the technology is familiar to those who have worked in enhanced oil recovery (EOR) operations, but the concept of deep-well injection and storage of dense-phase \( \text{CO}_2 \) is unknown to many regulators, elected officials and the population at large. In addition, these practices present many unanswered questions, including those addressing how such practices affect the environment and personal property or whether current understanding of the science also predicts future \( \text{CO}_2 \) storage behavior.

As a consequence, the road to popular acceptance and widespread use of carbon capture and storage (CCS), independent of the oil field, requires that demonstration field tests be performed over time. It is also imperative that findings from those tests be presented honestly and clearly to the community. Proving the capacity for safe \( \text{CO}_2 \) storage and containment and the effectiveness of geologic reservoirs and seals may be accomplished through the development of test projects that are scalable to the volumes of \( \text{CO}_2 \) emitted from commercial power plants. Early projects such as those in Japan, Germany and Australia injected up to about 100,000 metric tons [110,000 tonUS] of \( \text{CO}_2 \) using truck or pipeline delivery.

However, larger demonstration projects require pipeline delivery of \( \text{CO}_2 \) to an injection well at rates of about 0.25 to 1 million metric tons [0.28 to 1.1 million tonUS] or more per year. The objective of these larger projects is to create a \( \text{CO}_2 \) plume in a target formation that may be monitored effectively through well logging, chemical sampling, pressure and temperature monitoring, geophysical surveying and other means.

In the US, the US Environmental Protection Agency under the Underground Injection Control program, is promulgating regulations and associated guidance for the new Class VI operational classification. The US Department of Energy has had a program of multiple field tests and demonstrations in place since 2003 under the Regional Carbon Sequestration Partnership program, with several demonstration projects currently underway, including the 1 million metric ton demonstration at Decatur, Illinois, USA, described in this issue (see “\( \text{CO}_2 \) Sequestration—One Response to Emissions,” page 36).

Regional geologic screening followed by careful site characterization and selection constitute the foundation of safe and effective \( \text{CO}_2 \) storage. The objectives in this exploration process are to find a porous and permeable reservoir and a competent reservoir seal. Geophysical tools provide the initial look at a subsurface volume, while drilling, logging and coring confirm expectations of a suitable reservoir-seal system.

Project operators and technical staff members have gained considerable knowledge from the demonstration projects underway today and have shared much of this knowledge through conferences and peer reviews. However, as regulators ask future-oriented questions about reservoir simulation, groundwater flow modeling and other predictive approaches, the industry will need a comprehensive knowledge-sharing framework that will answer such questions and allow larger, commercial-scale projects to proceed.

The public also has a role in the future of CCS, but in some instances, project developers have not gained the community’s confidence. There is an ongoing need for open and complete communication with the general public in a way that understandably conveys the technical basis for CCS. This consideration should not be overlooked during project development and operation.

Although the portfolio of projects is not as diverse today as may have been envisioned five years ago, the next generation of projects—associated with hydrocarbon production, power generation and natural gas processing—is being developed now. Implementation of CCS in saline reservoirs is still in its infancy, but the results to date are encouraging.

Oil and natural gas production industry technologies and the experience of its personnel are essential for the success of \( \text{CO}_2 \) injection and storage projects. Successful demonstration projects will apply and even advance oilfield industry technologies, and knowledge acquired during project development and ongoing monitoring must be transparent to the public. This transparency will gain the confidence of stakeholders outside the industry and is key to ensuring the popular understanding that CCS is a viable tool for climate change mitigation.

Robert J. Finley
Director, Advanced Energy Technology Initiative
Illinois State Geological Survey
Champaign, Illinois, USA

Robert J. Finley is a Director of the Advanced Energy Technology Initiative with the Illinois State Geological Survey in Champaign, Illinois, USA. He has worked in reservoir development for unrecovered oil and natural gas, with coalbed methane and tight gas sandstone reservoir development in Texas and the Rocky Mountains in the US and in reservoir development for carbon sequestration in the Illinois basin. Robert earned a BS degree from City University of New York, an MS degree from Syracuse University, New York, USA, and a PhD degree in geology from the University of South Carolina, Columbia, USA.
1 The Future of CCS

Editorial contributed by Robert J. Finley, Director, Advanced Energy Technology Initiative, Illinois State Geological Survey

4 Specialized Tools for Wellbore Debris Recovery

Wellbore completion operations often generate downhole debris, including sand, perforating gun residue and metal particulates. In addition, drillers frequently discover assorted nuts, bolts, tools and other materials that have been accidentally dropped in the wellbore. Unless these materials are removed, optimal well productivity may be compromised. This article describes new tools and techniques for efficient wellbore debris recovery.

14 Revealing Reservoir Secrets Through Asphaltene Science

By combining downhole fluid analysis with advances in asphaltene science, oil companies are gaining a better understanding of reservoir architecture. Downhole analysis of asphaltenes—the heaviest components of petroleum—can help geoscientists determine asphaltene concentration gradients, which in turn, can help operators ascertain the presence of sealing barriers and assess the communication and equilibrium of fluids in complex reservoirs. Examples from the Gulf of Mexico and the Middle East show how companies are using asphaltene gradient techniques to learn more about reservoir connectivity and fluid distribution.
26 Landing the Big One—The Art of Fishing

Second only to blowouts, one of the worst situations a driller may encounter is the loss of equipment downhole. Fishing—the art of recovering lost, damaged or stuck objects from the borehole—draws on the experience, imagination and innovation of the fishing expert. This article describes tools and strategies developed for dealing with items lost in the wellbore.

36 CO₂ Sequestration—One Response to Emissions

One response to concerns that human activity is influencing climate has been to remove the CO₂ from emissions created when carbon-based fuels are burned and sequester it deep underground. Upstream oil industry experts are uniquely qualified to manage the selection, construction and monitoring of these complex injection projects.

49 Contributors

51 Coming in Oilfield Review

52 New Books

54 Defining Testing: Well Testing Fundamentals

This is the eighth in a series of introductory articles describing basic concepts of the E&P industry.

56 Annual Index
Specialized Tools for Wellbore Debris Recovery

In the late 1700s, Giovanni Battista Venturi, an Italian physicist, described a reduction in pressure when fluid flows through a restriction. Now, engineers are using this principle to design specialized wellbore cleaning systems capable of performing critical debris recovery operations in some of the world’s most challenging subsurface environments.

Debris removal is a vital step in assuring the success of drilling or completion operations. Debris removal involves the extraction of “junk” and unwanted materials from a borehole or completed wellbore. Junk typically consists of small pieces of downhole tools, bit cones, hand tools, wireline, chain, metal cuttings from milling operations and an array of other debris. Although not generally considered junk, sand and other materials used during completion, stimulation and production operations often require removal from the wellbore prior to production.

Because there are many types of debris, engineers have developed a variety of tools and techniques to facilitate debris removal from a wellbore. This article focuses on the postdrilling phase of well construction and issues related to ridding the borehole of relatively small fragments of debris such as metal cuttings, perforating gun debris, small hardware and sand. The article begins with a discussion on the sources of small debris and then reviews various techniques available to remove these materials from the wellbore.

Debris is also generated downhole by various well operations. Often, drillers must mill hardware such as packers, liner tops and equipment within the wellbore (above). Metal cuttings from these operations are among the most common type of debris found downhole. Circulation of drilling, milling or completion fluid transports much of the metal debris to the surface. However, some metal cuttings may still be left in the hole, frequently in locations that cause problems during the completion or production process.

Debris removal is a vital step in assuring the success of drilling or completion operations. Debris removal involves the extraction of “junk” and unwanted materials from a borehole or completed wellbore. Junk typically consists of small pieces of downhole tools, bit cones, hand tools, wireline, chain, metal cuttings from milling operations and an array of other debris. Although not generally considered junk, sand and other materials used during completion, stimulation and production operations often require removal from the wellbore prior to production.

Because there are many types of debris, engineers have developed a variety of tools and techniques to facilitate debris removal from a wellbore. This article focuses on the postdrilling phase of well construction and issues related to ridding the borehole of relatively small fragments of debris such as metal cuttings, perforating gun debris, small hardware and sand. The article begins with a discussion on the sources of small debris and then reviews various techniques available to remove these materials from the wellbore.

Sources of Small Debris

The drill floor is a busy place, providing numerous opportunities for small items to inadvertently fall into an open hole. In deepwater operations, the surface opening at the riser pipe may have a diameter of 1 m [3 ft], creating opportunities for larger items to fall to the depths.

Debris removal is a vital step in assuring the success of drilling or completion operations. Debris removal involves the extraction of “junk” and unwanted materials from a borehole or completed wellbore. Junk typically consists of small pieces of downhole tools, bit cones, hand tools, wireline, chain, metal cuttings from milling operations and an array of other debris. Although not generally considered junk, sand and other materials used during completion, stimulation and production operations often require removal from the wellbore prior to production.

Because there are many types of debris, engineers have developed a variety of tools and techniques to facilitate debris removal from a wellbore. This article focuses on the postdrilling phase of well construction and issues related to ridding the borehole of relatively small fragments of debris such as metal cuttings, perforating gun debris, small hardware and sand. The article begins with a discussion on the sources of small debris and then reviews various techniques available to remove these materials from the wellbore.

Sources of Small Debris

The drill floor is a busy place, providing numerous opportunities for small items to inadvertently fall into an open hole. In deepwater operations, the surface opening at the riser pipe may have a diameter of 1 m [3 ft], creating opportunities for larger items to fall to the depths.
During well completion, cased wells may be perforated using an array of specialized explosive charges mounted on perforating guns. When perforating guns are fired, shaped charges pierce the casing, cement sheath and formation. A shot density of 33 shots/m [10 shots/ft] across a producing zone may create hundreds of perforation tunnels; this perforation process generates a considerable amount of metal and formation debris that needs to be cleared from the wellbore.

Historically, fragments from explosive charges, the casing, the cement and the formation were left in perforation tunnels, which may cause a reduction in production efficiency. Postperforation analysis often showed that many perforation tunnels were plugged and nonproductive. Developments in perforating technology, such as the PURE perforating system for clean perforations, in conjunction with shaped charges that generate minimal debris, allow engineers to reduce this type of perforation tunnel damage. Although less debris remains in the perforation tunnels using these techniques, more debris may be deposited in the wellbore, potentially fouling latching mechanisms on retrievable bridge plugs or impeding the performance of completion hardware.

Certain materials are sometimes deliberately introduced into the wellbore, only to be removed during subsequent cleanout operations. Stimulation operations typically use sand to cover the top of temporary packers and open perforations to protect them from damage while drillers work in other locations within the wellbore (left). Once these operations are complete, the sand must be removed before production can commence. Other stimulation activities, such as those used in conjunction with the FRAC-N-PAC proppant exclusion system, intentionally place sand and synthetic proppant in the wellbore to aid production. In all cases, excess sand and proppant must be removed prior to producing a well.

Regardless of precautions taken to keep a wellbore and associated production equipment free of debris, unwanted materials often find their way to problematic locations and increase the risk of damaging completion equipment, reducing production efficiency and jeopardizing the long-term viability of a well.

Complexity of Design

Oil and gas wells are becoming more complex and expensive to construct. To drill wells characterized by remote locations, deepwater settings or great drilling depths, operational spread rates often reach US$ 1 million per day. In the face of such increasing complexities and to hold costs down, operators must make critical drilling and completion decisions. Risk analysis costs, as a result, are now considered on a per minute basis, rather than per day.

With wellbore geometries and completion designs becoming increasingly sophisticated, engineers recognize that risk management, improved efficiency and optimized production may require removal of debris that might have once been considered inconsequential. Even small amounts of debris have the potential to limit production and cause completion failure. Junk and small debris may create difficulties when operators run long and complex completion assemblies in deep and deviated wellbores. In advanced completion designs—such as those with production sleeves that selectively isolate producing intervals—small debris, including metal fragments and sand, may plug or otherwise render production sleeves difficult to access or operate.

Wells with tortuous trajectories are hard to clean using conventional methods. Determining optimal circulation rates is difficult when engineers must consider varying deviation, equivalent circulating density (ECD) limitations, telescoping casing sizes and pump capacity limitations (next page, top left). Even modest circulation rates, in combination with viscous fluids, risk lost circulation from elevated ECDs. These complex well environments demand new approaches.

Old Concept—New Application

One approach to overcoming the risks of high circulation rates—the venturi vacuum—has existed for centuries. In the late 1700s, Giovanni Battista Venturi, an Italian physicist, described the effect that came to be named after him. He and Daniel Bernoulli, a Swiss mathematician who worked in fluid mechanics, are known for discoveries that led to the development of the venturi vacuum pump. Engineers and developers have used the venturi vacuum pump design in many applications, from fluid mixing systems to health care and home maintenance equipment such as the common garden hose sprayer. Today, engineers are applying this fundamental principle—the venturi effect—to design specialized wellbore cleaning systems capable of performing debris removal operations in difficult subsurface environments.

The venturi effect can be described as a jet-induced vacuum. The laws of fluid dynamics described by Venturi and Bernoulli dictate that flow velocity increases with a constriction of the flow path diameter, satisfying the principle of continuity, while a corresponding decrease in pressure occurs, satisfying the principle of conservation of mechanical energy. A concurrent drop in localized static pressure creates a vacuum.

Venturi vacuum systems have numerous advantages over conventional mechanical pumps. Conventional mechanical vacuum systems typically have moving parts that can be troublesome: Valves may become stuck, intake filters may become clogged and motors are subject to failure. Venturi pumps, by contrast, have few or no moving parts and thus require little maintenance.

Debris from the Deep

Recently, engineers have used venturi vacuum pumps to remove debris from difficult-to-reach and problematic areas of wellbores. Multiple designs have been developed, each with unique features to meet an array of operational requirements. Several service companies, including M-I SWACO, a Schlumberger company, offer downhole debris recovery tools based on the venturi effect; some are configured to be used on coiled tubing and others to be used on conventional workstrings.

The WELL SCAVENGER tool offers a modular design that provides application flexibility. The upper module contains a single-nozzle fluid-driven engine designed on the venturi principle. Pressure from surface pumps generates an efficient, localized reverse-circulation flow that achieves optimal lifting velocities without high pressure drop and cleaning capacity. Most wells use consecutive strings of casing, with each subsequent string smaller in diameter than the previous one, creating a telescoping effect. In offshore deepwater wells, multiple strings of casing are required to control subsurface pressure and formation stress. The ability to move debris from the bottom of the hole to the top by circulation alone is a function of the fluid's carrying capacity and is directly affected by the fluid's annular velocity and viscoelastic properties. However, as the fluid moves uphole, its velocity slows with each increase in casing size and effective hydraulic diameter. This places greater demand on the viscosity characteristics of the fluid to carry debris. Compensating for loss of carrying capacity by increasing the viscosity or velocity of the carrier fluid may result in increased equivalent circulating density, which places greater hydraulic force on the formation and may promote lost circulation. Achieving satisfactory carrying capacity uphole while keeping the well within ECD limitations downhole is the driller's challenge. Because of this problem, debris removal by conventional methods can be difficult.
pump rates. This reverse flow causes debris to flow up the inside the lower tubular and into the collection chambers before it reaches the ferrous collection chamber and then flows through the filtration screen (left). The basic three-module system can be augmented with an array of ancillary tools such as the MAGNOSTAR magnet assembly, WELL PATROLLER downhole filter tool, RIDGE BACK BURR MILL device and single action bypass sub (SABS) to expand the scope of work (next page).

Because debris removal tools are often deployed in brine fluids that inherently have limited solids carrying capacity, conventional techniques typically require high circulation rates or viscous carrier fluids to lift debris into capturing baskets or chambers. These measures are not necessary with the WELL SCAVENGER tool. When perforations are open and subject to lost circulation or damage, when pressure sensitive downhole hardware is in place or when surface equipment limitations make it impossible to achieve high pump rates, the newer generation tools, such as the WELL SCAVENGER device, offer engineers a significant advantage. M-I SWACO engineers use proprietary flow regime software to determine the surface pump rate required to recover the expected debris without affecting downhole hardware or open perforations.

Depending on the volume of debris anticipated, engineers configure one or more debris collection modules at the lower end of the workstring. Each module is designed with a debris collection area, a flow diverter and an inner flow tube equipped with an internal centralizer to provide strength and stability. The inner flow tube provides the path for the reverse flow, and the diverter encourages debris to fall out of the fluid and into the collection area as the fluid flows through each chamber.

The screening unit is fitted above the debris collection modules and below the engine. Fluid flows up through the tool, passes over a magnet assembly and then through a filter before exiting the tool. The screen and magnet assemblies are internally centralized for stability in deviated wells. After cleanup, or when the system becomes filled or plugged, the SABS tool can be opened, allowing higher annular circulation rates, which help clean residual debris located above the tool. The WELL SCAVENGER tool is able to remove a wide variety of debris types from wellbores, including milling debris, bit teeth and cones, sand, small hand tools and debris from perforating guns.
At the surface, safe handling of the recovery tools loaded with debris is essential, especially when they have been exposed to zinc bromide and other completion fluids characterized by elevated HSE risks. To address these concerns, the WELL SCAVENGER tool modules are fitted with sealed lifting caps designed to contain recovered materials during tool extraction at the surface.

Sand and Gun Debris Removal
Operators typically set temporary bridge plugs above productive zones while performing operations such as reperforating upper zones. In addition, sand or ceramic proppant is typically placed on top of temporary plugs to provide additional protection to upward facing latching mechanisms that release and retrieve the temporary plugs.

In 2011, Eni SpA used QUANTUM gravel-pack BA packer plugs to carry out multizone gravel-pack completion operations in a series of wells in the Adriatic Sea offshore Italy. After the plugs were set, drillers spotted sand on top of each one to protect the plugs from gun and formation debris generated while perforating the zone above. On completion of perforating operations,
the WELL SCAVENGER tool was run in the hole and successfully cleaned the sand and the gun debris from the top of each packer.

M-I SWACO engineers in Aberdeen worked with Schlumberger engineers in Ravenna, Italy, to carefully plan each completion. The operator used 1.3 g/cm³ [10.8 lbm/galUS] of calcium chloride [CaCl₂] completion fluid in the wellbore and spotted 20 liters [5.3 galUS] of 2.7-g/cm³ [22.5-lbm/galUS] ceramic proppant on top of each temporary packer prior to perforating shallower zones. The first well, which was vertical, was perforated with 39 shots/m [12 shots/ft] (above).

After each zone was perforated, the driller ran a WELL SCAVENGER tool and washover shoe in the hole to remove excess ceramic proppant and clear the packer retrieval latching mechanism.

On the first run, the top of the debris was located with the WELL SCAVENGER tool; no circulation was initiated, thus allowing the washover shoe to slide over the debris and land on the packer plug. The sand and debris were successfully removed and the temporary plug retrieved without incident. However, to reduce the risk of the tool becoming stuck in the sand or damaging the packer, engineers chose to initiate circulation approximately 30 m [100 ft] above the anticipated top of the sand pill on future runs.

