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Wolfcamp Water Partners

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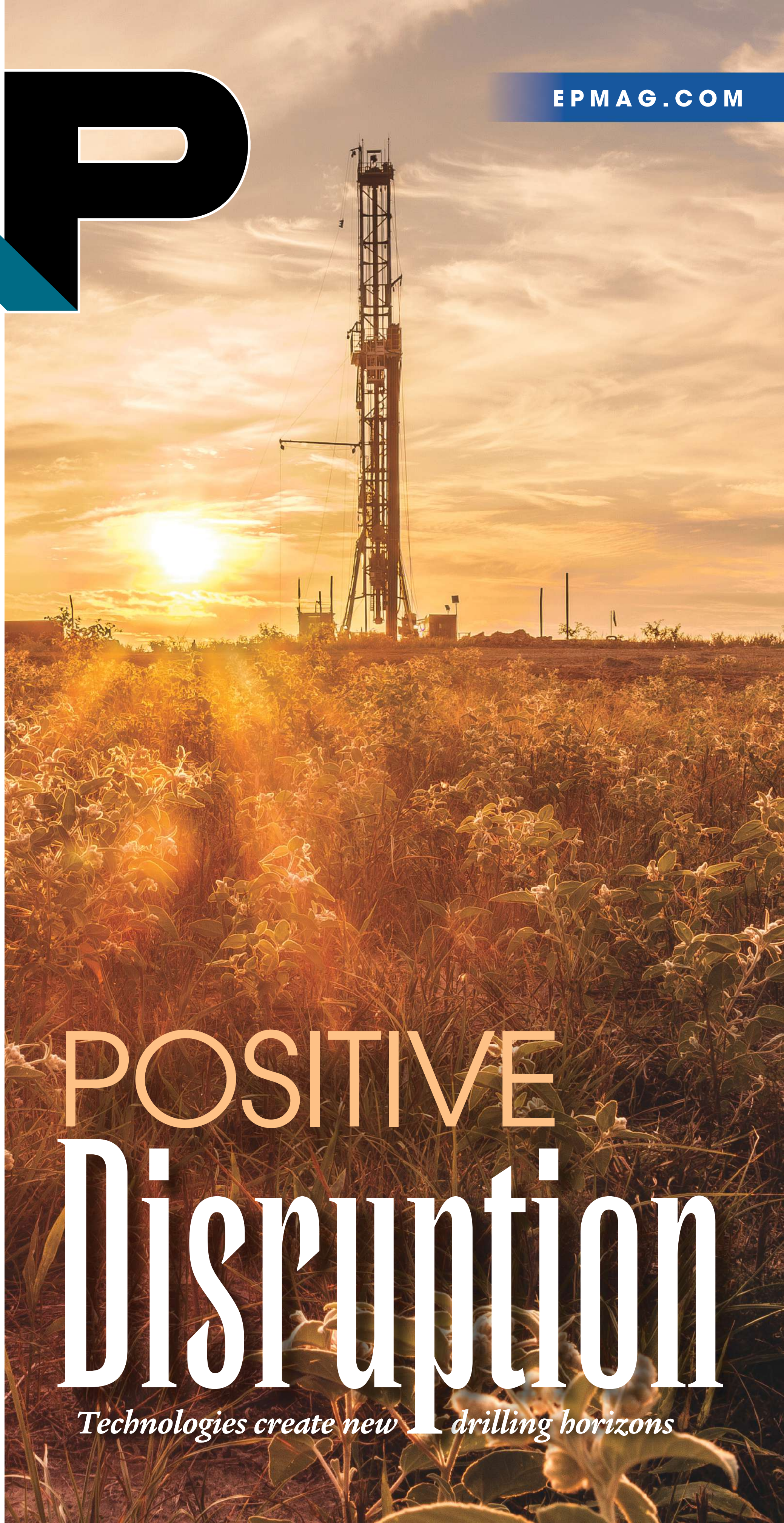

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Coiled Tubing Drilling & Tools

Powering Production

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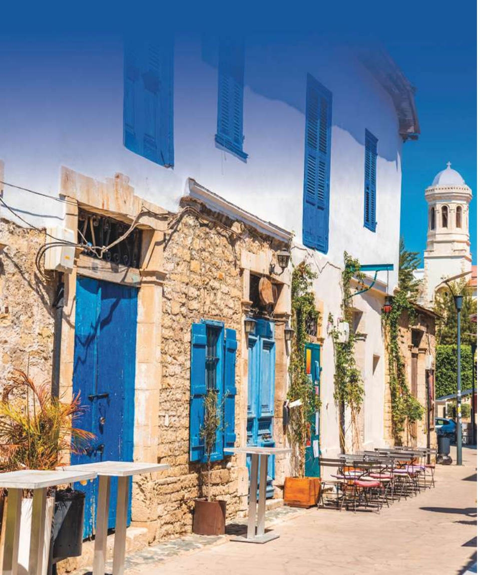

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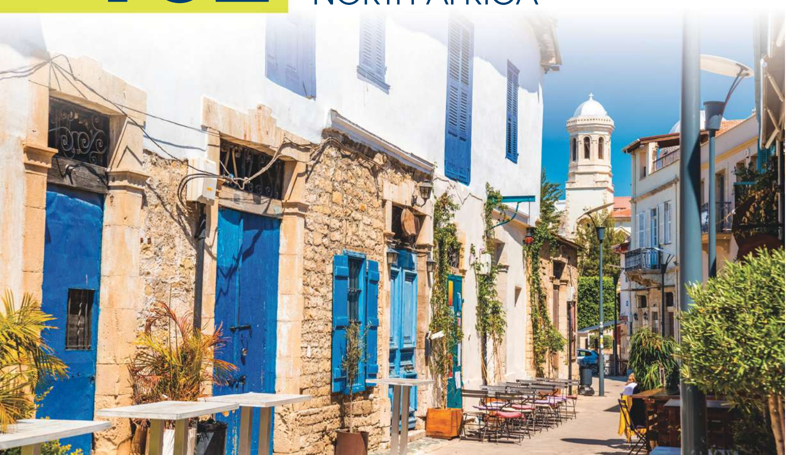

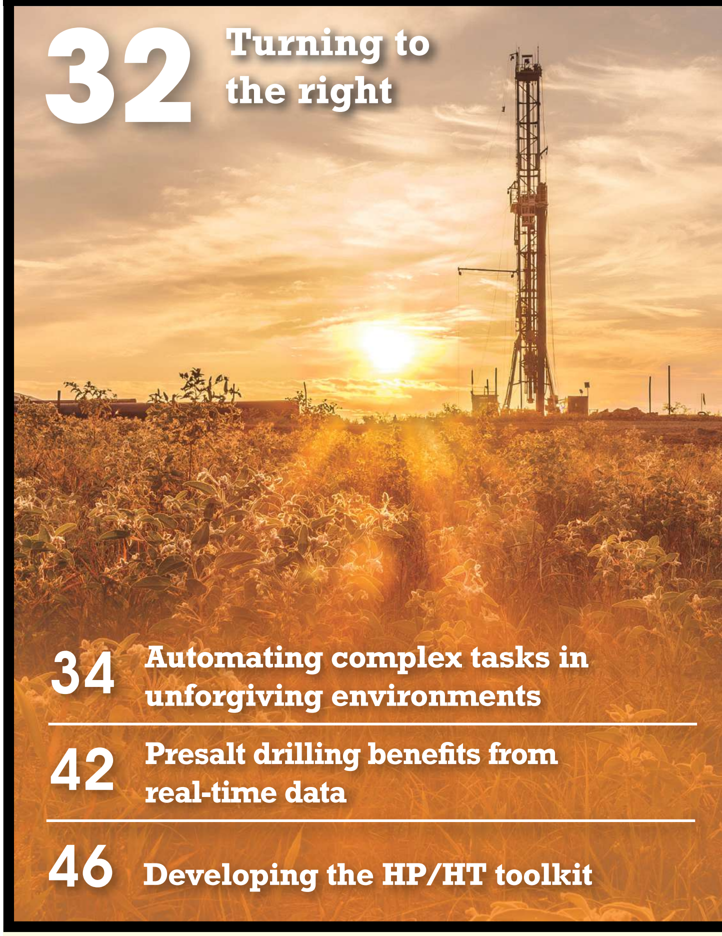

FEATURED SPEAKERS

Gary Willingham
Executive Vice President Operations,
Noble Energy Inc.

Randy Foutch
Founder, Chairman & CEO
Laredo Petroleum Inc.

Matthew Portillo
Managing Director, E&P Research
Tudor, Pickering, Holt & Co. Inc.

J. Ross Craft
President & CEO
Approach Resources Inc.

Clay Gaspar
Senior Vice President & Chief Operating Officer
WPX Energy Inc.

Mike Wichterich
President
Three Rivers Operating Co. III LLC

Erik Hoover
Executive Vice President – Operations
Brigham Resources LLC

Tom Petrie
Chairman
Petrie Partners

Matt Gentry
President & CEO
Monadnock Resources

Ole Engels
Director – Geoscience & Petroleum Engineering
Baker Hughes Inc.

View the conference agenda and speaker lineup at

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DUG Technology Showcase

2017 TECHNOLOGY SHOWCASE

Tuesday, April 4

BACK BY POPULAR DEMAND!

The Technology Showcase brings the latest solutions to the exhibit floor with case studies and live demonstrations from leading companies. Here's a preview of this year's topics.

Drilling In Stacked Pays

The Permian Basin may be enjoying its latest renaissance, but it's not a cakewalk. Stacked pays present a wealth of challenges for drillers, and only technology and technical savvy make these wells successful.

10:40 am	Welcome & Introductory Remarks
10:45 am	Moblize
11:00 am	Stasis Drilling Solutions
11:15 am	Schramm Inc.
11:30 am	DrillMec Drilling Technologies Inc.

Completing In Stacked Pays

Getting there is only half the fun. Once a well is drilled, it has to be completed successfully to reap the benefits of these voluminous pays. From specialty chemicals to proppant, completions is the secret sauce that brings these prolific wells online.

1:55 pm	Introductory Remarks
2:00 pm	Hexion
2:15 pm	Unimin Corp.
2:30 pm	Fairmount Santrol
2:45 pm	C&J Services

Production In Stacked Pays

Unconventional wells are notorious for their rapid decline rates. Production techniques help extend their lives and exploit their potential.

3:25 pm	Introductory Remarks
3:30 pm	Production Plus Energy Services Inc.
3:45 pm	Borets International
4:00 pm	Melzer Consulting

Operators Enter For Free!

Hart Energy invites all employees of **E&P companies, pipeline operators, refineries** and **utility companies** to enter the exhibition hall at **DUG *Permian Basin*** at no cost. Plus you have the option to upgrade to a full conference pass.

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DEPARTMENTS AND COMMENTARY

COMING NEXT MONTH The April issue of ***E&P*** will focus on subsea. Other features will include frontier exploration, MPD/UBD, production management, and rig and drillship efficiency. The regional report will focus on Mexico. As always, while you're waiting for your next copy of ***E&P***, be sure to visit ***EPMag.com*** for the latest news, industry updates and unique industry analysis.

ABOUT THE COVER A new day dawns as drilling technology becomes more automated. Left, a photo is shown of Genethliou Mitellla St., a touristic street leading to Ayia Napa Cathedral in Limassol, Cyprus. *(Cover image courtesy of NOV; left image courtesy of kirill_makarov,* shutterstock.com; *cover design by Felicia Hammons)*

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ACTIVITY HIGHLIGHTS

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Statoil completes Bakken, Three Forks wells from common drillpad

Statoil completed an extended-reach horizontal Bakken and a Three Forks producer from a common drillpad in Section 8-152n-98w in McKenzie County, N.D. The #1H Cheryl initially flowed 4.209 Mbbl of oil, 296 Mcm (10.461 MMcf) of gas and 3.189 Mbbl of water per day.

BHP plans to drill up to 28 tests in Green Canyon

According to an exploration plan filed by BHP Billiton Petroleum, up to 28 tests could be drilled at a four-block prospect north of the company's producing Shenzi and Neptune fields.

Owowo Field recoverable resource of up to 1 Bbbl of oil

An offshore Nigeria discovery has a potential recoverable resource of between 500 MMbbl and 1 Bbbl of oil. According to operator ExxonMobil Corp., the Owowo Field well, #3-Owowo, hit about 140 m (460 ft) of oil in a reservoir.

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Atlantic crossover: Tullow keeps focus offshore South America

By Velda Addison, Digital News Group

The London-based company is gearing up to drill the Araku prospect offshore Suriname and start seismic campaigns, including offshore Guyana updip of ExxonMobil's Liza discovery.

OPEC data promising, but price headwinds remain

By Jeff Quigley, Stratas Advisors

What do the production cuts mean for the balancing of the market? Analysts discuss the key issues they're watching.

Offshore drillers see gains, but recovery afar

By Velda Addison, Digital News Group

The sector has benefited from OPEC's production cut, analysts said, but declining demand remains.

India prepares new policies to attract oil, gas investment

By Gordon Feller, Contributing Editor

The country aims to increase domestic oil and gas E&P and development while reducing its reliance on imports to meet growing demand.

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Happy days are here again?

It depends on whom you ask.

Oddly, that dumb but catchy little song came out in 1930. It was meant to raise spirits during the Great Depression, but hindsight tells us the poor souls who lived through that economic crisis had many long years ahead of them before they could be "happy." And for much of Europe, Africa and Asia, the end of the Great Depression meant the start of World War II.

So why the long face? It's just that the pundits who hound me with emails on a constant basis seem all over the map when it comes to the potential recovery of the oil and gas industry. Here are some of the headlines:

- "2016 offshore discovered liquids resources were 90% lower than 2010" (Rystad Energy);
- "Shale productivity driving response to OPEC cuts" (Morningstar);
- "Global oil and gas exploration likely to return to profitability in 2017" (Wood Mackenzie);
- "U.S. oil and gas prices may tumble on Trump's 'Energy Revolution'" (Bloomberg);
- "OPEC data promising, but price headwinds remain" (Stratas Advisors); but then
- "Research shows rise in U.S. oil and gas industry confidence" (DNV GL).

So what's going on? Is 2017 going to be a good year or not so great? Personally, I like some of the more recent press releases I've gotten, starting with the DNV GL report. It points to short-term agility but long-term resilience, at least in the U.S. market, and is looking to natural gas to play an increasing role. Huh? Natural gas? The recent bully in product prices? But, yes, natural gas seems to be making a U.S. comeback. Again.

In more good news, the international rig count has increased for the third straight month, according to RBC Capital Markets. With a Brent forecast of $58/bbl, land rigs were up 5% year over year, though offshore rigs were down 9%. But overall, the rig count increased about 1% from December to January.

So my final note of sunshine? A report from Edison Investment Research titled "Tullow dipping a toe back into exploration." According to the report, despite Tullow's significant costs in its TEN and Jubilee prospects, the company is still dedicated to spending some money (though not as much as in the past) on exploration, not only focusing its efforts on near-field step-outs but also doing some wildcatting, including prospects in Ghana and Kenya.

"G&G [geology and geophysics] elsewhere is continuing with an eye to moving assets in Mauritania (3-D seismic in 2017) and Namibia (further work being performed) toward drill-ready status," the report stated.

In our "World View" this month, Leigh-Ann Russell from BP talks about learning from our mistakes of the past. I hope that will be the case. E&P

Rhonda

Value of collaboration

Working together is essential in a lower-forever environment.

Hari Vamadevan, DNV GL Oil & Gas

In collaboration with customers and supported by its 14,000 colleagues and research facilities, DNV GL runs joint industry projects (JIPs) to develop new solutions, standards and recommended practices that add value by solving industry challenges.

Despite challenging market conditions, DNV GL continues to invest 5% of its annual revenue in research and innovation projects to help customers become safer, smarter and greener. Half of these investments are focused on digital innovations, and one-fifth is dedicated to long-term strategic research.

The company has a long and successful track record of JIPs. In a period of cost constraints and increasingly complex oil and gas production, finding solutions that increase efficiency and production has never been more important. The first official JIP was undertaken in the Norwegian Continental Shelf in the 1970s. Over the period from the 1970s to date, having started an average 20 JIPs per year, the company has managed between 500 and 1,000 JIPs.

To address the industry's need for smart solutions that reduce complexity, DNV GL funded 43 new JIPs in 2016 in addition to launching a new Step Change innovation program to help customers leverage opportunities from digitalization. It is initiating a further 48 projects in 2017. In the last couple of years it has had about 40 ongoing and each year has funded 40 to 60 new ideas depending on budgets available and customer demand.

Steel pipe is cut at a Singapore laboratory. More than 60% of offshore pipelines use the DNV GL standard. (Source: DNV GL)

Industry benefits

All JIPs seek to solve a specific technical need and, where possible, to develop a new standard, recommended practice or technology that benefits the industry at large. DNV GL provides a neutral platform for sharing ideas in a fiercely competitive market. It provides a level of impartiality where discussions can take place and business performance and a drive for innovation can be safely improved.

The key benefit for the industry is that JIPs are identified by multiple stakeholders as a challenge, and the subject matter is addressed from many perspectives. It is an inclusive process, and the company's role is to be an independent expert and facilitator.

Collaboration challenges

The main challenges in collaboration are perceived loss of control and lack of trust between participating partners. This is managed by being transparent and clearly communicating intentions and agreeing parameters.

In a survey initiated two years ago the company asked the question, "What are the key issues hindering cooperation in the industry?" At that time, 44% reported that lack of trust between industry players was a factor. That said, 87% of the respondents at that time said that the industry could cooperate more. There seems to have been a change in attitude since the reduction in oil price, and cooperation is key to secure a strong and sustainable recovery.

Topic selection

DNV GL has a robust annual process for the collection of ideas. These must be whittled down into those which are deemed to be of greater importance to the industry. That is not to say that the others are not important. They may be ideas that are well in advance of current thinking or market requirements, and so these remain on standby for funding as the more pressing challenges are tackled.

The ideas come from DNV GL personnel who work closely with their customers discussing their key chal-

DNV GL's research facilities at Spadeadam, U.K., secured a large carbon capture and storage project toward year-end 2016. (Source: DNV GL)

lenges. They gather ideas, evaluate them and put forward suggestions for JIPs. The geographical regional management personnel facilitate the internal processes to capture ideas in their regions, for instance, by workshops, sessions at team meetings, etc. The person that suggests the idea might ultimately become the project manager of the JIP.

Ideas are evaluated with respect to value for customers in three areas: cost reduction; standardization; and operational efficiency such as aging assets, lifetime extension and digital services. The regional managers will then rank and prioritize JIP initiation ideas from their region and pass them on to the head office, which collates all the ideas and chooses those to proceed with.

The oil and gas industry understandably has a strong focus on reducing cost, but safety must be maintained. Great cost benefits are expected to be achieved through standardization, replication, simplification and advanced supply chain management. Energy efficiency and climate change also should be considered. The demand for energy is expected to increase by more than 50% by 2050. At the same time, climate change demands a more sustainable use of energy. On the pathway toward a sustainable energy mix, the oil and gas industry needs to take responsibility by being transparent and reducing its environmental footprint.

Downturn effects

Direct R&D budgets are suffering because of the downturn. The result has been a willingness from everyone in the industry to think carefully, not only about survival in the short term but how the industry will be shaped in the future. The industry needs to adjust to the mindset that oil prices will be lower forever.

Collaborative platforms unlock a lot of value. Typically, there are 10 participants in a JIP, so new ideas are being developed at a fraction of the cost. As an example, DNV GL's research facilities at Spadeadam, U.K., secured a large carbon capture and storage project toward year-end 2016, demonstrating a strong desire to drive new projects not only from a multicompany perspective but also geographically since companies in Scandinavia, Asia-Pacific and the U.K. are collaborating for this JIP.

Following a survey, Oil & Gas UK announced in December that the collaboration index score had moved up from 6.1 in 2015 to 6.6 in 2016. More than 85% said collaboration is part of their day-to-day business, and 98% recognize that collaboration is crucial for future business. So there is a definite positive move toward working together. To augment this view, 723 senior sector players were questioned on the benefits of collaboration as part of DNV GL's most recent Industry Outlook survey "Short-term agility, long-term resilience." It found that 22% of respondents said that they are increasing collaboration to maintain their innovation agenda.

Measuring success

There are some JIPs that originated and, due to lack of funding or participation, are challenging to continue. DNV GL is careful in that respect to select those that would be of most benefit to its customers to ensure cost benefit as the idea progresses.

Key to success with the JIP concept is to make the technical outcome tangible by publishing industry standards and recommended practices that serve as a reference point to all stakeholders. For example, the company's pipeline standard DNV-OS-F101, which was initially developed 40 years ago, has been used on 65% of offshore pipelines globally. It is a great example of what industry collaboration can achieve regardless of the peaks and troughs in oil price.

R&D will be a key enabler to make the industry more cost-effective, but it cannot innovate on its own. Working together on JIPs and improving operations through digitalization must be part of the solution. E&P

Have a story idea for the Industry Pulse? This feature looks at big-picture trends that are likely to affect the upstream oil and gas industry. Submit your story ideas to Group Managing Editor Jo Ann Davy at *jdavy@hartenergy.com*.

Three keys to maximizing digital investment in oil and gas

Organizations that plan and assess their digital needs have the greatest chance of capitalizing on its potential.

Jennifer Schwartz, CTG

A 2016 Gartner survey revealed, "Half of CEOs expect their industries to be substantially or unrecognizably transformed by digital" and that 84% of CEOs expect digital to result in higher profits. Digital is and will continue to be a topic of conversation.

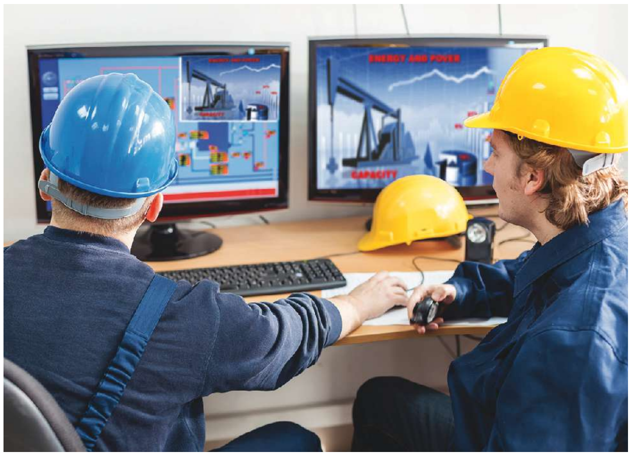
The oil and gas industry is no exception. Regardless of where a business sits along the process, digitization in the oil and gas industry is not a new concept. When we look at some of the major service providers, engineering contractors and even software vendors addressing the oil and gas space, we see growth in the areas that address field digitization. From flow stations being reviewed using data to pervasive corrosion monitoring or digital readings at wellheads, investment has been made to bring digital into operating areas like never before.

Companies have made digital a huge part of their core business strategy with hopes of leveraging its capabilities to improve operations, identify trends or address the challenges posed by the volatile industry. Ultimately, an oil and gas company with digital tenacity can do more with less by quickly bringing together assets from across their organization—on campuses, in the field and so on.

Still, many organizations haven't maximized their use of technology for a number of reasons ranging from resource allocation to talent. And while the challenges are real, there are things that companies can do now in the existing climate to maximize the value from digital. The following are a few considerations and tips for making the most of a company's digital investment.

Pick the right initiative

To date, the emphasis around digital transformation is on the value initiatives deliver rather than on how they improve operations. Most oil and gas companies have to be judicious right now regarding what digital projects they chase and how hard they chase them given the current economic climate and financial constraints they are under. For example, companies looking to "right-size" their organizations to fit within the Solomon Index might also want to look at ways digital can help automate the functions they hope to lighten or streamline. Individuals working through this tight climate are being asked to do more with less. Often that means taking on new responsibilities and finding new ways to accomplish tasks. Digital helps with both.



Data scientists can guide the manner of capturing data in a way that is seamless to the field workers' ability to execute the tasks they must fulfill. (Source: CTG)

For oil and gas companies to embrace and implement digital initiatives, the projects being considered must deliver real, tangible value to daily operations while simultaneously supporting strategy. Value has to be clearly understood by the workers who will feed, consume or interpret the information that drives any digitized task or action. Without that companies lack the grass-roots level buy-in that ultimately gives digital initiatives value and makes such projects worth the price and effort—something being deeply scrutinized at all levels in this climate.

Build the team strategically

Oil and gas companies should apply the same litmus test to hires for their digital strategy that they use for all employees—namely, does this hire reflect their needs now and in the future, or is this a skill set that they are better off acquiring through vendors or partners who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already have established expertise and are familiar with the systems and processes used within the industry? It's important for companies to make a frank assessment of the digital skills they have at hand, what they need and whether they have the resources required to provide the training and opportunities for career growth needed to keep digital talent onboard.

This also should include an equally frank assessment of the return on investment. For example, an office or field station might benefit from a Big Data expert or programmer who is intimately familiar with Hadoop. Data scientists in particular will likely be a great addition to oil and gas companies in the future, but only if they can guide the manner of capturing data in a way that is seamless to the field workers' ability to execute the tasks they must simultaneously fulfill. Remember, the industry's primary objective is to find oil and bring it to market safely and efficiently. Data gathering and analysis have to support that mission.

Even if their work does support field needs, companies should consider this: Do they have enough work to warrant having that individual onboard all of the time? It's a particularly important question when data scientists are in such great demand and there's significant competition to attract and retain them, let alone in the remote geographies where E&P often takes place. What's more, what would happen if this same individual leaves the organization once the digital initiatives involved are underway?


Input from operators and process engineers is important. (Source: CTG)

In most cases, the answer often is to go with a combination of in-house and contracted personnel. Regardless, it's imperative to work with a partner that can be trusted, relied on and can help sort out exactly what is needed. Finally, stakeholders from both IT and operations should be involved in this process. It's imperative to stress at all times that the hiring and investment in digital personnel is being made to further business and strategic goals. Operations teams need to know how the digital strategy enables them to do their jobs better and makes their lives easier. It's important that they see digital initiatives as a benefit, not a threat.

Create a support structure

Most oil and gas companies have teams invested in implementing or supporting digital technologies where it makes best sense. Often, though, there are two key areas where additional investment in business structures or reporting is needed to realize value from the growth of digital.

First, data analysis and interpretation is essential to drive the strategic roadmap, so if an analyst role or team is not in place, start there. Business analysts in the truest sense bring a lot of value to a digital strategy by representing both sides, melding the technology required to deliver results with the business case, process required and requirements of various stakeholders. Without talented analysts in this space the ability to realize the value intended by these initiatives can be drastically hindered.

Organizations also must have a process for business involvement that helps determine how and where digital hits the mark in delivering value (or, conversely, where changes need to be made to deliver the value expected). Operators and process engineers that help to implement technology in the field often are overlooked in the transition to a digital strategy. Their input on both how digital initiatives impact existing jobs and tasks as well as how it can be leveraged to streamline processes or gather data is incredibly important. Their front-row view allows them to see where costs and changes can yield real value.

In its FutureScapes 2017 report, analyst firm IDC noted that it has seen notable increases in digital transformation investments and estimates that there is "the potential for over $18 trillion of new value to be harvested" from it globally across industries. Organizations that invest the time into carefully planning and assessing their digital needs have the greatest chance of capitalizing on its massive potential and taking home a piece of that pie—value that is always welcome but is particularly needed in times such as these. E&P

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Answering the same-day billing challenge

Electronic field ticketing expedites processing and payment for services rendered.

Marcus Wagner, AcctTwo

Here's an ugly reality: Field tickets get destroyed, damaged or lost. Turning in a field ticket often requires the technicians to travel back to the company's main office for processing. In an industry where getting paid for services rendered can take up to 90 days, delays in getting the ticket submitted for processing and getting bills out the door can dramatically add days or weeks to collecting payment.

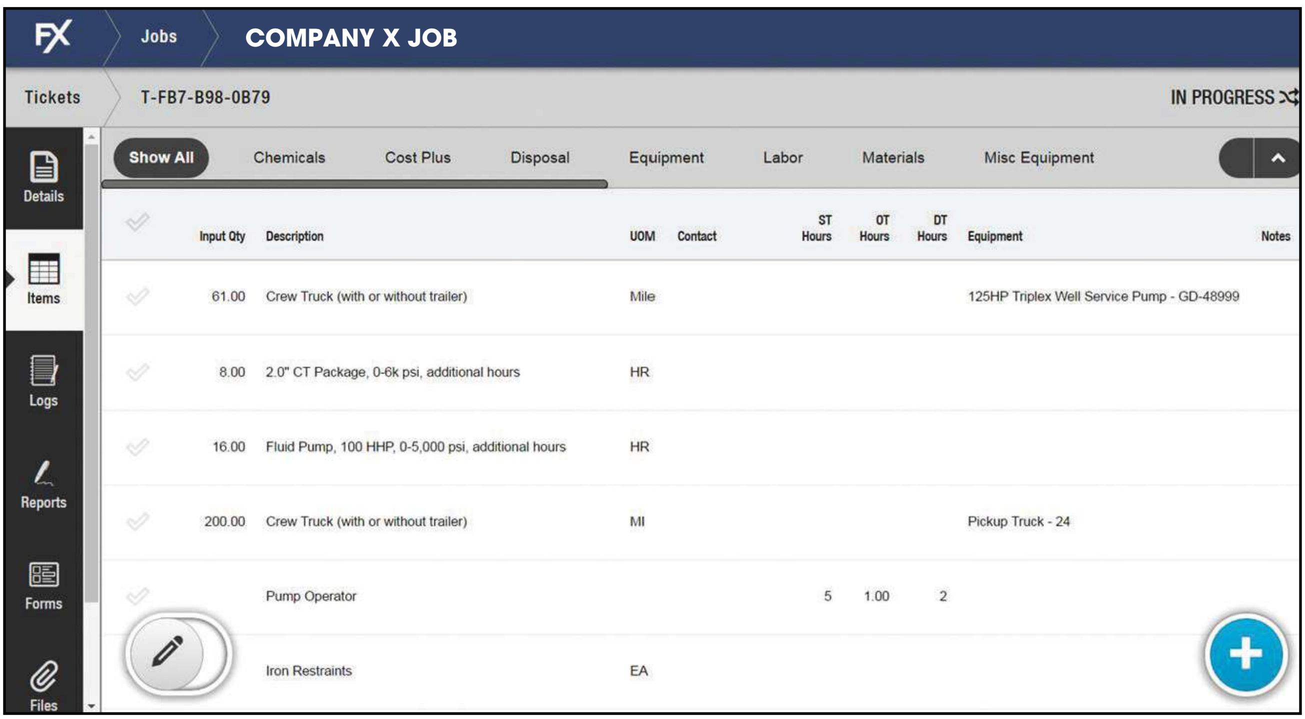
New technologies, however, are providing oilfield, environmental and industrial services companies with new tools to reduce field ticket processing time and the number of days sales outstanding (DSO). A few standouts in this group, due to their domain expertise, include LiquidFrameworks' FieldFX software suite, a cloud-based "quote-to-cash" field automation application, and Intacct, a cloud-based accounting application.

CFO Challenge

As a CFO, reducing DSO—the average time from when an invoice is created to the time that cash or payment is received—and improving cash flow should be the key goals. But shortening the "time-to-cash," the number of days between job completion and cash receipt, is something that can more easily be accomplished. Travis Parigi, founder and COO of LiquidFrameworks, has labeled this the "CFO Challenge." The challenge is to finish the field ticket when a job is completed and then send an accurate invoice to the customer on the same day as job completion.

How does it work today?

Let's take, for example, a wireline company. It will send field engineers out to a well site to perform various services for an operating company. The engineers generate a field ticket that includes information pertinent to that job including equipment, services, supplies and labor.



Service providers are able to shorten the "time-to-cash" with the FieldFX software for electronic field ticketing. (Source: AcctTwo)

The ticket also needs a signature and usually a stamp from the company man in the field.

Next, the field services engineer delivers that ticket to accounting. This might be done via email, FedEx or in person, which might be days after the fact. There have been cases where tickets have gotten misplaced, damaged or even lost during this process. All of this extends the amount of time required to generate the invoice—and the clock on DSO hasn't even started yet.

Even after the ticket gets to the accounting department, there are other pitfalls. The ticket needs to be accurate, contract-compliant and meet what LiquidFrameworks refers to as "The 4-Way Match." These four things must match the price book, quote, ticket and invoice. All of this needs to happen in one day.

How?

To accomplish this, the CFO will need to ensure that the company operates from standardized price books that are built on a common set of master data. The field engineer will need to electronically create an accurate ticket that can be signed and stamped electronically. And finally, an invoice needs to be created without redundant data entry, which could make the invoice inaccurate or noncompliant.

Business case for same-day invoicing

Revenue leakage is another significant problem due to lost field tickets, unreported man hours and missed charges. There is typically revenue leakage of about 4% across the industry. Also seen is unnecessary headcount dedicated to the manual processing of tickets and invoices.

Imagine a $100 million company with manual field tickets and a manual invoicing process. The company might have three clerical staffers needed to manage the process. Assume a weighted average cost of capital of 8% and revenue leakage of 4%.

If this company could implement same-day invoicing, it could save nearly $108,000 annually for the three workers that could be redeployed; a two-week reduction in its billing cycle, saving it $306,000 in annual cost of capital; and savings of $4 million annually in lost revenue from leakage. This totals to $4.4 million in additional cash annually to spend more wisely and be better stewards of investor dollars.

Solution

Cloud technologies such as FieldFX and Intacct provide companies with solutions that require minimal IT or development resources.

Jeff Ferguson Sr., founder and owner of Delta Oil Tools, a downhole completion and service company in Louisiana, chose Intacct for his accounting system and FieldFX for his ticketing system. "We settled on Intacct and FieldFX mainly because of their intuitive user interfaces," Ferguson said. "Our workforce, especially in the field, are in their early 50s and not necessarily all that computer-savvy. We did not want to spend a lot of time having to train people on the new system."

> **Today's technology and tools make it much easier to ensure that tickets are generated accurately and never lost.**

Once customers, price books, equipment and employees are set up, the data are synched in real time between the systems to be used on sales quotes and field tickets. The process works like this:

1. A sales person generates a sales quote in FieldFX.
2. Once the quote is approved by the customer, the quote is converted into a field ticket in FieldFX and scheduled based on the availability and appropriate certification of the crew and equipment.
3. Next, field supervisors complete the information on the field ticket using a tablet, attaching any supporting documentation. Since they might not have access to the Internet, they will save those data in FieldFX and then resynch them to the cloud when they have access.
4. With the click of a button, they send the ticket to accounting within FieldFX, and it automatically creates an invoice in Intacct.
5. A billing clerk reviews the invoice before transmitting it to the customer.

