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COMPLETION TECHNOLOGIES PUSH THE LIMITS

REGIONAL REPORT: EAST AFRICA


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JUNE 2014
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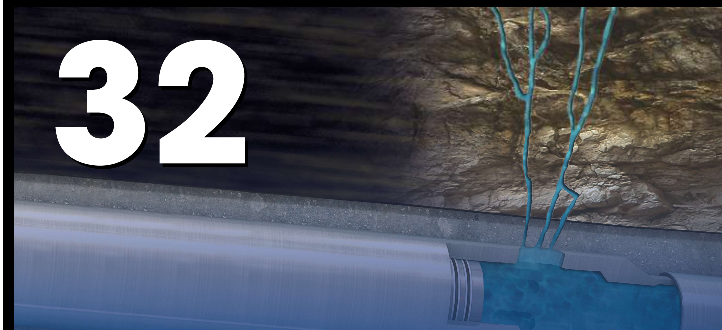

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Completion technology evolves to impact efficiency, effectiveness

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COMING NEXT MONTH The July issue of ***E&P*** will provide an update on the booming shale market, both in North America and internationally. Other features will examine petrophysics and well testing, coiled tubing, hydraulic fracturing, and floating production and topsides technology, and regional reports will feature the Bakken Shale and the Middle East. As always, while you're waiting for the next copy of ***E&P***, remember to visit ***EPmag.com*** for news, industry updates, and unique industry analysis.

ABOUT THE COVER Baker Hughes' Alpha Sleeve enables the use of ball-activated frack sleeves. Completion technologies continue to evolve to handle deeper wells, hotter temperatures and longer laterals. Left, East Africa continues to entice with oil as well as gas discoveries. (Main image courtesy of Baker Hughes; cover design by Laura J. Williams)

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Edvard Grieg appraisal well hits oil

Appraisal well 16/1-18 on the Edvard Grieg Field in the Norwegian North Sea encountered about 62 m (203 ft) of oil-bearing conglomeratic sandstone sequence dated late Upper Jurassic, Lundin Petroleum said.

Deep Sea Mooring launches new company

Deep Sea Installation, a new marine company focused on mooring FPSO units, has been launched in Singapore by Deep Sea Mooring to target projects across Asia, Europe and West Africa.

Statoil makes new find near Gimle

Statoil has made a small oil discovery in the Gimle Field area between the Gullfaks and Visund fields offshore Norway estimated to contain about 6.24 MMbbl of oil.

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Report predicts 'steady low' for UKCS activity

By Velda Addison, Associate Online Editor

Wells spudded offshore northwest Europe increased, while the number of oil and gas deals dropped for first-quarter 2014.

Malaysian E&P sector bears fruit

By Steve Hamlen, Special to **E&P**

Among the latest discoveries were two made by Shell offshore Sarawak, Malaysia.

Report unveils possible solutions to Arctic oil spill response problems

By Velda Addison, Associate Online Editor

Creating a long-term oil spill R&D program is among the recommendations.

Petraeus: US energy security could extend throughout North America

By Darren Barbee, Hart Energy

The last piece of continental energy independence, he said, will fall into place when Mexican reforms start in the years ahead.

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A shared future

Faced with the relentless challenge of not only replacing existing oil and gas reserves but also growing global production capacity to meet soaring demand, the question is constantly asked—where's it going to come from? That question, in turn, has led many over the last 15 years to identify the offshore sector—especially deepwater—as the likely source.

But with the astonishing rise of unconventional production in the U.S.—an energy renaissance happening before our very eyes—competition for the dollars needed to find and produce from these "rival" resources is fierce. By 2020 shale is expected to make up approximately 25% of total global E&P expenditure.

These rising volumes of unconventional oil are offsetting the decline in conventional oil in the U.S., and while deepwater will continue to add to conventional totals with the large volumes it produces, the long lead times, greater exposure to execution risk and higher costs remain challenging.

But it's worth pointing out that the break-even price for oil still remains similar between unconventionals and offshore.

Despite being two such different creatures, they retain many synergies. New and improved technologies remain integral to unlocking both, while the issue of social license to operate is equally applicable.

A panel at the recent Offshore Technology Conference in Houston flagged the importance of retaining that social license. "Getting it right in terms of public acceptance is actually more important than technology itself," said Greg Guidry, executive vice president of upstream Americas for Shell. "If our activity is not accepted, frankly the technology doesn't matter."

Commenting on the reputational aspect, he added, "I can't think of any major incident in deepwater that wouldn't have a dramatic impact on what we do onshore, and I can think of a number of incidents onshore that would have an impact on the acceptance of what we do offshore."

Guidry went on to point out that specific technologies also don't always naturally transfer between different regimes such as these. "In terms of synergy of technology, there are certainly learnings to be shared, but in terms of being a laboratory one way or the other deepwater is an awfully expensive place to evolve onshore technology," he commented.

Torstein Hole of Statoil agreed there were lessons to be passed between deepwater and unconventionals, but that they might be better applied to processes such as safety and management techniques. Marathon Oil's CEO, Lee Tillman, admitted both were necessary to meet a projected 60% growth in energy consumption over the next three decades. His company is spending $3.6 billion on onshore unconventionals this year, for example—more than it spent globally (onshore and offshore) just six years ago.

He summed it up nicely: "Fossil fuels, and especially oil and natural gas, are going to remain the largest source of energy going forward. When you consider unconventionals vs. deepwater, it's not an 'either/or' proposition." E&P

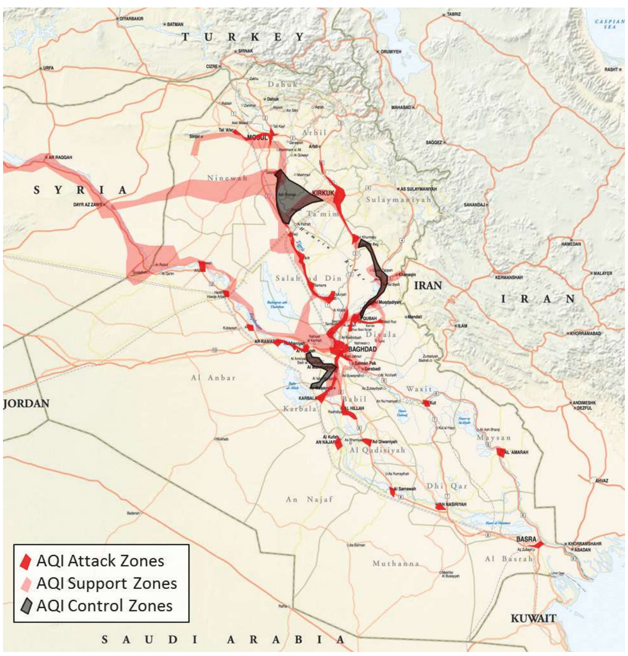
Iraq instability increases security, political risks

The conflict is far from over as disenfranchised Sunnis take their revenge on oil and gas assets.

Thomas Buonomo, Hart Energy Research & Consulting

After the withdrawal of U.S. military forces at the end of 2011, Iraqi Prime Minister Nouri al-Maliki quickly moved to consolidate his power, ordering the arrest of Vice President Tareq al-Hashemi on terrorism charges in December 2011, purging Sunni military and intelligence officers from the Iraqi security forces and replacing them with loyalists, and dispatching his security forces to detain Finance Minister Rafa al-Issawi's bodyguards in December 2012 in an act of political intimidation.

Hashemi fled the country and was sentenced in absentia to death by a judiciary heavily influenced by Maliki allies. Issawi, a high-ranking Sunni Arab official in a government dominated by Shi'a, resigned under pressure from his cabinet post, triggering largely nonviolent protests across Iraq's Sunni Arab majority provinces in the north-central and western regions of the country.



Al-Qaeda's foothold in Iraq is growing as some tribal leaders join the fray. (Source: Institute for the Study of War, November 2013)

In April 2013, Sunni Arabs held a demonstration in the town of Hawija to protest government corruption, lack of public services and their political marginalization. Iraqi security forces attempting to disperse the demonstration exchanged fire with protesters, resulting in nearly 50 deaths and contributing to a shift from nonviolent demonstrations to insurgency.

On Jan. 1, 2014, an estimated 1,000 to 2,000 militants seized control of parts of the Sunni Arab cities of Ramadi and Fallujah, the latter located less than 48 km (30 miles) west of Baghdad.

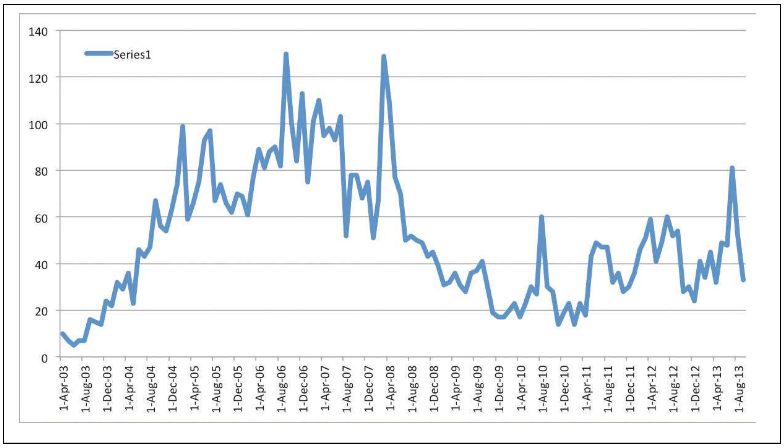
The Iraqi military has since established a cordon around the cities and is working with Sunni tribal leaders to eliminate them. The military is reluctant to get drawn into the urban fighting itself, and the U.S. has discouraged it from doing so out of fear that it will further inflame the situation by alienating the populace with harsh and indiscriminate tactics and possibly face strong resistance. The tribal leaders have divided sentiments; some are fighting on the side of the central government under the premise that they will be rewarded for their loyalty, while others are tactically allied with Al Qaeda and associated terrorist groups in an effort to overthrow the state.

Brett McGurk, U.S. deputy assistant secretary of state of Iran and Iraq, testified before Congress in February that the Iraqi military was unable to cut off the flow of militants from the west, many of whom are crossing the border from Syria, due to the inadequate armor of the military's armed air and ground forces as well as the advanced tactics of the insurgents. The Obama administration plans to send the Iraqi military more heavily armored Apache helicopters despite its wariness of the potential for their misuse against Sunni Arabs with legitimate political grievances or against Iraqi Kurds in the north, who have been contesting the central government for control of oil within their autonomous region.

The U.S. also is training Iraqi special operations forces in Jordan and providing counterterrorism support and technical advisory assistance to improve the security of Iraq's oil infrastructure.

Although few major attacks have been reported in the oil-rich southern provinces of Iraq, which are primarily

inhabited by Shi'a Arabs, the governor of Basra has hired Aegis Defence Services managed by the former British general who headed the occupation of the province from 2003 to 2007 to provide intelligence and security advisory services.



Insurgent attacks spiked after a rally protesting government corruption in April 2013. (Source: Iraq Body Count)

Risk outlook

The U.S. faces the dilemma of having to support an Iraqi government that has marginalized and abused its Sunni Arab minority while attempting to persuade it to bring the Sunnis back into the political fold—something it has thus far not demonstrated great inclination to do. There is a potential moral hazard in strengthening the central government with advanced weaponry—i.e., this may reduce its incentive to negotiate with its political opponents, driving them into a closer alliance with Al Qaeda-associated forces. On the other hand, if the Iraqi government does not receive what it wants from the U.S., other governments would be willing to step in.

An Iraqi military incapable of securing the government's writ over key territory, particularly oil infrastructure, would also lead to increased militant funding and activity from oil smuggling as well as the renewed growth of Shi'a militias, which killed thousands of Sunni Arabs per month at the height of the sectarian conflict in 2006 to 2007. This could lead Iraq's regional neighbors to increase their involvement in efforts to shape the political outcome through covert military support to the various armed factions.

Michael Knights, an Iraq specialist at the Washington Institute for Near East Policy, noted that Iraq has lost control of its border with Syria as well as two out of three of its major international trade and oil export highways—one to Jordan and the other to Turkey.

The Kirkuk-Ceyhan pipeline to Turkey, which exports about 20% of Iraq's crude oil production, has been cut north of the oil refining city of Baiji for more than two months, forcing Iraq's North Oil Company to shut down production stations at two oil fields in Kirkuk and reducing output from 500,000 bbl/d to 225,000 bbl/d. Repair crews have been repeatedly ambushed and prevented from fixing the pipeline despite having military escorts.

"The Baghdad government should understand this message: Stop spilling our blood and we'll stop attacking the oil pipeline," Abu Ammar, a Sunni tribal leader in Nineveh province told Reuters last year. "The Shi'ite government is killing and persecuting Sunnis in all parts of Iraq. As revenge we have to make the government suffer, and the best way is to keep blowing up the oil pipeline."

Thus far, however, they have demonstrated "almost zero capability" to reach into the target-rich oil-producing province of Basra since an attempt in 2004 to bomb its export facilities, according to Knights.

Whether Maliki wins a third term as Prime Minister will depend on how well he is able to repair his fraying relationships with the Shi'a political leaders in his coalition, whom he has ostracized by his increasing monopolization of power, as well as whether he can convince Iran that he will continue to show deference to its core national security interests—e.g. by continuing to turn a blind eye to Iran's weapons shipments to Syria via Iraq. It could take months in any case for Iraq to form a government.

If Maliki's Shi'a coalition fragments, he may resort to questionable legal and extrajudicial measures to maintain and strengthen his power as he has in the past. Knights described Maliki has having done a thorough job of "coup-proofing" his regime against the intrigues of Sunni leaders. A recent report from the Institute for the Study of War concurs that Maliki has purged most Sunni Arabs from the senior ranks of the military and intelligence officer corps and has established a parallel, informal chain of command within the security services that is staffed by trusted officials and commanders. He may not be so well-protected on his Shi'a flank, however.

Maliki's stacking of the political and security deck, intended to protect him from internal threats to his rule, may end up exacerbating political instability by convincing discarded officials and military and intelligence officers to plot against him in various ways including, in the case of the Sunnis, by supporting the insurgents in the west and north of Iraq as some are already doing. An increase in instability would spur Iran and Saudi Arabia in particular to intervene more aggressively behind the scenes. E&P

A new chapter for Ireland's offshore

Fresh partnerships have been formed to explore new acreage offshore Ireland. Is this—finally—the beginning of a more promising era for this previously underwhelming Atlantic Margin province?

John Bradbury, Contributing Editor

Exploration offshore Ireland is about to enter a new chapter with the award of new frontier exploration licenses (FELs) and the entry of some significant new players in the deepwater Porcupine Basin.

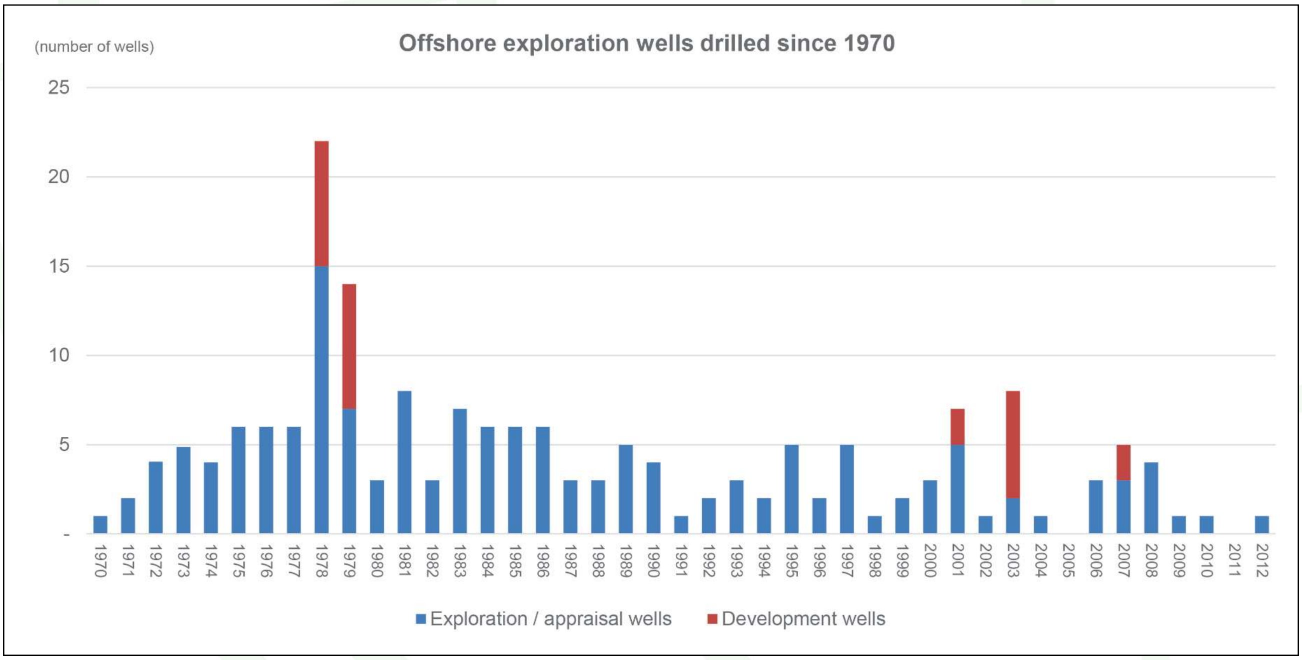
Irish independent Petrel Resources was recently granted two new FELs for the Porcupine Basin, 3/14 and 4/14, which cover 1,050 sq km (401 sq miles) out of 1,400 sq km (540 sq miles) originally allocated under previous licensing options (LOs) by Ireland's Department of Communications and Natural Resources in the 2011 Irish Atlantic Margin licensing round.

The new licenses run for 15 years with an initial three-year term followed by three further four-year phases.

Petrel, however, won't be tackling this acreage on its own. It agreed in June 2013 to farm out 85% equity in its LOs to Woodside Energy, through which Petrel is carried for the first three-year exploration term. This term involves reprocessing historic 3-D seismic data, environmental studies and potentially a new 3-D seismic sweep. The options cover LO 11/4, which includes offshore blocks 35/23, 35/24 and 35/25, and LO 11/6, comprising blocks 45/6, 45/11, 45/16 and 44/15.

Woodside's fresh ideas

A number of geological plays already have been identified on the acreage, justifying additional technical work, according to Petrel's managing director, David Horgan. "Our operating partner, Woodside, has brought additional ideas based on its technical expertise and past successes elsewhere," Horgan said. "The next phase of the work program is already underway." Last June Woodside also farmed in for a 90% equity in LO 11/3, comprising blocks 35/25(e), 35/30, 36/21, 36/26, 44/5 (part) and 45/1, encompassing a further 1,271 sq km (490 sq miles), with Petrel's Irish compatriot Bluestack Energy.



More than 200 exploration and appraisal wells have been drilled since 1970 offshore Ireland, but only 31 have been drilled in the Porcupine Basin, where Petrel's acreage is located. (Source: Irish Petroleum Affairs Division)

Woodside CEO Peter Coleman said at the time that the moves were a commitment to "pursue high-potential exploration opportunities that leverage its deepwater exploration and production capabilities."

Because the Irish offshore sector is still relatively underexplored, Horgan—a former CEO of explorer Pan Andean Resources—suggests that was one of the reasons that attracted Woodside to the acreage on offer. Another is the attractiveness of the fiscal terms.

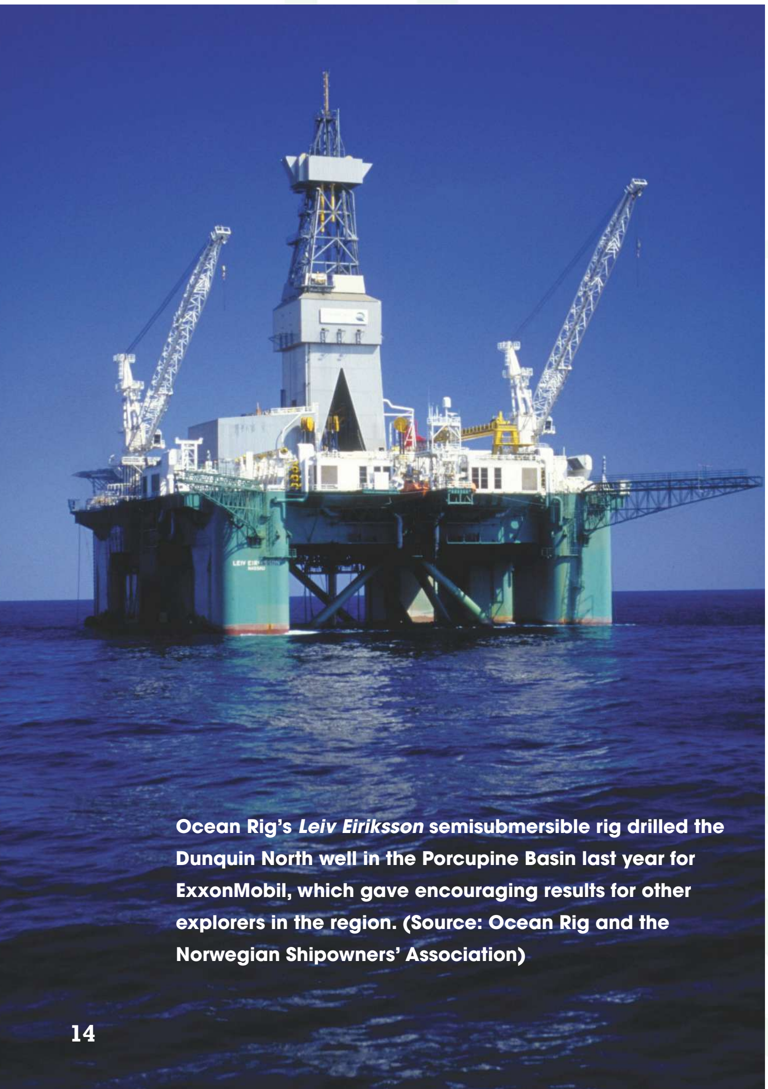
"The total number of wells drilled offshore Ireland is 158, of which 28 have been appraisals," said Horgan. However, those wells have been drilled in acreage covering more than 707,000 sq km (272,900 sq miles).

Porcupine Basin's 31 wells

"That is not a large amount," he added. "More than 100 of those wells were in the Celtic Sea [off southern Ireland in shallow water], and they were fairly shallow wells, up to about 3,810 m (12,500 ft). It is an area that is very, very sparsely drilled. But 31 wells have been in the Porcupine Basin, and all of those had oil and gas," he pointed out. These wells were drilled off Ireland's southwest coast in water depths of between 200 m and 2,000 m (656 ft and 6,560 ft).

Discoveries include Spanish Point, first found by Phillips Petroleum, 200 km (125 miles) offshore, as well as Connemara and Burren.

Further drilling on Spanish Point is due to kick off using the *Blackford Dolphin* semisubmersible rig operated by Cairn Energy in Quad 35 later this year after the Irish government approved Cairn's farm-in to FEL 2/04 with Providence Resources.



Ocean Rig's *Leiv Eiriksson* semisubmersible rig drilled the Dunquin North well in the Porcupine Basin last year for ExxonMobil, which gave encouraging results for other explorers in the region. (Source: Ocean Rig and the Norwegian Shipowners' Association)

Mixed views on Irish offshore

However, Horgan admits oil majors still have mixed views of the country's offshore sector, noting that Phillips and Marathon were both early explorers in the region. "In about 1985 the majors pulled back out again. They returned in the 1990s, but they have not been back since. More recently, the exploration terms have been dramatically improved: There is a 25% profit tax. You can write off any exploration costs, there is no royalty, no state 'back-in' and you have full depreciation [for capital assets]," he explained.

There is a "bonanza tax" for any megadiscoveries, which could increase tax to 40%. But oil prices remain steady, and there is an established Irish gas market and two interconnector gas pipelines to Scotland with a 4% premium to Scottish gas prices.

"This is the first time in 20 years that the Irish authorities have experienced real industry interest in the offshore sector," Horgan added.

In March this year Ireland's Department of Marine and Natural Resources appointed consultant Wood Mackenzie to advise the government on a new offshore tax regime.

Of Woodside, Horgan says they are "very, very good. They are all about how they operate. They take their time, and they will want to clarify everything."

He says the Irish energy minister has already committed to converting 12 of the 13 LOs awarded in the 2011 Atlantic Margin round to FELs. Accordingly, Horgan fully expected his company's two LOs to be converted to FELs when he spoke to *E&P* earlier this year.

However, after major changes in the Irish civil service (which saw a lot of experienced personnel leave), that process took several months longer than expected, although those FELS were eventually converted.

First exploration phase

With those FELs granted and the Woodside farm-in approved, Horgan said there will now be a first exploration phase of three years with existing seismic data to be reprocessed and new data acquired. "Most of the custom data are from the early 1980s. The seismic shows very little chalk, and the definition is very good, and there are some speculative 3-D data. The acquisition is very good, but the interpretation of spec 3-D is bad," he said. The company has already reprocessed some data. "But we expect Woodside to reprocess it again," he said. "There will be [the] purchase of additional data, and we expect further seismic acquisition in due course."

In the follow-up exploration periods for each license a well is expected to be drilled in each period. Given the water depth of the Petrel/Woodside acreage, ranging from 700 m to 800 m (2,300 ft to 2,624 ft) in LO 11/4 and up to 1,000 m (3,280 ft) in LO 11/6, a high-specification semisubmersible rig or drillship will be required to cope with greater wave frequencies and the likely wave heights in this harsh-environment region.

Petrel reckons its Quad 35 area has a potential 1 Bbbl in place, with stacked targets at Eocene, Lower Tertiary, Lower Cretaceous and Jurassic levels. It also anticipates stacked targets in Quad 45, where it has identified Lower Tertiary and Lower Cretaceous levels of interest after studying previous 2-D and 3-D data and conducting a petrophysical appraisal of 17 previous wells.

Dunquin North boost

The outcome of ExxonMobil's Dunquin North well—drilled in July 2013 by the *Leiv Eiriksson* semisubmersible—hasn't harmed prospects for the area as it encountered 44 m (144 ft) of residual oil shows and 244 m (800 ft) of carbonate. "It was an enormous plus for us," Horgan said. "This is the first well that proved that there was not just gas but also oil generation. It enormously eased the task of farming out 11/6. I've heard that the Dunquin well cost about $200 million. I would like to know the age of the rocks, but ExxonMobil have kept it very tight," he said. "Technically it was a very, very good success."

However, he believes Woodside may also have its own ideas about the region's prospects. "It is clear that they have their own particular model to roll out," he said. "I would be amazed if they did not drill several wells."

Another Irish Atlantic Margin exploration round also is due to close in September 2015. Full details will be released following the review of the existing fiscal regime later this year. E&P

New approach to training

Effective e-learning must take advantage of all that technology has to offer.

Rhonda Duey, Executive Editor

Computer technology often advances faster than our mental ability to imagine the new opportunities it provides. It took the exploration industry awhile to realize that digitizing their work meant more than transferring their colored-pencil drawings to a computer monitor. And it has taken training companies awhile to move beyond the "manual in a monitor" to harness the power of these machines to help people learn more quickly and thoroughly.

The concept of "e-learning" has become popular in the oil patch, and countless geoscientists and engineers have logged into their systems to take the required training. But the ability of computer software to provide animation, voice-overs, enlargements and simulations is increasingly being used to not only tick the training box but deliver more effective ways to educate.

Kevin Keable is the founder of Oilennium (now part of Petrofac), a company that has specialized in oil and gas training since its inception. "If you mention our name to people, they'll say, 'Oh, yeah—they're an e-learning company,'" Keable said. "But really our specialty is taking any subject matter and turning it into something that's easy to learn and easy to remember. It doesn't matter if the delivery is online or classroom-based—turning it into effective learning is what's important."

Keable said that the use of graphics and animation is at the heart of this strategy. "Most of the downhole tools that you see look the same from the outside," he said. "We take them apart and animate them so learners can really get to grips with what's going on inside." The company also builds simulators with which students can interact. "If people learn in an easier fashion, they tend to remember those pictures and interactions more than if we just tell them the information."

Taking it to the field

While many companies take advantage of Internet-based training, connections can't always be trusted in remote locations and offshore, "which is where most of the oil and gas is found," he said. Oilennium has come up with mobile solutions such as small servers or memory sticks that don't require an Internet connection but are still able to deliver high-quality, graphic-heavy modules. Quite soon these training modules will be available on tablets and smartphones, too.

One of the key benefits of e-learning is the number of people who can be trained. Keable said that one set of courses was implemented about a year ago within one specific company and allocated to about 1,000 employees. "Within three months 14,000 people had logged onto it because it was so good, and it was freely available," he said. "To train 14,000 people in a classroom at the rate of one class per week would be a 20-year, multimillion-dollar project. We did it in three months for less than $10 per person."

These types of trends, he added, mean that learning can be made available to many more people. Client demand also is pushing a move toward analogies, scenarios and simulations. "In the past e-learning was simply putting text on screen," he said. "You could put a presentation online, so companies did just that. But there's no real teaching in that. People just read it, so they may as well have been given a manual.

"This new trend is all about teaching people new information in a way that's fun and easy to learn and getting it to stick in their minds." Relevant analogies, good graphics, repetition and great questioning are the important factors in retaining knowledge, he added.

Off to the theater

In addition to these interactive types of training modules, some training companies are moving toward dramatic films and even live theater to get their point across. While this hasn't yet been thoroughly embraced by the oil industry, these types of training exercises can be hugely beneficial when it comes to behavioral issues like safety training.

"Training for skilled and semi-skilled workers is where we need to make some dramatic changes," Keable said. "Behavioral safety training is where you can get real engagement, get learners to understand the true consequences of their actions. If you or a colleague gets hurt or worse, what effect will that have on your family?"

While using this type of training can be challenging because the films are quite hard-hitting, Keable noted that one of the films he watched recently actually had a profound effect on his own behavior, even after 30 years in the industry. "It was because of the potential consequences on the family," he said. "That was the thing that got me, so I

modified my behavior, drove more carefully and watched out for others more closely."

Keep it simple, stupid

Making a difficult concept easier to understand might sound less onerous than the opposite, but it requires a certain skill set. "Imagine trying to explain deepwater drilling to someone—over the telephone," he said.

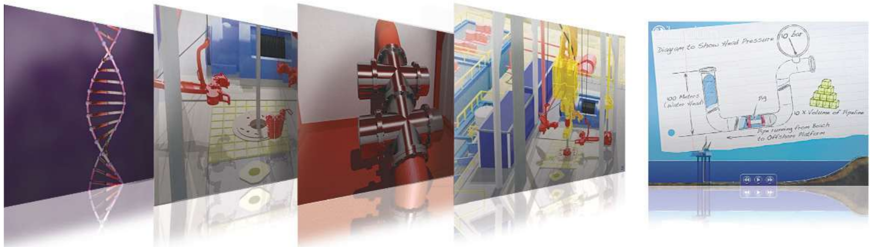
Keable has a well-established routine to train new recruits. Before employees are even hired they are asked to take a creativity assessment. If they pass this test and are subsequently hired, they are immersed in a three-month intensive training course. "They don't do any paid work in that time; it's all training," he said. "But we're a training company, so that's easy. The training doesn't stop there. We run at least one training course per week and are constantly reviewing one another's work."

So far, the system has been foolproof. "We've seen a spark of creativity in them, so we develop and enhance that," he said. "It's common for our staff to be requested to stay on a particular client's project. In fact, one recent hire, who is only 22, impressed a major drilling contractor enough with his technical project that the company wants to use him from now on."