In each well, after positioning the washover shoe on the packer plug, the driller circulated one and one-half to three annular volumes to assist in overall debris cleanout. The WELL SCAVENGER tool cleared each sand pill in an average of 25 minutes. Based on total nonferrous debris recovery, 16 kg [35 lbm] wet weight, or approximately 65% of the ceramic sand, was pumped through the filter screen and out of the wellbore. Gun debris and larger sand particles were retained in the collection chambers, and ferrous materials were collected on the filter module magnet assembly (below). The crews handled, cleaned, inspected and prepared debris chambers for rerun in subsequent bottomhole assemblies (BHAs).

Similar operations were conducted on two subsequent wells; the third well was deviated 24°. Using the WELL SCAVENGER tool, drillers successfully removed the sand and the gun debris in all 12 runs, allowing each packer to be retrieved without incident.

### Debris in Pressure Sensitive Areas

Accumulations of sand and other small debris on top of packers can make the packers difficult to retrieve. Similarly, these materials can interfere with the operation of other downhole mechanical hardware such as formation isolation valves (FIVs). Because these valves are pressure activated, debris removal techniques must ensure minimal localized pressure changes. The WELL SCAVENGER single-nozzle venturi engine provides debris removal at low circulation rates, thus minimizing pressure changes near an FIV. In a typical FIV cleanup operation, the BHA comprises WELL SCAVENGER system components and one or more complementary wellbore cleanup tools such as the MAGNOSTAR tool and the WELL PATROLLER tool (next page, left).

In 2012, a major international operator in the UK sector of the North Sea planned a targeted cleanup above an FIV. Conventional tools that require high flow rates may cause problems when they clean the area near the FIV. These conditions increase the risk of accidental valve actuation or damage to components of the completion assembly.

For optimal tool performance, the bullnose on the bottom of the WELL SCAVENGER tool should be placed 0.3 to 1 m [1 to 3 ft] above the FIV actuation ball. In this case, a 7¼-in. landing sub achieved this spacing, thus reducing the risk of damage to the FIV from accidental contact.

In this operation, the WELL SCAVENGER tool was run in the hole until the bullnose was approximately 6 m [20 ft] above the FIV actuation ball. The driller began pumping at a predetermined rate of 4 bbl/min [0.6 m³/min] while slowly running the tool in the hole. When the bullnose was approximately 0.75 m [2.5 ft] above the FIV actuation ball, the engineer increased the pump rates slightly to 6 bbl/min [0.95 m³/min], which ensured optimal cleaning around the FIV ball area without risking damage to the downhole hardware.

After pumping for 30 minutes, the rig crew retrieved the tool to the surface. The debris chambers had collected a total of 11.8 kg [26 lbm] of

<table>
<thead>
<tr>
<th>Zone</th>
<th>Depth, top</th>
<th>Depth, base</th>
<th>Zone length</th>
<th>Shots</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1.782 m [5,846 ft]</td>
<td>1.794 m [5,888 ft]</td>
<td>12 m [39 ft]</td>
<td>472</td>
</tr>
<tr>
<td>2</td>
<td>1.640 m [5,381 ft]</td>
<td>1.648 m [5,407 ft]</td>
<td>8 m [26 ft]</td>
<td>315</td>
</tr>
<tr>
<td>3</td>
<td>1.522 m [4,993 ft]</td>
<td>1.546 m [5,072 ft]</td>
<td>24 m [79 ft]</td>
<td>964</td>
</tr>
<tr>
<td>4</td>
<td>1.471 m [4,826 ft]</td>
<td>1.480 m [4,856 ft]</td>
<td>9 m [30 ft]</td>
<td>354</td>
</tr>
</tbody>
</table>

^Intervals perforated in an Adriatic Sea well.

Collecting wellbore debris in the Adriatic Sea. The WELL SCAVENGER magnet assembly attracts ferrous debris, which has circulated up through the WELL SCAVENGER tool (A). Ceramic debris (B) and perforating gun residue (C) were recovered from the debris collection chambers.
assorted nonferrous debris consisting mainly of sand and small pieces of rubber. Crews recovered an additional 0.91 kg [2 lbm] of ferrous debris from the internal magnet section of the tool.

The operator originally intended to operate the FIV within a relatively short period after cleanup. However, the well was temporarily suspended. Although final confirmation of cleanup cannot be verified until the valve is operated, the successful placement of the WELL SCAVENGER tool close to the FIV, combined with the amount of debris recovered, implied a successful operation. The company intends to return to this well in the near future.

Gravel-packed wellbores, particularly those with low reservoir pressure and that are subject to lost circulation, may also be easily damaged by debris removal techniques. Sand and other small debris may accumulate inside the gravel-pack screens and impede production. In recompletion operations, operators often need to remove these materials from the inside of delicate screens to improve production rates.

For completion engineers, the inability to circulate completion brine in low-pressure reservoirs limits debris recovery options. One of the unique features of the WELL SCAVENGER tool is its ability to recover downhole debris at low circulation rates, making it an ideal solution for these difficult applications.

This was precisely the situation in 2012, when an operator working on the North Slope of Alaska, USA, needed to recomplete an openhole gravel-packed well that began experiencing production declines. Engineers theorized that sand building up inside the gravel pack screens was choking off production. But when the well was reentered, low reservoir pressures resulted in loss of returns as workover crews attempted to circulate with 1.02-g/cm³ [8.5-lbm/galUS] filtered water. Engineers at M-I SWACO recommended cleaning the 9 5/8-in. casing to the top of the gravel-pack assembly at around 4,300 ft [1,300 m] and then running the WELL SCAVENGER assembly into the openhole gravel-pack assembly to clean out debris to a total depth of approximately 5,000 ft [1,500 m].

To protect the openhole gravel pack while cleaning and logging the upper 9%-in. casing, a temporary packer was placed just above the lower completion assembly. Next, 1,000 lbm [454 kg] of sand was placed on top of the packer to protect the release mechanism from falling debris during upper casing cleanout. After the casing was cleaned and the well logged, the sand was circulated to the surface and the temporary packer was successfully retrieved.

The M-I SWACO crew ran WELL SCAVENGER tools in the hole at 3 ft/min [1 m/min] while pumping at 4 bbl/min [0.6 m³/min] (above). Surface pump rates were maintained at the low
end of the tool’s optimal range, minimizing loss of returns. After the driller circulated down each stand, the pump rates were increased to 7 bbl/min [1.1 m³/min] for five minutes. The tool reached the targeted depth in one run. The workover crew recovered 14.5 lbm [6.6 kg] of formation sand, rubber and metal debris from the gravel-pack screens (below). Following successful debris recovery from inside the gravel-pack screens, the operator continued well recompletion operations.

Milling Debris Removal

Drillers use milling techniques for various well operations such as cutting windows in casing, smoothing burrs and edges on the top of tools and grinding plugs and packers into small pieces so that they can be circulated out of the wellbore.

In 2010, a major operator working in the Gulf of Mexico planned to remove a cast-iron bridge plug (CIBP) from the wellbore. Before the CIBP could be milled, the operator had to remove 200 ft [60 m] of cement that had been placed on the top of the plug. The driller ran into the hole with an 8½-in. roller cone bit and located the top of the cement at approximately 800 ft [240 m]. During drilling operations, a bit cone was lost in the hole.

The driller pulled the damaged bit from the hole and then ran back in with a mill but was unable to grind up the errant bit cone. To minimize additional lost rig time, the operator sought a solution that could remove the bit cone and mill the CIBP in a single trip. M-I SWACO engineers recommended the WELL SCAVENGER tool with a special BHA to meet the company’s objectives in a single trip.

The BHA comprised two pieces: a washover shoe—dressed with a smooth exterior, rough interior and rough leading edge—and a wash pipe extension dressed with two rows of finger baskets. Cable fingers were inserted to help capture the bit cone. The BHA allowed 16.5 ft [5 m] between the bottom of the WELL SCAVENGER tool and the leading edge of the shoe.

The driller tripped into the hole and located the top of the CIBP, broke circulation and began milling the plug. Operating the mill at 80 rpm, the fishing supervisor milled the CIBP in about five hours with 1,000 to 6,000 lbf [4,450 to 26,700 N] of weight on the tool and 1,000 to 3,000 lbf ft [1,356 to 4,067 N m] of torque. When the total interval of 2.0 ft [0.6 m] was milled, the rig crew pulled the BHA to the surface. The tool had collected between 12 and 15 lbm [5.4 and 6.8 kg] of metallic debris. Larger items that could not enter the WELL SCAVENGER tool were found inside the cable fingers and below the finger basket. These included the bit cone, cone rings, packer rubber and other CIBP components. Based on the amount of accumulated material, technicians determined that most of the debris had been removed from the wellbore.

Despite the inferior lifting properties of the seawater-base drilling fluid used in the wellbore, the WELL SCAVENGER debris recovery system removed the bit cone and debris associated with milling the CIBP. Drillers successfully tripped into the hole and retrieved the remaining tool elements with no interference from debris or junk, thus avoiding the cost of additional trips.

Recovered Debris

Close-Up View

Assorted debris removed from the depths. Drillers sealed the WELL SCAVENGER debris chambers as the tool was removed from a well on the North Slope of Alaska. When opened later at the M-I SWACO facility, the four collection chambers contained various materials, including a mix of formation sand, rubber pieces and ferrous material. A pen, not retrieved from the hole, illustrates relative size.
Removing Stuck Packers

Drillers and engineers make every effort to minimize operational risks. Despite these efforts, drillstrings become stuck, completion assemblies fail to reach their objectives and junk winds up in the wellbore. A major operator working on the North Slope of Alaska recently experienced such an event.

While the operator was running a packer in 9 5/8-in. casing, the packer set prematurely at 8,184 ft [2,494 m]. Previously, the operator had set a packer with a stinger assembly attached at approximately 10,100 ft [3,078 m]. Once the stuck packer was drilled out, the wellbore had to be cleaned down to the top of the deeper packer before the driller could resume further recompletion operations.

Debris removal was complicated by the well’s 80° deviation from approximately 2,500 ft [762 m] to total depth. After a competitor’s boot basket retrieval tool yielded very little debris in two runs, engineers from the M-I SWACO specialized tools group in Alaska and Houston recommended a specially modified BHA combined with the WELL SCAVENGER tool and several high-capacity MAGNOSTAR tools.

The BHA included 90 ft [27 m] of wash pipe, a HEAVY DUTY RAZOR BACK CCT casing scraper, the MAGNOSTAR tool, the WELL SCAVENGER tool and the SABS circulating sub. After the tools reached a depth of 6,200 ft [1,890 m], a large accumulation of debris on the lower side of the wellbore hindered progress. Through continuous circulation and near-constant pipe movement, the driller was able to push the tool assembly to 6,280 ft [1,914 m]. The tools were then pulled from the hole. Once the tools were on the surface, technicians recovered 184 lbm [83 kg] of ferrous debris from the MAGNOSTAR tools (above).

While technicians cleaned the MAGNOSTAR tools, the driller ran back into the hole with a competitor’s boot basket fishing tool and magnet assembly. When the tool was pulled from the hole, technicians recovered a packer slip and 20 lbm [9 kg] of ferrous debris. A second run of the WELL SCAVENGER assembly included three MAGNOSTAR tools. This run yielded an additional 287 lbm [130 kg] of ferrous debris on the MAGNOSTAR tools and 1,033 lbm [469 kg] of sand and silt along with 168 lbm [76 kg] of ferrous debris recovered from the WELL SCAVENGER tool collection chambers.

A final run made with the three MAGNOSTAR tools yielded an additional 145 lbm [66 kg] of ferrous debris. After clearing most of the debris from the wellbore, the driller was able to run in the hole with a polish mill to clean the lower packer bore. M-I SWACO tools removed a total of 1,817 lbm [824 kg] of ferrous and nonferrous debris from the wellbore.

Rapidly Evolving Tool Development

Complicated completions, complex borehole configurations and high rig-time costs are leading engineers to identify new applications for the WELL SCAVENGER assembly and associated debris removal tools. Because of new debris recovery tools and techniques, drillers are now better able to remove materials intentionally placed downhole or items accidentally lost in the wellbore. Tool combinations are evolving to address a broader array of completion and debris recovery needs. The evolution in debris recovery tool designs is reducing risks, cutting costs and improving well productivity.

Ongoing design work further enhances the range and scope of debris recovery tools used at great depths. Given the increasing cost of rig time, especially in deepwater settings, engineers are focusing on the development of systems that allow debris recovery to be combined with other well operations in a single tool run. For example, field tests have shown that debris recovery and milling tools can be combined with packer retrieval hardware to deburr casing perforations, recover the generated debris and remove a temporary packer all in a single tool run, thus improving operational efficiency and reducing costs. Other developments are underway to help operators recover debris in low-pressure, lost circulation environments, setting the bar for successful completions in increasingly challenging situations. —DW
Revealing Reservoir Secrets Through Asphaltene Science

Downhole fluid analysis of the heaviest components of petroleum can help unlock information about reservoir structure. Understanding how asphaltenes associate in oil columns permits scientists and engineers to use asphaltene concentration gradients to determine the presence of sealing barriers. Production results have confirmed the validity of this approach, which is being extended to address the structure and dynamics of fluids in complex reservoirs.

Long before scientists grappled with the heaviest component of petroleum—asphalt—humans were putting it to use. In the ancient world, Babylonians used asphalt as mortar, and Egyptians employed it for mummification. Asphaltenes are naturally present in crude oil hydrocarbons and can cause flow assurance problems in the formation, production tubing and pipeline. Additionally, crudes with high asphaltene levels are less valuable on world markets; their hydrogen deficiency limits their yield of liquid hydrocarbons and their sulfur and metal content creates problems for refining.
The high cost of offshore operations and the trend toward deeper wells worldwide have renewed the imperative for understanding reservoir fluids at a molecular level. Operators can no longer afford to view reservoirs as homogeneous tanks of oil and gas. In addition to knowing fluid composition, they must also be able to assess reservoir connectivity, particularly when costs dictate a limited number of wells. Imaging and pressure surveys are often insufficient to completely assess oil drainage patterns, so operators are turning to downhole fluid analysis (DFA) and asphaltene science to better understand reservoir structures.

In the recent past, operators characterized oil in reservoirs with a few parameters such as specific gravity, gas/oil ratio (GOR) and a simple chemical classification of the bulk oil. However, DFA measurements on oil columns from around the world reveal that reservoir fluids present a much more complex picture, both vertically in the oil column and laterally across the field. Such results, coupled with decades of analytical research, are yielding a more complete picture of asphaltene physical forms in the reservoir. These research advances explain how and under what conditions asphaltenes associate with each other and allow all components of the reservoir fluid mix—gas, liquids and solids—to be described by equations based on thermodynamic principles. The end result of this work enables use of predicted and observed asphaltene concentration gradients to confirm or disprove fluid drainage connectivity in an oil column.

This article focuses on new asphaltene science and covers its origins, development and uses. Cases from deepwater Gulf of Mexico and Middle Eastern fields illustrate how these developments are helping oilfield scientists and engineers learn more about connectivity in reservoirs and the distribution of gases, liquids and solids in the fluids contained therein.

Reservoir Fluids—A Complex Picture

A beaker of petroleum on a laboratory bench or an open hatch on a stock tank presents a deceptively simple view of underground fluids—that an entire reservoir consists of only black oil and gas. Fluid property gradients, where present because of reservoir conditions, may appear to affect only the GOR. However, this view is inaccurate because at actual reservoir conditions, composition gradients can exist not only for the GOR, but also for asphaltenes and the individual components of the oil.
Asphaltenes in petroleum have been a focus of study by oilfield engineers and scientists for decades. Much about asphaltenes has seemed complex and inconclusive. Interest in these compounds has taken on several dimensions over time. In the early years of the industry, downstream research was centered on optimizing uses for the asphalt by-products from refining operations. In the last half of the twentieth century, that focus turned toward efficient conversion of heavy ends and their asphaltene component as refiners sought to maximize the production of transportation fuels. In upstream exploration and production, the focus on asphaltenes has almost always been on mitigating and avoiding their negative impacts. These impacts include formation plugging because of precipitation and the effects of high viscosity during production and transportation (below). However, new science developed over the last decade has shown that asphaltene gradients in the reservoir can provide valuable insights about reservoir structure.

Asphaltenes found in reservoir fluids are a complex molecular mixture of particles colloidally suspended in oil that have no single chemical identity. They are usually defined as a solubility class—that is, those molecules that are insoluble in n-heptane but soluble in toluene. Asphaltene molecules are typically condensed aromatic rings that can contain heteroatoms such as nitrogen and sulfur as well as metals such as nickel and vanadium. Almost every chemical property of asphaltenes has been the subject of significant debate, except for their elemental composition. An early controversy centered on the nature of the covalently bound chemical groups versus those that are associated in noncovalent aggregates. The wide range of molecular weights obtained at that time—1,700 to 500,000 g/mol—was attributed to varying aggregate sizes. Over the last decade, research on asphaltenes has encompassed multiple branches of analytical chemical science to produce a much clearer picture of asphaltene properties and how individual asphaltene molecules associate to form larger particles (above).

### Table 1: Asphaltene Properties

<table>
<thead>
<tr>
<th>Property</th>
<th>Reported Values, 1998</th>
<th>Reported Values, 2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mean asphaltene molecular weight</td>
<td>10^1 to 10^5 g/mol</td>
<td>750 g/mol</td>
</tr>
<tr>
<td>Number of PAHs per asphaltene</td>
<td>1 to 20</td>
<td>1 dominates</td>
</tr>
<tr>
<td>Number of fused rings per asphaltene PAH</td>
<td>2 to 20</td>
<td>7 (average)</td>
</tr>
<tr>
<td>Number of PAH stacks in a nanoaggregate</td>
<td>unknown</td>
<td>1</td>
</tr>
</tbody>
</table>

### Asphaltene Viscosity

Asphaltene viscosity. In 1927, researchers at The University of Queensland, Australia, heated a sample of pitch, or asphalt, and placed it in a funnel that was subsequently sealed (inset). The asphalt was allowed to settle for three years at room temperature before researchers cut the funnel stem. Since that date, the asphalt has dripped from the funnel, averaging one drop every nine to ten years. In 2002, the ninth drop was starting to form. While the viscosity of heavy oils is not nearly as high as that of asphalt, viscosity rises sharply with increasing asphaltene content. Data on asphaltenes and deasphalted oil from several crudes show a rapid increase in viscosity with rising hexane asphaltene content that spans six orders of magnitude in viscosity. These data are represented by a Pal-Rhodes viscosity model. (Photograph courtesy of JS Mainstone, The University of Queensland.)

