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DEPARTMENTS AND COMMENTARY

COMING NEXT MONTH The May issue of ***E&P*** will focus on offshore. Other features will cover frontier exploration, pressure control equipment, offshore completions, flow assurance, and spill response and containment. The unconventional report will focus on the Bakken. 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 Baker Hughes, a GE company, provides field service engineers Smart Helmets, which enable engineers in the field to communicate with staff located at a headquarters facility who can guide the engineers through complex tasks by audio and video. Left, an ROV glides under the protective cage in preparation to manipulate the controls on a subsea tree. *(Cover photo courtesy of Baker Hughes, a GE company; Left photo courtesy of PixOne,* Shutterstock.com*); Cover design by Felicia Hammons)*

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Alliance Energy approved for Guitar Unit on North Slope

IHS Markit reported that Alliance Energy Inc. has received approval from the Alaska Division of Oil & Gas for a new unit on the North Slope, the Guitar Unit, which is approximately 7,573 acres and about 29 km (18 miles) west-northwest of Deadhorse, Alaska.

Stack play-Meramec well produces 1.17 Mbbl/d of oil

A Stack play-Meramec well by Marathon Oil Corp. produced 1.17 Mbbl/d of 49-degree-gravity oil, 69.3 Mcm/d (2.45 MMcf/d) of gas and 1.641 Mbbl/d of water. Marathon's #1-3-34MXH H.R. Potter 1511 well is in Blaine County, Okla.

West Gharib Concession hits 31-m oil pay zone

An oil discovery was reported by SDX Energy Inc. at the #2-Rabul well in the West Gharib Concession in Egypt. The well hit approximately 31 m (102 ft) of net heavy oil pay in Yusr and Bakr sands, with an average porosity of 20%.

AVAILABLE ONLY ONLINE

Oil, gas sector moves toward new subsea reality

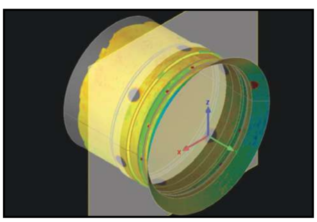
By Elaine Maslin, Contributing Editor

Norwegian subsea technology firms are pushing ahead with technologies to enable a new wave of seafloor field development.

CERAWeek: Rick Perry says innovation, not regulation, is 'new energy realism'

By Len Vermillion, Group Managing Editor, Digital News Group

The U.S. Energy Secretary touted 'an incredible energy revolution that is driven by a cascade of technology innovation' during his keynote address at CERAWeek by IHS Markit.



Lasers provide option to lower subsea metrology measurement costs

By Mark Venables, Contributing Editor

Laser scanning is one technique gathering momentum across the industry.

Ex-CIA cyber risk expert: It's all about people

By Joseph Markman, Senior Editor, Digital News Group

Now in the private sector, John Bass advises corporations on how to manage cybersecurity threats from without and within.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Transformation brings capital discipline

A change in mindset signals significant growth by the oil and gas industry.

At the various industry events that I have attended these past few years, the "cool kids" on the playground have been collaboration, innovation and standardization. One did not need to go far into an event's agenda to see one of the three or the whole trio featured in keynotes, roundtables and technical presentations. It appears that their message was, in large part due to the market downturn, received. I'm hearing more this year about a new kid in Oiltown—transformation—and it looks like it is here stay.

"The transformative change going across our industry started a couple of years ago, and it's accelerating at a pace like I have never seen in my whole career," Liam Mallon, president of Exxon Mobil Development Co., shared with attendees at this year's IADC/SPE Drilling Conference and Exhibition held in Fort Worth, Texas. With 35 years of experience working in all corners of the globe, Mallon noted that despite all of the challenges the industry has faced in recent times, it is still an exciting time to be in the oil and gas business.

Driving the transformation is the shale revolution, he said, adding that "in one hand, it is delivering the supplies that we need to meet the world's energy needs, but at the same time, it likely caused the coining of the lower-for-longer phrase."

A change in the industry mindset came about while adapting to that lower-for-longer environment.

"Doing more with less is so significant," he said. "For example, there is more activity as the rig count is 30% higher now than it was a year ago. Also, there were 11 non-U.S. FIDs [final investment decisions] made in 2016. There were 33 in 2017, so there's been a threefold increase in FIDs outside of the unconventional in the U.S."

While that increases set spending to go from about $70 billion to about $90 billion, Mallon noted, the staggering bit is that "we have not seen a threefold increase in spending, and that's because of how the industry is transforming the way it works."

He believes the industry's journey is still in its early days, but he has no doubt that the tremendous shift in thinking has led people to not spend money on noneconomic projects, as "the discipline around capital is like we've never seen before," he said.

Time will tell if the industry can maintain that discipline and the lower-for-longer mindset that have driven innovation to find new and improved ways to discover and recover the needed resources for future generations. E&P

Jennifer

Program brings safety-critical digital solutions to market

Digital technology will transform the pace of change within the safety and risk sector.

Dr. Maurizio Pilu, Lloyd's Register

Rapid developments in technology, the digital economy and the convergence of physical and cyber are transforming the way humans live and work and are creating enormous opportunities and challenges for society and business.

Lloyd's Register (LR) works to understand the transformative impact the Internet of Things (IoT), data analytics, remote sensing and disruptive technologies are having on business and the way people work. Through the company's existing software, services and digital innovation strategic focus areas, which include masters of risk, connected assets and super surveyor, LR delivers business efficiency and increased performance without compromising safety.

The company's Virtual Reality (VR) Safety Simulator, released in May 2017, is designed to help support training and knowledge transfer in the energy industry. Through the application of the latest VR technology advancements, which include augmented reality add-on modules, LR has built a virtual environment to help illustrate the need for a continued focus on safety and risk assessments in the industry.

LR's VR Safety Simulator utilizes the latest high-powered computing to simulate real-life situations with a high degree of interactivity for the user. (Source: Lloyd's Register)

Society has witnessed the transformative nature that digital technology has accomplished. Digital innovation has permeated sectors such as retail, finance and consumer technologies, but its full potential in deep industrial sectors has yet to be realized. Although the safety and risk market is significant, it is still relatively untapped by digital technology companies.

There are huge opportunities for the oil and gas industry to innovate new technologies to enhance safety in its operations. So why has adoption in the industry been relatively slow?

Digital technologies, from the early computers of the 1950s to the internet-equipped smartphones of the 21st century, have fundamentally changed the way industries function and have opened the way to trillion-dollar industries such as internet infrastructure, enterprise software, mobiles, online retail, gaming and apps—resulting in the world exploding into the Digital Revolution.

These technologies have emerged incrementally and to varying degrees and speeds across industrial sectors, growing hand in hand with increased levels of IT and automation. It is only recently that industry executives and analysts have begun talking about another revolution in which digitalization is taking over the industry, which has been dubbed the fourth Industrial Revolution, or Industry 4.0.

What makes Industry 4.0 different is the prospect of a new level of digital interconnectedness and integration between firms, supply chains, production, products, customer and end-use applications. This offers the prospect of generating the same dynamics the industry has seen in the evolution of the internet, which is why phrases such as "Industrial Internet" or "IoT" are often used to describe this new wave of transformation.

Several transformational digital technologies are contributing to realize possibilities in the industry, such as cheap sensing and pervasive wireless connectivity; the ability to capture, store and perform sophisticated analytics of vast quantities of data; the internet and cloud; robotics and autonomy; blockchain; and additive manufacturing.

Adoption of new technology is rarely driven by curiosity. For many organizations the imperatives are to keep increasing efficiency and revenues, and suppliers and customers expect a company to have digital interfaces implemented into their operations. However, digital technologies also have the capability to fundamentally reduce risk and improve safety.

In this rapidly changing landscape, and faced with these imperatives, companies in industrial sectors need to relearn how to innovate faster and better. While R&D still needs as strong a role as ever, market-facing innovation in the digital era requires companies to adopt an agile innovation culture driven by pilots, rapid iterations driven by customer feedback loops and an open innovation, collaborative mindset to partner with best-in-class technology providers.

Knocking down barriers

However, adoption of cutting-edge digital technologies to reduce risk and improve safety in industries is a long journey with many barriers. Regulatory, financial and cultural barriers cannot easily be overcome at the initial uncertain, but essential, stages of piloting and evaluating new technology. As a result, technology companies themselves are struggling to refine their products, gain visibility of the market potential and find a route to market—creating a vicious circle.

LR's Safety Accelerator, funded by U.K. charity Lloyd's Register Foundation, is a new initiative designed to help remove the key barriers preventing industry uptake of cutting-edge safety and risk technologies and solutions as well as create a "safety tech" market for technology providers.

The program will work with key industry players to identify areas of operation with the most significant challenges to safety and risk that can be addressed with cutting-edge data and digital solutions, including those that have been validated in other sectors. Small technology businesses seeking an application for emerging or existing digital solutions will be invited to apply for funding to trial these products in an industrial environment through the accelerator collaborators.

By providing the opportunity for industry partners and small innovative businesses to de-risk their initial engagement in the evaluation of the technologies, the Safety Accelerator will address issues acting as a barrier to improved industrial operation. Industry partners engaging with the Safety Accelerator also will get the opportunity to engage with a global community of cutting-edge small innovative firms and startups, specifically selected as having the potential to address their key safety challenges.

At the same time, the Safety Accelerator will support small innovative businesses through offering the ability to trial solutions in the real world with a leading industry player. The program will also fund the trial, industry-specific specialist support and training (e.g., regulator, data and systems) from LR and its clients, and entrepreneur development (e.g., marketing, IP, minimum viable product, business case and investor pitching). The program provides opportunities for all types of digital technology solutions, especially those that support data-driven innovation.

The Lloyd's Register Foundation brings a deep understanding of safety and risks and global industry challenges. The Foundation aims to constantly research safety and risk issues and will provide input for challenges or themes for the Safety Accelerator program in the form of published research, such as an insight report on global safety challenges. "Human safety onboard" has been selected as the first safety challenge theme for the program, and applications addressing this challenge area are scheduled to open this summer. E&P

The Safety Simulator is designed to help support training and knowledge transfer in the energy industry. (Source: Lloyd's Register)

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

Unconventionals lead American oil resurgence

ConocoPhillips adds Alaskan acreage while seeing global production growth.

Brian Walzel, Associate Editor, Production Technologies

In a presentation in late January in downtown Houston, ConocoPhillips CTO Gregory Leveille offered a bit of a history lesson on the perception of North America as an oil producer.

Leveille explained how since the dawn of oil and gas production in America in 1859 and throughout the next century or so, oil production experienced a steady, continuous growth, peaking in 1970 with more than 10 MMbbl/d having been produced. During the next third of a century, Leveille said American oil production began a steady decline, despite operators venturing into large offshore fields and Alaska.