Mistakes are eliminated because the ticket already matches the quote and the price book.

Control what you can

In an unpredictable energy economy with customers struggling to pay invoices in a timely manner and with a workforce scattered across the country in some of the most remote areas, there is no shortage of challenges for oilfield services companies to remain successful. The time it takes to generate an invoice and the accuracy of those invoices are two things, however, that they can actually control. Today's technology and tools make it much easier to ensure that tickets are generated accurately and never lost and that they get to accounting quickly so that invoices can get out the door.

The next great technological invention will be software that makes customers pay on time. E&P

Fueling business value with data and analytics

The oil and gas industry adopts a data-driven mindset to optimize production.

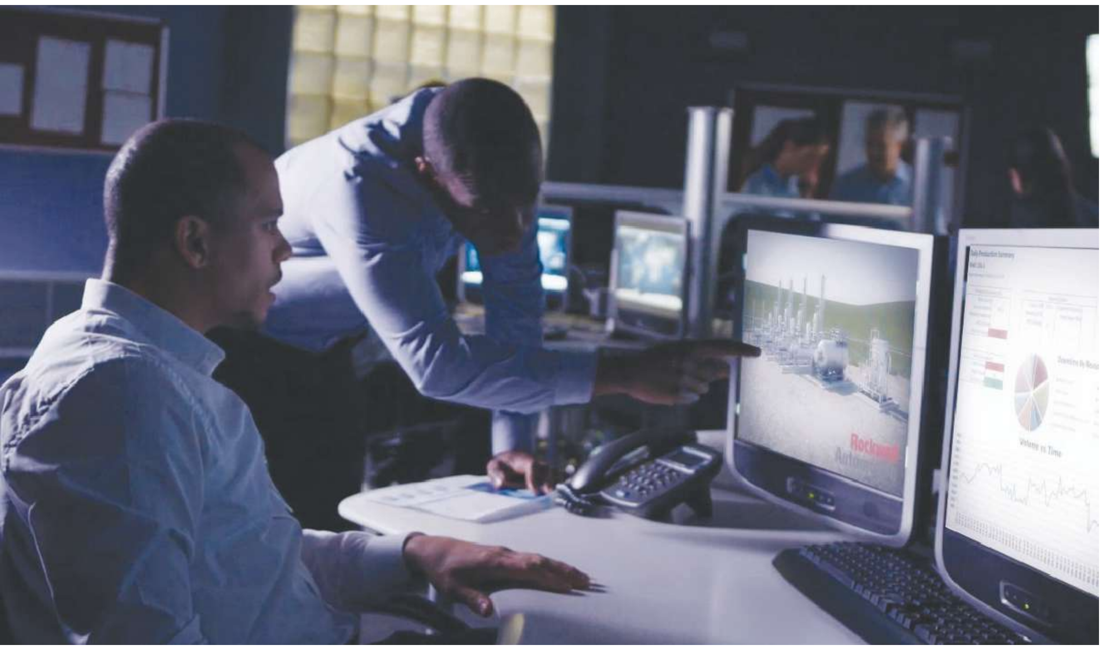
John Genovesi, Rockwell Automation

There's no denying the fact that data and analytics are gaining steam in the oil and gas industry. Just look at what Accenture and Microsoft found from a recent survey of upstream oil and gas professionals:

- Two-thirds (66%) said analytics is one of the most important capabilities for transforming their company, even though only 13% said their organization has fully mature analytics capabilities;
- The number of respondents who said they are investing in the Internet of Things (IoT) nearly doubled from 25% in 2015 to 44% in 2016; and
- More than half (56%) said they plan to use the cloud to enable analytical capabilities in the next three to five years.

So what is driving this trend? Certainly, oil and gas companies see a significant opportunity to improve their operations. Better insights into processes can uncover issues and improve decision-making to help boost production, improve processes, minimize downtime and increase asset utilization. But data and analytics also can help companies contend with some of their greatest challenges, including:

- *A growing skills gap:* Like other industrial sectors, the oil and gas industry is facing a skills shortage. Experienced workers are nearing retirement, and qualified young workers are increasingly hard to find to replace them;
- *Increasing operational complexity:* Oil and gas producers are capturing hydrocarbons from new and more challenging locations, whether it's deep subsea reserves or tight geological formations. This is requiring more complex systems than ever—some with more than 200,000 tags of data and alarms; and
- *Expanding regulatory challenges:* Environmental and safety regulations continue to evolve as governments continue to put pressure on oil and gas companies to help prevent environmental damage and protect lives. This is only making compliance more complex.



Remote-access technology can be used to monitor remote wellheads, pump stations and storage sites from a centralized location. This can help reduce safety risks and costs associated with sending workers to manually check on these systems. (Source: Rockwell Automation)

A connected enterprise

The unconnected and distributed nature of oil and gas operations has traditionally limited companies in their ability to collect data. But this is changing as they adopt connected, information-enabled technologies and replace disparate networks with a unified network architecture.

This modern infrastructure—in which people, processes and technologies can be seamlessly connected across an enterprise that stretches hundreds or thousands of miles—is known as The Connected Enterprise. It embraces technology advances that include not only Big Data and analytics but also open-standard IoT devices, mobility, virtualization and cloud computing. Most importantly, it creates nearly unlimited opportunities to improve and transform operations.

The Connected Enterprise presents the oil and gas industry with some key opportunities:

- By collecting valuable asset data and contextualizing it into actionable information, oil and gas companies can empower workers with critical operational information and help them optimize equipment performance;
- Equipment data also can be used to more quickly troubleshoot issues, create predictive maintenance strategies and better understand worker behaviors, all of which can help reduce downtime; and
- Remote-access technology can be used to monitor remote wellheads, pump stations and storage sites from a centralized location. This can help reduce safety risks and costs associated with sending workers to manually check on these systems.

These opportunities are not just theoretical. A number of oil and gas producers and operators are already demonstrating how connected, information-driven operations can improve their performance and solve business challenges.

Keeping tabs on offshore operations from afar

Even in the most remote and challenging environments operations are expected to run around the clock. That's certainly the case for one oil and gas company with offshore production platforms located off Alaska's coast.

The company's oil drilling platforms use submersible pumps to help keep production running 24 hours per day. If they stop, production stops, which costs the company \$100,000 to \$300,000 each day.

To help reduce risk of downtime, the company upgraded to more efficient and reliable electric submersible pumps and used a virtual support service to remotely monitor the drives that power the pumps.

The cloud-based service collects key equipment data such as speed, current, power and voltage and analyzes those data in real time. If any potential issues or failures are detected, a Rockwell Automation support engineer is notified immediately. The service nearly paid for itself in the first two weeks since it helped detect and notify key personnel of four incidents in that time frame after implementation.

Refining business models onshore

Onshore, the use of cloud technology is growing as a remote monitoring tool as well as for storing data and analyzing and contextualizing information. For example, M.G. Bryan, a heavy equipment and machinery supplier to the oil and gas industry, knew it needed a way to remotely monitor and maintain the performance of its \$1 million fracturing trucks. Downtime on the vehicles can cost \$3,000 to \$7,000 per day, and that's before lost product revenues are taken into account.

The company invested in a cloud-based fleet-management system. Using mobile technology and the seamless transfer of business information over the cloud, M.G. Bryan securely pulls data to web browsers. Then the software management system produces reports and dashboards showing the condition of individual vehicles' drivetrains and hydraulic fracturing performance. The system takes the guesswork out of maintenance scheduling, thus helping prevent unplanned downtime.

In addition, the instant visibility into remote-asset data has improved asset uptime and productivity for end users. It also has allowed the original equipment manufacturer to shift its business model from monthly agreements to pay-by-use, giving the company a competitive advantage. By using the cloud, M.G. Bryan maintains no infrastructure, and it can scale the solution from one truck to 4,000 trucks.

Data drives companies into the future

The potential for data and analytics in oil and gas is growing every day as more companies tap into it. For example, companies are beginning to explore the use of real-time production allocation.

Rockwell Automation is working with a producer to capture real-time multiphase flow volumes from all of its existing wells. This will enable operators to monitor data and allocate production to individual wells, specifically pinpointing assets that are underproducing and improving overall productivity.

That's just the beginning. The possibilities are unlimited. More advanced oil and gas companies are looking to integrate these field data with production planning and accounting systems to enable timely and accurate oilfield production reconciliation.

As more companies seek to capitalize on their data and make the journey to The Connected Enterprise, the decisions they make along the way will be critical to realizing long-term business benefits. Accessing and monitoring assets and merging disparate oilfield data into streams of actionable information are essential to remaining competitive. The space continues to grow with new technologies and smart devices. E&P

References available.

A bright future for drilling

BP's Leigh-Ann Russell is chairing this year's SPE-IADC drilling conference with hopes for an industry resurgence.

Rhonda Duey, Executive Editor

Leigh-Ann Russell

It's never easy chairing a major technology conference, and with the industry in a low oil price environment, it makes things even more challenging. But Leigh-Ann Russell is up to the challenge.

Russell, vice president of technical functions and performance for BP's Global Wells Organization, is chairing one of the industry's most important drilling conferences, a joint effort between the Society of Petroleum Engineers (SPE) and the International Association of Drilling Contractors (IADC). The conference takes place March 14-16 in The Hague, The Netherlands. Russell recently spoke to *E&P* about the upcoming conference and her hopes for the future of the industry.

***E&P*: How did you get tapped to be the chairperson for this conference?**

Russell: I volunteered. We do a lot of work with SPE and IADC, and when they were looking for a chair, I put my hand up because I'm a chief supporter of these organizations. I think they do incredible work for us in the industry. They rely on volunteers, so as volunteers, you have to start with yourself. I also was intrigued because I hadn't really seen that many women chair the conference before, if there had been any. Through some of the work I do on BP's diversity agenda, that appealed to me.

***E&P*: How would you describe the general state of the drilling industry, and what is the mood?**

Russell: This is a tough time in industry. We've seen considerable restructuring, and that's what's really hard. The most difficult thing is seeing your colleagues leave, particularly when they don't want to. I think we have to be respectful and mindful of that. We expect oil prices to be lower for longer, and although we're starting to see an uptick in price, we believe that the days of $100-plus oil are probably behind us. Our industry has made great progress in reducing our cost basis while continuing to enhance the safety of our operations. It allows us to be more competitive in a low oil price world and bring stability to our industry, which is more important than a high price environment.

We're more fit than we have been in the past. We have cut a lot of waste out of our processes and our systems. We are looking at how we can better adopt technology to stay at this competitive level. We're not sitting around waiting for things to get better. We as an industry and we as BP are actually turning the corner and making ourselves safer and competitive at the current price environment. That feels really good to a lot of people.

***E&P*: The upcoming drilling conference will cover a host of technologies. What are some of the new technologies that you are particularly excited about?**

Russell: We're looking at automation and how we bring in automation from other industries to make our industry safer and more efficient. This has made us look at things very differently. We've brought speakers to the conference who are not traditional oil industry speakers, like McLaren, to be a bit more thought-provoking about how other industries work more effectively. Many of these companies have year-over-year cost improvements by constantly applying improvement to their processes, whereas in our industry we're very cyclical. Looking at how they achieve these things has made BP think about things very differently. We're going to bring a flavor of that to the conference and hope that people go back and perhaps think a little differently about how they can make their businesses safer and more competitive.

The way that we use our data, the way that we visualize it and aggregate it, is going to be a feature of what McLaren shows us at the conference—how [the company] takes the information from its race cars and uses it in predictive mode to see what its cars are going to do next to actually help them win the race. It's completely analogous to drilling. The drift is that we use all of the information we have on our drilling rigs not just to tell us what we're doing at that moment but actually to help us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If our offshore teams could be freed up from doing some of their manual processes and actually have a computer drilling a section for them, they could sit back and have oversight of how that section is being drilled. That has the potential to improve safety because it provides a second level of oversight. It makes it more efficient because, no matter how brilliant you are, you can't outmatch a computer responding to information in nanoseconds. We are currently field-testing an automated drilling system in Oman that determines the optimum drilling parameters based on analysis of data in real time. These parameters are automatically executed via the rig's control, allowing the driller to use his or her expertise to focus on the overall drilling operation.

***E&P*: In your introductory letter on the conference website you mentioned, 'providing energy in a sustainable way' as one of the goals of the conference. What efforts are being made in that direction?**

Russell: I believe sustainability touches a number of different subjects. I certainly have been through a number of downturns in this industry. There's just a general feeling that we don't want to keep learning the same lessons from the past. How do we stop following those trends? How do we get ourselves more efficient so that we don't need to hire massive amounts of people and consequently have adverse effects in a downturn? We need to conduct our business in a stable manner with a stable number of people in a stable commercial regime so that we don't follow the commodity price but continue to work efficiently and competitively in a low-price environment and then benefit even more greatly from an upturn.

That's a model that works for the service companies and the drilling contractors too. We need to have the discipline to not just follow the trend of an upturn. And we can do that through the use of technology. We can do that through better application of how we deploy our people. There's a whole host of things that we'll bring to the conference that will address how we get that sustainability and stability into our industry despite the price environment.

***E&P*: What is your motivation to keep plugging away even though things are tough?**

Russell: I was with one of our millennials recently, and she said, 'It doesn't feel like our industry really grabs people. We need to become 'sexy' like Coca-Cola.' I didn't even need to think about that for one second. I just turned to her and said, 'Well, I don't get that. Our industry provides heat. It provides light. It provides power. The more efficient and clean that we can get at doing that means that we can help people come out of poverty in the developing world. That's what I think of our industry. Few other industries can claim to have that impact on the world.'

What a wonderful industry to be part of. Yes, things are tough right now, but our jobs are really important for the world. Not only that, but I get to do that job with a group of really amazing people. Right now the technologies that we're looking at for how to really shape our industry in the future are tremendously exciting. I don't want to detract from what's happening to people in the industry right now, but we have a super bright future ahead of us. I don't need any edge to get out of bed (most mornings, anyway) to go out and tackle this challenge with the great technology and people that we have. E&P

Russell (in orange gloves) poses with a crew on BP's Thunder Horse platform in the Gulf of Mexico. (Source: BP)

Four horsemen of completion

Crowd-sourced data reveal significant increases in well completion metrics.

Richard Mason, Chief Technical Director

Outlined against the blue-gray sky of the worst business setback in a generation, the four horsemen of oil and gas completion shed their seals and rode again.

Though originally known as Famine, Pestilence, Destruction and Death, to paraphrase the legendary sportswriter Grantland Rice, those are aliases. The real names of completion advancement are encapsulated in crowd-sourced stats and include longer laterals, more stages per well, greater proppant loading and a return to batch completions.

The truth is the oil and gas industry emerges from every downturn in an entirely different structure than what existed before, whether it was the move to natural gas offshore after 1992 or the return to conventional gas drilling onshore to meet rapidly rising consumer demand post-1999. That was succeeded by the switch to tight formation exploitation coming out of the 2002 downturn followed by widespread adoption of horizontal drilling and multistage fracturing in tight formation plays, first for gas, then liquids, in the post-2009 recovery.

- **Lateral length grew 14% in 2016.**
- **Stages per well rose 34%.**
- **Proppant per lateral foot rose 50% to 1,740 lb.**
- **Batch completions are back.**

Beset by a cyclone of the worst commodity prices in a generation, E&P companies embraced capital efficiency via largely homogenized completion strategies and are riding toward recovery as crowd-sourced metrics confirm surprising changes in tight formation completions.

The first horse of completion is longer laterals. Lateral length grew 14% in 2016, according to respondents in Hart Energy's *Heard in the Field* surveys, as E&P companies consolidated acreage into drilling units that allowed the horizontal drillbit to move beyond the previous standard of 1,372 m (4,500 ft) per section. Crowd-sourced metrics show average lateral length exceeding 2,530 m (8,300 ft) on average at year-end 2016: fewer wells in 2016 but longer laterals.

While lateral length reduced the cost of reservoir access vs. drilling additional wells, it took the second horseman, the number of stages per well, to fully exploit the opportunity. Stages per well rose 34% to 41 on average across the tight formation plays in 2016 as E&P companies sought greater access to hydrocarbon-bearing formations. Consequently, spacing between stages, which extended more than 76 m (250 ft) three years ago, now averages less than 61 m (200 ft).

Those spacing reductions opened a pathway for the third horse of completion, which is greater proppant loading. A sharp increase in proppant volume in fourth-quarter 2016 boosted the average proppant per lateral foot in tight formations 50% to 1,740 lb year-over-year. That's material. Average proppant per lateral also soared in 2016, finishing 2016 up 72% to an average 14.56 million pounds. Think of it as sand by the trainload.

The final horse rode forth in 2017. This is the return to batch completions. Batch completions bottomed at less than 44% of all horizontal wells one year ago as the industry faced a cyclone of rapidly declining commodity prices and allowed inventory to build as drilled but uncompleted wells (DUCs). The industry exited 2016 at about 48% of horizontal wells completed in batches. However, batch completions surged to two-thirds or more of wells regionally during the first six weeks of 2017 as E&P companies were comfortable enough with commodity prices to tackle the backlog of DUCs in a $50 oil environment.

Batch completions help E&P companies squeeze more goodie out of adjacent wells and allow contractors to expand margins by capturing wellsite efficiencies. If both sectors benefit, then the industry will see a full and complete economic recovery.

Will the four horsemen be enough? The narrative in first-quarter 2017 is that E&P companies are accelerating capital spending. The industry will know mid-year whether surging domestic production creates another commodity price pause or whether declining global inventories encourage E&P companies to gallop forward. E&P

Understanding NMR logs in shales

Scientists are attempting to explain the fast relaxation times in unconventionals.

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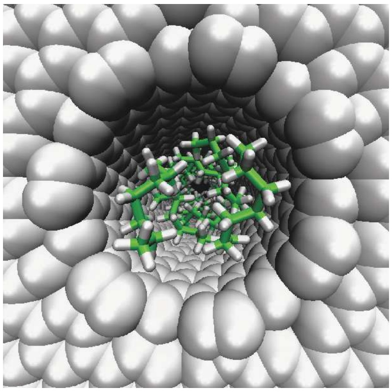
Read more commentary at
EPmag.com

In shale plays, on the opposite spectrum from the "factory drilling" approach is the "engineered well," where science plays a role in determining the best spots to land the lateral and perforate the well. Range Resources has perfected this technique in the Marcellus and Utica shales, first using focused ion-beam scanning electron microscope technology but later relying on nuclear magnetic resonance (NMR) logs to correctly land its laterals.

Now Rice University is extending that research, according to a recent press release. Researchers George Hirasaki and Walter Chapman are combining NMR measurements with molecular dynamics simulation to better define the contents of shale. Their findings have recently been summarized in the *Journal of Magnetic Resonance*.

NMR has long been kind of the outsider of logging measurements because of its cost and relatively newness. But because of its ability to identify the type of molecule present in a rock, it can provide valuable information relating to liquid distribution as well as pore size. Essentially the tool uses radio-frequency electromagnetic pulses to manipulate hydrogen atoms and then measures their relaxation time to determine the molecular mix.



Hydrogen molecules become perturbed by the NMR source, and their relaxation times can indicate the type of molecule present. (Source: Dilipkumar Asthagiri, Rice University)

In the press release, Hirasaki explained that in conventional reservoirs a water-wet rock will see the oil's relaxation time replicate that of bulk oil, while the water's relaxation time is a function of the pore size. In an unconventional reservoir, the relaxation times of both oil and water are short and overlap. "The diffusivity is restricted by the nanometer-to-micron size of the pores," he said. "Thus, it is a challenge to determine if the signal is from gas, oil or water."

The first goal of the study is to determine whether the rapid relaxation times are the result of paramagnetic sites and asphaltene aggregates on the mineral surfaces and/or the pore size restriction on the ability of the molecules to move.

Another focus of the study is the effect of water, the main ingredient in fracturing fluid, on the kerogen found in unconventional rocks. Water molecules tend to bind with kerogen and block the pore spaces containing hydrocarbons.

The study is applying NMR measurements to kerogen samples and comparing the output to computer models simulating the interaction of the substances. This is particularly applicable to the rock's wettability. The goal is to better interpret the NMR results in these tight rocks and also could help manufacturers develop fracture fluids that are less likely to interact with the kerogen.

"If we can verify with measurements in the laboratory how fluids in highly confined or viscous systems behave, then we'll be able to use the same types of models to describe what's happening in the reservoir itself," he said in the press release.

Another goal is to incorporate the simulations into Chapman's inhomogeneous statistical associating fluid theory, which simulates the free energy landscape of complex materials.

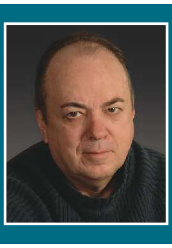
"Our results challenge approximations in models that have been used for over 50 years to interpret NMR and MRI [magnetic resonance imaging] data," Chapman said in the press release. "Now that we have established the approach, we hope to explain results that have baffled scientists for years."

For more information, visit *http://news.rice.edu.* E&P

Rhonda

US land drilling slowly recovering

E&P investments in North America are expected to increase by about 30% in 2017, according to industry surveys.



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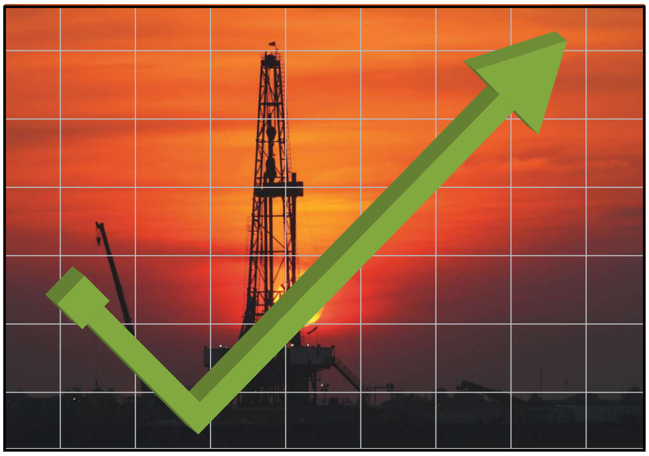
For the week that ended Jan. 27, the Baker Hughes rig count topped 700 active units with a total of 712 rigs. The last time the rig count was at 700 rigs was the week ending Dec. 23, 2015, as the count was moving steadily downward. This year's rising rig count gives hope to operators and service companies that the financial situation is looking up.

"E&P spending surveys currently indicate that 2017 North American E&P investments will increase by around 30%, led by the Permian Basin, which should lead to both higher activity and a long-overdue recovery in service industry pricing," said Schlumberger Chairman and CEO Paal Kibsgaard during the company's 2016 annual and first-quarter 2017 reports. "We expect the 2017 recovery in the international markets to start off more slowly driven by the economic reality facing the E&P industry."

However, there is a big "if" for the turnaround to continue. And that is "if" OPEC producers keep the promise to cut supply and U.S. shale operators don't ramp production up too rapidly again.

In an issue brief from the Center for Energy Studies at the Baker Institute for Public Policy, the question was asked, "How fast can U.S. shale producers scale up their activity levels if WTI [West Texas Intermediate] crude prices rise and stabilize in the $60/bbl range?"



For the first time in 13 months, the rig count is above 700 rigs. That could foreshadow the industry turnaround. (Image created by Felicia Hammons)

The pace at which shale responds to a higher price could become as much a function of logistics and oilfield service capabilities as it is geology and mineral rights, the brief stated.

"Despite the positive sentiment surrounding the North American land market, it is important to remember that our world is still a tale of two cycles. The North American market appears to have rounded the corner, but the international downward cycle is still playing out," explained Dave Lesar, Halliburton chairman and CEO, on the company's Jan. 23 quarterly call.

Martin Craighead, Baker Hughes chairman and CEO, said on the company's Jan. 26 quarterly call, "Looking ahead for the first half of 2017, we expect onshore revenue in North America to increase as our customers ramp up activity, with service pricing improving but limited by overcapacity. In offshore markets, particularly deep water, activity declines are expected to be more severe."

Helmerich & Payne Inc. President and CEO John Lindsay stated in the company's Jan. 26 quarterly call, "The outlook has been improving in the U.S. land drilling market, resulting in a significant increase in the company's activity levels and market share over the last few months. Spot pricing remains low, although we continue to see some pricing improvements for high-quality high-performing AC drive rigs."

Although optimism is beginning to increase, there is still a healthy skepticism not to ramp up too quickly. E&P

Scott

Harnessing disruption

Resilience, disruption and collaboration will pave the road to recovery.

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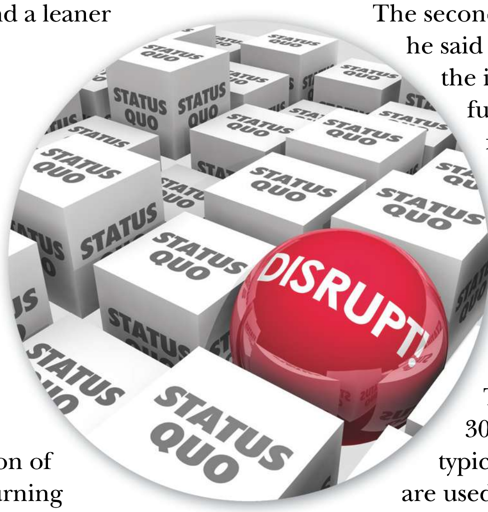
EPmag.com

Life is less dull with a little chaos. Without disruption, that drastic altering of structure, historians would have little to write about. Humans are tinkerers. We're always pushing the limits. We leave well enough alone for just as long as necessary for it to take root and hold. Then from there, we add or subtract; we branch out in new directions and break off the pieces that don't fit—we disrupt.

For example, thanks to a little tinkering and dogged persistence, the petroleum world was set on its collective ear with the evolutionary one-two combo of horizontal drilling and hydraulic fracturing. The global market pushed back and with a snip here and tweak there, a balance has been struck and a leaner industry has emerged.

Rather than dwell on the challenges from 2016 that led to that leaner industry, Lorenzo Simonelli, president and CEO of GE Oil & Gas, shared how the company is evolving at its 18th Annual Meeting recently in Florence, Italy.



(Source: iQoncept, *shutterstock.com*)

"I, like you, am here because I want to chart a new course for the industry around connectivity and growth," he told attendees. "We're heading into 2017 with the ambition of disrupting the status quo. We're turning the tables as leaders in this industry and harnessing disruption in many ways."

He shared that one way the company will do this through its role as a supplier is by bringing solutions that put technology in the center, but that GE Oil & Gas will not stop in its efforts to serve the customer.

"We've learned that to be disruptive, we need to adopt a new mindset that challenges tradition and bureaucracy," Simonelli said. "We have found that when you are being disruptive, structures need to evolve. Industries need to transform for the better."

The first way the company is "harnessing disruption" is through collaboration. "Today, instead of operating and developing solutions in isolation, we innovate in close collaboration with our customers. This involves sharing design concepts, testing, failing fast and landing together, a process at GE we call 'Fast Works'. In this way we foster a relationship of mutual trust and respect that values both parties."

The second is through digitization, which he said was, "the single largest change for the industry and the foundation for its future. We're driving the industry forward to unlock this potential."

He added that, according to a McKinsey study, the effective use of digital technologies in the oil and gas sector could reduce capex by about 20%.

"Today only 3% to 5% of oil and gas equipment is connected. The average offshore rig has 30,000 sensors that are generating, typically, less than 1% of the data that are used to make decisions," Simonelli said. "The data are stuck in data graveyards, where they lie dormant, unanalyzed and fail[ing] to grant insight on their decision-making. Fewer than 24% of operators describe their maintenance approach as being predictive when based on data and analytics.

"Using Big Data, operators can proactively make their decisions. With Predix, our cloud-based operating system for the industrial Internet, we're driving much-needed transformation for our industry."

In closing, Simonelli said, "Resilience, disruption [and] collaboration will pave the road to recovery." Just as they have for as long as humans have tinkered. E&P

Jennifer

TURNING to the Right

New developments in drilling technology are keeping bits spinning in the most complex formations.

Rhonda Duey, Executive Editor

Somewhere around the time that the industry stopped using cable-drop tools and started using rotary drilling tools, the habit formed to turn the drillstring to the right. And "turning to the right" has become a mantra for successful drilling ever since.

But so much has changed, and in the following pages we reveal some of the amazing strides that the drilling industry has made. This isn't your father's rope, soap and dope industry anymore. Rigs have been automated, and downhole sensors have become so sophisticated that the industry is playing catch-up trying to make sense of the ocean of data they provide. And operators are pushing the limits of temperature and pressure with the aid of new downhole tools that can withstand the harshest conditions.

The "easy oil" has been gone for a long time. But the industry still finds ways to push the boundaries. E&P

Automating complex tasks in unforgiving environments

As downhole conditions continue to become more difficult and well profiles more complex, some contractors and operators are introducing systems that aim to move the drill floor from mechanization to automation.

Rick Von Flatern, Contributing Editor

In the popular imagination, a truly automated drilling unit is one that is manned by one human and one dog. The human is needed to feed the dog and the dog to keep the human from touching anything. For those earnestly engaged in developing automated drilling processes, however, the guiding image is not the human-free robot-controlled assembly plant but the airplane autopilot system that advises the pilot and, when appropriate, autonomously flies the airplane.

A concept that has been discussed by the industry for more than a decade because the subsurface is a highly complex environment filled with unknowns, fully automated drilling operations have been slow to emerge. The road to full automation is being paved with very large volumes of data delivered to the surface from newly developed downhole sensors. These new data provide engineers with real-time insight into the state of the well as it is being drilled, but because the volumes arriving at record speed are so large and unwieldy, much of the information goes unused.

The first order of business, according to researchers, is to manage those data. "We don't have a Big Data problem," said Theresa Baumgartner, a researcher at the University of Texas (UT)-based Rig Automation and Performance Improvement (RAPID) consortium. "We have a messy data problem."

Other barriers to automation are more familiar to developers of oilfield technology, including the industry's famous resistance to changes that challenge long-held beliefs. For example, automated systems that process more real-time data significantly faster and more accurately than humans can might set drilling parameter limits that are less conservative than those with which drillers are comfortable. Typically, drillers resist or ignore such machine-generated commands and recommendations.

Still, progress toward automation moves forward. Spurred by increasingly remote areas of operation and complex wells, industry members are developing systems to answer operator demands for lower well construction costs and safe and efficient operations in difficult situations.

On the road to automation

Today automated drilling exists primarily as various diverse subsystems that are designed to perform or help humans perform specific repetitive drilling tasks. These subsystems range from those that act as advisers that depend on humans to implement recommendations to autonomous systems that gather and analyze data and then execute the necessary operational commands without human involvement.

Among these repetitive and predictable tasks, none of them impact drilling performance more than fluids management. Despite the proliferation of downhole sensors, drillers continue to rely on input from drilling fluid analyses performed by onsite personnel to help make critical decisions. Traditionally, because much of their time is devoted to managing drilling fluids properties, mud engineers are able to sample and fully analyze drilling fluids only three or four times per day. As a consequence, operators and drillers make drilling and well control decisions based on hydraulics models that were created using data that are often several hours old.

The Halliburton DRU is a skid-mounted unit that may be placed near the drilling rig to sample and analyze drilling fluids properties more frequently than is possible through traditional methods. (Source: Halliburton)

To address this shortcoming, Halliburton researchers have developed the BaraLogix density and rheology unit (DRU), which the company describes as a "fully automated unit that measures the density and rheology of drilling fluids." Installed near the rig's mud tanks, the skid-mounted unit incorporates a self-generating nitrogen purge system and is ATEX Zone 1 and IECEx certified.

Depending on the temperature of the mud captured at the supply or return line and the temperature to which it must be heated to meet operator test specifications, the system can be used to perform four or more six-speed rheology tests per hour. In addition, the DRU is able to calculate fluid density as frequently as once per minute.

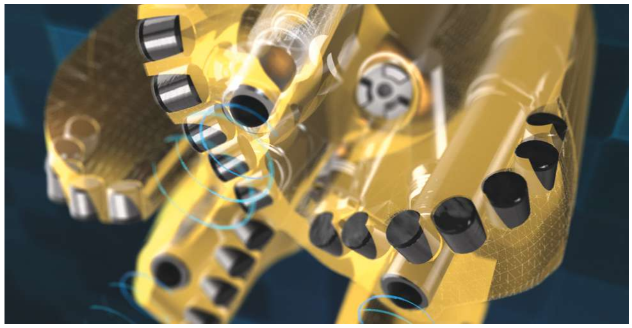
The data are captured by the Halliburton InSite data acquisition system, which uses the rig's LAN system to transmit the measurements to drilling engineers in a format that allows them to customize how the data are sorted and viewed. Mud engineers continue to maintain fluid properties based on traditional measurements but are assisted by BaraLogix results. "The mud engineer still performs his tests," said Jason Bell, product manager with Halliburton's Baroid business line. "This gives him advanced advisories about changes to make based on test results."

Automated routine fluid tests that collect and analyze more data more frequently allow drilling engineers to recognize data trends and changes in the drilling fluid and to make appropriate fluid adjustments as they occur. But the greater implications for end users arise from the marriage of the automated system and hydraulics models.

"The real value of this service is the data it provides for hydraulic models," Bell said. "By transmitting the data into models, we are able to use the model in predictive analytics for hole cleaning, lost circulation, pack-off and a host of drilling parameters."

Reaching the sweet spot

Because the easy reservoirs have been drilled, operators today are reaching target formations through complex and extended-reach wells drilled from a single surface location, so accurate wellbore steering and placement has become a critical function. To ensure wells do not collide and that they land precisely within the target formation, directional drillers guided by real-time downhole sensor data adjust wellbore trajectory using surface-controlled rotary steerable tools. But because trajectory is subject to many downhole variables, directional drillers might not have all the data necessary or might not be able to process and act on those data quickly enough to make adjustments that result in optimal well placement.