### Downhole Fluid Analysis

Downhole fluid analysis helps scientists and engineers examine reservoir fluids in their native environment. The DFA concept has evolved from a technique for fluid identification via openhole sample acquisition to a means of analyzing reservoir fluids and their spatial variations at formation conditions in real time. The concept is simple: Following drilling, a cylindrical sampling and analysis module is lowered into a well on wireline, and fluids are collected from the formation. This tool, the MDT modular formation...
Modular formation dynamics tester. The MDT tool (above) contains a complex array of instrumentation for downhole sampling and analysis. In a typical configuration (right), the MDT tool components include a section for storing samples in addition to an InSitu Fluid Analyzer system and LFA live fluid analyzer system for real-time downhole fluid analysis. Reservoir fluids enter the tool at the formation probe and are pumped in two directions—upward toward the InSitu Fluid Analyzer tool and downward toward the LFA module. The InSitu Fluid Analyzer tool contains two spectrometers and a fluorescence detector for analysis of hydrocarbons, CO₂, pH and fluid color; it also contains instruments for measuring density, resistivity, pressure and temperature. Reservoir fluid from the sampling probe that is pumped downward passes through the LFA module. This device employs an absorption spectrometer to quantify and monitor the amount of reservoir and drilling fluids that are present. A gas refractometer (not shown) in the tool differentiates between gas and liquids.

Identifying compartments in a reservoir is not as challenging as assessing oil drainage connectivity within those compartments, especially before production. Static pressure surveys may fail to find hard-to-image sealing barriers before production starts because pressure equilibrium and composition equilibrium are achieved over different time scales. Composition equilibrium is achieved slowly, and the difference between the fluid property variations interpreted from DFA measurements made at several depth stations in a well can sometimes indicate nearby sealing barriers (right).¹³

Identifying compartments in a reservoir is not as challenging as assessing oil drainage connectivity within those compartments, especially before production. Static pressure surveys may fail to find hard-to-image sealing barriers before production starts because pressure equilibrium and composition equilibrium are achieved over different time scales. Composition equilibrium is achieved slowly, and the difference between the fluid property variations interpreted from DFA measurements made at several depth stations in a well can sometimes indicate nearby sealing barriers (right).¹³

Sealing barriers. Using DFA to reveal the presence of fluid density inversions can sometimes help identify sealing barriers in a reservoir. GOR data for two depth zones in an oil column illustrate this concept. Using GOR as a proxy for density in this column, scientists found a low-GOR, high-density fluid at Point A (left), above a high-GOR, low-density fluid at Point B (right). This finding indicates the possible presence of a sealing barrier between the two zones.
time to reach pressure equilibrium and that to reach composition equilibrium for the heaviest fraction of crude can be several orders of magnitude (above).\(^{14}\) Massive fluid migration in the reservoir is required to achieve compositional equilibration, and for this to occur, there must be good reservoir connectivity. In contrast, pressure equilibration can be achieved with very small mass transfer, which can occur through leaky seals. Consequently, pressure equilibration is a necessary but insufficient condition to establish connectivity in the reservoir.

Nearly equilibrated asphaltene concentration gradients between two zones are indicative of connectivity. However, before that concept can be implemented on a practical basis, it is necessary to have a model for asphaltenes that accounts for their thermodynamic characteristics and how they associate with each other deep in the reservoir.

Modeling Asphaltenes
Since 2000, advances in analytical instrumentation and science have allowed a much clearer picture of asphaltene structure to emerge. Such advances have narrowed the knowledge gap about their properties and have led to a more refined description of asphaltene science as embodied in the modified Yen model.\(^{15}\) This model was later renamed the Yen-Mullins model.\(^{16}\) It envisions asphaltenes in crude oil as existing in three distinct and separate forms—as asphaltene molecules, as nanoaggregates of individual asphaltene molecules and as clusters of nanoaggregates (below). The number of analytical methods employed over the last decade to resolve the molecular weight, size and aggregation parameters in this model is extensive and includes time-resolved fluorescence depolarization and laser-based mass spectrometry for molecular and aggregate size and weight determination. For most model parameters, such as asphaltene molecular weight, scientists must apply several techniques to reduce the uncertainty.

The asphaltene molecule is at the first level of the Yen-Mullins model. The typical asphaltene molecule consists of several fused aromatic rings with peripheral alkane substituents, often with scattered sulfur and nitrogen heteroatoms. This molecule has a mean molecular weight of 750 g/mol with most of the population ranging from 500 to 1,000 g/mol and a length of about 1.5 nm. In this model hierarchy, the asphaltene...
nanoaggregate is the next structure in size. These particles represent an aggregation of about six asphaltene molecules in a single disordered stack about 2 nm in size. The asphaltenes in nanoaggregates are tightly bound, and exterior alkanes on the nanoaggregate particle project outwardly. The largest particle in the Yen-Mullins model is the cluster, which represents a group of about eight nanoaggregates. Clusters, which are loosely bound, are about 5 nm in size.

Although all of the forms envisioned by the Yen-Mullins model may occur in any oil column, the specific form depends largely on the asphaltene concentration. In wells that produce volatile oils and condensates with high GOR, the asphaltene concentration will be less than 0.5 wt % and the asphaltene particles will be 1 to 1.5 nm in size. At higher asphaltene concentrations, such as black oil columns with moderate GOR values, the asphaltene concentration will usually be less than 5 wt % and the asphaltene particles will be principally 2-nm nanoaggregates. In even higher asphaltene concentrations, as seen in mobile heavy oils that have low GOR, asphaltene levels will range from 5 to 35 wt %, with 5-nm clusters as the primary asphaltene particle.

Tar mats may occur in formations with significant levels of mobile heavy oil and are areas of nearly immobile asphaltenes usually found at the base of an oil column near the oil/water contact. There are two predominant forms of tar mats. One type occurs at the base of a mobile heavy oil column as a result of seemingly continuous extension of a large asphaltene concentration and viscosity gradient. The other type of tar mat occurs at the base of a lighter oil column and is discontinuous in asphaltene concentration.

The first type of tar mat results from a subtle destabilization of asphaltenes at the top of the oil column followed by transport of asphaltenes to the base of the oil column to form a mat. The second type of tar mat may occur when there is a significant gas charge into the top of a reservoir containing black oil. As the gas diffuses down the column, the GOR increases and causes asphaltene molecules and nanoaggregates to form clusters. These clusters descend ahead of the diffusive gas front, which moves lower in the column with time. When the gas front reaches the bottom of the column, the asphaltenes are expelled from the oil to form the tar mat (above right).
Correctly modeling asphaltenes requires a two-pronged approach. The Yen-Mullins model provides the solution to the first challenge—a useful framework for the asphaltene particles that form in an oil column along with estimates of particle size and molar volume. The second part of the problem is to mathematically describe the asphaltene concentration gradients for the various asphaltene physical states as predicted by the Yen-Mullins model.

In thermodynamic systems, a state variable is a parameter such as temperature, pressure or volume, which depends on the state of the system but not the path used to get to that state. The mathematical equation that relates state variables is called an equation of state (EOS). In 1834, Benoit Paul Émile Clapeyron, a French engineer and physicist, developed the ideal gas law, an EOS that relates pressure, volume and temperature. The ideal gas law is a first-order equation that ignores molecular volumes and forces and is accurate only for weakly interacting gases at moderate conditions. In 1873, van der Waals developed a cubic EOS that approximates gases at moderate conditions. Since that time, many variants of the classic cubic EOS have been developed, and these equations have been used for decades to model fluid behavior in oil columns. However, using these equations for black oil modeling in reservoirs containing significant levels of asphaltenes is not satisfactory. Because asphaltenes lack a gas phase or a critical point, they must be treated as a pseudocomponent and handled empirically. Although this approach is adequate to model hydrocarbon gas-liquid equilibria and determine parameters such asGOR, it is inadequate for modeling molecular and colloidally suspended particles such as asphaltenes, asphaltene nano-aggregates and clusters of nanoaggregates.

The need to model solution behavior of mixtures containing solvents and large molecules such as asphaltenes has existed for decades. Much research in the 1940s focused on the thermodynamics and solution behavior of polymer compounds and resulted in the Flory-Huggins theory. More recently, the Flory-Huggins approach has been used to examine asphaltene instability. Recognizing the need for a first principles approach to describe asphaltene concentration gradients in oil columns, scientists have developed the Flory-Huggins-Zuo EOS for this purpose. This equation incorporates a gravity term for asphaltenes using their known size. This gravity term is essential for modeling asphaltene gradients. The equation was developed starting with the free energy of a mixture of asphaltenes and solvent as a function of the free energies associated with gravity, solubility and entropy of mixing. At equilibrium, the derivative of the free energy sum is zero, and the solution of the resulting partial differential equations yields the Flory-Huggins-Zuo EOS. In its original form, this equation expresses the asphaltene concentration gradient as a volume fraction of asphaltenes at various depths in the oil column. Since oil color is directly proportional to the asphaltene concentration, the optical density ratio is usually substituted for the volume ratio for a more practical measurement. The resulting equation gives the asphaltene concentration in terms of optical density and is an exponential function of several parameters (above).27

The first term in the Flory-Huggins-Zuo EOS accounts for the effect of gravity and is the most significant term for asphaltenes in an oil column for low-GOR oils (next page, top right). Gravitational effects cause asphaltenes to accumulate at the base of a column, although thermal energy counteracts gravity to some extent. This first term expresses gravitational effects as the buoyancy of an object in a liquid—the gravity effect—divided by a function of the tempera-
ture—the thermal effect. For large physical forms of asphaltenes, such as clusters found in heavy oils, the gravity term is significant and gives rise to high concentrations of asphaltenes near the base of the oil column.

The remaining two terms in the new asphaltene EOS are similar to the original Flory-Huggins terms for entropy and solubility. The entropy is stated in terms of ratios of molar volumes of asphaltenes and solvent at two depths. The entropy effect tends to randomize the asphaltene distribution and counteract gradients, but is usually not large for asphaltenes in crude oils. The other factor in the Flory-Huggins-Zuo EOS that essentially corresponds to the original Flory-Huggins work is the solubility term. For asphaltene gradients, this term is expressed in solubility parameters that are calculated fromGOR or mass densities. This term accounts for changes of asphaltene solubility in the liquid phase and is important for high-GOR oil that produces a low-density liquid, rich in paraffinic alkanes that decrease asphaltene solubility. For low-GOR oils, however, the solubility term is usually not significant.

The end result of this new equation of state for asphaltenes is the prediction of asphaltene concentrations, directly proportional to fluid color, at any depth in the oil column. Almost all of the parameters may be measured or estimated from downhole fluid analysis results of the bulk oil at various depth stations. Those parameters not directly measured—such as the solubility parameters—may be obtained from correlations of known properties.

The only adjustable parameter in the Flory-Huggins-Zuo EOS is the asphaltene molar volume, which is related to particle size. The particle size cannot be determined directly from the downhole data, but there are other ways to find it. The first method is to tune the unknown size of the asphaltene particles to match the downhole fluid color data from measurements at different depths. This size is then checked against the Yen-Mullins model particle types to ensure it is within the boundaries described by the model. The second method is to assume that heavy ends in the oil column are either asphaltene molecules, nanoaggregates or clusters. In this case, the assumed size is used to predict the downhole asphaltene gradients in the oil column, which can be checked against the actual data. If there is consistency, then the data can be used to assess connectivity and other reservoir properties. Analysis of the data may not always suggest a single asphaltene particle type because multiple particle types may be involved (below).

Gravity effects. The effect of gravity depends on which asphaltene physical form predominates in the well. For a 100-m [328-ft] oil column containing mostly asphaltene clusters (black), gravity effects are large, as evidenced by the dramatic increase of asphaltene content with depth. The intermediate size nanoaggregates (blue) show a much more gradual change, while the asphaltene molecules (red) show only a small change from top to bottom of the column.

Multiple particle types. A black oil column that was subjected to a late gas and condensate charge shows evidence that more than one asphaltene particle type is present in the column. Analysis of DFA data using the Flory-Huggins-Zuo EOS indicates that nanoaggregates alone would not account for the increase in asphaltene concentration—as measured by optical density—with depth (left). In this example, the late gas charge destabilized the asphaltenes, causing clusters to form; these clusters settled toward the bottom of the oil column because of gravity (right). The presence of large viscosity and asphaltene gradients characterized this oil column, and production of this well proceeded with no significant problems.
Downhole fluid analysis, the new Yen-Mullins model and the Flory-Huggins-Zuo EOS can be used together to model asphaltene gradients in actual oil columns. The first step is the use of DFA to give experimental data on asphaltene concentration via fluid color, GOR and other physical parameters at several depth stations in a well. The Yen-Mullins model then provides a physical picture of the asphaltene entities that may be present and allows the operator to make reasonable assumptions on particle size. That size is then used in the Flory-Huggins-Zuo EOS to predict the asphaltene concentration gradient in the well. If this gradient matches the experimental data, it can be used to further assess reservoir connectivity. This analysis is not a mere curve-fitting exercise. The matching of sizes computed by the new EOS and the Yen-Mullins model gives the operator confidence that the system is in equilibrium.

**Asphaltene Science and Complex Reservoirs**

An example from a complex field in the Gulf of Mexico illustrates how asphaltene science is used in answering practical questions. This field, operated by Marathon, included an area producing intermediate-GOR black oil that consisted of six sand layers spanning 1,000 ft [300 m] of depth and intersected by multiple wells. The challenge for the operator was to develop an accurate description of reservoir fluid properties and understand connectivity among the various sand layers. The reservoir fluids were analyzed by multiple methods. DFA was employed using the MDT tool both to gather real-time information and obtain samples for further PVT analysis in the laboratory. Using advanced gas chromatographic analysis, the operator also performed geochemical fingerprinting on collected samples. Although the data covered multiple wells in the area of interest, not all analyses were performed at all depth stations; the most complete dataset came from two wells in one of the sands. These data and their analyses show how connectivity questions can be viewed through the lens of the new asphaltene science.

Prior to use of asphaltene gradients to give clues to connectivity in a reservoir sand layer, operators often used data from bulk oil sampling and formation pressure at several depths to make judgments on connectivity. Data on GOR, stock-tank oil density and formation pressure from the two Marathon wells spanning about 500 ft [152 m] of depth in Sand A show differences that suggest barriers to connectivity. In particular, the pressure gradients from the two wells do not appear to coincide, which is indicative of a sealing barrier. However, these differences may reflect either measurement imprecision or differences in the way the data were collected.


24. Resins are a solubility class similar to asphaltenes and are typified by polyaromatic hydrocarbon molecules.


26. The ability to absorb light and then fluoresce is characteristic of some light oils. Like optical density, fluorescence intensity is dimensionless. For more: Creek et al, reference 11.
Using these data, Marathon engineers found it difficult to determine whether Sand A is hydraulically connected between Wells 1 and 5.

In addition to these fluid properties and formation pressures, the operator also obtained downhole optical density measurements at several depth stations for the two wells in Sand A (above). The agreement with the Flory-Huggins-Zuo EOS prediction using 2-nm nanoaggregates as the asphaltene particle state indicates that the asphaltenes in the two wells are in equilibrium as 2-nm asphaltene nanoaggregates; this analysis predicts connectivity in Sand A between the two wells. Similar analyses of other sand layers in this field did not show equilibrium in some cases, prompting the operator to conclude that there was no connectivity between those sands. Actual field production data confirmed all asphaltene analysis–based predictions regarding connectivity between sands.

The new science on asphaltenes can also be useful in analyzing lighter oils and even condensates that contain essentially no asphaltenes but have heavy resins. A well in the Gulf of Mexico, operated by Shell, illustrates this concept. The light oil column from this well has virtually no asphaltenes and a large GOR variation: from 4,000 ft³/bbl [720 m³/m³] at the top of the column to 2,600 ft³/bbl [463 m³/m³] at a depth 440 ft [134 m] below it.

In most crude oils, optical densities offer good sensitivity for measuring the relative concentration of heavy ends. However, for nearly colorless oils, such as this Shell light oil, optical density is not sensitive enough, especially at very high GOR levels and low heavy-end concentrations. The difference between colorless oils that have 100% light transmission and almost colorless oils that have 99% light transmission is difficult to discern using only optical density. Fluorescence intensity, however, is applicable to this type of sample and may be correlated directly to the fraction of heavy resin or asphaltenes. In this case, both optical methods were used to give a complete color description of the resin concentration gradient with depth (below). Because of the small...
1-nm resin particle size, the gravity term in the Flory-Huggins-Zuo EOS is also small, and the expression is dominated by the GOR effect on the solubility term. The equilibrium distribution of resin molecules indicates that this oil column is connected, as confirmed by subsequent production data. These results suggest that this approach is useful not only for black oils but also light oils and rich gas condensates. Extending this methodology to mobile heavy oil in a large Middle Eastern field completes the picture.

A large anticlinal oil reservoir operated by Saudi Aramco has proved challenging to describe by conventional modeling. The low GOR oil column in this field is stratified and is characterized by black oil at the crest and mobile heavy oil below it, with a tar mat above the oil/water contact at the bottom. Although the black oil portion is manageable from a production viewpoint, the asphaltene concentrations in the tar mat are greater than 35 wt %, indicating that this zone is not equilibrated. The tar mat and heavy oil sections of this reservoir resulted from gravitational accumulation of asphaltenes at the base of the oil column, possibly from a late gas charge.

The combination of the detailed DFA data on asphaltene concentrations and viscosity, coupled with the agreement with the asphaltene science, is important in describing this complex reservoir. These data on viscosity, connectivity and location of the tar mat have a significant impact on production planning for this field.

Determining oil drainage patterns and connectivity in a specific area is an important outcome but is only the beginning for asphaltene science. Going from black oil, characterized by a few simple properties, to oil columns and reservoirs with detailed compositions is one part of that frontier—but there are other possible directions as well.

New Frontiers

Few compounds among the thousands found in crude oil have evoked as much interest and avoidance as asphaltenes. In the past, asphaltenes often meant operating problems for producers and difficulties for refiners because of their high molecular weight, high viscosity, plugging characteristics and high levels of molecular contaminants. Scientists and engineers, long fascinated by these heavy molecules, have persevered in their attempts to understand and characterize them. The result is a new branch of asphaltene chemistry that is changing the ways in which scientists view connectivity of oil columns within the same reservoir. Through the use of advanced sampling and analysis techniques such as DFA, scientists are able to extend these new ways of looking at asphaltenes from single wells to adjacent wells and reservoirs. The next step is to extend that view across entire producing basins.

Proper incorporation of diverse phenomena, such as large GOR variations, pressure gradients, asphaltene gradients and the presence of tar mats, will aid operators in field development and planning. At the current stage, these analyses allow the theory to be applied to a wider range of situations, as has been shown in deepwater wells in the Gulf of Mexico.25


In addition to advancements in understanding equilibrium, ascertaining connectivity and predicting oil column gradients, the new asphaltene science has spawned unexpected and potentially useful applications for other areas such as enhanced oil recovery. For some time, scientists and engineers have known that asphaltenes have certain interfacial characteristics that are similar to those of naturally occurring surfactants. For example, asphaltenes can alter the balance between oil-wet and water-wet zones in a reservoir. Because mixed wettability zones may contain nearly one half of field reserves in large Middle East reservoirs, the capability of asphaltenes to change wettability could result in large increases in recovery.