"Nobody expected oil production in America to ever rise again," he said.

Leveille said the U.S. government at the time began to insulate the country from falling oil prices by, for instance, turning to biofuels. But he said the world turned out very different.

"We are now producing again about what we were producing in 1970," Leveille said. "And that surge in production is coming from the unconventional reservoirs in the Eagle Ford, the Bakken and the Permian Basin, and a few other areas."

In its Short-term Energy Outlook released in March, the U.S. Energy Information Administration predicted average oil production in America will surpass 10.6 MMbbl/d by the end of the year, bypassing the mark set in 1970.

"There's been an incredible change in a relatively short period of time," Leveille said.

The primary driver behind the exponential increase in production has been the development of unconventional reservoirs—but even more specifically, advances in completions designs, he said.

"What you're seeing is the industry moving away from 3,000-ft [914-m], 4,000-ft [1,219-m] and 5,000-ft-long [1,524-m-long] laterals to laterals that are 7,500 ft [2,286 m] and 10,000 ft long [3,048 m]," he said. "There are people testing out 16,000 ft [4,877 m]. And these wells become more and more profitable as you do that, so if you put a 16,000-ft lateral it's getting almost three times as much production as a well that's 5,000 ft."

In addition to longer laterals, Leveille said production increases in unconventional reservoirs also are attributed to multilateral and stacked play completion designs. In the Eagle Ford, for example, ConocoPhillips has evolved from completing two wells in the Lower Eagle Ford in 2012 to a stacked design with up to 10 wells in the Austin Chalk, Upper Eagle Ford and Lower Eagle Ford in 2017.

According to Leveille, six years ago it was common for wells to have about 70 fracture clusters in a completion design while today's completions often feature more than 300 clusters, all of which have led to higher recovery per acre and higher well production across the country.

"Today, America produces around 25 million barrels of oil equivalent, or about one out of every six barrels of oil equivalent produced on the planet," he said. "We're ahead of Russia and ahead of Saudi Arabia. There are three countries

ConocoPhillips has optimized its completions in the Eagle Ford Shale by implementing multilateral and stacked well designs. (Source: ConocoPhillips)

that produce between 5 million and 10 million barrels of oil equivalent per day, and then every other country on the planet produces less than 5 million barrels of oil equivalent per day."

Without unconventionals the U.S. would be producing about half of what it is today and countries like Russia would be way ahead in terms of production, Leveille said.

"The work that has been done by our industry has changed the fate of America," he said. "Many people thought America was about to fade away in the 21st century. You hear talk about how America's century was the 20th century. The 21st century will be China's or somebody else's. What our industry is doing is creating the possibility of America being a superpower for a much, much longer time to come."

Worldwide production

While ConocoPhillips, along with a multitude of other producers, has found enormous success in North American unconventional production, the company has continued to weather the storm of the industry downturn while securing its place for the future.

During its year-end 2017 investor report, the company announced a $5.5 billion capital plan for the year, not including a recent $400 million bolt-on acquisition in Alaska. Its full-year 2018 production is expected to be 1,195 MMboe/d to 1,235 MMboe/d.

In February the company announced the transaction of the acreage in the Western North Slope of Alaska, acquiring Anadarko Petroleum Corp.'s 22% nonoperating interest as well as its interest in the Alpine Pipeline. According to ConocoPhillips, the gross production from these assets was 63 Mboe/d. ConocoPhillips now has a 100% interest in about 1.2 million acres of exploration and development lands in Alaska, including the Willow discovery.

The company's 2017 production in Alaska was 167 Mboe/d. At Kurparuk ConocoPhillips has implemented a managed pressure drilling (MPD) program that has resulted in a more than 40% increase in lateral lengths, with lengths reaching more than 8,543 m (28,028 ft),

ConocoPhillips has applied to decommission four of its Ekofisk platforms in the North Sea. (Source: ConocoPhillips)

a record for a conventional horizontal well in Alaska, according to the company. Two recent Kurparuk wells drilled with MPD recorded IPs of more than 10 Mbbl/d, a record for highest IP in the state, according to the Alaska Oil and Gas Conservation Commission.

In 2017 ConocoPhillips initiated the process of decommissioning four aging platforms at its Ekofisk Field. The company applied to the country's regulatory agency to begin decommissioning its Ekofisk 2/4A, 2/4H, 2/4FTP and 2/4Q platforms. Ekofisk was the first oil field to begin producing in Norway and has been producing since 1971. The four platforms up for decommissioning ceased production in 2013.

ConocoPhillips was awarded six production licenses in 2016 for the Norwegian Continental Shelf, three of which as an operator. Much of the infrastructure existing in the North Sea could lead to more efficient operations in the Ekofisk, Judy and Britannia fields as well as Tor II and Eldfisk North, the company reported in a 2018 investor presentation.

Between 2014 and 2016, ConocoPhillips' cost per well in Norway decreased by 40%, but its net liquids production decreased in Europe by 4% during that period, from 134 Mbbl/d in 2014 to 127 Mbbl/d in 2016, according to ConocoPhillips and Barclays. The company's total increased in 2017 to 134 Mboe/d. ConocoPhillips also saw production growth in Libya increasing from 2 Mboe/d in 2016 to 21 Mboe/d in 2017 and in Europe and North Africa increasing from 205 Mboe/d in 2016 to 230 Mboe/d in 2017.

In its fourth-quarter 2017 earnings report, ConocoPhillips predicted production growth for Asia-Pacific and the Middle East, Europe and Alaska for the second and third quarters of the year. Aiding in that expected turnaround will be first production from Bohai Phase 3 in China, Claire Ridge in the U.K., Aasta Hansteen in the North Sea and GMT-1 on Alaska's North Slope.

According to its 2018 analyst presentation, ConocoPhillips expects to add 90 Mboe/d in total production through 2025 from conventional, LNG and oil sands production from fields in Australia, Alaska, Asia-Pacific and the Middle East, and Europe. Expected increases could come from GMT-2, Fiord West and NEWS on Alaska's North Slope; Ekofisk 2/4V-D, Eldfisk North and Clair South in the North Sea; Bohai Phase 4 in China; and the Barossa LNG field in Australia. E&P

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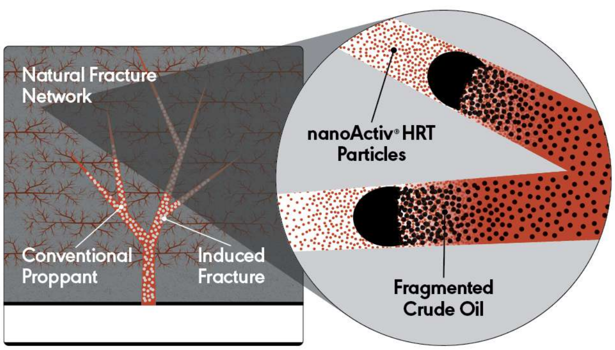

"Diffusion is the way they get there, disjoining pressure is what they do when they get there, and fragmentation is what allows the oil to more easily move back to the wellbore."

— David L. Holcomb, Ph.D.
President—Pentagon Technical Services, Inc.

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The return to Jurassic Park

New completion techniques are lowering the cost per unit of gas production and spreading across the Haynesville—and to basins beyond.

Richard Mason, Chief Technical Director

Remember the Haynesville? A decade ago, publicity about the nascent Ark-La-Tex play put the exclamation point on unconventional shales as a viable oil and gas target and not just a one-off North Texas anomaly.

The Haynesville was the first shale play where $25,000/acre leases became the new normal. Billion-dollar joint ventures financed the developmental scramble, and the parallel land rush became an analog for how E&P companies positioned themselves in subsequent tight formation plays.

The Haynesville faded with the collapse in natural gas prices in 2011—a precursor to the general industry collapse in 2014.

Coming off the bottom, Haynesville activity led all regions in the percentage gain. Rig count more than tripled to 49 units. While multiple factors influenced the regional renaissance, much centered on big-boy enhanced completion techniques. "Propageddon," the use of 5,000 lb of proppant per lateral foot on longer laterals of 3,048 m (10,000 ft) and closer stages of sub-52 m (sub-170 ft), debuted in August 2016 and brought about the reassessment of Haynesville prospects.

- **Longer laterals and "propageddon" are the new normal.**
- **E&P companies are extending the tight formation completion recipe to complex regional conventional plays.**

The completion recipe was an adaptation to a lower commodity price environment that used increased downhole intensity to lower the cost of hydrocarbon production per unit. The recipe was exported to Appalachia and the Eagle Ford in 2017, adding new zest to both plays.

Picture the Ark-La-Tex renaissance as the return to Jurassic-aged Park (with a side of Cretaceous). E&P companies are expanding Tier I acreage in the Haynesville and Bossier tight plays. Others, such as PetroQuest Energy Inc. and Range Resources Inc., are applying horizontal drilling and multistage fracturing to the conventional Cotton Valley and Terryville formations. Finally, intriguing developments surround a reviving Austin Chalk play in South Central Louisiana as E&P companies extend multistage fracturing to a traditional naturally fractured carbonate reservoir.

What have we learned?

The law of diminishing returns applies. Although 5,000 lb of proppant per lateral foot works, the sweet spot is likely between 2,500 lb and 3,500 lb. For perspective on propageddon, consider that the light sand slickwater fracture that characterized multiformational development pre-2012 was perfected in the nearby Cotton Valley more than 25 years ago.

While lateral placement is the primary factor driving improved recovery in most basins, lateral length trumps all in the geomechanically homogenous Haynesville.

Choke management was not invented in the Haynesville, but its implementation by Petrohawk in 2009 has become standard industry practice in improved reservoir recovery. BP cites 198 MMcm (7 Bcf) in cumulative recovery over 14 months on a new Shelby Trough well incorporating choke management versus 254.8 MMcm (9 Bcf) cumulative over half a decade in a neighboring well.

Elsewhere, BP is running four rigs on dual well pads codeveloping overpressured high-temperature Haynesville and Bossier laterals in the deeper Shelby Trough with a true vertical depth of 4,877 m (16,000 ft) and a total measured depth of 7,620 m (25,000 ft). BP will drill 25 wells this year, which is double its total in the last 18 months.

Chesapeake Energy Corp. will run three rigs this year and grow production 30% in the traditional Haynesville core. After a decade, the company has developed only 25% of its acreage. The rest is open to enhanced completions on multiwell pads, which have improved first-year cumulative recovery per well more than 100%.

Picture the unfolding Ark-La-Tex renaissance as Haynesville Version 2.0. E&P

Exploration success continues

Major discoveries have been announced in the past few months. Can this success persist?