Another successful project that relies heavily on simulation is a pipeline pig launcher. Keable said that students have to follow all of the steps of opening and closing valves in the correct sequence in the virtual space. It tracks their mistakes and gives feedback, so if they overpressure the equipment, something's going to blow. It's noisy and very realistic. "If you do it correctly, it will allow you to launch the pig into the pipeline," he said. "That sort of thing is so close to real-life operations that you really can teach people all of the elements of that operation short of getting their hands on a valve and operating it themselves."

Competence

Keable noted that the move toward "competence" has had a tendency to backfire in certain segments of the industry due to the lack of understanding and overly complex



E-learning training modules combine the best computer technology with modern teaching techniques to help employees better retain knowledge. (Source: Oilennium)

nature of some systems. "My personal opinion is that there can never be one real industry standard," he said. "Some parts of the industry and some people need more competence assessments than others." The main problem with this sort of process is that it can become so detailed and, therefore, time-consuming that people are never proved competent. "Competence is a growing requirement, and I think the industry needs to work hard to understand exactly what form it should take," he said.

The post-Macondo Big Crew Change upstream world also needs to focus more on its hands-on employees, who may get a lot of compliance and safety training but not much actual training in what they need to do their jobs.

"The graduate programs are good," Keable said. "Geophysicists receive very good training in universities. But the mid-level technicians need more training in what they do."

Computer technology, tablets and the Internet will continue to evolve faster than humans can keep up. But training investment needs to keep pace as best it can.

"For now, the investment in training should be in understanding the psychology of training and the practical requirements of ensuring that people are competent, putting more emphasis on better training rather than using computers just for the varied forms of delivery technology," Keable said. "How do you train people more cost-effectively to do the job that they are expected to do and enhance performance? That's where I would concentrate my efforts." E&P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Unconventionals boost artificial lift

Experienced labor can't keep up with demand for artificial lift services.

Richard Mason, Chief Technical Director

Sometimes it takes more than bootstraps when it comes to lift, and that's good news for the onshore artificial lift business. Two-thirds of respondents in a mid-April Hart Energy survey cited increasing demand for artificial lift services in a sector that would grow faster yet were it not for shortages of experienced labor.

The driver in artificial lift is the same as what's driving everything in oil and gas: rising demand in tight formation development, particularly in the Permian Basin; the Midcontinent; and the Niobrara, Bakken and Eagle Ford shales.

Currently a majority of that demand focuses on electric submersible pumps (ESPs) both onshore and offshore. ESPs are the primary choice in a majority of circumstances unless well production is low. In that case, customers are opting for gas lift, which is described as more efficient. In areas like the Permian Basin, customers are trying both ESP systems and surface lift systems with jet pumps.

The debate between surface systems and ESPs is robust. Proponents for ESPs argue that surface systems are best in specific applications only and can be inefficient. ESPs offer versatility with a wider range of variable speed controls, the argument goes, and can be designed for larger volumes. On the other hand, competing vendors note that ESPs are prone to plug up or suffer sand damage without any cost advantage for the customer.

In general, customers find ESPs best suited for high flow zones. Gas production systems mostly employ artificial lift for dewatering purposes. And gas lift is described as particularly effective in oily regions with low oil flow but sufficient reservoir natural gas, according to survey respondents.

- **Rising well count driving demand for artificial lift**
- **Lead times for installation expected to lengthen in 2014**
- **Rented artificial lift systems now used in flowback**
- **ESPs command greatest market share**
- **Skilled personnel shortage restricting growth**

Artificial lift systems have become part of the completion process for customers in unconventional basins and are installed immediately after hydraulic fracturing to aid flowback, then adjusted for permanent configuration.

"Artificial lift for flowback is usually rented for two to three months, and then a permanent system is designed for the well after initial production levels off and the well averages are known," said a mid-sized service provider and system manufacturer in the Rockies.

"We use ESP systems to handle the flowback and then test well production to determine what submersible pump to change to for the permanent system," a Texas manufacturer told Hart Energy.

Currently, lead times for onshore systems average less than three days onshore and less than 30 days offshore. But equipment providers told Hart Energy that rising demand in a growing market and a shortage of experienced personnel will prompt lead times to lengthen in 2014.

"Demand has outstripped the available experienced personnel, restricting growth," a mid-sized Texas manufacturer told Hart Energy.

One Rocky Mountain-based manufacturer cited implementation of additional training programs for employees to expand the firm's ability to meet growing demand.

Manufacturers participating in the survey outlined demand in various ways. Two of nine respondents said that 90% of all wells require artificial lift systems today. Three other respondents pointed to the use of artificial lift in the flowback stage adding incremental demand as well.

"Newer technology keeps improving the systems," said a top-tier Texas manufacturer. "Everyone wants better production, and that drives demand. We are currently doing $700,000 to $1 million per month just in Texas with artificial lift. We are booming."

Demand has increased in liquids-rich plays as operators attempt to maximize liquids output before production decline occurs. Operators also are installing gas lift systems in natural gas wells or using ESP systems for dewatering to increase gas production.

Pricing varies, but representative ESP systems are running about $100,000 per installation for standard configurations and $150,000 per installation if a customer needs slimline equipment for smaller casing sizes. E&P

Triton brings it all together

Ambitious survey is the first to combine so many new technologies in one multiclient survey.

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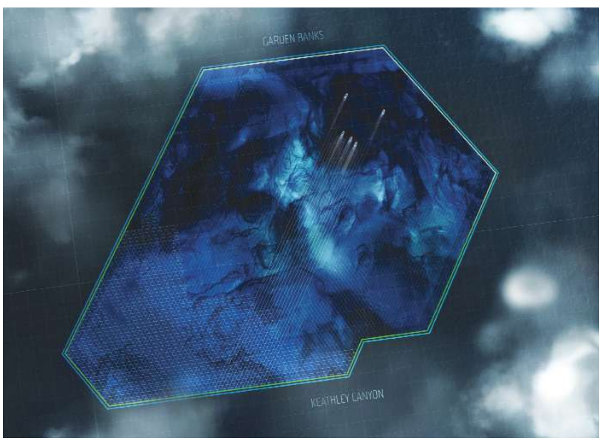
EPmag.com

Triton was a Greek god and the messenger of the sea. Like his father Poseidon, he carried a trident. This three-pronged spear provided the inspiration for one of the largest and most ambitious multiclient surveys ever conducted.

PGS embarked on its MultiClient Triton survey last November with the plan of surveying some 390 blocks in the Gulf of Mexico (GoM) Outer Continental Shelf over an area that covers approximately 10,000 sq km (3,861 sq miles). Encompassing areas in the Western and Central GoM planning areas, the survey will examine parts of Garden Banks and Keathley Canyon.

PGS is pulling out all of the stops on this survey. Taking advantage of several breakthroughs in marine seismic acquisition technology over the past few years, the survey will acquire full-azimuth (FAZ) data while adding numerous technology advances to the mix, including its proprietary GeoStreamer receivers. "There are uplifts in dozens of places," said Steven Fishburn, vice president of business development for GoM, PGS.

The survey marks a number of new technologies that are being merged to image this extraordinarily complex area of the GoM. Several recent discoveries, including North Platte in Garden Banks Block 949 by Cobalt and Gila in Keathley Canyon 93 and Tiber in Keathley Canyon 102, both by BP, have highlighted the need for clearer imaging under the salt. And in the interest of repeat data licensing, this area is facing serious license expirations—55 leases will expire in 2016, 67 licenses will expire in 2017, and 71 licenses will expire in 2018.



PGS' Triton survey combines several breakthroughs in marine seismic acquisition. (Source: PGS)

Planning the survey has consumed two years and a lot of R&D and modeling. The company has tried various geometries and has conducted intensive pre-survey modeling to ensure sufficient illumination below the salt. The result is a specially tailored plan involving two high-capacity streamer vessels towing 10 8-km (4.9-mile) GeoStreamer dual-sensor cables in combination with three independent source vessels in a simultaneous long-offset configuration, achieving offsets of greater than 16 km (9.8 miles). The configuration is proprietary to PGS and is known as "Orion," replicating the two "shoulder" stars (the source vessels) and the three "belt" stars (the receiver vessels) of that familiar winter constellation.

The GeoStreamer dual-sensor streamer technology provides deghosted data much richer in high frequencies as well as in the lower frequencies. Fishburn said that the system can record useable seismic energy as low as 2 Hz to 3 Hz.

Additionally, the Triton survey is being acquired in three directions to provide the FAZ coverage crucial to move subsalt imaging to the next phase of advancement. By providing illumination from every angle, FAZ surveying can provide clearer images in a notoriously difficult area to image.

Long offsets and high fold add to the unique acquisition design, and processing advances will combine tilted transverse isotropy and reverse time migration to take full advantage of the more robust dataset.

"All of these technologies have impact," Fishburn said. "But this is the first time they've been brought together." E&P

Hydraulic fracturing edges up seismic scale, shaking up regulators

Ohio is one of five states that are the driving forces for creating a work group to proactively discuss earthquakes attributed to injection wells.

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EPmag.com

The epicenter of the arguments over induced seismicity from wastewater injection wells and now hydraulic fracturing has shifted from Oklahoma to Ohio. The Ohio Department of Natural Resources (ODNR) investigated five small tremors in March in the Youngstown, Ohio, area of the Appalachian foothills and found a "probable" connection between hydraulic fracturing near a previously unknown fault and the tremors in the Utica Shale.

ODNR issued new permits regarding hydraulic fracturing in areas of known faults or past seismic activity. Under the permits, horizontal drilling within 4.8 km (3 miles) of a known fault or area of seismic activity greater than a 2.0 magnitude would require companies to install seismic monitors. If those monitors detect a seismic event in excess of 1.0 magnitude, activities would pause while the cause is under investigation, according to an April 11 ODNR press release.

If the investigation reveals a probable connection to the hydraulic fracturing process, all well completion operations will be suspended. For the company near Youngstown, additional hydraulic fracturing at the site is suspended, but the company will be allowed to produce from five of the previously drilled wells located on the pad. The department will review previously issued permits of other companies that have not been drilled.

In Ohio, horizontal drilling within 4.8 km of a known fault or area of seismic activity would require companies to install seismic monitors such as these. (Source: Wireless Seismic)

"While we can never be 100% sure that drilling activities are connected to a seismic event, caution dictates that we take these new steps to protect human health, safety and the environment," said James Zehringer, ODNR director.

This most recent flurry of seismic events led to the formation of a work group that will proactively discuss the possible association between those seismic events that occurred in multiple states and injection wells.

The Interstate Oil & Gas Compact Commission (IOGCC) and the Ground Water Protection Council are partnering with state oil and gas regulatory agencies and geological surveys in the Induced Seismicity by Injection Work Group.

Gerry Baker, IOGCC associate executive director, said the group would be a clearinghouse of information to better understand the nature of these occurrences. The chairman of the group is from Ohio.

The working group hopes to draw upon current and future research to develop common procedures for how to monitor seismic activity and respond if activity occurs. The work group product will be more knowledge, Baker explained. "Regulators want to know what is going on in other states and what they can do to improve their own regulations. We want to share what is going on in the regulatory community, and that is what we are trying to create."

The group is seeking other stakeholders from the industry, environmental groups and the scientific community. It will help keep the oil and gas industry off shaky ground. E&P

Scott

A biocide worth its salt

'Simple' solution offers safe, green alternative to conventional biocides.

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EPmag.com

There are lots of uses for ordinary table salt. You can remove wine stains from carpet, water rings from wood, light rust from tools, etc. But one company has found a way to use it to safely remove harmful bacteria from produced water in hydraulic fracturing operations.

When you consider the sheer volume of water needed for fracking operations and the significant scope of cleaning needed to decontaminate produced water for reuse or recycling, you start to see dollar signs adding up.

According to Charles Mowrey, director of business development in oil and gas for MIOX, that is not the case with MIOX's oxidant generators. They dispense its bacteria-disinfectant chemistries using only salt, water and electricity.

MIOX uses an electrolytic cell to create sodium hypochlorite (hypo) or a mixed oxidant solution (MOS) from the water and salt. MOS is simply hypo and peroxide. The solutions are ready for use after electrolysis occurs in the cell.

"It is very elegant and simple in my opinion, but there's been 18 years of science really put into this," Mowrey said. "MIOX is able to put more energy into the solution so we actually liberate not just chlorine but also hydrogen peroxide, and we do this very, very efficiently, using the least amount of salt and the least amount of power possible."

This MIOX Blackwater unit can reside onsite and leave a footprint of no more than 3 m by 12 m (9 ft by 40 ft). It uses MOS chemistry to kill both sulfate-reducing bacteria and acid-producing bacteria. (Source: MIOX)

This simplicity is what makes MIOX's water-treatment chemistry less expensive and safer for the environment and those that work with it, he said. It requires no Hazmat reporting.

"You can put your arm in this and it's not going to burn you. You can just wash it off with water," he said. "If it spills, it's not going to hurt anything. This really is one of the rare cases where safer can actually be lower cost."

MIOX can treat 20,000 bbl/d to 100,000 bbl/d of produced water with its Blackwater unit, he said. Blackwater, which is essentially the MIOX water-treatment technology in mobile form, uses the MOS solution and, depending on the application, can run automatically without needing to have a dedicated person working with it onsite. It creates disinfectant when it's needed and in the amount that's needed, Mowrey said.

"Conventional biocides are literally poisons; they poison the bacteria to kill them, and the bacteria become resistant to them over time, causing super strains," he said.

MIOX's MOS, however, completely kills virtually all acid-producing bacteria and sulfate-reducing bacteria without giving the bacteria a chance to become immune to the chemistry or feed off it and morph into a much larger problem.

As operators continue seeking new technologies and ways to reduce their environmental impact, they should consider the replacement of harmful biocides. After all, why create mutant bacteria and put your people and environment at risk when a little table salt might do the trick? E&P

New ‘workhorse’ set to sail in 2016

Subsea 7’s *Seven Arctic* is set to make an impact in subsea construction projects as the newest heavy construction vessel in the company’s fleet.

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As subsea production installations continue to move into deeper waters, the need grows for larger vessels capable of efficiently transporting and installing the systems. Douglas-Westwood—in its *World Subsea Vessel Operations Market Forecast*—forecast $106 billion in expenditure on subsea vessel operations between 2013 and 2017. This forecast is 54% higher than the preceding five-year period. The company sees a move in the market toward higher specification vessels to cater to the deeper and more complicated field development programs.

“Subsea development will continue to account for an increasing share of global offshore activity,” said Thom Payne, a Douglas-Westwood manager. “With the move to deeper waters, the requirements for vessels for a longer duration on site and with higher specifications are increasing.”

One such vessel is set to take the stage in 2016 with its launch from the Hyundai Heavy Industries Shipyard located in Ulsan, South Korea. At that time Subsea 7 will add the heavy construction vessel (HCV)—the *Seven Arctic*—to its fleet of 40-plus vessels.

The *Seven Arctic* will be the “workhorse of our fleet,” according to Stuart Smith, Subsea 7’s vice president of technology and asset development. Designed to address the operational challenges for subsea construction in ultradeepwater and hostile environments, the vessel will bring new capabilities to the market.

In addition to being equipped with a 7,000-mt Maats underdeck basket for flexible pipe/umbilical storage, a 325-mt top tension Huisman Vertical Pipelay System and a new design 900-mt Huisman rope-luffing knuckle-boom crane, the new HCV also offers increased deck space, higher deck load and faster transit speeds.

The *Seven Arctic’s* main crane is an active heave-compensated subsea construction crane capable of working in several different modes. (Source: Subsea 7)

According to the company, the crane design maintains knuckle-boom functionality for offshore construction activity but overcomes the weight penalty and impact on ship stability associated with conventional knuckle-boom crane designs. This results in a crane with great versatility and efficiency that can be used in 300-mt, 600-mt or 900-mt lift modes. Advancements in both ship and crane design are expected to increase the vessel’s overall cost effectiveness.

“With just the amount of equipment we will be able to get on deck—at 4,000-odd [metric] tons—means that customers potentially need fewer mobilizations for a particular scope of work, reducing the number of transits they have to do,” Smith said. “Also, our speeds are a little higher, so if they have a long transit to do, they can do that a lot quicker, and that saves on day rates.”

David Mair, the company’s group vice president of business development, added that “with the range of activities that we’ll be able to do with a vessel like this, it will fit nicely in a whole basket of different projects. It will be a useful addition to our portfolio and, therefore, we can expect to be using this vessel for a good number of days every year. That in itself can meter a more cost-effective rate per day for the vessel. If we can bring that down, then cost effectiveness for our clients naturally becomes a part of that.” E&P

Jennifer

Completion technology evolves to impact efficiency, effectiveness

Whether it is deepwater wells, shallow-water completions or onshore shale plays, the issues driving current development are simplicity and integration.

The learning curve for the oil and gas industry is steep and fast. In less than six years, the shale boom has seen the Bakken play top 6 Bbbl of oil. The evolution into the intelligent completion of the future will be an integrated solution that goes from the downhole hardware through the production infrastructure all the way to the desktop.

Whether it is technology for deepwater completions, redesign of completions in horizontal wells or new christmas trees for hydraulic fracturing and shallow-water wells, the industry is looking for ways to improve.

For example, operators must decide whether refracturing a well will be a viable and economical option. As part of the evolution of completion technology, operators must concentrate on finding wells where the completion quality was not optimized. Improved recovery can be gained from recompleting conventional wells. Refracturing existing wells costs a fraction of what it costs to drill new wells.

There is even more emphasis on well integrity in the deepwater Gulf of Mexico (GoM) after the Macondo disaster. U.S. Department of Energy's National Energy Technology Laboratory is working to unravel how foamed cement impacts well integrity in deepwater wells. A team was formed to conduct a thorough assessment of the research needs of the current state of knowledge regarding deep offshore cementing. As a result of the study, five research areas were identified for further analysis.

Christmas trees for offshore and onshore completions also are evolving to meet industry demands. Even though a lot of money is being spent on deepwater development in the GoM, the industry is turning its attention to shallow water on the outer continental shelf. A new generation of diver-assisted trees has been designed specifically for subsea development by jackup rigs.

With the increased use of hydraulic fracturing, trees are also evolving. Increased safety and reduction in the height and weight of frack trees has also led to lower costs.

Finally, intelligent completions have come a long way since their inception in the late 1990s. New systems are experimenting with electronics and fiber optics to avoid the wellhead complexity of hydraulic lines.

E&P's senior editors have compiled the latest technology in the latest evolutions of completion systems. ■

Refracturing the right wells could increase ROI

Unconventional wells may have more life to live than previously thought.

Amy Logan, Senior Editor, Production

It's never easy to admit that a well was not fully optimized the first time it was completed. As production drops off in wells with hydrocarbon reserves still *in situ*, operators must decide whether refracturing the well is a viable and economical option.

"It's hard to expect anyone to shut down a well and refracture it," said Francisco Fragachan, director of marketing and sales for Pressure Pumping at Weatherford. "It could be considered a high risk. That's why we're going to concentrate on wells where the reservoir quality is there, but the completion quality was not optimized. For the time being, we must gain more experience, and our clients must become more confident in the technology."

According to Juan Carlos Flores, product line manager for restimulation services and multistage completion and production systems at Baker Hughes, steep production declines characterize today's unconventional shale wells, which typically produce only 3% to 8% of the estimated reserves after the initial completion. The industry is familiar with the improved recovery that can be gained from recompleting conventional wells, but Flores said it wasn't until recently that operators started considering refracturing their unconventional assets as well.

"Right now, unconventional decline curves are reaching, on average, 85% in about three years," he said. "With the focus on short-term return on investment [ROI] and low-cost completion design, most of the hydrocarbons are left in place. Once initial production rates drop, the well is shut off and a new one is drilled."

However, this practice of shutting down an unproductive well and moving on to drill a new well instead is not always the best answer, Flores said.

"The focus should be on creating more effective wells that offer operators increased ultimate recovery," he said. "We know that refracturing can restore and even surpass initial production, and the same well can be rejuvenated several times—maybe five times or more based on what we've seen in the conventional space," he said. "This will require completion programs designed to sustain the entire unconventional production life cycle."

In a Northeast U.S. shale play, Weatherford returns to an unconventional well that has been determined to be a good candidate for a refracturing operation. (Source: Weatherford)

Determining feasibility for refracturing

It's important to understand that each well is unique and there is no "one size fits all" solution for improving oil recovery now or later, Flores said.

"Working with the operator up front to analyze the economics and understand the reservoir is a critical part of the process," he said. "The intervention has to be tailored to that well, so we need to have an extensive understanding of its performance, drilling and completion history, and reservoir characteristics. With this information we can generate predictive modeling that helps us visualize and estimate the potential return from each zone and further customize the refracturing program to best suit the operator's objectives.

"This is a different approach than just picking out a gadget at a hardware store," he added. "We want to understand the needs of the customers and work closely with them to determine the optimal solution based on a carefully planned, data-driven approach."

Fragachan said communication was crucial and that operators should understand up front that not all wells can be successfully refractured and recompleted.

"The first thing we do is ensure the well is a candidate and make sure refracturing it makes sense," he said. "We first select candidates that have good reservoir

quality and reserves. Second, we consider the diversion possibilities during fracturing treatments. There must be an opportunity for improving the efficiency of the completion."

Before fracturing the new zone, the producing zone must be plugged back, he said. With the right technology and process, the plugged zone can eventually be unplugged. The previous production can be combined with production from the newly fractured zone and can increase the overall production rate of the well, sometimes significantly. However, refracturing a well is a delicate operation that has to take natural reservoir heterogeneities into consideration, Fragachan said.

"Once you initiate a hydraulic fracture with multiple entry points, the fracturing energy tends to travel in the path of least resistance," he explained. "So once a fracture has been initiated at an entry point, it is very difficult to divert the energy to initiate a fracture into another entry point."

In fact, he said diversion is the primary challenge to adequate fracturing; it is what makes the candidate selection process so important, and it explains why not all wells will make good candidates for refracturing operations.

Realizing the ROI

Production across horizontal wellbores varies widely by fracturing stages, Fragachan said. "One of the first papers that caught our attention stated that 80% of production comes from only 20% of fracturing stages," he said. "That is obviously not ideal. There were also papers that stated between 30% and 40% of perforation clusters do not contribute to production. So we began to look at that and understand why that is."

Fragachan said Weatherford will publish two papers with the Society of Petroleum Engineers on recent refracturing successes in the Northeast area of the U.S.

"We went back to a well originally fractured in 2008 that was a good candidate for a refracture," he said. "The old perforation clusters had to be effectively sealed with a nondamaging, reliable system before we could perforate new zones. The well was basically treated in six prefracture batches, temporarily sealing 26 existing perforation clusters before we fractured 24 new perforation clusters."

The downhole pressure signature allowed the Weatherford team to understand what was happening in the well, he said. "We basically shut each of the existing perforation clusters down one by one and then initiated and fracked each of the 24 new clusters, diverting from one stage and from one perforation to the other," he said. "Then, at the end, we had the ability to put the well back into production—with all 50 clusters producing. That was important."

Fragachan said that ability to refracture a well and have it produce significantly better than before has made a good ROI case for operators who might have been hesitant about the practice in the past. He added that "anything above 20% is significant." "It's called 'refracture' actually perhaps incorrectly," he said, "because we're not actually fracturing into an existing fracture. We're entering into a horizontal section of a well—a new unfractured formation that is in contact with the well—and adding production within that new stage."

Ready, set, refracture

As the industry begins to realize the benefits of improved production and overall economics associated with refracturing, the practice is likely to gain more traction in the industry, Flores said. Refracturing existing wells costs a fraction of what it would cost to drill new wells, he said, and the opportunity goes beyond the wells that already exist. E&P


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Advancing the knowledge of wellbore cementing practices

Review of wellbore cements and cementing practices leads to technological advances.

Jennifer Presley, Senior Editor, Offshore

Perhaps the only thing more boring to watch than paint drying is cement curing. It is a slow process to observe with the naked human eye as all of the really interesting action is happening at a microscopic level. But how does one know when the curing is complete or if it is where it should be? Or how high temperatures and pressures may impact the stability of the cement?

On the Earth's surface, it is easy to spot if the cement is in the right place or to make the necessary measurements to determine if it has set up properly. But taking those measurements and monitoring the emplacement of wellbore cement hundreds or thousands of meters downhole? That's a far trickier process and one that researchers at the U.S. Department of Energy's National Energy Technology Laboratory (NETL) are working to unravel.

Setting a knowledge baseline

Wellbore cement integrity is critical to the safe and successful drilling and production of hydrocarbons from wells. As more and more wells in the Gulf of Mexico (GoM) are being drilled in increasingly extreme environments—water depths greater than 2,743 m (9,000 ft) to subsurface targets in excess of 6,096 m (20,000 ft)—concerns regarding the cement barrier in the wells have also increased. Subjected to a variety of temperature, pressure, *in situ* and formation conditions, the integrity of the cement over the lifetime of the well has generated many questions. The *Deepwater Horizon* incident brought many of these questions to light.

To find answers to these questions and to determine where knowledge gaps exist in the state of knowledge on wellbore cementing, researchers at NETL conducted a six-month review of cementing practices and conditions of offshore wells.

Following the *Deepwater Horizon* spill, "The explosion and subsequent environmental disaster made everyone readily aware of the significant research needs with respect to wellbore integrity in the Gulf of Mexico," said Barbara Kutchko, research scientist in NETL's Office of Research and Development. Based on that event and the preliminary findings of the Ocean Energy Safety Advisory Committee, an industry regulatory nonprofit advisory group led by the Department of Interior, NETL "formed a team to conduct a thorough assessment of the research needs of the current state of knowledge regarding deep offshore cementing." The assessment was accomplished by interviewing industry experts and conducting an extensive literature review. Industry experts came from a variety of major oil, gas and service companies and members of the American Petroleum Institute, Society for Petroleum Engineers, International Association of Drilling Contractors and Drilling Engineering Association.

From that review, five research challenges were identified:

- Developing new wellbore integrity monitoring;
- Understanding cement stability in field conditions;
- Ensuring quality control;
- Understanding the impact of temperature- and pressure-induced stress; and
- Improving standard calculations.

These five challenges are the focus of R&D efforts currently underway at NETL with partner universities and industry collaborators from across the U.S.

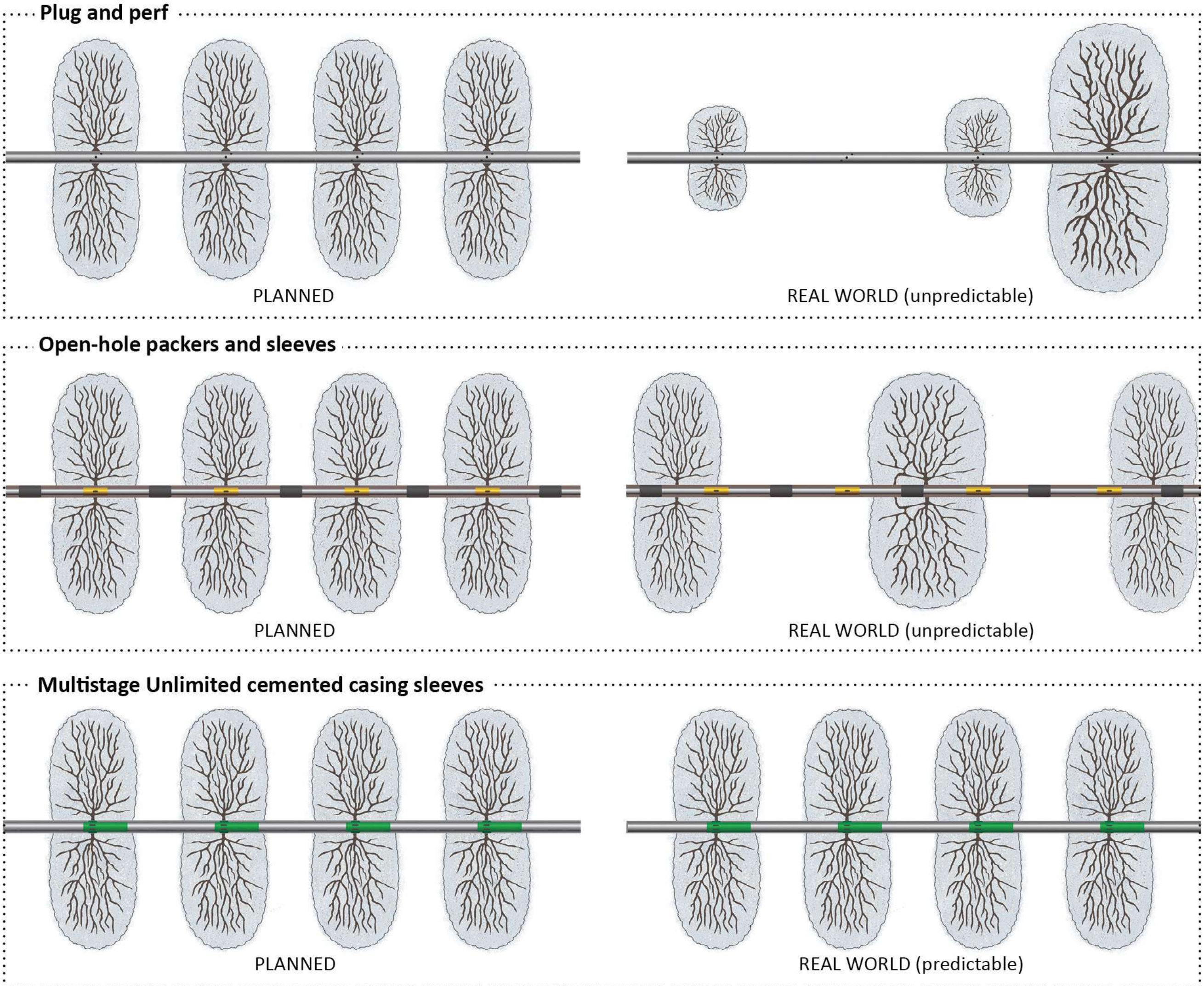
Tackling the challenges

Efforts are currently underway at NETL to address the challenge of understanding cement stability in field conditions. Currently, foamed cement is the system of choice in the high-stress environment of the GoM, in shallow flow environments, and increasingly in deepwater and ultradeepwater wells, according to Kutchko. However, knowledge about the behavior and performance of this cement under *in situ* conditions is relatively sparse.

Foamed cement is a gas-liquid dispersion that is produced when an inert gas like nitrogen is injected into conventional cement slurries to form microscopic bubbles. It is used in formations that are unable to support the annular hydrostatic pressure exerted by conventional cement slurries. Being lighter in weight and more resistant to temperature- and pressure-induced

The moment of truth:

Where do your fracs (and your well investment) go?



Plug-and-perf simply cannot deliver predictable frac results, and neither can open-hole packers and ball-drop sleeves. But, Multistage Unlimited single-point injection ensures that fracs initiate right where you plan them and proppant volume in every frac is exactly what you want. Cemented, full-drift casing sleeves deliver precise frac location, and frac isolation on coiled tubing provides real-time frac-zone pressure to help you control proppant placement and frac growth on every stage. Learn more about achieving the most efficient field frac network at ncsfrac.com.

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stresses and having superior fluid displacement have helped to make foamed cement systems a popular choice.

But their increased use has made understanding stability in the wellbore environment vital. For example, gas can coalesce and cause gas pockets to form and rise in the cement column if the foam cement is unstable. Unstable foams can, according to Kutchko, result in failure to achieve zonal isolation. A stable foam will be able to provide the desired zonal isolation when installed properly in the wellbore.

To better understand the stability of foam cement, Kutchko and her team are comparing lab-generated foam cement samples that are tested at atmospheric conditions against those generated in the field.

Traditionally, "when foam cements are tested, they're generated at atmospheric conditions. Yet we know foam cement, just by the nature of the material, will behave very different in a well," she said. "Pressures, temperatures, shear—those parameters—will affect the behaviors and properties of the foam cement. What we don't know is how it affects the properties. We don't know what happens. That has been the primary focus of the foam cement project."