Another branch of work on asphaltenes applies to viscosity and its prediction. Large viscosity gradients are a natural consequence of the asphaltene concentration gradient. The ability to predict gradients in asphaltenes and viscosity for oil columns brings up an interesting possibility.

Advanced reservoir simulators—such as the INTERSECT reservoir simulator—now use clusters of parallel computers to solve the thousands of equations necessary to model and predict the properties of an entire field. These equations simulate the material, energy and property balances for small cubic reservoir sections—called cells—as a function of time and position in the reservoir. Cell size in these simulators has continued to decrease as computational power has increased, and modern simulators now handle cells as small as 50 m [164 ft] in the large reservoirs of the Middle East. Geoscientists hope to merge the new asphaltene science and gradient predictions with reservoir simulation so that asphaltene and viscosity predictions are made for the entire field—vertically and horizontally. These new reservoir simulators not only model field composition and properties but also include modules for field management and facilities planning. The ability to make good predictions for asphaltene gradients would be an additional step in optimizing field development.

Future possibilities for applying fundamental knowledge about asphaltenes abound. Knowing more about property and asphaltene gradients throughout oil fields will not only aid operators in making better decisions about field development, but may yield benefits in areas as diverse as reservoir connectivity, viscosity gradients and enhanced oil recovery.

—DA
Landing the Big One—The Art of Fishing

Drillers often refer to tools and equipment left in the borehole as “lost.” In reality, these items have been misplaced thousands of feet below the surface. Removal of these objects from the wellbore has challenged drillers since the earliest days of the oil field.

In the oil field, a fish is any item left in a wellbore that impedes further operations. This broad definition encompasses every variety of drilling, logging or production equipment, including drill bits, pipe, logging tools, hand tools or any other junk that may be lost, damaged, stuck or otherwise left in a borehole. When junk or hardware blocks the path to continued operations, these items must first be removed from the hole through a process known as fishing.

The origins of this term are attributed to the early days of cable-tool drilling, in which a cable attached to a spring pole repeatedly lifted and dropped a heavy bit that chiseled away at the rock to create a wellbore. When the cable parted, drillers attempted to retrieve the cable and bit from the bottom of the hole using an improvised hook lowered on a length of new cable hung from the spring pole. Experts in the art of retrieving junk from the subsurface became known as fishermen. Over the years, their services have become highly sought after, and the art of fishing has grown to fill a specialized niche within the well services industry.

All manner of equipment may fail, become stuck, need replacement or otherwise require retrieval from a wellbore. Fishing operations may be needed at any point during the life of a well—from drilling through abandonment. During the drilling phase, most fishing jobs are unexpected and are often caused by mechanical failure or by sticking of the drillstring. Sticking may also occur during wireline logging or testing operations. Later, during the completion phase, operations may be thwarted by a variety of problems, including stuck perforating guns, prematurely set packers or failed gravel pack screens. After a well has been put on production, fishing operations may be scheduled as part of the overall process of maintaining, replacing or recovering downhole equipment and tubulars during workover or abandonment procedures. In many fields, the workover process entails cleanout or retrieval of tubing that has sanded up after years of production, thus prompting a fishing job at the outset of operations. During abandonment, operators often try to salvage downhole tubulars, pumps and completion equipment before plugging the well. Even the fishing equipment may become stuck, necessitating revision of the original fishing strategy. In the oil field, no operation, it would seem, is exempt from the possibility of fishing.

Statistics from the mid-1990s indicate that fishing operations accounted for 25% of drilling costs worldwide. These days, fishing can frequently be avoided or sidestepped using other, more cost-effective options. For instance, modern drilling technology, such as rotary steering, is creating a shift in fishing strategies by influencing the economics used to determine whether to fish, to buy the stuck equipment, known as the fish, and sidetrack, or to junk and abandon (J&A) the hole.

Each fishing situation—planned or unplanned, openhole or cased, coiled tubing or wireline—is unique, and each presents its own set of conditions.
Root Causes

Most fishing jobs may be traced to one of three basic causes: human error, faulty equipment or wellbore instability. Nearly everything that goes into the hole can become a fish. Under the wrong circumstances, any object smaller than the bowl diameter of the rotary table master bushing can be lost downhole (right). Hand tools, chains and flashlights have made their way from the drill floor into the wellbore, as have pieces of tongs, slips and other items that can junk a hole. Fortunately, most drilling crews are alert to such dangers, which are preventable through scrupulous attention to housekeeping and maintenance practices on the drill floor.

Downhole, mechanical failure of the drillstring can turn a routine drilling operation into a fishing job. Modes of failure are manifold. Tubulars—drillpipe, casing or tubing—may collapse, burst, part or twist off (right). The drill bit may break apart. A tool joint may simply come unscrewed from the drillstring, or the pipe may become stuck. Each case produces a different type of fish, which in turn dictates how the fishing job will be conducted.

Although pipe failure may not be common, avoiding this problem ranks as a top priority for drillers. Pipe collapses as a result of excess external pressure, bursts from too much internal pressure, parts when subjected to excess tension or twists off because of too much torque. The industry has instituted various practices to reduce the risk of drillstring failure, beginning with inspection of tools, pipe and threads for wear and corrosion before they go into the hole, followed by careful use of pipe handling equipment and avoidance of excess torque during makeup.

In today’s high-angle wells, pipe wear can be accelerated by sharp changes in trajectory. Sharp turns impose alternating bending stresses on the pipe as it works through a dogleg. In addition, high-angle wells are often beset by hole cleaning problems. To prevent cuttings from packing off around the drillstring, the driller may resort to high rotation and circulation rates to clean the wellbore. Such practices, however, increase the likelihood of creating a hole, or washout, in the drillstring itself. When a drillstring washout develops before the well has been cleaned out, the operator must choose between continuing to circulate the wellbore clean or attempting to trip
out of the hole. Continuing to circulate runs the risk of enlarging the washout and weakening the drillstring; pulling out before the wellbore is clean runs the risk of sticking the pipe.4

To prevent pipe collapse, drillers keep the pipe filled with mud to offset external hydrostatic pressure of the mud in the annulus. They monitor makeup torque, hydraulics, rotary speed, weight on bit and hook load to avoid exceeding drillstring design limits. When tubulars do fail, they often produce a jagged, irregular length of pipe, which the fishing expert must contend with.

The drill bit is another common fish. Bits are engineered to withstand the rigors of weight, torsion and abrasion; nevertheless, drillers must be attentive to weight on bit, rotary speed, drilling fluid hydraulics, solids control, formation characteristics and time on bottom to prevent excessive bit wear and associated problems. Occasionally, a bit may seize up and break apart, leaving bit cones, bearings and teeth downhole (above). Although small, these components are hard and robust, and typically must be recovered to prevent damage to new bits or other equipment subsequently run in the hole.

Tool joints sometimes back off, or come unscrewed, from the drillstring. This development may occur when insufficient torque is applied as one joint of pipe is made up to another, or when the drillstring spins counter to its normal clockwise rotation. However, worn or damaged pipe threads may also be a culprit; this problem can be avoided in part through careful handling of tool joints during makeup on the drill floor and by monitoring vibration and rotary speed while drilling to minimize stress on the drillstring.

Sometimes, the fault is traced back to manufacturing controls, as one operator discovered. Having set a liner, the driller ran the bit to the top of cement. Although the topdrive stalled several times while drilling out the liner shoe, the driller was able to continue some 150 m [490 ft] beneath the shoe before observing erratic torque readings at the drill floor console. Later, approximately 5.5 kg [12 lbm] of steel shavings, circulated to surface in the drilling fluid, were recovered from the shale shaker screens and ditch magnets, providing confirmation to the driller that there was a problem downhole.7

As the driller pulled out of the hole, the operator ordered junk baskets and a junk mill dispatched to the wellsites. (Upon its arrival, the junk mill was rejected for lack of proper inspection certification; the operator chose not to risk compounding the problems downhole.) The driller ran in the hole with a bit and junk basket, drilling slowly for 3 m [10 ft] before readings of normal parameters confirmed that the hole was free of junk. Several more kilograms of metal cuttings were recovered when the basket was pulled out of the hole, along with more at the ditch magnets. Further investigation revealed that the pipe threads on the liner shoe connection were not designed to withstand the same torque loads as those on the liner string. The operator concluded that back torque produced by stalling of the topdrive probably caused the left-hand thread of the liner shoe to break loose.

A large number of fishing jobs are instigated by sticking of the drillstring (next page). Many such incidents are caused by unstable formations; others are related to drilling practices:

• Loose or unconsolidated formation sands or gravels can collapse into the borehole and pack off the drillstring as supporting rock is removed by the bit. Schists, laminated shales, fractures and faults also create loose rock that caves into the hole and jams the drillstring.
• In regions where tectonic stresses are high, rock is being deformed by movement of the Earth’s crust. In these areas, the rock around the wellbore may collapse into the well. In some cases, the hydrostatic pressure required to stabilize the hole may be much higher than the fracture initiation pressure of exposed formations.
• Mobile formations—typically salt or shale—can behave in a plastic manner. When compressed by overburden, they may flow and squeeze into a wellbore, thereby constricting or deforming the hole and trapping the tubulars.
• Overpressured shales are characterized by formation pore pressures that exceed normal hydrostatic pressure. Insufficient mud weight in these formations permits the hole to become unstable and collapse around the pipe.
• Drillstring vibration may cause caving of the wellbore. These cavings pack around the pipe, causing it to stick. Downhole vibration is controlled by monitoring parameters such as weight on bit, rate of penetration and rotary speed, which can be adjusted from the driller’s console.
• Differential sticking presents a common problem downhole. It happens when the drillstring is held against the wellbore by hydrostatic overbalance between the wellbore pressure and the pore pressure of a permeable formation. This problem occurs most commonly when a stationary or slow-moving drillstring contacts a permeable formation, and where a thick filtercake is present. Depleted reservoirs are the primary culprit for differential sticking.
• Keyseating takes place when rotation of the drillpipe wears a groove into the borehole wall. When the drillstring is tripped, the bottomhole assembly (BHA) or larger-diameter tool joints are pulled into the keyseat and become jammed. A keyseat may also form at the casing shoe if a groove is worn in the casing or the casing shoe splits. This problem normally occurs at abrupt changes in inclination or azimuth, while pulling out of the hole and after sustained periods of drilling between wiper trips. Wireline logging tools and cables are also susceptible to keyseating.
• Undergauge holes may develop while drilling hard, abrasive rock. As the rock wears away the bit and stabilizer, the bit drills an undergauge, or smaller than specified, hole. When a subsequent in-gauge bit is run, it encounters resistance in the undergauge section of hole. If the string is run into the hole too quickly or without reaming, the bit can jam in the undergauge section. This problem may occur when running a new bit, after coring, while drilling abrasive formations or when a PDC bit is run after a roller cone bit.
• Cement blocks can pack off the drillstring when hard cement around the casing shoe breaks off and falls into the new openhole interval drilled out from under casing.

---

5. Ditch magnets are strong magnets placed in the flowline to collect metallic debris from the drilling fluid as the mud is circulated to the surface.
Uncured, or green, cement may trap a drillstring after a casing job. When the top of cement is encountered while tripping in the hole, a higher than expected pressure surge may be generated by the BHA, causing the cement to set instantaneously around the BHA.

Collapsed casing occurs when pressures exceed the casing collapse pressure rating or when casing wear or corrosion weakens the casing. The casing may also buckle as a result of aggressive running practices. These conditions are typically discovered when the BHA is run in the hole, only to hang up inside the casing.

Hole cleaning problems prevent solids from being transported out of the wellbore. When the cuttings settle at the low side of deviated wellbores, they form layered beds that may pack around the BHA. Cuttings and cavings may also slide down the annulus when the pumps are turned off, thus packing around the drillstring. These problems are frequently caused by low annular flow rates, inadequate mud properties, insufficient mechanical agitation and short circulation time.
Indications that a fish might be lost downhole are usually seen on the drill floor as sudden changes in drilling rate, mud pressure, hook load or rotary torque; these changes typically spur a trip out of the hole. The condition of the last joint of pipe to clear the rotary table tells the drilling crew most of what they may have already suspected. A jagged joint of pipe, paired with an accurate pipe tally, tells the driller not only that the pipe has parted, but also how much pipe remains in the hole. By contrast, a damaged bit indicates that a few small metal pieces remain in the hole.

**Tools of the Trade**

The type of fish and the downhole conditions dictate the fishing strategy. Numerous innovative tools and techniques have been developed for retrieving pipe, downhole components and miscellaneous junk from the wellbore. Most fishing tools fit into one of five categories:

- **Junk baskets** catch small objects or pieces of debris that are too heavy to circulate out of the hole.
- **Milling tools** grind down the upper surface of an object.
- **Cutting tools** sever pipe.
- **External catch tools** retrieve fish by engaging the outer surface of the fish.
- **Internal catch tools** engage the inner surface of the fish.

The solution to any fishing problem depends on where the fish is, how it came to be there, its condition, its dimensions and its orientation within the wellbore. The orientation and size of the borehole are also critical; these parameters can limit the type and diameter of the retrieval equipment and restrict the space available for maneuvering retrieval equipment over the fish. A large-diameter wellbore, however, may make it difficult to locate the top of the fish.

To devise a fishing program, the operator must know the exact size and shape of the fish. Lack of correct dimensional data can doom a fishing job. For this reason, company representatives require each item that goes into the hole to be accurately drawn, then strapped with a measuring tape for length and calipered for breadth.

If the driller is not sure what type of junk must be retrieved, the drilling crew may run an impression block in the hole to ascertain the position and shape of the top of a fish (below left). Impression blocks have a short, tubular steel body fitted at the lower end with a block of soft material—typically a lead insert. The tool is lowered on the end of the fishing string until it makes contact with the obstruction. Some impression blocks have a circulation port for pumping drilling fluid to clean the top of the fish before the block sets down on it. The weight of the fishing string helps press the lead against the top of the fish, creating an impression; the driller or fishing expert carefully studies this impression when the block reaches the surface. This preliminary information helps the operator determine the depth of the fish and the type of fishing equipment to deploy. Impression blocks can also be run on slickline, which is much faster than running in on drillpipe; however, there are weight and size limitations for this method.

Small pieces of junk or debris, such as hand tools, bit cones or pipe-tong dies, can be retrieved with a junk basket or junk magnet. Junk baskets are available in a variety of configurations, each taking a different approach to recovering lost items.

To retrieve small pieces of junk from the bottom of a well, fishermen sometimes use a core-type junk basket. By slowly cutting a core from the formation, this device recovers the junk along with the core. This operation is often employed in soft to medium-soft formations.

Boot baskets, used in drilling and milling operations, catch debris that is too heavy to be circulated out of the hole. These baskets are run as close as possible to the bit or mill and are sometimes run in tandem to increase junk retrieval capacity. The boot basket is used at the bottom of the hole and relies on circulating mud to carry the junk off-bottom. Because the annulus is wider above the junk basket, the annular mud velocity decreases, and as a result, the junk settles out of suspension and lands inside the basket (above).

A jet junk basket produces a circulating force that is capable of lifting stubborn items such as chain from the bottom of the hole. These baskets use ports near their base to produce a reverse circulation that forces the material up through the center of the basket. The jet junk basket can be run in cased or open hole to retrieve small debris from the wellbore and is effective in vertical or horizontal applications (see “Specialized Tools for Wellbore Debris Recovery,” page 4).

Junk magnets are used to retrieve ferrous debris such as bit cones, bearings, milled cuttings and pins that may be hard to retrieve using other methods (next page, top left). These tools have a highly magnetized internal pole plate within a nonmagnetic body. Junk magnets are also typically run in advance of diamond bits to remove debris that could damage the bit.

If the junk is not fully recovered, the operator may elect to run a used bit and attempt to drill and wash past the fish. Should this strategy fail, the junk can be broken into smaller pieces using a junk shot or a mill. A junk shot is a shaped charge, designed to direct its energy...
downward to break up the object. A more conventional approach is to grind the object using a concave mill (below). The concavity of the mill helps to center the junk beneath a thick cutting surface of tungsten carbide that breaks the junk into smaller pieces, which can then be washed or circulated for capture by junk baskets above the mill.

Mills are available in a range of configurations for use in various applications (right). They are often used to dress the top of the fish to accommodate a fishing tool, but some are also used to grind float collars, bridge plugs and retainers. The debris produced through milling is then picked up by magnets or junk baskets or circulated from the well.

**Techniques for Larger Fish**

Retrieving large fish, such as drillpipe or collars, requires a different approach. Many of these jobs start with the assumption that any pipe left in the hole will likely become stuck. With no mud circulating around the fish, cuttings can settle around the pipe or the formation might pack off, which will restrict further movement. Thus, when a drillstring gets stuck, twists off or backs off, the recovery plan typically involves freeing the fish.

When fishing for pipe, the basic strategy involves running jars and an overshot into the hole, latching onto the fish, jarring the pipe free and then pulling the fish out of the hole. However, no fishing job is typical and no job is that easy; the top of the fish may be damaged, requiring a mill to dress the fish, or the fish may be difficult to engage, requiring several attempts to latch onto it. Furthermore, each of the basic steps above encompasses a number of procedures.

When a drillstring becomes stuck, the driller usually activates downhole jars to free the pipe through percussive force. In the case of differential sticking, the operator typically orders a pill—a special blend of surfactants, solvents or other compounds—to be pumped downhole to help free the pipe from differential sticking. The driller pumps this spotting fluid downhole to penetrate and break up the filtercake along the pipe and reduce the area of pipe subjected to sticking. This helps decrease the force required to move the pipe and free the drillstring. The likelihood that this approach will remedy the problem decreases rapidly with time, so once a drillstring
is stuck, it is essential to spot the fluid as quickly as possible. While the spotting fluid is working, the operator usually starts planning the fishing job and mobilizing equipment and personnel.

If the spotting fluid does not free the pipe, the operator may elect to sever the pipe and pull out of the hole to prevent sticking farther up the hole. The goal is to part the drillstring at the greatest depth possible and thus recover the maximum amount of pipe. The first step in this process, however, is to determine the uppermost depth at which the pipe is stuck. In accordance with Hooke’s law, when a drillstring is subjected to pull or torsion within its elastic limits, the pipe deforms linearly. Such behavior can be used to calculate how much free pipe remains above the stuck point.

The operator typically calls for an FPIT free-point indicator tool to precisely measure pipe stretch and torque. The FPIT device is lowered on wireline through the center of the drillpipe, then anchored in place as a given amount of force is applied to the pipe. FPIT strain gauges sense changes in torque and tension as the drillstring is subjected to rotation or pull, respectively. The tool should detect no forces the cutter arms against the inside of the pipe. The cutting surfaces are dressed with a mill to accommodate subsequent retrieval operations. A third method uses mechanical pipe cutters, which are lowered on washpipe to the desired depth. Hydraulic pressure forces the cutter arms against the inside of the pipe. The cutting surfaces are dressed with crushed tungsten carbide to sever the pipe as the tool rotates slowly inside the pipe.