The Baker TerrAdapt bit is able to react instantly to rising downhole loads and to control DOC autonomously by extending elements against the wellbore wall, which prevents stick/slip from occurring. When the bit detects that the loads have lessened and the risk of torsional issues has past, the elements retract, allowing the bit to optimize ROP by drilling aggressively. (Source: Baker Hughes)

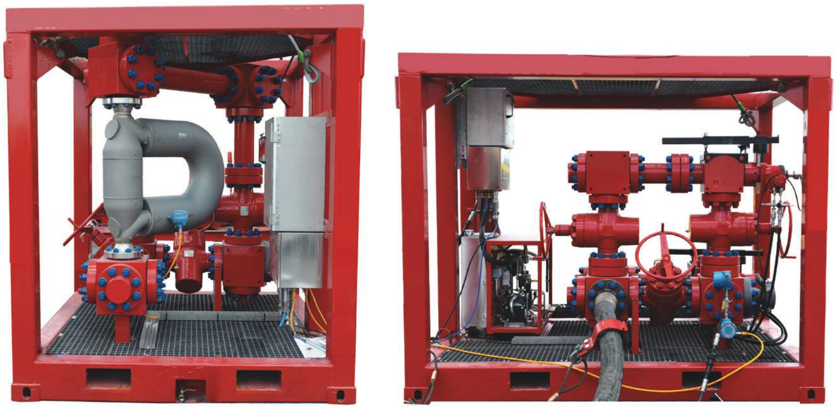
Service providers are working on automating the process with rotary steerable systems that monitor all available real-time data and use them to correlate commands given with the bottomhole assembly's actual response to those commands. The systems use those data to create accurate wellpath projections and to recommend commands that will result in the desired trajectory.

Engineers report they are field-testing a fully automated version of the system that executes downhole steering tool commands autonomously. Also with an eye toward autonomous downhole drilling tools, Baker Hughes has released an automated polycrystalline diamond compact (PDC) depth-of-cut (DOC) control bit that prevents certain drilling dysfunctions by adjusting proactively and autonomously to load increases at the bit.

PDC DOC control bits have been in use since the early 2000s. They are designed to prevent the cutting elements from digging too deeply into the rock and creating loads that lead to torsional vibration or stick/slip events. Like all bits, however, when a DOC bit underperforms, the operator's only option is to pull the drillstring and replace the bit or to endure less than optimal performance.

By contrast, the Baker Hughes TerrAdapt bit incorporates movable elements that react to the load at the bit. When the bit experiences an increased load that indicates onset of stick/slip, those elements extend outward against the formation to resist the sudden change, limiting the DOC and protecting the cutting structure. During intervals of smooth drilling the elements retract into the bit body and, because the bit can cut more aggressively, ROP is optimized.

The mechanics of the new bit are a cartridge-like component that contains fluid and a restrictor that creates a



Weatherford's Microflux pressure control system uses a Coriolis meter (left) to detect fluid influxes or losses more quickly than is possible using traditional methods and automated chokes (right) to mitigate those volume changes autonomously. (Source: Weatherford)

pressure differential, explained Baker Hughes Product Line Manager Danielle Fusilier. Baker Hughes researchers, who documented the rate of load change associated with the onset of stick/slip, designed the movable elements to move outward in reaction to that rate.

"Typically, if an operator determines stick/slip is occurring, the reaction is to reduce DOC through parameter adjustment," Fusilier said. "That takes time and may not solve what is happening at the bit. With TerrAdapt we are able to react to vibration issues in real time and prevent further damage. It is a good fit for automated drilling because it is very hard for an operator to know what is happening 10,000 ft [3,048 m] downhole at the bit."

As Baker released TerrAdapt bits to autonomously adapt to changing rock conditions, Weatherford has developed an automated pressure-control system. Weatherford Global Director of Well Control Technology Robert Ziegler said the system is "a fully integrated real-time multisensor process-control system" that combines the company's Microflux control system with its OneSync software platform.

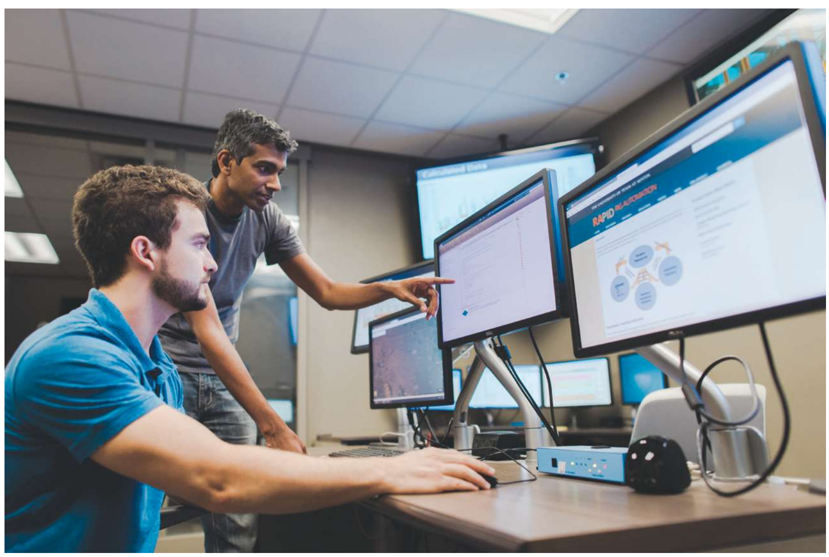
The Microflux system measures return flow using a Coriolis flowmeter installed in line with the chokes to detect fluid gains and losses earlier than is possible using traditional methods. This early detection capability minimizes fluid gains or losses. OneSync is the company's well planning, dynamic drilling simulation and operations software platform.

By using the two in combination, Ziegler said, the driller is able to detect minute losses and influxes and mitigate them without interrupting the drilling process. The combined systems are able to determine the drilling window between pore pressure and fracture initiation pressure and to ensure that the driller remains within those pressure boundaries.

"A very good analogy is the 'autoland' system incorporated in every modern transport category aircraft, where automation lands the plane much better than the average pilot with zero visibility, controlling all aircraft systems in real time and showing the pilot via virtual reality where the plane will touch the runway," Ziegler said.

Data flood

The common thread that both hinders and aids efforts to create automated systems is the unprecedented volumes of real-time drilling data available to drillers today. Because of the volume and because data are not usually presented in a way that is easily and quickly understood by the user, converting those data into useful information that impacts operational actions and performance is key to automation.



Working in its real-time operations center at UT Austin, researchers analyzed field data provided by a RAPID consortium member company. They used the results of those analyses to develop templates of single-page visuals that help drillers organize data into useful information. (Source: RAPID Consortium)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To help manage this embarrassment of riches, researchers at RAPID first analyzed a unique set of actual field drilling data gathered by a consortium member company. Based on their analyses, performed in the consortium's real-time operations center at the UT School of Engineering, the team developed templates of single-page visuals created automatically from the data. Presented in an easily interpreted format, these visuals enable engineers to make quick decisions that result in improved drilling performance. The contributing company is reportedly working to implement these innovations into its operational workflows.

RAPID researchers, including UT's Baumgartner, also addressed diagnostic challenges associated with the rate of data transfer between the bit and the surface. To replace the inadequate transfer rates of mud pulse telemetry, some in the industry have begun turning to wired drillpipe, which can deliver up to 57,600 bits/sec compared with the traditional mud pulse technique that typically delivers data at 1 bit/sec to 3 bits/sec. However, because it encourages the industry to add complex downhole sensors that have high sample rates, resulting large volumes of data can make it difficult for end users to detect or identify drilling dysfunctions.

RAPID scientists attacked the problem using field data from multiple operations to develop a value-based approach, which specifies minimum data collection frequencies for each type of drilling dysfunction. "Many different downhole events contribute to movements and vibrations in the drillstring and the bit," Baumgartner said. "Recognizing distinct patterns and frequency spectra helps us to unravel all these events from a single signal."

Inevitable

The overall arguments for automated drilling systems, as for all new drilling technologies, are optimized drilling performance, enhanced safety and operating cost reduction. And as complex wells push current drilling performance limitations, some level of automation will almost certainly become standard on high-end drilling rigs. It is much less likely, however, that even the most sophisticated units will be populated by just one human and one dog. E&P


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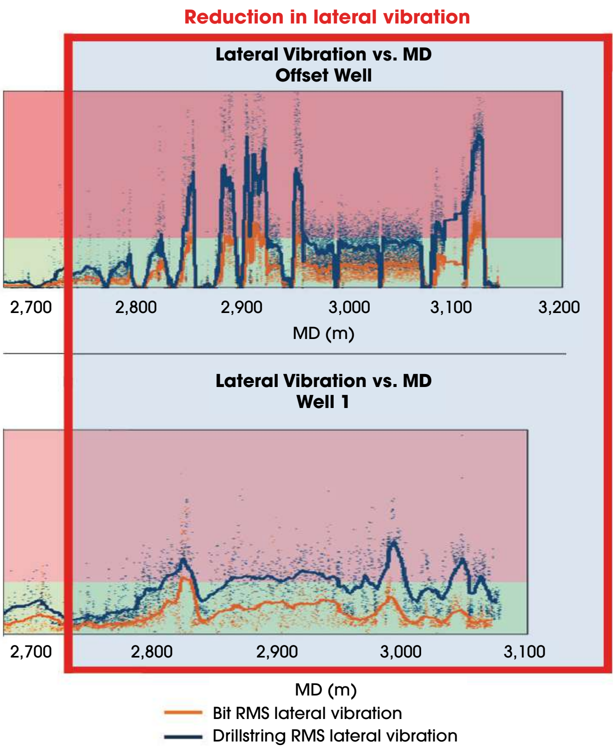
Presalt drilling benefits from real-time data

System uses tiered approach for challenging wells.

Stephen Forrester and **Isaac Fonseca**, NOV

Increasingly difficult wells have led to a significant number of new drilling challenges, particularly in the offshore market. Operators that are actively searching for new ways to combat the persistent decline in oil prices are becoming more aware that technical innovation must be the catalyst for industry change. To deliver innovation that drives impactful performance increases in complex offshore well environments, work must be done outside the confines of what has historically been considered "ordinary."



After redesigning the BHA and implementing NOV's suggested parameter changes, the client saw a significant reduction in lateral vibration in the optimized well both at the bit and in the drillstring. Mitigating vibration was one of the factors leading to increased performance and reduced equipment damage in this application. (Source: NOV)

Drilling the presalt

A conversation on difficult offshore wells would not be complete without discussing how the presalt is drilled. The presalt has become a major area of interest for operators working offshore Brazil and Angola, with important discoveries in the past decade revealing vast reserves of oil and natural gas and a potential to change the landscape of the offshore drilling market. Drilling the presalt, however, presents distinct challenges. The deepwater or ultradeepwater location of typical presalt layers and the large areas over which such layers are spread often present issues of economic feasibility. In addition, the expertise necessary for extraction necessitates significant investment in researching, both onsite and offsite, looking for the best methods and technologies to drill such difficult formations. Despite these challenges, the rise of these new technologies and access to such reserves will provide powerful opportunities for the industry to move forward.

National Oilwell Varco (NOV) has developed the eVolve Optimization Service, a tiered approach ranging from surface data-based optimization to full closed-loop downhole drilling automation, to address the changing economic and technological landscape of the oil and gas industry. The eVolve service brings together technologies from several NOV product families and proven drilling expertise to enable improved operational efficiency and enhanced decision-making. BlackBox memory-mode logging tools placed in the drillbit, bottomhole assembly (BHA) and/or drillstring capture data on pressure, torque, weight transfer and vibration and provide insight into how drilling practices affect performance and reliability. The driller is alerted to potential dysfunctions such as stick/slip and torsional/lateral vibration, and dynamic behaviors downhole are assessed to provide a deeper understanding of the drilling environment. In addition, combining surface and downhole data to analyze drilling dynamics creates an optimization foundation, enabling better design and component selection for the BHA in subsequent wells.

Case study

NOV worked with a South American client to develop a comprehensive solution in a unique presalt application using the eVolve service. The client was experiencing a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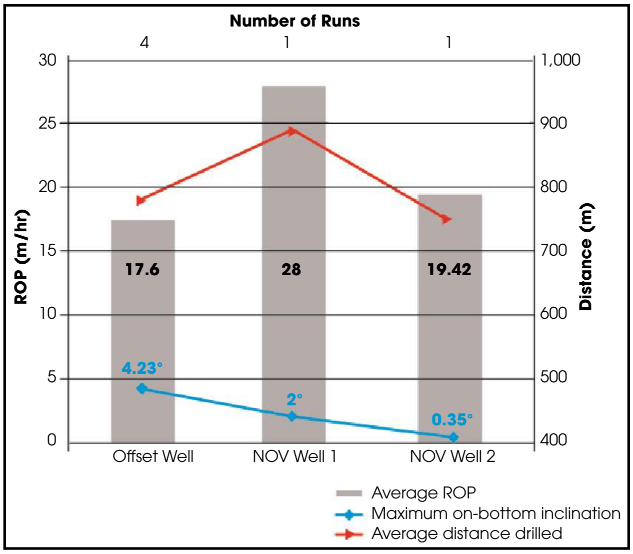

Improvements in ROP, including an increase from 17.6 m/hr in the offset well to a field record of 28 m/hr with NOV's recommendations, were one of several benefits on this project. Inclination continued to decrease after the offset well, reaching as low as .35 degrees, and the client was able to drill the entire section in one run on each well vs. four runs on the offset well. Optimization yielded drilling time savings of 1.5 days vs. the offset well. (Source: NOV)

number of drilling dysfunctions in the project, including high torque, which was stalling the motor and topdrive with the original bit, and deviation issues, which were compromising ROP due to low weight on bit. It was also necessary to reduce and then maintain inclination to optimize ROP. Previous offset wells had used a positive displacement motor and were usually drilled in either two runs with roller-cone bits or a single run with a polycrystalline diamond compact (PDC) bit. The complex lithology of the challenging formations was also a concern.

The first step in this project was to use the BlackBox tools to obtain high-frequency downhole data. These data were then analyzed to determine optimal drilling practices and parameters moving forward, with the client setting the objectives of maintaining low inclination, improving ROP and drilling the entire section in one run through the surface hole formation, stopping in the salt. Hole verticality and tortuosity, limited torque at the topdrive, high reactive torque and potential stick/slip when drilling the anhydrite, and potential equipment damage were the main challenges determined from the analysis. In addition, high circumferential contact needed to be maintained while drilling to achieve improved lateral stability, and caution needed to be taken so that the cutters did not break when drilling the salt.

NOV worked with the client to design a completely new and innovative BHA, using a 17½-in. PDC bit matched with a 26-in. concentric reamer and impact-resistant Helios cutters. This redesign enabled a proven 17½-in. rotary steerable system to be used to aggressively drill the challenging 26-in. section and reduced the time required to change the BHA for the next hole section, allowing both the bit and the BHA to be reused. Vibration was mitigated at the end of the run in the anhydrite, allowing the client to reach total depth (TD) without damage to the equipment, and the offset and spiral of reamer and midreamer blades provided 360-degree circumferential contact to maximize lateral stability. Drilling practices and parameters were optimized through use of computational fluid dynamics, torque and drag analysis, and finite element analysis, ensuring optimal performance.

ROP in the offset well, using the original 26-in. PDC bit, was about 17.6 m/hr (57.74 ft/hr), and the field average of ROP for the project was about 14.4 m/hr (47.24 ft/hr). Using the redesigned, optimized BHA, improved bit selection and the drilling parameters recommended by the eVolve team, the client was able to achieve a field record ROP of 28 m/hr (91.9 ft/hr) when drilling the presalt. This improvement represented an ROP increase of more than 57% over the best offset well and almost double that of the field average. The client also achieved the objective of reaching TD in a single run without incident, and low inclination was maintained as per the well plan. The significant increase in ROP combined with the various other performance improvements enabled a reduction in total drilling time of more than 1.5 days in comparison to the offset wells, yielding savings in excess of $700,000 for the project.

The analysis of the large amounts of data collected by the BlackBox tools and the actions taken as a result of this analysis were not only beneficial to the client on this project, improvements on additional wells, in fact, were enabled through implementation of this project's lessons learned. On the subsequent well of this drilling campaign, for example, another customized BHA was designed, and the client was able to avoid areas with high-resonance vibration potential in the BHA due to NOV's parameter recommendations. Implementation of these recommendations combined with continuous, real-time feedback while drilling from the client's operations center enhanced overall efficiency and yielded ROP gains that were equal to or greater than those achieved on the previous well. Torsional and lateral vibration also were reduced, and mechanical-specific energy use was optimized in the system. E&P

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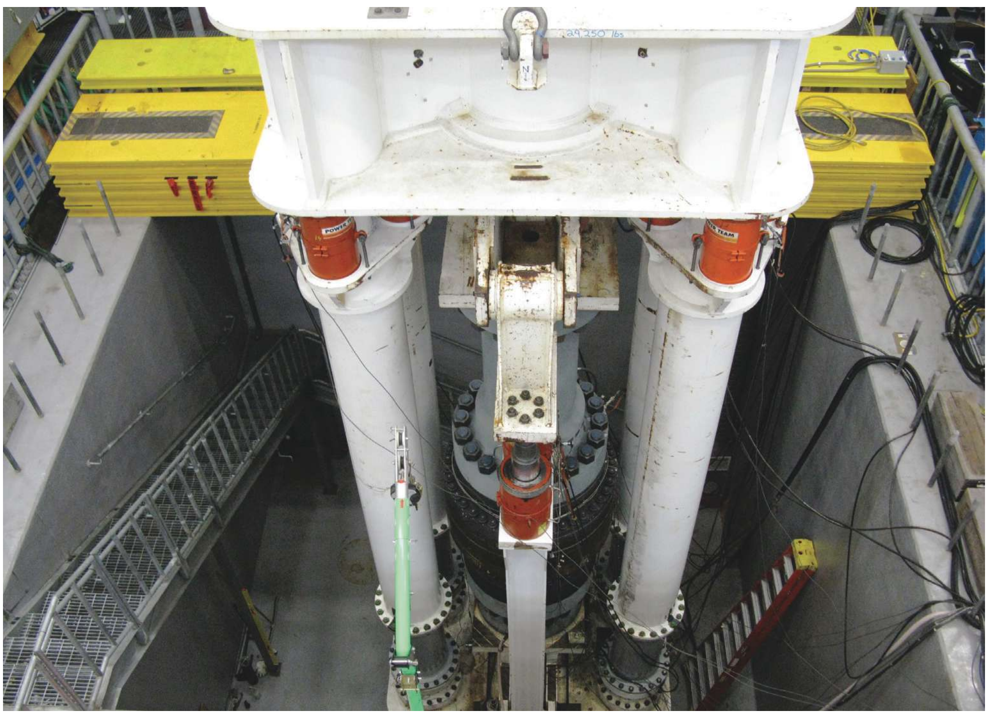
Developing the HP/HT toolkit

The industry is developing 20K drilling systems to tackle challenging reservoir portfolios.

Greg Myers, **Viral Shah**, **Katie Kotarek** and **Jim Sauer**, GE Oil & Gas

The economic promise of vast offshore hydrocarbon reservoirs, currently out of reach due to extreme formation pressures and temperatures, continues to motivate operators and contractors to evaluate the technology portfolio needed to safely harness these resources. GE Oil & Gas has embarked upon a comprehensive technology mission with its customers to develop enabling drilling equipment required to handle the extreme pressures and temperatures. Lower Tertiary fields such as the Shenandoah, Kaskida and Tiber in the Gulf of Mexico are a few examples where pressure and temperatures might be beyond the 15,000-psi and 121-C (250-F) ratings of currently available equipment. GE and its customers are collaboratively designing, building and testing the equipment needed to safely drill wells with pressures of 20,000 psi (20K) and temperatures of 177 C (350 F) and a riser with a 4.5-million-pound flange capacity for global deployment.



A 20K wellhead connector undergoes bending load testing. (Source: GE Oil & Gas)

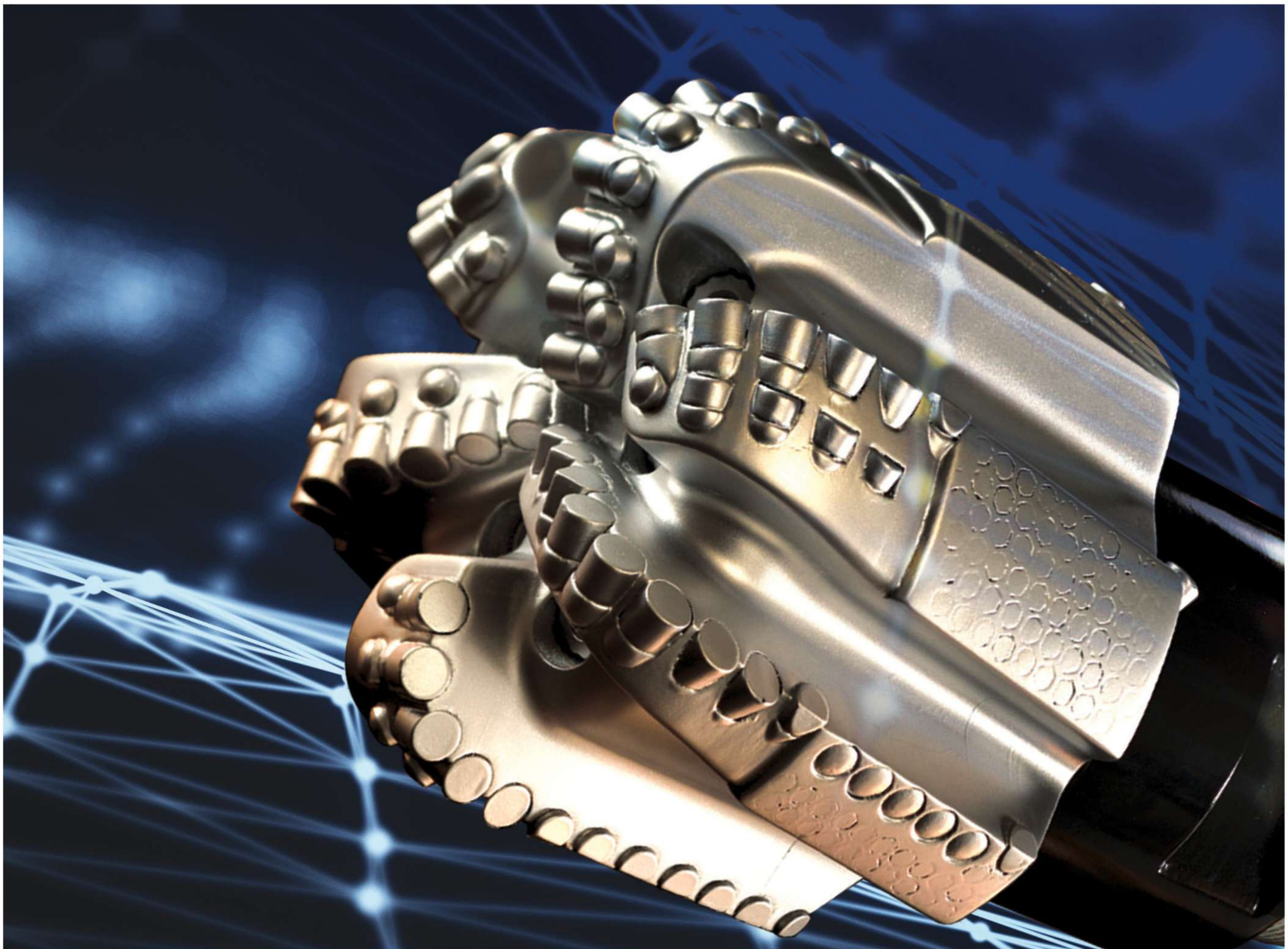
Regulatory requirements, design considerations

Designing, building, testing and maintaining equipment that is fully compliant with regulatory bodies is a paramount goal, yet fully balloted regulations governing 20K systems are not available. In lieu of prescriptive industry regulatory guidance, GE's drilling project initially used both the American Society of Mechanical Engineers' BPVC Section VIII Division 2 and Division 3 design paths to design each component along with following the guidelines in American Petroleum Institute (API) 17TR8. This led to a conservative approach that might yield an increased component weight. Recent industry publications have suggested that the more conservative Division 2 design path might be the preferred option for HP/HT subsea drilling equipment, which aligns with GE's design approach.

Multiphase system approach

This highly complex project necessitates the application of funding and resources on key equipment at staggered intervals. The BOP and wellhead connector were the first systems for HP/HT development. The GE 20K wellhead connector has been fully designed, built and qualified in preparation for deployment as part of a capping stack. The system, including GE's new 18¾-in. 20K flange, has completed a 30,000-psi hydrotest, exceeded the cycle counts for the API 16A Sealing and Locking Mechanism tests and performed combined pressure/tension/bending load tests. Additionally, the flange and gasket have completed a PR2 test up to 20K from -18 C to 177 C (0 F to 350 F) per API 6A and pressure cycling per API 17D.

The riser and associated support equipment design is the next large 20K drilling system slated for completion.



An H4 connector undergoes post-machining inspection. (Source: GE Oil & Gas)

A BOP stack is assembled and tested. (Source: GE Oil & Gas)

An extraordinary amount of finite element analysis has been conducted to date as well as a global riser analysis to validate the myriad design options such as auxiliary line load sharing, 27-m (90-ft) joint lengths and 177-C temperature ratings for the choke and kill lines. The riser connection configuration will initially be MR-6J-SE, which uses six retractable latching dogs to positively connect corresponding riser joints. The "J" is associated with the API 16R tension class of 4.5 million pounds, which also could apply to a bolted flange configuration if desired by a customer.

BOP qualification has progressed well. The development of a casing shear ram, Hydril Variable Ram, blind shear ram and pipe rams using 22-in. and 28.5-in. operators is well underway. Recent shear testing of a complex sample using a blind shear ram was performed successfully followed by a high-pressure seal at 20K for 35 minutes. GE is conducting testing above and beyond the API requirements to prove reliability for critical HP/HT equipment.

Other 20K developments

As part of the overall 20K system GE also has designed, developed and qualified a 20K choke and kill (C&K) connector and qualified a 20K C&K valve. GE will supply its next-generation SeaPrime I and SeaONYX controls to meet the reliability and availability demands of 20K systems.

The road to developing and providing a complete suite of 20K-ready drilling products is not without its pivots. Commercial realities arising from lower commodity prices as well as technical challenges have impacted the development pace, yet these have not lessened the commitment for success. All indications are that the industry is committed to the development of 20K drilling systems to support the development of challenging reservoir portfolios. E&P

Great Basin elephant hunt

Untapped riches could lurk in the western U.S.

Alan K. Chamberlain, Ph.D., Cedar Strat

Most of the giant oil fields on earth, elephants, are found in passive margin shelves like the Paleozoic passive margin shelf of the Great Basin of western Utah and eastern Nevada. These shelf Paleozoic sediments thicken from several thousand feet from the Utah Hingeline in central Utah to more than 12,192 m (40,000 ft) in central Nevada. Many age-equivalent North American producing oil shales were deposited in this stratigraphic wedge. However, the Great Basin shales are not just as organically rich as the other shales, but they are many times thicker. The eastern Great Basin, covering 71 million acres, most of which is available for leasing, is the last underexplored onshore basin in North America likely containing elephant oil and gas fields.

The Bakken age-equivalent Mississippian-Devonian Pilot oil shale is up to 274 m (900 ft) thick in the Great Basin, in contrast with only 46 m (150 ft) or less in parts of North Dakota. One of the favorite stops on Cedar Strat's helicopter-supported fieldtrips is an outcrop of tight Pilot sandstone that bleeds oil when it is freshly broken just like oil bleeding from freshly broken Mississippian limestone (Figure 1). Oil seeps from organic-rich Marcellus age-equivalent Middle Devonian shales in some Nevada outcrops. One well with gas shows cut 2,438 m (8,000 ft) of Utica age-equivalent Ordovician Vinini shale and was still in Vinini at total depth. Oil shales in these Ordovician strata are so organic-rich in some outcrops that they have been retorted for oil.

Organic-rich Great Basin Mississippian Antler Foreland Basin oil shales are measured in thousands of feet in contrast to the age-equivalent Barnett Shale that is measured in only hundreds of feet in Texas. Combining shale thicknesses and sample analyses results in showing that the shales have enough organic carbon to literally generate trillions of barrels of oil (Figure 2).

FIGURE 1. Oil bleeds from fractures on an outcrop. (Source: Cedar Strat)

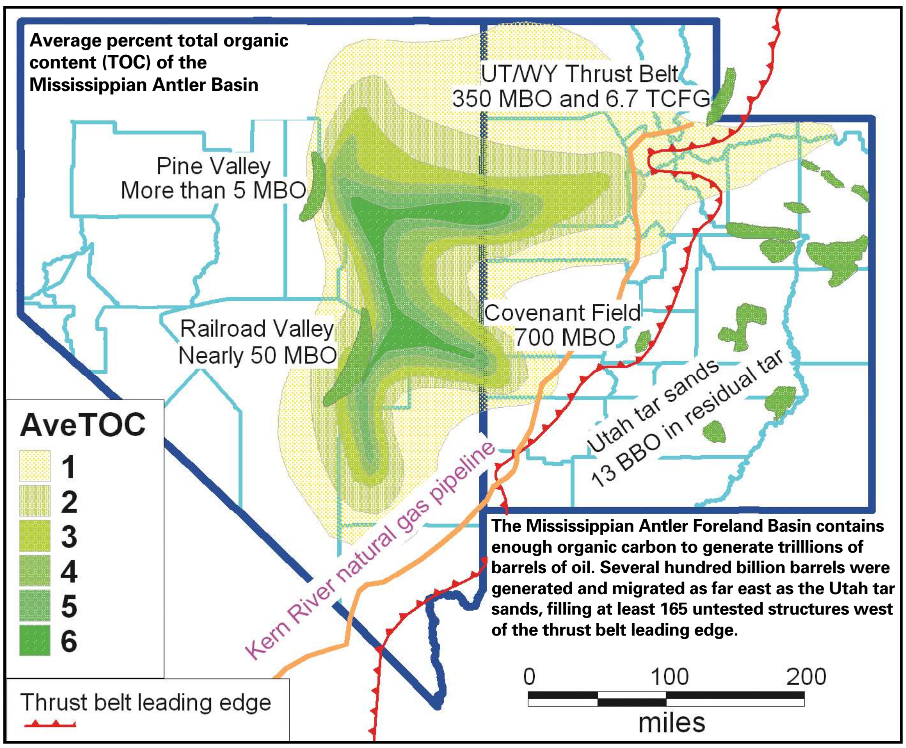


FIGURE 2. This figure indicates the richness of the shale content in the Mississippian Antler Foreland Basin. (Source: Cedar Strat)

Mapping

Some of that oil was generated soon after thrust loading in the Late Cretaceous and Early Tertiary. The hydrocarbons then migrated through thousands of feet of subthrust Jurassic sandstone to oil traps along the leading edge of the western North American Cordillera thrust belt in central and northern Nevada and onto the giant folds in the Colorado Plateau of eastern Utah. Subsequent erosion by the Colorado River removed the structural seals, allowing most of the hydrocarbons to escape and leaving only a residue of 13 Bbbl of oil in the Utah tar sands.

Oil seeping from structures in Nevada was trapped by a blanket of Oligocene volcanic rocks and formed commercial oil fields in Railroad and Pine Valleys. One well in Railroad Valley, flowing 4,000 bbl/d, kept the record for the most prolific onshore flowing oil well in North America for about 10 years. However, due to the lack of a state geological survey and the erroneous structural model dictated by conventional wisdom, exploration companies did not discover the source of these commercial oil seeps.

FIGURE 3. A helicopter perches on the Keystone Thrust fault, where the Jurassic root of the mountain of Paleozoic rocks has been exposed by Colorado River erosion. (Source: Cedar Strat)

Using its geological survey, Cedar Strat created a structural contour map on the top of the Mississippian Joana Limestone and believes it has discovered the source of the commercial oil seeps. This map combines stratigraphic field measurements, geologic mapping and gravity data to create a structural contour map on the Mississippian Joana Limestone that lies parallel to the Mississippian and Pilot shale source rocks.

The contour map was made on the top of the Joana because the Joana forms a prominent cliff above a strike valley in the Pilot Shale below and a strike valley in the Mississippian Antler Basin shales above, it is easily distinguished on surface and subsurface gamma ray logs and it is extensively distributed.

The structural contour map literally has become a treasure map because it identifies at least 165 untested structures possibly full of oil and gas covering 20 million acres between the Antler Basin oil-generating kitchen and the leading edge of the Cordillera thrust belt. As oil migrated from central Nevada to Utah, it filled up each fold to spill point before flowing over to the next structure to the east. Each of the structures could contain 1 Bbbl or more of oil or oil equivalent. Fortunately, erosion by the Colorado River has exposed thousands of feet of subthrust Jurassic sandstone that forms the cores of mountains in the Las Vegas area.

Surface evidence

Cedar Strat typically begins its helicopter-supported field trips in Las Vegas, where mountain roots are exposed, and then moves northward, where only tips of hanging wall thrust duplexes are exposed (Figure 3). Two wells penetrating thousands of feet of Precambrian and/or Early Paleozoic rocks confirm that subthrust Mesozoic rocks occur below the thrust sheets west of the leading edge of the thrust belt. This evidence suggests that thick subthrust Mesozoic sandstones also might core some, if not many, of the 165 untested structures north of the Colorado River Basin. Not only are the subthrust sandstones the conduit for oil migration, they are also the reservoir rock that already has produced trillions of cubic feet of gas and hundreds of millions of barrels of oil along the leading edge of the thrust belt. E&P

Have a story idea for Shale Solutions? This feature highlights technologies and techniques that are helping shale players overcome their operating challenges. Submit your story ideas to Group Managing Editor Jo Ann Davy at *jdavy@hartenergy.com*.

Sky is not the limit

Advanced AIM is made simple with satellite technology.

Michael Hall, Airbus Defence and Space

Any number of facility and pipeline accidents or incidents is too many. They can cause major business disruption, significant environmental damage and, in some cases, human fatalities. In the U.S. alone there were more than 30 incidents in 2016, and each of these instances increased the pressure on business owners and operators to improve the design and maintenance as well as inspection management of their assets.

However, help is at hand. The availability of new advanced satellite technology, software and sensors is enabling businesses to monitor assets using a more holistic, integrated approach, generally described as asset integrity management (AIM). To function effectively and to accurately inform operators about plant-related network issues, precise and up-to-date data are crucial. Gaining this insight requires the appropriate tools to be in place to constantly monitor assets, which can span several hundred kilometers. This is where commercial access to satellite innovations and premium satellite operators' oil-and-gas-specific intelligence and expertise provides new, valuable datasets to support and cost-effectively inform operational AIM activities.