The goal of the project is to develop a predictive relationship between the gas distribution and the physical properties using the lab's CT imaging capabilities as well as mechanical geophysical characterization methods, she added. Kutchko and her team are looking at three datasets: foamed cements prepared according to the API RP 104-B under atmospheric conditions, foamed cements generated and collected in the field at various pressures, and those generated in the laboratory under a range of *in situ* conditions using a foam generator that is on loan from project partner Schlumberger.

"We have a suite of atmospheric prepared foam cements using a couple of different industry surfactants and stabilizers, and we are looking at those across a range of foam qualities," she said. "Foam quality means how much entrained air or nitrogen is in the cement.


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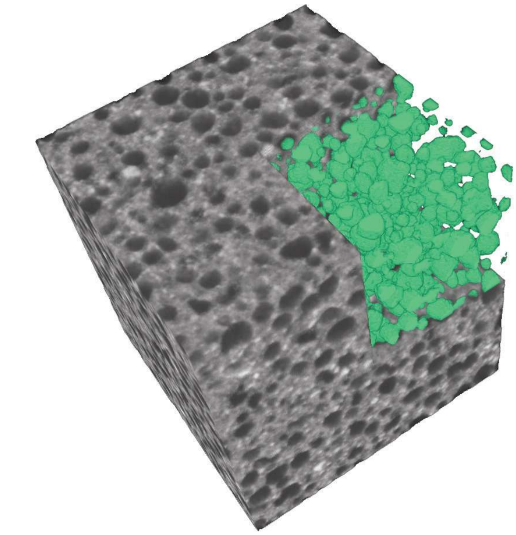


A 3-D rendering shows a 3.12-cu.-mm digital subsection of a 30% foam-quality cement sample. One-eighth of the volume has been post-processed to isolate the gaseous voids within the foamed cement. (Source: NETL)

For example, if I say it's a foam quality of 20%, it's 20% air or nitrogen."

The spirit of cooperation between industry and government also plays a key role in the acquisition of field-generated samples.

"We've been very fortunate to have had three of the major service companies to date—Baker Hughes, Halliburton and Schlumberger—provide us with field samples. These are foam cements that were collected using actual field equipment," she said, "the same full-scale industrial equipment and methodology that is used to generate cement in a well. This has never been done before; nobody's ever seen samples like this. This has provided us with a very unique set of samples that are highly significant to this project so that we can look at actual field conditions vs. laboratory conditions."

Initial findings

What Kutchko and her team are discovering is that the field samples are very different from the lab-generated samples. "What we're finding is that the lab samples and the field samples don't look anything like each other," she said. "Basically, in the atmospheric cement we measured permeability, proxy and strength. They all held out very well in the foam quality range that you would expect in a well. What we're seeing in the CT scans of the field-generated samples is a significant distribution of small bubbles," she said.

Work is still underway to understand the differences between the lab and field samples. For example, the data on the mechanical testing are still being collected.

"The foam cement project is still going strong," Kutchko said. "We're right in the middle of it, and we're just beginning to understand these systems. We're laying down the foundation, and as we begin to understand how these systems work and bring in our modeling capabilities, then we'll start to understand the long-term integrity of wellbore cement."

Work also is starting in other areas of cement research.

"We're also starting to utilize our CT scanning capabilities and expertise to look at other parameters, other challenges, other research needs in the well," she said. "For example, right now we are looking into the effect of temperature and pressure cycles on the integrity of cement with respect to zonal isolation." E&P

Editor's note: *For more information about this project and products of this research see* edx.netl.doe.gov/offshore.

Offshore, onshore trees designed for safety, specific applications

From an onshore horizontal frack tree that reduces bending stress to newly developed shallow-water trees, service companies are adapting equipment for safety and reducing costs.

Scott Weeden, Senior Editor, Drilling

With the large number of acquisitions of assets in the shallow waters of the Gulf of Mexico (GoM), finding and developing smaller fields near existing infrastructure is now in vogue. Given the smaller reserves, cost effectiveness is the name of the game in developing these oil and gas deposits.

Service companies are developing equipment to address the issues involved in working in shallow water. Diver-assisted trees that can be installed from jackup rigs provide a much less expensive method for developing these fields.

At the same time, development of unconventional reserves with horizontal drilling and hydraulic fracturing is requiring some new approaches to the design of onshore frack trees. By reducing height and weight on frack trees, costs and safety can both be addressed.

Shallow-water systems

Although much of the emphasis on development in the GoM is in deepwater, operators are now focusing renewed efforts in shallow waters to tap smaller fields. FMC Technologies is offering its shallow-water subsea Jackup X-mas Tree (JXT) for operators wanting to exploit stranded reserves near existing infrastructure.

The JXT is "fully optimized for shallow water. It is based on FMC Technologies' deepwater production systems and has been simplified with fewer functions compared to our deepwater offering," explained Henning Gruehagen, business manager, shallow-water systems, FMC Technologies, at the 2014 Offshore Technology Conference.

The trees have been standardized for 10,000 psi and are in stock. These are fully compliant with API standards. The mudline tree can be operated by divers or ROVs in water depths to 130 m (430 ft) and is adaptable to any mudline suspension system. The tree can be delivered in four to six months, thus improving economics, lowering installation costs and reducing abandonment and salvage costs.

These trees are designed for stranded reserves near existing infrastructure in jackup applications. The fields would typically be within 16 km (10 miles) of existing platforms with excess production capacity. The wellheads are suitable for exploration, development or injection wells.

"With this tree, the well can be tied back subsea to existing infrastructure, which is much more cost-efficient than adding a new platform," Gruehagen explained.

There are three shallow-water JXT tree options available: JXT-1, JXT-2 and JXT-3. The JXT-1 is a diver-assisted installation with a $3\frac{1}{16}$-in., 10,000-psi block tree system with up to $3\frac{1}{16}$-in. or $2\frac{1}{16}$-in. annulus access. It is capable of four downhole hydraulic penetrations and has a 10-year design life.

The standard JXT-2 configuration is for diverless, ROV-assisted installation with a $4\frac{1}{16}$-in., 10,000-psi block tree system with up to $3\frac{1}{16}$-in. annulus access. It is capable of one electric and three downhole hydraulic penetrations. It has a 10-year design life.

Finally, the JXT-3 tree is for diverless and ROV-less installation on a mudline suspension system or a UWD subsea wellhead. The $5\frac{1}{8}$-in., 10,000-psi block tree system allows

The JXT tree is lowered to the mudline, where divers can assist in the installation. (Source: FMC Technologies)

A JXT designed by FMC Technologies is prepared for installation from a jackup drilling rig. (Source: FMC Technologies)

seven downhole functions (five hydraulic and two electric). It is designed for a 20-year life.

Frack trees go horizontal

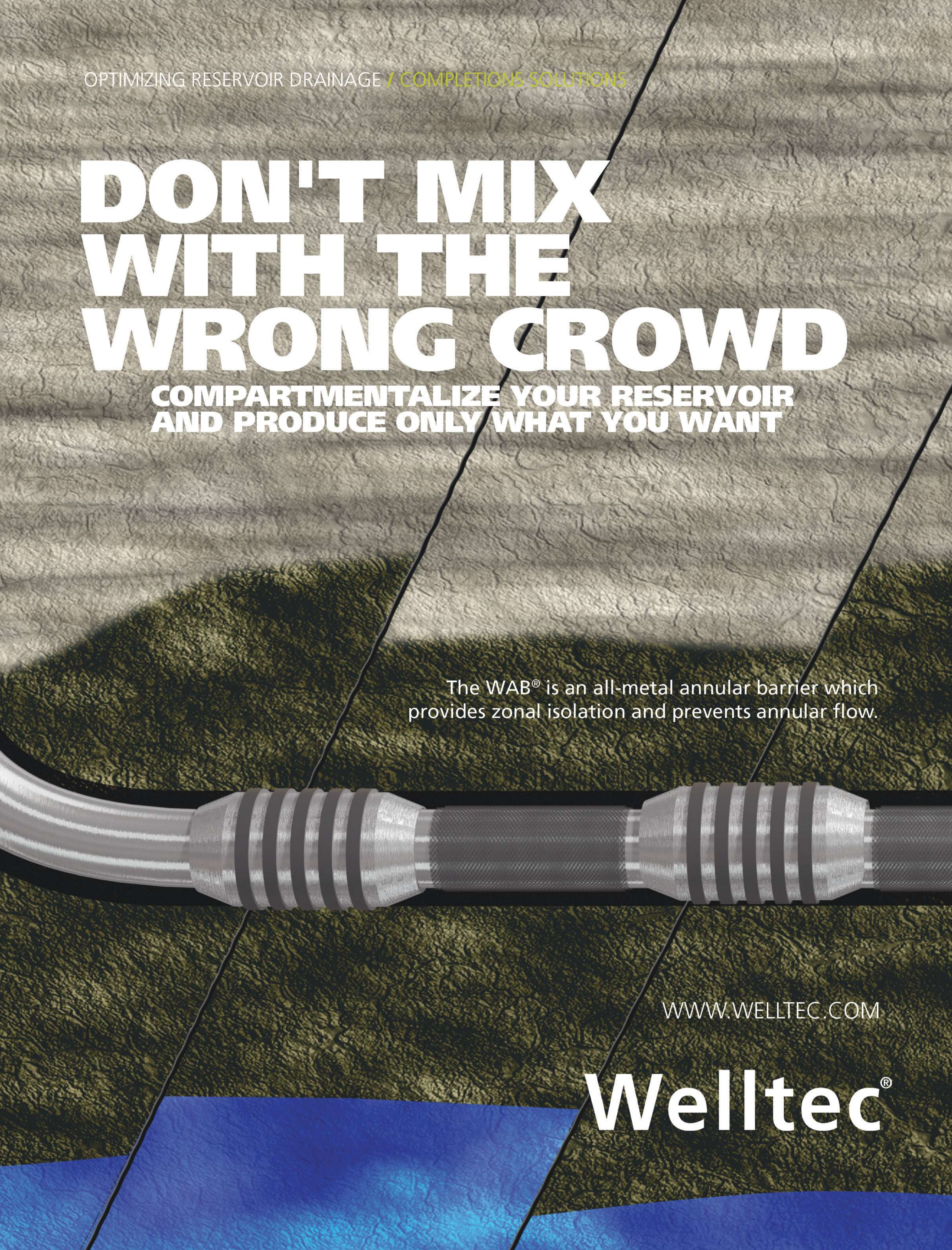
Even though the downhole tools needed for hydraulic fracturing and production are important, the surface equipment for fracturing operations is also key to increasing efficiency, improving safety and cutting costs. The emphasis on more stages and higher hydraulic horsepower has led to the redesign of surface frack trees for unconventional wells.

The most effective hydraulic fracturing treatment is dependent on a reliable and effective frack tree. To this end, these surface frack trees recently evolved from conventional frack tree configurations to now include a horizontal frack tree configuration. As they have been developed to reflect industry needs, this new design configuration has been an incremental improvement in efficiency, reliability and safety of the fracturing operation.

The F-T90 horizontal tree from Cameron offers an ultracompact footprint and reduced height and enhances the integrity of overall fracturing operations. This tree is built to reduce bending stress at the tree connection. It can be operated with pneumatic, hydraulic or electric actuation. The system is designed to handle 15,000 psi.

For a $5\frac{1}{8}$-in., 15,000-psi system, the horizontal tree represents more than 50% reduction in size and about 25% reduction in weight from a conventional frack tree. Built to minimize the bending moments induced by the cycling of high-pressure pumps during fracturing operations, the new horizontal tree has a substantially reduced moment arm that minimizes bending stress at the wellhead and tree connection. With two valves and a flow cross integrated, the horizontal tree's compactness offers quicker installation in the field and is less susceptible to leak paths. The design also offers a buffer zone to offset erosion.

Safety remains paramount in all fracturing operations, playing a big role in the development of the horizontal design. In the past, an operator had to be raised up to the frack tree to perform operation or maintenance, but with the horizontal design, the need to raise the operator up to the tree in a man basket is eliminated. E&P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Downhole intelligence

From pie-in-the-sky ideas to modern reality, intelligent completions continue to push the envelope.

Rhonda Duey, Executive Editor

The concept had many names—Intelligent Wells, the Downhole Factory, the Field of the Future. But all of these monikers described a new form of completion technology that would give operators the ability to better control their wells downhole.

The term "intelligent completions" is often used to describe a variety of different technologies that have evolved over the past 10 to 15 years to address operators' needs. In its infancy the concept spawned several highly ambitious ideas.

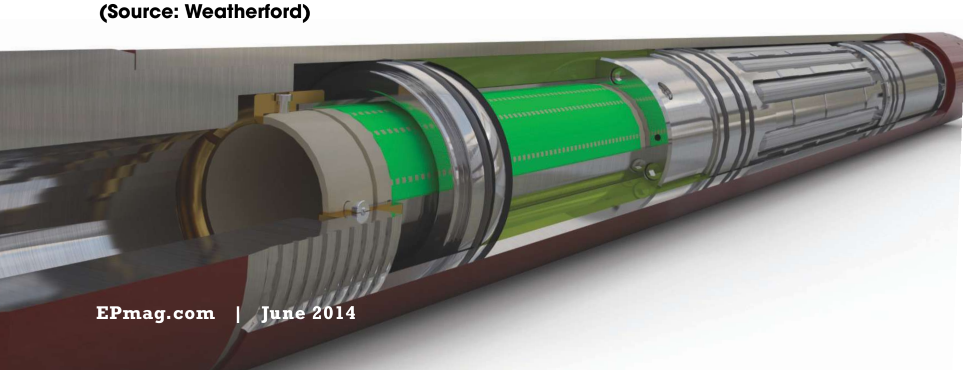
"There was originally a vision of these fully autonomous wells that would control themselves and provide the ability to self-optimize and have wireless communication up the wellbore," said Darrin Willauer, director of intelligent production systems at Baker Hughes. "We had the vision of the downhole factories where all of the separation would happen downhole. There were a lot of crazy concepts being tossed around back then."

But there also were some compelling drivers. For one thing, drilling technology was undergoing dramatic changes. "The industry's key challenge was how to drill wells to intercept and maximize the contact with the reservoir," said Mohamed Aly Sadek, completions marketing and technology manager at Schlumberger. "We started with horizontal wells, then extended-reach, and now multilaterals. The drilling technology started to evolve very fast, and what used to be out of reach in the '80s and '90s is a common practice today.

"While this was happening, many challenges started to come up. We could drill the wells, but how could we complete them and produce them efficiently? It became very obvious that the current completion technology was no longer suitable."

Another very real driver was the rising cost of well intervention, particularly offshore. "People didn't want to go in and move a sleeve because they wanted to shut off a zone that was producing water," said Savio Saldanha, senior product manager for intelligent flow control at Halliburton. "That meant they would have to mobilize a rig just to do a sleeve movement on one well. Given the expensive day rates, it didn't make economic sense."

With the tubing tested and the well isolated, a series of pressure pulses are applied that instructs the Keystone to open the setting port inside the production packer. (Source: Weatherford)



The Schlumberger IntelliZone Compact multizonal management system brings together as one compact unit a fully integrated completion module and a powerful, user-friendly remote operating system. (Source: Schlumberger)

The need for intelligent systems also was driven by the difficulty of obtaining production logs in horizontal sections or multilateral wells. Sadek said that in a multilateral well only the mother bore can be logged. "You can have four or five laterals in the same well," he said. "We cannot ignore the production coming from these wells."

So intelligent completion technologies were developed. Early deployments were relatively simple, combining flow control valves with pressure and temperature sensors. As they have evolved over time, these systems have become more complex, but they also have provided tremendous benefits to the industry.

Current technology

Saldanha outlined numerous situations that have benefited from intelligent completions. They help reduce opex and capex by enabling commingling of zones with different pressure profiles. They can shut off water or gas breakthrough from particular zones. And they can enable the production of marginal assets.

"If you have a smaller asset that is only going to produce 50,000 bbl overall, it doesn't make economic sense when you're spending $100,000 to drill a well," he said. "But if you're drilling it as part of a major find and you use intelligent completions to extract whatever comes from that marginal reservoir, those are incremental reserves."

Operators also are using intelligent completions for secondary and tertiary recovery, particularly in water injection wells to control the sweep, he said.

Technology enhancements are having an impact as well. Willauer said that downhole flow meters enable operators to determine the amount of production coming from each zone, or each well in a subsea completion. Fiber optics are also playing a larger role since this technology enables distributed sensing.

But key challenges remain. One of the major questions regarding intelligent completions is how to power the downhole instruments. Early electric systems were notoriously unreliable. "It's not like a drilling tool that's going to drill the well and pull out," Sadek said. "We have to design a system that will stay downhole for at least 10 years."

So the industry moved to hydraulic systems and hybrid systems combining both electronics and hydraulics. Early versions of the hybrid system were also plagued by reliability issues, and Saldanha said that any electronic failure in the system caused the operator to lose control of the well. Hydraulic systems are much more reliable, but the wellbore can get pretty congested with multiple lines.

"Real estate is beginning to be reduced," he said. "You might need a line for a safety valve, for injection, for gauges, for other valves. Pretty soon you end up with eight or nine lines."

The industry is slowly revisiting the idea of all-electric systems as reliability has improved. Baker installed an all-electric system several years ago that is still functioning properly, but many operators are still hesitant to embrace the technology.

Weatherford, meanwhile, relies on a radio-frequency identification (RFID) system in a wireless completion set-up. "When you move into a wireless scenario, you have to talk about downhole power generation," said Yvonne McAnally, global product line director, upper completions for Weatherford's Well Completion Technologies division. "Our RFID system is powered by batteries. We can actuate a sleeve without any control lines. But we have the restriction of the lifespan of the batteries."

Tendeka has licensed technology from Statoil to produce its FloSure autonomous inflow control valve, allowing operators to even out the inflow profile to prevent fluid coning. The valve operates by responding to the velocity of the fluid coming into the well.

Finally, there is the issue of cost. While intelligent completions might save a subsea well from watering out, the systems are becoming so complex and expensive that operators might begin to question their return on investment.

"Some operators might struggle with the cost-benefit proposition since the benefits are not realized until several years into the future," McAnally said. "They might be wondering if there is a better way."

What is needed

While intelligent completions technology has come a long way from its early beginnings, most agree that it's still evolving. The main issues driving current development are simplicity and integration.

"We have to simplify these systems in terms of the number of control lines and the number of electric cables," Sadek said, adding that Schlumberger is

perfecting an integrated platform that can be deployed as one piece of kit. The first generation, the IntelliZone Compact modular multizonal management system, was launched about four years ago, and he said that many customers who are not usually early technology adopters have been asking for the system.

Willauer agreed that an integrated system is more than the sum of its parts. "There is no one key technology," he said. "It's really the aggregation of all of these technologies that is enabling multiple markets right now. It's not just the high-end markets. We can provide solutions for some of the lower end markets now."

He added that the intelligent completion of the future will be an integrated solution that goes from the downhole hardware through the subsea infrastructure all the way to the desktop. "It's that level of intimacy and integration that we need to continue to pursue," he said.

The challenge in realizing a fully automated intelligent completion will require more than the participation of the completions engineers. Sadek said that it's

Fiber-optic sensors enable distributed temperature, pressure and acoustic sensing downhole. (Source: Baker Hughes)

necessary to work closely with the drilling department to understand their well construction plans. "There's no value in drilling a well if we can't complete it," he said. "We have to have a clear understanding of how they're going to be drilling the wells."

And production engineers need to be involved as well. "I see a blending of the completions engineer and the production engineer," Willauer said. "The completion design is impacted by the production goals to a much greater extent than it has been in the past." E&P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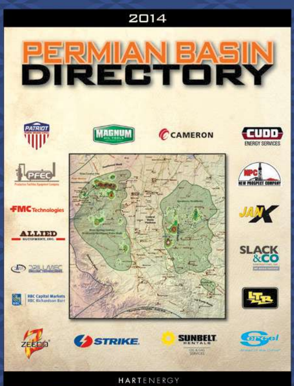

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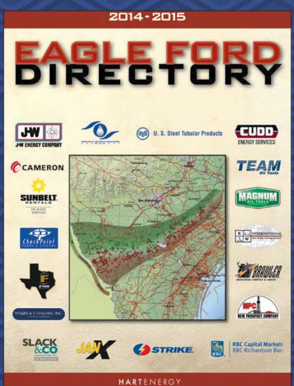

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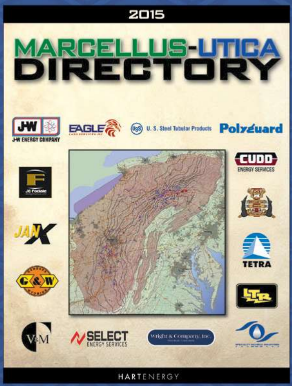

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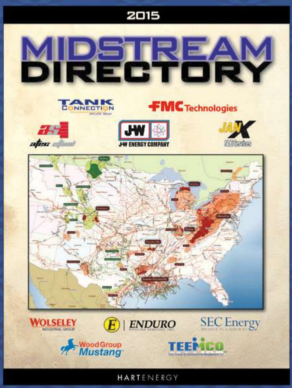

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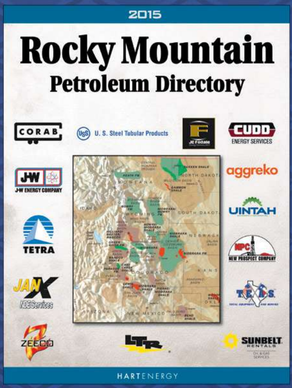

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Global, risk-based shale development verification service launches

Initiative seeks to establish 'safe harbor' for shale practices.

Richard E. Green, DNV GL

DNV GL has launched a comprehensive, tailor-made independent verification service based on the provisions of its Recommended Practice for Risk Management of Shale Gas Developments and Operations (DNV GL RP U-301), regulatory requirements and other publicly available standards. DNV GL offers the only global third-party verification service with comprehensive coverage of shale project operational risks.

Recommended practice development

In early 2013 DNV GL released the recommended practice (RP) to provide stakeholders with a comprehensive understanding of potential risks and the best practices to mitigate them. The RP was originally shaped as a risk primer for gaining a license to operate for new shale developments and to assure existing shale projects, especially in North America, could be sustainably operated. The RP is the foundation for DNV GL's newly launched verification service. The RP was developed because there wasn't a single compendium of risk descriptions and mitigation practices. The idea was to provide assistance to stakeholders such as governments, operators or local communities to create more factual dialogues about risks. In the U.S., the need for best practices is more centered on cost control and optimization and, for some stakeholders, whether or not unconventional oil and gas development is sustainable in business, technology, infrastructure and environmental terms.

Verification purpose

The verification service will use the RP best practice provisions to help assure stakeholders that an independent assessment can assist in preventing incidents, reducing operational costs and limiting the environmental footprint of shale developments. Best practices measured in the verification process include environmental, occupational and process safety; resource use; human factors; well integrity; logistics; permitting stakeholder engagement; and other elements that may help address day-to-day operational risks and the low-probability, high-consequence incidents under scrutiny today such as transport of shale liquids.

There is a fair amount of public concern about the potential consequences of shale developments and hydraulic fracturing in particular. One of the things the RP verification process will do is help stakeholders differentiate between perceived risks and actual risks, keeping the discussion grounded in engineering and science.

Stakeholder benefits

As shale gas and liquids development are experiencing exponential growth in North America, a wide range of operational risks have been realized, including gas flaring, fugitive emissions, rail transport incidents, water management, fracking chemicals, explosions, fires, infrastructure limitations, occupational risks and asset integrity issues. The industry can gain stakeholder acceptance only by implementing best practices and proactive risk management. Operators need to demonstrate that their development activities can be executed in a safe, responsible and sustainable manner.

For this purpose, the verification process determines whether a comprehensive, transparent risk-management approach related to risk identification and mitigation has been implemented to allow sustainable shale gas project development or expansion. The verification service may be used by operators, regulators, insurance companies, banks, and other oil and gas stakeholders to frame the risk dialogue based on international approaches to risk identification, mitigation and monitoring best practices.

Global variations

Around the world, most organizations define risk as the product of the frequency with which an event can occur multiplied by the gravity of its consequences. However, sometimes the definition of risk can be more focused on potential consequences. The regulatory framework in the U.S. on both the state and federal level has strong links to historic consequences, and as a result the regulatory frame is less performance-based than in other parts of the world. Institutions seeking to operate in the U.S. must navigate through a myriad of federal, state, county and

municipal regulations. From a risk standpoint, a company can get along reasonably well in the U.S. as long as it complies with all of the regulations applying to its particular operation and obtains the necessary operating permits. Following the specific regulatory requirements is absolutely essential. However, there may be some shale risks that are not fully addressed through existing laws and regulations or perhaps not in the most efficient or risk-based way. That is where the DNV GL RP Verification Tool can assist organizations; its foundation is tied to ISO 31000.

This rendering shows a classic shale operation. (Source: DNV GL)

Stakeholder concerns

The verification service can address one or more elements of the RP or risk points. For example, the RP recommends that environmental risks be identified through baseline studies and/or environmental impact studies prior to operations. Ideally, these studies would be conducted by an independent organization. A number of other risks to shale project operations also fall under the environmental umbrella, including storage, handling and disclosure of chemicals used; handling of drill cuttings and other wastes; greenhouse gas emissions via fugitive emissions and flaring; odors, dust, noise and lighting impacts; energy efficiency, logistics and infrastructure demands; emergency preparedness planning; environmental monitoring; and post-operations impact analysis. Understanding water resources and management is especially pertinent right now for fracturing in terms of water acquisition from surface, groundwater, reservoir and other water supplies as well as treatment and disposal options that have considerable cost variations. DNV GL is initiating a joint industry project (JIP) to relook at formation water, flowback water and produced water with an aim toward creating a better water treatment regime. Hopefully a means can be found to reduce transportation, treatment and/or deep well disposal costs and achieve nearer a 100% recycle rate of water.

Expanding the library

The RP and the associated verification service are not static initiatives. Together they are intended to be an industry "harbor" for best practices. One way DNV GL codevelops new best practices is through JIPs. This year five JIPs will be launched to solve specific technical issues. In addition to the zero water discharge management activity noted above, the four others include development of a decision analysis tool for operational optimization, analysis of well cement failures, quantification of fracking risk (FRISK) and a decision model for selecting water treatment options. In these particular JIP projects, DNV GL hopes to join academia, service companies, producers, regulators and other stakeholders to help reduce the cost of water management for hydraulic fracturing operations, optimize operations and demonstrate that FRISK can be quantified to better assure stakeholders.

In the case of the water management JIP, there are opportunities for companies to reduce the amount of descalers, biocides and friction reducers used and reduce the environmental footprint of the operations. That would be both a reduction in operating expense and an environmental benefit. These are win-win situations where the reduction in the operational costs come together with the environmental improvements.

Next steps

In 2014 DNV GL will concentrate on testing the verification process in the marketplace and soliciting additional best-practice inputs through industry contacts and other forums to attract stakeholders interested in safely developing this vast energy resource. The RP can be downloaded from *dnvgl.com*. Search: shale. E&P

Solving Arctic challenges

Harsh-environment research is moving industry toward expanding Arctic operations.

Han Yu, **John Dolny** and **Dan Oldford**, ABS

The oil and gas industry has been carrying out Arctic research for decades, but there has been a resurgence of interest in the recent past that has pushed harsh-environment operations to the forefront.

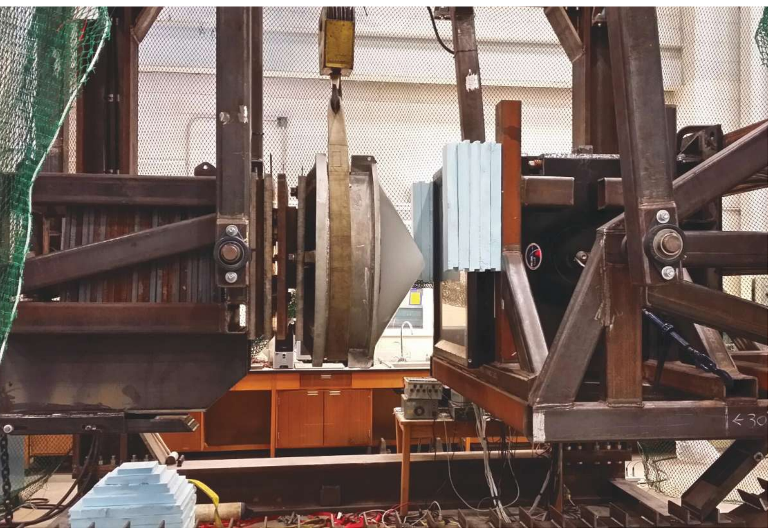
Partnering for solutions

Recognizing the need to address Arctic challenges, ABS established a Harsh Environment Technology Center (HETC) in partnership with Memorial University of Newfoundland (MUN) in St. John's, Newfoundland and Labrador, Canada, in 2010. The primary objective of the center is to develop technology for the design and assessment of ships and offshore structures that operate in harsh environments—particularly the Arctic and low-temperature areas. Research undertaken through HETC includes ice-hull interaction, ice loads on offshore units and winterization issues.

Contending with ice-hull interaction

Through HETC, ABS is contributing to projects in which full-scale structural arrangements close to Polar Class strengthening levels are being subjected to ice samples shaped as ice cones and loaded on hydraulic rams to more than 300 mt of force. The results of these tests are being used to validate numerical simulations of both ice and structural deformation. The information gained through testing is providing valuable insight to the plastic overload capacity of typical icebelt structures.

Dynamic experiments include high-energy collisions using a novel double pendulum collision apparatus capable of swinging more than 9 mt of ice and steel at a closing speed greater than 10 m/sec (33 ft/sec).



One of the goals of the Sustainable Technology for Polar Ships and Structures program that ABS is a part of is to develop validated practical tools that will permit the safer design and assessment of ships and offshore structures for Arctic conditions. (Source: ABS)

Managing ice loads

As Arctic offshore developments venture into deeper water, the industry will face new challenges related to the safety and station-keeping capabilities of floating structures subjected to global ice loads. HETC is managing the first phase of a joint industry project (JIP) aimed at closing knowledge gaps that exist in understanding ice loads on floating structures.

Workshops hosted in St. John's have facilitated a comprehensive review of the subject, addressing different structural configurations, interaction scenarios, ice management, station-keeping systems, numerical models, model-testing procedures, design codes, full-scale data and operational experience. In the process, workshop participants identified a number of areas of uncertainty. These will be further explored to provide recommendations toward a dedicated full-scale measurement campaign that will be coupled with physical model testing and numerical modeling efforts that will target prioritized areas of development. The work will serve as a guideline for later stages of the JIP in which knowledge gaps will be addressed.

Traditionally, ice management has been an operational issue. Recently, however, the industry is taking a broader view of ice management. ISO 19906 provides the first comprehensive treatment of the subject in a standard and sets requirements for overall system reliability. Ice management systems typically consist of a series of processes and procedures such as detection/tracking/forecasting of ice conditions, threat evaluation, physical ice management, ice alert procedure and disconnection/move off from the site. For floating drilling systems—and potentially for production systems—physical ice management could include icebreaking, ice clearing or iceberg towing to reduce the station-keeping loads on a unit.

ABS has initiated a project aimed at developing novel technologies to quantitatively assess the effectiveness of physical ice management. The project includes performance models of ice breakers in various ice conditions and under different tactical maneuvers.

Accompanying software incorporating GPU hardware technology is being developed to carry out performance estimates and to visually display the simulation. The GPU environment provides a massively parallel domain for solving complex interactions among icebreakers, offshores structures and ice floes at hyper-real-time speeds. Currently, the simulation can run 12 times faster than real time, which enables the practical assessment of performance by simulation.