Having separated free pipe above the stuck point, the driller trips out of the hole. The fishing expert will be on the drill floor to examine the last joint of pipe when it is brought to surface. The condition of that joint dictates the course of the ensuing fishing job.

Catching On
The two methods most commonly employed to retrieve a fish are the external catch and the internal catch. The dimensions of the fish and its orientation with respect to the wellbore determine which approach is used.

The external catch is provided by a box tap or an overshot. The box tap uses a tapered thread to screw over the top of the fish (left). Typically used to engage ragged, parted pipe, this tool is slowly rotated as it is lowered onto the fish. The bottom lip of the tool is often dressed with hard metal or crushed tungsten carbide to aid in cutting a thread into the surface of the outer diameter of the fish.

The overshot is designed to engage, pack off and retrieve parted drillpipe or drill collars (above). A tapered helical bowl within the overshot houses a grapple used to grip the outside of the fish. As the overshot is lowered toward the top of the fish, the driller circulates mud while reciprocating the fishing string to clean the top of the fish and flush out the inside of the overshot.

Before engaging the fish, the driller records fishing string weight and torque. After washing over the top of the fish, the driller slowly lowers the overshot until a slight reduction in weight indicates it has landed on top of the fish. The overshot guide slides over the top of the fish as the driller slowly lowers and rotates the overshot. By turning to the right, the grapple opens to engage the fish. Upward pull, with no rotation, will cause the grapple to retract inside the tapered bowl, thus constricting around the fish. With the top of the fish gripped firmly inside the overshot, the driller pulls the fishing string and fish out of the hole.

Overshots can be fitted with a variety of grapples, control packers and accessories, with some strong enough to accommodate backoff and jarring operations. A common accessory is a mill guide, installed at the base of the overshot to grind away flared or jagged edges of the fish to permit passage into the grapple. The mill accessory makes it possible to dress off and engage the fish in one trip. Fishermen deploy another basic but useful device when the wellbore is enlarged or washed out near the top of the fish. The wall hook guide is attached to a bent joint of pipe or a hydraulic knuckle joint to sweep a washed-out section of hole (above). Once the overshot has passed the top of the fish, the string is slowly rotated until the rotary torque indicates that the fish has been hooked. The torque is held while the string is elevated. When the torque decreases, the fish slips into position for engagement by the overshot.

Although the basic overshot has changed very little over the past few decades, it continues to be used to great effect. An operator in New Mexico, USA, had to contend with a downhole pipe failure in a well. During drilling of a 7 7/8-in. hole, a joint of 6 1/8-in. drill collar twisted off, leaving behind a parted drill collar and the BHA. While pulling out of the hole, the operator called on Schlumberger fishing services to retrieve the remaining drillstring from the hole. The fishing expert made up a fishing string consisting of drillpipe, drill collars, a jar, a bumper sub and an overshot (above). The driller ran the fishing string in the hole and
succeeded in reaching the top of the fish. After the overshot engaged the twisted off collar, the fisherman noted an increase in weight as the driller slowly pulled on the fishing string. Once the fishing specialist was assured that the overshot had latched onto the fish, the driller tripped out of the hole and laid down the fish for examination on the pipe rack. There, the operator attributed the problem to pipe fatigue.

If the orientation or condition of the fish will not permit use of an overshot, then the fisherman must resort to an inside catching device to engage the fish. Variations on the inside catching device include the pin tap, taper tap and spear (above).

A pin tap is used with a fish that has been backed off from the string of pipe. This leaves a box tool joint facing upward so it can be engaged by the tap. A taper tap provides an internal catch on tubulars that have a restricted internal diameter. It has a long tapered profile and is used to cut new thread while screwing into the top of the fish. This tool is run in the hole to the top of the fish and then rotated to engage the threads. It is normally used in conjunction with a safety joint, which provides a means of detaching the workstring from the fish in the event that the workstring becomes stuck.

A spear uses an internal grapple, or slip, that expands to grip against the inside wall of the pipe as the driller pulls out of the hole. The tool is made up on the end of the workstring then lowered through the top of the fish. When the fishing expert determines that the spear is positioned deep enough within the fish, the workstring is rotated to engage the grapple. A straight pull, with no further rotation, wedges the grapple against the pipe as the driller retrieves the workstring and fish from the hole. Some spears come with accessories such as mills, which are placed at the base of the spear to grind away jagged edges or other obstructions.

Another basic tool deployed inside tubulars may need to be run to open the way for further fishing. The casing swage is used to restore dented, buckled or collapsed casing to nearly its original shape and diameter (below). The swage relies on mechanical force supplied by downhole impact equipment such as a bumper sub or drilling jar to open casing obstructions. Incremental sizes allow swaging to repair various degrees of casing collapse. This tool is frequently run before production equipment is deployed to ensure that tools will pass cleanly through the casing.

---

**Economic Considerations**

The decision to fish—or not—must be weighed against a need to preserve the wellbore, recover costly equipment or comply with regulations. Each choice is fraught with its own costs, risks and repercussions. Before committing to a specific course of action, the operator must consider a number of factors:

- Well parameters: proposed total depth, current depth, depth to top of the fish and daily rig operating costs
• Lost-in-hole costs: the value of the fish minus the cost of any components covered by tool insurance
• Fishing costs: daily fee for fishing expertise and daily rental charges for fishing tools and jars
• Fishing timetable: time spent mobilizing fishing tools and personnel, estimated duration of the fishing job and the probability of success.

Cost usually dictates the maximum duration of the fishing job. Thus, a shallow hole with little rig time and equipment invested will probably warrant a minimal expenditure in fishing time. By contrast, when the lost equipment represents a large capital investment, more time and expense are justified. Some operators mandate that once fishing costs reach about half the cost of kicking off and redrilling, then fishing operations should be abandoned in favor of sidetracking.10

Various formulas and proprietary programs have been developed to help operators determine how much time should be spent trying to retrieve a fish (above right). Experience has shown that the probability of successful retrieval diminishes rapidly with time. This conclusion tends to provide an incentive for starting fishing operations as soon as possible, with the assurance that beyond a certain point, the chances of catching the fish become nil. When it comes to fishing for stuck pipe, for example, many operators draw the line at four days, including time spent working the pipe or spotting pills.

If the decision is to abandon the fish, the operator must then decide whether to J&A the hole, complete the well above the fish or sidetrack around it. In the case of junking and abandoning the well, the operator’s geoscientists may be able to find value in the data obtained from the well, which may influence subsequent decisions regarding whether or not to drill an offset well.

Some wells encounter productive horizons on their way to deeper pay zones. If reserves in shallower horizons are sufficient to justify completion, the operator may decide to forgo pursuit of deeper pay when faced with a fishing job; instead, the company can abandon the deep hole and set pipe in the shallower pay. This option will be impacted by the replacement cost of the equipment left in the hole, the probability of its recovery, the cost of the shallow completion and the amount of reserves in the shallow zone.

Another option is to sidetrack. In addition to accounting for the cost of equipment left in the hole, the operator should weigh the following:
• the cost and time required for shipping a whipstock, drilling motor or other equipment used to sidetrack the well
• the cost of setting cement plugs down to the kickoff point, setting time and tripping in preparation to sidetrack
• the cost of drilling from kickoff point to TD
• the probability of getting stuck in the same interval again.

In certain areas, an operator may find that fishing is more expensive than sidetracking, or that the latter may have a more reliable outcome. For openhole jobs, setting a cement plug and whipstock may be an attractive alternative to days of nonproductive time. This option is not popular in all regions, however, and demand for fishing may actually see a resurgence in some areas.

Training for the Future
Fishing expertise is hard won, gained primarily through on-the-job exposure to a myriad of challenging operational situations in difficult wellbores. Currently, the “great crew change” is sweeping a number of experienced fishing hands into retirement, thus reinvigorating the imperative to train more fishing specialists. In response, Schlumberger has instituted a training program for fishing crews. The curriculum is designed to develop students’ fishing skills and sharpen their technical knowledge; the curriculum is supplemented by actual field operations to strengthen proficiency.

The program provides progressive exposure to a wide range of tools and fishing techniques. With a prerequisite that ensures all trainees are familiar with the tools used in their region of operations, the first-level course provides field specialists and field engineers with hands-on training that concentrates on shop assembly and disassembly, supplemented by classroom instruction and rig-site training.

The trainees are then assigned to the field to a number of fishing, wellbore departure and well abandonment jobs before they become eligible for the next step in their development. These jobs are carried out by experienced personnel with the trainee assisting.

The second level of training goes into greater depth on fishing techniques and is supplemented by case studies. The trainees conduct job planning exercises based on actual fishing jobs. They design a complete BHA for the job and present their plans to the class for evaluation and brainstorming. Following this class, the trainees continue their field training and conduct a number of solo jobs before moving on to the next level.

The final level of training focuses on the managerial side of fishing and remediation to train personnel for supervisory roles. Such training is vital to the future of the oil patch, because as long as downhole equipment or wellbores fail, fishing expertise will be in demand. —MV

That human activity is having a deleterious effect on the Earth’s natural heating and cooling cycle is widely accepted by the scientific community. However, how humans can and should respond is far less certain. One approach now being demonstrated at the field scale around the world—carbon capture, utilization and storage—removes carbon dioxide from emissions sources and seals it beneath the Earth’s surface.

Most scientists have concluded that Earth’s natural temperature fluctuations are distorted by man-made greenhouse gases (GHGs), particularly carbon dioxide \([\text{CO}_2]\). These greenhouse gases enter the atmosphere as a by-product of industrial activity (below). In 2010, the Intergovernmental Panel on Climate Change (IPCC) set a target to limit global temperature increase to 2°C [3.6°F] above the preindustrial average. The panel proposed to accomplish this goal by limiting the growth of GHG concentrations in the atmosphere to between 445 and 490 parts per million (ppm) \(\text{CO}_2\) equivalent. At the end of 2010, concentrations had grown from preindustrial concentrations of about 270 ppm to 390 ppm. However, limiting GHG concentrations by focusing on the source—carbon-fueled human activity—presents significant challenges. According to the IPCC data, emissions from existing infrastructure account for 80% of the \(\text{CO}_2\) allowed by the cap. Therefore, as the world’s population and carbon fuel–based economies
Winter 2012/2013

continue to grow, many consider capping emissions to be synonymous with capping economic growth—a trade-off few political leaders are willing to make.

Staying below the CO₂ cap through the use of alternative energy sources alone has thus far proved an unlikely solution. Today, solar, wind and other renewable sources are able to supply only a small fraction of the world’s energy demands. Nuclear energy, while technically mature and economically viable, has become politically unpalatable worldwide since a 2011

---


2. The IPCC sets the beginning of the industrial age at around 1850 as fossil fuel usage began to rise dramatically and fossil fuel quickly became the most commonly used fuel.


earthquake and tsunami destroyed a nuclear power plant in Fukushima, Japan. Consequently, the vast majority of the world’s growing appetite for energy in the foreseeable future will be satisfied by traditional fossil fuel sources.

Given this reality, it is clear that the world’s demand for energy and its environmental concerns are not likely to be reconciled through reduced emissions alone. One solution to this apparent impasse may lie not in reducing emissions, but instead in preventing the most significant GHG component—CO₂—from entering the atmosphere by removing it from emissions as they are created.

The process of carbon capture, utilization and storage (CCUS) removes CO₂ gas from emissions, dehydrates and purifies it and compresses it to a liquid state. The liquid CO₂ is then transported to wellheads or other locations for use in enhanced oil recovery projects, injected deep into the Earth to be stored for millennia or utilized as feedstock in chemical manufacturing. For the upstream oil and gas industry, the transport and storage segment of the process is a familiar one. For decades, engineers have been designing subsurface injection systems for formation pressure maintenance, gas storage, enhanced oil recovery and disposal. This article examines how upstream oilfield expertise, methods and technologies are being applied to CO₂ geologic storage.

Resource
Governments worldwide are concerned with capturing CO₂, separating it from stationary point source emissions and storing it (above). To that end, they are seeking realistic estimates of potential carbon dioxide storage resources. In the US and part of Canada, these approximations are supplied by the US Department of Energy (DOE) through the creation of Regional Carbon Sequestration Partnerships (RCSPs). The DOE sought to determine available underground space for CO₂ sequestration by considering three types of formations—oil and gas reservoirs, saline formations and unminable coal deposits.

The resulting resource estimates represent the fraction of pore space volume in sedimentary rocks that is accessible to injection and available for CO₂ storage. Potential resources were screened using the following criteria:

- isolation from shallow groundwater, producible hydrocarbons, other strata, soils and atmosphere
- gravity segregation
- maximum allowable injection pressure
- caprock or seal capillary entry pressure
- displacement efficiency.

Overview of large-scale injection projects (LSIPs) around the world. According to the Global CCS Institute annual survey undertaken in 2011, 74 LSIPs around the world are in varying stages of planning and completion. LSIPs are defined as those that involve the capture, transport and storage of CO₂ at a scale of not less than 800,000 metric tons (Mt) (882,000 tonUS) of CO₂ annually for a coal-based power plant and not less than 400,000 Mt (441,000 tonUS) of CO₂ annually for other emission-intensive industrial facilities such as natural gas–based power generation. Projects in the first three columns denote LSIPs in planning stages. The Identify column represents those on a developer’s short list of options that are undergoing concept and site screening studies. Those in the Evaluate column are further refined and in prefeasibility, cost and site assessment studies. Those in the Define column are being examined for technical and economic viability. Projects in the two columns on the right are active projects. Those in the Execute column are in the final stages of design, organization, construction and commissioning. Those in the Operate column are in full operation mode per regulatory compliance requirements. [Adapted from the Global CCS Institute: “The Global Status of CCS: 2011,” http://cdn.globalccsinstitute.com/sites/default/files/publications/22562/global-status-ccs-2011.pdf (accessed August 23, 2012).]
Engineers assessed oil and gas reservoirs at the field level based on the volume of oil and gas that has been or can be produced and based on the assumption that the volume could be replaced by an equivalent volume of CO2. Saline formations and unminable coal deposits were assessed at the basin level.1

Saline formations consist of brine-saturated porous rock capped by one or more regionally extensive low-permeability rock formations. Saline formations assessed for storage by the US DOE and the RCSPs were restricted to those with the following characteristics:

- pressures and temperatures able to keep the CO2 in a dense liquid phase
- a suitable seal system able to limit vertical flow out of the reservoir
- hydrogeologic conditions able to isolate the CO2.

Unminable coal deposits were limited to those areas containing water with a total dissolved solids concentration greater than 10,000 ppm. Depending on the geothermal and geopressure gradients in a coal formation, gaseous CO2 adsorption may be possible down to a depth of only about 900 m [3,000 ft].2 At greater depths, liquid-phase CO2 may enter the solid coal and change its properties, swelling the coal matrix, and causing injectivity problems.3 Additionally, injection may cause closure of coal cleats, reducing permeability.4

The methodology developed for the estimation process for all three types of environments is based on volumetric methods, in situ fluid distributions and fluid displacement processes. Such methods assume an open system in which in situ fluids are displaced from the formation by the injected CO2. The primary constraint on pore space available for CO2 is based on displacement efficiencies rather than on pressure increases.

There is a great degree of uncertainty associated with US DOE estimates of storage volume available in saline formations because of the sparsity of well data. In the oil and gas industry, the designation of a formation as a resource indicates a lack of data and a level of uncertainty about the presence, size or recoverability of specific hydrocarbon deposits. As more data are gathered through exploratory and delineation wells, increased certainty allows the operator to change the play classifications from possible to probable to proved developed (PDP) reserves. These well-defined classifications are used globally, including by the US Securities and Exchange Commission, to assess company assets for public accounting purposes.

Engineers evaluating porous and permeable zones may use a similar system to classify a carbon capture and storage (CCS), or sequestration, resource (above).5 Moving a resource from the PDP classification to storage capacity—the CCS equivalent of reserves—requires greater certainty about formation properties. The operator must determine the rate at which the formation

---

5. Although the term storage is often used to denote the possibility the CO2 will be retrievable for future use and the term sequestration is used to indicate permanent isolation of the gas, the two terms are often used interchangeably.

6. The US Department of Energy (DOE) has created seven subclassifications based on volumetric methods, in situ fluid distributions and fluid displacement processes. Each subclassification is then further divided into project status subclasses to show project maturity. For example, the exploration phase is divided into subsets that include comprehensive evaluation processes for classification comparable to those performed by E&P engineers for site screening, site selection and initial characterization processes. (Adapted from Rodosta at al, reference 12.)

---

^ Proposed classification system. In an effort to establish a common framework for dividing CCS resources into classifications, scientists have suggested adapting analogous ones used by the E&P industry. The proposed framework is divided into three phases that correspond to resource classes: the exploration phase (bottom), in which prospective resources are comparable to prospective storage resources; site characterization (center), in which contingent resources are comparable to contingent storage resources and an implementation phase (top), in which reserves are comparable to storage capacity. Each resource class is then further divided into project status subclasses to show project maturity. For example, the exploration phase is divided into subsets that include comprehensive evaluation processes for classification comparable to those performed by E&P engineers for site screening, site selection and initial characterization processes. (Adapted from Rodosta et al, reference 12.)

---


11. Coal cleats are natural fractures in coal beds.

nearshore fluvial–tidal delta–shallow shelf distribution (advanced geostatistical prediction of the interpreted depositional facies model of an open marine to interpretations to develop a more realistic structural model. The engineers apply their findings to an from nearby wells (INJ1B, INJ2B, INJ3B, INJ4B, INJ5B, INJ6B), seismic data and new surface dipping flat layers (proposed CCS storage area. This model assumed only broad indicators, with the reservoir as a set of CCS injection projects. With limited data, engineers may be able to develop a simulation model of a that is the target for CO2 injection. The equivalent of the oil and gas PDP classification for carbon storage may be thought of as proved developed storage capacity.13

Before the wells are drilled, a site must be selected using specific criteria that often differ from oilfield practices. Among the parameters sought for CCS well injection sites is proximity to the source, which may allow the operator to dispense with the cost of building pipelines. In contrast to the oil industry, CCS operators seek areas with minimal penetrations into the zone of interest. Though this reduces offset well data that are valuable to engineers for selecting oil and gas well drilling sites, for injection purposes, a lack of wellbores through the storage formation minimizes the potential for leaks through the caprock seal. Similarly, geoscientists seek formations that are below any other mineral- or hydrocarbon-bearing zones to discourage future drilling through the storage formation.

When considering potential CCS formations, geoscientists favor formations with a combination of porous and permeable reservoirs, effective trapping mechanisms and an overlying caprock seal. They also look for indications that the targeted zone has experienced minimal prior tectonic activity, thus reducing the likelihood of fault-induced pathways through which injected CO2 may migrate from the injection formation.