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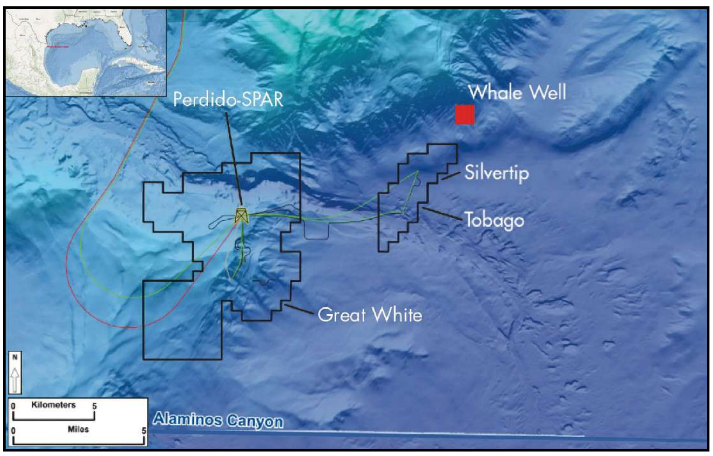
Some might say oil and gas exploration is dead. I would disagree with this statement, although with a few caveats.

A recent study by Westwood Global Energy Group noted several major discoveries in the past few months, basing its metric on discoveries of more than 100 MMboe. The study listed nine of these discoveries and later added Shell's Whale discovery, which was announced earlier this year. A few of these discoveries are listed below.

The Yakaar find offshore Senegal, which Kosmos Energy announced in May 2017, was a major gas discovery and the first in a series of four independent tests of the basin floor fan fairways, according to the company. The well intersected a gross hydrocarbon column of 120 m (394 ft) and encountered 45 m (148 ft) of net pay.

The Payara-2 well offshore Guyana, which Exxon Mobil reported in July 2017, encountered 18 m (59 ft) of high-quality oil-bearing sandstones that increased the overall Payara resource to about 500 MMboe. This find is located about 19 km (12 miles) from the Liza Phase 1 project. The company recently announced its seventh oil discovery in the region.

At Nanushuk, Repsol continued to prove the Alaska North Slope has not lost its luster by making the largest U.S. onshore oil discovery in 30 years, the company announced in March 2017. The Horseshoe well extends an existing play by 32 km (20 miles) in an area known as Pikka, the company reported. Preliminary developments anticipate first production by 2021 at a projected rate of 120 Mbbl/d of oil, and recent wells "confirm Nanushuk as a significant emerging play in Alaska's North Slope," Repsol reported.



Shell's Whale discovery is north of other recent discoveries in the GoM, including its Perdido Spar complex. (Source: Shell)

The Zama well offshore Mexico, which Talos Energy has not been shy about touting, was one of the first discoveries since Mexico allowed private-sector entities to drill its acreage after oil and gas reforms. Announced in July 2017, the Zama-1 well reached an initial vertical target depth of approximately 3,383 m (11,100 ft) and discovered a contiguous gross oil-bearing interval of more than 335 m (1,100 ft) with 170 m to 200 m (558 ft to 656 ft) of net oil pay, according to the company. Estimates of oil in place range from 1.4 Bbbl to 2 Bbbl.

And finally, there's the Whale discovery in the Gulf of Mexico (GoM). Clearly, Shell gets the GoM. In January the company announced its Whale discovery in Alaminos Canyon. The well encountered more than 427 net m (1,400 net ft) of oil-bearing pay, according to Shell, which is currently doing appraisal drilling.

The Westwood study noted that the number of "high-impact exploration wells" was similar to 2016 but well below 2014 levels. However, a frontier discovery was reported in the Laptev Sea in Russia and another "play-opening discovery" was made in the Barents Sea. While not commercial yet, these new finds should keep the momentum going. E&P

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The partnership between public and private entities continues to drive innovation in U.S. unconventional resource plays.

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The current shale revolution was made possible by the application of public R&D dollars to develop the needed technologies to unlock energy supplies for future generations.

For example, the U.S. Energy Research and Development Administration (the precursor to today's U.S. Dept. of Energy [DOE]) partnered with General Electric in the 1970s to develop the polycrystalline diamond compact bit for use in tough rock formations like shale to reduce drilling costs. Between 1978 and 1992, the DOE invested about $137 million in research that developed the technologies used to unlock production in the Barnett Shale and other plays.

It's an investment that continues to generate positive results for the industry.

The DOE's National Energy Technology Laboratory (NETL) teamed up with the Gas Technology Institute (GTI) in 2014 to "develop and execute a hydraulic fracturing test site program to answer questions, advance the understanding of the hydraulic fracturing processes to attain greater efficiencies and improve environmental impacts," according to the project's online fact sheet.

(Source: EtiAmmos, *Shutterstock.com*)

The NETL-GTI project field site, provided by Laredo Petroleum in 2015, is located in Reagan County, Texas. The site includes 11 existing wells with 3,048-m (10,000-ft) horizontal legs drilled through the Upper and Middle Wolfcamp Formation in the Permian Basin. The work conducted by GTI researchers includes before and after seismic surveys of hydraulic fracturing operations, core sampling and more, according to the project's online fact sheet. Work on the project is expected to end in June.

The DOE's field efforts do not end in the Wolfcamp. Six projects were selected by the agency to receive approximately $30 million in federal funding for cost-shared R&D in unconventional oil and natural gas recovery. The projects, announced earlier this year, seek to "address critical gaps in the understanding of reservoir behavior and optimal well completion strategies," as stated in a press release announcing the projects. Four of the six are field projects.

GTI will perform multiple experiments in the Delaware Basin's Wolfcamp Formation to evaluate well completion, design optimization and environmental impact, according to the press release.

The Texas A&M Engineering Experiment Station will conduct a field study of stimulated reservoir volume, fracture characteristics and EOR potential in the Eagle Ford Shale, the press release stated.

The University of Louisiana at Lafayette will address knowledge gaps regarding the Tuscaloosa Marine Shale, according to the release.

The "Field Laboratory for Emerging Stacked Unconventional Plays in Central Appalachia" project awarded to the Virginia Polytechnic Institute and State University will quantify the benefits of novel completion strategies for lateral wells in the unconventional Lower Huron Shale, according to the release.

By continuing in the spirit of partnership struck more than four decades ago, public and private entities are unlocking the energy supplies needed for future generations. Long may that spirit flow! E&P

Jennifer

The workforce of the future

As digital innovations take hold, the oil and gas industry is undergoing an evolution of its workforce.

BRIAN WALZEL
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Read more commentary at EPmag.com

In much the same way unconventional production has disrupted the global energy industry, industry leaders believe digital technologies also will impact the oil and gas industry's workforce.

Technological innovations like artificial intelligence (AI), machine learning, automation and robotics are gaining an increasingly larger stake in all sectors of the industry, and fear is creeping in that just about all of us might be, if not replaceable, severely disrupted in our professions. Regardless of your job tasks, it probably doesn't take too much of an imagination to picture a robot performing the same task at least as well.

But smart machines are likely just another brick in the industrial evolutionary wall. Future generations may look back on this information age and perceive it as the latest in a line of revolutions brought on by technological innovations in much the same way as the Agricultural and Industrial Revolutions.

While writing this month's cover story—"Upgrading the industry in the information age" (Page 26)—I talked with several companies, including BP and Devon, which addressed the impacts that the move to digitalization will have on the industry's workforce.

"Every time there has been a big inflection point in technology in the world, there's always been this fear," Devon Energy CIO Ben Williams said. "It has never ended up with fewer jobs on the other end of these industrial transformations. We do not expect there to be fewer people in the workforce, but I for sure envision many of the jobs that even our most senior technical people do are going to be influenced by these highly available and very effective technologies. The workforce of the future is not the same as the workforce of today."

In many cases, such technologies are taking people out of dangerous situations, enhancing their safety in risky environments and improving their training. Inspection work in oil and gas, for example, is a particularly risky task.

"If robotics were a cake, digital ethics must be baked in and not sprinkled on afterward."

—Dyan Gibbens, Trumbull Unmanned

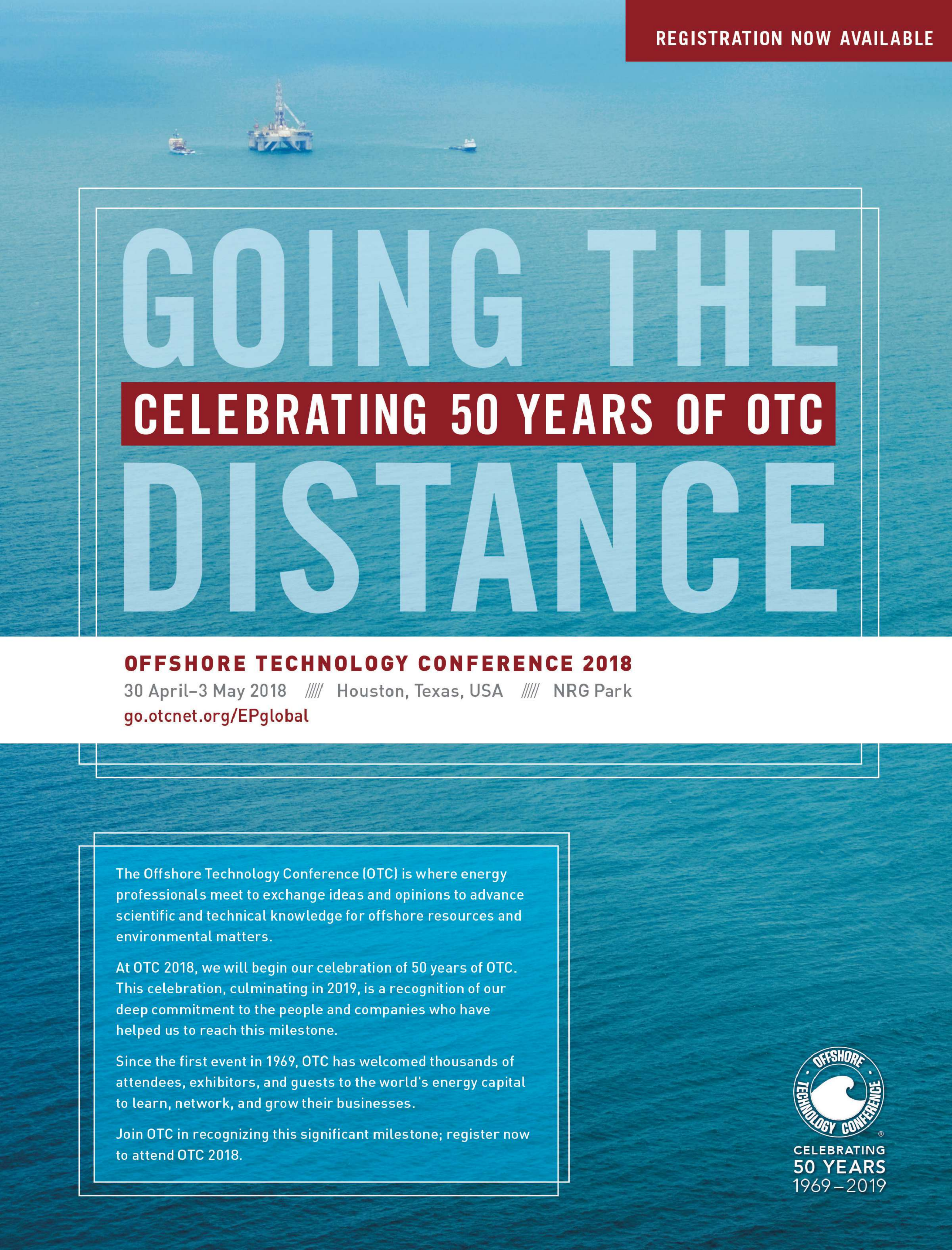
"It's quite conceivable most people would rather not be dangling from a rope and collecting data but instead have the knowledge and skills to now operate the devices that are actually doing that," said Dave Truch, BP technology director. "What we are seeing is a shift in the evolution of work."