Advanced satellite innovations for AIM strategies

Very high-resolution and wide-swath satellite sensors already have proved to be successful tools, especially when assets are located remotely, allowing oil and gas operators to monitor facilities and pipelines in a timely manner, no matter how far away these infrastructures might be from management or decision makers. Many satellite providers also have given oil and gas operators direct access to tasking their constellation of satellites. One of these providers is Airbus Defence and Space, which not only gives access to its satellites but also offers value-added services and intelligence solutions, supporting each stage of the oil and gas project life cycle.

Optical sensors such as the Pléiades satellite constellation take very high-resolution images in fine detail (Pléiades offers 50-cm imagery products). The other sensor type is a highly sensitive radar sensor such as TerraSAR-X. Radar images, for example, are very suitable

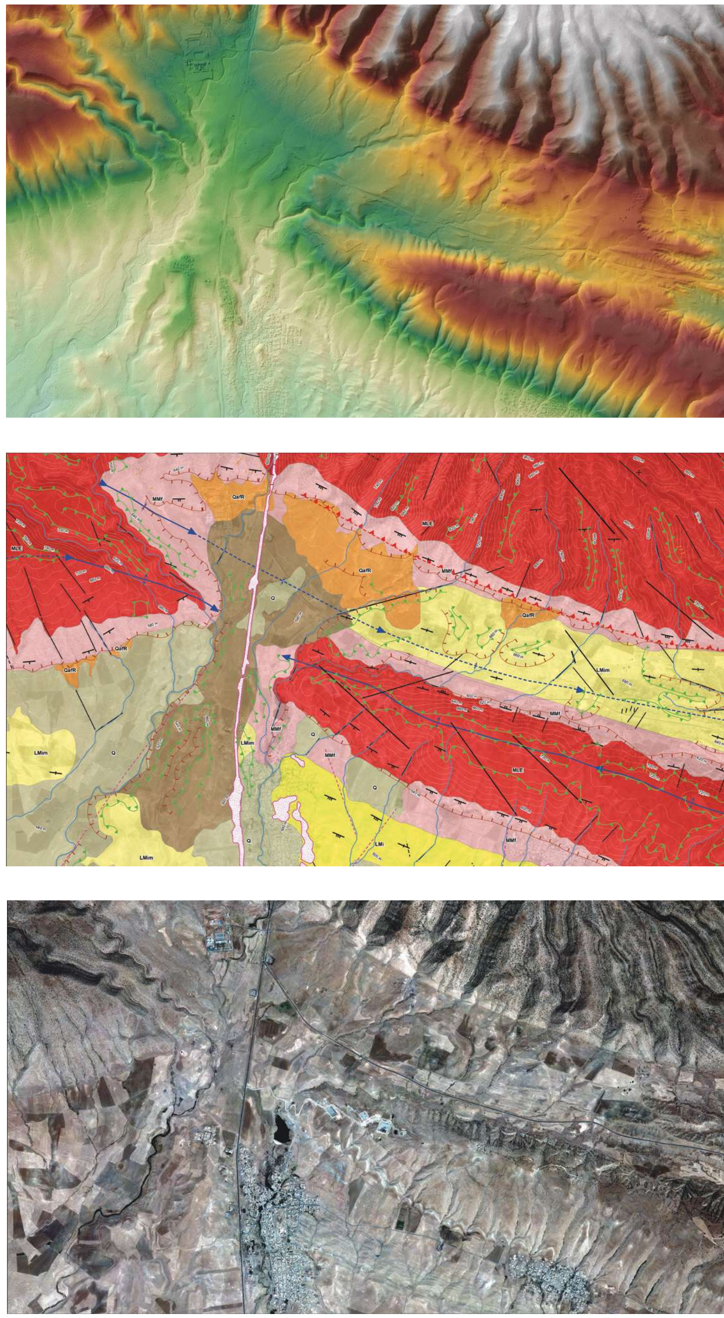


FIGURE 1. Very high-resolution satellite imagery and derived map layers, including elevation information and geological interpretation, aided in the routing of a pipeline. (Source: CNES 2014/Distribution Airbus DS, all rights reserved)

to help detect offshore oil leaks regardless of the weather or light conditions by identifying the dampening effect oil has on sea surface waves. Equally, complex civil engineering projects, which can cause movements of the Earth's surface, use TerraSAR-X-based analysis to detect even the smallest changes to ensure the safe implementation and maintenance of infrastructure constructions, excavations and underground engineering.

When selecting a satellite imagery provider, operators should ensure they choose a partner that has access to the full gambit of radar and optical satellite constellations and has user-friendly platforms in place to facilitate quick satellite tasking and dissemination. This is particularly important when urgent and timely images of an area of interest are required. In addition, the satellite provider's expertise in responding to oil- and gas-specific needs and challenges should be an important aspect of the selection process.

The availability of the latest satellite technologies provides a unique opportunity to gain important insights into an asset's safety and environmental impact throughout its life cycle and at an affordable cost.

An asset's design stage

AIM is focused on ensuring that a particular asset or group of assets is performing its required function effectively and efficiently while also protecting HSE. From initial design stages satellite imagery and intelligence can play a valuable supporting role, helping to inform key planning and construction decisions, which can have long-term implications.

Satellite technologies have for decades helped advance the geological interpretation of onshore and offshore regions to evaluate potential areas of development. Beyond this, they can support the projects' further development.

For example, onshore satellite imagery-based maps are used to assist the seismic planning process. The images allow mapping "go" areas, which are areas that are easily accessible, and "no go" areas, which don't allow seismic acquisition vehicles to easily collect data. This simple process can substantially reduce the time the staff needs to spend onsite for data collection, and it also reduces the multiple risks team members are exposed to when moving around the world, particularly in difficult-to-reach and inhospitable locations.

In addition, Airbus also offers a number of satellite-based elevation products, including a worldwide homogeneous elevation map named WorldDEM. Using this dataset in conjunction with satellite images gives engineers detailed information to develop optimized construction routes, locations and appropriate designs, which can help increase an asset's efficiency and safety from an early stage.

In one recent example ILF Consulting Engineers needed detailed information to calculate an optimized, fast and cost-effective pipeline route traveling between Georgia and Azerbaijan. Due to the short lead time of the project, Airbus was tasked with providing data for the project prior to construction with a required accuracy level of 1-m (3.2-ft) root mean square. Initially, very high-resolution Pléiades archive imagery and off-the-shelf digital elevation models and elevation datasets were provided that allowed ILF to verify the pipeline corridor position and correct prerouting errors; this was then advanced with new acquisition of Pléiades stereo pair datasets and onsite acquisition of ground control points that provided a highly accurate Elevation 1 Digital Terrain Model, helping identify a shorter route than initially considered as a result (Figure 1).

All of this was successfully planned and engineered remotely on a computer with the provided datasets. This enabled the team to ensure compliance with numerous factors, which overall minimized risk and cost during the construction stage and during the pipeline's operational phase, minimizing site data collection.

The benefits are equally significant in an offshore scenario. Airbus' One Tasking satellite service provides an important tool for monitoring the environmental impact of construction work, enabling early interventions if required. In a recent example, the environmental impact of nearshore pipeline construction activities was monitored in the Caspian Sea using satellite imagery to identify the impact of dredging activity on the dispersion of sediments. Traditional water quality monitoring techniques would have presented logistical and operational inconveniences as well as long processing times, whereas with flexible satellite tasking capability images were delivered just 2.5 hours after acquisition. This allowed the customer to define the quantitative and spatial dispersion of sediments and make rapid, informed decisions based on the findings.

FIGURE 2. This Pléiades satellite image shows a burning asset in Tripoli, Libya. (Source: CNES 2014/Distribution Airbus DS)

Monitoring during the production phase

The continuing depression of global oil prices and the resulting reductions in budgets have led to the lifespan of many operational assets being extended to maximize return. The increasing age and potential structural vulnerability of these dated assets brings along a whole host of new challenges for AIM, but even new assets require rigorous maintenance and continuous inspections to guarantee that their condition is "fit for service"—all requirements that can be supported by satellite imagery and its derived intelligence.

In contrast to other imagery acquisition tools such as airplanes and helicopters, satellites offer data acquisition that is significantly more cost-effective since the satellites already are circling the globe and no expensive equipment or experts are required onsite, particularly useful when long pipeline stretches need to be monitored. The satellite-produced datasets can be used to plan maintenance checks and infield monitoring activities more precisely or to increase the efficiency of infield operations. They also can be used to identify pipeline leaks or structural changes in almost real time to enable rapid action to be taken.

Some satellite providers also offer the automated detection of imagery changes using historic and up-to-date satellite imagery. Airbus' automated change detection software can provide valuable insights and prewarning information for integration into AIM systems.

Emergency detection and response

It is not only structural issues or the lack of maintenance that can cause problems. Illegal pipeline tapping, vandalism, terrorist attacks or unintended attacks caused by geopolitical conflicts are major threats for oil and gas assets, presenting an ever-evolving danger that is difficult to manage. In one example, Pléiades was tasked when a fuel storage facility in Libya caught fire during conflicts between rival militants. By using Airbus' GeoStore, the Pléiades satellite constellation was tasked and very high-resolution images were received just 90 minutes after the satellite passed the area, quickly providing fresh and important information regarding fire source points and nearby areas that were at risk as well as details to plan any response (Figure 2).

The process of tasking a satellite to retrieve exactly what is needed has now become even easier with the launch of One Tasking, which only requires a few clicks using this online platform. The flexible service also provides the option to create regular tasking plans in line with client-specific AIM system milestones, which means the satellite can be scheduled in advance to capture a specific area of interest on the exact day(s) required.

Should the AIM system detect an emergency issue, the first priority is to get the right information to the right person. Satellite communication tools, which also track asset locations using a geographic information system, provide an efficient way to communicate important action plans and share datasets across global team members, enabling an appropriate response to issues. SAFECommand is an example of this type of satellite communication tool, providing a secure platform that provides real-time location intelligence for staff and vehicles as well as integrated operational planning, response and communication functionalities.

Satellite technology—advancing AIM

The availability of the latest satellite technologies provides a unique opportunity to gain important insights into an asset's safety and environmental impact throughout its life cycle and at an affordable cost. Moreover, the addition of intuitive satellite tasking services, the environmental monitoring capability of radar satellites, automated change detection and satellite-based communication tools can all be used in isolation or integrated into a suite of resources available 24/7 to maximize an operation's effectiveness and to benefit the organization. E&P

Have a story idea for Operator Solutions? This feature highlights technologies and techniques that are helping upstream operators overcome their challenges. Submit your story ideas to Group Managing Editor Jo Ann Davy at *jdavy@hartenergy.com.*

Navigating EPA emissions regulations

The use of automated logic controls helps ensure compliance in the collection of emissions data necessary to meet reporting and recordkeeping requirements.

Sheri Vanhooser, OTA Compression/KIMARK

In an effort to further reduce volatile organic compounds and methane from new, modified and reconstructed sources in the oil and gas sector, the Environmental Protection Agency (EPA) issued OOOOa (Quad Oa) May 12, 2016. The updates to Quad Oa add methane to the list of pollutants covered by the original rule. Guidelines were added for detecting and repairing leaks at various sources within wellsite or compressor stations, among other rules.

Detailed recordkeeping and reporting requirements also were implemented within the new rule, which have operators scrambling to maintain compliance. By using advanced logic controls that collect and assimilate data, OTA Compression/KIMARK simplifies and automates the required reporting and recordkeeping, saving operators time and money.

A BMS with onboard Modbus, data logging, remote input/output, analog input/output and ultraviolet flame detection ensures compliance. (Source: OTA Compression)

Data management

Combining proprietary software advances with Modbus communication protocol, accessory equipment is interfaced with burner management systems (BMS), vapor recovery units (VRUs), vapor combustor units and flowmeters to generate compliant reporting and analytical data to help manage well sites efficiently and economically.

"Operating the BMS system could not be easier, and all the data generated make assembling reports much simpler," said an operator from Williams. "With multiple ways to generate data, retrieving data logged to the flash memory card or tying our system directly in to the KIMARK control panel, we have all the required data at our disposal."

The operator added that a few of the key numbers the company analyzes and sends to the EPA include run time/uptime, amount of failed/downtime, temperatures, valve state verification and venting occurrences.

"With the ability to examine these data ourselves, we are able to troubleshoot our own equipment and maximize the run time on our units and prevent downtime or venting situations," the operator said.

Smarter flare management

As stated in Title 40 Code of Federal Regulations 60.18 (2), flares shall be operated with a flame present at all times, and there must be a recording of time, date and duration of any pilot flame loss or auto-ignition failure. In addition to recording flame losses or auto-ignition failures, the KIMARK Smart Flare system reports the number of auto-ignition attempts and pilot outages. These datapoints assist in further diagnostics of unit performance.

"The flare system has built-in features that make environmental reporting much easier," said an operations manager at OXY. "Onboard flow rate and gas measurement on both the pilot and main burner lines let us know exactly how much gas is being burned in the unit. The unit is set to come on and go off at certain user-configurable pressure set points."

These set points are tailored to each specific location and the amount of pressure those storage tanks can hold, the manager said.

"Some storage facilities have water and oil tanks manifolded together, requiring the Smart Flare to operate at lower pressure running points to prevent venting. If a vent relief valve is tied into the Smart Flare, the valve will log any venting time and occurrences as well. Part of our operator's duties is to gather unit run times and vapors burned each day from the smart flare control station.

"We also have the ability to track all of these data with them being saved to a data chip and also [the ability to] log on to our server via our SCADA system. Regulations have only become stricter, but the KIMARK Smart Flare generates all the data we need to stay in compliance," the manager said.

VRU reporting, savings

Detailed reports can be generated from the VRUs and wellhead compression to help maintain compliance with federal and state regulations and document profitability. The onboard computer system gathers the data and then summarizes and graphs out critical datapoints such as inlet pressure, stack temperature, flame intensity level, igniter retries and more.

Operators can determine if there is a problem with their thief hatch or venting from the data that are obtained and make adjustments accordingly. From the data the savings attained can be calculated through recovered vapors.

For example, a VRU that services four wells with a common tank battery recovering 1,359 cu. m/d (48 Mcf/d) of 1,704 Btu vapor providing incremental annual revenue of more than $200,000 results in a 180% return on investment and multiple intangible benefits.

The data provide operators with the knowledge needed to manage costs and realize equipment payouts within a few months. They can then calculate future revenue streams based on recovered vapors. It is a silver lining as a result of the stricter regulations.

Fugitive emissions detection

With the addition of Quad Oa regulations, fugitive emissions from new, modified and reconstructed well sites and compressor stations are monitored. Operators must create a leak detection and repair (LDAR) program to identify and repair gas leaks. A fugitive emission is any emission visible using optical gas imaging or a reading of 500 ppm or greater using EPA's Method 21.

A VRU system collecting data from the tanks and compressor provides effective reporting and recordkeeping to maintain federal and state compliance. (Source: OTA Compression)

Operators must conduct an initial LDAR survey within 60 days of startup or modification. Subsequent surveys are conducted semi-annually for well sites and quarterly for compressor stations, thereafter separated by at least 120 days for well sites or 60 days for compressor stations. The initial compliance period concludes June 3. Initial surveys are to be conducted before this compliance period ends.

Optical gas imaging cameras are used for gas leak detection in leak monitoring surveys and site surveys. Many chemical compounds and gases are invisible to the naked eye. The FLIR GF-Series infrared cameras produce a full picture of the scanned area, and the fugitive gas appears as smoke. The image is viewed in real time and can be recorded, stored and used in reporting EPA compliance. If leaks are found during a survey, operators must replace or repair the sources of any detected fugitive emissions "as soon as practicable but no later than 30 days after detection," per the regulation.

Once the leaks are repaired, the location must be resurveyed within 30 days to ensure that the leak has been corrected. Operators can place all of their stations into a single monitoring plan or create multiple plans based on how they internally organize their facilities. OTA/KIMARK will prepare a comprehensive report with pictures, leak source (if applicable) and resolution as well as a statement of compliance and all other necessary documentation to comply with the Quad Oa guidelines in regard to LDAR testing. E&P

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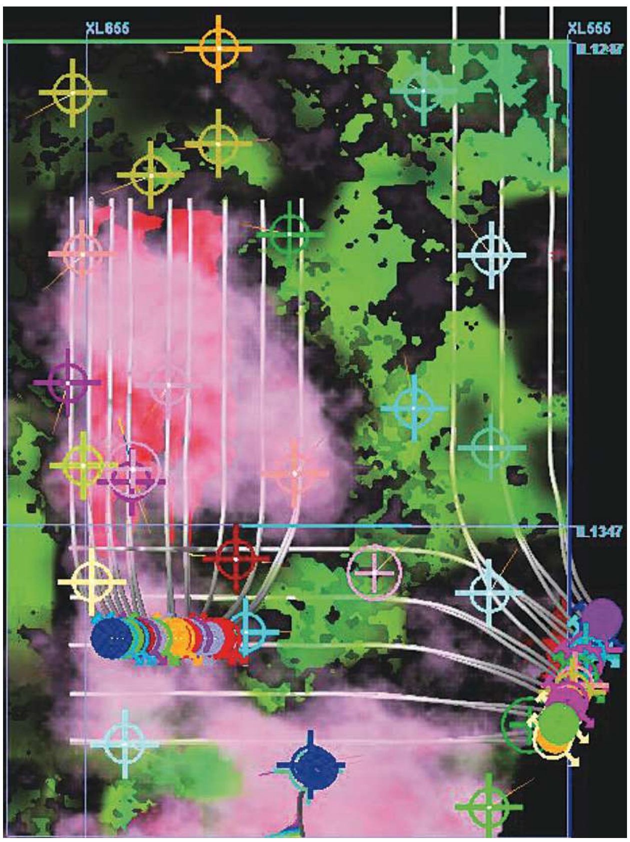
Four-dimensional seismic in the downturn

Time-lapse seismic still provides important information. But it's getting harder to make the value proposition.

David H. Johnston, Contributing Editor

The industry downturn has had a devastating impact on the seismic industry. Tied closely to E&P budgets, seismic spending is roughly half that seen prior to 2014. In the marine sector vessel rates have declined sharply to values that have not been seen since 2003, and there appear to be few drivers to push rates higher. Even with the recent increase in oil prices, the 2017 E&P spend for major operators appears to continue its decline. For those companies that expect modest 2017 increases in their E&P budgets, most of that spend will likely be focused onshore.

The only relative bright spot in the marine seismic business is multiclient acquisition. For companies such as PGS and CGG, multiclient sales account for more than half of their revenues, and the expectation is that the market will grow as oil companies position themselves for strategically important license rounds. This comes at a time when contractual marine seismic surveys have all but disappeared, accounting for less than 20% of CGG's and PGS's revenue, according to the companies' financial reports. Even Polarcus, which has maintained a 70% to 80% contractual utilization rate over the past few years, is working to build its multiclient library and has a cooperation agreement with TGS.

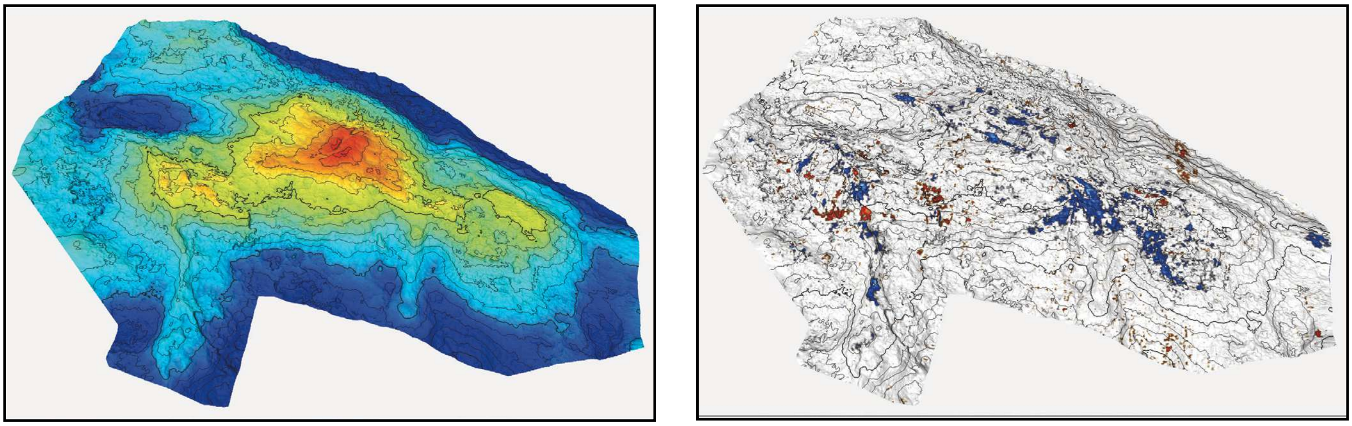


However, the contractual marine seismic market is not completely dead. Some operators with sufficient cash flow can take advantage of low vessel rates to acquire proprietary exploration surveys. Of the two proprietary marine seismic surveys acquired by Apache in 2016, one was an exploration 3-D survey in Suriname which, according to David Monk, director-worldwide geophysics, was acquired at a "time when we could capture bargain-basement prices. An equivalent survey three years ago would have cost four times the price, and my guess is that if we had waited for a couple of years, it would double." However, these surveys of opportunity are likely an exception and not the rule.

Although exploration activity has been significantly curtailed by many operators, there is a sense that companies may be focusing greater attention to producing assets and, as a consequence, 4-D seismic surveys. Is that true?

In a Sept. 20, 2016, press release, Andrew Latham, vice president of exploration research at Wood Mackenzie, said, "Companies are no longer trying to fully replace production via conventional exploration as they used to. Now their reserves replacement will also require inorganic, brownfield or shale investments." In an article on the FairfieldNodal website, Charles Davison, CEO of FairfieldNodal, said, "The 'E' in E&P

In this time-lapse image from a SAGD 3-C/4-D seismic monitoring project in Alberta, Canada, the green geobodies are interpreted to be mobile bitumen based on changes in the ratio of compressional-wave to shear-wave velocities. Pink is interpreted to be the steam chamber. (Source: Nexen)



The Top Forties reservoir depth surface (left) with extracted 2013-2000 4-D amplitude differences (right) is shown. Blue 4-D anomalies identify water-swept portions of the reservoir. For additional information, see "Resaturated pay: A new infill target type identified through the application and continuous improvement of 4-D seismic at the Forties Field" by G. Byerley *et al.*, The Leading Edge, October 2016, 831-838. (Source: Apache)

is dead … at least for the short to medium term, however long that may be." He continued, "Despite the fact that producers are attempting to rein in expenditures in every stage in the life of field, it is clear that they will be much more focused on maximizing the productive capacity of existing brownfields."

Indeed, it appears that many of the contractual marine seismic surveys are in the production sector. The other Apache survey acquired in 2016 was 4-D over the Forties Field. "Since 4-D [activity] keeps the asset going, it's tough to simply cut this out of a capital budget, whereas 3-D [activity] for exploration can typically be delayed," Monk said.

Data from the Norwegian Petroleum Directorate (NPD) show that of the 52 seismic surveys completed in Norway during 2015 and 2016 (excluding 2-D and site surveys), 30 were multiclient and 22 were contractual acquisitions. Of the 22 proprietary surveys, 17 were 4-D. However, 11 of the 17 4-D surveys were shot over permanent reservoir monitoring (PRM) systems at the Snorre, Grane, Ekofisk and Valhall fields. In these cases, the operators have significant upfront investments that must be recovered. Fortunately for PRM, monitor survey costs are lower than for comparable towed-streamer surveys.

A large fraction of a small number is still a small number

Although it appears that there might be an increase in the relative percentage of proprietary 4-D monitoring surveys vs. 3-D exploration surveys, the overall decline in seismic acquisition activity has hit 4-D.

Data from the NPD show that the number of 3-D surveys completed in Norway during 2015 to 2016 has declined 45% from the preceding two-year period (64 to 35 surveys). Over the same period the number of 4-D surveys declined by 37% (27 to 17 surveys), with most of the cuts focused on streamer surveys.

For Statoil there has been about a 30% reduction in overall seismic activity since 2013, according to a company source. There is roughly a 50:50 split between exploration surveys, which are dominated by multiclient acquisition, and production seismic surveys. For Statoil, which has a long history of 4-D seismic acquisition, there is no refocusing of effort. This ratio is similar to historical levels. But, as the company contact puts it, there is "just less for everyone."

The reduction in overall seismic activity, including 4-D, is a common theme among global operators. For many companies surveys that might have been planned for 2016 to 2017 have been deferred until 2018 to 2020 or beyond. One case in point is Petrobras. A company source noted that new PRM projects, due to their high initial investments, are being delayed.

According to a source at Chevron, 2016 to 2017 4-D surveys are driven by either contractual obligations or drilling opportunities. Beyond 2017 only very large projects are even being considered for new 4-D surveys, and the economic threshold for their approval is high. In the past, management might have required justification not to shoot 4-D surveys. But that is not the case currently. The long-term value of 4-D surveys often is neglected in favor of impact on immediate drill/no-drill decisions.

At Shell, where a company source said most 4-D surveys were acquired as planned in 2016, 4-D activity is region-dependent. Several surveys were deferred, in part because alignment with joint venture partners can be a challenge in this economic environment. The situation is expected to remain the same over the next few years.

Fewer wells imply fewer 4-D surveys

Recent successful surveys for BP in the Gulf of Mexico (GoM), approved before the downturn, are spurring plans for additional 4-D activity. According to a company source, as long as there are active drilling campaigns, it does not appear to be hard to justify new surveys.

However, outside the GoM the future for 4-D surveys at BP does not appear as bright. In Angola and the U.K. North Sea, where the company has had past 4-D success, options for drilling and, as a result, for 4-D surveys seem to be running out.

As another operator said, "It doesn't help to find more 4-D targets if the drillers don't have the budgets to drill them. Four-dimensional seismic competes with other field development investment projects (templates, wells, etc.). We've had to ensure that our business cases are robust and competitive in a lower oil price."

A similar story for land

The weak seismic market is not limited to the offshore. Reporting the company's third-quarter 2016 financial results, Stephen C. Jumper, president and CEO for Dawson Geophysical, said, "Demand for seismic data acquisition services in North America and worldwide continues to be soft in response to low and uncertain oil prices and reduced client expenditures." CGG, which operated 22 land crews in 2013, reduced capacity to five crews by 2016, according to the company's financial reports.

Excepting North Africa and the Middle East, onshore operators are focusing their limited land seismic budgets on producing assets. In Western Canada, where the seismic industry has been especially hard-hit by the downturn, Mike Doyle, president of the Canadian Association of Geophysical Contractors, said in a 2015 interview with the *Daily Oil Bulletin* that there is still seismic work. "There will be some work in the oil sands," he said. "Typically, you need some 4-D dealing with steam-assisted gravity drainage (SAGD), and that type of work still tends to occur because it is linked to production." In fact, operators not only continue to acquire 4-D surveys for thermal recovery monitoring, as evidenced by recent technical publications, but companies such as Nexen and Devon are even working to enhance 4-D imaging of steam chambers using multicomponent (3-C) seismic.

With potentially better near-term investment returns compared to exploration, some operators are turning to EOR to boost production. Apache's only 2016 land seismic survey, planned to start before year-end 2017, was a 4-D test to evaluate the potential to monitor CO_2 flooding in an old onshore field. According to Monk, the asset is willing to fund this survey even though the team understands there is no guarantee of success.

However, most 2017 E&P spending increases are likely to be focused on unconventional oil and gas, areas that have proven to be challenging for 4-D activity.

Silver linings

Although there are signs the seismic market is stabilizing, most acquisition companies don't expect any immediate rebound in activity. However, there might be some areas of increased 4-D activity. As noted by several companies, there is growing interest in lower cost monitoring solutions such as distributed acoustic sensor vertical seismic profiling, high-resolution 4-D activity and the use of small seismic sources.

Some operators also are turning to reprocessing of legacy surveys shot over producing fields as proxies for new 4-D acquisition. Recent technical papers show time-lapse comparisons between ocean-bottom seismic (OBS) and streamer data as well as wide-azimuth vs. narrow-azimuth seismic. This approach maximizes the value of the operator's seismic assets and can serve as a bridge to future 4-D acquisition using systems such as OBS.

The downturn also has provided time for companies like Petrobras and Chevron to refocus their attention on enhancement of older 4-D surveys using new processing algorithms and technologies such as improved imaging based on full-waveform inversion.

With improving oil prices some companies are indeed looking forward to increased 4-D effort. According to a company source, during 2017 to 2018 Petrobras will acquire the first 4-D survey covering a portion of a presalt carbonate field undergoing alternating gas and water injection. And during 2018 to 2019 the company will cover many of its giant oil fields with OBS technology. There are also indications from several other operators that 4-D surveys deferred to 2020 or beyond might be accelerated to the 2018-2019 timeframe.

For those operators willing to take a longer term perspective, the current drilling downturn might ultimately result in greater 4-D value. As the industry recovers, companies might be less willing to engage in long-term rig contracts. As a result, there could be less pressure to "feed the rig monster," allowing 4-D seismic data to drive drilling programs rather than reacting to them—but only if the data are acquired.

Ultimately, it is all about demonstrating value, as it always has been for 4-D seismic. As one company source put it, "As long as you have a good business case, with a competitive breakeven, you can shoot 4-D seismic with us." E&P

Factors influencing the repeatability of 4-D ocean-bottom surveys

A study indicates that 4-D noise levels are sensitive to the quality of correlation between data volumes.

Peter Stewart, ION Geophysical

Four-dimensional or time-lapse seismic is well established in the industry. The concept involves comparing the differences between two or more datasets shot with a time interval between them. The time interval can be as small as a few months up to several years. The objective of 4-D seismic is to reveal only changes in the reservoir due to production, including phase changes due to gas coming out of solution, compaction of the reservoir interval due to the emptying of the pore spaces and fluid movement over time. Depending on the production method, such fluid movement may be natural as pressure is released or stimulated from injector wells. Nonproduction-related differences are regarded as unwanted noise. Four-dimensional noise is highly detrimental as it can obscure the subtle changes associated with production in the reservoir. The sources of 4-D noise can be many and varied.

Seabed seismic

The typical progression of a 4-D campaign is to initially explore an area with towed streamer seismic acquisition followed by some exploratory wells. If successful, the project will move into a production phase. Prior to any significant production, the first dedicated 4-D seismic shoot will take place. This survey is referred to as the "baseline," and a large percentage are increasingly likely to be seabed seismic surveys.

The reason for the switch to seabed is twofold. First, production infrastructure does not negatively impact the positioning of seafloor sensors when compared to towed sensors. Second, seabed sensors can be placed with greater accuracy. This is important because successive "monitor" surveys must attempt to mimic the baseline survey as closely as possible, including acquisition equipment, geometry and positioning. If every nuance of the baseline survey is reproduced exactly, there will be minimal 4-D noise and only changes due to production. However, this is rarely the case. In particular, repeating the sensor positions exactly can be challenging. This is one of the motives for using permanent reservoir monitoring programs with fixed receiver positions, but these tend to be prohibitively expensive in most instances.

Methods have evolved over the years to measure and quantify survey repeatability, including measuring the remnant background noise after surveys are differenced. The normal root mean square (NRMS) measurement is perhaps the most established metric. The NRMS equation (Figure 1a) is fundamentally a ratio-based equation expressed as a percentage with a dynamic range of 0% to 200%, with a lower value being better.

$$NRMS(a,b) = 200\,\frac{RMS(a-b)}{RMS(a)+RMS(b)}$$

FIGURE 1a. This figure shows the well-established NRMS equation. (Source: ION)

Typically, an NRMS measurement is made between survey a and survey b immediately after acquisition and at every step in the processing sequence. Ideally, the value is decreasing or at least not increasing.

Juan Cantillo with Total E&P (2010 SEG expanded abstracts) showed that the NRMS equation can be reformulated to be a function of cross-correlation and amplitude ratios (Figure 1b).

$$NRMS(a,b) = 200\sqrt{1-\left(\frac{2m}{(1+m)} * (1+\rho)\right)}$$

FIGURE 1b. The "reworked" NRMS equation allows a graph to be made whose axes are amplitude ratio and cross-correlation. (Source: ION)

The reworking of the NRMS equation allows a graph (Figure 2) to be made whose axes are amplitude ratio (horizontal axis) and cross-correlation (vertical axis). The contours of the graph are NRMS value. Clearly there appears to be greater sensitivity in the vertical (cross-correlation) axis than the horizontal (amplitude ratios) axis. This is important because it backs up observations on controlled synthetic experiments.

Noise factors

To evaluate influencing 4-D noise factors, ION generated a synthetic geometry where a patch of 4-km by 4-km (2.5-mile by 2.5-mile) shots are fired into a single receiver station. The subsurface consists of 10 flat reflecting interfaces with a simple vertical velocity profile convolved with a 60-Hz Ricker wavelet. The model was laterally homogenous. Although fairly simplistic, this common receiver cube is adequate to show the relative sensitivity of the node to many factors.

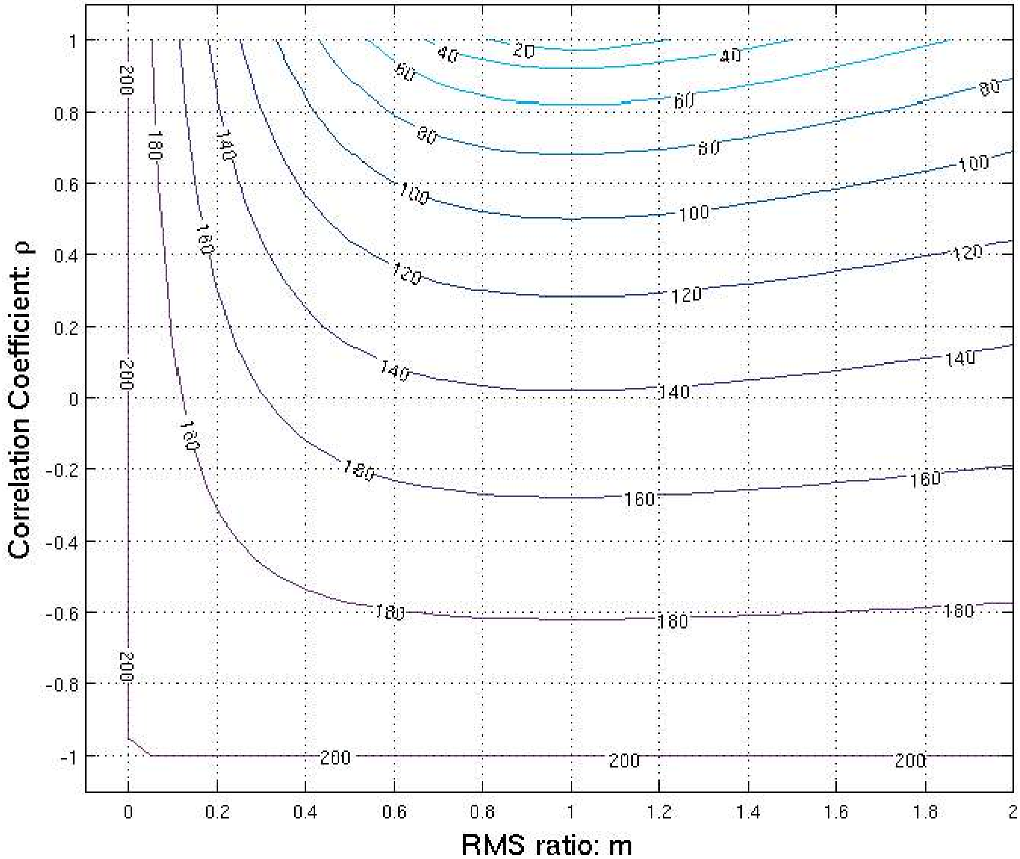


FIGURE 2. NRMS contours act as a function of correlation coefficient and RMS ratios. (Source: ION)

A perturbation-free baseline receiver cube was made initially followed by multiple monitor surveys, each with a perturbation representative of what could actually happen in the field. For each perturbation from the baseline, the NRMS noise was measured.