As opposed to hydrocarbon reservoirs and gas storage facilities, four-way closure for a potential sequestration site is not a prerequisite. The ideal reservoir may also be one with minimal regional dip with low saline fluid flow. Modeling has shown that over long periods of time—hundreds of years—CO2 migrates very slowly and stabilizes over time in formations under these conditions as new residual CO2 saturation is created and dissolution in brine occurs.

**Capacity**
Upgrading a resource to a capacity designation may be difficult. CCS resources are often in regions with little or no oil and gas activity or may lack data with which to characterize the formation. Conclusions about the proposed resource are usually derived initially from logs, core data and 2D seismic lines. In many cases, the data pertain to offset wells that are many kilometers away.

Early characterization of prospective injection zones helps predict formation injection rates, pressures and containment capacity. Geoscientists first interpret available seismic data to answer questions about the formation's seal, thickness, porosity and optimal injection intervals and the presence of faults. They also attempt to resolve additional parameters such as the following:

- location with respect to state borders, towns, nature preserves, local gas and oil fields, potable water, porosity window and legacy wells
- regional formation dip
- appropriate depth for sequestration in a dense phase
- proximity of CO2 source to injection well
- secondary seals and reservoir heterogeneity.

A product of the geoscientists' efforts is often a geocellular model of the reservoir (above left). Reservoir engineers use these basic models to run flow simulations to further understand a formation's injectivity, reservoir capacity, potential subsurface movement of injected CO2 and pressure response.

The knowledge gained from flow modeling often generates a round of new questions for geoscientists, especially about the relationship between CO2 plume migration and permeability. Modeling the migration of the CO2 once it enters the formation is critical to accurately predict the behavior of injection zones for both sequestration and EOR projects. A key parameter for the model is residual CO2 saturation in the brine-saturated
Prior to CO2 injection, engineers derive this value in the laboratory by analyzing rock properties and interactions between the formation fluid and CO2 to build predictive equations. Once injection has begun, engineers may use time-lapse sigma logging measurements in both injection and observation wells to determine reservoir saturation, lithology, porosity and borehole fluid profiles. Such was the case for the Frio Brine Pilot Project site near Houston, which is managed by the Bureau of Economic Geology at the Jackson School of Geosciences, The University of Texas at Austin. The project engineers used the RSTPro reservoir saturation tool on wireline to verify laboratory-based CO2 saturation values.

Project engineers presented a Schlumberger Carbon Services petrophysics team with two challenges: measure the CO2 saturation in the formation fluid at its maximum level during injection and measure the residual CO2 saturation in the reservoir after the plume had expanded within the target injection formation. Wells available for taking measurements included an observation well and an injection well downdip 100 ft [30 m] away.

Engineers ran a baseline log on both wells before injection. Repeat logs were run immediately following breakthrough at the observation well and then again two days after, one month after and nine months after injection was halted. The resulting data allowed geoscientists to compare in situ saturation measurements with laboratory and modeled measurements.

Resource to Capacity
Numerous regions in the US and elsewhere have been identified as having CCUS potential. In the Illinois basin in the US, the Cambrian-age Mt. Simon Sandstone was identified as a potentially suitable formation for CO2 storage. It is an areally extensive saline reservoir that overlies a Precambrian granitic or rhyolitic basement and is overlain by the Eau Claire Shale—a low-permeability formation comprising shale, siltstone and tight limestone. The decision to develop the Mt. Simon Sandstone in a demonstration of CCS technology was made easier by the fact that Illinois has some of the largest gas storage facilities in the US. For more than 50 years, predominantly near the large Chicago metropolitan area in the northern end of the state, utility companies have been using natural gas stored in the upper zones of the Mt. Simon Sandstone, which extends across nearly the entire state and parts of Indiana and Kentucky (above). Consequently, the overlying seal and the injectivity and reservoir continuity of the upper 200 to 300 ft [60 to 90 m] of the sandstone are understood. However,
when a well was drilled deeper, to the basement, the lower zones of the Mt. Simon Sandstone were found to have porosity as high as 30% with permeability up to 1,000 mD. The familiar upper zones average around 100 mD. Additionally, the Mt. Simon has at least three sealing formations between it and the surface and is a continuous 1,500-ft [460-m] thick, clean sandstone.

To demonstrate the feasibility of long-term CO₂ geologic storage, and to change the classification of the Mt. Simon from resource to capacity, the Illinois State Geological Survey (ISGS), with funding from the US DOE to the Midwest Geological Sequestration Consortium, is leading the Illinois Basin–Decatur Project (IBDP) with Archer Daniels Midland (ADM) Company, Schlumberger Carbon Services and other partners. The IBDP started in December 2007 when funding was first received and began injection operations in November 2011. The project captures CO₂ from the fermentation process, which is used to produce ethanol at the ADM corn processing plant in Decatur, Illinois. The compressed and liquefied
CO₂ is then transported to and injected into the Mt. Simon Sandstone at depths of around 7,000 ft [2,100 m]. The IBDP is one of a series of such projects within the US DOE RCSP program to demonstrate that CO₂ can be successfully and securely stored over extended periods using best engineering and geologic practices and that projects can be performed in the best interests of local and regional stakeholders.²³

The IBDP site selection was the result of a combination of suitable geology and relatively low-cost CO₂ supply, which have helped create numerous projects in the area. A second project—the Illinois Industrial Carbon Capture and Sequestration (IL-ICCS) project—is also in Decatur. IL-ICCS project partners are the same as the IBDP partners with the addition of nearby Richland Community College; the project is funded by the American Recovery and Reinvestment Act (ARRA) of 2009.

Emissions from ethanol production at the ADM plant are typically 99% pure CO₂ saturated with water vapor at 80°F [27°C] and just above atmospheric pressure. Capturing CO₂ is therefore easier and less costly than when the process is applied to more-complex emission compositions such as those from coal-fired plants in which the cost of isolating CO₂ using current technology may reduce plant efficiency by a quarter to one-third. Additionally, the IBDP injection, monitoring and verification wells are on ADM property at the project site in Decatur, which minimizes pipeline construction costs and allows implementation of extensive environmental monitoring.

The IBDP captures CO₂ at the ADM facility and dehydrates and compresses it to 1,400 psi [9.6 MPa] at the wellhead. The consortium began injecting 1,100 tonUS/d [1,000 Mg/d] of this liquid-phase CO₂ with a goal of injecting a total of 1.1 million tonUS [1 million Mg] over three years.²²

Developing the IBDP

During project planning stages, using regional geology, a 2D seismic line and logs from two wells 38 mi [61 km] northeast and 50 mi [80 km] south of the intended injection well site, ISGS and Schlumberger Carbon Services geoscientists created an initial geologic model with the Petrel E&P software platform. From this model, reservoir engineers created a flow model using ECLIPSE reservoir simulation software.

Schlumberger Carbon Services was responsible for managing the drilling and completion of the injection, verification and geophone wells for the project. Well completion design choices such as perforation intervals, tubular and wellhead size were based on the injection rate and pressures calculated by early reservoir modeling. Because additional data to refine these models could come only from drilling and testing wells in the area, injection rates were estimated and wells were designed with a significant safety factor.

Project engineers drilled an injection well in 2009 (previous page, left). Later that year, a 3D seismic survey was conducted. In 2010, the verification well was drilled 1,000 ft [300 m] to the north and petrophysical logs and core data were acquired (previous page, right). A geophysical well to monitor formations above the Eau Claire Shale was completed with geophones cemented outside the casing every 50 ft [15 m] along the openhole section (right).

As part of the sequestration containment process to prevent CO₂ from breaching the caprock sealing formation, each casing section of any well penetrating a storage zone must be cemented all the way back to the surface. This requirement creates challenges for drilling and completion engineers. The hydrostatic pressure created by a full column of cement in the production string–formation annulus may create pressures along the wellbore, which may result in lost circulation events.

This issue arose during drilling of the IBDP injection well when engineers encountered a lost circulation zone in a carbonate formation above the Eau Claire Shale. Traditional lost circulation countermeasures did not resolve the problem.²¹ When drilling conventional wells, engineers often accept the loss of drilling fluids to thief zones long enough to drill past them and set pipe. In this case, however, they knew that this practice would not be a solution. While cement tops behind casing are typically far below the surface, each casing string of a CCS well must be cemented to the surface. The lost circulation zone, therefore, must be made strong enough to support a full annulus of cement.

Engineers solved the lost circulation problem by placing a dispersed cement slurry across the weak zone, allowing some cement to enter and set up in the formation matrix. They then drilled through the newly created cement plug, leaving a section of cement-lined wellbore across the lost circulation zone that was able to withstand the hydrostatic pressure created by a full column of cement used for the production string.

A more daunting problem for CCS well construction is that CO₂ can cause cement to degrade through the process of carbonation, which occurs when traditional portland cement is exposed to CO₂.²² To counter this threat, the drilling team used EverCRETE CO₂-resistant cement. During laboratory experiments that included exposing the cement to liquid-phase CO₂ under downhole conditions, the cement showed no signs of failure. EverCRETE cement was circulated down the injection string behind the cemented plug.

^ Geophysical well. A geophysical well includes geophones cemented in place within the well’s tubing-openhole annulus. The bottom of the geophysical well is shallower than the sealing formation. With these geophones in a geophysical well and an injection well, engineers can use microseismic monitoring software to locate subterranean sounds to within about a 50-ft [27-m] radius sphere. The well includes 91/4-in. surface casing and 31/2-in. tubing from the surface to 3,498 ft [1,066 m] inside 3,500 ft [1,067 m] of 81/2-in. open hole.

a lead slurry of standard portland cement. The top of the EverCRETE cement was 750 ft [230 m] above the intermediate casing shoe, ensuring that CO₂ would not come in contact with the vulnerable conventional cement.

Measuring Progress
The verification well is equipped with a Westbay multilevel groundwater characterization and monitoring system. Developed for groundwater monitoring, the system can measure fluid pressure, collect fluid samples and repeatedly perform hydraulic testing from multiple zones in a single well. For the IBDP project, the system was configured for deeper applications and for monitoring CO₂ storage. It allows engineers to collect fluid samples at formation pressure and to monitor real-time pressure and temperature data from multiple zones before and after CO₂ arrives at the verification well. At the IBDP well, engineers are using the reconfigured Westbay system to monitor 11 intervals, and the data are used to support simulation models of CO₂ movement through the Mt. Simon Sandstone.

The monitoring device consists of a multipacker tubing completion string installed inside cemented and perforated casing. The tubing string has 27 packers to isolate selected segments of perforated and blank casing. Each zone has a measurement port that is accessed by a wireline-deployed probe that measures fluid pressure and collects fluid samples.

Thirteen probes measure pressure and temperature at 11 perforated zones, at one quality assurance zone to identify any breaches of packer integrity and at one zone to monitor internal tubing pressure. The probes are connected through a common slim cable to a data logger interface at the surface. Technicians remove the wireline string of pressure probes from the tubing string for sampling and then reinstall it to continue monitoring until the next sampling operation.

Before a series of sampling operations, engineers run a wireline RSTPro log to determine which zones have CO₂. Samples are collected only from zones where CO₂ has not arrived. The sampling process includes a standard sequence of steps that provides repeatability for later time-series evaluation of fluid-chemistry data. A selected volume of fluid is purged from the targeted sampling zone, and formation fluid is collected using a sampler probe and canisters. The canisters are sealed to preserve the fluid at reservoir conditions and retrieved to the surface. Laboratory technicians remove the fluid from the canisters using a pressure-controlling apparatus that preserves the integrity of the sample. The chemical analysis typically includes dissolved anions, cations and gases.

The project is equipped with RTAC real-time acquisition and control software that uses a supervisory control and data acquisition (SCADA) system for interfacing with numerous tools and equipment. The RTAC system also includes a secure web-based data visualization and archive interface, which may be used in standard modules or customized for specific purposes. For the IBDP wells, the RTAC system is configured to be accessible to project stakeholders who wish to remotely monitor injection and other relevant well data (next page).

Injection began in November 2011 and geoscientists offered a wide range of predictions about initial formation response. Engineers included provisions for venting CO₂ to the atmosphere in the event the formation did not immediately take the volumes of gas captured. Extra pump capacity at the ADM plant was also available should injection pressure need to be higher than initially predicted. However, neither contingency was required because injection rates were higher and pressures required were below those predicted by the model.

Refining the Models
With wells drilled and injection underway, reservoir engineers and geoscientists obtained data to update Petrel models and optimize the next step in the operation. For example, to ensure injection capacity and optimize plume geometry, engineers designed the completions after drilling and logging the injector well. Using the updated models, engineers then designed water injection and fall-off tests that represented downhole conditions. Data from those tests were used to calibrate the models to reevaluate and verify the completion strategy. After the verification well was drilled and logged, geoscientists used the new data to update predictive models.

A team of reservoir engineers, petrophysicists and geoscientists identified the locations of sampling and measurement zones in the verification well using information from the updated model. Sensitivity analyses were carried out at different stages to understand what new data were needed.

Engineers and geoscientists began to accumulate large amounts of data with the commencement of injection at the IBDP and began studying the models in anticipation of the IL-ICCSP project. The injection operations are scheduled to begin early in the third and final year of injection into the IBDP well. Spinner data were used to detect flow distribution between perforations in the injection well. RSTPro well logs were used to gather CO₂ saturation data around the injection and verification wells. Data from the IBDP well included the real-time injection rate and injection bottomhole pressure (IBHP) using a downhole gauge placed about 600 ft [180 m] above the perforations. Data were also gathered using the Westbay monitoring system, which measured real-time pressures at specific zones in the verification well located 1,000 ft north of the injection well. Five of the 10 Westbay zones were used for model calibrations.

Using ECLIPSE reservoir simulation software, engineers ran reservoir simulations that included the CO2STORE module, which was developed to model CO₂ storage in saline formations. Using the model, engineers considered three phases: a CO₂-rich phase, an H₂O-rich phase and a solid phase. The static geologic model included the entire Mt. Simon Sandstone and the overlying Eau Claire Shale.

This model covers a 40-mi² [104-km²] area and was represented with a 1,288 × 1,308 × 534-cell grid with average cell size of 150 ft × 150 ft × 3.5 ft [46 m × 46 m × 1 m]. The horizontal cells of the geologic model were downscaled from 150 ft to 50 ft [15 m] around the wellbore for better reservoir model resolution there. In the far-field region, horizontal cells were upscaled from 150 ft to 1,500 ft [460 m]. Vertical resolution of the geologic model was maintained in the lower 700 ft [210 m] of the reservoir where CO₂ was expected to remain. In the upper section of the model, the vertical dimension of the cells was decreased to 75 ft [23 m]. The resulting cellular model was represented by a high-resolution 143 × 143 × 143-unit grid locally refined around the injector.

The porosity within the injection interval ranges from 8% to 26%. The temperature and pressure gradients of approximately 1°F/100 ft [1.8°C/100 m] and 0.45 psi/ft [10.2 MPa/km] were based on in situ measurements made after drilling the IBDP wells. The formation pressure gradient in the lower half of the Mt. Simon Sandstone is slightly higher than a typical freshwater gradient because of the high-salinity water present in this part of the reservoir, which ranges from 179,800 ppm to 228,000 ppm total dissolved solids based on analysis of actual formation fluid samples recovered during the drilling of the injection well. Another governing parameter used in the reservoir simulation was the fracture pressure gradient of the lower Mt. Simon Sandstone, which
Real-time data. With RTAC real-time acquisition and control software, project stakeholders were able to monitor the injection rates measured downhole (top). Real-time downhole pressures recorded in the injection well (center) confirm that targeted injection rates were achieved. Westbay measurements from 11 perforated zones along the verification well (bottom) reported real-time downhole pressures. That pressure changes are seen only in Zones 1, 2, 3 and 4, indicates that CO₂ has not risen above Zone 4.

was demonstrated by a step rate test in the injection well to be 0.715 psi/ft [16.2 MPa/km].

For the reservoir simulations, the bottomhole injection pressure (BHIP) was allowed to reach up to 80% of the fracture pressure in the IDBP well. The BHIP in the IL-ICCS injection well will be allowed to reach 90% because of its planned higher injection rate. During the course of the simulation, CO₂ is injected into the IDBP well for two years at 1,100 tonUS/d [1,000 Mg/d], followed by one year of dual injection of 1,100 tonUS/d into the IDBP well and 2,200 tonUS/d [2,000 Mg/d] into the IL-ICCS well. Injection continues for four years into the IL-ICCS well at 3,300 tonUS/d [3,000 Mg/d]. At the end of this 7-year injection period, a 45-year postmonitoring period was simulated to understand the long-term behavior of the CO₂ plumes and the reservoir pressure within the injection zone.

In both wells, injection is confined to the lower part of the Mt. Simon Sandstone because it is the most porous and permeable. In the case of the IDBP well, reservoir engineers used the existing perforated interval of 55 ft [16.8 m] in the simulation. For the IL-ICCS well simulation, they used the 330-ft [100-m] perforation interval of the completion plan.

The team calibrated the site model using data obtained during the first four months of the IBDP injection period. The engineers input the IBDP injection rate into the simulation to calculate the pressures at five zones at the verification well. The simulated pressures were comparable to the observed pressures. Engineers concluded that reservoir permeability and skin were the main parameters impacting injection pressure calibration, thus were used as fitting parameters. Engineers used spinner data from a wireline production log to determine the proportion of total CO₂ injection entering each of the sets of perforations in the injection well. These data, along with the simulation, allowed engineers to fine-tune skin values at respective perforations and calculate permeability to match IBHP (above).

Engineers used RSTPro well logs to estimate the location, saturation and thickness of the CO₂ column around the injection and verification wells. This information helped engineers fine-tune the endpoints of relative permeability curves, which govern CO₂ and brine flow in the reservoir. Using the calibrated model, engineers ran a predictive simulation to evaluate the development of the plume and its pressure during the course of the injection program.
Based on the simulation, the CO$_2$ plume resulting from injection into the IL-ICCS well will interact with the IBDP well plume. Because the injection interval is near the base of the Mt. Simon Sandstone, and CO$_2$ is less dense than the native brine, the CO$_2$ flows upward from the injection interval. As it rises, CO$_2$ saturation increases below the lower-permeability intervals within the Mt. Simon Sandstone. This pooling causes the CO$_2$ to spread laterally beneath the lower-permeability strata, which results in slow growth of the plume. The lower-permeability strata within the Mt. Simon Sandstone limit the ultimate vertical migration of CO$_2$ through the injection zone. As a consequence, simulation shows that after five years of continuous injection through the IL-ICCS well and 45 years of shut-in, the CO$_2$ is expected to remain well within the lower half of the Mt. Simon Sandstone (right and next page).

**CCS in the Long Term**

When combined, the two projects at ADM will have injected more man-made CO$_2$ into geologic storage than any project has pumped elsewhere in the US. The lessons learned from these two projects have significant implications for treating emissions from the burning of fossil fuels.