The current environment has resulted in a co-worker concept in which autonomous machines serve as co-workers to humans, he said. BP Technology Principal Blaine Tookey believes that rather than being replaced, workers will be "upgraded," much like a smartphone's operating system, with the latest wearable technologies like exoskeletons and holographic lenses.

At the heart of the man versus machine dynamic lies an ethical issue. Will humans really create the devices of their own professional demise? Thankfully, there is a heightened awareness of such a danger. Organizations like Future of Life—which counts, among other notables, Elon Musk on its advisory board—work to ensure AI and machine learning do what we want them to do and not the other way around.

Dyan Gibbens, CEO of drone company Trumbull Unmanned, said in situations where digital technologies might replace—not displace—human workers, it's important to incorporate a sense of ethics from inception.

"If robotics were a cake, digital ethics must be baked in and not sprinkled on afterward," she said. E&P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Autonomous technologies transform operations

Removing people from harm's way is only the tip of the iceberg.

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Read more commentary at
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The oil and gas industry often is accused of dragging its feet when it comes to adopting new technology. The long-standing joke is that nobody wants to have serial number one, and everybody wants serial number two.

So the fact that Suncor Energy has made the move to use self-driving trucks on its oil sands operations in northern Alberta is a milestone worth looking into.

In January Suncor announced that it would begin phasing in autonomous haulage systems with the goal of deploying more than 150 vehicles over the next six years. According to the company, this is one of the largest investments in electric autonomous vehicles in the world.

Studies indicate autonomous technology offers advantages over existing truck and shovel operations, including enhanced safety performance, better operating efficiency and lower operating costs.

All vehicles entering an area where autonomous haulage systems are working are equipped with GPS location technology and can be monitored from a control center to mitigate the risk of contact between manned and unmanned units. The trucks drive on predefined routes and react if there is an obstacle in the way. Unlike manned trucks, an autonomous haulage system can operate 24/7, stopping work only for maintenance and refueling.

Hands-off technology is gaining ground offshore as well. One interesting example is a subsea project that was completed in late 2017 by Newton Labs, which recorded its first subsea project using the recently released M3200UW subsea and marine laser scanner. The unit was used in conjunction with the company's short-range M210UW scanner and deployed with tools designed and engineered by Ashtead Technology. On contract for Subsea 7, the units captured scans in water depths of 110 m (361 ft) on Chevron's Captain Field in the U.K. North Sea.

Newton's M210UW ultrahigh-resolution short-range underwater laser scanner and a horizontal mapping survey using the longer-range M3200UW unit captured more than 100 short- and long-range scans that were used to generate a 3-D model of a casing structure. The short-range M210UW scanner delivers high-detail underwater inspection and measurements through optical triangulation. The projected laser line sweeps the target surface while a high-resolution camera captures and records the visual data to create a point cloud 3-D model. According to the company, the system can operate with either a scanning or a fixed laser line to measure underwater objects to 0.02-mm accuracy.

While this survey was carried out using divers, the scanners can be controlled by ROVs as well.

Interestingly, although the scanners were designed for use in water, they also can operate in air.

And on the subject of aerial advances, a drone flown by Canada's SkyX Systems Corp. recently completed an unmanned data collection flight of 100 km (62 miles) over a gas pipeline in Mexico. The robotic flight was programmed and monitored from the company's Greater Toronto Area SkyCenter mission control and supported by a crew of engineers on the ground in Mexico.

Using high-resolution imagery, the longest of multiple flights identified more than 200 potentially significant anomalies along the length of the remote pipeline, ranging from unauthorized buildings and cultivation to a fissure possibly caused by seismic activity.

On the Mexico pipeline project, a single drone gathered data in a little more than an hour, which would have normally taken a person more than a week.

Amazing advances in autonomous technology are changing oil and gas industry operations. On land, in water and in the air, these technologies are taking people out of harm's way and delivering faster and more precise results than ever before. E&P

Judy

THE DIGITAL HUMAN

Equipping problem solvers for tomorrow's challenges

Brian Walzel, Associate Editor, Production Technologies

Whether it is called the information age, the digital transformation or just the changing of the times, the ways in which the oil and gas industry works is evolving. No longer is it a question of if the cutting-edge technologies leveraged by tech-savvy companies and imagined by science fiction will make their way into the oil and gas industry, but rather how far-reaching their impact will be and how they will affect the industry's workforce. Today's workers are becoming more efficient and more productive, and tasks are becoming safer thanks to innovations that push the limits of reality.

Augmented reality (AR) and virtual reality (VR) are transforming training and maintenance programs by helping the workforce see and understand their environments in ways never before possible. Aerial drones are making the industry safer by taking workers out of potentially hazardous situations while collecting data at a faster rate and in quantities not possible by traditional methods.

Oil majors like BP, Devon and Total, along with service providers like Halliburton, Schlumberger and Baker Hughes, a GE company (BHGE), are either testing many of these technologies or have fully adopted them. Once—or if—fully realized across the industry, these innovations could have a profound impact.

A January 2017 World Economic Forum white paper, compiled in collaboration with Accenture, reported that digital transformation in the oil and gas industry could result in more than $1.5 trillion of value for the industry, its customers and wider society.

E&P's cover story this month focuses on trends in digital innovations that are being leveraged by companies around the world. "Upgrading the industry in the information age" focuses on how companies are utilizing aerial drones and robots, AR and VR, and wearable technologies to improve efficiencies and enhance safety. In addition, editors spoke to Binu Mathew, senior vice president and global head of digital products for BHGE, about the challenges of implementing artificial intelligence and digital technologies.

Seismos, a technology provider for the oil and gas industry, reports on a suite of products that monitor perforation effectiveness and well connectivity in real time, while AspenTech addresses ways in which the large amounts of data are best utilized. In addition, Seven Lakes Technologies offers insights into how capital planning can help streamline existing processes and reduce errors, and Quorum Software describes innovations in well life-cycle reporting in the digital age.

These technologies, among countless others, are leading the oil and gas industry into a new age that features streamlined operations, substantially improved safety and a workforce that blends human know-how and ingenuity with cutting-edge digital innovations. E&P

BHGE provides field service engineers Smart Helmets, which enable engineers in the field to communicate with staff located at a headquarters facility who can guide the engineers through complex tasks by audio and video. (Source: Baker Hughes, a GE company)

Upgrading the industry in the information age

Drones, AR/VR and wearable devices enhance the workforce's efficiency while improving safety.

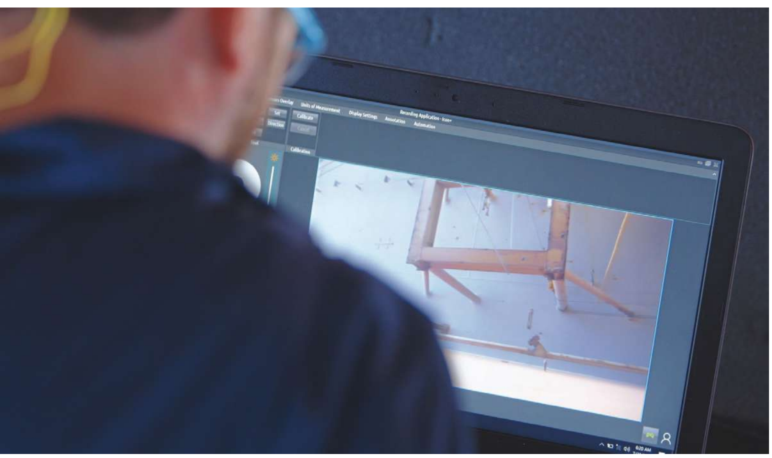
Brian Walzel, Associate Editor, Production Technologies

For at least the first couple of thousands of years, astronomy was essentially an observational science. Using only simple tools and the naked eye, early astronomers tried to gain a better understanding of the stars and planets. Some of it was accurate, and some of it was not—despite Copernicus' insistence that the sun was the center of the universe.

It wasn't until the 17th century with the invention of the telescope that astronomy began to transition to a theoretical—or quantitative—science, one which leverages the development of computer or analytical models to describe objects and phenomena.

The oil and gas industry has undergone a similar, albeit more condensed, transformation. The tools used to produce hydrocarbons have come a long way in 200 or so years, and today the industry sits on the brink of its own quantitative revolution. Many of the tools of the modern oil man and woman would be nearly unrecognizable by those drilling the first wells in the late 19th century.

Aerial drones, holographic lenses, robots and devices that dramatically alter the view of the universe are no longer the tools of tomorrow. They are in use today, and their applications are rapidly emerging across a wide array of industry operations. Tech-savvy businesses and digital flexibility are no longer limited to Silicon Valley. An emerging trend out of the energy recession has been an effort for companies to become more innovative, efficient and nimble in their operations. A variety of reports suggest substantial money is being invested by oil companies in the digital space as they learn that devices such as these can help save on costs and enhance worker safety.



A field technician reviews footage from a drone inspection at a BP offshore unit. (Source: BP)

The "Global IoT in Oil and Gas Market—Analysis & Forecast, 2017-2026" report by BIS Research stated the global Internet of Things (IoT) market is expected to reach $30.57 billion by 2026, increasing at a compound annual growth rate (CAGR) of 24.65% during the forecast period through 2026.

According to the study "Confidence and Control: The Outlook for the Oil and Gas Industry in 2018" by DNV GL, more than one-third of senior oil and gas professionals said they expect to increase spending in R&D and innovations this year—the highest level indicator DNV GL has tracked in four years.

"We will see more R&D going into digital, artificial intelligence [AI] and automation, which is really about costs, and about other ways of doing our business," Maria Moræus Hanssen, CEO of German-based E&P company DEA, stated in the report. "R&D is now less likely to be focused on ultradeep water, the Arctic or other extreme environments. It will be more about rationalizing the business—making the industry more profitable, more productive and modernized."