First, the sensitivity to spatial positioning was examined. Spatial positioning can fall into two categories. The first is where the receiver station is some distance from the target but it and the target have known XY locations. The second is where there is some uncertainty in the XY locations.

If the receiver station was 2 m (6.5 ft) from the target and the positions known, the 4-D difference showed negligible NRMS noise. Even if the receiver station was 25 m (82 ft) off target with positions known, the 4-D difference showed negligible NRMS noise on the near offset and only 1.6% noise on the far offset. However, we must keep in mind that this is a laterally homogenous model. Any dip or lateral amplitude changes would see greater values.

Four-dimensional noise levels are very sensitive to the quality of correlation between data volumes.

Next, 2 m of inaccuracy were examined due to the coordinates being unknowingly in error. The near offset still shows negligible noise, but the far offset now reveals a 7.6% noise level. Increasing the error to 25 m reveals a massive 82.5% noise level. The reason for this is the significant travel time difference on the far offsets between the two surveys, resulting in a poor cross-correlation coefficient (supported by Figure 2).

Intuitively, any timing differences between the surveys (even if their amplitudes match perfectly) should also result in high NRMS noise levels. This is exactly what was observed. For example, a 1-ms node clock drift resulted in a 36.8% NRMS level on both near and far offsets. A 2-ms drift (one seismic sample) resulted in a massive 73.7% NRMS level.

Clearly any amount of time difference between surveys has a huge impact on noise levels. Besides clock drift, the elevation level of the shooting vessel during the cycles of tides can result in travel time differences. An uncorrected 1.5-m (5-ft) tide height difference results in 1-ms time shift or 36.8% NRMS noise. Unfortunately, a simple tidal static correction is not enough. Ghosts and multiples will be embedded in the data with different periods. These must be independently removed in processing.

Similarly, a phase difference between two surveys can result in poor correlation. Geophones tend to have low frequency distortion (roll-off). If these differ between surveys by 10 degrees, it results in 7.6% NRMS noise levels, while a 30-degree difference results in 22.5% NRMS noise levels.

Other noise

Next, the study looked at nonsource-generated noise differences between surveys. In a production environment there are likely many sources of unwanted noise such as those from drilling, shipping and pipeline activity. Adding widespread 10% random noise results in 10.2% NRMS noise.

Finally, the noise associated with simultaneous shooting was assessed. Driven by the quest for faster and cheaper acquisition, there has been a trend to fire sources simultaneously and "de-blend" them in processing. Untreated blended data result in noise levels of 60% to 100%. After de-blending this can reduce the noise levels to 0% to 35%.

In summary, 4-D noise levels are very sensitive to the quality of correlation between data volumes. In that regard, any associated time or phase differences should be minimized as much as possible.

Unknown errors in receiver positioning can result in a correlation error, which increases with offset. To minimize this, acoustic pinging for every receiver station location is recommended. Preferably, the transducer should be built into the sensor unit. Externally strapped-on transducers might unbalance the center of gravity or affect coupling. Moreover, additional positioning quality control via first-arrival analysis is recommended.

Clock drift must be completely eliminated. Even the more accurate chip-scale atomic clocks should include additional residual corrections. GPS satellite synchronization between all receivers would be preferred (as used in cable-based systems). Phase difference between recording systems must be carefully removed. Tidal static corrections should be accurate and followed with quality de-ghosting and de-multiple.

Finally, if simultaneous shooting is planned, it should include a thorough de-blending process. E&P

Friction reduction has advantages in CT drilling

Tool uses pressure in CT to generate movement in the tubing and reduce friction.

Lisa Woods, CT Energy Services

Coiled tubing (CT) drilling is the ever-evolving concept that combines CT with directional drilling using a mud motor to create a system that allows operators to reach target depths. Relatively speaking, CT drilling is a modern technique within the industry for drilling wells compared to the conventional method of using drillpipe. Although CT drilling is not the first choice for drilling wells, there are a number of cases where it is the best option.

The most suitable applications for CT drilling are reentry drilling, or sidetracking, from existing wellbores. The ability to run through the existing production tubing with ease provides an edge over alternative methods. Another occasion for choosing CT drilling is for wells where downhole pressure is a concern, for example, in underbalanced drilling. Finally, as a cost-saving application, CT drilling may be paired with a conventional rotary drilling rig, allowing precise entry into a desired zone followed by the completion of the well.

Apart from niche applications where CT drilling is the most suitable technology for the job, there are a number of benefits to CT drilling. The main advantage over conventional drilling is the ease in which CT drilling may work in underbalanced conditions. The second is reduced drilling times since operators do not need to stop to make and break the connections of jointed pipe. Furthermore, communication from downhole to surface improves, the environmental footprint decreases and efficiencies can be seen in transportation as well as the personnel required to complete a job.

Increased efficiencies

The rise and fall in popularity of CT over the last couple decades can be attributed to these advantages and the challenges that accompany them as the demand for increased efficiencies and greater depths become more pronounced. Some of the major disadvantages of using CT drilling include the cost of consumables and the inability to rotate, which leads to a number of drilling obstacles. Operators rely on the expertise of service companies to provide solutions to these problems.

CT Energy Services specializes in developing downhole tools for drilling and completions. Specifically, it is the company's expertise in friction reduction devices through the use of vibration that have the ability to overcome the disadvantages or obstacles of CT drilling.

The inability to rotate the pipe accounts for the greatest obstacle when using CT technology. The resulting disadvantages are reduced ROP and the inability to reach target depths. CT's Toe Tapper uses the existing pressure in the CT or drillstring to induce a negative pressure pulse when operated. This negative pressure pulse causes what is known as a water hammer effect in the tubing, generating movement in the tubing and reducing friction. The pressure pulse also improves helical buckling by creating a dynamic stiffness in the tubing.

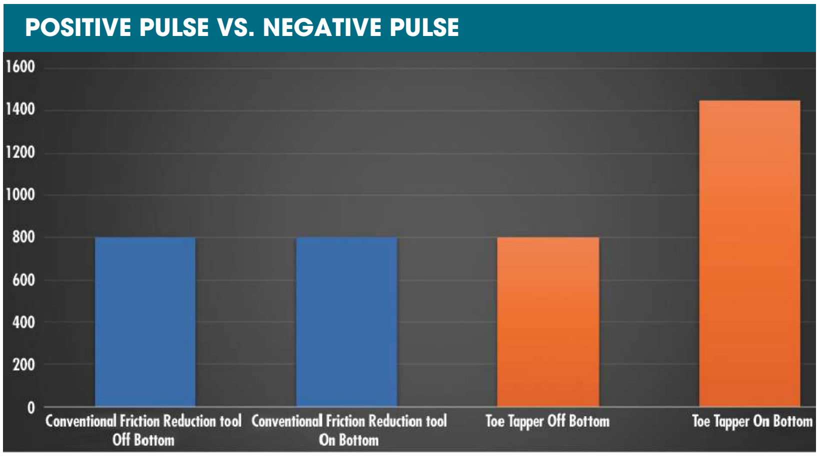
What makes the negative pressure pulse so dynamic is the fact that it uses existing tubing pressures to enhance the pressure pulse. By venting the excess pressure, a larger pulse amplitude is generated, making the tool's performance integrated with the operating environment.

Performance study

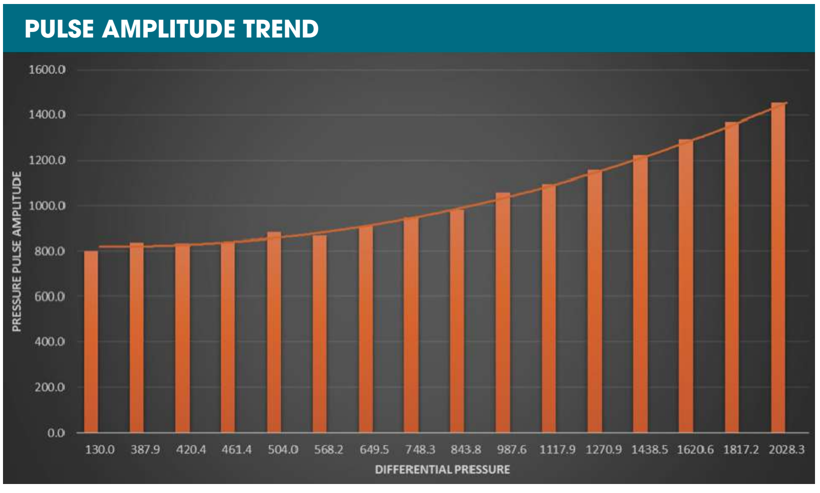
A pulse amplitude study was performed to quantify the gain in performance due to the negative pressure-pulse approach. What was determined was that when drilling motor operating pressures were introduced, the performance of the tool increased by 40%. What this means for CT drilling is that for the same pressure loss as conventional friction reduction devices, the Toe Tapper negative pressure pulse uses the system pressure more efficiently and improves tool performance.

The effects on the motor performance are negligible—only a small volume of fluid needs to be vented to achieve effective negative pressure pulse amplitude. Bit speeds in the motor are only affected by about 5%, while torque is still maintained.

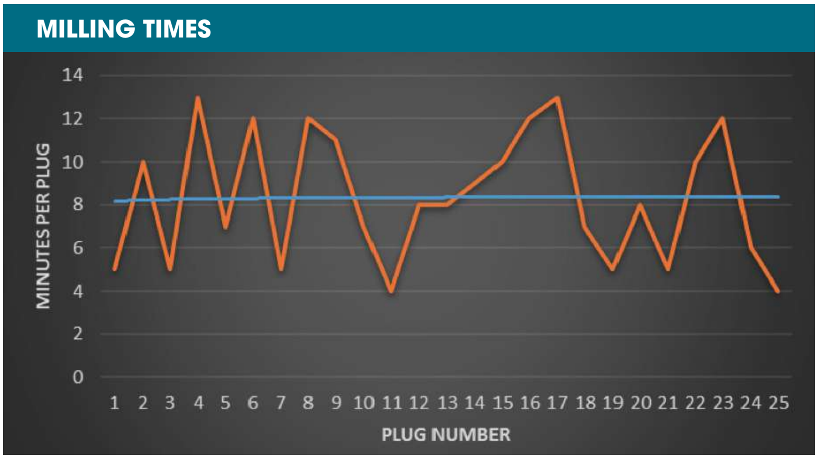
Since the motor differential exists during most of the operation, the Toe Tapper performance is truly realized. Evidence of this can be seen in the trendline for milling times during completions operations in CT. Typically, mill times increase when operating farther and farther



This figure compares conventional and negative pressure-pulse performance. (Source: CT Energy Services)



Results from the pulse amplitude study indicate that the Toe Tapper negative pressure pulse uses the system pressure more efficiently and improves tool performance. (Source: CT Energy Services)



This snapshot charts mill times vs. plug number. (Source: CT Energy Services)

out in a well. With the Toe Tapper in the field operators have experienced average milling times that maintained a more level trend. This is due to the increase in localized hydraulic forces generated when the motor differential is increased. A parallel can be drawn, and this gain in performance also can be applied to CT drilling.

When comparing the cost of consumables between jointed pipe and CT, it is the longevity of jointed pipe that puts it in the forefront. Operators might recut or resurface connections or simply swap out a single joint, but CT is a consumable product. Spool-off tubing has a finite number of times it may be tripped in and out of the hole before the properties of the pipe are compromised and the entire string must be discontinued or sold to less demanding applications. Limiting the number of times a spool is unraveled to complete a job is where a tool like the Toe Tapper becomes significant.

Two features of the Toe Tapper remedy the need to trip out of the hole during CT drilling. First is the negative pulse that vents fluid from the tool up the wellbore, and second is the low frequency of vibrations. Both components allow cuttings to circulate up the wellbore more efficiently. Hole cleaning is often the main reason for a reduced ROP, and wiper trips are traditionally the solution to this problem. The combination of the patented venting system of the Toe Tapper, which allows an additional area of turbulent flow to assist in the movement of the cuttings, and the low frequency of the tool, which produces more of a sweeping movement of the tubing to dynamize cuttings, reduce the need to perform a wiper trip. Therefore, the cost of CT as an expendable is minimized.

The Toe Tapper was developed from CT Energy's Ratler system used in drilling applications. The design utilized knowledge in wear patterns and flow dynamics specific to negative pulse generation. This yielded a design capable of operating in the harshest environments; has been used with high lost circulation material content, substantial solids concentrations, acids and nitrogen; and is capable of having cement pumped through it. E&P


CUDD

Solving the blind spot problem with reentry CT drilling

GWD avoids sensor inadequacies.

Toni Miszewski, AnTech Ltd.

While the main drilling attention over recent years has been about new unconventional and deepwater wells, nearly 70% of the world's hydrocarbon production comes from declining fields. There is a compelling economic case that extracting more from known reservoirs is a better idea than the cost and risks of a new project. In practice, working over mature fields involves various EOR techniques and reentering wells to drill horizontal laterals from a window cut in the existing wellbore. An established if not yet widely adopted technique to do this is to use coiled tubing (CT) drilling to drill in underbalanced conditions.

Declining well challenge

An efficient operation is an essential requirement for working over wells that might have a limited production capacity but at the same time still have significant unrecovered reserves. It is not realistic to expect a multiyear payback time, especially with a low and uncertain oil price environment. Drilling in the right direction is a fundamental requirement of directional drilling, and drilling in the wrong direction, even if the error is only small, is one of the easiest ways to reduce efficiency. This is surprisingly easy to do because of the distorting effect of steel casing on the magnetic sensors of a CT drilling bottomhole assembly (BHA), which creates a blind spot when first exiting the window. This effect might extend as far as 6 m (20 ft) from the vertical casing. While this is a problem for all casing exits, the problem is worse for CT drilling operations. There often is limited vertical depth between the window and the target formation, so high build rates are required, and this leaves little room for error.

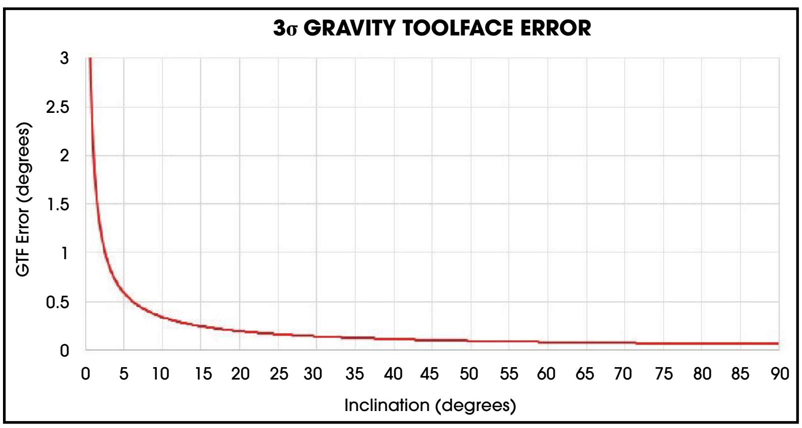


FIGURE 1. Gravity toolface increases at low angles. (Source: AnTech)

Blind spot

Most MWD tools use magnetic sensors to help the driller steer the drilling BHA on the desired azimuth. This is perfectly acceptable in openhole conditions but not in or near steel casing, where the magnetism of the steel swamps the earth's magnetic field and induces large and unpredictable errors in the azimuth reading, meaning the driller is effectively drilling blind.

Two measurements are required to drill accurately out of a casing window: toolface and azimuth. In a vertical well both of these measurements are derived from magnetic sensors, so they cannot be relied on. Sometimes, if there is a sufficient inclination (usually taken to be more than 5 degrees) and the trajectory of the well already is accurately known, it is possible to kick off using only the inclinometer of the directional sensor. However, just as it is not possible to use a plumb-line to indicate any direction other than down, an MWD steering tool cannot give an accurate toolface when inclination approaches zero. Below 5 degrees of inclination the toolface error increases dramatically (Figure 1). The trouble is that the vast majority of reentry drilling opportunities for CT drilling are from vertical wells.

Using gravity toolface at low inclinations creates uncertainty when setting the whipstock as well as when drilling the initial curve out of the window. A precise reading of wellbore azimuth will only be obtained once the magnetic sensors are away from the casing. Because these sensors are several feet back from the bit and because the wellbore initially only diverges slightly from the mother bore, up to 46 m (150 ft) of hole might have been drilled before an accurate azi-

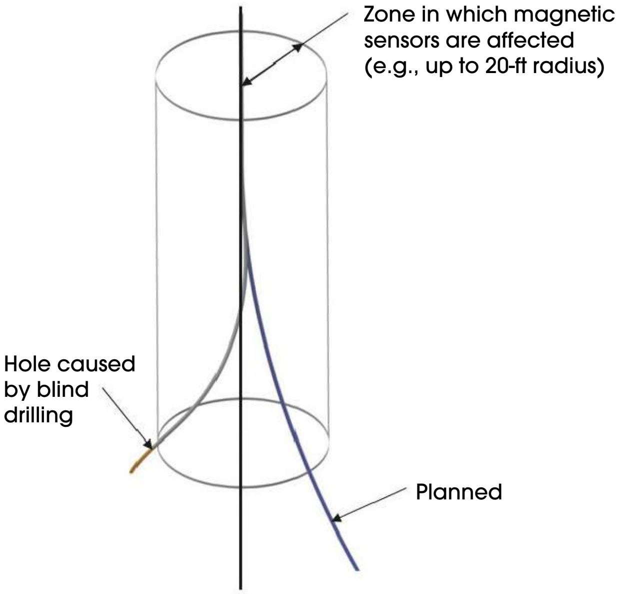


FIGURE 2. This figure represents a hole potentially drilled at constant inclination but with no control of azimuth. (Source: AnTech)

muth measurement can be made, and by then it might be too late to make a correction to hit the target (Figure 2). In the worst-case scenario, the bit could track back onto the casing that has just been exited.

Recent case study

In a near-vertical well (less than 2 degrees) the large uncertainty in toolface for the whipstock setting and the initial build meant that the initial sidetrack was found to be 50 degrees away from the planned azimuth. This caused two problems. Although the azimuth of the borehole was brought back on track, it hit the reservoir 30 m (100 ft) away from its intended position. Furthermore, while the azimuth was being brought on track, the BHA was unable to build inclination, so it dipped below target and had to be brought back up. In this case the deviation from target was not critical, but it could have ruined the well had there been a water layer that needed to be missed.

New gyro

Fortunately, new gyro-while-drilling (GWD) technology is available that not only helps position the whipstock accurately in near-vertical or vertical holes but also provides accurate orientation of the BHA as it exits the casing. It gets around the problem of magnetic interference because it is not affected by the steel environment. This means that the initial exit from the casing does not need to be done blind and the directional driller does not have to wait several hours to determine an accurate hole trajectory.

It has been especially developed for CT drilling applications and is based on the same technology used to drill the world's first GWD air-drilled well. GWD gyros need to be robust to withstand the shocks and vibration of drilling under normal conditions. In underbalanced drilling with CT given the small size of the tools and the use of aerated fluids, these shocks and vibrations can be an order of magnitude higher than normal drilling, with levels up to and exceeding 250 g-force.

Why the new GWD service is different

Traditionally, drilling gyros have been based on spinning mass mechanical technology. These intricate mechanical devices have been ruggedized in an attempt to make them endure the harsh conditions encountered onboard a drilling BHA. Taking a different approach, the new gyro is based on inherently robust solid-state micro-electromechanical devices that were originally designed for the military to be put on the tip of mortar shells for guidance.

As an e-line tool the gyro can be commanded to take a survey whenever one is required. There is no need to cycle pumps to initiate a survey and no need to pump up the data when the survey is complete since all commands and data are transmitted on the e-line. All power is delivered via the e-line, so there is no requirement for downhole turbines or battery packs.

The gyro provides an absolute measurement of azimuth or gyro toolface. It does not need to be calibrated pre-job (though check shots are always sensible), and measurement does not degrade over time in hole.

This new gyro technology reduces the risk of errors and therefore the overall cost, which will make the technology viable for a wider range of candidate wells and fields. E&P

FIGURE 3. AnTech performs a CT drilling job using its POLARIS BHA. (Source: AnTech)

Deployed liner system enables efficient repair of parted pipe

CT deployment and no drill-out requirement saves days of rig time while delivering the well to its full production potential.

Greg Galloway, **Jeff Harts** and **James Wheeler**, Weatherford

An operator completing a natural gas well in the Marcellus Shale of northeastern Pennsylvania encountered a casing integrity problem during the 12th stage in a planned 30-stage fracturing operation. Loss of wellbore integrity, which the operator suspected was caused by a leaking connection in the heel of the well, prevented completion of the remaining 18 stages.

The operator needed a solution that would resolve the problem under tight time constraints. The solution also would have to reliably withstand pumping pressures of more than 10,000 psi.

The operator initially considered bringing in a workover rig. However, because the work site was on a mountainside with a limited footprint, accommodating a workover rig would require moving the existing equipment offsite during intervention operations and remobilizing the fracture spread after the intervention. Because of time constraints coupled with logistical challenges and rig rental costs, the operator ultimately decided against the prospect of a workover rig.

The operator also considered running a cement squeeze to isolate the exposed section of the wellbore. However, the time required to pump cement, let it set, drill it out and test the barrier would have taken too long. There was also little guarantee that the squeeze would reliably hold the 10,000 psi during pumping.

Novel approach

In light of these challenges, the operator investigated the possibility of deploying a wellbore integrity restoration technology on coiled tubing (CT) and asked Weatherford for assistance. Compared to deploying a casing repair solution on a jointed tubing string via a workover rig, a CT deployment significantly shortens operational time. The continuous CT string can be run in-hole relatively quickly without stopping to make or break connections. Once the repair solution is installed, the CT is then tripped out just as quickly. In addition, a CT unit requires a much smaller footprint than a workover rig, meaning that it can be brought onsite with less maneuvering or moving of pumps, trucks or other equipment at the well site.

Following the successful fracturing of 12 zones in the Marcellus well (1), parted pipe in the heel prevented further fracturing (2). The MetalSkin cased-hole liner deployed on CT quickly isolated the parted section and allowed the operator to resume fracturing operations for the remaining 18 stages (3). (Source: Weatherford)

Weatherford first deployed a wireline crew to run a caliper log. The log confirmed that a connection leak was the root cause, as previously suspected. The installation was performed in a live well with 4,000 psi wellhead pressure, which required a lubricator to be used for pressure isolation.

Working closely with the operator, the service company's engineers designed a high-pressure (HP) casing repair procedure that would accommodate the lubricator on location for pressure control. The procedure also would have to facilitate deployment on CT while enhancing equipment integrity and personnel safety at the site.

The operator and service provider selected a 4.25-in. by 5.5-in. MetalSkin cased-hole HP liner system to regain casing integrity in the parted pipe. The system provides permanent isolation using a robust liner, or clad, that seals and isolates damaged casing or perforations. Unlike short-term repairs such as cement squeezes, this solid-tubular expandable system is designed to be highly reliable and eliminates the need for repeated workover operations.

The cased-hole liner system also provides minimal reduction to the inner diameter (ID) compared to isolation straddles or conventional liners. The larger ID enables easier access for future drilling, completions, production or injection operations and maximizes production rates. The system is installed in one trip and does not require any cement or drillouts.

The liner system was engineered to withstand the high well pressures and provide enhanced burst and collapse resistance. A solid elastomer coated the length of the expandable liner to fill the narrow gap between the expanded liner and the pipe wall. This compressible material results in cladding of the liner to the casing, which provides support between the two pieces of pipe and thereby increases the pressure resistance of the liner.

Running the job

While the system is typically installed using a workover rig, adapting the system for deployment on CT enabled the service provider to meet the tight time constraints and pressure requirements for this 10,000-psi fracturing job. The service provider and operator worked closely to ensure that the expandable liner system and lubricator were safely made up on the CT string prior to deployment in the well.

The cased-hole liner system and lubricator had a combined length of more than 36.5 m (120 ft) at the surface. To avoid damage to the expandable liner system while picking up, knuckle joints were installed into the string. The joints are designed to bend while picking up and moving the expandable liner into position over the well.

The crew made up the lubricator to the wellhead and ran the CT with the expandable liner assembly to depth. Hydraulic pressure was applied from the surface to activate the expansion tool, initiate expansion and then set the anchor. Subsequent hydraulic cycles completed the expansion process through the entire length

MetalSkin provides permanent isolation using a clad that seals and isolates damaged sections. (Source: Weatherford)

of the liner. This setting option made the MetalSkin system better suited to the job than other expandable liner systems that are activated by darts or balls. Because there are no jointed connections in CT, a dart would have to be run in place before heading downhole, complicating the operation and eliminating any possibility of circulating the well.

While setting the liner, the wellhead pressure dropped to 2,500 psi, which confirmed that the expandable liner had fully isolated the parted section. Once the liner was fully expanded, the residual pressure was bled off, and the assembly was pulled out of hole. The cladded section of the well was successfully pressure-tested to 10,000 psi for 30 minutes, confirming that well integrity had been restored.

The deployment of the expandable liner system on CT was quick and efficient. The cleanout/drift run, installation and pressure testing was completed in 24 hours. The expandable liner system did not require drilling out, which enabled fracturing operations to resume as soon as the CT unit was moved off of the well. The remaining 18 stages were completed using the plug-and-perf method, and the crew completed the well two days earlier than planned despite delays caused by the parted pipe. Ultimately, the successful completion ensured that the well would produce to its original full potential.

Expanding the application

In another recent application, an operator in Alaska ran a multijoint expandable liner system on CT in a remote multilateral well. With multiple successful applications the deployment of this expandable liner system on CT is a routine and reliable operation. E&P

Enabling smart oil fields through IIOT-enabled solutions

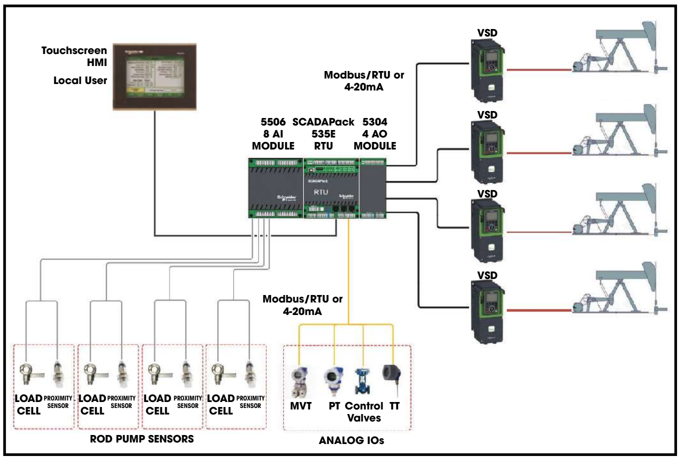
Automated artificial lift system offers operators a solution to the challenges of maximizing productivity and reducing costs.

Helenio Gilabert and **Fahd Saghir**, Schneider Electric

In less than two years the price of oil dropped from more than $145/bbl to $35/bbl, intensifying an effort from producers, manufacturers and operators to reduce operating costs across the oil and gas industry. The industry as a whole has shifted from focusing on production volume to being cash flow-driven. This means operators of mature oil fields globally were forced to make an organized effort to improve the overall efficiency of their operations to increase their chances for long-term success.

Though there are now signs of a rebound in the industry, external pressures such as smaller profit margins, increased regulations and a focus on energy efficiency have caused the oil and gas industry to put a much larger focus on becoming smarter with the use of digital technology and real-time data to make informed decisions quickly and accurately, maximizing productivity and reducing costs. These steps will last even if prices rebound.

Of particular importance to the efficiency of operations is the implementation of artificial lift automation solutions that provide operators with more visibility and control over operations. Instead of running pumps full-time at a constant speed, companies can invest in real-time pump control to monitor downhole and surface conditions for multiple wells.



With Realift operators can manage four rod pumps from a single RTU, reducing upfront equipment cost and minimizing the footprint at the wellhead. (Source: Schneider Electric)

The influx of data required to manage wells means artificial lift automation has become more connected, and solution providers are offering holistic end-to-end solutions to operators, including information control, safety solutions and related maintenance services that allow companies to increase oil production, decrease power consumption and extend equipment life.

Smarter oil fields

To help reduce production costs and save revenue, oil producers are making much larger investments in the Industrial Internet of Things (IIoT). Data derived from the IIoT have the potential to provide useful insight when leveraged and analyzed effectively. To keep up with the amount of data generated and available to oil enterprises, automated artificial lift systems operate as a single hub for autonomous operation by maximizing performance through the utilization of real-time data on production to provide insight on subpar asset performance. Data, combined with advances in automation technology, allow operators to configure assets to specific operations to achieve better performance and business standards.

By providing a flexible and open automation platform for artificially lifted wells, upstream operators have the ability to comprehensively manage and control production wells and surface facilities, giving operators a single platform to work from and helping them control every asset of the enterprise to achieve real-time business control. Comprehensive artificial lift solutions are based on remote terminal unit (RTU) platforms that require a solid software backbone to monitor and manage the performance of wells in real time to optimize production, serving as a first step in creating smart oil fields.

Additionally, the newest solutions across the industry focus on combining a comprehensive hardware platform with a software backbone to create holistic solutions that reduce operating costs, increase production and improve the pump's lifespan, helping operators meet critical production and maintenance key performance indicators.

By combining technology capabilities of control systems with SCADA, numerous wells in a geographically dispersed infrastructure can be automated and monitored. (Source: Schneider Electric)

For example, Schneider Electric's artificial lift rod pump control Realift is in use in oil fields across the U.S. as well as locations worldwide such as Canada, Mexico, Venezuela, Colombia and others. It provides operators with all major automation components in a single solution, including variable speed drives, RTUs, SCADA, instrumentation, communications and human-machine interfaces, to reduce ownership risk and improve production efficiency. With a point-and-click configuration interface that runs via Ethernet, operators can leverage Realift to monitor and configure the drive and parameters locally or remotely in real time.

The rod pump control also allows operators to manage four rod pumps from a single RTU, reducing upfront equipment cost and minimizing the footprint at the wellhead. This is ideal for well pad applications where multiple wells are completed in close proximity. Another key advantage with the Realift technology is its inherent dual resource functionality, where each resource can be individually programmed for various applications.

By default, the first resource is used for artificial lift applications, whereas the second resource is open to operators for custom programming based on the International Electrotechnical Committee's 61131 standard and can be used to run well test automation, flow measurement applications, tank level monitoring and more. So even if the artificial lift method on the wellhead changes, say from progressive cavity pumps to rod pumps, the program on the first resource could easily be transitioned to manage well-specific artificial lift methods. This allows the same hardware platform to be used over the production life cycle of the well.

The combined technology capabilities offered in Schneider Electric's solution have been used to automate numerous wells with the company's controllers and its ClearSCADA software offering for monitoring remote assets across geographically dispersed infrastructure. With real-time control and monitoring the technology can help increase average net oil production, decrease customer power consumption and extend the life of customer assets. The technology ties data management and control under one roof to track temperatures, pressures and other datapoints to make the entire oil field smarter, from the wellhead to enterprise level.

Enabling operation

While operators already have real-time capabilities on artificial lift wells, looking at single-source solutions that are IIoT-enabled promotes open communication between assets and ensures the entire oil enterprise is connected, reducing operating expenses, improving overall energy consumption and business performance and increasing the level of safety across the enterprise.

Because smart artificial lift automation platforms must work alongside other components of the smart oil field, the newest technology incorporates distributed network protocol (DNP3) to manage data starting from the source to track information from the wellhead to the enterprise level, making data management easier and more insightful. While DNP3 began on the electrical side and has been commonly adopted in that area, the proliferation of IIoT has enabled the automation industry to leverage the technology to more easily merge the management of electrical resources in the oil field from both generation and distribution under one protocol. Besides supporting multiple masters, DNP3 also offers an automated data back-filling capability, which allows data to be recovered automatically in case of communication loss.

Connected systems inherently present a cybersecurity risk. Currently, the drive among regulatory groups has started with electrical infrastructure, but the oil and gas industry is quickly realizing the importance of cybersecurity for upstream applications. While the industry as a whole is moving toward automation technologies that provide more robust and customizable solutions, it has not historically used the built-in cybersecurity capabilities provided on automation platforms. DNP3 open telemetry applications apply encryption when customers are using wireless or wired communications, which adds an added layer of cybersecurity capability to prevent breaches across the operation.

Comprehensive strategy

The shift to smarter, more comprehensive artificial lift automation is enabling the industry to make great strides in adopting a more comprehensive enterprise strategy. With all major components of artificial lift automation under one roof, smart solutions ensure reduced system downtime to decrease failures and improve production optimization. Built-in communication encourages more proactivity in terms of troubleshooting and locating problems before systems become disturbed. By giving operators more remote visibility into operations, safety can be improved by preventing well operators from physically traveling from well to well throughout the oil field.

While subsurface technologies have continued to advance steadily, artificial lift automation has historically lagged behind. The number of pad completions enabled by better directional drilling and fracturing has increased, which has dramatically reduced drilling and completion costs.