The two Illinois projects will help determine how large amounts of anthropogenic CO$_2$ behave in the Mt. Simon Sandstone, which has the potential to hold billions of tons of CO$_2$. Because the formation stretches across three states beneath some of the largest coal plants and industrial installations in the US, and because it is in the midst of coal-dependent Midwestern states, a sizable portion of CO$_2$ generated in the US can be transported to the region and stored there; these advantages make CCS commercially viable in the US.

The IBDP and IL-ICSS have been and are being constructed to meet specifications of the US Environmental Protection Agency's newly created Underground Injection Control Class VI injection well guidelines. Under the new well classification, operators must closely monitor how an underground CO$_2$ plume moves in porous rock. To comply, scientists at the Illinois State Geological Survey, in Champaign, are testing equipment that has never been used with carbon sequestration; such equipment includes seismic sensors to create a detailed image of the CO$_2$ plume.

The two demonstration projects in Illinois will answer numerous questions about the viability of CCUS. Simultaneous injection of the two projects will provide crucial information that will help scientists understand how two underground CO$_2$ plumes interact with each other. This information is important for the viability of future projects because large power plants will require multiple injection wells to manage the CO$_2$ they generate.

Additionally, data from the Illinois projects will resolve questions about geologic storage safety and sustainable injection rates that have caused government policy makers to hesitate funding large-scale CCUS projects. If those questions can be addressed, the US will be able to take advantage of storage capacity from 11 identified deep saline formations with an estimated

^ Year 1. Map view (top) and cross-sectional view (bottom) of the IBDP CO$_2$ model-predicted footprints of the pressure front and the plume after one year of injection into the IBDP well indicate that the CO$_2$ remains at or near perforation depth. The green bar represents the designed perforation interval for the IL-ICCS injection well.
Even as debate over anthropogenic climate change seems to be waning, public concerns have arisen about the environmental impact of CCUS. Large-scale projects, such as the IBDP, the IL-ICCS and others now underway may alleviate some of those concerns. If so, CCUS technology may offer at least a partial solution to governments caught in a seemingly irreconcilable position that, on the one hand, concedes that human activities are indeed aggravating climate change, but on the other hand, admits that curbing those activities is politically difficult. —RvF

storage capacity for 100% of projected US surplus CO₂ from emissions for 100 years. 24

Ahsan Ali has been a Project Manager with Schlumberger Carbon Services in Champaign, Illinois, USA, since 2011. Previously, he was a drilling optimization engineer. Ahsan received a bachelor’s degree in civil engineering from the University of Illinois at Urbana-Champaign.

A. Ballard Andrews, a principal scientist at Schlumberger-Doll Research in Cambridge, Massachusetts, USA, specializes in optics, photonics, laser applications, infrared thermography, spectroscopy and asphaltene science. He earned a PhD degree in condensed matter physics from The University of Texas at Austin, USA, and conducted postdoctoral research at Los Alamos National Laboratory, New Mexico, USA. He later worked for Brookhaven National Laboratory in Upton, New York, USA, on computational scientific visualization and X-ray microtomography. Ballard has published more than 50 articles in physics, chemistry and energy journals and coauthored a chapter in Handbook of Physics and Chemistry of the Rare Earths. He has presented at more than 35 conferences and has 16 patents granted or filed. His current interests include downhole gas compositional analysis.

Eric H. Berlin is a Project Manager with Schlumberger Carbon Services in Champaign, Illinois. He has held various positions with Schlumberger since 1981 in Illinois, California and Ohio, USA. Eric attained a BS degree in geoengeering from the University of Minnesota Institute of Technology, Minneapolis, USA.

Bill Black is a Senior Hydrogeologist and Westbay® Sales and Marketing Manager for Schlumberger Water Services in Burnaby, British Columbia, Canada; he has worked with the Westbay system for more than 34 years. His technical interest lies in groundwater behavior, and his current projects include demonstrating the value of Westbay technology for environmental monitoring of unconventional resource developments such as oil shale, oil sands, shale gas and coal seam gas. Bill received a BSc degree in geological engineering from the University of British Columbia in Vancouver, Canada.

Michael Carney is the North America Subsurface Technical Manager for Schlumberger Carbon Services in Houston; he leads a team of petrotechnical experts in geology, geophysics, petrophysics and reservoir and production engineering. He joined Schlumberger in 1991 as the district geologist for most of sub-Saharan Africa in Port Gentil, Gabon, and was then the data center manager in Luanda, Angola. In the US, he has served in several positions, including management and technology development. He has recently been focusing on production and reservoir optimization and permanent downhole sensing. He serves as a coleader of the production and completions engineering community and of the Schlumberger sensor technology special interest group. Michael earned a BSc degree in geological engineering from the Colorado School of Mines, Golden, USA.

Ethan Chabora is a Reservoir Engineer for Schlumberger Geothermal Services in Richmond, California; his focus is resource assessment and reservoir optimization for clients such as geothermal power operators and project investors. He began his career with Schlumberger Wireline in 2000 as a field engineer and has since held the roles of general field engineer, engineer in charge and project manager with Schlumberger Carbon Services. Ethan received a BA degree in physics from Cornell University in Ithaca, New York, and an MS degree in petroleum engineering from Stanford University, California.

Brian Coll is the Business Support Manager for New Technologies with M-I SWACO LLC, a Schlumberger company. Based in Aberdeen, he works in the Wellbore Productivity Segment with a focus on the WELL SCAVENGER® tool and other new tools under development. He joined the oil industry in 1997 as a field engineer for Gyrodata Ltd, running gyroscopic and magnetic measurement tools to obtain high-accuracy directional wellbore surveys in Europe, North Africa, the Middle East and Asia. He served as Gyrodata operations coordinator for Saudi Arabia, Kuwait and Bahrain followed by operations manager in Kalimantan, Indonesia. Brian joined SPS International in 2006 as product support engineer to oversee the development of the CENTURION circulating valve, which evolved into the WELL COMMANDER® tool. Following the acquisition of SPS by M-I SWACO in 2006, he became business development manager for new technology and conducted market research, field trials, data collection and analysis and global introduction and offered training and support for the WELL COMMANDER tool.

Chengli Dong is a Senior Fluid Properties Specialist with the Shell FEAST (Fluid Evaluation and Sampling Technologies) team in Houston. Before moving to Shell, he was a reservoir domain champion for Schlumberger. He has been a key contributor to the development of downhole fluid analysis (DFA) measurements and their applications in reservoir characterization. He conducted extensive spectroscopic studies on live crude oils and gases and led the development of interpretation algorithms for the DFA tools. In addition, he has extensive field experience in design, implementation and analysis of formation testing jobs. He has published more than 50 technical papers, holds nine patents and nine filed patents and has one trade secret award. Chengli holds a BS degree in chemistry from Beijing University and a PhD degree in petroleum engineering from The University of Texas at Austin.

Hani Elshahawi is Deepwater Technology Advisor at Shell in Houston. Previously, he led FEAST, the Shell Fluid Evaluation and Sampling Technologies Center of Excellence, where he was responsible for the planning, execution and analysis of global high-profile formation testing and fluid sampling operations. With more than 25 years of experience in the oil industry, he has worked in both service and operating companies in more than 10 countries in Africa, Asia, the Middle East and North America and has held various positions in interpretation, consulting, operations, marketing and product development. Hani has lectured widely in various areas of petrophysics, geosciences and petroleum engineering, holds several patents and has written more than 100 technical papers. He was the 2008–2010 president of the SPWLA and an SPWLA distinguished lecturer in 2010 and 2011. Hani attained a BS degree in mechanical engineering and an MS degree in petroleum engineering from The University of Texas at Austin.

Robert J. Finley is a Director of the Advanced Energy Technology Initiative with the Illinois State Geological Survey in Champaign, Illinois. He has worked in reservoir development for unrecovered oil and natural gas, with coalbed methane and tight gas sandstone reservoir development in Texas and the Rocky Mountains in the US and in reservoir development for carbon sequestration in the Illinois basin. Robert earned a BS degree from City University of New York, an MS degree from Syracuse University, New York, and a PhD degree in geology from the University of South Carolina, Columbia, USA.

Julie Jeapert, based in Ravenna, Italy, began her career in the oil industry in 1998 as a gas pipeline construction project engineer for Gaz de France. In 2001, she joined Schlumberger as stimulation and sand control engineer. Currently, she is a Technical and Sales Engineer for sand control and matrix acidizing in Continental Europe. Her technical expertise is in sand control pumping and downhole tools in cased hole or openhole completions, matrix acidizing of sandstones and carbonates, water shutoff and fracturing. Julie has a degree in mechanical engineering from École Nationale Supérieure des Arts et Métiers, Paris, and obtained a master’s degree in natural gas engineering from École Nationale Supérieure des Mines de Paris.

Enos Johnson is a District Manager in Hobbs, New Mexico, in charge of Schlumberger fishing and remedial services. He coordinates fishing and reversing jobs on drilling and workover rigs operating in New Mexico and West Texas. Enos has worked in the oil field since 1969; his career has taken him from the tool shop to the rig floor and on to operations and sales.

Jim Kirksey has worked for Schlumberger for 31 years and is currently Well Engineering Manager for Carbon Services North America in Champaign, Illinois. He has served in many management and technical positions. Jim holds a BS degree in petroleum engineering from Mississippi State University, USA.

Winter 2012/2013

Contributors
Jimmy Land is a Business Director for Schlumberger fishing and remediation services. He has a background in drilling and production support and more than 30 years of oilfield experience, 20 of which was in senior operations management. Jimmy has a BA degree from McMurry University, Abilene, Texas.

David Larsen is a Geotechnical Engineer with Schlumberger Water Services in Burnaby, British Columbia, Canada. Before beginning his career with Schlumberger in 1986, he was an engineering consultant specializing in hydrogeology. He has authored several publications on advanced groundwater instrumentation and is the senior technical expert on application of the Westbay system. David obtained a BS degree in geotechnical engineering and hydrogeology from the University of British Columbia, Vancouver.

Graeme Laws is the Director of the Specialized Tools Technology Centre for M-I SWACO in Aberdeen. In 1975, he began as a cementing engineer in the North Sea and held field positions in various locations working with a range of downhole tool systems, including drillstring testing, gravel packing and tubing-conveyed perforating. He began his management career in Brunei in 1983 working with Baker Hughes Sand Control. He ran and managed liner hanger systems in the North Sea with Nodoco Limited and then became director of the company. Graeme joined SPS International in 1999 and worked in various technical management positions; he was a technical director when M-I SWACO acquired SPS in 2006. He has contributed to the design of several downhole tools, including the WELL SCAVENGER tool.

Mark Lee, based in Houston, is the Director for Career Development and Training with Schlumberger. He joined the company in 2009 and has been in the oil industry for 38 years. Mark previously worked for Weatherford International as the country business manager of North Africa and for Baker Hughes as a field engineer. Mark has a BS degree in engineering from Louisiana Tech University, Ruston, USA.

Hannes E. Leerar is a Senior Petroleum Geologist at the Illinois State Geological Survey in Champaign, Illinois. His focus is the geology and geophysics of the subsurface in relation to carbon sequestration activities at the Illinois Basin–Decatur Project. He is also the Principal Investigator for a US Department of Energy–funded study on the carbon sequestration potential of the Cambrian and Ordovician strata in the Illinois and Michigan basins in the US. He has worked as a petroleum geologist with Getty Oil Company and Union Pacific Resources in Houston and was involved in exploration and development projects in the East and West Texas basins and the Hugoton Embayment in Kansas, USA. Hannes, who has published numerous industry papers, received a BS degree from the State University of New York at Fredonia, an MS degree from Syracuse University, New York, and a PhD degree from the University of Illinois at Urbana-Champaign, all in geology.

Scott Marsteller joined Schlumberger in 1989 as a wireline field engineer in south Texas. Since then, he has held many positions in sales, marketing and operations management in the US. He recently served as the Illinois basin projects manager in Champaign, Illinois, managing the Illinois Basin–Decatur Project from the planning phase through CO₂ injection. He is currently a Marketing Manager for Schlumberger in Anchorage. Scott attained a BS degree in mechanical engineering from Rose-Hulman Institute of Technology, Terre Haute, Indiana, USA, and an MBA degree from Erasmus University, Rotterdam, the Netherlands.

Scott McDonald is Director of Biofuels Development for Archer Daniels Midland (ADM) Company in Decatur, Illinois. His responsibilities include identification and development of projects and novel product applications that will expand the use of biofuels and bio-based products into the marketplace. He leads the biofuels technical services team. Prior to joining ADM, he was the commercial trading manager for Total, where his responsibilities included trading and risk management for feed and finished product streams for the company’s US refining and petrochemical assets. His 20-year career has included trading and risk management, business development, economics and planning, fuels formulation and unit process design, startup and operation. Scott has a BS degree in chemical engineering from The University of Texas at Austin.

Oliver C. Mullins, a chemist, is a Science Advisor to executive management in Schlumberger. He is the primary originator of downhole fluid analysis for formation evaluation. For this, he has won several awards, including the SPE Distinguished Membership Award and the SPWLA Distinguished Technical Achievement Award; he has been a distinguished lecturer four times for the SPWLA and SPE. He authored the award-winning The Physics of Reservoir Fluids: Discovery Through Downhole Fluid Analysis. Oliver also leads an active research group in petroleum science. He has coedited three books and coauthored nine chapters on asphaltenes and 185 publications. He coinvented 51 allowed US patents, is Fellow of two professional societies and is Adjunct Professor of Petroleum Engineering at Texas A&M University, College Station.

David Petro is a Senior Technical Consultant at Marathon Oil Corporation in Houston; he has more than 32 years of experience in the oil and gas industry. During the past 17 years, he has worked on reservoir characterization and implementation of deepwater Gulf of Mexico projects. David has coauthored many papers on reservoir evaluation and performance.

Andrew E. Pomerantz is the Geochemistry Program Manager at Schlumberger-Doll Research in Cambridge, Massachusetts. His research focuses on the development of novel techniques to characterize the chemical composition of kerogen and asphaltenes, including methods in mass spectrometry, X-ray spectroscopy and infrared spectroscopy. That molecular information is used to understand fundamental physical and chemical processes in petroleum such as asphaltene compositional grading and storage and transport in shales. Andrew, who has coauthored 40 publications, received a PhD degree in chemistry from Stanford University, California.

Robert Robertson has been a Schlumberger Global Product Engineering Advisor since 2011. Based in Stavanger, he has more than 25 years of fishing and remedial experience as a fishing tool supervisor, senior well specialist, operations supervisor and operations manager in every part of the world. In his current position, Bobby is responsible for product development, reliability and technical follow up of the fishing and remedial product line with an emphasis on global plug and abandon technology.

Douglas J. Seifert is a Petrophysical Consultant with Saudi Aramco in Dhahran, Saudi Arabia. He works as the Petrophysics Professional Development Advisor in the Upstream Professional Development Center, where he oversees the Petrophysics curriculum and development of petrophysicists within Saudi Aramco. He specializes in real-time petrophysical applications and pressure testing and fluid analysis. He previously worked for Pathfinder Energy Services, Maersk Olie og Gas, Halliburton and Texaco. Doug is the President of the Saudi Arabia Chapter of SPWLA and also serves on the SPWLA Technology Committee. He holds a BS degree in statistics and an MS degree in geology from The University of Akron, Ohio.

Ozgur Senel has been a Reservoir Engineer with Schlumberger Carbon Services in Sugar Land, Texas, since 2008. He is responsible for analyzing field data, creating and calibrating reservoir models, simulating CO₂ injection, predicting and optimizing CO₂ plume development and optimizing well sizing, completions and injection programs for carbon capture and storage (CCS) projects in the US and Canada. In addition, he manages surface facilities–flow assurance projects. Ozgur has a BS degree in petroleum engineering from the Middle East Technical University, Ankara, Turkey, and an MS degree in petroleum engineering from Texas A&M University, College Station, where he is a PhD candidate in petroleum engineering.

Valerie Smith is a Reservoir Geophysicist with Schlumberger Carbon Services in Westerville, Ohio. Before obtaining her current position, she worked for West Virginia University, Morgantown, USA, as a research assistant. Valerie attained a BA degree in physics from the State University of New York at Potsdam, a BS degree in geology from West Chester University of Pennsylvania, USA, and an MS degree in geology from West Virginia University.

Marco Sportelli joined Eni SpA as a completion supervisor on offshore rigs in 1986. He then became Drilling and Completion Superintendent and has held that position since 1999. His expertise is in development and workover in the depleted gas fields of the Adriatic Sea. Marco has extensively used dual selective sand control completions. He is based in Ravenna, Italy.
An asterisk (*) is used to denote a mark of Schlumberger.
A dagger (†) is used to denote a mark of M-I SWACO LLC, a Schlumberger company.

Charles Svoboda is the Director of Business Development for M-I SWACO wellbore productivity in Houston. He began his career with Halliburton and transferred to M-I SWACO, formerly IMCO Services, in 1984 and has held operational and technical positions in the drilling fluids and wellbore productivity segments since that time. His focus is on developing and commercializing technologies pertaining to completion fluids, reservoir drill-in fluids, breakers, specialized tools and filtration. Charles received a bachelor’s degree in civil engineering in 1982 from the University of Illinois, Urbana-Champaign.

Mark Trimble began in the oil industry as a roughneck on the drill floor and then progressed to a driller position. In 1980, he joined Baker Oil Tools, where he worked for 10 years as a field technician running downhole completion and remedial tools. He left the industry for 18 years; when he returned in 2008, he started at M-I SWACO as a technical service engineer focusing on designing, recommending and writing procedures for downhole cleanup tools primarily in deepwater and extended-reach applications. Since 2010, he has been a Business Development Manager. Based in Houston, Mark promotes and conducts training and support for new technology for cleanup tools worldwide.

Murat Zeybek is a Schlumberger Reservoir Engineering Advisor and Reservoir and Production Domain Champion for the Middle East area and is based in Dhahran, Saudi Arabia. He works on analysis and interpretation of wireline formation testers, pressure transient analysis, numerical modeling of fluid flow, water control, production logging and reservoir monitoring. He is a member of the technical editorial review committee for SPE Reservoir Evaluation and Engineering and served as a committee member for the SPE Annual Technical Conference and Exhibition. He also served on the industrial advisory committee for the petroleum engineering department at King Fahd University of Petroleum and Minerals, Dhahran. Murat holds a BS degree from Istanbul Technical University, Turkey, and received MS and PhD degrees from the University of Southern California in Los Angeles, all in petroleum engineering.