In the past two years, only 15% (2016) and 14% (2017) of oil and gas companies were planning increases in technology R&D, which DNV GL suggests signals an imminent turnaround after three years of cuts and freezes.

In addition, the McKinsey and Co. report "The Next Frontier for Digital Technologies in Oil and Gas" stated that digital technologies have the ability to create additional profits from existing capacity.

"The effective use of digital technologies in the oil and gas sector could reduce capital expenditures by up to 20%," the report stated. "It could cut operating costs in upstream by 3% to 5% and by about half that in downstream."

Operators and service companies alike are seeing the future and seeing the value of these digital innovations. In 2017 Halliburton and Repsol announced partnerships with Microsoft to initially develop cloud-based computing systems before expanding to mixed reality applications and robotics to deliver integrated systems across the entire energy value chain.

Chandra Yeleshwarapu, senior director of R&D and head of global services at Halliburton Landmark, said augmented reality (AR) and virtual reality (VR) systems have been integrated at Halliburton through its DecisionSpace enterprise platform, which was founded about five years ago.

A team of technicians discuss a drone inspection operation at a BP offshore unit. (Source: BP)

"We've always had a high-volume of APIs [application programming interfaces] to connect with other immersive technologies," he said. "But over the past two to three years, mixed reality has become more prevalent so we started building DecisionSpace with the same APIs used for connecting to a 3-D-based system, thus creating the capability to connect to AR."

Meanwhile, companies like Devon and BP have been at the forefront of digital technologies, such as the use of drones for data gathering and monitoring operations.

But as BP Technology Director Dave Truch explained, all of these types of technologies have emerged from a single building block—the quest for more data ingested by new approaches to digital data analytics.

"For various reasons, we collect data primarily by humans," Truch said. "If you look at the algorithms out there, and look at the amount of data humans can collect, there is a disconnect. There's no way I can put enough humans in the field to actually run these algorithms with any kind of surety about the results. By nature of trying to run these new algorithms, we had to consider a whole new way of capturing data. That led us into autonomous machines."

Drones and robotics

In a recent report issued by IHS Markit, the use of aerial drones was identified as one of several "transformative technologies" likely to emerge in the industry this year. Another report by research firm Mordor Intelligence stated that the market for drones in the oil and gas industry is projected to reach $4 billion by 2020, with a CAGR of 37% during the forecast period. The Mordor Intelligence report also stated that drones have the ability to collect "as much data available in the last 30 years within 45 minutes" and are "poised to become the next major disruption to influence the oil and gas industry."

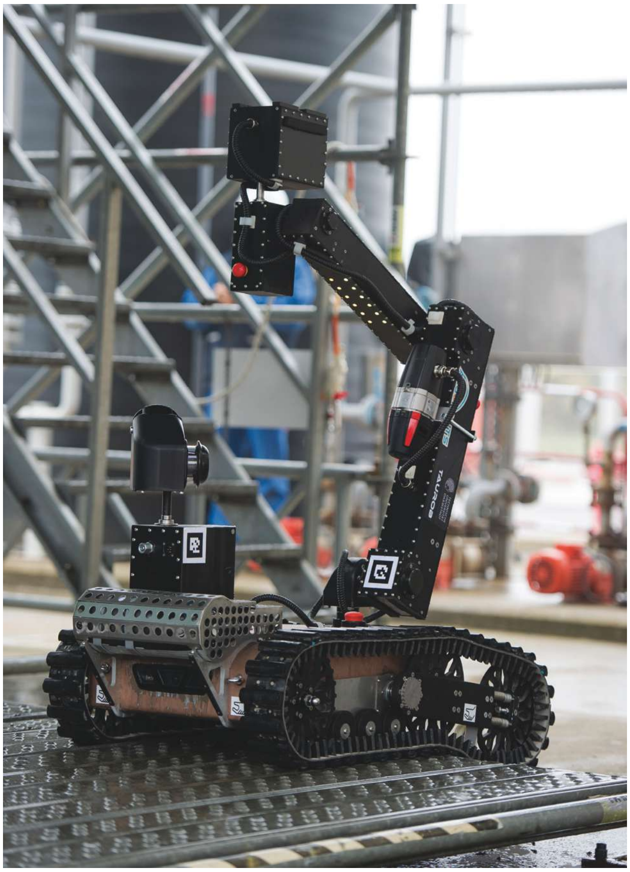
In fact, according to a report by Technavio, oil and gas is the leading end-user industry in the robotics market, with a 58.5% share of the market.

Trumbull Unmanned provides drone operations to companies in the oil and gas sector such as BP and was named Exxon Mobil diverse supplier of the year. The company has performed more than 100 live flare inspections both onshore and offshore, which CEO Dyan Gibbens said in an emailed response is about one-tenth the price and one-tenth the time of traditional flare inspections. She also said the savings vary from client to client, but if a typical inspection were to take a week, for example, a drone inspection can be done in less than a day and oftentimes less than an hour.

"Drone services provide several unique benefits to the oil and gas industry," Gibbens said. "First, they allow companies to greatly reduce risk and start allowing individuals to perform important work while never having to put themselves in harm's way. Second, in order to start effectively applying productivity increasing algorithms to work, the data need to be collected in a structured format."

Gibbens said drones offer the ability to collect large amounts of data in those needed formats. Operational improvements often can be seen in three primary areas—efficiency, safety and quality, she said.

"For example, many operators have integrated drones into their offshore inspection activities," she added.



A team of engineers from Austria and Germany recently developed this robot, which won Total's ARGOS competition and will be piloted at a Total facility in the near future. (Source: Laurent Pascal, Total)

"They have done this because it has greatly reduced the costs of inspections with no reduction in production, allows dangerous work to be performed with no risk to people and has the ability to collect high-resolution data that was not previously possible."

Truch said compared to traditional inspections on offshore platforms that required rope teams, drone inspections can reduce crew sizes by one-third. He also said such an inspection can be performed in about half the number of days with "significantly more" data acquired.

Intel and Cyberhawk, an aerial drone inspection company, recently partnered on a flare stack inspection in Saint Fergus, Scotland, using the Falcon 8+ drone system. According to Intel, such an inspection conducted by a drone can save $1 million to $5 million per day in potential production losses.

"Traditional inspections of oil and gas assets of this scale require either full or partial facility shutdowns," Intel reported in a case study of the operation. "This could take days to weeks to bring the plant offline and accessible for inspection workers."

According to the study, the Falcon 8+ deployed for the mission captured 1,100 images in 10 flights, which translated to 12 GB of data over the span of one to two days. A similar inspection would typically take a three-man team three days to complete, the study reported.

Truch said that AI algorithms run by BP offered the company new insights into how it is using devices such as drones and how those devices are influencing their perception of their operations. This led BP to go back to its risers in the Thunder Horse Field in the Gulf of Mexico, in which oil was first produced in 2008.

"At the Thunder Horse trial, our focus was on full data collection, the value of the data, the ability to actually run [drones] on our platform in a safe manner and, from there, to turn around and say the data we collected are very meaningful and very useful," Truch said. "Now we're starting to look at how we can take some of these new approaches and look at the data. Meanwhile, the data collected are still being analyzed in the traditional way, because we're still getting huge value in the data we're collecting."

Truch said during the course of the drone inspections of the Thunder Horse risers, BP realized the mission began to evolve from merely data collection to a method that provides insight across a variety of the company's operations.

"What we discovered is that a lot of the structural engineers, coating engineers and maintenance individuals were also interested in the data collected from the same mission," he said. "That's allowing us to change the nature of how we collect these data. In the past it was very specific to a single-use case. So, we put people on ropes to collect data about the risers. If we then wanted to look at some structural elements on the platform, we'd put people on ropes a different time to look at the structural elements. If we wanted to do some coating inspection, yet another group of people would go out on ropes to look at the coating. All of that information was collected on a single mission [with drones and crawlers]."

Much like unmanned aerial vehicles, robots are accessing both physical spaces and data that humans previously could not or where it was dangerous for them to do so. In the early 2010s, Total recognized that no existing autonomous surface robot existed in the oil and gas industry to meet the needs of E&P activities. In December 2013 Total, in partnership with the French National Research Agency, launched an international competition to design and build an autonomous robot for oil and gas sites. The ARGOS Challenge included five teams from Austria and Germany, Spain and Portugal, France, Japan and Switzerland. Each team was given about $740,000 and three years to design their surface robot prototypes.

According to Total, the ARGOS surface robot was to have three main missions: to carry out inspections currently performed by humans, detect anomalous situations and intervene in an emergency. More specific tasks included performing inspections during the day or night; being able to locate, read and record inspection points; take measurement and analyze readings; and detect anomalies ranging from malfunctions to dangerous situations such as gas leaks, suspicious heat sources or excess pressure, Total reported.

According to Total, the five robot prototypes were tested in a former gas dehydration facility in southwestern France in conditions representative of other company facilities. The final iteration of the competition was held in March 2017, and the prototype from the Austrian-German team was selected as the winner and was chosen by Total to start operating on one of its facilities beginning in 2020, the company reported.

In December Total successfully trialed an aerial drone system, its Multiphysics Exploration Technology Integrated System (METIS), for geophysical imaging. The goal of the METIS project, according to the company, is to obtain quality geophysical data in complex topographical locations, minimize environmental and safety risks, and improve turnaround time and costs.

The drone system uses Downfall Air Receiver Technology (DART) to "carpet" the ground in the exploration area with DART wireless geophysical sensors, Total reported. The drone fleet can deploy up to 400 DART receivers per square kilometer, with seismic traces recorded and sent in real time to a processing center, the company reported.

Devon Energy CIO Ben Williams said the use of robotics offers the potential to improve a company's safety objectives through automating potentially high-risk tasks.

"Anytime you have the proposition of potentially removing someone from a high-energy work environment through robotics, that's definitely something we're interested in doing," Williams said. "Where we can partner with service providers in which we can get people out of high-energy, hazardous environments like the rig floor or like a dangerous location in the field, that's definitely worth doing. You've got to have a value proposition for any investment you make. Keeping people safe is quite a tremendous value for us."

Total successfully tested its METIS seismic acquisition drone, which is designed to acquire seismic data in challenging topographies. (Source: Ramlo Productions)

AR/VR

Technological innovations in the oil and gas industry are breaking down the limitations of space and time. Data-gathering is achieved much more rapidly and in quantities that never before seemed possible. AR and VR innovations are allowing industry workers to virtually be in two places at the same time and can drastically alter the visual perception of their workspaces.

For example, operators and service companies are finding AR is an ideal tool for training simulations and troubleshooting mechanical problems in the field.

Honeywell recently released a cloud-based simulation tool that uses a combination of AR and VR to train plant personnel on critical industrial work activities.