By using solutions that are IIoT-enabled, artificial lift solutions become the hubs for automation of wells or well pads, giving operators access to real-time monitoring and analytics capabilities. Realift controllers will allow the concentration of automation into a single platform, not only bringing new benefits to pad completions but providing the first step in realizing a comprehensive enterprise oil strategy. E&P

Thinking inside the box

A plug-and-play CNG solution, when combined with trucks, creates an alternative to the traditional pipeline system.

Daniel Tse, GE Oil & Gas

Advances in drilling and well stimulation technology continue to be made in oil and gas wells across North America with the purpose of increasing production and improving cost-effectiveness of operations. However, as the quest for new wells stretches farther into uncharted territory, a significant portion of new wells are sited in increasingly remote areas, sometimes at great distances from the existing pipeline structure. A side effect is that, due to the inaccessibility of well sites, excess produced gas must be flared.

GE Oil & Gas' "CNG In A Box" system allows E&P companies to use and monetize more of their produced gas, even at wells in inaccessible off-grid locations. The first stage of the development of the CNG In A Box system was directed to natural gas vehicle (NGV) refueling, but with a few simple improvements, it turned out to be well suited to "virtual pipeline" applications.

The CNG In A Box system is a modular plug-and-play CNG product. (Source: GE Oil & Gas)

Creating a virtual pipeline

The CNG In A Box system is a virtual pipeline product that aims to help move beyond the physical pipeline network with a modular "plug-and-play" CNG solution when combined with trucks to move gas vs. a traditional pipeline system. This helps operators improve availability, access more customers and monetize their flare gas.

The system delivers exceptional availability and efficiency ensuring continuous, reliable unmanned operation; long intervals between maintenance; and an easy, cost-effective maintenance regimen. The H series high-speed compressor is a reliable proven frame with thousands of hours in the field and a wide install base.

CNG In A Box performance equates to 4,000 gal to 20,000 gal of gasoil equivalent per day for virtual pipelines. It features a portable design, minimal pad, quick installation and highly automated operation. It is ideally suited for rig-site gas distribution, flare capture and storage on remote sites.

The same technology can be used to flare gas, enable onsite power generation and be suited for on-road transportation fueling of NGVs because of the modularity and flexibility of the design.

Developing a fueling technology

GE Oil & Gas has taken its CNG In A Box technology and partnered with Ferus Natural Gas Fuels to provide a reliable, fully integrated natural gas fueling option for some of Ferus' E&P customers. Where GE Oil & Gas specialized in providing natural gas fueling technologies such as the CNG In A Box system, Ferus specialized in fuel supply, transport and logistics, including the dispensing of fuel onsite, pressure reduction and vaporization solutions.

Together the companies built a fueling technology, eliminating the need for flaring, and instead captured the flare gas and delivered it straight to fueling applications. This fully integrated technology and logistics system was designed to make natural gas fueling available for high-horsepower operations. It did this by taking previously uneconomic natural gas directly from a wellhead or oilfield production site or from a remote pipeline, removing the impurities, compressing it with a CNG In A Box system and delivering the CNG with Ferus' tankers the final distance to a drilling location to be consumed as fuel, displacing diesel. The aim was to allow cleaner, cheaper fueling, which is economical in the most remote areas for E&P operations while reducing environmental impact.

Working together

The fuel technology was designed to provide customers with a fit-for-purpose turnkey natural gas fuel solution;

The virtual pipeline technology provided Statoil with an alternative fuel source for its Bakken operations. (Source: GE Oil & Gas)

therefore, early engagement with operator stakeholders was vital to commercial success. First, the process of developing the technology involved developing an operations overview that looked at the priority of the asset and formation, the rig schedule, and the gas source and composition. Second, a fueling strategy was developed that considered fuel selection and aligned clients' needs with Ferus' and GE Oil & Gas' product offerings. Finally, an implementation plan was drawn up that includes the deployment strategy and a logistics plan.

The method

Gas supply at about 1 MMscf/d to 2 MMscf/d during a four-month to 12-month period bypasses flaring and was taken straight to the gas treatment stage. It was then converted to NGL and CNG. These products were then used in gas transport applications, with NGL storage and transport being a locally marketed product and CNG destined for rig and frack fuel as a gas-lift primer and for third-party sales.

The CNG In A Box package was provided with a 400-hp H304 compressor using four throws. While the four-stage unit used was well-suited, it could have been even better for virtual pipeline if it had been configured as a two-stage unit, which was an option.

The package featured onboard priority panel, dryer, cooler and programmable logic controller/human machine interface with remote monitoring and diagnostics capability to support fast commissioning at remote locations. The CNG In A Box technology, however, is flexible and can be provided with a variety of compressors from 100 hp to 400 hp using two or four throws. Much of the onboard equipment is optional, allowing a solution that can be optimized for turnkey remote virtual pipeline locations to less demanding NGV refueling applications. In any case, the CNG In A Box features are designed to simplify and expedite installation for their operators.

The virtual pipeline technology is used by several oil producers in the Bakken, with plans to expand beyond the Bakken into other basins in North America.

Case study

In early 2014 the Ferus/GE Oil & Gas partnership conducted a successful virtual pipeline pilot with Statoil to capture flare gas and use it as an alternative fuel to diesel to power its oilfield operations.

The fueling technology initially captured 2 MMscf/d of natural gas for Statoil, and the number had capacity to grow to 6 MMscf/d. This translates to total emission reductions of 70,000 tons/year, or the equivalent of 17,500 cars in a year. Statoil will use 500 MMscf/year of its own captured natural gas to fuel its operations. When used in place of diesel, it equates to an additional 18,000 tons/year of smog reduction and 4 tons/year of particulate matter reduction.

From an economic perspective this results in $6 million in fuel cost savings. The remainder of the captured natural gas from Statoil's oil and gas operations will be compressed and sold to third parties either in oil and gas or other high-horsepower markets.

In this case, the virtual pipeline technology enabled Statoil to tackle the challenges related to the lack of pipeline capacity and mobility issues surrounding flaring in the Bakken. As a result of the success of the pilot, the parties are moving into the commercial phase, which involves fueling up to six rigs with natural gas that would have otherwise been flared. The project expansion will be the first step in moving into full commercial adoption of the virtual pipeline technology.

E&P companies can use the CNG In A Box system as part of a virtual pipeline technology to remain compliant with stringent gas flaring standards. Companies also can reduce their emissions profile by eliminating flaring and using the previously wasted natural gas as an alternative fuel to diesel in their drilling and completions operations. This technology can reduce natural gas flaring in North Dakota by 1.6 MMcm/d (60 MMcf/d), or 20%, and has the potential to play a critical role in flare gas reduction in wells beyond the Bakken, including expanding gas processing capability and powering production. E&P

Power automation and power on demand deliver multiple benefits

Reduced fuel costs, lower emissions, less maintenance and improved reliability are available from scalable automation systems.

David Dickert, Aggreko

Compelling factors for incorporating power automation in oilfield operations extend beyond reducing generator fuel consumption and lowering emissions. Generators powering artificial lift systems, primarily rod pumps, idle for prolonged periods due to intermittent pump cycles. Besides the inefficiencies resulting from this practice, its impact on an oil and gas operator's ability to comply with Environmental Protection Agency (EPA)-mandated Tier 4 diesel engine emissions limits cannot be understated. Moreover, prolonged idling could expose generators to the two leading causes of failures, plugging and carbon deposit buildup.

Smoothing power fluctuations

Power automation and power-on-demand technology has been applied in various commercial and industrial processes with intermittent loads or where standby generators are needed to ensure uninterrupted power, such as hospitals. Power automation is delivering the oil field significant cost reductions in rod pump and dewatering service operations. Scalable power automation systems incorporate a hybrid battery control kit that receives a signal from the pump's programmable logic controller (PLC) for start/stop synchronization. The automation kits also can receive signals from tank level switches, thermostat contacts and any other digital switches. Power automation systems can be found running on diesel engine-generators (gensets) in the Eagle Ford Shale and Permian Basin.

Trailer-mounted units offer operators in the Permian Basin an alternative power option for remote operations. (Source: Aggreko)

Compared to other oil fields, the high-viscosity crude produced from the Eagle Ford is better suited to lower horsepower rod pumps, requiring relatively small genset drivers with simplified battery requirements. In some instances the operator is running the rod pumps continuously on a variable speed drive or variable frequency drive (VFD) to avoid operational fluctuations. Instead of shutting down the rod pumps, the VFDs are used to minimize pump rpm from about 30 rpm to 2 rpm. This strategy helps avoid engine idling and save fuel costs to a certain extent, particularly when crude demand is low.

By eliminating idling, emissions and diesel consumption can be reduced by as much as 60%, as demonstrated with a midstream operator's 200-hp positive displacement booster pump moving produced oil from the field by pipeline to gathering facilities. In this application a power automation package allowed the PLC on the booster pump to communicate with the generator and to automatically start/stop the power as needed. Since the booster pump only needed power about 10% of the time, the pump and the generator remained off 90% of the time.

A major producer in the Permian Basin also significantly reduced idling employing power automation. In this case diesel generators were running 24/7 and idling most of the time while serving five wells with 40-hp rod pumps operating intermittently. Formation hydrogen sulfide levels were too high at the well sites to consider using field-gas-driven generators economically. Because the producer's goal was to reduce overall lease operating expenses, the power automation option was considered. In this instance five 60-KW diesel generators with power automation kits resulted in a $13,000-per-pump savings over a six-month span.

This actually reduced annual diesel costs by 50%, or $130,000, for these five sites. Emissions also were reduced more than 50% while maximizing uptime and extending genset maintenance schedules.

Nominal loading

Upon closer examination load fluctuations seen in oilfield operations can cause generators, which are made to be loaded, to be loaded at about 50% nominal, for example, part of the day (eight to 10 hours) and less than 1% for the remainder of the day. This is a typical scenario where the operator can benefit from power automation. In other scenarios, maximum load pulling off a rod pump control panel is seen at about 1.5 amps and 120 volts. However, if there is a need to increase to 25 amps at 120 volts, there are batteries available that can scale to accomplish the increase.

Scalability is an important consideration with the evolving trend toward centralized facilities, such as with the batteries needed with gensets supporting multiple wells. In fact, power-on-demand systems are being developed for centralized tank sites supporting as many as 250 wells, requiring high startup amperage (e.g., 1,250 KW) provided by multiple gensets (e.g., five 250-KW generators). These generators are more efficient if only one is optimally loaded after a high-amperage startup and the other four are shut down rather than idling after pumping operations level out. Generators need to run at a higher load percentage; idling at low loads for long periods predicates carbon buildup and resulting emissions.

Generators used for peak shaving in oilfield operations are another compelling reason for incorporating power on demand, such as for efficiently running four generators during peak time (e.g., two hours). After peak time the other three generators are shut off while the primary generator is still running. Even the primary generator can be turned off with power drawn from battery storage. This strategy permits "hour sharing" to balance the engine hours, running the unit with the least amount of hours, prolonging engine life and reducing maintenance costs.

Mandates affecting operations

Going forward, emissions reduction requirements are becoming one of the most important drivers to installing power automation. EPA-mandated Tier 4 standards require significant emissions reduction of particulate matter and nitrogen oxides. These standards govern most diesel engines used in power generation, including standby generators used intermittently and installed or located at a production site for at least 12 months. An important aspect to consider with Tier 4 is engine manufacturer's minimum load requirements to maintain emissions. Under older Tier 3 requirements elimination of idling was merely a cost reduction option.

Considering engine inefficiencies typical of oil and gas operations, Tier 4 regeneration predicates the need to significantly reduce idling time, which is where the benefits of power automation can be realized. The industry has certainly embraced oilfield automation to reduce costs. Future applications benefiting from power automation and power on demand include transfer pumps serving tank facilities and dewatering systems. A first-time application for power automation on field-gas-driven generators in the Eagle Ford will soon go online.

Mobile power generation units help make it possible for operators to increase process efficiencies. (Source: Aggreko)

Efficient options

The evolution of oilfield automation is occurring as more production operations take place outside the utility grid, predicating the need for temporary power solutions. Power companies are reluctant to build out distribution networks from their substations to new or extended oil fields because investment recovery becomes riskier at lower oil prices. For example, the utility company's return on investment isn't justified to make 20 MW of power available when the operator uses 2 MW for only a short period of time. Against this backdrop, automated remote power solutions are a practical option that adopts well to cost-cutting initiatives. With other automation assets like remote monitoring and PLCs on pumpjacks already commonplace in the oil field, added enhancements such as power on demand and power automation are a feasible solution for one generator or multiple generator configurations. E&P

Stepping up exploration, subsea plans

Market conditions and cost-cutting give Norwegian player renewed confidence.

Steve Hamlen, Contributing Editor

Statoil plans to drill about 30 exploration wells in 2017, up about 30% compared to 2016, on the back of better market conditions and improvements the company said it has made.

Between 16 and 18 of the planned wells will be drilled on the Norwegian Continental Shelf (NCS), the operator said. Of these, five to seven are planned for the Barents Sea, with the rest spread between the Norwegian Sea and North Sea. This campaign already is paying dividends as the Cape Vulture probe was revealed as a new oil discovery Jan. 17.

In 2016 Statoil completed 23 exploration wells as operator and partner—14 of them on the NCS.

"Taking advantage of our own improvements and changed market conditions, we have been able to get more wells, more acreage and more seismic data for our exploration investments in later years," said Tim Dodson, Statoil's executive vice president for exploration.

Statoil reported that the Gina Krog development is expected to come onstream during summer 2017. (Source: Statoil)

Renewed confidence

Statoil was one of the first operators to cut back spending in 2014 before the industry's downturn really kicked in that year. The slump in oil price and resultant massive wave of investment cuts forced the industry to evolve from a high-spend culture to one based firmly on cost control, efficiency and, in the North Sea especially, one where collaboration is the norm and not the exception.

Statoil certainly has been able to slash the cost of its subsea development projects since the crash due to contractor bids coming down by about 30% to 40% in many cases. When combined with its "own improvements," fields that were borderline marginal are now worth pursuing even if the oil price remains about $55/bbl, although most forecasts suggest this price will climb a little this year and next. Given Statoil's ability to adapt to the new industry reality, the company clearly feels the time is right to start spinning the drillbit and hunt for new reserves that can be fast-tracked into development.

This view is backed up by the government, which said it must continue to provide operators with new opportunities to explore for oil and gas.

"I will be on the offensive when it comes to awarding new acreage to ensure the continued development of this industry," Terje Soeviknes, Norway's new minister of petroleum and energy, said in January.

Near-field success continues

Looking for hydrocarbons near existing field projects—which enables subsea tiebacks to nearby infrastructure—has been a successful strategy for Statoil, and the company intends to mix this strategy with exploring new areas during 2017.

"Exploring new acreage and near-field exploration is important to add new and profitable volumes to our NCS production. Today's Cape Vulture find 6 km (3.7 miles) from the Norne Field is an example of this," Statoil told *Subsea Engineering News* Jan. 17. "Maturing and identifying new targets near existing fields/infrastructure is part of our exploration scope in 2017 as well. Our exploration program this year is a mix of frontier exploration (Barents Sea southeast) combined with near-field exploration in mature basins."

In terms of Statoil's improvements, the operator told *Subsea Engineering News* that "planning for utilization of existing capacity and infrastructure near developed fields in operation reduces costs significantly and allows resources to be planned for development, such as the Byrding prospect near the Troll Field and Utgard near the Sleipner Field, both in the Norwegian North Sea. A key factor is simplification of concepts and strong collaboration across the industry, with operators and suppliers working together.

"Gina Krog is expected onstream during summer this year, Aasta Hansteen in 2018 and Johan Sverdrup in 2019 as scheduled," Statoil added in reference to ongoing field development projects.

Buoyed as Cape Vulture soars

Statoil's 2017 drilling plans were boosted recently as the partners in Production License 128 (PL 128) made an oil discovery with wildcat well 6608/10-17 S on the Cape Vulture prospect in the Norwegian North Sea.

The well was drilled about 5 km (3 miles) northwest of the Norne Field in the northern part of the Norwegian Sea and about 200 km (124 miles) west of Sandnessjøen. Statoil is the operator of PL 128 with a 63.95% stake, while Petoro holds 24.55% and Eni has 11.5%.

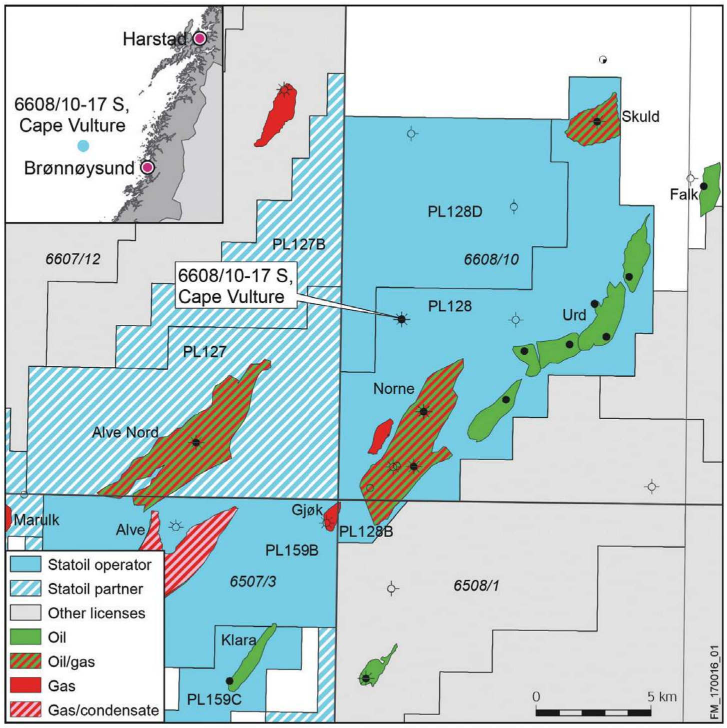
A preliminary estimate of the size of the discovery ranges from 70 MMbbl to 200 MMbbl of oil in place, with a further additional potential to be evaluated. The well will be permanently plugged and abandoned after extensive data collection and sampling.

Eni said the discovery is in line with its "near-field strategy that, in case of success, allows a fast exploitation of reserves thanks to the synergies with existing nearby infrastructures."

The Norwegian Petroleum Directorate added, "The licensees will consider further delineation of the discovery with regard to a potential development via the Norne [FPSO] vessel."

Statoil's near-field strategy was given further credence Jan. 17 when a plan for development and operation (PDO) for each of its Utgard and Byrding fields in the Norwegian North Sea were approved by the government. Utgard is a gas and condensate field that straddles the NCS and the U.K. Continental Shelf. Byrding is an oil and gas field that lies north of the Troll Field.

"These projects will give valuable new volumes to the Sleipner and Troll fields," said Torger Rød, senior vice president for project development at Statoil, in a company statement. "Efficient utilization of existing infrastructure contributes to reducing the costs and makes these developments profitable."



Statoil began drilling the Cape Vulture exploration well in December 2016. (Source: Statoil)

Capex for Utgard is estimated at about $414.1 million, while capex for Byrding is estimated to near $118.3 million. Utgard's recoverable reserves are estimated at 56 MMboe. Utgard was discovered in 1982 and is located 21 km (13 miles) from the Sleipner Field.

The Utgard PDO includes "two wells in a standard subsea concept, with one drilling target on each side of the median line. The installations and infrastructure will be located in the Norwegian sector," Statoil added. Utgard is scheduled to come onstream in fourth-quarter 2019. Utgard partners are operator Statoil (38,44%), Statoil UK (38%), Lotos Exploration and Production Norge (17.36%) and Kufpec Norway (6.2%).

Byrding's recoverable volumes are estimated at about 11 MMboe. The Byrding PDO includes a dual-lateral well drilled from the existing Fram H-Nord subsea template through which oil and gas from Byrding will flow to Troll C. Byrding is scheduled to come onstream in third-quarter 2017. Byrding partners are operator Statoil (70%), Engie E&P Norway (15%) and Idemitsu Petroleum Norway (15%). E&P

Editor's Note: *This article first appeared in* Subsea Engineering News *in January 2017. To subscribe to the newsletter, visit* www.epmag.com/M66ENP.

UK Harrier takes off as Catcher trims costs

Downturn helps uptick in project progression.

Steve Hamlen, Contributing Editor

The U.K. North Sea saw a very quiet 2016 in terms of field development activity, but this year has started at a decent pace.

Ithaca Energy and Premier Oil are pushing ahead with projects; however, Chevron is rethinking its Rosebank plans West of Shetland.

Ithaca Energy has launched the North Sea Harrier Field development program, with development drilling due for completion in 2017. First production is expected in second-half 2018. On top of this, the project will be developed for half of the original estimate, according to Ithaca. Investment in the Harrier Field development project will start this year. The development involves drilling a multilateral well into two reservoir formations on the field. The well will be tied back via a 7.5-km (4.7-mile) pipeline to an existing slot on the Stella main drill center manifold for onward export and processing of production on the *FPF-1* unit.

"The Greater Stella Area (GSA) joint venture has contracted with Ensco Offshore UK for the provision of a heavy-duty jackup drilling rig, which is expected to arrive on location in the second quarter of this year," Ithaca stated. "The drilling program is forecast to be completed in the second half of 2017 and the subsea infrastructure installation activities in summer 2018, resulting in the anticipated startup of Harrier production in the second half of 2018."

Ithaca's forecast net capex for 2017 is about $70 million, most of which is allocated for North Sea development. (Source: capturelightuk/*Shutterstock.com*)

The net capex associated with execution of the development over 2017-2018 is about $75 million, "equating to a development cost significantly less than $10/boe," the company stated.

"This represents a cost reduction of approximately 50% from that originally forecast. The substantial reduction in [capex] is driven by both detailed well engineering design work that has enabled the move away from drilling two individual wells to one multilateral and securing attractive contracting terms across the supply chain," Ithaca said.

Ithaca's forecast 2017 capital investment program of $70 million is "primarily centered on GSA activities" but includes development drilling on the Harrier Field. The forecast 2017 unit opex of about $18/boe is down nearly 30% on 2016 due to "the positive impact of low-cost Stella volumes on the production portfolio."

"The painstaking electrical inspection program on the *FPF-1* is nearing completion, and the vessel will be ready shortly for startup of the Stella Field," Ithaca CEO Les Thomas said. "While this will have taken longer than planned, the transformational step it delivers for the business remains undiminished. The company moves into 2017 in good health, with increasing cash flow, continued deleveraging and the launch of the low-cost Harrier satellite development."

With the electrical junction box inspection and remediation work program nearing completion, forecast first hydrocarbons from the Stella Field is scheduled for February 2017, Ithaca said.

"Production this year is anticipated to be in the range of 19,000 boe/d to 22,000 boe/d, reflecting the updated Stella startup schedule," the company added.

"The producing asset portfolio has performed well over the last 12 months, with production running ahead of guidance largely as a result of solid performance from the Cook Field, for which the company took over operatorship in March 2016."

Ithaca's forecast net capex for 2017 is about $70 million. Most of this is allocated for Harrier development activities, completion of the GSA oil export pipeline investment program and Vorlich Field development planning activities. "The forecast expenditure is also inclusive of any additional Stella startup costs, which are expected to be minimal," Ithaca said.

Premier cuts Catcher costs

Premier Oil said costs have been reduced on its North Sea Catcher Field development, while production has increased by nearly 25%. "The Catcher project continues to progress well and will provide another step change in production, generating enhanced tax-free cash flows for the group," said Premier Oil CEO Tony Durrant.

The operator said Catcher is on schedule for startup later this year with total capex now forecast at $1.6 billion, 29% lower than the estimate when the project was sanctioned. Premier also said that approval of the U.K. Tolmount development concept is expected shortly and "will provide a next phase of growth."

The company registered record production of 71,400 boe/d in 2016, a rise of 24% on 2015. The figures are "in line with previously upgraded guidance." The 2017 production guidance is 75 Mboe/d "before any contribution from Catcher and adjusted for lower Solan profile," Premier added. Opex per barrel for last year was $15.70/bbl, while Premier's estimated capex in 2016 was $690 million, which was below the guidance of $730 million. The 2017 capex guidance is $350 million, including abandonment spending.

Chevron rethinks Rosebank

Chevron Corp. is considering launching a new tender for an FPSO vessel for its Rosebank development project West of Shetland.

Chevron axed its order for an FPSO vessel with Hyundai Heavy Industries (HHI) in December 2016. A termination notice cancelled the deal, which was valued at about $1.85 billion. Chevron signed the original contract in April 2013.

But one month after the cutting of the HHI deal, Chevron was reported to be preparing to launch a new FPSO tender. The retender will be a cost-saving exercise as 2013 prices were much higher than the present day. Indeed, a spokesman for Chevron North Sea said recently that the operator "is committed to working with its project joint venture participants and stakeholders to improve project value and make the right decisions for the Rosebank development."

Chevron also recently said FEED work for the Rosebank project is continuing. Rosebank's development plan includes an FPSO vessel, production and water injection wells, subsea facilities, and a gas export pipeline.

The Rosebank Field was discovered in 2004 and is estimated to contain recoverable resources of 240 MMboe. Rosebank is located 130 km (81 miles) west of Shetland. Chevron operates Rosebank with a 40% stake, while Suncor Energy holds 30%, Siccar Point has 20% and Dong E&P holds 10%. E&P

Editor's Note: *This article first appeared in* Subsea Engineering News *in January 2017. To subscribe to the newsletter, visit* www.epmag.com/M66ENP.

Eagle Ford close-up

Turnaround to double-digit growth is just around the corner for the South Texas play.

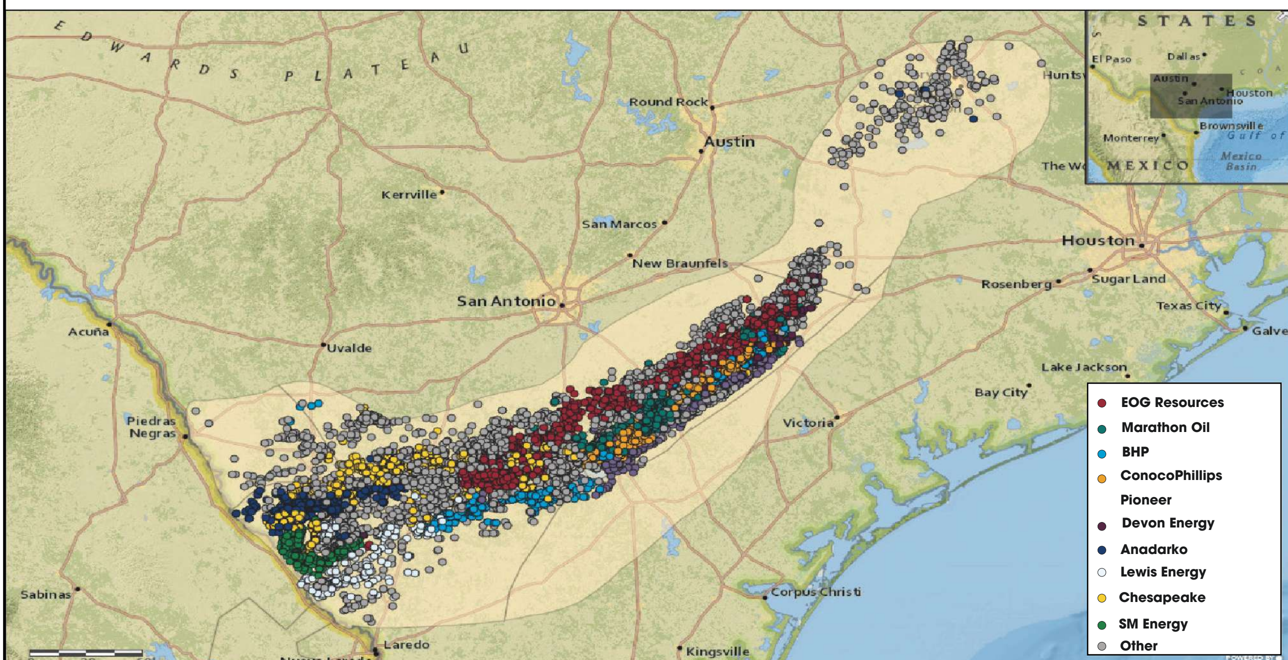
Contributed by **Wood Mackenzie**

The Eagle Ford is an institution of tight oil development. Beginning in 2010, the play launched into the unconventionals arena and quickly emerged as the leading U.S. Lower 48 resource play. Throughout the downturn, it remained the single largest contributing play to U.S. tight oil supply. Activity temporarily slowed as prices fell, but a turnaround already is in the works, with double-digit growth expected beginning in 2019. Nearly 7 Bboe breaks even below $50/bbl, leaving operators with a lengthy runway to look forward to in the coming years.

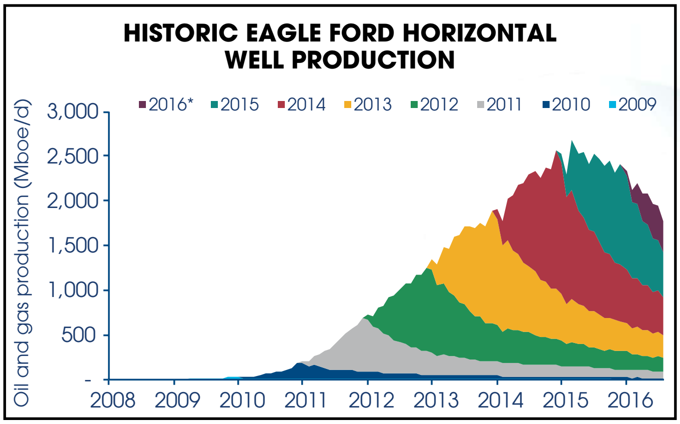
The Eagle Ford holds enormous value, with more than $90 billion on a net present value at a 10% discount rate basis, suggesting it will be a formidable resource for years to come. Future value is primarily driven by the condensate sub-plays, where improved well performance coupled with falling well and service costs have kept the area competitive. Operators have used the downturn to explore new ways of optimizing well designs to improve productivity. A new focus on higher proppant loads, longer lateral lengths and precision drilling have boosted EURs by 10%. Breakevens have even dipped as low as $36/bbl in the core Karnes Trough sub-play.