Julian Y. Zuo is currently a Scientific Advisor and Interpretation Architect for a next-generation formation testing and sampling tool at the Schlumberger Houston Pressure and Sampling Center in Sugar Land, Texas. He has been working in the oil and gas industry since 1989. Recently, he has been leading the effort to develop and apply the industry’s first simple Flory-Huggins-Zuo equation of state for predicting compositional and asphaltene gradients to address concerns such as reservoir connectivity, tar mat formation, asphaltene instability, flow assurance and nonequilibrium with late gas charging. He has coauthored more than 150 technical papers for journals, conferences and workshops. Julian holds a PhD degree in chemical engineering from the China University of Petroleum in Beijing.

Coming in Oilfield Review

Well Placement and Completion Evolution. The advent of new LWD tools and measurements has led to changes in the way some operators approach drilling horizontal wells. New tools are able to detect boundaries in the formation away from the borehole and in front of the drill bit, resulting in an improvement in well placement techniques. In addition, tools have been developed that accurately image borehole details and identify naturally occurring fracture networks. Engineers use these data to create effective completion designs. This article presents some of the technologies and processes that are making these changes possible.

Evaluation While Drilling. Motivated by environmental, health and security reasons, scientists have spent years developing alternatives to radioisotope-based logging tools. Through the use of pulsed-neutron generators that have replaced chemical sources in other logging tools, engineers have developed a radioisotope-free gamma-gamma density measurement. This innovation allows operators to deploy a full suite of LWD tools that have no chemical sources.

Wireline Formation Testing. Wireline-conveyed fluid sampling tools enable operators to capture and analyze reservoir fluids faster than ever before. Until recently, however, use of these formation testers was limited by some types of formations and the flow regimes of certain fluids or required an extended period of time on station to capture clean samples. A new design has overcome these challenges and, in so doing, greatly expanded the realm of wireline formation testing.


In our commitment to understanding climate change, Dieter Helm, professor of energy policy at University of Oxford, England, argues that we have failed to tackle the issue of global warming and advocates for a rethinking of energy policies. Included in this argument is a suggestion of a broad transition from coal to gas to electrification with a focus on the economics of new technologies.

Contents:
• Part One: Why Should We Worry About Climate Change?: How Serious Is Climate Change?: Why Are Emissions Rising?: Who Is to Blame?
• Part Two: Why Is So Little Being Achieved?: Current Renewables Technologies to the Rescue?: Can Demand Be Cut?: A New Dawn for Nuclear?: Are We Running out of Fossil Fuels?: A Credible International Agreement?
• Part Three: What Should Be Done?: Fixing the Carbon Price; Making the Transition; Investing in New Technologies
• Conclusion
• Endnotes, Bibliography, Index

Dieter Helm superbly articulates why some of the alternate energy sources touted as solutions (such as wind power) aren’t cost efficient, and how countries claim to have reduced harmful carbon emissions only by increasing carbon imports that don’t add up to a net reduction. This intelligent though depressing tome should inform future debates.

“The Carbon Crunch: How We’re Getting Climate Change Wrong and How to Fix It
Dieter Helm
Yale University Press
302 Temple Street
New Haven, Connecticut 06511 USA
2012. 304 pages. US$ 35.00
ISBN: 978-0-300-18659-8

The Face of the Earth: Natural Landscapes, Science, and Culture
SueEllen Campbell with Alex Hunt, Richard Kerridge, Tom Lynch, Ellen Wohl and others
University of California Press
2120 Berkeley Way Berkeley, California 94704 USA
2011. 334 pages. US$ 27.95

Author and editor SueEllen Campbell, a professor of English, examines Earth’s landscapes through both scientific and cultural lenses by weaving science, cultural myth, literary studies and personal experience. Accounts by Campbell as well as scientists and other writers explore, explain and chart humankind’s interdependence with and mark on the natural world.

Contents:
• Landscapes of Internal Fire: On the Spot: Over a River of Lava; Imagining the Interior; On the Spot: At the Edge of an Overthrust Belt; Mundus Subterraneus; On the Spot: Among the Aeolian Islands; The Globe, Tectonic Plates, and Mountain Building; On the Spot: Along the Disturbance Gradient; Volcanoes and Their Erupions; On the Spot: Along the Chaitén Volcano; Hot Springs and Geysers
• Climate and Ice: On the Spot: Up and Down the Himalaya; How the Climate Works; The Ghosts of Climates Past; Our Ice Age; Landscapes Shaped by Ice; On the Spot: In the Channeled Scablands; Ice-Age Humans; On the Spot: On the Arctic Tundra; The Little Ice Age; Glaciology, and the Sublime; On the Spot: Toward a Glacier’s Edge; The Story Now
• Wet and Fluid: On the Spot: In the Rocky Intertidal Zone; The Water Cycle; On the Spot: Along a Rain Forest Stream; The Moving Waters of Rivers; The Dream of Water in Deserts; The Slow Water of Wetlands; On the Spot: At the Bog on Céide Fields; Peat, Mires, Bogs, Fens; On the Spot: At Wicken Fen; Marshes and Swamps; Wet/Dry; On the Spot: At the Billabong
• Desert Places, Desert Lives: On the Spot: Down a Desert River Canyon; Dry, Hot, Windy, and Dusty; On the Spot: In Jabal Ajij; What We See; On the Spot: In the Chihuahuan Desert; Clever Plants; On the Spot: In the Red Center; Clever Creatures; On the Spot: In the Negrí Desert; The Human Desert
• The Complexities of the Real: Underfoot; On the Spot: In Antarctica’s Dry Valleys; Oceans of Grass; The Shapes of Complexity; On the Spot: On the Chalk Downs; Evolving Together . . . ; On the Spot: In the Tallgrass Prairie . . . ; And Moving Apart; On the Spot: On the Tibetan Plateau; Among Trees; On the Spot: In a Eucalypt Forest; Zooming In: Return to Wonder
• Epilogue: In a High Flower Meadow
• Sources, Contributor Biographies, Index

SueEllen Campbell and her colleagues draw on a scholarship model that employs the collaborative research-team approach . . . typical of the sciences. . . . The result is masterful: a hugely ambitious, necessary, articulate, and generous intellectual undertaking, executed with scholarly exactitude and lyrical beauty.


. . . readers will encounter nature writing that rivals Annie Dillard’s fiction, combined with personal responses to the environmental state of our earth’s natural landscapes and practical suggestions that offer hope in the face of overwhelming issues like climate change.

Parameter Estimation and Inverse Problems, Second Edition
Richard C. Aster, Brian Borchers and Clifford H. Thurber
Academic Press, an imprint of Elsevier
225 Wyman Street
Waltham, Massachusetts 02451 USA

This textbook explores classical and Bayesian approaches to linear and nonlinear inverse theory problems and also looks closely at computational, mathematical and statistical issues related to their application to geophysical problems. A companion website features computational examples for the exercises in the book.

Contents:
• Introduction
• Linear Regression
• Rank Deficiency and Ill-Conditioning
• Tikhonov Regularization
• Discretizing Inverse Problems Using Basis Functions
• Iterative Methods
• Additional Regularization Techniques
• Fourier Techniques
• Nonlinear Regression
• Nonlinear Inverse Problems
• Bayesian Methods
• Epilogue
• Appendices, Bibliography, Index

As is true of the original, the book continues to be one of the clearest as well as the most comprehensive elementary expositions of discrete geophysical inverse theory. It is ideally suited for beginners as well as a fine resource for those searching for a particular algorithm that could be brought to bear on a particular inverse problem. . . . All examples in the book are beautifully illustrated with simple, easy to follow ‘cartoon’ problems, and all painstakingly designed to illuminate the details for a particular numerical method.


To Forgive Design: Understanding Failure
Henry Petroski
The Belknap Press of Harvard University Press
79 Garden Street
Cambridge, Massachusetts 02138 USA

By surveying some of the world’s infamous engineering failures, the author reveals the interconnectedness of technology and culture and explores the larger context in which accidents occur. Petroski explains how even simple technologies are embedded in cultural and socioeconomic constraints, complications and contradictions and demonstrates how dangers may emerge from complexity.

Contents:
• By Way of Concrete Examples
• Things Happen
• Designed to Fail
• Mechanics of Failure
• A Repeating Problem
• The Old and the New
• Searching for a Cause
• The Obligation of an Engineer
• Before, During, and After the Fall
• Legal Matters
• Back-Seat Designers
• Houston, You Have a Problem
• Without a Leg to Stand On
• History and Failure
• Notes, Illustrations, Index

Despite the book’s meanderings and repetitions, there is much to learn from it. . . . The most brilliantly explained engineering failure concerns the ocean-bed blowout involving the Deepwater Horizon oil rig in 2010. Petroski’s exposition is immensely detailed and benefits from being linear in its narrative. This section of the book is exemplary in its remorseless exfoliation of the technical and commercial reasons for the incident.


Ignorance: How It Drives Science
Stuart Firestein
Oxford University Press
198 Madison Avenue
New York, New York 10016 USA

The author posits that in science and research, knowledge follows ignorance, rather than the other way around. Firestein argues that ignorance is the force that propels scientists and researchers. The book includes four case histories that illustrate how individual scientists use ignorance to direct their research.

Contents:
• A Short View of Ignorance
• Finding Out
• Limits, Uncertainty, Impossibility, and Other Minor Problems
• Unpredicting
• The Quality of Ignorance
• You and Ignorance
• Case Histories
• Coda
• Notes, Suggested Reading, Index

An excellent read, Ignorance would be a fine companion text for potential scientists at the beginning of their studies. . . . Firestein’s short account may even make you embrace your ignorance, wearing it like a badge of honor. You may gradually become more and more ignorant as you read, and you will enjoy the journey. Ignorance in this telling is truly bliss.


To show how scientists depend on ignorance, Dr. Firestein has written a short, highly entertaining book aimed at nonscientists and students who want to be scientists. . . . Dr. Firestein. . . celebrates a tolerance for uncertainty, the pleasures of scientific mystery and the cultivation of doubt.


Wild Hope: On the Front Lines of Conservation Success
Andrew Balmford
University of Chicago Press
1427 East 60th Street
Chicago, Illinois 60637 USA

As the title suggests, Balmford offers hope that our natural environment is in recovery, not on its way to disaster. Organized geographically, the book highlights the people who are discovering and generating new ideas to make conservation a success. Balmford recognizes the difficulties and challenges of conservation but offers solutions and accounts of citizens, governments and corporations working together to implement such solutions.

Contents:
• The Glass Half Empty
• Guarding the Unicorn: Conservation at the Sharp End
• Ending the Woodpecker Wars
• Problem Plants, Politics, and Poverty
• Rewilding Goes Dutch
• Seeing the Good from the Trees
• The Greening of a Giant
• Fishing for a Future
• The Glass Half Full
• Appendix: Stemming the Loss (Or What We Can All Do to Save Nature)
• References

[. . . there is a kind of genius in [the book’s] opacity and simplicity that sets it apart from bibliographic congeners in the genre of conservation writing. Science plays a critically important role in framing the dialogue for how and where we manage ecosystems. Balmford makes this clear. . . . Balmford’s vague, but sincere, impassioned, response makes more neurons fire in the region of the heart than in the head. Nonetheless, perhaps that is just the muscle needed for protecting nature.]

Well and formation tests, which entail taking measurements while flowing fluids from the reservoir, are conducted at all stages in the life of oil and gas fields, from exploration through development, production and injection. Operators perform these tests to determine whether a formation will produce, or continue to produce, hydrocarbons at a rate that gives a reasonable return on further investments. Operators also use test data to determine the limits of the reservoir and to plan the most efficient methods for producing wells and fields.

During testing, operators measure formation pressure, characterize the formation fluids and reservoir and determine permeability and skin—damage to the formation incurred during drilling or other well operations. Data that indicate how the formation reacts to pressure increases and decreases during a test can also reveal critical information about the reservoir.

Well and formation tests are also primary sources of critical data for reservoir models and are the principal means by which engineers confirm or adjust reservoir model parameters. Engineers use these models to understand how reservoir fluids, the formation and the well interact and use that knowledge to optimize completion and development strategies.

Operators assess the production potential of wells through several test methods, singularly or in combination. They may choose to perform a production well test in which the well is flowed through a temporary completion to a test separator (right). Or they may use a wireline formation tester (WFT) to capture fluid samples and measure pressure downhole at the zone of interest. Engineers sometimes perform both types of tests.

During production well tests, technicians flow reservoir fluids to the surface through a drillstring or a drillstem test (DST) string. Packers isolate the zone to be tested while downhole, or surface equipment provides well control. The well is flowed at different rates through a choke valve that can be adjusted to control the flow rate precisely.

Reservoir fluids produced to the surface are sent directly to holding tanks until test operators determine that contaminants such as drilling fluids are eliminated, or at least minimized, from the flow stream. After cleanup, flow is redirected to a test separator where bulk fluids are divided into oil, gas and water, and any debris, such as sand and other material, is removed. The three fluid phases are measured and analyzed separately. Operators may opt to obtain additional reservoir and fluid flow data by simultaneously running production logging tools into the well on wireline. These tools measure the downhole flow rate and fluid composition and can indicate which zones are contributing to the total flow.

During well tests, reservoir fluids are produced to the separator at varying rates according to a predetermined schedule. These tests may take less than two days to evaluate a single well or months to evaluate reservoir extent. Test types include buildup, drawdown, falloff, injection and interference. For most tests, engineers permit a limited amount of fluid to flow from or into a formation. They then close the well and monitor pressures while the formation equilibrates.

Buildup tests are performed by shutting in the well after some period of flow to measure increase in bottomhole pressure (BHP). By contrast, for drawdown tests, engineers open the well after a specified shut-in period to observe BHP decrease. During injection tests and falloff tests, fluid is injected into the formation, and BHP, which increases as a result, is monitored. The well is then shut in and the ensuing decreasing BHP is recorded. Interference tests record the pressure changes in adjacent wells when the test well pressure is changed. The time it takes for changes in the test well to affect pressure at the observation well gives engineers an indication of the size of the reservoir and flow communication within it.

Engineers analyze responses to pressure change schemes using pressure transient analysis, a technique based on the mathematical relationships between flow rate, pressure and time. The information from these analyses helps engineers determine the optimal completion interval, production potential and skin. They can also derive average permeability, degree of permeability heterogeneity and anisotropy, reservoir boundary shape and distance, and initial and average reservoir pressures.

Engineers use specific variations on well buildup and drawdown tests to evaluate gas wells. During a backpressure test, a well is flowed against a specified backpressure until its BHP and surface pressures stabilize—an indication that flow is coming from the outer reaches of the drainage area. An isochronal test is a series of drawdowns and buildups. Pumping rates vary for each drawdown, while subsequent buildups continue until the well stabilizes.
across a production interval. WFTs that include a quartz pressure gauge and a fluid sampling tool placed in the well can mine the relationship between backpressure settings and flow rates of which the well would flow if backpressure on the sandface, or the borehole formation potential, skin and drawdown and buildup periods are of equal duration—may also be used. While the contamination level decreases. Once engineers determine that the first flowed or pumped through flowlines in the tool into the wellbore, formation or between packers set above and below the sampling site. Fluids are pumped or flowed into the WFT through a probe inserted into the formation. A quartz pressure gauge measures and into storage bottles (orange) where the fluids are kept at in situ conditions. Multiple samples can be taken on one trip into the well. When all tests are completed, the samples are brought to the surface and may be sent to laboratories for advanced testing. A quartz pressure gauge measures and records bottomhole pressures.

Formation is delivering minimally contaminated reservoir fluids, they redirect flow to sample chambers within the tool. The chambers are retrieved to the surface and transported to laboratories for analysis. Scientists also use downhole fluid analysis (DFA) to monitor the sampling process. Using optical spectroscopy, or the recorded light spectrum, engineers identify in real time the composition of fluids as they flow into the tool; this method also reveals critical data about the reservoir without waiting for laboratory tests to be completed. Additionally, the DFA measurements confirm that the sample is uncontaminated and eliminate uncertainties associated with fluid transport and laboratory reconstruction of in situ conditions necessary for fluid analysis. Technicians also use DFA data to identify gas/oil ratios, relative asphaltene content and water fraction in real time.

A variety of well and formation test schemes are performed throughout the stages in the life of a well or field. At the exploration stage, operators may use well tests to simulate production after a well is completed to establish production potential and reserves estimates. In addition, capturing large fluid samples at the surface gives experts an opportunity to perform laboratory measurements on the reservoir fluids.

Well tests at the exploration stage also allow operators to determine if low flow rates are affected by skin or are the result of natural permeability of the reservoir. Armed with the knowledge of either situation, engineers can then take appropriate actions, plan treatments that may be necessary once production commences or decide to abandon the project for economic reasons. For instance, well tests can be used to estimate reservoir size, which allows operators to abandon a small reservoir that will not be economical despite high initial flow rates.

During the field development stage, well tests help indicate wells that may require stimulation treatments. Using well test data, engineers predict induced or natural fracture length and conductivity. They can then estimate productivity gains that may be realized from a stimulation treatment. In addition, WFTs can be used for pressure testing to determine static reservoir pressures and to confirm fluid contacts and density gradients. This information helps analyze communication within the reservoir, tie reservoir characteristics to a geologic model and identify depleted zones.

During the production phase, well tests are aimed at monitoring reservoirs, collecting data for history matching—comparing actual production with predicted production from reservoir simulators—and assessing the need for stimulation. These tests use a pressure gauge placed at formation depth to collect data during pressure buildup and drawdown.

Well productivity usually diminishes over time, sometimes as a result of formation damage from fines migration—the movement of very small particles through the formation to the wellbore where they fill pore spaces and reduce permeability. Engineers may perform formation tests to predict the likely effectiveness of treatments to remove these fines. The effects of completion choices may also be assessed using formation tests to aid engineers in planning required remedial operations.

Well and formation test data provide operators with information about their new and producing wells that is critical to making near-term operational decisions. But the real power of well test data is their application to construction or correction of reservoir models, which allow operators to make better long-term decisions about their assets.
ARTICLES
Basin to Basin: Plate Tectonics in Exploration

CO₂ Sequestration—One Response to Emissions

Drilling Automation

The Expanding Role of Mud Logging

Landing the Big One—The Art of Fishing

Logging Through the Bit

Microbes—Oilfield Enemies or Allies?

Offshore Permanent Well Abandonment

Revealing Reservoir Secrets Through Asphaltene Science

Seismic Detection of Subtle Faults and Fractures

Sonic Logging While Drilling—Shear Answers

Specialized Tools for Wellbore Debris Recovery

Testing the Limits in Extreme Well Conditions

When Rocks Get Hot: Thermal Properties of Reservoir Rocks

Working Out of a Tight Spot

EDITORIALS
Drilling Automation: Generating Greater Reliability and Profitability

Frontier Hydrocarbon Exploration: The Importance of Tectonic Models

The Future of CCS

Offshore Idle Iron: Remains of the Past or Infrastructure of the Future

DEFINING... INTRODUCING BASIC CONCEPTS OF THE E&P INDUSTRY

Defining Cementing: Well Cementing Fundamentals

Defining Perforating: Detonation for Delivery

Defining Porosity: How Porosity Is Measured

Defining Testing: Well Testing Fundamentals