"With as much as 50% of industrial plant personnel due to retire within the next five years, the Honeywell Connected Plant Skills Immersive Competency is designed to bring new industrial workers up to speed quickly by enhancing training and delivering it in new and contemporary ways," the company stated in a press release.

The training tool combines mixed reality with data analytics and Honeywell's experience in worker competency management to create an interactive environment for on-the-job training. The program uses Microsoft's HoloLens and Windows Mixed Reality headsets to simulate various scenarios.

"Megatrends, such as the aging workforce, are putting increased pressure on industrial companies and their training programs," Youssef Mestari, program director for Honeywell Connected Plant, said in the release. "There is a need for more creative and effective training delivered through contemporary methods such as immersive competency, ultimately empowering industrial workers to directly improve plant performance, uptime, reliability and safety."

Return to Scene, a company that specializes in visualization and data technologies, has partnered with tech startup Mozenix to develop a mobile AR application, R2S AR. The application supports the digitalization and automation of oil and gas operations. Return to Scene also works with companies like BP and ConocoPhillips on visual asset management.

"Offshore oil and gas assets are complex, adaptive structures with a constant flow of actions being undertaken by international teams," Martin McRae, Return to Scene's head of product development and support, stated in a press release. "The systems, which enable these actions, are underpinned by asset registers, which are represented by physical tags attached to equipment. The location of these tags and the ability to visualize data in a certain way is crucially important."

Halliburton has implemented digital innovations into its field operations to enhance the efficiencies and productivity of its workers. (Source: Halliburton)

However, for oil and gas companies to fully leverage the benefits of AR and VR, enough data—and enough of the right kind of data—must be in place. Devon's Williams said an example of a key initial step to implementing these types of technologies is to collect 3-D images of the needed work locations, rather than just traditional diagrams.

"The emergence of drones and machine learning technologies are allowing us to—at a very low cost—capture and manage 3-D imagery of our field locations such that we can integrate that dataset into what is today a fairly developed set of automation tools for monitoring and identifying," he said. "So if I can put someone in that space and highlight with AR the equipment that has the problem, then I can speed up someone's activity out in the field, instead of them having to go out and start from scratch."

Companies are beginning to leverage the capabilities of digital twins of their assets. According to Baker Hughes, a GE company (BHGE), a digital twin is a digital representation of physical parts, assets, processes or systems. Digital twins continuously collect data from sensors on the assets and apply analytics and self-learning AI to gain insights about its performance and operation, BHGE stated.

As part of its partnership with Microsoft, Halliburton has implemented AR and VR capabilities for training and field operations and has incorporated these innovations into its DecisionSpace enterprise platform. Halliburton's Yeleshwarapu said the effect is the ability of the worker to interact with a digital twin of a reservoir or of a wellhead, for example.

"We have the platform and the unique ability to create an oil and gas digital twin," Yeleshwarapu said. "Microsoft has the ability to provide the capability around AR and VR tools. You put that together with DecisionSpace Well Construction or DecisionSpace Production and you end up with an immersive way to interact with and understand the industry's only true oil and gas digital twin."

Schlumberger has implemented VR training systems for onboarding new employees who have no experience in the field and, more specifically, for its cementing downhole tool systems.

Steve Uren, head of simulation at Schlumberger, said, "The training for the cementing downhole tool systems evolved from what was primarily a traditional classroom environment into a VR simulation of the actual working environment of the system.

"We redesigned the entire program with some prework requirements. Once the employees arrive at the learning center, they engage in daily activities in the VR environment," he said. "We basically removed all of the traditional classroom activities."

Uren said the purpose of utilizing a VR environment rather than traditional classroom methods was to increase the fluency of specialists, make them more comfortable working in the field and enhance trainees' ability to better process operational steps.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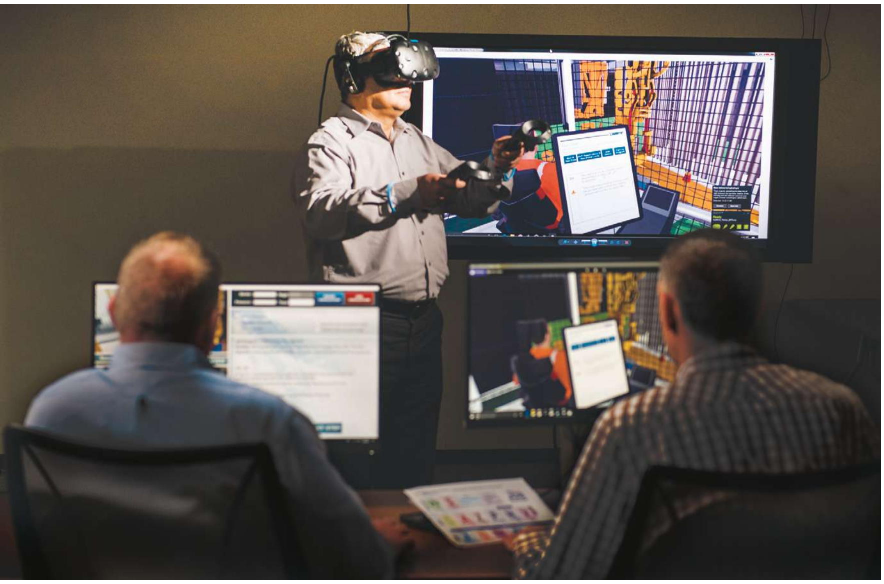


Schlumberger is using VR systems to train employees who are new to the oil and gas industry. (Source: Schlumberger)

"In December 2017 Schlumberger rolled out a VR onboarding training program for new entrants to the industry, such as engineers and technicians who typically have not had field experience," Uren said. The VR training environment simulates a variety of environments, such as a land rig, offshore jackup rig and offshore semisubmersible unit.

"The trainees can explore the general arrangement of the rig," he said. "New employees are given an accelerated introduction to the different rig types they will experience; they have the opportunity to walk around and understand where the equipment is and what the equipment does."

Uren added, "Feedback from the training has been very positive with employees embracing the change of learning environment and tools."

The upgradable workforce

The leading case for many technological innovations in the oil and gas industry has been improvements in safety and efficiencies. Another component to the suite of advances, such as drones, robotics and AR/VR, are wearable technologies—physical devices worn by industry workers that augment their environments, monitor their functions and even track their movements.

BP has applied a variety of wearable technologies in its operations, particularly tagging devices that track employees for safety and to optimize worker performance. BP Technology Principal Blaine Tookey said such devices have been met with an overwhelmingly positive response where they have been implemented.

"We're moving into scale deployments in some facilities where [managers] are saying 'This can really make a difference to our operations,'" Tookey said. "This is really impactful for their emergency and safety performance. But also they can see the value added in day-to-day operations around understanding how people move and how we can support them better."

He said companies typically rely on a worker to communicate physical or environmental problems they may be experiencing while on the job, which is a challenge wearable tracking devices potentially solve.

"We're leaving it up to them to report that they have an issue," Tookey said. "People might be getting fatigued or they might be getting dehydrated, but now we've got the capabilities through wearables to monitor those key parameters and understand in advance whether their performance might be dropping off and call them up and tell them to take a break, tell them to get some water and even intervene in more problematic issues."

As wearable devices become more commonplace and accepted in the industry, they could become a part of a worker's usual personal protective equipment that all field or facility workers take out with them, Tookey said.

"This opens up brand new opportunities—particularly in biometrics and streaming video, neither of which people don't commonly use in a facility or as a wearable at the moment," he said. "We're also looking at exoskeletons, which are basically structures that you strap to yourself allowing for better endurance, safer lifting, safer holding and longer carrying."

Although Tookey said wearable devices are still in the early days of being applied widely in the industry, there may soon come a time when wearables are in high demand by industry workers and may even become essential tools.

"In the longer term, wearables will evolve to more sophisticated monitoring and visual/cognitive aids essential for the work role and be seen as normal upgrades," Tookey said. "People will wonder how they ever worked without them in five years' time. And then [wearables] will develop to the point where people will perform significantly better with them. What you may see in 10 years' time is people demanding, 'I want to be upskilled, I want to have more capability, and I can't compete without a wearable to help me understand the world and do my job.'" E&P

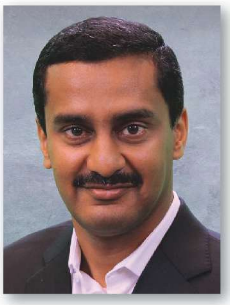
Examining the industry's AI and digitalization challenges

An executive shares his views on how the oil and gas industry can benefit from the application of technology advances made in AI and digitalization.

Mark Venables, Contributing Editor

Artificial intelligence (AI) is coming of age, and the oil and gas industry is searching for the most effective uses of this nascent technology. Binu Mathew, senior vice president and global head of digital products for Baker Hughes, a GE company, spoke with Hart Energy about technology, digitalization and how AI can prove beneficial for the oil and gas sector.

Editor's Note: This interview has been edited for clarity.



Binu Mathew

Hart Energy: Where is the oil and gas industry when it comes to digitalization?

Mathew: First of all, you must remember that the oil and gas industry has always had digitalization in some way. Just look at the original supercomputers. If you look at the oil and gas industry now, what you have is tons of data across the board, but those tend to be very siloed. Individual plants and individual machines generate a lot of data, but it leads almost to what I call a bit of a dichotomy.

An operator today will have streams of data, not necessarily actionable information, but many, many streams. In fact, it makes it more difficult. You have all this information coming to you on different screens, and you have to make judgment calls based on that.

If you are on an operations team with a lot of experience, you make good judgment calls, and if you're not, you don't. So you are seeing significant shift differentials in terms of performance.

The other thing that's also changed in the last two years with the changes in oil prices is that there is far more emphasis on operational efficiency. You have to get the breakeven costs, the dollar per barrel of oil, to a significantly lower level—especially for the upstream industry. That's changed the name of the game from leasing acreage, essentially a real estate game, to operational efficiency. But to do that you have to be able to use whatever data you have to see where you can run your processes more efficiently. You need to reduce nonproductive time. You need to increase overall performance and efficiency. If you're doing field planning, you need to drill and you need to plan that more effectively.

There's a lot of inefficiency in the oil and gas industry, because whenever you had an upcycle, you were able to ignore it for a long time.

Hart Energy: Do you have any examples from your experience on this fluctuating performance?

Mathew: That was one of the problems BP noticed, and it is why the company started using its plant operations adviser [an offshore digital technology]. When you are dealing with the independency of multiple machines on a big offshore platform, the machines may all be working fine. But if they are not working within parameters for the process, you still have a process upset. They would see several trips that were being triggered due to that.