Over time, more operators are expected to flock to the southern reaches of the play, where dry gas wells are beginning to resemble the Haynesville and Marcellus shale plays. Economics in the Southwest Gas sub-play experienced the greatest improvement of all Eagle Ford sub-plays, pulling down breakevens by more than 40% to less than $2.70/Mcf. On top of improvements in well performance, proximity to emerging demand centers along the Gulf Coast gives Eagle Ford gas producers a competitive advantage. E&P

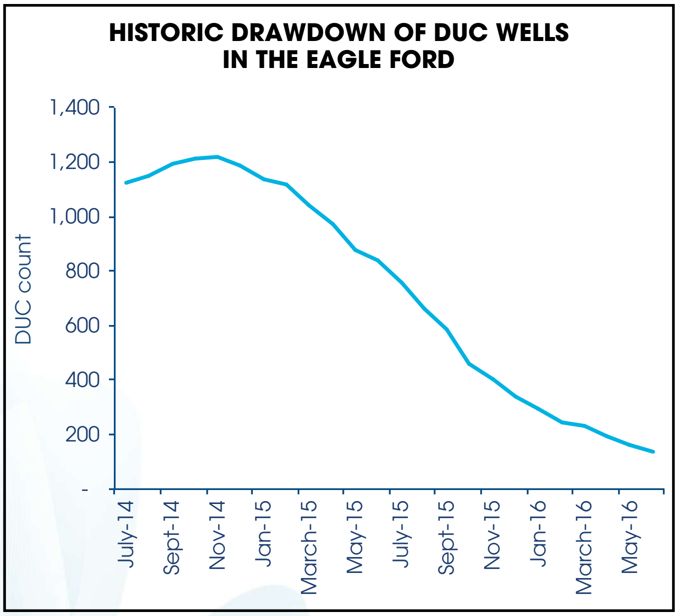
LEADING OPERATOR POSITIONS IN THE EAGLE FORD



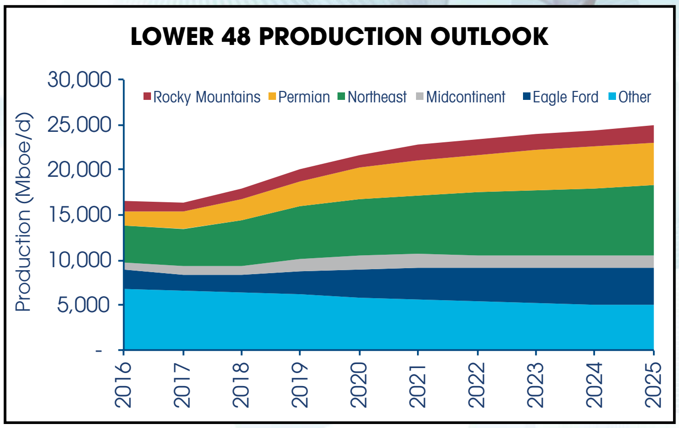
EOG holds the largest position with more than half a million acres, largely concentrated in the core condensate sub-plays. ConocoPhillips holds the most remaining well locations, but several operators are beginning to extend drilling inventory with downspacing and stack-and-staggered lateral well designs. (Source: Wood Mackenzie)



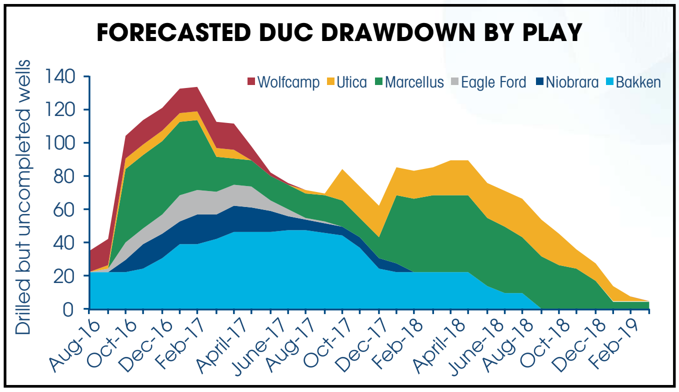
Eagle Ford production rolled over in May 2015 as sustained low oil prices reduced activity in peripheral sub-plays. The drop in oil prices led operators to retrench to the core. EOG, Marathon and BHP have been the most active during this time. Operators across the play have focused on optimizing well designs to generate attractive returns at lower prices. (Source: Wood Mackenzie)



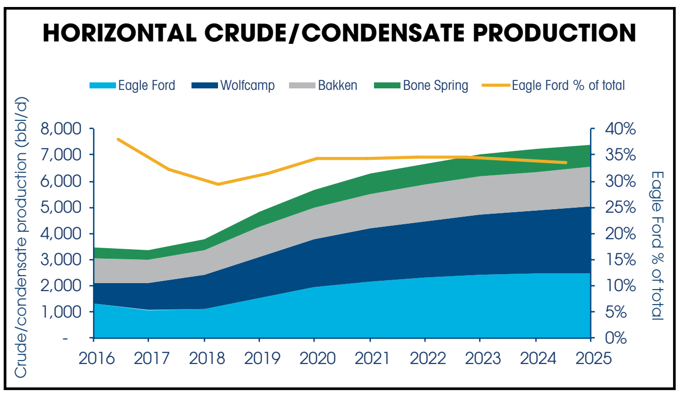
Drilled but uncompleted wells (DUCs) provided operators with a lever during the downturn to maintain or increase production without the added cost of contracting new rigs. Operators typically need about $50/bbl to complete a DUC well economically, given drilling costs are considered sunk. (Source: Wood Mackenzie)



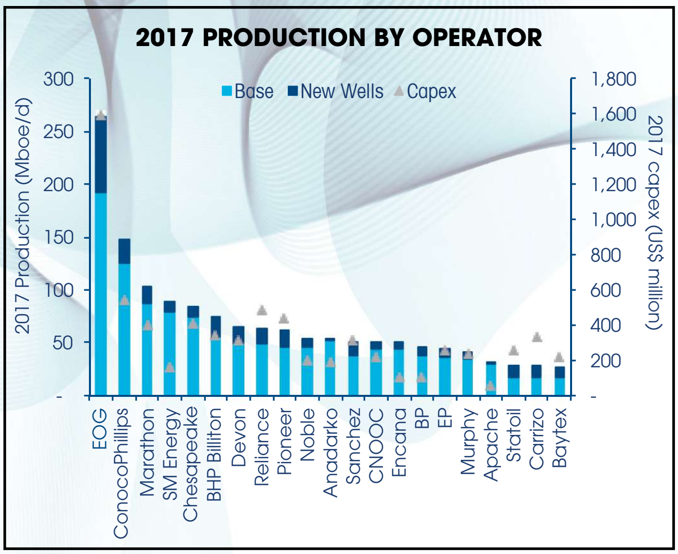
The Eagle Ford should return to growth in 2018 after a brief pause during the downturn. The play will grow by an average of 16% annually in the five years that follow as oil price fundamentals improve. (Source: Wood Mackenzie)



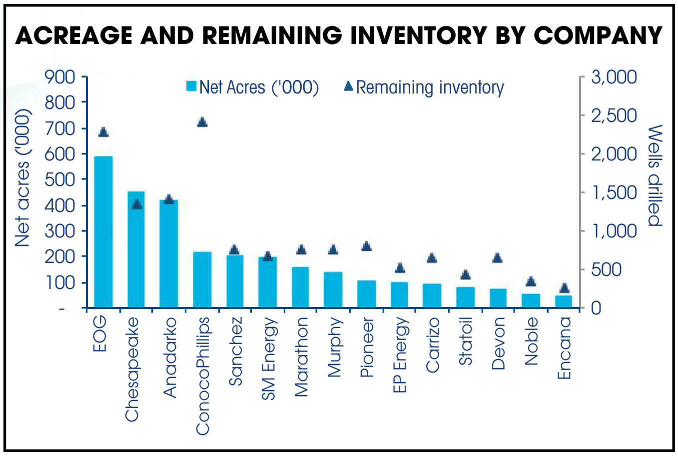
The remaining DUC inventory in the Eagle Ford is minimal. Most drawdown opportunities left are found in the Bakken and Northeast regions. (Source: Wood Mackenzie)



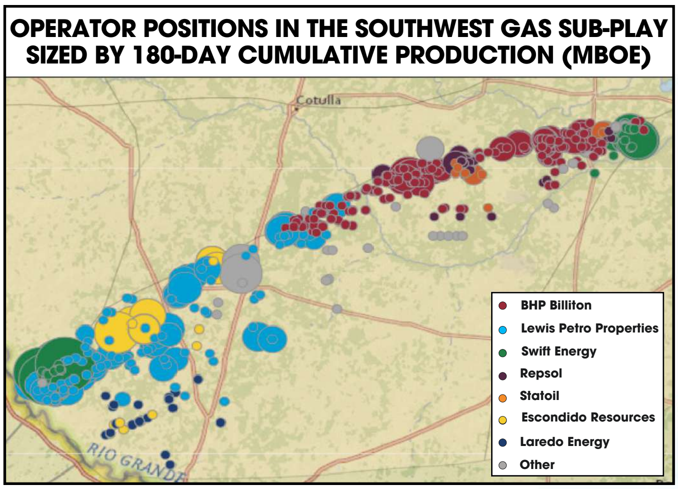
The Eagle Ford comfortably outpaces the Bakken but will struggle to keep up with the growing momentum in the Permian during the downturn as activity spreads throughout the Midland and Delaware basins. (Source: Wood Mackenzie)



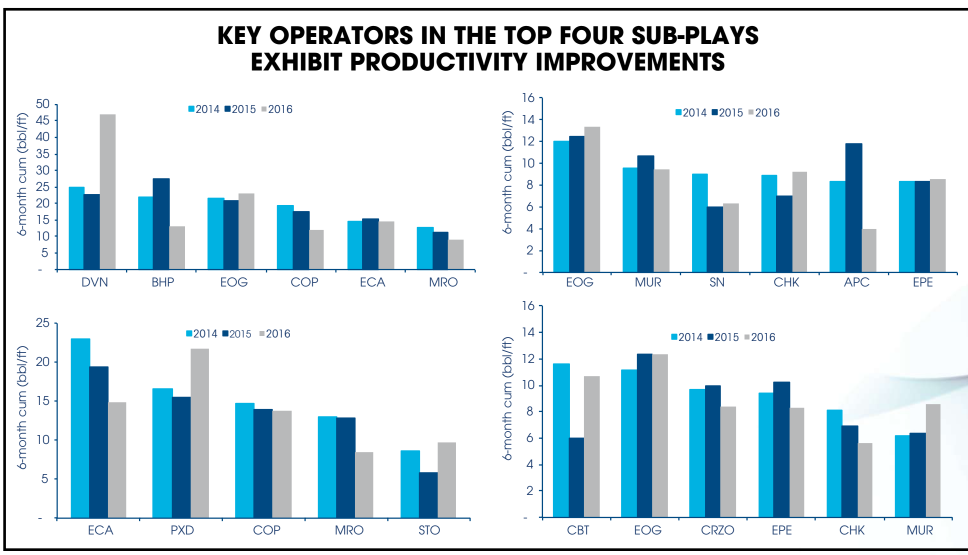
EOG dominates production in the Eagle Ford due to its early foothold and high level of activity in the play. Four of the next six leading operators by production also hold strong positions in the play's core: Edwards Condensate and Karnes Trough. (Source: Wood Mackenzie)



ConocoPhillips holds the most remaining well locations. Inventory has increased with downspacing and stack-and-staggered lateral well designs. (Source: Wood Mackenzie)



Right, Swift's Fasken Field wells put the Southwest Gas sub-play on the map. Well performance in this area rivals portions of the Marcellus and Haynesville shales. LNG facilities, exports and industrial growth are fueling new demand along the Gulf Coast. Eagle Ford activity will move south by 2035 to focus on gas production. (Source: Wood Mackenzie)



Left, Wood Mackenzie charts out annual operator performance in four popular sub-plays, using cumulative production volumes over a six-month time period to understand how companies perform over time. Although Devon has drilled fewer wells than some of its peers, performance has been noticeably stronger in 2016. (Source: Wood Mackenzie)

Onshore US regulatory overview

Jack Belcher and **Beth Everage**, HBW Resources LLC

As the Trump administration began assuming the reins of the federal government, a number of executive and legislative actions were initiated impacting the oil and gas industry:

- The White House initiated a "Regulatory Freeze Pending Review" of federal regulations;
- A presidential memo called on TransCanada to resubmit its application for a Presidential Permit for a border crossing for the Keystone XL Pipeline;
- A presidential memo called for expediting review and approval of regulatory actions regarding the construction of the Dakota Access Pipeline;
- An executive order expedited environmental reviews and approvals for "High Priority Infrastructure Projects"; and
- An executive order was made on "Reducing Regulation and Controlling Regulatory Costs."

Additionally, Congress has taken steps on its Congressional Review Act authority to overturn the following regulations impacting the oil and gas industry:

- Disapproval of the Stream Protection Rule;
- Disapproval of the Securities and Exchange Commission disclosure rule on payments to foreign governments;
- Disapproval of the venting/flaring rule; and
- Disapproval of the Bureau of Land Management process for preparing, amending and revising Resource Management Plans.

Other federal actions

Venting and flaring rule challenged: In January a U.S. District Court denied requests from industry groups and western states for preliminary injunction to halt implementation of the venting and flaring rule. Later that month congressional Republicans began invoking authority under the Congressional Review Act to repeal rules finalized during the end of President Obama's term. The House considered a resolution (H.J. Res. 36) in early February to revoke the rule.

Fracking rule hearing gets court date: Oral arguments will be in heard at the 10th U.S. Circuit Court of Appeals on March 22 in Denver. In 2015 the rule was challenged in court by states, industry and tribes. A U.S. District Court struck the rule down in 2016. That decision was appealed to the 10th Circuit by the government and environmental groups.

State/local actions

Colorado

- The Colorado Attorney General sent Boulder County commissioners a letter asserting that the city's moratorium on hydraulic fracturing, currently in place through May 1, is illegal.

Florida

- State Senator Dana Young (R-Tampa) filed a bill (SB 442) to ban hydraulic fracturing in the state. The proposed legislation will be considered during the state legislative session beginning March 7.

Ohio

- Governor John Kasich (R) proposed a budget calling for a 6.5% tax on oil production and a 4.45% tax on natural gas and NGL. Kasich previously sought the same rate increases in the 2015 budget. ■

A new breed of ocean-bottom seismic

With backing from a major, a startup is providing quality seismic at vastly reduced rates.

Rhonda Duey, Executive Editor

Most major oil companies make significant investments in R&D. But they can't always go it alone. That's why several companies have formed "technology ventures" arms to find and fund technology startups that promise to eventually give them a competitive advantage.

Shell was the first company in the energy industry to form such a program, launching Shell Technology Ventures (STV) in 1997. Since then the company has funded multiple startups and has helped to commercialize a considerable amount of useful technology.

One company, Magseis, came to STV's attention about six years ago at the behest of Shell's geophysics department. The company had pioneered a new approach to ocean-bottom seismic, combining the productivity of seismic streamer acquisition with the data quality delivered by bulky ocean-bottom nodes. The idea behind the latter is that cables equipped with autonomous sensors are laid on the ocean bottom, providing better coupling and hence a better signal than towed streamers. Ocean-bottom nodes are untethered but require ROVs to place them on the sea surface, which adds tremendous cost to the acquisition process.

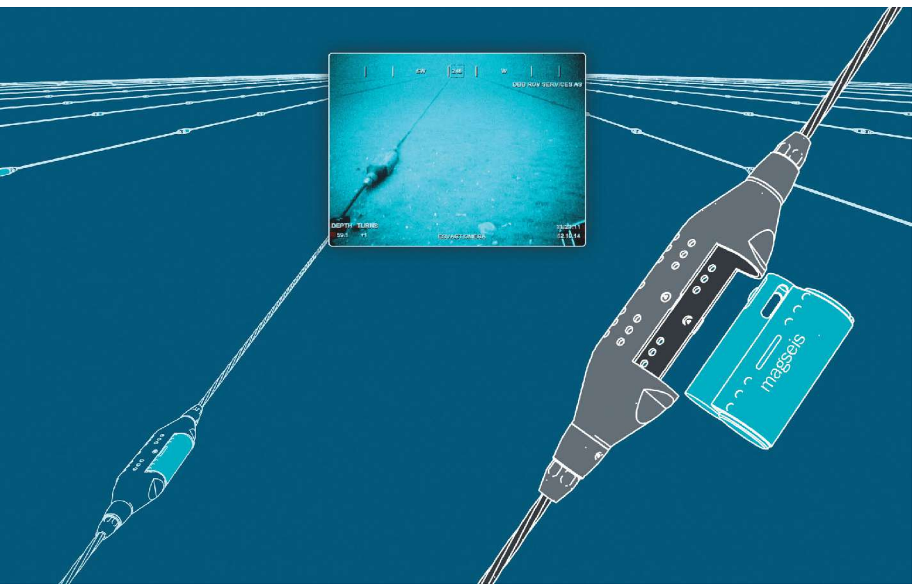
"The speed by which the ROV can position these sensors is very slow, and hence it's very expensive," said Peter van Giessel, a senior principal for STV. "And the vessel cannot hold many sensors."

The advantage of Magseis, he explained, is that the cables simply hold the sensors and don't contain any electronics of their own. "They're totally autonomous, and the sensor is a mere 7 kilos [15 lb]," he said. A vessel can hold several hundred kilometers of cable containing thousands of these autonomous nodes. And a robotic system on the rear deck speeds up deployment.

"One aspect that separates Magseis from the others is that it's not just the sensor," he said. "They thought through the entire value chain. They also have a completely automated back-deck handling system. If you tour their vessel, it's like a factory, full of robots. It's totally different than normal streamer seismic."

While the concept had been kicked around since the early 2000s, the developers had to wait on the availability of certain classified technology. "They could not get their hands on miniature, low-power atomic clocks," he said. "These were developed by the U.S. military to put in rockets.

"Only in 2009 or 2010 did they become available for the civil market, and Magseis immediately made sure that they got all the capacity they could get their hands on to put in their sensors."



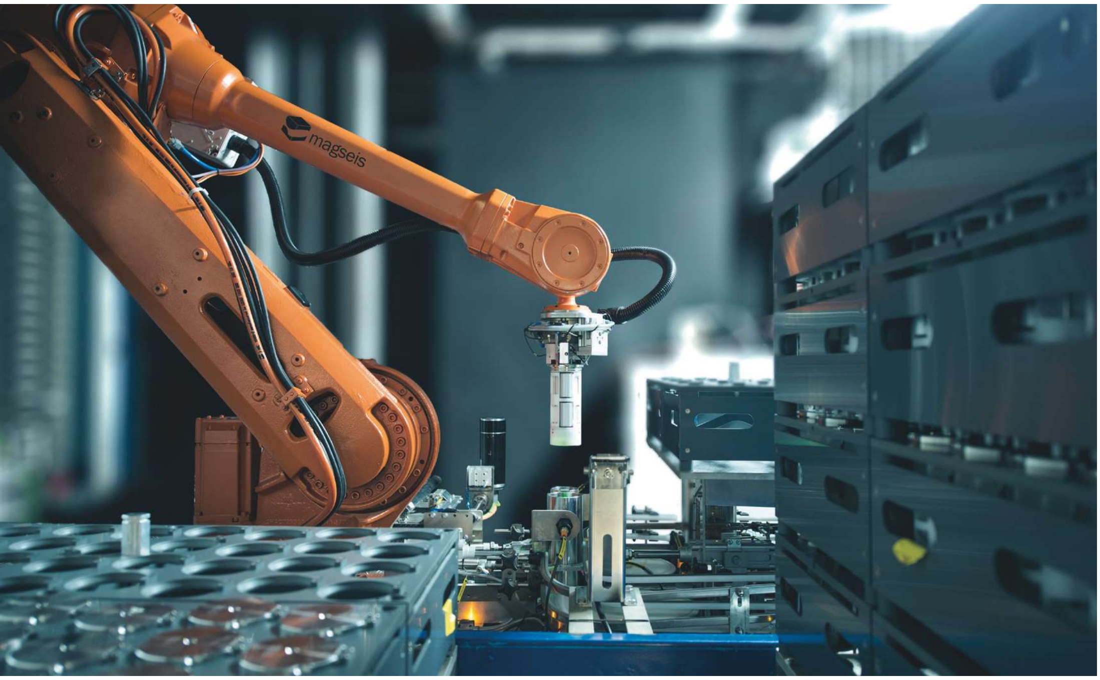
A Magseis sensor (inset) is shown on the ocean floor. The lightweight sensors use technology adapted from the telecommunications industry. (Source: Magseis)

The next step

While Magseis currently runs one vessel and has no shortage of work, Shell wanted to take the company to the next step.

"Our portfolio is mostly focused on deep water and ultradeep water," van Giessel said. "When you go into really deep water, it's hard to ensure that you're placing the sensors accurately. If you want to do 4-D seismic, can you repeat it? That's where there was a challenge."

Shell signed a joint development agreement with Magseis and also made an equity investment in the company. Current research revolves around the behavior of the "nodal



Robotics run the back deck on the Magseis vessel. (Source: Magseis)

multiplier," which is connected to the vessel through an umbilical and helps precisely place the nodes.

"You need to really understand the dynamics in water and take into account the currents to do extra positioning so that you know at all times where the sensor is and how it behaves," he said. "The software around it is the tricky bit."

The goal is to have a deepwater system available this year, but as part of the joint development agreement Shell needs to test it first. This presents its own set of challenges.

"Given the current plan, our operating units could come up with that survey," he said. "We did a test deep in the fjords earlier this year that was quite successful, so the company is gearing up to build the prototype that they can use in an asset. Our challenge is to find the right asset to do this with."

It's also a challenge to find room in Magseis' busy schedule. "They're a one-vessel operation, and the vessel is completely occupied," he said. "The next step for them is the next vessel, but the financial risks to such a small company are substantial. They can only do it with sufficient backing."

But the existing system already has proved its worth. Shell and its partners deployed it on the Bokur Field in Malaysia in very challenging conditions. They used a dense spacing in an environment crowded with infrastructure as well as vessel traffic. "The operator was very pleased," he said.

Idea flow

STV is continually on the lookout for these types of opportunities. Van Giessel said that many of them crop up in a fashion similar to Magseis, through a department at the company that has caught wind of a new idea.

"That's a good source because we already potentially have a launching customer," he said. "We, of course, like investing in companies that potentially lave large deployment value to Shell."

The company also works with other venture capital firms, including its competitors at Statoil and Chevron, he said. "That's not uncommon to us because we realize that these kinds of companies take a long time to be pulled through the valley of death," he said. "It can take six, eight years, sometimes even longer. We all need to partner to have several shots on goal and to share risk with others."

External venture firms are important as well. "They like us because we can serve as a launching customer to these startups, and they also like us because we, like them, are focused very much on the financial return aspect," he said. "To be a strong partner to these venture capitalists, you need to have a strong focus on creating exit value as well as creating deployment value. If you can deliver on those promises, they will bring you the best inflow."

Downturns often give bright people the time they need to work on their ideas, and STV is reaping the benefits. "It's a good moment to invest because there are a lot of interesting technologies for oil and gas out there that are looking for money, and money is scarce," he said. "There's no shortage of deal flow at interesting valuations."

Added Geert van de Wouw, managing director at STV, "While we are not shooting seismic at the moment, we know we will be shooting seismic again in the years to come. You have to be anti-cyclical in your investment thesis to deliver the technologies when they are ready and needed." E&P

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Lucrative use for 3-D printing in oil and gas industry

Certain tools are ready for additive manufacturing.

Harshit Sharma, Lux Research

With revenues dropping by more than 50% for a majority of upstream companies, the focus for the industry is gradually shifting from high exploration activities to operational efficiency in all aspects of the industry's value chain. While production and drilling activities have seen an uptake in new technologies in sensors and data analytics, the industry's manufacturing is finally looking to one of the biggest disrupters of the modern day, 3-D printing.

Three-dimensional printing at its core is a tool for efficient manufacturing that reduces material wastage and the overall steps required in the manufacturing cycle. The technology also enables the option of lightweighting parts by printing them with materials such as polyether ether ketone and carbon fiber over steel and aluminium. However, it is important to establish that the technology does not displace existing subtractive manufacturing techniques. Three-dimensional printing offers a new alternative next to computer numeric control machining or injection molding at the manufacturer's disposal.

The 3-D printing industry already is a $3.5 billion market, growing at a 15% compound annual growth rate. However, the oil and gas segment (represented as "other" in Figure 1) is still relatively small in comparison to the aerospace, automotive and medical segments.

The oil and gas industry has speculated about the application of 3-D printing for quite some time, with suggestions ranging from drillbits and perforated pup joints to complex pump housings and heat exchangers. However, the technology has yet to integrate into the industry's manufacturing completely. Two primary reasons for the slow adoption are a lack of focus on cost reduction tools up until recently and a proper framework for identifying parts or use cases that are appropriate for printing. The present guiding principle for selecting printable parts in the industry is the "high complexity/low units" practice that focuses on parts with complex geometries produced in small volumes.

Developing the right framework

The high complexity/low units practice alone does not account for the oil and gas industry's complex supply chain, nor does it establish the business case for printing these use cases and consider the maturity of the existing 3-D printing technology. It is important to analyze if printing a particular use case is beneficial and address whether the existing 3-D printing technology is indeed capable of producing it. Encompassing the above-discussed criteria, Lux Research developed a methodology to score the use cases on scales of one to five using two comprehensive metrics: value and suitability.

Lux scored 12 use cases from different segments of the oil and gas industry to identify the most lucrative use cases for 3-D printing. These use cases included applications or ideas speculated in the industry as well as proven applications already in field use.

While all of the four discussed proven use cases were forthcoming, two speculative use cases that also appeared in this quadrant were sand control screens and pipeline pigs. All of the use cases

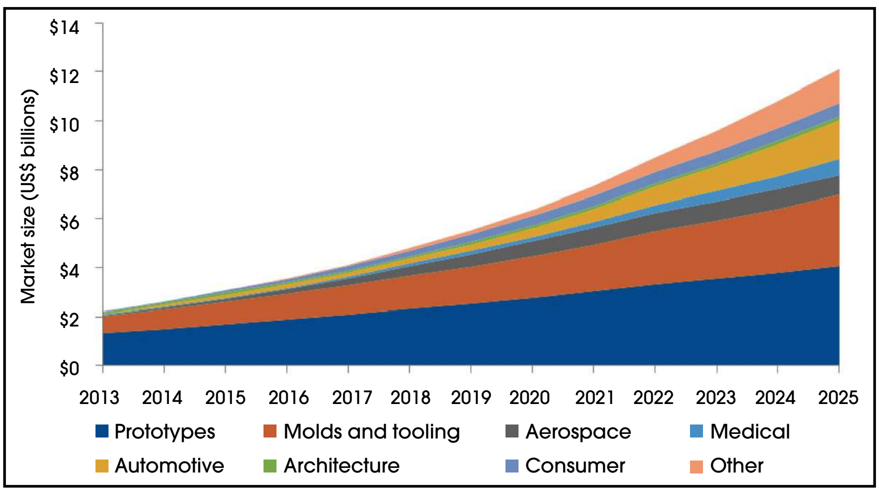

FIGURE 1. The oil and gas segment ("other") is still relatively small in comparison to other industries. (Source: Lux Research)

ranked here are perfect examples of the type of parts the industry should consider printing. Three-dimensional printing these use cases leads to significant material savings, and the incumbent printing technology is capable of producing them in the required lead times.

Use cases such as drillbits and liner hanger spikes hold high potential. Printing these parts leads to significant material savings; however, the existing 3-D printing technology is not mature yet for these applications. While the 3-D printing industry is still perfecting metal printing on pre-machined tubular components for creating spikes, availability of materials such as tungsten carbide for the drillbits is still an issue.

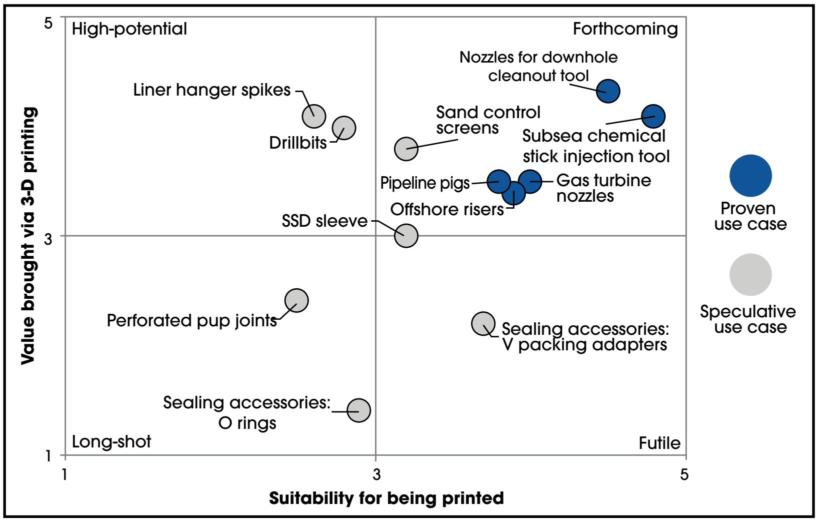

FIGURE 2. Some technologies are much better suited to near-term 3-D printing capabilities than others. (Source: Lux Research)

Three-dimensional printing does not offer much value for applications similar to V-packing adapters and O-rings. The industry uses incumbent techniques such as molding and extrusion for efficient production of these parts with minimal material wastage. Analysis of such use cases highlights the important takeaway that not every part is a good fit for 3-D printing, and different manufacturing techniques will work in tandem in the future.

A three-pronged approach for 3-D printing adoption

Looking ahead, as the interest for 3-D printing in the oil and gas industry grows, its successful adoption will require a three-pronged approach of internal conceptualization, partnerships and infrastructure.

- *Internal conceptualization:* Developing a framework for identifying lucrative use cases is the first step toward adoption. Companies should develop methodologies and filter out use cases appropriate for 3-D printing. The eventual success of use cases identified through such frameworks will pave the way for printing of more critical parts in the future;
- *Partnerships:* For the technology's adoption in the short term, the oil and gas industry should look toward working with innovative 3-D printing startups for overcoming technological barriers they are likely to come across. Lux Research identified three such startups from its global coverage of more than 10,000 startups: Arevo, Questek Innovations and Nanosteel; and
- *Infrastructure:* For the long-term adoption of 3-D printing, however, the oil and gas industry will need to invest in infrastructure conducive for 3-D printing and build industrial collaborations as seen in the aviation and automotive industries. Companies should look into GE's successful adoption of 3-D printing. GE has established research centers for additive manufacturing worldwide and has grown its 3-D printing facilities by acquiring companies such as Morris Technologies, Arcam AB and SLM Solutions Group AG. The oil and gas industry also should consider collaborations with major industrial players. A recent example is the joint venture between Michelin and Fives for developing metal 3-D printers.

The industry can no longer afford excessive wastages and operational costs, be it in the field or in the manufacturing yard. Despite adopting lean manufacturing in its supply chain, the industry continues to struggle with as much as 70% of material wasted in fabrication of highly complex geometries. Identifying the right set of applications for 3-D printing remains one of the biggest hurdles for the technology's adoption. Lux Research's methodology for filtering out various speculated applications concluded that parts such as sand control screens and drillbits were lucrative, while printing applications such as O-rings and V-packing adapters were not profitable. To bring these ideas into reality, the industry should look toward novel 3-D printing startups for collaboration in the near term and invest in additive manufacturing facilities with an eye for the future. E&P

Have a story idea for Tech Watch? This feature highlights leading-edge technology that has the potential to eventually address real-life upstream challenges. Submit your story ideas to Group Managing Editor Jo Ann Davy at *jdavy@hartenergy.com*.

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Completion system expedites multizone frack and gravel packs

To speed up sand control completions in land and offshore wells, Schlumberger offers its MZ-Xpress single-trip multizone frack- and gravel-pack system. After the zones of interest are perforated and the well is cleaned, hardware for all zones is run into the well in a single trip, permitting rapid gravel- or frack-packing. To ensure reliable operations in a wide variety of applications from land to deep water, the system incorporates robust debris management to minimize the risk of malfunctions and nonproductive time during sand control operations. The system also incorporates field-proven modular subassemblies that increase application flexibility in challenging well architectures, including multiple casings. *slb.com*

The MZ-Xpress completion system is deployed after all zones of interest have been perforated. Individual zones are isolated and gravel- or frack-packed from the bottom up in a single trip. (Source: Schlumberger)

Buoy swivel technology reduces maintenance downtime

Flexible Engineered Solutions International (FES) has developed new technology for a major manufacturer of marine equipment based in China, a press release stated. The CALM Buoy Swivel, which is fully certified by DNV GL, includes new swivel technology that allows the buoy to rotate while maintaining a leak-free joint between the subsea pipelines and vessel during the transfer of fluid. Because it enables the replacement of seals onboard without the requirement to bring the main buoy into a repair yard, the new swivel will significantly reduce maintenance downtime for the CALM Buoy, avoiding it being offline for long periods of time. *fesinternational.com*

The new patented technology was scheduled to be delivered in January to China as part of a contract awarded to FES 12 months previously. (Source: FES International)

First rigless-deployed ESP system installed

Baker Hughes recently installed the first TransCoil rigless-deployed electric submersible pumping (ESP) system, which is designed to help operators bring wells on production faster and lower the costs associated with installing and replacing ESPs, the company said. Because they can eliminate the need for a rig in fields where rig availability is a concern or where high intervention costs can limit artificial lift options, operators can minimize deferred production and lower their overall lifting costs to extend the economic life of their assets. The TransCoil system developed in participation with Saudi Aramco features an inverted ESP system with the motor connected directly to a new proprietary power cable configuration, eliminating the traditional ESP power cable-to-motor connection. Unlike wireline-deployed ESPs, the fully retrievable TransCoil system does not have an in-well "wet connection" that requires a rig to pull and replace if the wet connection fails. The TransCoil system was installed and commissioned in a well at 1,493.5 m (4,900 ft) in 7-in. tubing in Saudi Aramco's Khurais Field. The rigless operation reduced installation time nearly 50% over a rig-based installation, and further deployment efficiency improvements are expected in the future. *bakerhughes.com*

New technology to dehydrate natural gas

ExxonMobil's development of cMIST technology dehydrates natural gas using a patented absorption system inside pipes and replaces the need for conventional dehydration tower technology, a press release stated. This "in-line" technology could be deployed at land-based and offshore natural gas production operations. The new technology, developed and extensively field-tested by ExxonMobil, more efficiently removes water vapor present during the production of natural gas. Removing water vapor through the use of dehydration technology, typically accomplished using large and expensive dehydration towers, reduces corrosion and equipment interference and helps to ensure the safe and efficient transport of natural gas through the supply infrastructure and ultimately to consumers. cMIST is designed to reduce the size, weight and cost of dehydration, resulting in reductions of surface footprint by 70% and the overall dehydration system's weight by half. *exxonmobil.com*

Reservoir modeling capabilities maximize recovery

Emerson Automation Solutions has released the Roxar API (Application Programming Interface), a press release stated. This extensibility interface is designed for reservoir modeling and, in particular, for the company's software Roxar RMS. Roxar API helps operators customize their workflows to achieve specific goals, improves data management capabilities with greater interoperability and flexibility, preserves vital reservoir information across multiple-stage workflows and enables users to analyze and visualize their models in different and innovative ways for improved reservoir interpretation and increased recovery. Using Python, a powerful but simple-to-use programming language, the Roxar API enables operators to integrate their own intellectual property into reservoir modeling workflows. In addition, applications can be written or extended to access RMS project data. *emerson.com*

Drillbit technology increases toolface control

Halliburton has released its Cruzer depth-of-cut rolling element, which is a drillbit technology designed to increase toolface control without reducing drilling efficiency, a company announcement stated. This technology provides operators with the ability to increase their ROP at a lower cost per foot for improved economics. Halliburton drillbits are developed through a proprietary process called Design at the Customer Interface (DATCI), which customizes each bit for an operator's specific application. DATCI employs a global network of design specialists who are familiar with regional characteristics and collaborate with customers for optimized solutions. *halliburton.com*

Ice charting capability for weather forecasting

BMT ARGOSS (BMT), a subsidiary of BMT Group, has released its ice charting capability, which coupled with its extensive weather forecasting expertise will provide a more enhanced and cost-effective service to customers globally, a press release stated. As part of this new capability, a number of BMT's key senior meteorologists have completed an intensive training program at the Danish Meteorological Institute. BMT's Mark van der Putte, who took part in the training, said, "The training has allowed us to better understand the ice regime, i.e., how ice builds up, how it moves and reacts, and how it evolves during the season. Interpreting satellite images is also a key requirement for delivering an effective output. The ice buildup and movement is very dependent on the weather; therefore, our extensive meteorological knowledge and experience will help us to further improve the service we provide." *bmtargoss.com*

Rigless system enables ESP pump swap

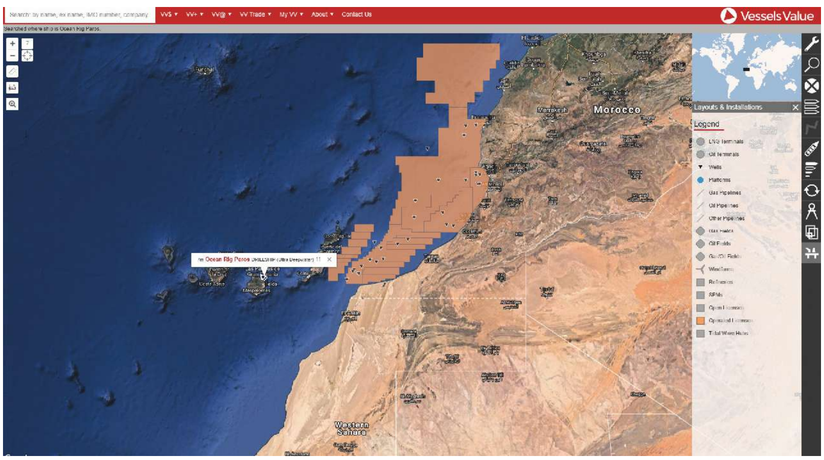
AccessESP has showcased its rigless electric submersible pump (ESP) conveyance system in the industry's first pump swap for an operator on the North Slope of Alaska, a press release stated. In two days through a live well intervention the AccessESP system enabled retrieval of the existing ESP pump and the install of a newly optimized ESP using only a slickline unit, lubricator and a crane, marking the industry's first ESP pump swap on a commercial well. Surface diagnostics determined that the Access375 permanent magnet motor was fully functional; therefore, replacement was not required, thus reducing operational time and costs. In this case, the ESP pump had not failed but was proactively replaced with an optimized pump. This would be cost-prohibitive using a workover rig, requiring the replacement of the entire conventional ESP system. To resize a conventional ESP pump, the operator would mobilize a workover rig, kill the well, pull the tubing and ESP, and then replace the ESP and rerun the tubing. The costs associated with the intervention and downtime inherent in this approach can be substantial. However, by using a standard slickline unit, lubricator and crane, the AccessESP rigless conveyance system reduces the cost, time and risk associated with ESP resizing. *AccessESP.com*