The development will continue in 2014 to include more complicated interactions such as floe splitting, floe submergence, rubble pile-up, mooring systems, etc.

Addressing winterization issues

One of the roles of a classification society is to understand industry's changing safety needs and to develop guides that help to achieve safety goals. Recognition of the industry's desire to move into harsher environments led ABS in 2006 to publish the *Guide for Vessels Intended to Operate in Low-Temperature Environments* (LTE Guide), which has since undergone multiple revisions based on industry feedback. The LTE Guide represents a set of mostly prescriptive requirements based on assumptions about vessel operations. The prescriptive nature of the LTE Guide is quite helpful in many scenarios, but for others with historical experience prescriptive requirements can contradict the proven service experience. So there is a clear need for an approach to safety that allows companies to demonstrate competence in dealing with risk without following prescribed action.

One way HETC is moving toward this goal is in developing a risk-based winterization approach that offers an avenue for owners and operators to comply with the intent of the LTE Guide in situations where it is neither practical nor feasible to meet certain prescriptive requirements. The developed methodology is a systematic approach to vessel design that delivers a low level of risk while permitting the use of practical solutions. This approach currently is being applied collaboratively with a designer to a new vessel design intended for harsh-environment operations where the operators have a long history of safe operations. Areas of noncompliance with the prescriptive requirements are being highlighted and risks evaluated based on probability and consequences of failure. The exercise is providing valuable feedback to ABS for the future enhancement of the LTE Guide and to the client for making informed decisions in the detailed design phase.

Developing the Arctic Operations Handbook

Another JIP established in 2012 and concluded at year-end 2013 has resulted in the Arctic Operations Handbook, which addresses safety and sustainability of offshore operations in the Arctic. The JIP, which is made up of 15 companies, focused on operational activities associated with transporting and installing fixed, floating and subsea units as well as dredging, trenching, pipelaying and floating oil and gas production in Arctic and cold-weather conditions.

The goal of the investigation into existing rules, regulations, standards and guidelines was to provide a common understanding for the offshore industry. Significant effort was expended to identify gaps in existing guidelines. A framework was defined early on to facilitate the identification of key aspects of safe Arctic operations. With that goal in mind, offshore operations were divided into subactivities to allow specific conclusions and recommendations to be reached. Potential risks that could arise in specific Arctic conditions were identified for each subactivity to improve the understanding of the operational challenges involved.

Dealing with ice is a serious challenge in Arctic operations. (Photo by Valerie Cannon; Source: ABS)

The project report, "Arctic Marine Operations Challenges and Recommendations," provides a list of the identified gaps and a large number of recommendations that have the potential to close these gaps. Published in late 2013, the report provides an overview of what is required to prepare for and perform transport, installation and production operations in Arctic environments. The hope of the JIP is that specific recommendations will contribute to the development of internationally accepted standards and guidelines including ISO/TC67/SC8 (Arctic operations), ISO 19906 SC7 (offshore structures) and ISO 19901-6 (marine operations). E&P

Optimizing the Permian Basin Wolfcamp pay zone

Hybrid bit technology drills curve 50% faster while achieving high build rates.

Matt Hoffman and **Shelly Cory**, Baker Hughes Inc.

A technical challenge West Texas operators face is to drill interbedded conglomerate formations in curve sections with just one bit while achieving high build rates to land target formations as planned. For Cimarex Energy Co., a recent focus was to drill the curve section 50% faster in the Wolfcamp Shale while maintaining high build rates that range from 12 degrees to 14 degrees per 30 m (100 ft) consistently.

Optimizing ROP while maintaining toolface control is a difficult task many directional drillers face while building curve sections with legacy bit offerings. A secondary goal was to apply this technology to other counties with similar challenges.

Legacy drillbit options

Past solutions included a choice of roller cone or polycrystalline diamond compact (PDC) drillbits, which required multiple trips and faced directional drilling challenges. Roller cones delivered the manageable toolface control; however, typical limits on ROP were common due to the method of rock removal, which is crushing of the formation. PDCs were another legacy solution that provided the increased ROP by continuously shearing the rock formation. One method to gain ROP in the curve with a PDC bit was to increase the weight applied to the drillbit. When weight is increased on a PDC bit, the torque is increased, which can lead to another unwanted result, stick/slip, if induced. The fluctuating torque makes the toolface extremely difficult to control or maintain and many times leads to increased vibrations.

Vibrations can cause downhole tool issues, borehole quality concerns and unwanted bit performance. These concerns limit the directional driller on the amount of weight that can be applied. Often, the result for directional drillers is lower-than-desired build rates in the conglomerate curve sections to mitigate the toolface control issue with PDC bits. Additional results can lead to not reaching the target as planned, adjustments to well plans such as lengthening the curve section, setting kickoff point sooner with lower build rates than desired, changes to bottomhole assemblies (BHAs), and motor selection alterations and additional trips, depending on which bits are selected. All of this adds to the overall drilling cost.

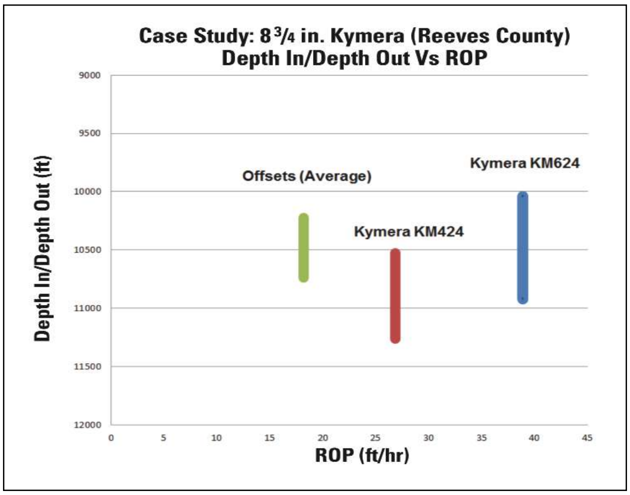


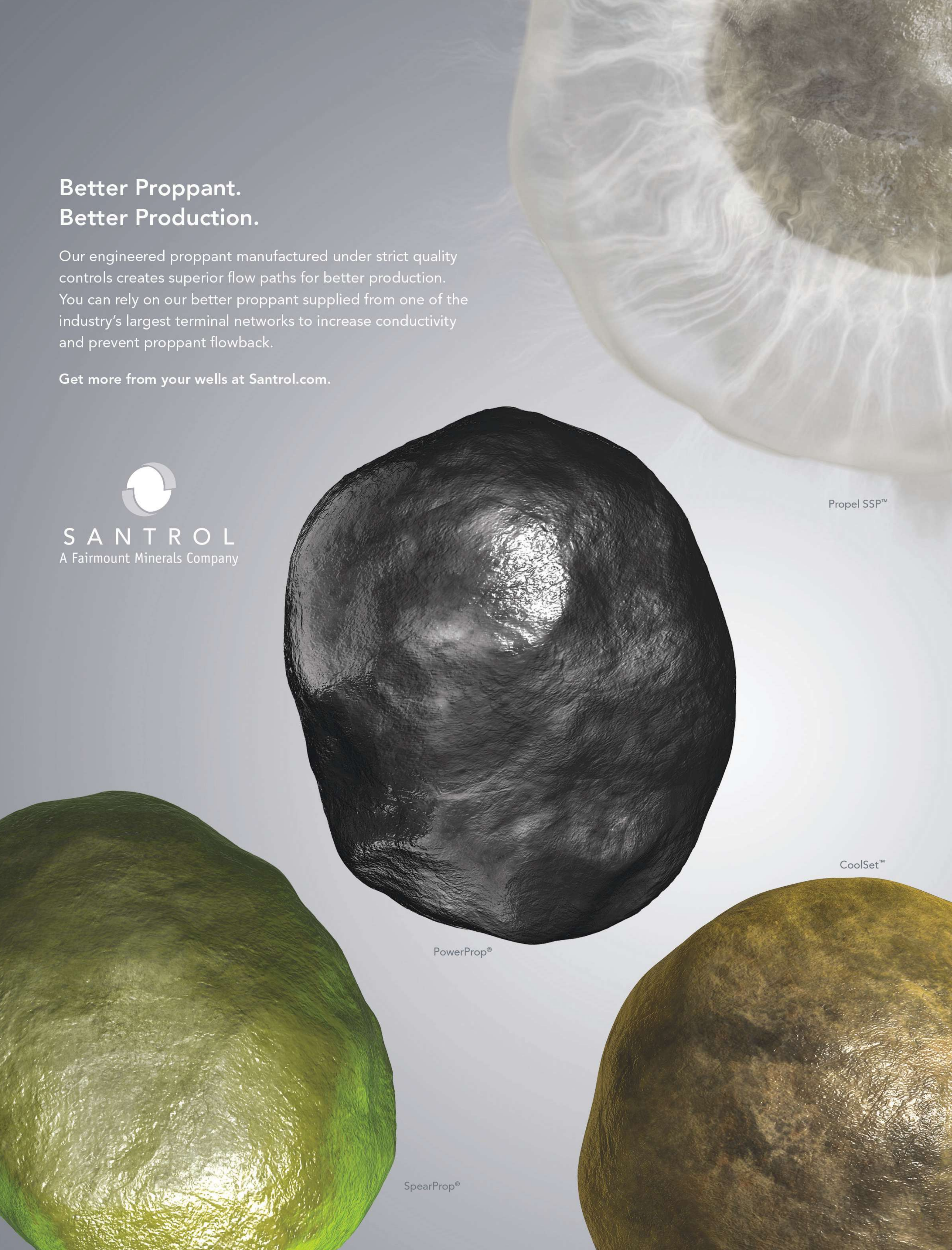
FIGURE 1. Based on offsets in Reeves County, the Kymera KM624 had an ROP more than double the average rate. (Source: Baker Hughes)

The solution

Cimarex Energy Co. partnered with Baker Hughes to take advantage of Baker's fit-for-purpose hybrid drillbit technology and was able to drill the curve more than 50% faster than predefined baseline ROPs without sacrificing the planned high build rates. This performance has been repeated from well pad to well pad and from county to county.

Case studies

The Wolfcamp shale is a well-known source rock throughout the Permian Basin. To reach the Wolfcamp Formation, operators must first drill through the Third Bone Spring Sand Formation. This formation has a rock strength varying from 10,000 psi to 20,000 psi and can be challenging to drill through directionally. Based on offsets of the 8.75-in. curve section within a 16-km (10-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mile) radius in Reeves County, the Kymera KM624 reached a landing point of 65 degrees with a ROP of 11.8 m/hr (38.8 ft/hr) compared to the offset average rate of 5.5 m/hr (18 ft/hr). This rate is more than double the average (Figure 1).

The build rates were consistent, reaching an average of 14 degrees per 30 m and have been achieved consistently using a 2.12 adjustable kickoff motor. Both the directional driller and operator were very pleased with the selected BHA package, which delivered excellent toolface control and bit run (Figure 2).

Overall, the use of hybrid technology in Reeves County shows improvements of 17% for distance drilled, from 159 m to 186 m (522 ft to 609 ft) when compared to offsets that include both PDC and roller cone bits. The ROP also doubled when compared to average offset ROP with the use of the latest design.

In Ward County, with the hybrid technology drilling in the Wolfcamp formation, the rig made it to casing point in only 11 hours and reached a landing point of 70 degrees. The ROP achieved was 16.3 m/hr vs. 5.6 m/hr (53.5 ft/hr vs. 18.4 ft/hr) in the offsets available from Third Bone Spring with average depth ranging from 3,353 m to about 3,658 m (11,000 ft to about 12,000 ft), shown in Figure 3.

With heightened activity in the oil-producing Wolfcamp Shale and Bone Spring sands, operators are looking for innovation to optimize their drilling performance in all sections of the well. Drilling the curve faster without sacrificing high build rates and alterations to well plans are new goals that seek innovative technology.

"With the Kymera solution, we've had consistent one-run curves with good penetration rates," said Spencer Bryant, a drilling and completion engineer for Cimarex. "It's rare to have a two-bit curve with the Kymera hybrid technology."

The results also have shown that many of the dynamic dysfunctions typical to legacy bits, such as stick/slip, re-crushing cut rock or back-whirl, can be minimized with new hybrid technology, which exploits the best attributes of each legacy bit type and bridges the gap between them.

The hybrid technology can efficiently drill shale and other formations with problematic malleable characteristics. The synergistic combination of the diamond scraping and roller cone crushing allows the bit to last while drilling conglomerates and interbedded sections. Specific results from this case study prove consistent and repeated build rates as high as 14 degrees per 30 m. The findings also prove that drilling in the Wolfcamp Shale doubles the ROP baseline, defining new goals that will foster the next evolution of hybrid technology. E&P

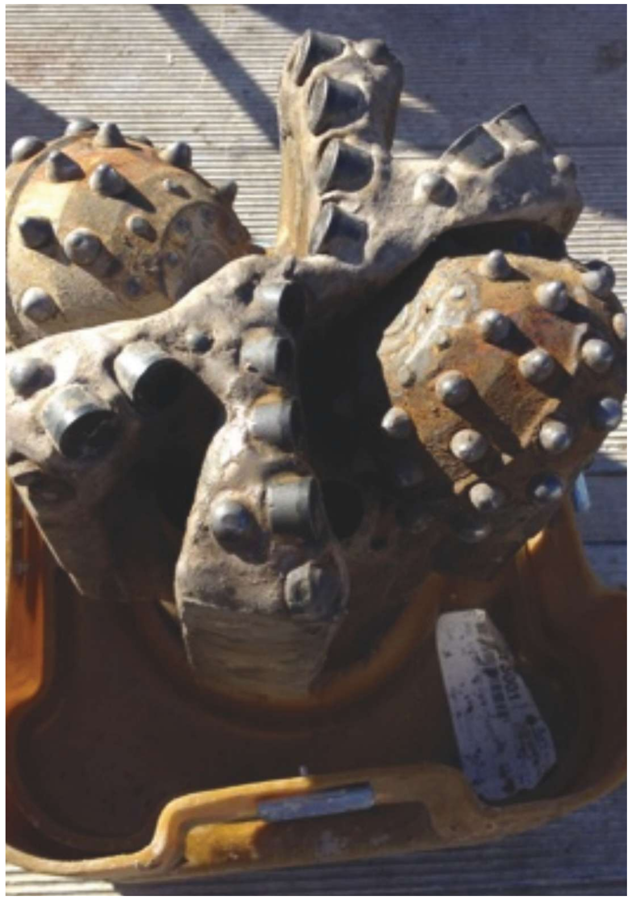


FIGURE 2. The 8¾-in. bit's dull condition was good after the run. (Source: Baker Hughes)

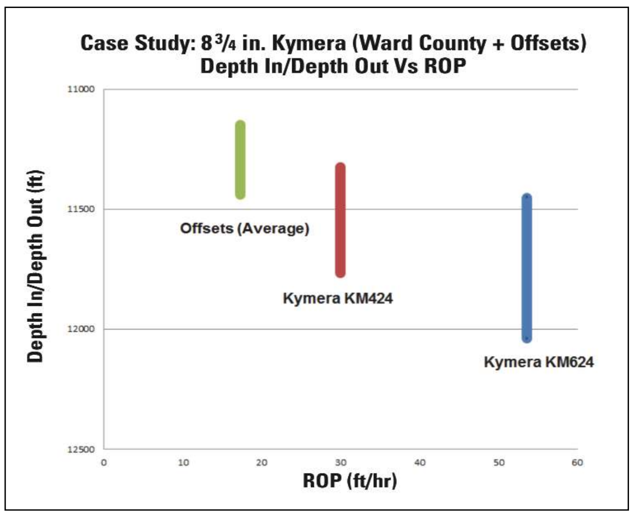


FIGURE 3. ROP with the hybrid bit is more than double that of the offsets. Best practices are now shared among these counties in West Texas to improve drilling optimization. (Source: Baker Hughes)

Use of real-time monitoring aids in water management

Program reviews produced water variables in real time, encouraging onsite treatment effectiveness.

Mark Patton and **Dr. Jinxuan Hu**, Hydrozonix

With water taking on a more critical role in unconventional oil and gas, the need to properly manage and recycle produced water has taken on greater importance. Until now, produced water management has focused on the logistics of moving, storing, disposing of and treating produced water. As critical as these aspects have been, they are missing a key component to a successful produced water management program: identifying and managing water quality objectives throughout the produced water cycle—from the wellhead to its reuse.

Produced water quality and quantity can vary from well to well. Combine this with the fact that produced water quality can also change over time, and there is a dilemma of multiple produced water quality variables in continuous flux. Periodic sampling can often be misleading as current data can be inconsistent with the changing water quality variables in the field. The delay between sample collection, shipping and analysis can sometimes be too long, leading to the need for real-time testing.

KCl equivalency

In general, fluctuating produced water quality on slickwater fractures is less likely to create significant problems, but the use of produced water as a clay stabilizer highlights the need to know changes in produced water quality to identify a specific potassium chloride (KCl) equivalency for the produced water. In this case, even during slickwater fractures the need to collect and manage real-time data is critical to ensuring a specific KCl equivalency (Table 1).

To maintain a specific KCl equivalency, real-time monitoring is needed to identify when to adjust blend ratios to keep the KCl equivalency within the range required. To do this, chloride levels are monitored, and the chloride partner is assumed to be equivalent to potassium. This assumption has been verified by performing fines migration testing.

Sampling days or weeks ahead of fracturing will not account for evaporation within pits, concentrating salinity of produced water or the changing water quality over time. Even salinity stratification within a pit adds to the variable nature of produced water, requiring a real-time solution.

It is not unusual when using produced water to achieve clay stabilization that ratios of fresh and produced water have to be adjusted during a fracture to maintain a specific KCl equivalency. This adjustment can't be made without the real-time data to know when and how much of an adjustment needs to be made.

Treatment efficacy

Another critical parameter that requires real-time monitoring is that of effectiveness of the treatment program. Because the nature of produced water varies, the changes in water quality need to be understood to determine whether these changes will influence the effectiveness of the treatment program. An example of this is the practice of using a continuous biocide dose rate during a hydraulic fracturing job. Monitoring of bacteria levels shows that these can fluctuate significantly during a fracturing job, and as a result it is highly unlikely that a continuous dose rate can address the full range of these fluctuations.

Figure 1 shows the variable nature of bacteria levels during a fracturing job. Real-time monitoring is required to adjust the bacterial disinfection to match the variable nature of bacteria levels.

TABLE 1. This table shows the KCl equivalency for different blends of produced water and freshwater. (Source: Hydrozonix)

Calculated Blend Ratios (% of Produced Water) to Achieve Different KCl Equivalency						
Targeted KCl Equivalency	Chloride Level in the Produced Water, mg/l					
	30,000	40,000	50,000	60,000	70,000	80,000
2.0%	31.8%	23.8%	19.1%	15.9%	13.6%	11.9%
3.0%	47.7%	35.7%	28.6%	23.8%	20.4%	17.9%
4.0%	63.5%	47.7%	38.1%	31.8%	27.2%	23.8%
5.0%	79.4%	59.6%	47.7%	39.7%	34.0%	29.8%
6.0%	95.3%	71.5%	57.2%	47.7%	40.8%	35.7%

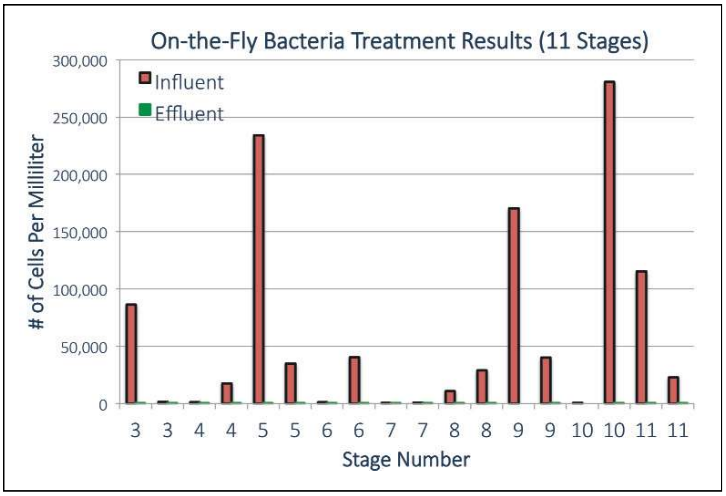


FIGURE 1. Bacteria levels vary during a fracturing job. (Source: Hydrozonix)

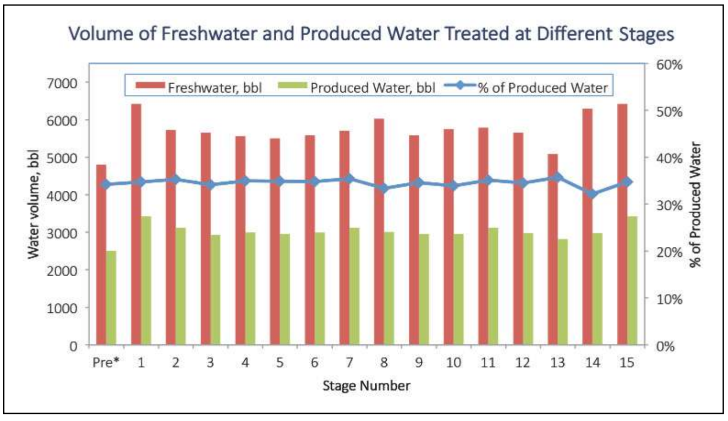


FIGURE 2. This figure shows results from the real-time monitoring of a crosslink-gel fracture with a produced water blend. (Source: Hydrozonix)

Using an exceptionally high dose rate to address higher levels of bacteria can lead to an incompatibility when bacteria levels are low. When the bacterial disinfection program is based on oxidation, a higher dose rate can oxidize other additives that shouldn't be oxidized—like friction reducers or gel in the case of gel fractures.

Bacteria can be monitored in real time using adenosine triphosphate (ATP). ATP is a molecule in and around the nucleoplasm and cytoplasm of every living cell. ATP calculations involve measurement of the light coming through its reaction with luciferase using an illuminometer. The light produced is equal to the amount of organisms in the sample measured.

ATP is useful because it detects both anaerobic and aerobic bacteria without being affected by medium conditions or compositions. Another thing that makes this process useful is its swiftness; ATP results are generated immediately. With ATP, adjustments can be made to the bacterial disinfection program to avoid creating incompatibilities with other additives by overdosing.

When treating bacteria prior to the working tanks on a fracturing job, ATP can determine treatment effectiveness by monitoring the fluid in the working tanks. This technique makes it possible to add biocide in the blender only when ATP levels indicate an unacceptable level of bacteria is present in the working tanks. This technique verifies properly disinfected water before it goes downhole and allows the opportunity to make an adjustment when required.

Real-time testing

X-FRaC (Crosslink Gel Frac Recycling and Control) is a program developed by Hydrozonix to provide real-time testing of a variety of water quality parameters to allow the recycling of produced water on crosslink gel fractures. Because of the sensitivity to chlorides, boron and total dissolved solids, real-time testing can assure these parameters are monitored and controlled stage by stage during a hydraulic fracturing operation.

Changes in these parameters can negatively affect gel quality and as a result have made recycling produced water on crosslink gel fractures a risky scenario. X-FRaC eliminates this risk by providing real-time results prior to each stage and allowing adjustments in blend ratios to maintain the desired water quality required for a stable gel.

The X-FRaC program has been successfully employed on 15 crosslink gel fractures using produced water at recycle rates between 20% and 40%. Figure 2 shows the real-time monitoring used on a crosslink gel fracture with a produced water blend. The produced water source was agitated to provide a more consistent blend.

Real time, real results

In an effort to maximize the amount of produced water used for recycling, Hydrozonix has turned to real-time testing to allow fast decision-making in the field. The data obtained through the X-FRaC program have helped operators ensure proper bacterial disinfection, provide consistent water quality and optimize produced water and freshwater blends for different purposes.

Many operators use produced water but use lower recycle rates to avoid the challenges of inconsistent produced water quality. Real-time testing allows operators to maximize their recycle rates, getting the greatest benefit possible from the recycling of produced water. Real-time testing allows the water management program to go from risk avoidance to risk management. E&P

Robotization in seismic acquisition—a glimpse into the future

With 1 million channels looming as the next step in land seismic acquisition, automation becomes an enticing opportunity.

Guus Berkhout and **Gerrit Blacquière**,
Delft University of Technology

The trend in seismic data acquisition is to collect more and more data to further improve the quality of imaging and inversion. The number of recording channels follows Moore's law of seismic data acquisition (Figure 1). This figure shows that systems of more than 1 million channels can be expected in the near future. On land the number of geophones per channel is generally more than one, meaning that in the future millions of geophones must be planted to record the response of a single shot.

But there is more. A strong increase on the source side is anticipated as well. The current trend is blending (also referred to as simultaneous shooting). In blended acquisition a crew no longer needs to wait to fire the next shot until all echoes of the previous shot have been captured. As a consequence, the number of shots increases considerably within a given survey time, leading to improved subsurface illumination and better image quality with favorable economics.

Recently, the Delphi Consortium introduced the dispersed source array (DSA) concept for blended acquisition that replaces seismic arrays of complex broadband sources by distributed arrays of relatively simple narrowband sources.

From the above acquisition trends it is clear that the current-approach seismic surveying will become a logistical nightmare. Therefore, robotizing seismic data acquisition seems an inevitable next step. An extra argument is that the HSE issues associated with surveys that are increasingly carried out in human-unfriendly areas like polar regions, mountainous terrains and remote deserts can be successfully addressed by the use of robots.

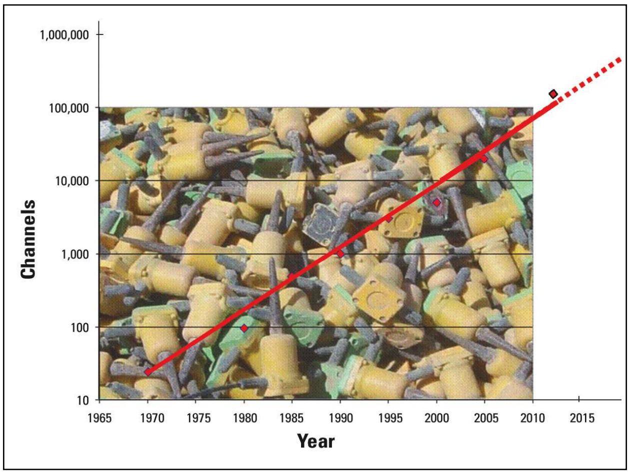


FIGURE 1. The number of seismic recording channels obeys Moore's Law (based on a figure by D. Monk, Apache Oil) and extends to the future. (Source: Delft University of Technology)

Robot vibes on land

In the concept of blending, where recording is largely continuous and shots are fired while the echoes of previous shots are still being captured, the sources may be fundamentally different. Rather than trying to produce the optimum signal by each localized single shot, which leads to complex sources with a compromised design, blending a diversity of distributed simple sources can produce a much better signal, not simultaneously but in a blended fashion. This is because the bandwidth of the individual sources may be relatively narrow as long as the total bandwidth is covered by the combination of sources. Compare this with modern home or car audio systems, where a distribution of diverse loudspeakers with different limited bandwidths deliver the full temporal and spatial bandwidth of high-quality sound.

The broadband seismic vibrator is the most common land source. It transmits sweeps with frequencies ranging from 5 Hz to 100 Hz. It is a major technical challenge to design and manufacture a single vibrating source that is capable of transmitting such a wide frequency band without distortion. These vibrators are heavy, expensive pieces of equipment. The concept of blended acquisition with DSAs is most suitable for vibrators. Instead of using one broadband vibrator unit, a blended array of different vibrator units is used with relatively narrow bandwidths (e.g., low, mid and high fre-

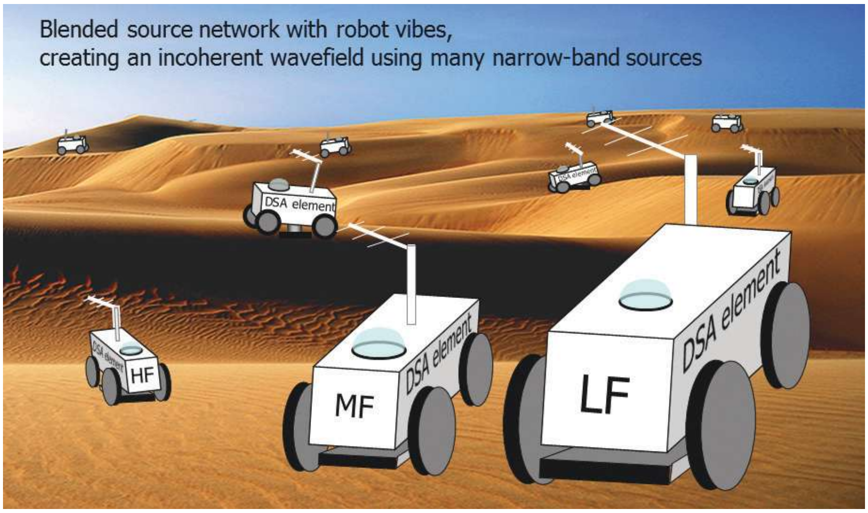


FIGURE 2. This cartoon shows autonomous seismic vibrators, each representing an optimized narrow-band source. All of these robot vibes form together a DSA. DSAs cover the full spatial and temporal bandwidth to illuminate the subsurface in an optimum way. Spatial sampling is source-dependent. (Source: Delft University of Technology)

quencies) and different spatial sampling intervals, together producing a large temporal and spatial bandwidth. Blended land acquisition with DSAs may create a new generation of vibrators that are optimized for a small frequency band, allowing simpler designs and smaller units for the high frequencies. Such vibrators could be based on principles other than hydraulics; e.g., they could be driven in an electromagnetic way. They are the prime candidate to function fully autonomously.

Robotization in seismic acquisition can be compared with the current revolution that is emerging in the car industry, with unmanned and self-driving vehicles on the public road. The schematic shown in Figure 2 describes a distribution of unmanned vibes, each of them covering only a small part of the total bandwidth but together representing DSAs. They produce a spatial and temporal bandwidth that illuminates the subsurface beyond current capabilities.

Seismic remote sensing

The properties of the Earth's surface can be determined in a very accurate way from radar interferometry data obtained by satellites. This technology is already being used in the oil and gas industry to measure changes at the surface caused by the effects of steam or by CO_2 injection in reservoirs by or the effects of gas storage. In such cases, the height of the Earth's surface changes as a result of changes in the subsurface. Obviously, such changes are slow, meaning that they are characterized by very large spatial and temporal scales. This explains the success. Note that a time scale in the order of a week corresponds to a frequency of 10^{-6} Hz.

Of course, in the seismic method geoscientists are interested in frequencies up to the order of 102 Hz. Furthermore, they are aiming at displacements of millimeters down to nanometers. This means that there are still large gaps, both temporal and spatial, between what current remote sensing technology delivers and what is required. In Delphi's robot project the goal is to close this gap, starting with the very low seismic frequencies and large displacements.