> "AI is getting to the point where, once appropriately trained, it can do better than a human being."
> *—Binu Mathew, Baker Hughes, a GE company*

On one hand you have the operators, and on the other hand you have the engineers. The engineers have a lot of data, but to put those into a form that is usable you must spend a lot of time analyzing that. The tool that is probably most widely used is [Microsoft] Excel. The engineers will do models from this. We have a lot of analytic capability in the oil and gas industry, but it takes you weeks or even months. If you take an operations team that's working within a five- to 10-minute window and engineering teams that are operating in periods of weeks to months, there's this big gap. That is where a lot of change is going to happen in the next few years. It's certainly the area that we're focused on.

Hart Energy: When other industries such as automotive have traveled down the digitalization path, they have struggled with the volume of data. How is the oil and gas sector coping with this?

Mathew: Like the automotive sector, we have alarms and exceptions, and part of the challenge when you get an alarm is what you do and if the action you're taking is effective.

It all changed dramatically in 2012. This was the first time that the deep neural network made a step change in image recognition. There was a competition on the internet for machine learning on image recognition. The general threshold around that used to be around the 70% level, and every year it would go up by a small fraction. The reason was that up to that point it was all being done by traditional techniques.

The odd thing was that until that point neural networks were considered almost an academic curiosity. The math had been around since the '60s, but what people hadn't realized was what you needed was enormous computational power, and that turned up right about then.

It has improved to such a degree that as of late 2017 we're not just coming close to human capacity; AI is getting to the point where, once appropriately trained, it can do better than a human being. That is across the board, and you're going to see this dramatic change over the next five years.

Hart Energy: Can you give us an example of this form of AI in action?

Mathew: A very simple example comes from BP's IntelliStream product, which deals with production optimization. The traditional way of carrying out failure diagnostics on rod lift pumps is to look at the dynamometer card. A technician would go out, pull out a set of flat cards and compare the patterns. This is a situation that's absolutely tailor-made for AI. We have AI-based pattern recognition that can meet or exceed human capacity in terms of recognizing the situations, and do it in a fraction of a second.

Hart Energy: There are numerous oil and gas companies dipping their toes into AI in all sorts of diverse applications. Do you have a clear vision of where you're going with it?

Mathew: On the demand side, you have to improve operational outcomes; you have all these data and you must be able to process those. On the supply side, you have all these new technologies. But how to marry the two? This is part of our reason for our partnership with Nvidia. Nvidia can provide a lot of the technology, but they're having a challenge in how to take these powerful new technologies and apply it from a domain perspective.

It's not just in the case of AI; you can see this across the board. If you take the cloud and other technologies that have been developing over the last few years, how do you get that into the oil and gas industry? Because you've got to make it domain specific, you've got to have an end-to-end workflow and you've got to have something that somebody can use. E&P

Providing additional insights into unconventional plays

Digital technologies help expand access to well information.

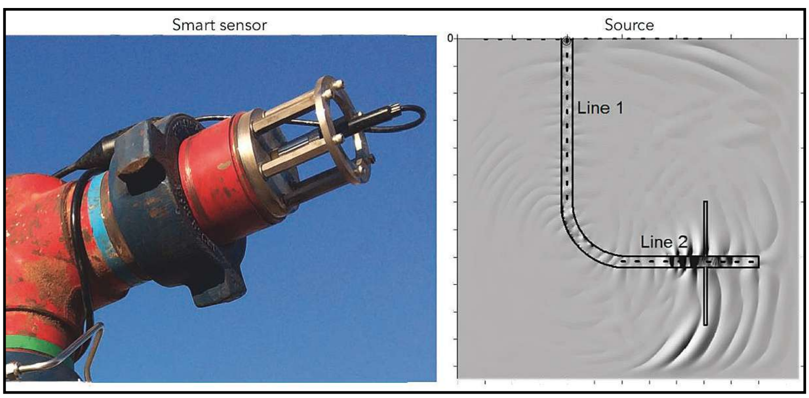
Jakub Felkl, Seismos Inc.

Modern digital technologies, sensor networks and the Industrial Internet of Things (IIoT) enable operators to acquire and access larger amounts of data than ever before. As additional information becomes available for completions in unconventional resources, companies have ever-increasing potential to benefit from this wealth of data encompassing the entire life cycle of a well. Whereas most recently it has been the lower oil price that drove operational efficiencies in unconventional plays, digital technologies will lead the next wave of data-driven efficiency improvements, optimization of production and resource recovery. Ongoing developments will lead data analytics to the forefront of the oil and gas industry.

Integrated approach to data acquisition

Modern oilfield machinery is increasingly equipped with sensors and other IIoT devices. Every unconventional drilling and completions operation includes trucks, pumps, blenders, pump lines, valves, transducers and hundreds of pieces of hardware and equipment as well as many workers. Nearly every piece of machinery has embedded sensors.

Companies are increasingly using or investigating data analytics-based predictive maintenance programs; thus, with more data available and appropriate software, costly failures and glitches can be predicted and avoided.



Seismos smart sensors enable real-time analysis of wellbore condition and the fracture network. (Source: Seismos)

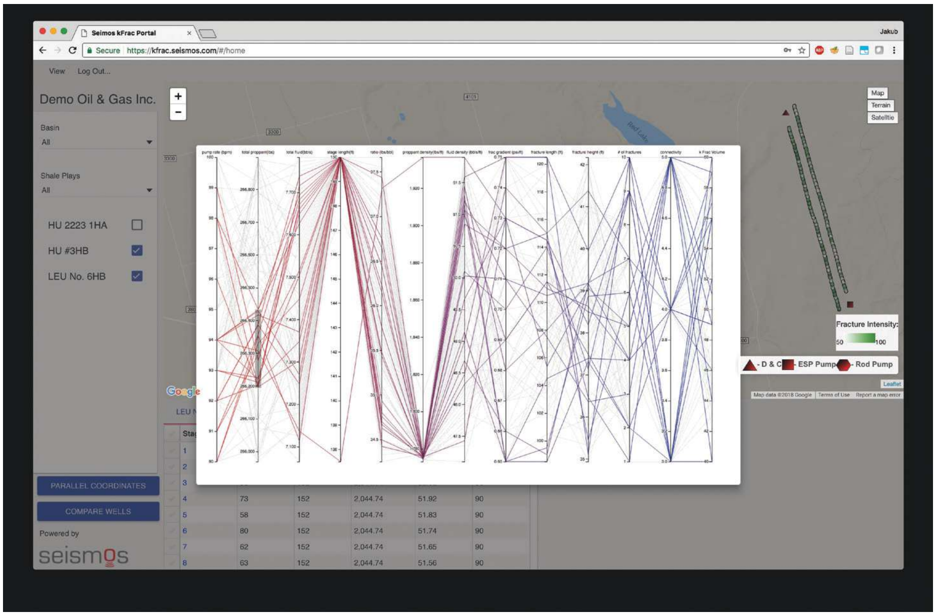
Real-time data on formation and wellbore conditions during hydraulic fracturing are scarce, expensive and difficult to obtain without intervention inside the wellbore. For those reasons, outside of the standard operational and machinery parameters, no wellbore-condition parameters are monitored during a typical hydraulic fracturing operation. This results in less-than-optimal stage and well performance.

Seismos offers a real-time view into the wellbore. The company developed a technology based on borehole geophysics science to address this need without wellbore intervention. This technology combines proprietary geophysics with custom-smart, surface-based, noninvasive sensors and connected devices to acquire wellbore acoustic signals and process data to monitor the stimulation operation in real time. The signals provide typically unavailable measures on the state of the wellbore and fracture network that enriches existing well data information.

The Seismos suite of products focuses on monitoring perforation effectiveness and well connectivity in real time, identifying operational abnormalities before they cause shutdowns and allowing monitoring of near-well and far-field fracture properties, namely connectivity to the wellbore and reservoir.

The onsite acquisition, joint data streams and a processing module perform measurements throughout the fracturing process offering valuable insights and early warning signals. Each local node is connected to the cloud; acquisition and management of constant multichannel data streams in kilohertz ranges present a Big Data challenge, especially in combination with onsite pumping parameters. The expanded dataset can be incorporated along with the well data information for a more comprehensive understanding of the wellbore, state and progress of the hydraulic fracturing operation.

Processed and analyzed, real-time data streams provide instant feedback on the ongoing operations and information available to the person in charge both onsite and in the



This geographical information system interface example reviews well and stimulation-related parameters. (Source: Seismos)

office. Taking a real-time approach allows the lead engineer or operator to identify abnormalities and make appropriate, timely and informed decisions or adjustments concurrently with ongoing treatment—all without downhole intervention. The measurements allow the operator to tweak pumping designs and treatments from stage to stage for more agile, flexible and stage-optimized completions. By updating completion design, spacing, sand parameters and other specifications in real time, operators can manage geological and financial risks for optimal success rate.

Seeing the big picture

Acquiring data is only a first step in creating value and data-driven efficiencies. Without disturbing the operations flow, all additional information and data that exist should be incorporated and tied together wherever possible. The data must be properly managed, not only acquired and stored. Good data management will preserve access, reliability, relevance and relationships among various datasets.

Performing larger-scale data analytics that allow data mining is the next step in getting the most value out of the data. To make sense of the ongoing development, access to real-time, cloud-based processing of acoustic data can give insights on expected relative stage productivity. As the datasets grow and more information (such as well logs or historical production data) enters the data store, engineers can rapidly query the database for various questions and seek correlations, not only about the ongoing jobs but also on a host of prior completions. The machine learning algorithms then provide additional insights that inform the engineers on expected efficiency and production, giving them the tools to make better decisions.

Seismos applies advanced pattern recognition to identify typical behavior of stages that tend to screen out, typical optimal treatment designs, correlations between top producing stages, top producing wells, operational techniques and/or unique challenges encountered during completions. The task for the engineers is then to use this augmented knowledge to design even more productive completions.

The fundamental paradigm shift to bespoke stage design opens up the potential to significantly increase the number of stages that contribute to overall production. As an additional benefit, the data can be used as an input to fracture models, to improve simulations and to help optimize future completions.

Seeking hidden value in utilizing broader datasets and their relationships, Seismos' overall goal is to provide a smart, interactive, real-time cloud platform for operators and fracture engineers to aggregate, review and connect data in a useful way. This requires advanced data analytics, statistics and machine learning to truly leverage all the datasets. A practical, platform-independent graphical user interface with the most up-to-date information offers a solution. It is supplied through a web browser, delivering valuable results.

This information can be ready in near-real time and then streamed for fracture engineers in the office, who can then communicate proposed changes based on real-time data to the onsite fracturing crew. Seismos provides a portal that combines several of these capabilities in one user-friendly interface designed to be simple, robust, affordable, up-to-date and accurate. Such applications are poised to initially enter the more data-rich and real-time demand sector of unconventional plays (hydraulic fracturing) but, with the addition of production information and monitoring, they will likely transfer across the spectrum to more conventional, existing wells or older reservoirs. E&P

Well life-cycle reporting in the digital age

Cloud-based well completion systems help operators make data-driven decisions and improve performance.