Companies collaborate to offer asset integrity management

Honeywell and Dover Energy Automation plan to collaborate as part of the Honeywell INspire program, which is Honeywell's joint customer development program for its Industrial Internet of Things (IIoT) ecosystem. The program is designed to help industrial energy customers improve the safety, efficiency and reliability of their operations, a press release stated. Honeywell's capabilities in data consolidation, cybersecurity and software development combine well with Dover's deep domain knowledge in condition monitoring and asset optimization to offer a robust IIoT ecosystem that is designed to help customers solve previously unsolvable problems. The goal is a simple-to-use infrastructure that gives users secure methods to capture and aggregate data so that they can be leveraged by using analytics and applying a range of domain knowledge from a vast ecosystem of equipment vendors and process licensors. With a larger consolidated dataset, manufacturers can apply higher analytics for more detailed insights, scale the data as needed to meet the varied needs of single-site or enterprisewide operations and leverage a wider pool of data experts for monitoring and analysis. *dovercorporation.com, honeywell.com*

Daily valuations for MODUs

VesselsValue, an online valuation provider, is releasing daily valuations for mobile offshore drilling units (MODUs), a press release stated. This new vessel type is part of VesselsValue's recent push into the offshore space. In May 2016 VesselsValue released daily updated market and demolition values for 6,500-plus offshore support vessels. The new vessel types, which are available on the VesselsValue website, comprise 1,020 individual MODUs (including drillships, semisubmersible units and jackups) and can be presented via company fleets and portfolios. To arrive at daily valuations, VesselsValue uses a complex algorithm that considers the full specifications of the vessel (age, size, ship type and features) as well as the recent spot rates, secondhand sales, newbuilding prices, oil pricing and other market indicators. These data are made available for VesselsValue clients through the VesselsValue Deals database. *VesselsValue.com*



VesselsValue is releasing daily and automated valuations for the MODU fleet. (Source: VesselsValue)

Closeable system reduces time, costs

Packers Plus Energy Services Inc. recently worked with an operator in Egypt to complete a six-stage StackFRAC system using the drillable closeable (DC) FracPORT sleeve in a short time frame, a press release stated. "Packers Plus' advanced manufacturing capabilities ensured the product was delivered and tested within three days, meeting the client's operational timeline and technical requirements," said Packers Plus President Ian Bryant. "Not only was the client working in a short turnaround time, they also were interested in a closeable system that would simplify future operations." The openhole approach was chosen over the plug-and-perf method to shorten operational time, simplify operations and reduce overall cost. The DC FracPORT sleeve is a ball-actuated hydraulically activated injection/production port. The closeable feature of the sleeve provides the operator with options to shut off water encroachment if required, reducing operational costs and optimizing production performance. The operation, installation and completion—done in conjunction with Packers Plus' global marketing alliance partner, Schlumberger—were executed according to plan. Additional systems were planned for late 2016. *packersplus.com*

Hydrogen sulfide detector for arid locations

Tyco Gas & Flame Detection's DG-TT7-S hydrogen sulfide (H_2S) gas detector with a metal oxide semiconductor sensor underwent stringent functional safety assessments by an external certification body and is now SIL 2 approved, a press release stated. The DG-TT7-S gas detector is used mainly for the detection of H_2S in arid locations having air present or in locations with continuous H_2S background. The sensor specifies a wider continuous operating temperature range than the standard electrochemical sensors up to +65 C (+149 F). The MultiTox DG-TT7-S features onboard relays, plug-and-play sensors and a highly visible display that changes color depending on the status mode. *TycoGFD.com*

Dust suppressant provides safety from sand mine to wellhead

The Oilfield Technology Group of Hexion Inc. has released its Sentinel dust suppressant, a press release stated. This new technology is designed to reduce dust generated from uncoated fracture sand. The Sentinel dust suppressant is designed to reduce the amount of respirable silica to levels below the new Occupational Safety and Health Administration and existing Canadian permissible exposure limits. The dust suppressant is capable of reducing respirable silica dust below 25 µg/cu. m. The chemical system traps fine dust particles and remains on the proppant during transportation and transfer. This liquid dust control agent is effective on all mesh-size sands. The Sentinel dust suppressant helps provide safety and compliance from the sand mine to the wellhead. The versatile application method allows users to apply the product at the sand mine, transload or at the fracture site. The delivery system can be mobile or stationary and has a small footprint on location. It will not decrease throughput at the sand mine or decrease sand offloading time when deployed at a transload or fracture site. *hexion.com/oilfield*

Composite fracture plug for zonal isolation

TEAM Oil Tools has developed the TOMCAT fully composite fracture plug, an addition to the TOMCAT product line, a press release stated. The TOMCAT fully composite fracture plug uses high-strength composite components to provide a dependable, durable and cost-effective design for zonal isolation during multistage completions. These fracture plugs are constructed of machined composite material with composite upper and lower slips. The plug is compact in length with zero metal components and has pump-down kits that allow 500-plus feet-per-minute run in speed. The specialized design features ceramic buttons that do not damage the mill/bit bodies during plug drill-outs. *teamoiltools.com*

The TOMCAT composite fracture plug was first released as a dual cast-iron slip plug in early 2016. In April 2016 TEAM released the Hybrid design, which incorporates an upper composite slip. (Source: TEAM Oil Tools)

Online intelligence resource provides data analytics

Douglas-Westwood has released Sectors, a service that provides access to core and previously unavailable data, a company announcement stated. A brand new online data analytics subscription service, Sectors enables users to interrogate, screen and visualize oilfield intelligence from anywhere in the world. The first Sectors module focuses on the global drilling and production sectors, with additional modules to be rolled out through 2017. The service enables users to build bespoke charts and export data using global, regional, country and field-level filters with multiple attributes. Users can keep track of the market, have visibility to current and future movements, quantify and qualify strategy and planning assumptions, identify key questions to challenge investment decisions, or triangulate internal and third-party data. *douglas-westwood.com/sectors*

The online subscription service, Sectors, launched Jan. 24. (Source: Douglas-Westwood)

Simplifying offshore asset maintenance

Two new coatings, Hempadur Quattro XO 17820 and 17870, have been released by Hempel to increase the service life and reduce on-station maintenance requirements of offshore assets, a press release stated. The high-performance pure epoxy uni-primers combine corrosion protection with construction flexibility. Hempadur Quattro XO 17820 and 17870 are part of a series of two-component epoxy primer coatings that provide advanced crack resistance using Hempel's patented fiber technology. They can be applied in immersed and nonimmersed areas of any offshore asset, from offshore platforms and drilling rigs to support vessels. Their high-volume solids ratio (80%) means that fewer volatile organic compounds are released into the atmosphere. Hempadur Quattro XO 17820 and 17870 can be applied to multiple areas above and below the waterline, including ballast water and oil cargo tanks, and also can be applied year-round with workability from -10 C (14 F) to 45 C (113 F). *hempel.com*

HP/HT electrical connector reduces downtime, system costs

Rampart Products has specified the VICTREX HT polymer for a new HP/HT KTK (aka Kintec) electrical connector for the efficient and safe transmission of power and data during the drilling process, a press release stated. Used in oilfield equipment, the reliability of the multi-pin connector is crucial to reducing costly downtime. The material as well as the connector has been tested beyond industry standards in real-world environment simulations. During material selection and the development of the molding process Rampart and Victrex worked together, enabling Rampart to release its first connector using the VICTREX PAEK (polyaryletherketone) polymer. The new connector has been rated for temperatures beyond 200 C (400 F) and pressures at 20,000 psi, providing a reliable electrical connection while protecting expensive sensors and electronics. *rampartproducts.com, victrex.com* E&P

Please submit your company's updates related to new technology products and services to Ariana Benavidez at abenavidez@hartenergy.com.

Mapping the Eastern Mediterranean gas puzzle

Monetization might be challenged if more large discoveries are made.

Bas Percival, Wood Mackenzie

This year is set to be pivotal for the Eastern Mediterranean upstream sector, with players expected to position themselves on an ever-evolving chessboard of markets, exploration activity and pricing.

In many ways, 2016 laid the groundwork for the activity Wood Mackenzie expects to see this year. Israel implemented a regulatory framework that will speed the way toward final investment decision (FID) for the Leviathan development; progress on the super giant Zohr Field continued at breakneck speed following FID in February 2016; and Cyprus launched its third licensing round, garnering interest aplenty.

However, with a heady mix of geopolitics, regulatory and gas pricing issues, commercialization of natural gas in the Eastern Mediterranean is far from straightforward. Major projects such as Leviathan's Phase 2 (Israel) and Aphrodite (Cyprus) are dependent on export routes for their gas to make the projects economically viable—making 2017 even more interesting.

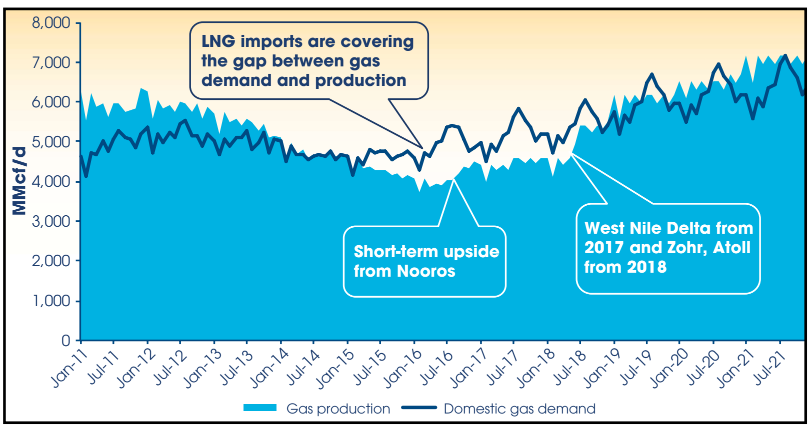
Finding markets

Egypt has witnessed severe swings in its gas market over the last decade. Until very recently, it was seen as the premier destination of discovered gas in the Eastern Mediterranean, swinging from the world's eighth largest LNG exporter in 2009 to the world's eighth largest LNG importer in 2016. And things are set to change again.

New indigenous gas production will give the country breathing space to ramp down costlier LNG imports and alleviate ongoing gas shortfalls. The space that existed in the Egyptian domestic market is rapidly disappearing, and any new discoveries could see more gas diverted to Egypt's idle LNG plants. Original letters of intent (LOIs) that were signed back in 2014 allowing Israeli gas access to idle Egyptian LNG infrastructure could be squeezed out as Egyptian projects move ahead under pragmatic revisions of gas pricing.

Wood Mackenzie's latest analysis shows that Egypt could be self-sufficient in gas by 2019. Analysts are planning a multiclient study into this dynamic market for clients in need of a deeper dive into the Egyptian gas market.

Israel and Cyprus have gas markets that are too small to absorb all of the reserves from Leviathan (622 Bcm or 22 Tcf) and Aphrodite (127 Bcm or 4.5 Tcf). To fully realize value in the Leviathan project, large-volume gas sales agreements will need to be signed. Egypt's reversal of fortunes means the large-volume LOIs with Leviathan now look less likely to translate into full gas sales agreements, but smaller volume offtake contracts might still be possible.



The balance between Egypt's supply and demand has been changing. (Source: Wood Mackenzie)

In addition, Turkey and Europe remain possible markets for Israeli and Cypriot gas. However, significant challenges remain to realize either market as a viable offtaker of gas from the Eastern Mediterranean. In Turkey's case, the main stumbling block is Cypriot unification, while a high-cost pipeline through a seismically active seabed is a challenge to carving out space in the European market.

Exploring for the future

Exploration activity was hardly on a high in the Eastern Mediterranean during 2016; no exploration wells were drilled in Cypriot or Israeli waters and only two wells drilled offshore Egypt. However, Egypt, Cyprus and Israel all launched licensing rounds, with considerable excitement around the new carbonate reef play proven by the discovery of Zohr (850 Bcm or 30 Tcf).

The proximity of blocks 10 and 11 to Zohr and the identification of "Zohr-like" structures/prospects on these blocks raise the distinct possibility that further large volumes of gas could be discovered.

If more gas materializes offshore Cyprus, Eastern Mediterranean puzzle pieces will rearrange themselves, changing the dynamics again. Upstream players will have to take stock of their position and maneuver accordingly, opening up new possibilities for monetization. For example, onshore Cyprus LNG, which was shelved in 2014, could be revisited.

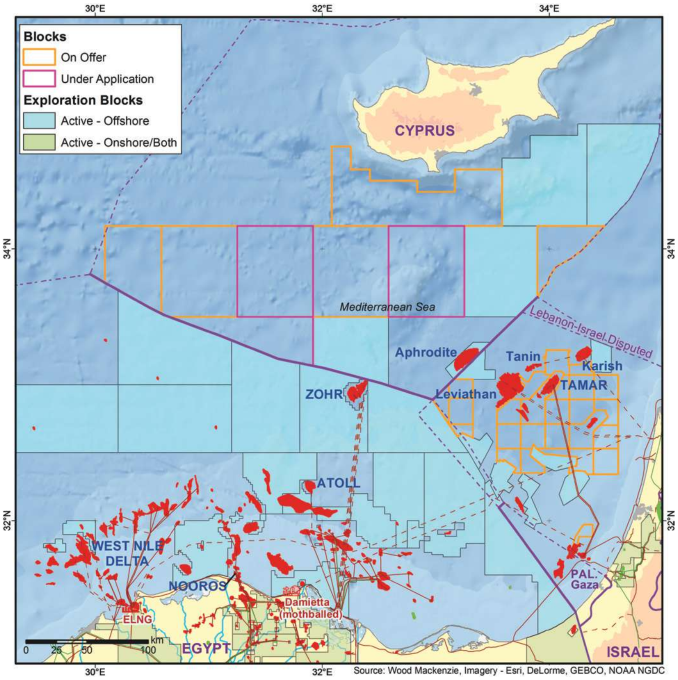
Israel, meanwhile, will be following what happens in Cyprus with great care. If significant additional volumes of Cypriot gas are found, it would take a favorable position in front of Leviathan or Tamar expansion gas. Shell's interest in both Egyptian LNG at Idku and Aphrodite in Cyprus has a negative impact on Idku as a destination for Israeli gas, especially if more gas is found (and developed through Aphrodite) and allowing Cypriot gas to realize Idku capacity. The Israeli licensing round that was launched in November 2016 will likely attract limited interest due to demand in Israel for gas and the lack of export solutions.

Complicating possible offtake routes for Israel is the soon-to-be announced Lebanese licensing round. The round has been on hold since its original announcement in 2013 due to a political stalemate in the Lebanese parliament. The recent passing of two key pieces of legislation has allowed the round to move forward. The Lebanese government estimates reserves of 2.7 Tcm (96 Tcf) of gas and 865 MMbbl of oil could be contained within the 45% of acreage covered by interpreted seismic data.

Offshore Lebanon is thought to be prospective and is likely to attract upstream companies that stayed away from Israeli blocks due to their interests in other Middle Eastern/Gulf countries.

However, the Egyptian export options that exist for Israel, Cyprus and possibly Lebanon could be put under pressure if Egyptian exploration success continues. EGPC awarded six blocks in 2016, and EGAS plans a new offshore round for next year. All in all, there is a lot of exploration acreage to go after, and those blocks near Zohr will be closely watched.

On top of this, there is already quite a bit of gas discovered in the Nile Delta waiting to be developed as well as several high-profile onshore wells due to be drilled this year with high pre-drill estimates.



The continued promise of Mediterranean oil and gas might outstrip available markets and/or pipeline route feasibility. (Source: Wood Mackenzie)

Pragmatic pricing

The final piece on the Eastern Mediterranean chess board is that of price. The willingness and ability to demonstrate pragmatism on pricing will be important for both governments and operators. An example of this can be seen on the Egyptian side, where the government has been quite pragmatic over the last couple of years, contributing to FID on big projects such as West Nile Delta, Noroos, Atholl and Zohr. These projects cumulatively will add an impressive 113 Mcm/d (4 Bcf/d) of production by 2022 and have, in part, been made possible by operators managing to negotiate higher prices with EGAS, of up to $5.88/MMBtu.

On the operator side, Energean Oil & Gas in Israel has identified price as a key lever for access to market. In Israel's saturated domestic gas market, the much larger Leviathan project is seen to have locked up nearly all of the contestable demand available. However, the Karish and Tanin project (57 Bcm or 2 Tcf), which Energean operates, is attempting to compete with Leviathan by offering a quicker development option (FPSO unit) and a lower price. Price openers in 2019 for existing contracts with Tamar might tempt customers to go with cheaper gas. The fact that Leviathan might not compete in those price openers might give Karish and Tanin the edge in securing that contestable demand. E&P

1 Gulf of Mexico

According to IHS Markit, Cobalt International Energy hit 198 m (650 ft) of net oil pay at its North Platte development on Garden Banks Block 959. The total depth was not disclosed, but the appraisal test was expected to reach 10,455.5 m (34,303 ft). Area water depth is 1,493.5 m (4,900 ft). A previously drilled appraisal, #3 (ST) OCS G30876, encountered 152 m (500 ft) of net oil pay.

2 Guyana

ExxonMobil Corp. announced a second oil discovery, #1-Payara, in the offshore Guyana Stabroek Block. The venture targeted similar aged reservoirs found at #1-Liza, which was discovered in 2015. The well encountered more than 29 m (95 ft) of high-quality oil-bearing sandstone reservoirs. It was drilled to 5,511 m (18,080 ft) and is in 2,030 m (6,660 ft) of water. Two sidetracks have been drilled, and additional testing and evaluation is underway.

3 UK

Cuadrilla Resources Ltd. is preparing to drill at a shale gas site in Lancashire, U.K. The company's well, #1-Preston New Road, will be in PEDL 165 and will target the Bowland Shale. The vertical venture has a planned depth of 3,500 m (11,483 ft) and will be logged. Afterward, the depth and orientation of other horizontal wells will be determined. Up to four exploration wells could be drilled at the site, and laterals could extend to 2,000 m (6,562 ft).

4 UK

A new North Sea gas field discovery in Cleveland Basin Block 41/24 named Maxwell was announced by Arenite Petroleum Ltd. The new field is in offshore England's Yorkshire coast at Scarborough. In the 1970s Total drilled and completed five wells in the field that produced about 424,753 cu. m/d (15 MMcf/d) of gas. Arenite is planning to drill a proof-of-concept horizontal well into the Permian carbonates with two major target horizons identified and to deepen this well to test the underlying Carboniferous strata.

5 Norway

Det Norske Oljeselskap ASA completed wildcat well #25/2-18 S and appraisal wells #25/2-18 A and #25/2-18 C in production license PL 442 in the Norwegian North Sea. The objective of #25/2-18 S was to prove petroleum in Middle Jurassic Hugin and Sleipner. It encountered a 30-m (98-ft) column and an 86-m (282-ft) column, both with moderate-to-good reservoir quality. Appraisal well #25/2-18 A was drilled 1 km (.62 mile) northeast of #25/2-18 S and hit a 27-m (88.5-ft) and a 34-m (111.5-ft) oil column in Hugin, both with moderate-to-good reservoir quality. Appraisal well #25/2-18 C, which was drilled 1 km west of #25/2-18 S, encountered a 27-m column, a 23-m (75-ft) column and a 55-m (180-ft) oil column in Hugin, all with moderate-to-good reservoir quality. A 7-m (23-ft) condensate column also was encountered, of which 3 m (10 ft) in sandstones was of moderate reservoir quality. At #25/2-18 A, a drillstem test flowed 600 cu. m/d (21 Mcf/d) of oil during testing on a $^{40}/_{64}$-in. choke in the lowermost oil zone. The production rate in the uppermost oil zone was 210 cu. m/d (7.4 Mcf/d) of oil per flow day through a $^{24}/_{64}$-in. choke. All of the wells were terminated in the Dunlin Group in the Lower Jurassic, and area water depth is 121 m (397 ft).

6 Italy

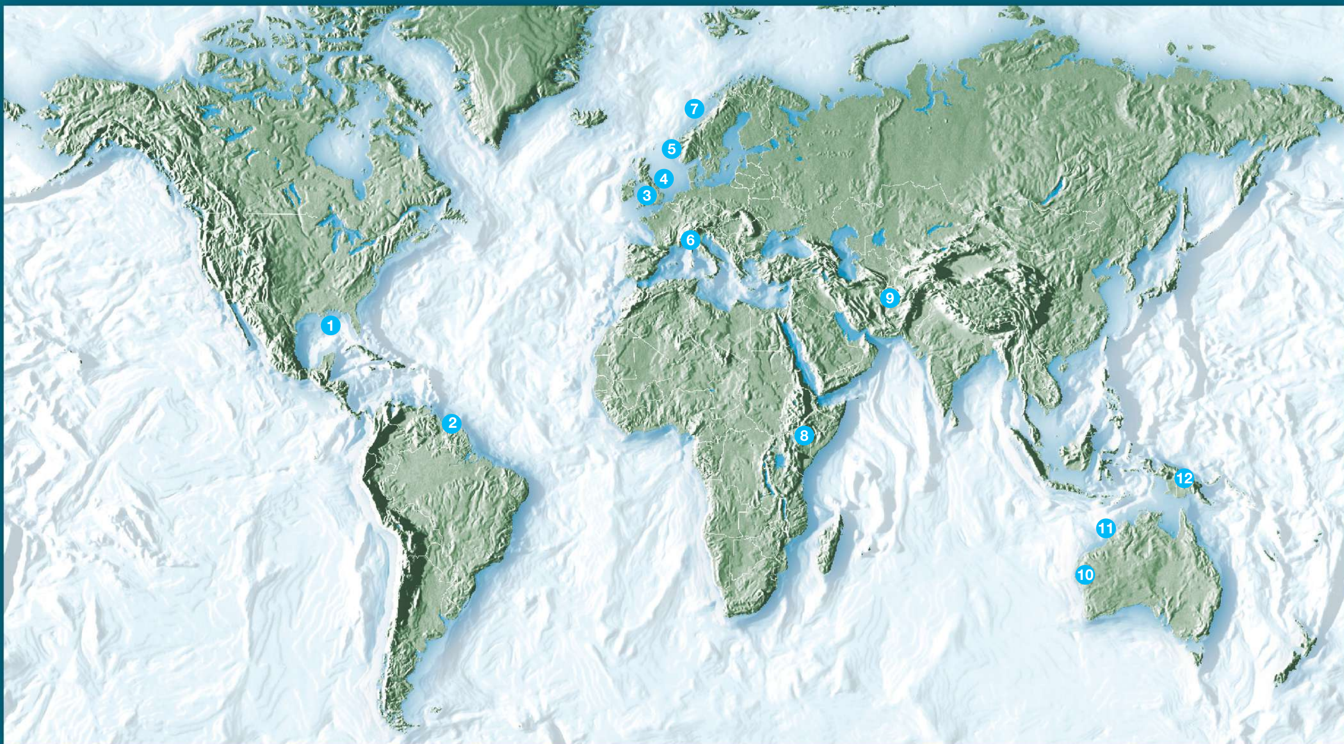
A rig is ready to drill a Sound Energy Plc exploration well at #1-Badile in northern Italy's Po Valley Badile Block. The well has a planned depth of 4,600 m (15,092 ft), and it will test the hydrocarbon potential of Lower Jurassic Conchodon Dolomite. An independent study indicates an unrisked best-case estimate of 5 Bcm (178 Bcfe), an upside high case in excess of 18.9 Bcm (670 Bcfe) and low case of 1.3 Bcm (46 Bcfe).

7 Norway

Statoil announced an oil and gas discovery that is estimated to have between 20 MMboe and 80 MMboe. The Cape Vulture exploration well, #6608/10-1, is in License 12. Statoil plans to analyze the area to identify new exploration targets and also plans appraisal drilling. The discovery is northwest of Norne, and a tieback of the discovery to the FPSO unit at the Norne Field will be considered.

8 Kenya

Tullow Oil Plc announced results from #1-Erut in Kenya's Block 13T. The company hit a gross oil interval of 55 m (180 ft) with 25 m (82 ft) of net oil pay at a depth of 700 m (2,296.5 ft). The overall oil column for the field is considered to be 100 m to 125 m (328 ft to 410 ft). The objective of the well was to test a structural trap at the northern limit of the South Lokichar Basin. Fluid samples taken and wireline logging all indicate the presence of recoverable oil. According to Tullow, oil has migrated to the northern limit of the South Lokichar Basin and has allowed the company to de-risk multiple prospects in this area. The well was drilled to 1,317 m (4,321 ft), and the rig is being moved to spud appraisal well #6-Amosing in the southern part of Block 10BB.



9 Pakistan

A gas discovery was completed by Jura Energy Corp. in the Zarghun South Development and Production Lease in Pakistan. The development well, #3-ZS, flowed 297,327 cu. m/d (10.5 MMcf/d) with production from Dunghan Limestone (Paleocene). The well was drilled to 1,820 m (5,971 ft). It was tested on a $^{32}/_{64}$-in. choke with a wellhead pressure of 1,800 psi. According to the company, the gas is 920 Btu/scf, and it will be tied in to nearby gas processing facilities.

10 Australia

A gas and condensate discovery was announced by Empire Oil & Gas NL from the #1-Red Gully North well in Western Australia's Perth Basin. The Perth Basin Block EP389 venture was tested flowing 419 bbl/d of condensate, 35,962 cu. m/d (1.27 MMcf/d) of gas and 684 bbl/d of water during an eight-hour test of C Sand, with 24-hr testing planned soon. Testing was suspended so that additional surface facilities could be secured. Empire also planned to test Upper D Sand, but testing indicated a low-permeability reservoir, and no hydrocarbons flowed to the surface. Additional testing is planned to determine if both formations will produce in commercial quantities.

11 Australia

Quadrant Energy Pty Ltd. announced results from the offshore Western Australia venture #2-Phoenix South in the WA-435-P permit area on the North West Shelf. The well hit an estimated 39-m (128-ft) hydrocarbon-bearing zone between 5,176 m and 5,215 m (16,982 ft and 17,110 ft). A significant gas influx was reported with elevated reservoir pore pressures. Due to high pressure from the Caley reservoir below 5,215 m, the company was unable to assess as much as 185 m (607 ft) of potential. Additional testing is planned.

12 Papua New Guinea

Operator Oil Search Ltd. announced a new gas field discovery in Papua New Guinea's northern Highlands about 21 km (13 miles) northwest of Hides Field. The #1-Muruk exploration well was drilled in PPL 402, and it encountered high-quality sandstone reservoirs similar to those found in Hides Field. The well was drilled to 3,130 m (10,269 ft). Additional drilling and testing is planned by the company. E&P

PEOPLE

LaMarr Barnes was named CEO of U.S. Water Services.

OPITO reported the death of its CEO **David Doig**. Doig, 57, suffered a heart attack Dec. 31, 2016, and later passed away in a hospital.

Houston Technology Center elected **Lori Vetters** to succeed **Walter Ulrich**, who retired Feb. 1, as president and CEO. Vetters joined as president/CEO-elect to begin the transition.

Charles J. Reith Jr. assumed the role of CEO of Solomon upon the retirement of former president and CEO **Dale A. Emanuel**.

Tullow Oil Plc announced changes to its board: **Paul McDade** will be appointed CEO; **Simon Thompson** will step down from the board; **Aidan Heavey** will succeed Thompson as chairman of the group; **Ann Grant**, senior independent director, will retire; and **Jeremy Wilson** will succeed Grant as senior independent director. Also, CFO **Ian Springett** took an extended leave of absence to undergo treatment for a medical condition, and **Les Wood** was appointed interim CFO.

Approach Resources Inc.'s **Qingming Yang** has been promoted to president.

Global Maritime Consultancy & Engineering appointed **Reid Berger Stokke** to head its new line of business, GM Solutions.

Science Group Plc appointed **Dan Edwards** president of the group's North American operations. **Chris Covey** was promoted to head up the group's Boston office as vice president, East Coast, and **Henry St Aubyn** was selected to head up the Houston office. **Mark Tuckwell** and **David Pettigrew**, vice presidents, were appointed to launch the group's new Californian operation.

Carl Neuhaus is returning to MicroSeismic as vice president of engineering. **William B. Barker** has been appointed to vice president of analysis, and **Eric Bourdages** has been appointed to vice president of operations.

Expro named **Bill Inglis** senior project manager.

Danos promoted **Jeremy Adkins** to Permian area manager for the company's operations in the West Texas region.

ENODO Global selected **Joseph Gochal** as its chief data scientist.

Jean Gould has joined PESA as senior director of public policy.

Rodger & Hartnolls named **Nick Search** partner and managing director.

Tina Campbell has been named marketing coordinator by Asset Guardian Solutions Ltd.

International energy logistics provider Peterson appointed **Sarah Forbes** director of projects and innovation.

Dimitrios Parikos joined Alliant as first vice president within its Energy and Marine Group.

Beverley Smith, former vice president of Exploration and Growth for BG Group, has been appointed director of POWERful Women, an initiative that exists to advance the leadership and development of women across the U.K.'s energy sector.

The Gazprom board of directors reelected **Vitaly Markelov**, **Vladimir Markov**, **Elena Mikhailova** and **Igor Fyodorov** as members of the Gazprom Management Committee.

Seadrill Ltd. selected **Michael Grant** and **David Weinstein** as directors of the company.

Cairn appointed **Nicoletta Giadrossi** an independent nonexecutive director.

Chevron Corp.'s **Michael K. Wirth**, executive vice president of Midstream and Development, was named vice chairman.

J. Mike Stice has been elected to Marathon Petroleum Corp.'s board of directors.

COMPANIES

Global Tubing LLC's Northeast Service Center moved to a purpose-built five-acre facility in Smock, Pa. The upgraded center is located near the Marcellus and Utica plays.

Petroplan has expanded its presence in the Sultanate in Oman, working with international operators and service companies to help fill specialist roles while working within Oman's strict workforce nationalization rules.

The Waste Isolation Pilot Plant (WIPP) has reopened and resumed waste operations. WIPP is the nation's first deep-geological facility in the U.S. for disposal of

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Science Group Plc opened an additional U.S. office in the San Francisco Bay area.

Noble Energy Inc. acquired **Clayton Williams Energy Inc.** for $3.2 billion of equity, cash and debt.

GEODynamics acquired **Paradigm GeoKey's** Aberdeen, Scotland-based perforating business unit.

Targa Resources Corp. has executed definitive agreements for its subsidiary, Targa Resources Partners LP, to acquire 100% of the membership interests of **Outrigger Delaware Operating LLC**, **Outrigger Southern Delaware Operating LLC** and **Outrigger Midland Operating LLC**. Targa will pay initial cash consideration of $565 million for the membership interests.

Shearwater GeoServices AS is a newly formed, jointly owned marine geophysical company between **GC Rieber Shipping** and **RASMUSSEN-GRUPPEN**. Formation of the new company and the transaction were completed in January.

Halcón Resources Corp. has engineered deals to purchase nearly 21,000 net Southern Delaware Basin acres while exiting its El Halcón position in the East Texas Eagle Ford. Halcón also optioned the purchase of an additional 15,040 net acres in Ward and Winkler counties, Texas.

Anadarko Petroleum Corp. has agreed to sell its Eagle Ford Shale assets in South Texas for about $2.3 billion to **Sanchez Energy Corp.** and **Blackstone Group LP**.

Halliburton announced in January a technology cooperation agreement with **Petrobras** that will advance collaboration in a diverse set of projects targeting complex reservoirs.

Petrobras finalized the sale of 100% of Petrobras Chile Distribuición Ltda to the **Southern Cross Group** Jan. 4.

Acteon has enhanced its capabilities in the provision of temporary and permanent mooring systems by acquiring **Bruce Anchor**. E&P

ADVERTISER INDEX

Not invented here

There are dangers to being skeptical to new technology.

Jim Summers, Yesss Oil

One day my father drove home his brand new 1973 Ford Thunderbird. Neighbors gathered in the driveway to admire it, and one, an engineer in the atomic energy industry, noticed the tires were low on air pressure. My father proudly told him that they were fine and how it was fitted with the latest "radial" Michelins. The nuclear engineer went on to explain how those tires would wear quickly, have poor steering and certainly would have a higher rolling resistance, which would reduce gas mileage. Today it is well-known that radial tires are better in every way. All passenger cars are fitted with them due to their longer tread life, better steering characteristics and lower rolling resistance.

When introducing the latest in upstream oilfield technology, I'm more often than not met with the same resistance that our neighbor had with those Michelins. Most people that have been in the oil patch for 20-plus years are pessimists with respect to new technology. Is it because they have tried so many things that have not yielded the results promised, or rather is it a lack of understanding of the technology? Or is it because the technology was not invented here?

Yesss Oil Managing Director Adam Mackie snapped this photo with his iPhone while on a tour of "heavy" oil leases west of Bakersfield, Calif., last winter. (Source: Yesss Oil)

Companies should not let the "not invented here" syndrome keep them from discovering a new technology that will help them attain their goals.

I came across this phenomenon in the early 1990s while working with pump-off controllers. Lease supervisors were questioning why someone would want to shut off a beam pump. They didn't believe they could make more revenues without the walking beam, well, walking.

Like the radial tires, pump-off controllers are standard equipment today for numerous leases.

In relation to Yesss Oil's EOR technology, there are those that tried products of similar design or theory base in the mid-'80s with no increase in oil production. When Yesss Oil studied the 30-plus-year-old technology, the company found that the design was of much lower power output and in no way could elevate near-wellbore temperatures to provide magnitude production increases. The companies behind those early designs were well-known for their great engineering feats. It is just that $10/bbl oil wasn't economically valuable enough to warrant high power solutions.

Others say the production data are flawed or they simply can't understand how the technology could work. Many are nervous of the life span or durability. More often than not, the company's offering is dismissed as ineffective. Others respond with, "If your technology worked, it would be everywhere."

Yesss Oil's current solution is not a panacea for every well or crude composition. Like radial tires, it has its fit and will become more mainstream as more upstream veterans understand it, see published data and come up with the idea of deploying it on their own.

Companies should not let the "not invented here" syndrome keep them from discovering a new technology that will help them attain their goals. E&P