For calibration purposes the seismic remote sensing information is supplemented with sparsely distributed calibration sensors referred to as autonomous transition multirotor observation vehicles (ATMOVs). ATMOVs are

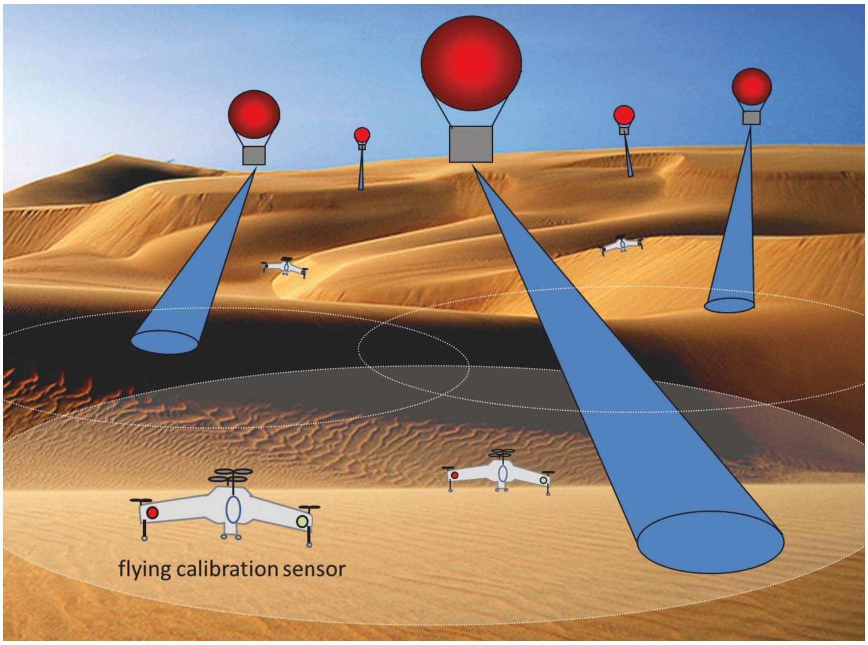


FIGURE 3. Seismic remote sensing is combined with a limited number of specially designed flying calibration sensors. This concept is considered the holy grail in seismic acquisition. (Source: Delft University of Technology)

FIGURE 4. A hovering ATMOV prepares to plant a calibration sensor. When flying longer distances, the wing is rotated 90 degrees, allowing high speeds. (Source: Delft University of Technology)

the latest technical creation from the Micro Aerial Vehicle Lab at Delft University. The application concept is shown in Figure 3, and Figure 4 shows the current model.

Important characteristics of an ATMOV are its ability to take off and land vertically as well as to hover like a helicopter but fly efficiently like a plane. In the Delphi vision, a swarm of ATMOVs provides support in the remote sensing scenario as "flying calibration sensors": The ATMOVs carry the calibration sensors to the required positions, perform the seismic measurements and return to their base once the mission has been completed. In addition, they may carry out other tasks.

Robotization and automation

In addition to acquisition, seismic processing also will become more a matter of intelligent systems and less a matter of human processors. The classical human processor will disappear in the emerging automation wave. This vision, however, does not imply that smart algorithms on powerful computers will take over all of the imaging work in the future. Computers will not replace geophysicists on creativity issues such as imaging strategy and residue analysis, particularly for land.

Without robotization, however, the trend of increasing numbers of sources and detectors in seismic acquisition will level off.

For sensing, the holy grail is to combine advanced airborne sensing technology to simultaneously record the seismic response of an entire area. In the Delphi Consortium, a long-term innovation project on the robotization of seismic acquisition has started. Robots will do all kinds of tasks that they fulfill better than humans, particularly in unsafe areas. E&P

Increased sampling improves signal

As channel count soars, many are reaping the benefits of better land seismic images.

Rhonda Duey, Executive Editor

Anyone who follows seismic acquisition is probably aware of the vast strides made in the marine environment in just a few short years—wide-azimuth surveys, broadband technology and node acquisition, to name a few.

On land it's mostly been about brute strength.

Land acquisition is kind of the ugly stepchild of marine seismic. Instead of towing streamers behind a boat on vast unobstructed tracts of ocean, land acquisition encounters issues with topography and cultural obstacles such as roads and towns. Some areas are so challenging topographically (or environmentally) that vibrator trucks, the standard source mechanism for land acquisition, are unable to access the area, and dynamite must be used. And after all of this additional hassle, land data are never quite as good as marine data due to ground roll effects, shot-generated backscatter, and seasonal and water table changes.

Better sampling density will lead to improved imaging in land surveys. (Source: CGG)

These issues are particularly significant in the Middle East, where a complex near surface tends to obscure the relatively low-relief structures beneath. Over the past few years Saudi Aramco has sought to overcome this problem by experimenting with sampling density, and that discussion is the topic of this year's Society of Exploration Geophysicists' Distinguished Lecture, being given by Peter I. Pecholcs.

An uncooperative environment

In his abstract, Pecholcs describes the near-surface environment as formed by the dissolution of carbonate and anhydrite, or karst, formations. "This dissolution process formed a complex network of open and collapsed caverns that act as secondary scatterers that mask the primary reflections during seismic acquisition," he noted. "Under these conditions, when only 240-channel recording systems were available, it was routine to use a 72-geophone array (six by 12 geophones/string) laid out over an area 108 m by 50 m [354 ft by 164 ft] along with five vibrators per fleet, sweeping simultaneously with a 10-m [33-ft] move-up. Yes, it was a sea of geophones."

Early failed attempt

Technology would soon change, however. In 2001 the company upgraded a 480-channel 2-D crew to 2,880 channels using individual geophone strings and single sweeps instead of infield receiver and source arrays. The group interval was reduced from 25 m to 5 m (82 ft to 16.4 ft). The hope was to attain a higher resolution subsurface image. But the results were disappointing.

During his talk, Pecholcs showed an image from this survey after one year of processing. The data were scrappy at best.

"I was the proponent—I was the guy pushing for source density, receiver density and sampling density," he said. "I thought I was going to lose my job."

He and his team were faced with numerous questions. "It was unclear why we could not extend the high-frequency limit beyond 40 or 60 Hz at best," Pecholcs wrote in his abstract. "Was the signal buried in a broadband backscattered noise floor?"

Over the next few years the group took advantage of increasing recording channel count to improve spatial sampling grids using longer offsets and wider azimuths.

"If you want to do full-azimuth [FAZ] survey designs and you do a single azimuth, you may be unlucky enough to pick the wrong azimuth," he said. He compared the original image with an FAZ acquisition image, brute-stack with post-stack migration. Even the near-surface area showed superior resolution to the original 2-D line. Prior to full processing, the signal to noise (S/N) ratio was vastly improved, he noted.

By 2010, he wrote, "We experienced a seismic revolution in channel capacity." Saudi Aramco was using 25,000 active channels for two production crews and 100,000 channels for one pilot crew, regularly producing several terabytes of data per day. One project, Pecholcs noted, produced one petabyte of raw source records covering 1,700 sq km (656 sq miles). Hardware and software had to be modified to manage these large datasets, and new workflows were developed for traces with low S/N ratios.

"The formation of an integrated team with efficient transverse communication procedures was the key to creative and innovative solutions," he wrote. "The high-resolution time and impedance images, attribute maps, and extracted geobodies brought us one step closer to the engineers."

More to come

In Pecholcs' view, sampling is everything. He said that during the time he and his Saudi Aramco team were seeking to improve spatial sampling, the question came up: How much fold is enough? The answer always seemed to be, "It is not enough," regardless of the sampling density.

To gain the needed improvements, his team experimented not only with receiver density but with source density as well. By using five vibrator trucks and shooting 400 vibrator points per square kilometer (.38 sq mile), the S/N ratio was improved.

The next test was a 32,000-channel survey design. The results with 100-m (328-ft) receiver and line intervals were good. "So I said, 'OK, let's cheat,'" he said. "Let's use the best parameters from this and just decimate the line intervals and see what happens. When we did that, we found out that the line interval also played a very important part in S/N ratio."

In relatively flat areas like those in the Middle East, it's possible to shoot what Pecholcs refers to as a "carpet" of shots, increasing the source density and using high-productivity methods to create a good FAZ design.

In the Middle East a complex near surface tends to obscure the relatively low-relief structures beneath. (Source: CGG)

Ultimately, improving the sampling density can improve the quality of land seismic data to be almost comparable to marine data. Pecholcs showed images comparing conventional land to conventional marine data and also broadband land and broadband marine. "I would argue that land is getting pretty close to marine if you're lucky to get the sampling density that's required," he said.

As the industry continues to make strides in land acquisition technology, seismic processing methodology is struggling to keep up. One improvement Pecholcs would like to see is a move from using acoustic wave algorithms to elastic wave algorithms. "We record in an elastic wavefield; we don't record acoustic wavefields," he said.

And sampling density will continue to increase. "There is one company that has announced that it will be able to record 1 million channels," he said. "Who can pay for 1 million channels is a whole different story." E&P

Formation pressure testing added to LWD suite for complex wells

Modularity allows pressure measurements to be custom-calibrated to further enhance accuracy of the formation pressure testing tool.

Jeff Hemsing, Weatherford

Formation pressure plays a major role in all things related to drilling and producing oil and gas from within a reservoir. Downhole formation testers have long been a key component in a reservoir engineer's analysis arsenal, but acquiring this data has grown more difficult as wellbore geometries have increased in complexity, such as S-shaped, short-radius and increasing horizontal lateral lengths.

Success in these wellbores has come through numerous advancements in directional drilling and LWD technologies. The recent development of LWD formation pressure testing tools is an important step in this evolution. Integration with the LWD platform provides a means of acquiring formation pressure data in wellbores where conventional methods or deployments are difficult or unsafe. The data are transmitted in real time and stored into memory, providing instant access to formation pressures and reducing uncertainties when needed.

Technical answers

LWD formation pressure testing tools present several unique environmental considerations when compared to other formation pressure testing tools. The LWD tools must operate at downhole conditions of temperature, pressure, shock and vibration that are typically encountered while drilling. This is difficult because, generally speaking, formation pressure testing tools are delicate, relying on quartz crystal pressure gauges and moving mechanical parts to provide the measurement.

Any formation pressure testing tool needs to operate autonomously as mud-pulse telemetry limitations prohibit any surface intervention. The level of sophistication required in sensors and controls challenges electronics developers to continually invent new algorithms. The LWD formation testing tools work in a hybrid world between drilling and formation evaluation, requiring high-quality data in minimal time.

The design of Weatherford's PressureWave LWD formation pressure testing tool addresses these challenges in several ways. Data acquired by the tool are handled in real time while drilling via mud-pulse telemetry and recorded to high-resolution, 32-bit data memory. The onboard memory records formation pressure data along with key diagnostic information at much higher resolution and frequency than possible with real-time telemetry. At the surface the data are quickly processed to support decision-making.

The PressureWave formation tester is deployed as part of Weatherford's LWD suite. (Source: Weatherford International)

The tool employs an electromechanical drawdown mechanism that is reliable and easier to maintain than complex hydraulic devices. It also has greater accuracy with precise stopping and locking for advanced analysis and repeatability through a range of temperatures and pressures. The tool's seal-pad construction ensures accurate pressure data measurements in the mud-pulse telemetry environment of the LWD system, with a sealing efficiency of more than 95%.

A modular design consists of valve, pressure, pump and drawdown components. The concept simplifies and speeds replacement to reduce maintenance cycles and lower running costs. Modularity also allows pressure measurements to be custom-calibrated to further enhance accuracy. Operating parameters such as drawdown volume and pad pressure can be changed in response to formation variations to optimize measurement accuracy.

Experience with formation pressure tools

Globally, experience with the LWD formation tester has proven its utility in addressing a variety of well and reser-

voir requirements. These field operations clearly illustrate that the ability to make formation pressure measurements on demand while drilling validates the added LWD expense and exposure. At the same time, acquisition of high-quality data enables optimization of the completion and long-term production.

In Colombia, the combination of an LWD quad combo (resistivity, gamma ray, neutron porosity, formation density and sonic) and the LWD pressure tool provided key data in generating a real-time wellbore stability model. This allowed the customer to extend the drilling window of a long horizontal section safely and efficiently. The pore pressures measured by the LWD pressure tool ultimately validated the regional pore pressure model, enabling the customer to safely drill other wells in the same area.

A North Sea deployment resulted in seven pressure stations that confirmed the presence of a water leg inside the reservoir with a high degree of confidence. The resultant information was then used to validate the overall reservoir and regional pressure trends. The value of an LWD formation pressure measurement solution saved the customer additional rig time, resulting in a savings of more than $1.5 million.

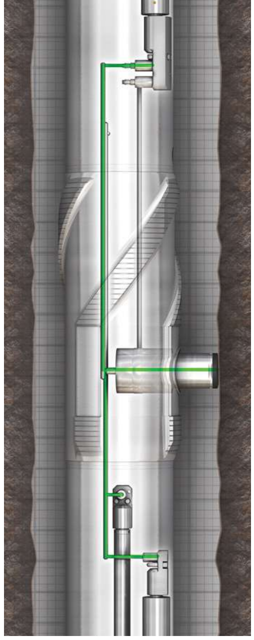
Difficult hole conditions in Ecuador were causing premature cancellation, or worse, lost-in-hole events during formation pressure runs. Typically, the formations that were being drilled were overlain by a severely depleted section that commonly resulted in expensive fishing operations. The LWD pressure tool was able to provide the needed information in an environment where the customer had been looking for alternatives to the conventional way of doing things.

As an introductory test, the customer compared the LWD pressure testing tool against its incumbent technology. The LWD tool was able to successfully acquire the entire testing program while the incumbent technology was prematurely aborted due to hole conditions. The resultant formation pressures successfully identified an oil/water fluid contact and proved the LWD tester's viability as an alternative.

In a Middle East field, the operator used a quad-combo (gamma, bulk density, neutron porosity, resistivity and sonic) along with the LWD formation pressure tester. The data were evaluated while drilling and identified several points for acquiring formation pressures. The formation tester was included primarily for reservoir compartmentalization analysis.

After drilling the hole to total depth, execution of "pumps on" formation pressure stations produced erratic test results that did not meet quality criteria. The cause was a very thick layer of mud cake and fractures in the formation. It was decided to perform the 33 formation pressure stations in "pumps off" mode and retrieve the station results once the tool was on the surface.

The memory pressure tests were successfully conducted, and within an hour of laying down the LWD tools the operator was provided with high-quality data.



The design of PressureWave makes key tool functions easily accessible in the bottomhole assembly, where the tool can be deployed in all operating conditions. (Source: Weatherford International)

Well trials in Gabon

Formation pressure testing with LWD technology was studied in a series of well trials in Gabon. The tests were conducted to integrate the pressure testing tool with the bottomhole assembly, determine operational procedures, and assess data quality and relative efficiency.

The trials examined the performance and measurement quality in a complex field consisting of many interbedded sands with complex fluid flow paths and questionable interconnectivity. The benchmark comparison against previous well operations confirmed identical measurement quality for an LWD triple-combo (gamma ray, resistivity, formation bulk density and neutron porosity) and formation pore pressure. In the end, the economics and performance resulted in selection of the LWD formation evaluation system.

Overall, in the first 10 runs, a success rate of more than 95% was achieved in obtaining a mechanical seal with the formation. Of nearly 400 stations attempted, approximately 60% of the stations were able to obtain valid pore-pressure readings. The remainder did not meet the established pressure quality-control criteria.

The Gabon experiments showed the LWD data quality was equal to the ongoing wireline program and that significant gains in rig efficiency were possible. Following the studies, the operator changed the formation evaluation program to a while-drilling operation using the LWD pressure tool in concert with a triple-combo suite to provide viable alternatives to conventional formation evaluation methods.

LWD formation pressure testing is a significant step in logging wellbores with complex geometries. In these wellbores, where wireline is often challenged, the development of testing technology that operates with the LWD system provides new opportunities to optimize the completion and long-term performance. E&P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Reservoir mapping-while-drilling tool expands well placement

By mapping multiple formation layers at reservoir scale, the mapping-while-drilling service provides a more detailed characterization of production capability.

Bret Peppard, **Cristina Arroyo-Garcia**, **Gunnar Holmes** and **Pablo Tejera-Cuesta**, Shell Brazil; and **Rajeev Samaroo**, **Jean Seydoux**, **Charles Silva**, **Igor Hernandez** and **Jean-Michel Denichou**, Schlumberger

With the rapid development of LWD technology, more detailed real-time information allows improved reservoir understanding. The LWD data collection can provide critical measurements for determining the position of subsurface layers and fluid boundaries, which bridge the gap between surface seismic data and near-wellbore petrophysical information.

Ongoing innovation has taken the industry from the first nondirectional LWD methods with minimal depth of investigation capabilities to a new deep-directional resistivity tool that can map bed boundaries more than 30 m (100 ft) from the borehole.

The electromagnetic directional mapping-while-drilling service delineates intrinsic layering of contrasting resistivity and maps multiple reservoir boundaries and fluid layers in real time. As operators shift their focus to new frontiers with reservoirs of increasing complexity, the new reservoir mapping tool service greatly expands the capability to strategically drill and place well trajectories.

The reservoir mapping-while-drilling service provides a more detailed characterization near the wellbore of a reservoir's ability to produce hydrocarbons. This is possible through the mapping of multiple formation layers at reservoir scale, identifying fluid contacts to determine sweep efficiency and indicating transitions between large sand/shale formations.

Applicable in any well type, the tool consists of multiple subs in the bottomhole assembly that measure resistivity changes along the borehole and map the environment to characterize the reservoir structure at a larger scale. By mapping the reservoir while drilling, the service provides a real-time capability to update reservoir models.

Shell Brazil Petroleo Ltda. used the service with other LWD tools to identify and map the boundaries of a deepwater reservoir to optimally place a horizontal production well. By mapping reservoir boundaries as far as 22 m (72 ft) above and below the wellbore, the service enabled Shell Brazil to more accurately and completely characterize the reservoir and make informed drilling decisions that resulted in significant time and cost savings.

Mapping faulted formation

The well drilled by Shell Brazil was in a deepwater reservoir that targeted a reservoir zone that extended across two fault blocks. The objective was to drill and steer the horizontal production interval from downthrown to upthrown blocks of the fault zone to access reserves on both sides while targeting the reservoir areas with the highest porosity. A pre-job model was built based on conventional seismic and structural data and incorporated petrophysical properties from the surrounding wells.

A small area of the model was updated after a pilot well was drilled in the downthrown fault block. The geological environment of the reservoir is interpreted as unconfined turbidite sands characterized by amalgamated distributory channels with shale zones above and below the reservoir.

The complexity of the reservoir led Shell Brazil to plan for deep electromagnetic directional measurements while

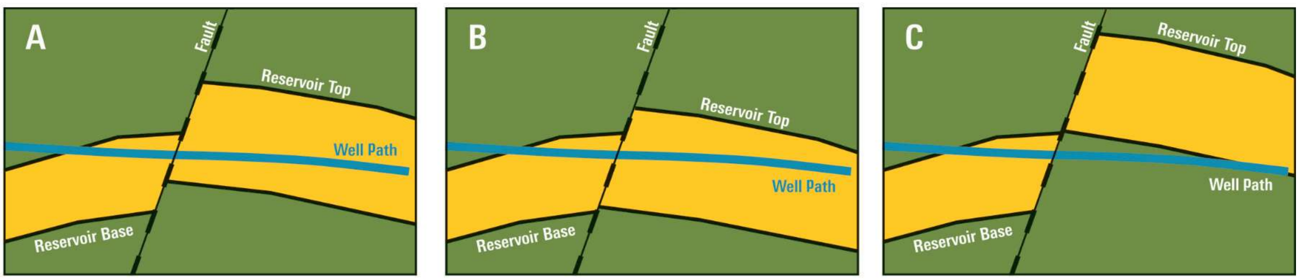

FIGURE 1. Possible scenarios were identified on crossing the major fault (pre-job planning phase). (Source: Schlumberger)

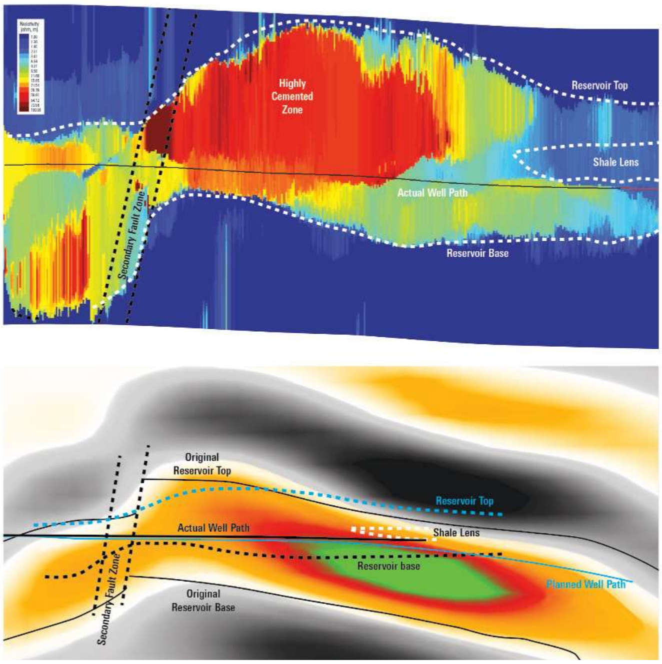

FIGURE 2. Final interpretation of the major reservoir structural and stratigraphic features is shown along with the new interpretation overlaying the seismic section. (Source: Schlumberger)

drilling, mapping the horizontal well path beginning at the casing shoe just above the downthrown fault block, traversing the block and crossing a normal fault into the upthrown fault block. The primary challenge was to determine the degree of offset along the fault plane in conjunction with the uncertainty of reservoir quality encountered after crossing the fault into the upthrown fault block.

Shell devised three scenarios based on the degree of displacement along the fault plane. The first scenario (A) assumed an accurate interpretation of the seismic map, while the other two scenarios (B and C) assumed a smaller or larger than expected fault throw. Scenarios A and B would require only minor adjustments to place the well path in the most productive zone of the reservoir, while scenario C would require a trajectory change upward to re-enter the reservoir (Figure 1).

Based on those scenarios, the mapping tool would allow Shell Brazil to determine the dip, thickness and resistivity profile of the reservoir in the downthrown fault block; ascertain the relative position of the wellbore to the reservoir upon crossing the fault plane; and map the boundaries of the reservoir geometry and resistivity profile while drilling through the upthrown fault block.

Assessing reservoir quality

After exiting the casing shoe, the tool mapped the top of the reservoir to be about 4 m (13 ft) above the well path, as expected from the pre-job model. However, the tool detected the base of the reservoir in the downthrown fault block to be roughly 8 m (26 ft) total vertical depth (TVD)—more shallow to the well path than predicted from seismic.

As drilling progressed, real-time interpretation highlighted the quality of the reservoir, which was within expectation in the downthrown fault block. As the well approached the interpreted fault plane, conventional LWD measurements, including laterolog resistivity images, showed no direct indication of the fault or fault zone, while the electromagnetic directional inversion did.

This revealed significant changes in the resistivity profile away from the wellbore as well as a change of structural dip. As the well entered the upthrown fault block, the base of the reservoir was mapped at about 3 m (9.8 ft) TVD below the well path, while the top of the reservoir was mapped at 22 m TVD above the trajectory. This led to the conclusion that the reservoir was similar to scenario C.

As drilling continued, the inversion continuously mapped key features of the base of the reservoir. After crossing the fault, the resistivity profile from the top to the base of the reservoir was shown to be consistently high, a signature of a more highly cemented interval that was later confirmed with mud-logging data.

While drilling into the upthrown fault block, the top of the reservoir was shallower than pre-job modeling and seismic data had predicted and was at the limit of the tool's detection capabilities.

When the trajectory passed the cemented zone, the resistivity profile of the formation abruptly lowered and continued to reduce as drilling progressed. This area of the reservoir coincided with the high-amplitude zone of the seismic dataset, which was the primary target in the upthrown fault block. The mapping data identified four layers from top to bottom: a low-resistivity reservoir layer, a conductive and likely shale layer or lens just above the trajectory, the lower resistivity reservoir layer in which the trajectory was being drilled, and the underlying shale below the reservoir (Figure 2).

Using the reservoir mapping-while-drilling information, Shell Brazil decided to lower the trajectory from the original plan to better access the more prolific part of the lower reservoir. As drilling neared the planned total depth of the well, reduced resistivity was detected away from the wellbore as well as at the bit. The decision was made to stop drilling 100 m (328 ft) measured depth short of the plan to avoid unnecessary and costly drilling over a nonproductive interval. Following the successful operation, Shell Brazil used the service in 15 wells in 2013 and is currently deploying it for 20 more wells in 2014. E&P

'Look outside the tank'

Water storage issues bring benefits of above-ground tanks to surface.

David Nightingale, Rockwater Energy Solutions

The life cycle of water in the oil field is primarily viewed as a logistical problem concerning the movement of water from a source to the field and from the field to treatment or disposal. One of the most overlooked factors is storage.

Storage issues are associated with the process at nearly every step and affect the economics of water reuse. Although great strides are continually being made in oilfield water-treatment technologies, water storage is one of the biggest impediments to universal oilfield water reuse.

Tanks and in-ground pits have historically been used for field water storage and continue to be used in many operations. The high-capacity above-ground storage tank (AST) is a recent innovation that has quickly become an industry standard in large-volume temporary storage because it allows operators to save money on their produced water recycling operations.

With capacities ranging up to more than 40,000 bbl, ASTs supplied by Rockwater Energy Solutions can replace more than 80 standard tanks used in hydraulic fracturing operations—tanks that, on average, can handle 500 bbl each. ASTs are available in multiple sizes ranging from 4,500 bbl to 41,000 bbl. These steel ASTs can be more than 3 m (10 ft) tall and are typically lined with a system of recyclable polyethylene liners and geotextile underlayments to prevent leaks. Structural integrity of the tanks is usually checked through regular nondestructive tests like magnetic particle inspection and ultrasonic testing.

Environmental responsibility

Operators seeking to advance sustainability goals have turned to ASTs to reduce truck trips and their associated emissions, dust and road damage when compared with conventional tanks. A 40,000-bbl AST can require four to 12 tractor-trailers to hold the ancillary equipment required for setup vs. the 80 tanks requiring 80 tractor-trailers. That can amount to a reduction of more than 150 truck trips.

The physical footprint of ASTs compared to average tanks provides an additional environmental benefit as it relates to ground disturbance and logistics on location. For example, a 40,000-bbl AST covers approximately 1,858 sq m (20,000 sq ft), whereas the same volume would require 80 tanks covering about 3,344 sq m (36,000 sq ft). Not only does an AST take up less space, but it also reduces clutter on location by eliminating manifolds and hoses, helping to prevent slips, trips and falls.

Economics of water storage

ASTs were designed to maximize per-well capital efficiencies—a concept that is now field-proven as horizontal wells completed on multiwell pads become more widespread. AST costs—including daily rental, set up and tear down—are usually lower than tanks for large fluid volumes and multistage wells.

Beyond the set-up costs, water transfer is where the most significant cost savings are realized. ASTs improve the efficiency of water transfer operations, reducing the number of failure points by using fewer connections and valves. An illustrative breakdown of the cost per barrel reveals lower set-up and tear-down water transfer costs, daily rentals, and labor charges, which in turn translates into significant savings on overall water management (Table 1).

TABLE 1. AST and traditional hydraulic fracturing tank costs are compared, where water transfer rates are held constant during a typical plug-and-perf completion in a long-lateral shale play application. (Source: Rockwater Energy Solutions)

Water Transfer Costs with Tanks	Per bbl	Water Transfer Costs with AST Storage	Per bbl
Manifolds, hoses, etc.	$0.08	Manifolds, hoses, etc.	$0.01
Pumps - 2 pumps	$0.03	Pumps - 1 pump	$0.01
Labor - 1 supervisor, 2 operators (24-hour operations)	$0.42	Labor - 1 supervisor, 1 operator (24-hour operations)	$0.28
Rig up and tear down	$0.09	Rig up and tear down	$0.05
TOTAL	**$0.62**	**TOTAL**	**$0.35**
43% Savings in Water Transfer Costs with AST			


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Optimal storage for water treatment

Water treatment programs stand to gain the most by incorporating ASTs for incoming water and treated water storage. Water stored in 80 tanks instead of one 40,000-bbl AST is more challenging to maintain operationally and to assure the consistent quality of treated water. This is important to any field water-treatment system because water in an AST can be homogenized before and after treatment.

The process of collecting and analyzing samples from 80 tanks requires significantly more time than evaluating four or five samples from a continuous content storage unit, whether a pit or an AST. A consistent water base before treatment means fewer variation requirements in the treatment process, which reduces labor and materials and also ensures more consistent water afterward.

A homogenized treated-water base for hydraulic fracturing allows the pressure-pumping company to maintain operations without having to change chemistries due to base-water variation, which can be the key to a successful completion. Although a more consistent treated-water quality can be achieved by improving the consistency of the incoming raw water from an AST, treated water can and does vary.

Changes in treated water alkalinity, pH, dissolved iron, oxidation reduction potential, free available chlorine, dissolved oxygen, bacteria numbers and biocide residuals may change as the time between treatment and use is lengthened. Changes in just one of these attributes may have a profound impact on guar hydration or crosslinked fluid stability.

Regulations on fluid storage vary widely by state depending on the fluid type. Progress is being made in North Dakota, Pennsylvania, Colorado, Wyoming, and other states toward the use of ASTs for produced-water storage. A nested tank in a system recently piloted by Rockwater demonstrated how a liner failure could be isolated, thereby reducing the risk of catastrophic tank failure. This innovation should improve the economics for water reuse and potentially change the landscape of oilfield water storage.

Smaller footprint, lower cost

Determining the true cost of storage requires looking outside the tank. It is simple math that above-ground storage can have a tremendous environmental impact by reducing the number of truckloads. However, the cost of conventional storage is often overlooked in terms of supporting services such as water transfer and water treatment programs.

When water management is approached holistically and all processes and services are considered in the construction of a well instead of looking at compartmentalized services, the result can be an optimized solution with a reduced environmental footprint at a lower cost to the operator. E&P

A Rockwater AST can hold more than 40,000 bbl of water and can replace more than 80 standard tanks that, on average, can handle only 500 bbl each. A nested tank system is shown. (Source: Rockwater Energy Solutions)


HYDROZONIX


Legislation could keep good times flowing in Texas shales

Possible infrastructure solution could circumvent state water-transportation issues.

Sue Snyder and **Taylor Holcomb**, Vinson & Elkins

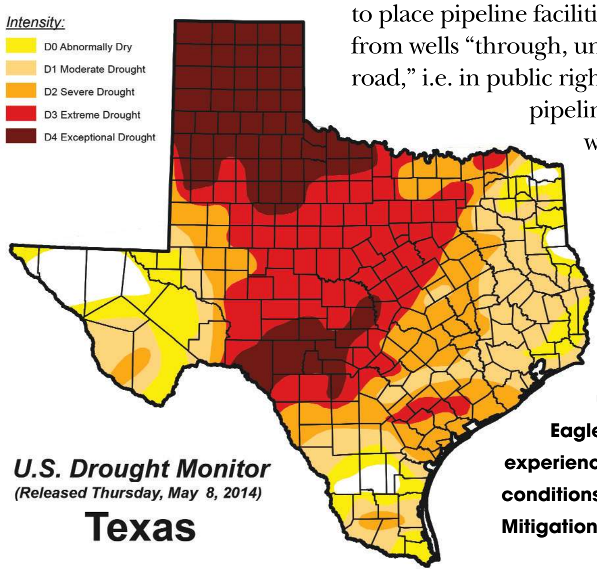
Long a staple of Texas' economy, the oil and gas industry is again robust, thanks to the shale revolution. According to the Texas Petro Index, for example, Texas oil production is at a 34-year high and comprises 36% of total U.S. production. But a lingering concern for oil and gas companies hoping to continue riding the shale revolution wave is water availability.

Recent activity in the Texas Legislature provides hope for the oil and gas industry to add to the state's water infrastructure and also make easier the use, reuse and recycling of water. This may provide operators with more operational flexibility and conservation options.

Water availability

Drought conditions concern the oil and gas industry not just because of lack of water availability but also for public relations purposes—many critics of the industry and of hydraulic fracturing specifically voice concerns about the industry's water usage even though the entire usage of water by those involved in hydraulic fracturing is less than 1% of total water consumed in Texas (although amounts vary widely by region). Water concerns are being expressed especially at the local level, where some groundwater conservation districts have attempted to limit or restrict use of groundwater for hydraulic fracturing through the permitting process.

The backdrop for the water concerns is the persistent drought condition. Texas Gov. Rick Perry issued on July 5, 2011, and subsequently reissued as recently again as March, a proclamation certifying exceptional drought conditions in the state and suspending all rules and regulations that may inhibit or prevent prompt response to drought threats. The review of the U.S. Drought Monitor's Texas drought map reveals that drought effects are much more serious in some areas of the state than others. In particular, the areas around the Permian, Eagle Ford and Barnett shale plays are experiencing "severe" or "extreme" drought conditions.



As of early May when this map was updated, areas around the Permian, Eagle Ford and Barnett shale plays were experiencing "severe" or "extreme" drought conditions. (Source: The National Drought Mitigation Center)

Infrastructure for water transportation

Water is not easily moved within Texas. With respect to surface water, for example, the Texas Water Code prohibits transfer of surface water from one state river basin to another absent special authorization from the Texas Commission on Environmental Quality. And with respect to groundwater, some groundwater conservation districts have enacted rules making it challenging to transport groundwater outside district boundaries.

The general lack of a large water transportation infrastructure impinges on the use of both water and recycled water. With respect to alleviating problems associated with the lack of infrastructure necessary to convey water over distance, the enactment of Senate Bill 514 should be of immediate interest to oil and gas companies. Trucks are currently the primary means of delivering water to and removing it from production sites. The intent of S.B. 514 was to reduce roadway use by such trucks by authorization to place pipeline facilities to transport waters produced from wells "through, under, along, across or over a public road," i.e. in public rights-of-way. S.B. 514 defines eligible pipeline facilities as those transporting water "containing salt or other substances" produced during drilling or operating an oil, gas or other type of well. Thus, an oil and gas operator producing water from wells ranging from oil and gas to

groundwater may possibly rely on S.B. 514 to transport the water for oil and gas sites along public rights-of-way.

To take advantage of this new authorization, pipeline operators must comply with three requirements. First, they must comply with applicable Texas Department of Transportation (TxDOT), county and municipal rules. Second, pipeline operators must restore public roads to former conditions after pipeline installation. And third, they must pay fair market value for use of public rights-of-way.

TxDOT is currently developing rules to implement S.B. 514. It has held a stakeholder meeting to gather industry input but has not yet formally proposed rules. Because S.B. 514 took effect on June 14, 2013, oil and gas companies can approach TxDOT about using these beneficial provisions even before it promulgates rules. Operators will want to watch and perhaps comment on the proposed rules when they issue.

What to expect going forward

The 83rd Texas Legislature considered numerous measures concerning the use of water for oil and gas operations. Environmental issues and encouragement of recycling were the subjects of many bills that did not pass. One of the lesser known bills—S.B. 514—actually became law and is of much more significance than many may think. It offers solutions not just for transportation of produced water but also for other types of water associated with oil and gas activities. The rules coming out of TxDOT will be closely watched to make certain the bill is implemented to allow effective use of pipelines in a manner that promotes conscious water management and minimization of environmental impacts.

Whether S.B. 514 will successfully alleviate the state's water transportation infrastructure problems or whether oil and gas companies will widely use it remains to be seen. Regardless, oil and gas companies should be encouraged that new opportunities are available to alleviate economic and environmental issues and that will assist in enabling more water conservation and reducing environmental effects while promoting further resource development. E&P

Technology takes hydrocyclone water treatment to next level

New process for safe, stable water treatment introduced.

Mark Wolf, National Oilwell Varco

The march of offshore production facilities into deeper and more hostile environments combined with increasing environmental awareness and regulation drove the quick adoption of hydrocyclones for water treatment on offshore platforms. The argument for hydrocyclones was compelling: Substitute pressure-driven centrifugal force for gravity to do the separation work.

The hydrocyclone promised superior water quality at a fraction of the real estate needed for its traditional onshore cousins, the skim tank and the float cell. Several hydrocyclones were installed in the North Sea. They worked well, so adoption of the technology moved rapidly to the Gulf of Mexico (GoM), answering the call for space and weight reduction on floating structures. Today every corner of the offshore world looks to hydrocyclones as the primary method for produced water treatment.

Lessons on hydrocyclones

While hydrocyclones became a go-to solution everywhere, the engineers designing and operating deepwater facilities in the GoM soon learned a lesson about turbulence, shear and oil-droplet size that would impact the hydrocyclone's ability to make clean water. Engineers on the big floating facilities dealing with much smaller separation vessels had to pass water along with the oil through control valves with large pressure drops.

When produced water with oil passes through a control valve, severe turbulence chops and disperses oil drops into much smaller droplets in much the same way that the nozzle on a garden hose can atomize water into a mist. The same hydrocyclones installed in the GoM were not as effective as they had been in the North Sea.

Larger oil droplets will move quickly to a hydrocyclone's core, where they can be separated. The tiny oil droplets formed by control valves move much more slowly so that some of them don't reach the core and instead pass through with the water. Because of this, U.S. operators dealing with less efficient hydrocyclones adapted by adding water-treatment chemicals and more sophisticated equipment downstream, including vertical flotation cells, filters and oil-adsorbing media.

The second lesson on hydrocyclones is their poor response to changes in flow and pressure. A well-tuned hydrocyclone operating at steady conditions can produce very clean water with oil concentrations well below most discharge standards. Unfortunately, oil is produced in a complex network of wells, piping and separation vessels that stubbornly refuse to provide steady conditions for the water treatment system. The job of tuning the hydrocyclone is complex and usu-

Mark Wolf, left, product line manager for Process Technologies at NOV and inventor of the WaterWolf DOR System (shown in the background), stands with Colin Tyrie, right, principal consultant for Clean H_2O Services. (Source: National Oilwell Varco)

ally involves breaking containment to change internal components. Since water flow rates can vary by the hour, the hydrocyclone is almost never tuned well enough to produce water quality that meets discharge standards.

Safe and sound, onshore and off

National Oilwell Varco has addressed the problems created by turbulence and changing water flow rates with the introduction of its WaterWolf, which combines hydrocyclone and progressing cavity pumps with a new process called dynamic oil recovery (DOR). The DOR process keeps the hydrocyclone properly tuned regardless of changes in flow and pressure from the separation system without using control valves that can shear oil droplets and make the water difficult to treat. The result is a water treatment system that produces water suitable for discharge without the use of chemicals or additional treatment steps.

While initially conceived as a solution for the offshore community, it is the onshore operating community that has first taken notice of the technology. Since integral progressing cavity pumps generate the pressure energy needed by the hydrocyclones in the DOR process, a WaterWolf skid can replace or operate side by side with traditional skim tanks and doesn't need additional pressure from the main separator.

This means that hydrogen sulfide gas (H_2S), which is highly soluble in water and is often collected, burned and released into the atmosphere as sulfur dioxide gas (SO_2) after a skim tank cleaning, is no longer an immediate threat at a pad where the WaterWolf is operating.

Unlike skim tanks, removal of oil and solids occurs within a pressurized and fully contained system. That means an operator can eliminate the emission of hazardous pollutants and greenhouse gases from skim tanks and also can eliminate costly and hazardous tank cleanouts to remove accumulations of solids in the tank bottom if it is using a WaterWolf instead of or along with a skim tank.

Simple economics

A well-designed and -operated skim tank working in conjunction with a good chemical treatment program can still leave in excess of 100 ppm of oil in the produced water. This residual oil is lost once it goes down a saltwater disposal well. Many tanks will pass as much as 1,000 ppm to 2,000 ppm of oil. While this may not sound like a lot of oil, the lost volume can quickly add up.

One hundred ppm of residual oil equals 1 bbl of oil for every 10 Mbbl of water. And 1,000 ppm equals 10 bbl of oil for every 100 Mbbl of water. Approximately 60 MMbbl of water are produced from oil wells every day in just the U.S., which means the country may be throwing away 5 Mbbl to 50 Mbbl of oil per day with its wastewater.

The new system, which does its job without the need for water-treating chemicals, will recover 90% to 95% of the lost oil while removing solids that will otherwise plug disposal wells and drive up energy and maintenance costs. These results make the DOR process an economically attractive addition for operators of mature high water-cut fields and saltwater disposal facilities as well as for the offshore industry, where its hydrocyclone roots originated.

The new system can help provide a much cleaner and safer future for workers and for the neighbors who live and work around oil production facilities. By reducing the overall cost and environmental impact of handling higher water volumes, it can extend the life of mature wells so they can contribute to the economy for many more years to come. E&P

The WaterWolf combines hydrocyclone and progressing cavity pumps technologies with the DOR process. (Source: National Oilwell Varco)

Direct electrical heating goes deeper

As the oil and gas industry continues to move into ever deeper waters, the need for flow assurance technologies increases.

Stine Kvande, Nexans Norway

The trend toward deeper waters and longer transportation distances presents a particular challenge for subsea production flowlines since the combination of high pressures and low seawater temperatures can result in hydrate formation or wax deposits inside the flowline. Such deposits can reduce and even completely block the flow of oil and gas from the template, especially during operational shutdowns and tail production periods.

Several methods are employed to prevent the formation of hydrates, with chemical injection perhaps still being the most widely applied. During the last decade, however, direct electrical heating (DEH) has emerged as an attractive alternative. DEH controls the flowline temperature to maintain it above the critical threshold for hydrate formation. By heating the flowline electrically, the need for chemical injections is reduced considerably. This "cleaner" approach also leads to significantly reduced operating costs.

DEH

The DEH system takes advantage of the fact that an electric alternating current (AC) in a metallic conductor generates heat. The flowline to be heated serves as an active conductor in the electric circuit formed by the riser cable, the feeder cable, the piggyback cable and the flowline.

AC is supplied from the topside power system via the riser cable. Subsea, the riser cable is connected to the feeder cable in a subsea junction box. Using the feeder cable, one of the phases in the riser cable is connected to the flowline near end, while the other phase is jointed to a piggyback cable. The latter is strapped to the flowline along the entire length to be heated and connected to the flowline at the far end. The flowline then becomes the primary return conductor in the system and is heated due to its own electrical resistance (Figure 1).

For safety and reliability reasons, the flowline is electrically connected to the surrounding seawater (i.e. it is an "open system") through several sacrificial anodes. These aluminum anodes are rated for both corrosion protection and sufficient grounding of the system during the

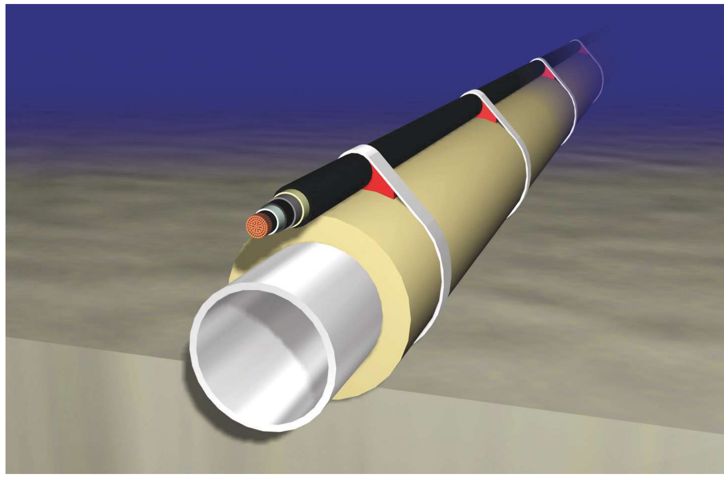


FIGURE 1. The piggyback cable is strapped to the flowline, which then becomes the primary return conductor in the system. (Source: Nexans)

expected lifetime of the flowline and the service life of the heating system (Figure 2).

During operation, current is fed to the far end of the flowline through the piggyback cable, and the current returns through the steel flowline and seawater. At each end of the flowline the current is distributed between flowline and sea. Here, additional anodes are mounted to the flowline to form a well-defined low-impedance path for the current to sea (Figure 3). This part of the flowline is known as the current transfer zone.

Nexans Norway has pioneered the development of DEH in partnership with Norwegian operators and research organizations. Nexans has carried out qualification testing for more than a decade and has designed cables and equipment to meet the specific needs of each DEH system. The world's first DEH installation was performed in 2000 for Statoil's Åsgard oil and gas field in the Norwegian Sea, where it serves to heat the flowlines from 6 C to 27 C (43 F to 81 F) to prevent hydrate formation.

To date Nexans has delivered more than 225 km (140 miles) of DEH cables to heat 19 flowlines.

Deeper waters

Nexans is currently manufacturing the DEH system for the subsea flowlines serving the Lianzi oilfield develop-


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FIGURE 2. For safety and reliability reasons, sacrificial aluminum anodes electrically connect the flowline to the surrounding seawater. (Source: Nexans)

ment located in a unitized offshore zone between the Republic of Congo and the Republic of Angola. With a water depth of up to 1,070 m (3,510 ft), this will be the world's deepest DEH system.

In the future, the goal is to reach even greater depths. Nexans has performed feasibility studies, and in an internal development project Nexans is working on developing a DEH system for deeper waters, aiming for 3,000 m (9,843 ft).

When designing a DEH system for such large water depths, there are several new issues to consider. Increased weights and loads, material qualification data, water pressure influence and long cable catenary lengths are some of the issues that differ significantly from the traditional DEH systems typically installed at 300-m to 400-m (984-ft to 1,312-ft) water depth. One of the biggest challenges is that copper is unable to carry its own weight at deeper waters due to poor mechanical properties.

Because of the growing interest in deepwater applications in the offshore industry, Nexans has previously qualified a dynamic deepwater power cable for 3,000-m water depth.

The dynamic deepwater power cable contains three copper conductors, and an optimized combination of lay-angles is applied to achieve a desirable stress distribution in the cable cross section, thereby preventing mechanical overload of the conductors. This is achieved by transferring as much of the tensile load as possible from the copper to the armor by applying steel armor with long lay lengths (small lay angle) while the copper conductors are wound with short lay lengths (large lay angle). This means that the length of the copper is greater than the length of the armor per meter of cable. The longitudinal elongation of the armor is therefore larger than the longitudinal elongation of the copper. The friction between the layers combined with the compressing effect from the armor when tensioned ensures that the elements do not slip inside the cable. In addition, a flexible center profile allows the power phases to move toward the center due to induced contact forces from the helically wound armor wires. This will further reduce the conductor stress and also give a more uniform distribution of induced contact stresses acting on the insulation.

The same principle also can be used in riser cables, and this is one possible method for designing a dynamic riser cable for large depths. Alternative material choices and configurations also are being explored.

It is not only the riser cable that provides challenges when designing a DEH system for large water depths. If the piggyback cable is to be designed for a traditional repair scenario, it must be brought to the surface and must therefore be able to carry its own weight. Metallic elements in the piggyback cable other than the conductor reduce the efficiency of the DEH system, and this is not recommended. Therefore, alternative methods of reducing weight or increasing axial stiffness must be considered. This can be achieved by considering new conductor material choices or configurations. E&P

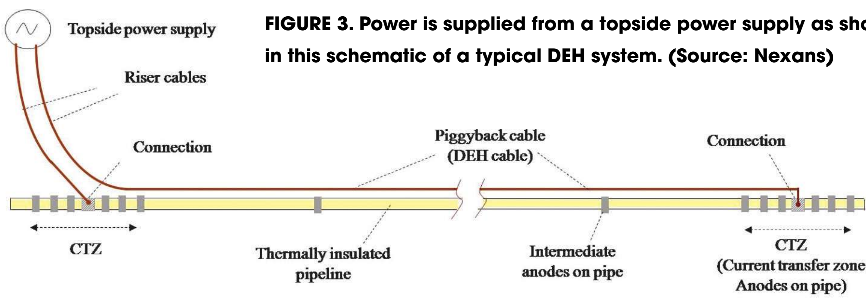


FIGURE 3. Power is supplied from a topside power supply as shown in this schematic of a typical DEH system. (Source: Nexans)

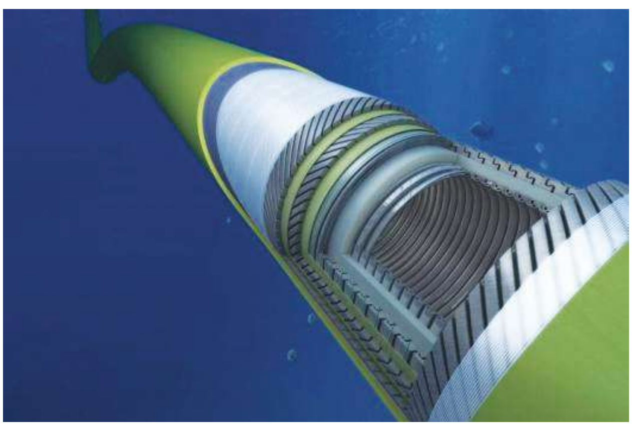
New inspection ensures structural integrity of flexible risers

New approach to integrity management uses electromagnetic stress measurement technology.

Geoff Eckold, GE Oil & Gas

Flexible pipes are the physical link between the seabed and topside of offshore installations, used to safely and cost-effectively transport hydrocarbons from the ocean floor to the surface, or for gas lift and water injection purposes. As offshore exploration and production has increasingly ventured into deeper fields, flexible risers have become a critical component of floating offshore facilities such as FPSO installations. Recognizing the importance of these flexible risers, operators are now using innovative technologies to monitor their performance to ensure integrity while maximizing availability and reducing the possibility of unnecessary downtime.

Monitoring the integrity of a riser can be challenging due largely to its complex design. To cope with the demands of the dynamic loading typically experienced with floating installations, the construction of flexible pipe consists of multiple unbonded steel armor "wire" and polymer layers enclosed within an outer sheath. While these layers are critical—each has a different role from preventing collapse or leaks to enabling the movement of the surface support—the resultant complex structure makes it difficult for conventional inspection techniques to provide the necessary monitoring for impactful integrity management. It is a situation that is further complicated by the confined area at which a flexible pipe faces the most significant integrity risks: the region between the splash zone and the top termination. This area is particularly congested, allowing no access for externally mounted inspection equipment.



The multilayered structure challenges the effectiveness of conventional inspection or monitoring methods. (Source: GE Oil & Gas)

A new approach for overcoming these difficulties involves the use of an electromagnetic stress measurement technology deployed to the outer surface of the flexible pipe with the ability to sense deep into the structure to gauge the integrity of the primary load-bearing elements—the steel armor wire layers. This methodology, known as MAPS-FR and underpinned by GE Oil & Gas' MAPS stress measurement technique, allows for actual stress levels in the multiple wire layers to be measured, enabling operators to detect capacity degradation at the onset, thereby presenting new opportunities for assessing and reacting to structural condition.

With conventional inspection methods, typically the measurement equipment needs to be sited directly over the area where integrity is in question to enable the opportunity for detection. MAPS-FR is unique in that it is able to sense the effects of wire damage many meters away from the actual damage site itself. This is possible due to the unbonded nature of the pipe's construction, which means that wire stress distribution can be seen both at the break and from an extended distance away in either direction. Another feature of the MAPS-FR approach is that it is not reliant on the detection of a transient response. Because wire degradation leaves a lasting impression on stress distribution, MAPS-FR instead can detect this at any time following an event. Coupled with its ability to provide information wire by wire and layer by layer, the system takes measurement reliability for flexible pipe to a new level.

The magnetic stress measurement technique

Magnetic techniques offer the scope for stress measurement in flexible pipe because they can be noncontacting, allowing them to measure steel wire stress through the

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polymer layers used in the outer protective sheath without any penetration into the structure. The magnetic properties of a ferromagnetic material (for example, iron and nickel) are sensitive to internal stress, with the MAPS-FR technology able to pick up and compare stress changes across adjacent wires to establish a good stress state vs. a bad stress state.

With factors such as mechanical hardness, grain size, texture and material properties also affecting magnetic parameters, the challenge lies in the ability to separate these effects from the desired stress signal. In addition, such techniques rely upon the creation of a magnetic circuit to measure the properties of the steel material, with the performance of this circuit highly dependent upon the distance between the measurement sensor and the steel (or in the case of flexible pipes, the details of the various wire layers and their interaction).

Application to flexible pipe

The application of MAPS-FR on flexible pipe is possible in two forms: as a monitor for permanent installation or as a scanning system for in-service inspection.

For monitoring purposes, multiple fixed sensors are distributed around the pipe with the number of sensor elements dependent upon diameter and wire count. The MAPS-FR can be fitted to the exterior of the pipe, allowing the equipment to either be integrated within a newbuild or retrofitted onto an existing riser in service. Meanwhile, the software system is flexible, and data management can be configured to meet the needs of the operator.

For an inspection device, a single sensor can be deployed and used to scan the riser surface so as to obtain information from each of the wires. The scanner system is controlled by a software script that manages both the sensor movement and the collection of data in a format ready for transmission and interpretation.

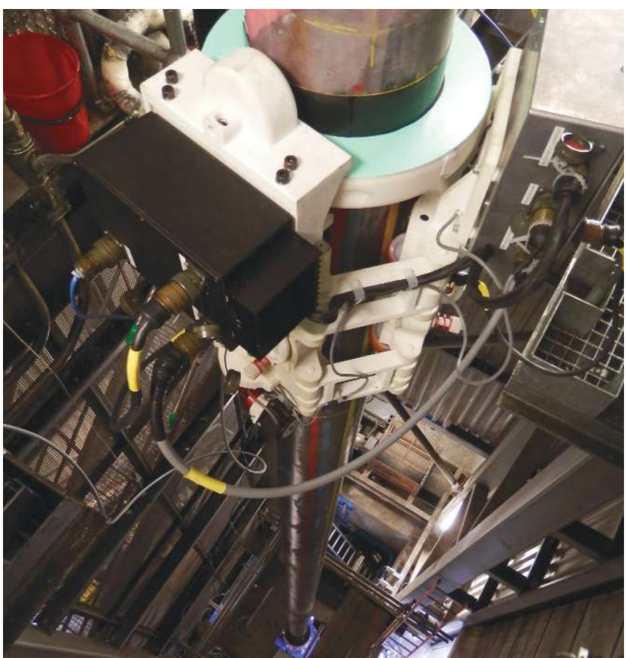
For a flexible riser, regions of particular concern lie in the top section of the pipe, including close-to-the-end fitting, where there is a significant change in stiffness between the riser and the connector; within the I-tube, where elevated temperatures can accelerate degradation; underneath the bend stiffener at the "work point," i.e. the position of maximum cyclic bending; and the splash zone itself, where damage to the outer sheath can result in flooding of the annulus between the inner and outer polymer layers. The MAPS-FR technology can effectively monitor or scan in service this entire region from a single location, tackling the typical access issues posed by this congested region.

In some geographies the requirement for the inspection of flexible pipe continues to be an increasing need as systems approach their originally specified design lives and strategies to allow life extension are developed. Meanwhile, changing field conditions provide further incentives. For example, in some reserves increasing levels of hydrogen sulfide have the potential to put riser structures originally designed for "sweet" service at greater risk, with significant amounts of the acidic gas capable of causing damage through sulfide stress cracking. A means of monitoring and/or inspecting the load-bearing armor wires therefore becomes even more of a necessity.

Then there are the inevitable consequences of long-term operation in the rigors of the offshore environment: physical damage sites due to third-party incidents, for example, and the need to manage the repair to ensure satisfactory continued service.

Practical infield examples

Today, the technology is being used to carry out offshore inspections on in-service flexible risers with a current focus on assets in the U.K. Continental Shelf. This region was an early adopter of flexible pipe, and there are now several examples of installations presenting life extension opportunities. Inspection equipment such as that described above has been deployed, configured to suit the FPSO vessel's constraints of access and with the inspection tasks proceeding as planned. There are now examples of risers in continued operating service following a MAPS-FR inspection. This activity shows that electromagnetic stress measurement technology can provide a valuable contribution to the integrity management of flexible pipe in-service. E&P



By using the MAPS-FR inspection scanner, the integrity of the primary load-bearing elements of the flexible pipe—the steel armor wire layers—can be gauged. (Source: GE Oil & Gas)

Midcontinent continues to evolve

Conference presentations reflect evolution in players' knowledge of play's resource versatility.

STAFF REPORT

Of the 77 counties in the state of Oklahoma, 70 are oil- and gas-producing. Many of the wells in those producing counties touch in some way the Mississippi Lime or Woodford Shale resources that have bumped the state back into the petroleum-producing picture that it once starred in. At Hart Energy's recent DUG Midcontinent event, several presentations focused on the state's resource versatility, and one keynote looked at the global energy picture.

Petrie's perspective

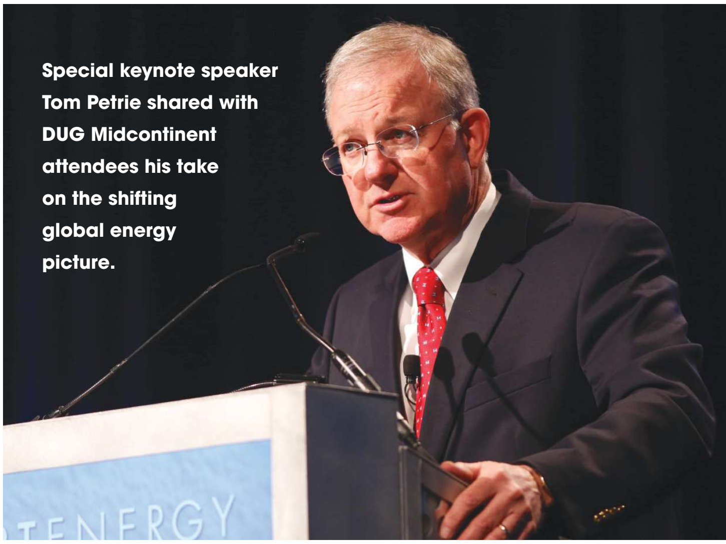
If Tom Petrie peers into a crystal ball in his home in Colorado, he likely sees clouds. Not dark clouds, necessarily, just enough to mask conventional wisdom.

"One thing I've learned over 40 years is that the future usually turns out differently than the emerging consensus at any one time," the chairman of Petrie Partners told an attentive crowd at the event. "And I think that's likely to prove the case today."

The former vice chairman of both Bank of America and Merrill Lynch is no pessimist. He has overseen more than $200 billion in energy merger and acquisition (M&A) deals in his career and possesses a keen understanding of the relationship of the industry to global geopolitics. At the moment, he sees a wealth of potential in the North American unconventional oil and gas bounty, but he tempered his rosy outlook with a list of risks and challenges that he believes the industry must recognize and confront.

"The pursuit of those shales and the power of that pursuit have become something of enormous proportions and strategic significance for the U.S.," Petrie said. He noted three major trends that led to today's boom in unconventional exploration and production:

- ***Oil price supercycle:*** "The industry's pricing prospects are very event-driven, and many of those events are very geopolitical in nature. And that's something we should not lose track of because it's where the surprises could very well come." Influential events in the past four decades include the Iran-Iraq war, Iranian revolution, OPEC quotas, Iraq's invasion of Kuwait, OPEC production cutbacks, the 9/11 terror attacks, "peak oil" fears, "fiscal cliff" concerns and the Syrian civil war.



Special keynote speaker Tom Petrie shared with DUG Midcontinent attendees his take on the shifting global energy picture.

- ***Three M&A consolidation waves:*** The first was in the first half of the '80s, another occurred in the late '90s with the creation of oil supermajors and the third and most important in 2001 to 2005 resulted in a major consolidation of publicly traded independent companies. This last consolidation freed up a lot of intellectual capital that went back to work for private equity and played a major role in the rapid pursuit of shale opportunities.
- ***Evolution of technology:*** "The power of that notion that the old model was giving way to a new one." M. King Hubbert built his projections of peak oil on the old model, one that involved multiple risks of generating hydrocarbons, having them migrate in a timely way, be captured in highly productive reservoirs and have a good seal. Multiplying out each of those factors creates an industry formula for wildcat success of one chance in eight.

The result: "Unlocking hydrocarbons from tight shales and doing it economically; making sure the energy in is meaningfully above the energy out; and doing it with the now-evolved state of technology where we can drill deep, go horizontal, stay in zone and achieve an unlocking of those hydrocarbons with ever-more-effective fracking designs, well seals and so on—it is, in fact, incredibly transformational," he said.

Petrie cited research in *The Future of Natural Gas,*

published by the MIT Energy Initiative in 2011, for his argument in favor of U.S. natural gas exports. One of the study's co-chairs was Ernest Moniz, now the U.S. secretary of energy.

"This is a critical pressure release valve," he said. "If one just poses the alternative of not allowing gas exports, which is clearly off the table at this point, one would realize that, in the absence of this pressure relief valve, we'd be snuffing out one of the great economic opportunities of this century, or the first half of this century."

The MIT study reinforces a favorite theme of Petrie's: the interaction of seemingly disparate events and how they influence the course of actions.

"If you look at this forecast that was done in 2010, there was a big component forecast by MIT for Haynesville," he said. "We're falling well short of that. What's happened is the Marcellus, coming on in the way it has with its potential to actually exceed the productivity of the country of Qatar later in this decade, squeezing down productivity and the prospectivity, at least for a while, for both the Haynesville and the Fayetteville. And it's that kind of interaction—that dependent interaction, if you will—that I think is going to characterize some of the other plays as we go forward. It's worth keeping an eye on that."

Petrie warned of a number of risks that demand attention by the industry. Fugitive methane is a major one. He also focused on opposition from environmental entities opposed to hydraulic fracturing.

"We really need to take the anti-fracking initiatives in Colorado and elsewhere quite seriously," he said. "The fact is, if they gain momentum as in the past, we could begin to change the supply prospects later in this decade and certainly in the decades beyond."

And that's a future that Petrie does not want to see.

Evolution of the Mississippi Lime

Predictable, repeatable and oil were three of many descriptors often applied to the Mississippi Lime play in 2010 and 2011, according to Gibson Scott, director of energy research for ITG Investment Research. But now? Words such as complex, variable and NGL dominate conversations about the play.

"It is pretty clear that the industry's understanding, and by virtue of that, investors' perceptions of the play have changed over time," Scott told attendees at the event. "Key themes that Mississippi Lime operators and investors face today include the variability of performance, how geologic indicators may be used to determine sweet spots in the play and how completion designs differ by operator."

In compiling the analysis of the play for the conference, the ITG team looked at oil production data taken directly from production reports of more than 1,000 Oklahoma and Kansas wells. Public operators included in the analysis were Chesapeake Energy, Devon Energy, Midstates Petroleum, Range Resources and Sandridge Energy.

"Few plays are as geologically complicated—or found in jurisdictions with data qualities as challenging—as the Mississippi Lime play in Oklahoma and Kansas," he said. "We spent a great deal of time collecting, parsing, scrubbing and analyzing oil production data directly from production reports rather than the state data."

These well production reports provided many key insights. Take, for example, variability in well performance across the play. It is driven by both geology and operator completion designs, Scott said.

Noting that the data showed a general trend to oilier production moving east across the Nemaha outlet, he added that the hydrocarbon mix is extremely variable, even across short distances. "The geology of the Mississippi Lime itself is extremely complex," he said. "Often a single lateral may encounter limestone, dolomite and chat."

It is due to this variability that most operators tend to focus on discrete regions of the play, he said, with small programs varying widely from the mean. Plotted out, the well data showed that Midstates Petroleum achieved the highest per-well oil productivity of the group, about 200 bbl/d on average.

"Sandridge and Midstates have drilled some of the best-performing individual wells within our sample," Scott said. "In fact, several wells drilled in Grant, Woods and Alfalfa

Gibson Scott spoke on the Mississippi Lime's ever-evolving nature.

counties produced more than 1,500 barrels per day during their peak month."

High-rate wells, or those wells that produced more than 1,000 bbl/d during their peak month, showed a steep decline profile, Scott noted, with production from an average high-rate well falling 90%.

"Overall, we observe a peak calendar month IP-to-EUR [initial production to estimated ultimate recovery] relationship of about 1 to 600, which indicates that the Mississippi Lime average well, or at least its oil production, tends to decline more steeply than some of the other resource plays we look at," he said.

The completions process also can have an impact on the performance of Mississippi Lime wells. "Given the geologic variability of the plays, it's pretty unlikely that one practice would fit all regions," he said. "We believe that operators will have to tailor their specific approach to their own respective areas."

The typical Mississippi Lime well today is drilled with about a 1,219-m (4,000-ft) lateral, up from 762 m (2,500 ft) in 2009, he said. About a million pounds of sand was typically used in these wells, a figure that has remained pretty consistent over the past three to four years.

"Chesapeake historically used the most proppant in its completions," he said. "In fact, Chesapeake has decreased its sand volumes each year and is now more in line with Sandridge's at about 700,000 pounds of sand. This doesn't appear to have materially impacted its test rate, which actually climbed over time."

The analysis found that the average Mississippi Lime well recovers about 97 Mbbl of oil, with Alfalfa and Woods counties exhibiting best-in-class peak oil rates and recoveries, Scott said, adding that activity here is dominated by Chesapeake, Midstates and Sandridge.

"In terms of Chesapeake specifically, its activity is really concentrated in Alfalfa and Woods counties, where it's achieved a three-year average oil recovery of more than 120,000 barrels," he said. "We estimate that Chesapeake's most recent wells recover more than 130,000 barrels of oil."

Woods and Alfalfa counties are home to most of Mid-

states' activity, he noted, adding that while its oil recoveries have deteriorated, they still remain among the best in class for Mississippi Lime operators.

Devon's activity spans five counties focused east of the Nemaha outlet, according to Scott. "Although production east of the Nemaha is generally oilier, oil recoveries tend to be lower," he said. "We estimate Devon's most recent wells recover about 60,000 barrels of oil, with its best results coming from Payne and Noble counties."

Range Resources' activity also is concentrated east of the Nemaha outlet and is similar to Devon in its production results. Its wells tend to be oilier and also tend to recover less oil, according to Scott. "We estimate that Range's Mississippi Lime wells recover about 70,000 barrels of oil on average," he said.

With activity in 16 of 22 counties, Sandridge is the more widely distributed operator across the play. "Alfalfa, Harper and Grant are among its best performing counties," he said. "Sandridge also has exposure in Sumner County, Kansas, which may identify as being an emerging and a potential new core area. Our average Sandridge curve, which includes its exploratory and extensional acreage, recovers 99,000 barrels of oil over a 30-year well life."

While performance across the play varies widely, Scott noted that operators like Sandridge are able to gain a competitive advantage through large statistical programs, established infrastructure and cost-saving measures. Companies like Midstates were dealt a better hand geologically, but each company will have to tailor its own drilling and completion designs for its respective areas, he said, adding that "we're still on the learning curve in terms of what's going to work best in each area."

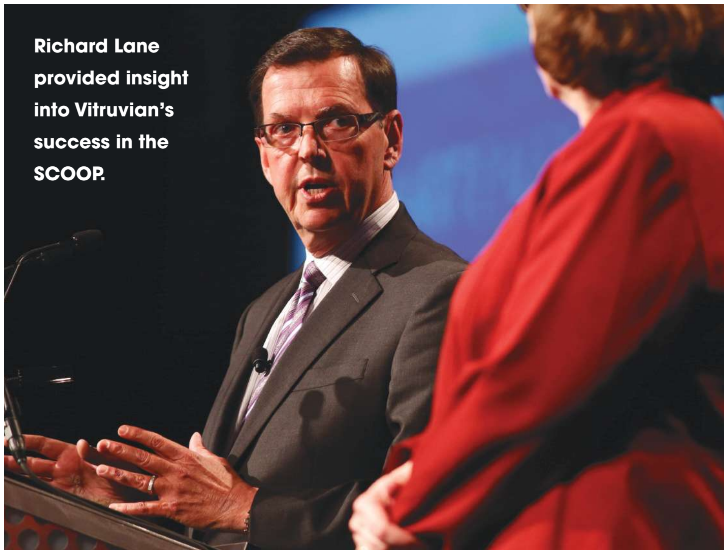
Vitruvian SCOOPs up success

By the end of this year, Vitruvian Exploration II aims to have 16 producing horizontal wells in the Woodford South Central Oklahoma Oil Province (SCOOP) shale play with an operated production growth of 270%.

Richard Lane, the company's president and CEO, shared insight on the company's operations and plans for the SCOOP area during the event. The company is entering the second year of its drilling campaign in the area after acquiring Chitwood-Knox legacy assets in December 2012.

"What really got us interested in the SCOOP area was the excellent reservoir rock," Lane said. "Our team described it as the best unconventional reservoir rock that we've come across. That's after looking at a lot of plays in a lot of different basins.

"It's got the right kerogen type. It's got great organic carbon. It has good maturity indexes. It has the condensate to go with it and the NGL," Lane continued, later



Richard Lane provided insight into Vitruvian's success in the SCOOP.

adding the average EURs are greater than 2 MMboe. "The thickness is excellent, [with] high porosities, good permeability, fairly silica-rich rock. All of that gives rise to a tremendous resource with about 150 Bcf to 200 Bcf [4.2 Bcm to 5.7 Bcm] per section."

Vitruvian operates about 62 sections. The Woodlands, Texas-based company's SCOOP assets, totaling about 38,000 contiguous net acres, are located in a highly concentrated liquids-rich window. About 350 vertical wells came with the purchased acreage. "We have to manage those vertical wells, but the other nice attribute is that our acreage block is held by production," Lane said.

But this year Vitruvian will dive deeper into its drilling campaign, investing $181 million. The company currently has three rigs operating, with averaged IPs of about 1,400 boe/d. A fourth rig is expected to be operating by July 2014. Plans for the year includes spudding six 1,372-m (4,500-ft) laterals and 12 laterals of 2,286 m (7,500 ft). Of the 18 wells spudded, hopes are for 16 to be producers by year-end, with production ramping up to about 12,000 boe/d.

That equates to revenue. The company anticipates bringing in more than $12 million in revenue per month and will consider adding rigs based on how well operations go in the first half of this year. "In the pretty near term, with the activity levels we have planned, this starts to be a self-funding asset from the cash-flow that is generated," Lane said. However, the positive outlook doesn't mean there is nothing left to learn or improve.

Vitruvian has learned that not all wells are the same. Each requires area-specific optimization. The company is learning, as it goes, where to drill wells longer and where not to and continues to learn from its nonoperated interests to gain data points to obtain more knowledge. E&P

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All-electric subsea system can improve functionality

Technology allows longer step-outs and is not limited by water depth.

Mary Hogan, Associate Managing Editor

OneSubsea's all-electric subsea production control system represents the first of its kind. The system—formerly known as the CameronDC System—first came online in September 2008 and is able to address issues related to functionality, long step-outs, water depth limitations and common failure modes of conventional electro-hydraulic (EH) MUX systems. The technology, which also can help prepare operators for the digital oil field, won Hart Energy's 2009 Meritorious Award for Engineering Innovation in the production systems category.

Since the system's introduction and initial use as part of the K5F project, OneSubsea has received a purchase order for delivering a third tree for the field, located in the Dutch sector of the North Sea. "This extension to the 2008 scope is currently under construction and builds on the performance and lessons learned during the initial installation," said Jan van den Akker, control systems product manager for OneSubsea. The system's all-electric controls can offer advantages in functionality by providing a more intelligent way to control chokes whereby field data are instantly driving the choke position to allow certain flow regimes. A standard choke may be too slow and not geared up for the increased use over the life of the field.

The system also allows longer step-outs. "With our patented technology there are no real limits when it comes to distance, compared to the challenges faced when using a control fluid in offsets longer than 200 km [124 miles]," van den Akker said.

Additionally, the company's all-electric actuators are not affected by water depth by design, a significant trait when considering that the size of a hydraulic actuator is heavily influenced by the water depth in which it operates.

Many failure modes in traditional systems stem from seal degradation or control fluid property issues like contamination. The company's all-electric system does not use any hydraulics but instead uses electronics and electric actuators. "Similarly to other industries, electronics reliability is easier to achieve and control," van den Akker said.

With more and more equipment operating off the seafloor, future installations will require more data to implement software models that read diagnostic data, support preventive maintenance regimes and allow the use of more sophisticated production optimization tools. With preventive maintenance set to play a larger role than today's reactive behavior, it is more important than ever for operators to be prepared for the challenges of the digital oil field. "The implementation of all-electric technology from OneSubsea will provide significantly more data that can be used to implement intelligent field management tools," van den Akker said.

"With our patented technology there are no real limits when it comes to distance."
—Jan van den Akker

Since the system's introduction, the company has completed the development of a second-generation all-electric system. "The inputs come from lessons learned, standardization targets and the drive to reduce costs," van den Akker explained. "Our latest generation is as modular as OneSubsea's current EH MUX Control System, and it shares the same communication network using fiber optics and our standard protocol." The updated system has been optimized for more field scenarios and more capabilities such as simultaneous actuator operations.

While the first generation needed two modules per tree, the latest version has been condensed to a single module that shares the same footprint as the company's standard EH MUX subsea control module. "With these enhancements, an all-electric production control system is as cost-effective as our standard EH MUX system, while further enhancing the reliability of the complete system," van den Akker said.

OneSubsea is a company jointly owned by Cameron and Schlumberger. Visit *onesubsea.com.* E&P

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Nanotechnology changing company asset protection

Insulating film holds up to harsh climates and corrosive conditions.

Francesca Crolley, Industrial Nanotech Inc.

When Henateks, a textile manufacturer for Nike, Adidas and Reebok, was looking for a way to lower its energy-intensive yarn and fabric dyeing, its general manager explored a then-new product that was a clear insulating coating based upon a patented nanotechnology. It used the paint-on insulation to coat large dyeing machines, steam pipes and valves to lower heat loss, thus lowering energy consumption for its manufacturing process. At the end of the second year the company had saved more than $852 million in NGL costs, and its project payback was seven months.

Now, after a decade of proving itself, this technology has been used by many other market sectors around the world, including the oil and gas industry, which was the sector the technology was originally created for.

A technician measures the thickness of the nanomaterial on a tank wall. (Source: Industrial Nanotech Inc.)

New technology addresses industry needs

In 2002 the founder and CEO of Industrial Nanotech Inc. was investigating industry needs that might be addressed with the scientific discoveries happening in the field of nanotechnology. He saw an opportunity in the oil and gas industry to help reduce the large costs experienced due to corrosion under insulation (CUI). The problem stems from traditional forms of insulation in use as far back as 1938, when fiberglass insulation was invented that did not bond with the surface and trap moisture beneath the insulation. This causes the dual problem of corrosion from the trapped moisture and degradation of the fibrous insulation, which is not made to stand up to moisture.

By working with a specific nanomaterial that has an extremely low thermal conductivity as well as a hydrophobic nature, he was able to incorporate the nanomaterial into a clear water-based coating system and create a patented technology that both insulates and prevents corrosion, thus solving the CUI issue.

Corrosion and insulation data

When the technology was first introduced to industry and government at an annual corrosion conference in 2005 for insulation and corrosion control of pipelines, tanks and other assets, there was skepticism that a water-based coating could perform as well as the epoxies currently in use. So the company tested and presented data that proved that this new technology was up to the standards that industry depended upon and that it performed well in corrosion, prevention of CUI, adhesion and thermal insulation tests.

The technology was tested to the GM9540P standard, an accelerated cyclical salt-spray test that is used by the U.S. Navy. Passing eight cycles with no rusting is considered a minimum “pass” for a corrosion control coating. The Nansulate nanotechnology-based coating passed 24 cycles with no rusting or loss of adhesion.

Two other oil- and gas-related standards tested were BP standards for resistance to CUI and thermal conductivity. The testing is done over a pipe section with heated oil inside held at 130 C (266 F) that is subject to being sprayed with artificial seawater periodically every 24 hours throughout the test. After the 100-day test, the coating showed a consistent insulating performance

with no loss of performance due to the salt spray and excellent resistance to corrosion with no flaking.

Adhesion is a very important element to any coating, especially those meant to prevent corrosion, since any loss of adhesion leaves open an area of the surface, which could corrode. Nansulate was tested to the ASTM D4145 for pull-off strength and, with a rating of 2,400 psi to 2,450 psi, was comparable to the high-quality marine epoxies on the market.

Breaking through barriers

The main barrier to wider initial adoption of this technology was that it was innovative and changed the way one equates thickness to insulation. So education was a large part of the introduction process, explaining how thermal barriers work and why thermal conduction is a more accurate way to express insulating ability than a simple R-value. When new technology allows insulation in a much thinner layer than in the past, standards that evaluate performance need to keep up with that technology, which is not always the case.

Along with education and testing data came field studies, which Industrial Nanotech knew would help to prove performance in real-world conditions. Over the last 10 years the company has gathered these data in multiple industries and in climates as varied as Alaska and the Middle East. The field studies remain a testament to the performance of this technology in facilities around the world, including in some of the harshest environments.

Offshore China

Nansulate coatings are a patented nanotechnology-based form of thermal insulation that provide additional benefits such as corrosion prevention and moisture resistance. Because the technology is meant to be applied at much less than an inch (just a few hundred microns), explaining the way that it insulates to the oil and gas industry proved a challenge but one that was well worth the time educating engineers about the newest advances in nanotechnology.

One large and innovative company that has seen the advantages firsthand is Sinopec, China's state-owned oil and gas company. During the winter of 2012-13, it performed a field study on an offshore fuel oil storage tank stationed in the East China Sea. The degraded fiberglass insulation and cladding was removed, and the company treated the corroded areas that had been caused by CUI and coated the large tank with a 12-coat (1,200-micron) application of the Nansulate thermal barrier and corrosion prevention coating. Testers observed its performance from October 2012 through March 2013, the months when keeping their fuel at between 68 C and 72 C (154.4 F and 161.6 F) provided the biggest challenge due to the cold temperatures.

At the end of the testing period, it was determined that the nanotechnology coating kept the oil temperature within 3 C (5.4 F) of the 8.0-cm rock wool insulation with cladding that the company had used previously to insulate its tanks, plus it did not degrade in the moist, salty air environment, and it prevented corrosion of the tank. In addition, engineers had the ability to see the surface of the tank through the clear insulation coating, which would allow them to easily inspect it as needed. After the field study, they were convinced by the performance and plan to upgrade to this new insulating technology to protect more of their assets.

Changing with the times

A benefit of this paint-on insulation is that it improves how people insulate on a large scale—from buildings to tanks to manufacturing equipment. It lasts much longer than fibrous insulations in humid and outdoor environments, and it greatly lowers payback periods when compared to technologies like solar.

There was a time when Bill Gates and Steve Jobs spent years educating companies about their new computer technology. They were turned away by many until the technology spoke louder than the naysayers. Nansulate is following a similar path—the coatings have been proving themselves since 2004, and corporations are now taking a serious look at them as they realize the impact this technology has on their bottom line, energy efficiency, asset protection and carbon impact on the planet. E&P

The Nansulate coating is sprayed on a steam pipe. (Source: Industrial Nanotech Inc.)

Embracing the next digital wave

Executive provides a 35-year reflection and projection on the future of the industry.

Steve Roberts, BP

Geophysicists 35 years ago used colored pencils, 10-point dividers, and hand-drawn maps and contours, and computers were just being introduced. People predominately communicated through telephone or telex, and the Internet, fax, CD and multiterabyte hard drives didn't exist.

Since then, the pace of digital change has significantly accelerated. What will the next 35 years bring? How will we ensure that the oil and gas industry can continue to keep up with these advancing developments?

Fast-growing industry

Due to the increasing global demand from many industries, computers have developed very quickly, and the digital industry has continued to evolve at an increasing pace. We now have the ability to display data and information in real time on electronic 3-D seismic displays to interpret geological models and use geosteering techniques to guide in real time where the wells are directed. Drillers also have embraced the digital information era, starting to use data streams analyzed in real time to avoid stuck pipe and to optimize the position of the wellbore. Increasingly, operating engineers are relying on vibration and equipment monitoring to optimize maintenance schedules, track chemical treatments and optimize water handling.

Considering the future

It is extremely difficult and challenging to imagine what the next five or 10 years will bring. But the plants, rigs and production platforms being built today will probably still be operating in 25 to 35 years.

How are we future-proofing the design of our facilities? How are we planning to upgrade them several times over the next few decades to take advantage of the inevitable advances in digital technologies that will come along?

The industry is still using the same methods to extract oil and gas as it has done for more than 100 years, and it is fascinating that with intelligent energy we are trying to combine one of the fastest-changing technologies with perhaps one of the slowest-changing extraction techniques.

One of the big questions facing the upstream oil and gas industry is how we will attract and retain the next generation of engineers when there will be so many exciting opportunities in other industries to leverage predictive and autonomous digital analytic and modeling techniques.

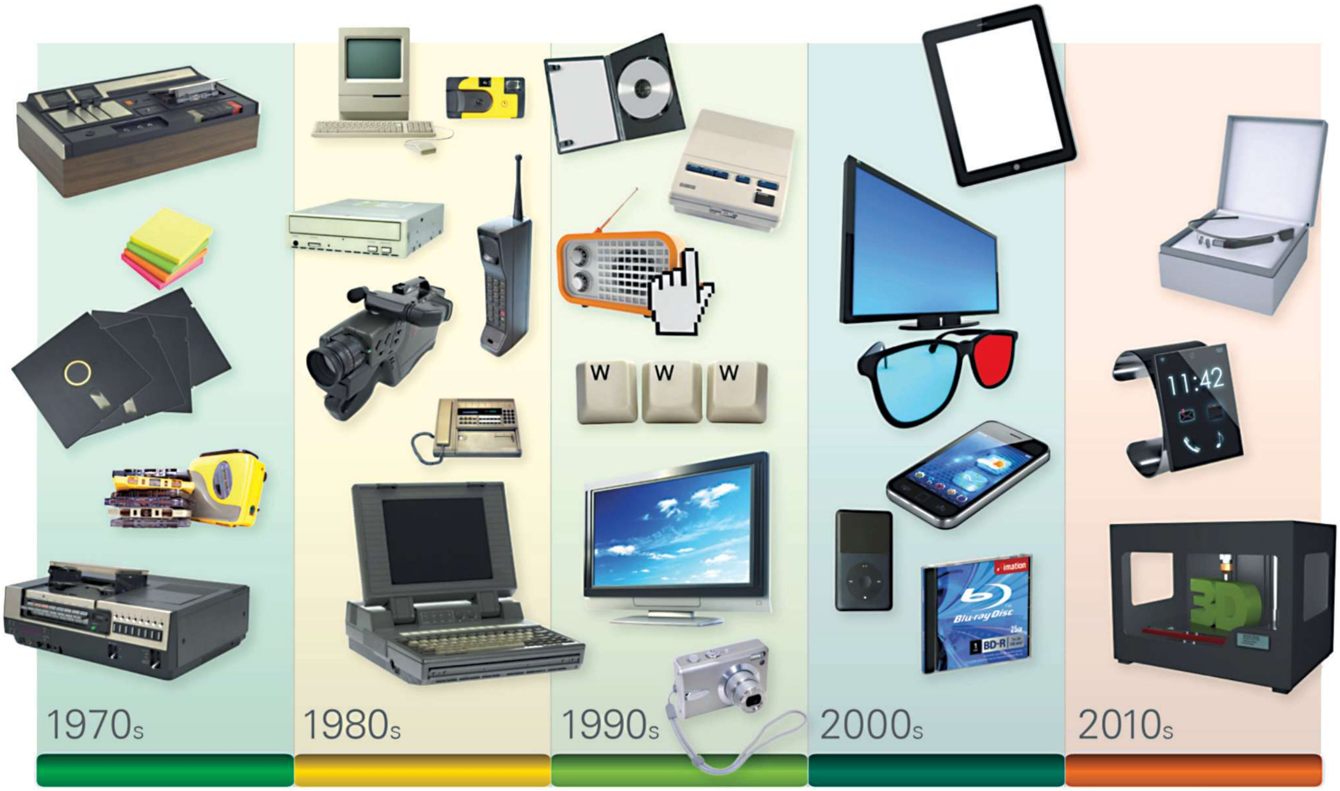
These are challenges the industry will soon face. However, we are still catching up, experimenting in many areas on how to further leverage the currently available digital hardware and analytic capacity to the issues we face today upstream. We are not yet forward-thinking enough to set ourselves up for true success.

By anticipating the future rather than just focusing on the "what's available now" or the "what's the flavor-of-the-month technology," the industry can better embrace the short-term opportunities while stretching its aspirations.

Anticipation

First, how should the industry anticipate what is coming along on the digital front that might be relevant to it? It can help to look back and identify trends to help us think more directionally about the future. The last 35 years have highlighted a number of trends that many think will continue. Some of these are:

- ***Redundancy:*** Devices and technologies have been invented, put to good use and then surpassed and replaced by the next generation. The time cycle has been reduced during the last century and certainly during the last 35 years. The pace of redundancy will continue to accelerate;
- ***Miniaturization:*** The space race was the catalyst for miniaturization of electronics. It led to more of an uptake in electronics by many industries for multiple purposes. Now miniature computers can be fitted nearly anywhere, from the car to the refrigerator. Finding space in facilities and drilling rigs to take advantage in the future won't be a problem;
- ***Convergence:*** Ten years ago many people carried cameras, mobile phones and laptop computers. Today's devices multitask, and one device can nearly do everything. Software originally designed for specific purposes has converged toward integrated interpretation and optimization systems that are beginning to meet the needs of several disciplines;



Integrating and accessing data are the latest trends in data management. (Source: BP)

- ***Standardization:*** This is becoming increasingly important as the need to exchange data continues to grow. The proliferation of standards groups is evidence of the emerging need to manage data in a more structured and standardized way;
- ***Visualization:*** The increasing subtleties and complexities of information mean that it will be crucial to more powerfully visualize it in a way that removes ambiguity and facilitates understanding. This has happened in the aerospace industry, where much more information is now available but the cockpit landscape is still relatively small. Information has to be presented in integrated and sequential ways, where only relevant information is visible when required, but users have the confidence that it can be viewed at any time;
- ***Amalgamation:*** Data centers and "cloud services" have consolidated where information is stored and from where services are provided. People don't know where much of their personal digital data is stored and probably don't care as long as it is secure and they are able to access it quickly; and
- ***Capacity:*** Demand for and the supply of bandwidth also has been growing at an increasing rate. Wired cables have been surpassed by fiber-optic and wireless connectivity. This growth is likely to continue to the point that fast connectivity becomes ubiquitous. Similarly, compute capacity has seen exponential growth, and cycle times will continue to become shorter. In the near future, the expectation that complex models and workflows will deliver results in near-zero time will be a reality.

As the upstream industry transitions from conventional, generally manual ways of working to running the business based on predictive, actionable information that is updated in real time, integrating and accessing information will become the new tools of the trade. The challenge will be to make information ubiquitously available, understandable and unambiguous.

Coping strategies

Some coping strategies will minimize the impact of future change and enhance industry's ability to adapt and apply new technologies.

- ***Standardization:*** As outlined earlier, this is a trend that has been increasing over the past few decades. The use of data exchange standards such as those that Energistics and others are developing will become more and more important. Standard ways of storing, transmitting and integrating data will

need to become mandatory to fully unlock the future potential of intelligent information. Data standards will be the key to mass adoption and the ability to integrate actionable information;

- ***Centralization:*** One means of reducing the footprint of change could be to centralize activities, infrastructure and services, but this could be regarded as a high-risk strategy since it has vulnerabilities. This strategy can also help the industry grapple with the demographic change and skill shortages it faces. In theory, centralization of activities should require less person power and be more efficient if the intelligent information is available to support the model;

A modern visualization workstation resembles the cockpit of an airplane. (Source: BP)

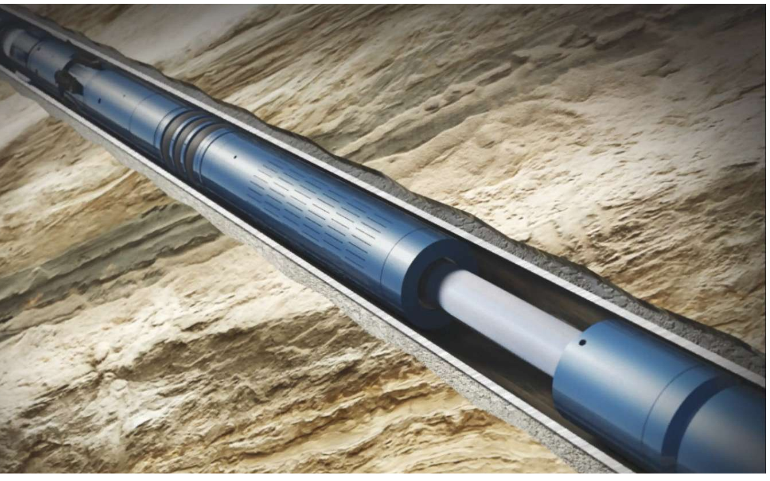
- ***Agnosticism:*** In our information technology choices, it would be prudent to be agnostic to device, server and to some extent architecture designs. More enduring choices are needed in areas such as data-exchange standards that might outlive several phases of IT hardware or in the ability to minimize the exposure footprint. Existing technology will not be in the same form in 10 years' time;
- ***Minimization:*** This requires judiciously selecting data that needs to be collected from where and for what purposes and then designing, with a minimalist bias, where the analytics and presentation occurs. The aim of this strategy is to take a holistic view of where the supply and demand for intelligent information is in a given asset system and to try to segregate and minimize where the analytic centers should be. This approach should lead to more evenly distributed digital systems with no one center dominating. Everything is interconnected, and this design should help with resilience and backup;
- ***Automation:*** This approach is aimed at reducing the need for engineers to do everything manually. Many manual checking processes could be automated and provide additional assurance. The more the human element is reduced, the less process adjustment and training effort will be needed when the inevitable system upgrade comes along; and
- ***Simplification:*** Simplification of business processes will contribute to reducing the footprint required for intelligent systems, thereby minimizing the upgrade/redundancy burden. Simplifying the design of the system so that it is easier for mass adoption and upgrade is another benefit.

Business or technology leaders are often asking themselves, "Are we taking advantage of the latest technology to continually improve our business?" and adjusting their investment plans accordingly. However, a far more important question might be, "Are we adequately planning for and anticipating the pace of change that we need to embrace to be successful in the longer term? Are we moving fast enough to simplify what we do, automate where we can and minimize the upgrade footprint of our intelligent systems?" The facilities being built today will probably still be operating several decades from now, but the technology being invested in to run them will be obsolete, sometimes before construction completes or plateau production is reached. Applying coping strategies to the design of intelligent information systems, organizational constructs and process changes could help in the near future.

It is impossible to predict how data will be stored, transmitted, manipulated or presented in the next 35 years. However, the work purposes for which we want to use data can be determined as well as the ways to minimize the requirements for them. This offers the best chance to take advantage of these future intelligent information technologies. E&P

Spear performs multiple cut and pull operations in one trip

The Harpoon cut and pull spear from Baker Hughes is designed for casing removal during plug and abandonment and slot recovery operations. The spear can be set and reset several times, enabling multiple cut and pull attempts in a single trip. This increases the likelihood of retrieving the casing in one run, improving efficiency and reducing costs. The ability to reset the spear is advantageous in situations where cement stringers, scale buildup and other downhole factors can make pulling the casing at the initial cut point very difficult. The spear is run with a cutting assembly and does not require a stop ring, which allows the spear to engage the casing directly above the cut and ensure maximum force is distributed at the cut point. The tool reduces nonproductive time associated with additional trips and increases the overall efficiency, safety and economics of casing removal, the company said in a product announcement. *bakerhughes.com/harpoon*



The Harpoon cut and pull spear can be set and reset several times, increasing the likelihood of retrieving the casing in one run. (Source: Baker Hughes)

Slim hanger expands limits of where gauges can be placed in wellbore

Peak Well Systems' Hi-Ex Gauge Hanger allows the slickline deployment of data acquisition devices through narrow constrictions in the well, expanding the envelope of where gauges can be positioned within a wellbore, according to a company news release. The slim but expandable design of the hanger minimizes flow restriction so that operators can record accurate data during production or injection conditions. The tool is deployed to suspend data acquisition gauges during well testing

The Hi-Ex Gauge Hanger allows the deployment of data acquisition gauges through narrow constrictions in the well. (Source: Peak Well Systems)

and production monitoring and also can be used as an anchoring platform in nonmonobore wells. The Hi-Ex Gauge Hanger is deployed from surface using Peak's eSetting Tool. At the required depth in the well, the eSetting Tool activates and sets the hanger, expanding its arms and centralizing it in the tubing. The hanger is securely anchored in the well via bidirectional slips. It is retrieved using an external fishing neck pulling tool along with any gauges that may have been deployed. *peakwellsystems.com*

Gauge allows measurements from one side on internally corroded pipes

The 27MG Ultrasonic Thickness Gauge from Olympus is designed to make accurate measurements from one side on internally corroded or eroded metal pipes and structures, a company press release said. It is made for inspectors and maintenance engineers who need to monitor the wall thickness in metal pipes, tanks, beams and structural supports that are susceptible to corrosion on the inside surface. The ultrasonic gauge saves time and cost by transmitting sound into the material from the outside without needing to damage the part. The tool has many measurement features that are available on more advanced-thickness gauges despite weighing only 12 oz. and being easily operated with one hand. The battery-operated gauge features a large backlit LCD and a color-coded keypad with direct access to many features. Standard features include automatic probe recognition to optimize transducer performance, auto zero compensation for accurate measurements on hot surfaces, gain adjust to improve measurement on sound-attenuating materials and differential mode. *olympus-ims.com*

Printers aid analysis in harsh environments without extra supplies

The Printrex 920 and Printrex 980 color printers are useful to oil and gas companies for addressing the complexities of analyzing both seismic data and oil wells during all phases of exploration and production, TransAct Technologies Inc. said in a press release. The Printrex 920 was developed specifically for use in the oil field. The clear and detailed printouts from the machine show important information allowing accurate, real-time analysis and decision-making at the well site. The printer also is designed to withstand the harsh environments of remote locations. The 920 uses thermal technology allowing it to print in color and black and white without ink cartridges or ribbons so no supplies are needed. The Printrex 980 color office printer is a full-color inkjet printer with the ability to print continuous well logs at the rate of 8 in. per second. *transact-tech.com*

Leak detector features industry's first ANN intelligent drive

Designed with artificial neural network (ANN) intelligence and real-time broadband acoustic sound-processing technology, the Gassonic Observer-I Ultrasonic Gas Leak Detector provides ultrasonic gas leak detection with suppression of false alarms. Its applications include FPSO vessels, petrochemical refining plants, gas/hydrogen storage facilities, gas compressor stations, LNG/GTL trains and LNG regasification plants. The ANN technology makes it possible to fully analyze the sound spectrum down to 12 kHz, and its algorithm has been "trained" to automatically distinguish between unwanted acoustic background noise and dangerous gas leaks. This design provides a broader leak detection range, which also increases sensitivity to smaller gas leaks without interference from unwanted background noise. The technology also enables the detector to be installed without time-consuming "training" sequences and provides a detection distance up to 28 m (92 ft). *gassonic.com*

The Gassonic Observer-I Ultrasonic Gas Leak Detector's ANN technology enables operators to analyze the sound spectrum down to 12 kHz. (Source: Gassonic)

Ruggedized DTS designed for remote, hostile environments

Silixa Ltd. released the XT-DTS, a high-performance ruggedized distributed temperature sensor (DTS) for remote and hostile environments, the company said. The unit collects extremely fine-resolution data over an operating temperature range of -40 C to 65 C (-40 F to 149 F). The XT-DTS is part of the company's Ultima DTS family and is a low-power DC-operated sensing unit that offers a new level of insight into previous unobtainable data collected in very harsh environments. The system can be configured and controlled remotely via a wireless or satellite link, enabling remote data collection. The DTS also contains a self-calibrating utility and onboard solid-state storage. The unit comes with four channels with a sampling resolution of 25 cm and spatial resolution of 60 cm over a measurement length of up to 10 km (6.2 miles). It has a minimum measurement time of 5 seconds. *silixa.com*

Technique rids data of remnant marine-diffracted multiples

Geotrace Technologies has developed Targeted Apex Shifted Elimination Routine, or TASER, a post-surface related multiple elimination (SRME) technique that eliminates remnant diffracted multiples from marine data, the company said. SRME is a powerful, time-proven 3-D process to eliminate multiples appearing in marine acquisition. However, despite the strength and generality of standard SRME methods, there are situations where they are unable to completely eliminate these spurious reflections. One such situation appears when there are strong diffracted multiples. The nonspecular nature of the diffracted multiples makes it hard for SRME to eliminate them. This new technique is based on the realization that diffractions have special kinematical characteristics that can be exploited to separate them from the primaries and eliminate them. *geotrace.com* E&P

Oil prospects add to East Africa's charm

As companies continue to push forward gas production plans, others are targeting oil with early success.

Velda Addison, Associate Online Editor

East Africa has become synonymous with natural gas as developers flock to the region in hopes of capitalizing on what could become a robust LNG trade scene to meet the world's growing energy needs.

The region is believed to have a substantial amount of proved natural gas reserves. But it is the approximately 7.5 Bbbl of proved crude oil reserves, according to U.S. Energy Information Administration estimates, that oil-driven Tullow Oil is seeking as the U.K.-based company leads exploration efforts in frontier areas that include Kenya.

Not too long ago, East Africa's energy sector lived in the shadow of other, more prolific oil and gas producers in places such as Nigeria, Algeria, Angola, Egypt and Libya. But times are changing as risks—political turmoil, security concerns, theft and other negatives—mount for some of Africa's top hydrocarbon-producing nations and push developers elsewhere.

The Amosing-1 well in Block 10BB onshore northern Kenya hit net oil pay between 160 m and 200 m (525 ft and 656 ft), Tullow Oil announced this year, noting the find exceeded its predrill expectations. (Source: Tullow Oil)

Presently, E&P activity in Africa is mainly driven out of East Africa, according to Elias Pungong, Africa oil and gas sector leader for Ernst & Young.

"There is a lot of challenge still ahead like infrastructure [and] getting regulatory framework in place in Kenya and Uganda. But I think the governments are doing all they can to encourage the sector, and I think it is promising looking forward," Pungong said. "In terms of trends that we are seeing—yes, of course, you've heard about a lot of gas around the Rovuma Basin in Mozambique, which goes into Tanzania. We all know that, but we've seen discoveries in Uganda and Kenya. The prospects there are really encouraging with a lot of drilling this year."

Drilling is expected to continue in Tanzania and Mozambique to firm up and increase reserves as companies look to make final investment decisions for LNG and make sure there is enough gas in place, he said. But there is also plenty of activity in Kenya, Ethiopia and Madagascar as the entire East African region continues to attract interest from abroad with potential for both oil and gas.

"You cannot discount Mozambique for the gas and maybe Kenya for the oil just for the sheer amount of activity and exploration. Tullow drilled seven wells that were successful. That is unprecedented for the industry by any statistics that you look at," Pungong added. "It's a prolific province, and the prospects there are very, very high."

Targeting oil

Tullow highlighted its drilling success in Northern Kenya's South Lokichar Basin during an April 2014 interim management report, saying "the campaign in the first basin has delivered seven successful discoveries from eight wells drilled to date." The finds have increased discovered resources for the basin to more than 600 MMbbl.

"As a company we focus on oil. Our exploration strategy in East Africa is focused on Kenya and Ethiopia. In Kenya alone, Tullow is undertaking a significant pro-

The Sabisa-1 well, located in the South Omo Block in southern Ethiopia, has encountered hydrocarbons; however, Tullow Oil has not been as successful in Ethiopia as it has in other parts of East Africa. (Source: Tullow Oil)

gram of 40 exploration and appraisal wells over the next two years," George Cazenove, head of media relations for Tullow Oil, told *E&P*. "This will assess the South Lokichar Basin and a further six separate Tertiary rift basins across our Kenyan acreage."

Additionally, Tullow and its partner have agreed with the Kenyan government to start development studies and are involved in a pre-FEED study for an export pipeline proposed to travel, mostly underground, 850 km (528 miles) from the basin to a marine terminal near Lamu, Cazenove said. But "as this project is in its early stages, it is too early to suggest production targets."

In 2013, Tullow directed about $515 million toward its East African operations, but that is expected to grow as the company accelerates its parallel exploration, appraisal and development programs.

In Uganda, work is progressing on a commercialization plan approved by the Ugandan government in February. "The concept of the MoU [memorandum of understanding] involves an integrated development of the upstream, an export pipeline and a refinery of 60,000 barrels of oil per day to be developed in a modular manner starting with 30,000 barrels of oil per day," Cazenove explained. "A lead investor in the refinery is expected to be chosen by the government of Uganda soon. Meanwhile, the partnership is progressing [with] a comprehensive pre-FEED study for the crude oil export pipeline."

Aside from Uganda and Kenya, Tullow has pursued hydrocarbons in Ethiopia, Madagascar, Mozambique, Namibia and Tanzania. But "it's clear that Kenya and Uganda have the most commercial potential," Cazenove said. Last year alone, 15 of 17 exploration and appraisal wells drilled in Uganda discovered hydrocarbons. Tullow hopes to replicate the success of Uganda in the rift basins of Kenya and Ethiopia.

"There are differences between these basins," Cazenove said of the South Lokichar and Turkana rift basins, "but the fact that they are all rift basins is the key geological analogy."

Riveting rifts

Rifts have given rise to oil and gas finds and prospects in East Africa. These include the Tertiary rifts leading to oil finds in Uganda and hydrocarbon potential in Kenya as well as the Permo-Triassic rifts bringing heavy oil prospects in Madagascar and gas hopefuls in Ethiopia.

However, despite having proven prolific in some areas, it is a domain that is not well known and as a result presents a need to search for analogues for certain sedimentary models and appropriate seismic acquisition, Dominique Janodet, vice president of new business for Total E&P, said during Offshore Technology Conference (OTC) 2014. The company has operatorship in the EA-1 and EA-1A licenses in Uganda, where it estimates oil and gas resources are more than 1 Bboe.

"It can be challenging because some of those rifts are covered by natural troughs," he said. Moreover, "East African rifts are situated in remote areas. You need to think about your crude export scheme. So definitely there is some potential still to be unveiled in the rifts."

But the path from model to concept to data acquisition to evaluation of reserves and discoveries for frontier plays such as those in East Africa demands certain technologies for exploration progress. The most critical one remains seismic—both for data acquisition and appropriate imaging of what has been recorded to make the subsurface understandable, Janodet said. Technology has helped put countries in the oil business that weren't on the agenda 10 years ago, he said. These include Mozambique, where "a huge amount of gas has been discovered in a province that was not considered as very attractive for exploration," Janodet said. "Definitely, it's not the end of exploration. We see new petroleum provinces emerging all around the world in new plays."

Emerging plays

Exploration is warming up in Ethiopia, but it is too early to tell whether efforts will pay off. Cazenove admits that while Tullow has found oil in Kenya and Uganda, it has not been successful in Ethiopia yet. In the meantime, drilling continues in the Chew Bahir Basin.

Marathon Oil also recently signaled interest in the area after signing a deal with Africa Oil to acquire a 50% interest in Ethiopia's Rift Basin area.

Covering 42,519 sq km (16,417 sq miles), the Rift Basin area extends northeast of highly prospective blocks in the Tertiary rift valley that include the South Omo Block and Kenyan Blocks 10BA, 10BB, 13T and 12A, according to Africa Oil, which anticipates acquiring a 1,200-km (746-mile) 2-D seismic survey in the second half of 2014.

"Currently we have seven rigs running, and after releasing one in midyear will have at least six rigs running full time through the remainder of the year," Africa Oil CEO Keith Hill said in a news release. "Our program has three objectives: to appraise the existing key discoveries, to drill out the remaining prospects in the South Lokichar Basin and to open at least one of the four new basins being tested along trend.

"Additionally, we are pushing hard to move the development studies along with the aim of sanctioning a pipeline development for the South Lokichar Basin by the end of 2015 or early 2016," he continued.

Hopes also are high for Madagascar. The same geology that is present onshore and offshore the East African countries is thought to carry through the channel to Madagascar, which has been gaining attention lately.

Seismic companies are assessing the area's potential with plans for new multiclient surveys. TGS announced this year its pursuit of two 2-D surveys covering a total of 8,847 km (5,497 miles) offshore Madagascar, with the final data scheduled to be available to clients in fourth-quarter 2014.

The waters offshore the island as well as onshore are attracting operators. The latest farm-in deals include an agreement between Tullow and OMV Group, which acquired a 35% participating interest in Block 3109 (Mandabe) and Block 3111 (Berenty) onshore Madagascar. The first well in the Berenty Block is set for first-quarter 2015. The deal allows OMV to expand to onshore acreage of more than 14,000 sq km (5,405 sq miles), adding to its Madagascar portfolio that includes a 40% stake in the offshore Grand Prix Block.

The majors also maintain interest. ExxonMobil, operator of three production-sharing contract licenses offshore Madagascar, anticipates deepwater drilling will begin in 2015 and 2016, according to the company's website.

"There is quite a bit of opportunity," Pungong said of Madagascar. "It's a country that you should keep an eye on in East Africa."

Remaining challenges

Venturing into frontier areas typically brings myriad challenges both above ground and below ground. East Africa is no exception. For Tullow, the most common obstacle has been the lack of infrastructure.

"Although Tullow has introduced much of the infrastructure currently in place in our areas of operation in Kenya and Uganda, significant upgrades will be required to transport oil from both regions, still largely inaccessible by roads and rail, once production begins," Cazenove said, before turning to other foreseen challenges—access to a wide range of skills as well as competitive, high-quality goods and services.

"Many of these skills are still scarce in new oil provinces such as these, but we are committed to bridging the existing skills gap to ensure that the emerging oil and gas industry in East Africa brings real, lasting benefits to the people of the region. We are constantly looking at development opportunities for graduates and experienced personnel to drive our localization programs both nationally and with respect to the area of operation," Cazenove continued.

Stakeholder concerns, specifically in Kenya, also have impacted operations. In October 2013, for example, community concerns about local employment and business opportunities forced the temporary shutdown of drilling operations there after a disturbance. In wake of the incident, Tullow worked with national and local governments as well as others in the community on an MoU

Sources say seismic technology is the key to understanding what is below the surface in the East African rifts. (Source: Tullow Oil)

that made way for new community resource offices in the Lodwar, Lokori and Lokichar areas.

"These offices are staffed by dedicated teams who work closely with our mobile field-based stakeholder engagement teams to facilitate dialogue between Tullow and our stakeholders," Cazenove said. "This means we are able to manage our impacts more effectively and bring greater benefits to local communities."

Developing gas

In the meantime, natural gas production plans continue to move forward as companies work to develop huge gas fields offshore Mozambique and Tanzania while representatives of these countries continue luring more investors. "Don't fear that once you've invested there you will come out empty-handed. It is not possible," Ana Maria Raquel Alberto, senior commercial counselor for the Embassy of Mozambique, told a crowd during a session at OTC.

Anadarko and its partners have discovered an estimated 1.3 Tcm to 2.1 Tcm (45 Tcf to 70 Tcf) of recoverable natural gas after drilling more than 20 deepwater wells in Offshore Area 1 Block since 2010, the company said on its website.

McDermott, an EPC offshore contractor, supports Anadarko on FEED studies, particularly Offshore Area 1 subsea production systems for the Prosperidade complex. Speaking during OTC, Scott Munro, senior vice president and general manager, North Sea and Africa, McDermott, spoke about the challenges of the region and how to make the projects sustainable.

"We're currently working on how we are going to execute those projects, and it's a challenge. The infrastructure isn't there yet. The capacity isn't there yet," Munro said. "What we need to do is decide how we will develop that capacity and infrastructure over the course of the project and how we can make it sustainable. We'll deploy and use tactics we've used in other megaprojects in other parts of the world." That means forming partnerships and developing talent.

Anadarko and its partners also are moving forward with plans for a commercial LNG facility onshore with first cargoes expected in 2018, preparing Mozambique to become one of the world's major LNG exporters.

But they aren't alone. Statoil, which is the operator for blocks 2 and 5 in the Rovuma Basin offshore Mozambique and has additional assets offshore Tanzania with partner ExxonMobil, is also in the game.

However, where East Africa will fit into the future global LNG trade picture—given the abundance of resources in North America and massive LNG projects underway in Australia—remains to be seen.

"East Africa is strategically placed not far from the Far East. They are very, very well poised. Overall, it will depend on what we see with the global economy," Pungong said. "With the amount of gas involved, you really can't write them off. But today we haven't had a firm decision on LNG, when it's going to happen. Some people talk of Mozambique 2018. You have all of the FLNG [floating LNG] options that they have. Until they make a firm decision, we're not going to know. But my view is that it depends a lot on other global economic factors."

The Sabisa-1 well is among the wells Tullow Oil has in southern Ethiopia where an accelerated exploration and appraisal campaign is underway. (Source: Tullow Oil)

It also depends on the area's ability to maintain its attractiveness to investors. Although Alberta pointed out Mozambique's infrastructure is being improved, she admitted that challenges—such as construction of gas pipeline and LNG facilities, local processing of natural gas and guarantees for competitive prices for natural gas in the local market—remain. "Mozambique needs to improve its economic competitiveness," she said, later noting the country is working to lower its 17% VAT. "Otherwise, we will fall behind other countries."

But it goes beyond the fiscal tax regime, according to Pungong. Oil and gas companies want to know that laws are stable, he said, noting Kenya keeps postponing its oil and gas regulations, bringing uncertainty.

"Uncertainty causes a big problem, [and] I'm finding skills, qualified local human resources, is always a challenge," Pungong said. "Those challenges are there, but they are not insurmountable. As you have seen with other areas in Africa at times, oil companies always find remedies to these challenges." E&P

For additional information on these projects and other global developments:
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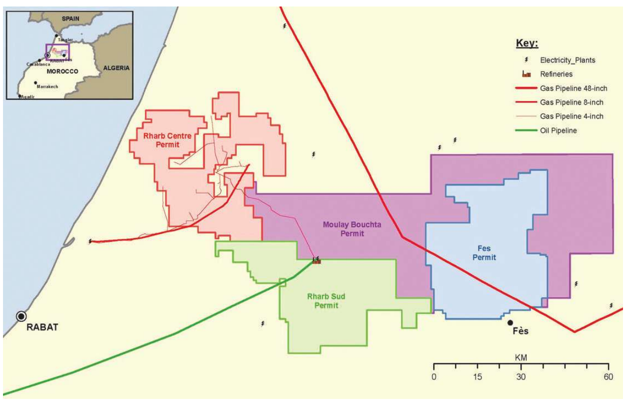
AFRICA

Gulfsands clinches new Moroccan license

Gulfsands Petroleum Plc has finalized agreements with Morocco's Office National des Hydrocarbures et des Mines (ONHYM) for the acquisition of the newly created Moulay Bouchta permit, according to a Gulfsands press release. Gulfsands will operate the permit with a 75% participating interest while ONHYM will retain a 25% participating interest. The Moulay Bouchta permit encompasses an area of approximately 2,850 sq km (1,100 sq miles) and is located to the north of Gulfsands' Rharb Sud permit. It extends eastward to surround the western, northern and eastern boundaries of the Fes Block onshore northern Morocco.



Gulfsands acquired the newly created Moulay Bouchta permit, which is located north of the Rharb Sud permit and surrounds the western, northern and eastern boundaries of the Fes Block. (Source: Gulfsands Petroleum)

Total discovers oil offshore Ivory Coast

The Total-operated Saphir-1XB exploration well on Block CI-514 proved the presence of liquid hydrocarbons in the deep offshore west of Ivory Coast, the company said in a news release. It is the first discovery in the San Pedro Basin, a frontier exploration area in Ivory Coast. Lying in 2,300 m (7,546 ft) of water, Saphir-1XB is the first well in Block CI-514. It was drilled to a total depth of 4,655 m (15,272 ft), encountering around 40 m (131 ft) of net pay containing light 34°API oil in a series of 350 m (1,148 ft) of reservoirs, the release said.

ASIA-PACIFIC

Shell makes Malaysia deepwater gas find

The Rosmari-1 well encountered more than 450 m (1,476 ft) of gas column in Block SK318 about 135 km (84 miles) offshore Malaysia, Shell said in a press release. The well was drilled to a total depth of 2,123 m (6,965 ft). Shell said the finding is a positive indicator of the gas potential in an area of strategic interest for the company where it has further exploration planned. Shell operates Block SK318 with an 85% interest. The remaining 15% is held by Petronas Carigali Sdn Bhd.

Oilex confirms hydrocarbons with Cambay well

Cambay-77H in the Cambay Basin of Gujarat, India, has reached total depth at 2,370 m (7,776 ft) and intersected the primary reservoir target. Increased gas readings similar to Cambay-76H indicate the reservoir is hydrocarbon-bearing, Oilex Ltd. said. Cambay-77H is offset 300 m (984 ft) from the Cambay-76H horizontal well that underwent a successful multistage fracture stimulation program in 2012. It was suspended before testing because of mechanical problems. Prior to the well being suspended, gas and condensate flowed to surface during well operations.

RUSSIA CIS

Tethys finds shallow gas in third Kazakhstan well

Analysis of data from Well AKK19, the third shallow gas exploration well of Tethys Petroleum Ltd.'s 2014 program, has indicated that the well has a pay zone twice as thick as the AKK15 well. The AKK15 well tested gas at a stable rate of about 195 Mcm/d (7MMcf/d), and the AKK19 well is anticipated to test at significantly more than that rate, a Tethys press release said. The AKK19 well was drilled to a depth of 800 m (2,624 ft) about 5 km (3.1 miles) southeast of AKK15 and encountered an 8-m (26-ft) interval of gas-bearing Tasaran sand with an average porosity of 30%.

MIDDLE EAST

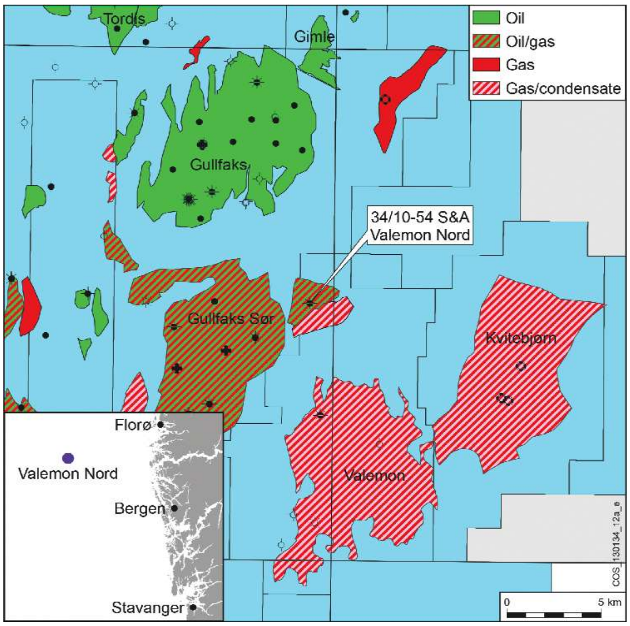
ShaMaran: AT-4 well flows oil in Kurdistan

The Atrush-4 (AT-4) appraisal/development well in the Kurdistan region of Iraq has been suspended as a potential future producer, according to ShaMaran Petroleum. Three separate drillstem tests were conducted in the Jurassic reservoir with maximum rates totaling 9,059 bbl/d of oil of 27°API to 28°API from two of the tests, a news release said.

EUROPE

Statoil discovers gas, oil in Valemon area

Statoil and the Valemon Unit partners have made a gas and oil discovery in the Valemon Nord prospect in the North Sea, a Statoil press release said. The main wellbore, 34 10-54 S, proved a gross 164-m (538-ft) gas/condensate and oil column in the Middle Jurassic Brent Group. The sidetrack, 34/10-54 A, proved a gross 100-m (328-ft) gas/condensate column in the Brent Group and in sand of unspecified Jurassic age and an additional gross 140-m (450-ft) gas/condensate column in the Statfjord Group. Gas/condensate also was found in the Middle Jurassic Cook Formation. Statoil estimates the total volumes in Valemon Nord to be in the range of 20 MMboe to 75 MMboe.



Statoil and its partners made an oil and gas discovery in the Valemon Nord prospect offshore Norway. (Source: Statoil)

Netherlands may become net natural gas importer

The Netherlands, Europe's second-largest gas exporter, may become a net importer by 2025 as output falls from its Groningen province and progress in unconventional sources stalls, the International Energy Agency said. Prime Minister Mark Rutte's government was forced to cut gas output from the Slochteren Field in Groningen by 21% this year to 42.5 Bcm (1.5 Tcf) in 2014 and 2015 after earthquakes linked to extraction led to a public backlash. A new production plan for the gas field, Europe's largest, will be presented by July 1, 2016.

NORTH AMERICA

Seismic partners pair up offshore Canada

Two Norwegian-listed seismic companies will collaborate on an expanded seismic survey offshore Canada using two vessels starting next month. TGS and PGS will work on a survey covering more than 30,000 km (18,641 miles) of territory in the Labrador Sea and in the northeast Newfoundland and Flemish Pass regions using multisensor technology from PGS. According to TGS, the 2-D survey will cover areas of interest to Canada's Newfoundland and Labrador Offshore Petroleum Board, due to form part of new licensing areas.

Magnum sells remaining Canadian assets

Magnum Hunter Resources has agreed to sell 100% of its ownership interest in its Canadian subsidiary to a Canadian private company for about $67.5 million, according to a news release. The assets consist primarily of oil and gas properties located in the Tableland Field in Saskatchewan, Canada. The transaction will complete Magnum Hunter's goal of exiting and divesting all of its Canadian assets, the release said.

LATIN AMERICA & CARIBBEAN

Leni hits oil onshore Trinidad

Leni Gas and Oil Plc's first new Goudron, Trinidad, development well GY-664 has encountered oil between 174 m (571 ft) and the current well depth of 335 m (1,100 ft) with combined pay intervals of about 59 m (193 ft) in the upper Goudron Sands, according to a company press release. Drilling is continuing in the remaining Goudron Sands, estimated to be 122 m (400 ft) thick, to the first casing point at about 469 m (1,540 ft) where electric logs will be run. Drilling will then continue to test the primary objectives in the Gros Morne and the Lower Cruse Sands at depths below 853 m (2,800 ft).

GULF OF MEXICO

Stone Energy's Cardona South hits oil in GoM

The Cardona South well (MC 29 #5 well) has encountered more than 84 m (275 ft) of net oil pay in three separate sections of the well, Stone Energy said in a news release. The Cardona South success extends the productive zone of the Mississippi Canyon 29 TB-9 well to the adjacent fault block to the south and sets up a potential second and third well in the fault block. Plans are to flow the Cardona South well to the Pompano platform, with first production expected in early 2015, the release said. E&P

PEOPLE

KBR Inc. named **Stuart Bradie** president and CEO.

James Smith took over the role of finance director for Cairn Energy Plc and will join the board of directors.

Josu Jon Imaz San Miguel was named CEO of Repsol.

Scientific Drilling International tapped **Phil Longorio** (left) to be president of the company.

CMS Energy made **Brian Rich** vice president and chief information officer.

Steve Ross (left) joined Summit ESP as vice president of finance.

Fang Zhi assumed the position of CEO of Nexen.

Gulfport Energy Corp. selected **Michael Moore** as CEO and **Ross Kirtley** as COO.

Lilis Energy Inc. named **Robert A. Bell** president and COO. **Abraham Mirman** advanced from president to CEO, and **Nuno Brandolini** was appointed chairman of the board.

Diamond Petroleum Ventures LLC appointed **Em Roosevelt** (left) as technical sales representative.

Continental Resources Inc. promoted **Gary E. Gould** to senior vice president of operations and resource development. The role of **Eric S. Eissenstat**, senior vice president, general counsel and secretary, has expanded to include chief risk officer.

Aker Solutions is splitting into two companies. **Luis Araujo** will be CEO of the new Aker Solutions. **Frank Ove Reite** will become CEO of Akastor, the spin-off. **Leif Borge** will be CFO of Akastor, and **Svein Oskar Stoknes** will be CFO of the new Aker Solutions.

James T. Brown has retired as president and COO of Whiting Petroleum Corp. **Rick Ross** has been promoted to senior vice president of operations, and **Pete Hagist** has been promoted to senior vice president of planning.

London Offshore Consultants appointed **Zhoongkeun Kim** (left) as country manager for South Korea.

Kemira Oyj appointed **Tarjei Johansen** (right) president of the oil and mining segment and the Americas region.

Chuck Diggins took on the role of vice president and Houston center manager for Sterling Seismic Services Ltd.

Sigma^3 Inc. appointed **Janet McGuire** as Denver operations manager for microseismic and borehole seismic imaging.

Kevin McLardy (left) has become CFO for ACE Winches.

Tall City Exploration named **Michael Marziani** (right) as CFO.

Duncan Cuthill has become general manager of InterMoor Marine Services Ltd.

Geotrace Technologies Inc. added **Ram Srivastav** (left) to its team as chief metrics officer.

Terry Wagstaff has assumed the position of vice president of acquisitions and engineering at EV Energy Partners LP. **Richard Parrish** was promoted to vice president of acquisitions and engineering at EnerVest Ltd., and **Tony Lopez** was promoted to vice president of acquisitions and engineering at EnerVest Operating Co.

Liquefied Natural Gas Ltd. made **John G. Baguley** COO and **Rick R. Cape** chief commercial officer for the company's subsidiary, Magnolia LNG LLC.

Fred Sloan (right) joined TAC as vice president and COO of the company's energy marketing division, TAC Energy.

Compressor Products International hired **Chad Moore** (right) as vice president of global operations.

Bahamas Petroleum appointed **Bill Schrader** as nonexecutive chairman on its board of directors. **James Smith** has been appointed as deputy chairman.

Leslie O'Connor has been named as a director for BNK Petroleum Inc.

Gary G. Rich, (left) president and CEO of Parker Drilling Co., was elected chairman of the company's board of directors.

Quicksilver Resources Inc. added **Scott Pinsonnault** to its board of directors.

COMPANIES

Halliburton will open a drilling, testing and training facility near Cameron, Texas, that will include wells for testing and training, a workshop for tool preparation and inspection, offices, classrooms and conference rooms.

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The company will use the facility to test new technologies and to train employees for all of its business lines. Construction is expected to be completed in late summer 2014.

The technical division of **Dynamic Construction Services**, a DYNESI company, opened its new facility in Gonzales, Texas. The division will provide automation, instrumentation and electrical, power generation, fire and safety, H_2S safety services, and a specialty control panel shop to the region.

Trelleborg's marine systems operation has established a new sales and business development office in Houston. The team in the new office will include a specialist docking and mooring representative and an oil and gas transfer and vessel technology salesperson. The office will serve the local U.S. and Mexican region across all five product areas of Trelleborg's marine operations: marine fender systems, oil and gas transfer technology, vessel technology, docking and mooring, and marine products.

Halker Consulting opened a new office in Durango, Colo., to serve the San Juan Basin region, helping clients with environmental compliance, worker safety and cost management concerns. It will provide engineering and design services, automation, project management, geographic information systems and field services.

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Consumer vs. enterprise-grade satellite Internet service

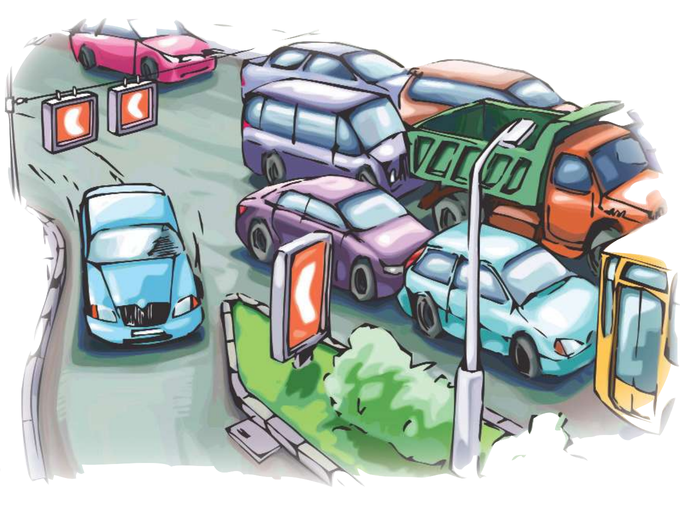
Sharing Internet services can lead to costly nonproductive time.

Rick Hodgkinson,
Galaxy Broadband Communications Inc.

Using satellites to connect remote sites has become a staple in the oil field. At first glance, the attractive pricing of consumer-class Internet service may seem like a worthwhile choice for a company's satellite Internet needs. Much like the transportation industry moving people and goods around, there is a variety of methods to transfer data over the Internet. For the transport business, a company might choose a bus, a car or a heavy truck. However, using a car to move a hockey team could get a little crowded.

Likewise, Internet networks today are "shared." Multiple customers use the available bandwidth capacity from the Internet service provider (ISP). By squeezing the maximum number of paying customers on the network, ISPs can achieve maximum profits. This oversubscription model has been a mainstay for the economic model of ISPs since the inception of the Internet and is based on the premise that it is virtually impossible for multiple users to press "enter" at precisely the same time.

Unfortunately, this network design is becoming more and more challenged very quickly. Many consumer-class networks now have oversubscription ratios of 100:1 or more. An oversubscribed network with proper care and attention by ISPs could deliver reasonable speeds for basic email and surfing. However, as Internet use evolves to more of an entertainment medium through applications like Hulu, Netflix and YouTube, ISPs are seeing exponential demand for bandwidth, and traditional models simply won't work anymore.



Enterprise networks are not grossly oversubscribed. In a model where fewer customers share the same resource, it costs more. Conversely, users will have a much better chance of obtaining optimum speeds on an enterprise network. In terms of raw cost per bit transported in a well-managed enterprise network, it may be surprisingly affordable.

The strongest reason to select enterprise over consumer-class is the ability to customize connections to maximize performance. For example, Galaxy Broadband has the ability to prioritize, throttle, block or manage a specific site's traffic, ensuring the best possible performance and strongest connection. Like the bus vs. car analogy, true enterprise ISPs have engineers on staff to design, implement and monitor clients' connections. They are professionals with specific training on applications and work with a client's IT resources to customize solutions to transport data.

Adding speed without adding network management is not the solution. Installing a device on a LAN also is not a solution unless a company has a large budget to acquire the hardware and even larger budget to monitor and manage the system effectively. Nonetheless, most affordable appliances on the market are only partially able to detect, identify and in some cases control the worst offenders. The solution is network management and application customization that an enterprise ISP can provide.

As smart rigs become more common, requiring increased video and data demands, the quality of the streaming video with constant information rates (CIRs) becomes even more important. A CIR will ensure delivery of the required bandwidth in a very predictable and steady manner.

With all Internet connections, technical glitches or connectivity issues can happen. Therefore, an occasional call for help can be frustrating if using consumer-grade services. Enterprise technical support offers engineering-level expertise and real people to talk to at any time who have the ability to modify service profiles as requirements change onsite.

In a corporate environment time is money. Sending critical information on a poorly suited connection ultimately costs more than taking the bus. E&P