Matthew Mott, Quorum Software

The process of drilling and completing wells is expensive. It requires E&P operators to have access to accurate and timely field data to make informed operational decisions.

To stay ahead of lower-for-longer prices and rebounding service company day rates, operators need to gather more data in the field now more than ever. The ability to capture accurate data, uncover trends and optimize operational processes helps operators succeed in any market condition. Yet, operations teams often struggle with managing multiple spreadsheets or using complex legacy software solutions for data management.

Specifically during the completion phase of a well, E&P operators receive large datasets from multiple vendors onsite. These data often are left in silos in various PDFs, spreadsheets and email inboxes. By implementing an easy-to-use, cloud-based solution to capture, manage and report these data, operators are uncovering more ways to unlock value from their assets.

For example, Felix Energy searched for a solution to reduce time spent manually combining and distributing data from onsite vendors to office personnel. In 2014 the company began using Quorum Software's well data management system, WellEz, for operations in the Permian Basin.

"This transmission of all well data to the office via the cloud saves us countless emails from the field staff and an abundance of confusion," said Dan Graeve, completions engineer at Felix Energy. In addition, the ability to receive timely updates on the stages fractured per day, water usage and stage performance has enabled the company to set and achieve performance goals.

Efficient communications

Operators in unconventional shale plays are drilling and completing wells faster than ever. To do so, they need real-time access to operational data. "The ability to access KPIs [key performance indicators] from any computer or device with a couple of clicks has all the data I need to run my crew right at my fingertips," Graeve said.

Cloud-based applications like WellEz On Demand are designed for the modern energy workplace by supporting new and improved methods of collaboration. This includes connecting individuals regardless of their location by using any modern device, such as smartphones, tablets or even the Microsoft Surface Hub. The ability to leverage these powerful tools means that access to operational data, and the potential to make informed decisions from those data, is possible wherever and whenever it is needed.

For example, during traditional fracturing operations, the onsite vendor or completion crew member collects stage information in large spreadsheets or word-processing documents and manually emails those updates to the

Quorum's WellEz software connects individuals regardless of their location using any modern device, including smartphones, tablets and PCs. (Source: Quorum Software)

COMPLETION STAGE PERFORMANCE

	12/28/2014	12/29/2014	12/30/2014	12/31/2014	1/1/2015	1/2/2015	1/3/2015	1/4/2015	1/5/2015	1/6/2015	1/7/2015	1/8/2015	1/9/2015	1/10/2015
Stages Complete	1	2	1	2	3	4	4	1	1	2	1	1	3	2
Nonproductive Time (hrs)	0.0	0.0	4.8	7.0	7.0	1.3	6.0	3.0	8.0	1.8	4.3	8.0	6.5	1.0
Target	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Daily Cost	$146,139.75	$177,662.08	$209,519.62	$394,465.64	$191,085.54	$388,502.05	$244,920.11	$427,092.80	$295,872.01	$340,696.68	$294,090.01	$166,026.51	$245,286.33	$336,964.95

The WellEz system helps operators make timely decisions by distributing single or multiwell analysis reports that track completion performance and nonproductive time (NPT). (Source: Quorum Software)

office at specific intervals. This time-consuming process is inconsistent and prone to human error.

With WellEz, the data are collected from all parties with an easy-to-use application, which then can be accessed immediately by engineering team members. Reports also can be scheduled to automatically be sent at specified time intervals. This provides a complete and accurate dataset for the current completion job and allows the operator to analyze performance across wells, assets and teams.

Boosting performance, reducing costs

In addition to gathering daily operations and fracture information, WellEz also includes an effective field cost tracking system. This allows operators to capture field cost estimates against the authority for expenditure, generate accurate accrual reports before invoices are received and compare financial performance for similar projects. By providing an easy-to-use system to capture field invoices, operators have reported a reduction in field costs estimates versus actual costs to as little as 5%.

Customers can track and report key completion information such as perforation depths, stage summaries, water usage and flowback readings. By taking the historical reporting information that might have sat unused in filing cabinets or inboxes and storing it in a reporting database, companies are able to have immediate insights into their operations.

Felix Energy use to spend hours in legacy software systems building post-job performance reports to optimize their operations; however, with a cloud-based system that can be configured to fit a specific workflow, this could be done quickly and to their specifications. "The customizable reports allow post-job analysis on each well to take a matter of minutes compared to hours with our previous software," Graeve said.

Easy implementation

Many operators find that the Quorum system solves the limitations, user difficulties and support issues that are experienced from traditional reporting practices or legacy software programs. With a software-as-a-service (SaaS) delivery model, the reporting system bases its charges on field activity. This allows operators to pay for current reporting needs and hedge the risk of unexpected operational inactivity. In addition, the SaaS method of information delivery means no additional cost to the operator's IT infrastructure.

The system can be implemented in as little as five days, and personnel can be trained to use the system in a 20-minute online training session. Through cloud-based technology, the system can help operators capture accurate data, provide robust reports to support decision-making and ultimately optimize operations to improve their bottom line. E&P

The road map to upstream profitability

Models encapsulating the reservoir, production processes, equipment and economics provide the opportunity to fully leverage available data.

Ron Beck, AspenTech

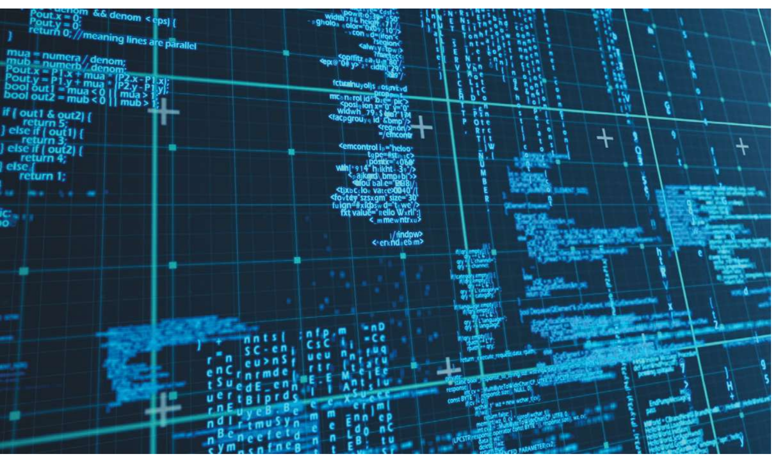
The new reality of oil and gas economics has had a major effect on the upstream industry. For most organizations the main goal has been to reduce production costs, with many turning to advanced technology. A key initiative showing initial success has been the digitalization of the oil asset. The vision is that increasing the amount of data collected and the ability to make decisions based on data will improve proactive management and reduce opex.

This digitalization is exciting, but it is only an enabling step. It involves instrumenting and collecting broader sets of information to achieve process insights.

Future of oil and gas economics

Long-term energy scenarios show continued demand for hydrocarbons but at a flattened growth rate, suggesting prices will likely remain near current levels. To sustain this, new production from existing and new assets must be brought online. This drives the need for future upstream investments sustainably and at close to today's breakeven costs, meaning structural industry changes are needed. These include

- A move toward standardized versus one-of-a-kind designs enabled through the capture of best-practice unit and module designs via data and models, which reduce overall capex;
- An increased collaboration between industry players focusing on better use of people and resources across the execution chain; and
- A breakthrough in using data to achieve higher summits of reliability with the combined use of techniques such as machine learning, deep-insight process models and statistical models to turn Big Data into production-predictive and prescriptive knowledge. This has the promise of significantly driving opex reductions.



Data analytics and visualization are being used to make optimal and rapid operating decisions. (Source: AspenTech)

On the capex side, operators are driving engineers toward adoption of lower risk standardized and modularized asset designs. On the opex side, putting buyer pressure on contractors has resulted in short-term results but not a sustainable longer-term tactic. Instead, fundamental improvements in efficiency, capex designs and reliability are essential.

Promise of automation productivity

The upstream segment is characterized by its technical complexity, remote production environments, the challenge of developing the experienced technical experts who can guide these dynamic and ever-changing production environments and the expense of putting technical teams in place at the asset.

The upstream industry has lagged overall in terms of the types of automation common in other manufacturing sectors. The first area that has evolved rapidly is the automation of the drilling domain, specifically advanced directional drilling. Improving asset performance and reliability through technology is the current frontier. Today's upstream world is ripe to benefit from a productivity growth opportunity.

Digitalization driver

Many organizations look at data analytics for uptime solely in the context of equipment maintenance, but there is a wealth of information types that provide valuable insights to enable machine learning tools to understand patterns leading to process problems and failure:

- Equipment data, including embedded sensor data and asset history data;

- Process data, including historian-based capture of all instrumentation across a process, unit or site;
- Maintenance data, including maintenance history, frequency, severity and equipment lifetime;
- Process safety data, including safety and asset integrity incidents associated with equipment and processes;
- Condition data, including results of measurements and inspections related to corrosion, equipment degradation and metal fatigue; and
- Enterprise resource planning, which provides a variety of insights into asset performance and yields.

The combination of these data types—understanding interactions of the hydrocarbon flows, the process and the equipment—allows prescriptive strategies to modify operating strategies, maximize uptime and minimize maintenance costs.

What to do with production data

More data are becoming available from equipment like turbines and new compressors as well as large pumps and subsea modules. However, equipment that can play a spoiler role in production levels and uptime have limitations on information collection and instrumentation costs. It is not simply about using data to understand equipment. Equipment interacts with the flowing hydrocarbons and the processes; those complexities and dynamics must be unraveled to optimize assets.

To make future unconventional assets feasible to produce, approaches such as machine learning combined with advanced optimization modeling will be key to achieving the economics that are required.

There are converged technology components that turn data into predictive knowledge. Advanced Big Data process historian applications can capitalize on the production accounting and allocation, online key equipment monitoring and safety systems data streams coming from the largest and most complex fields. Operations advisory and key performance indicator visualization systems in the form of operator-friendly dashboard tools take the data power of any process historian and turn it into an asset optimization and reliability weapon by removing people from remote and expensive-to-staff offshore environments.

Standardization

Design, operations and maintenance have long persisted as isolated worlds of automation. The current upstream environment demands a different approach.

An upstream enterprise achieves operational excellence with a strong life-cycle view of the process and the asset and by continuously improving its assets to improve operability, maintainability and uptime. To take advantage of that, a feedback loop captures the digital image of that well-operated and optimized asset to use in the next similar asset development project.

Further innovations will provide even more insights and capabilities into optimizing designs for operability and maintainability. A few of the key breakthroughs include module-costing models within capital cost estimation tools. These provide a powerful environment to compare modular construction with "stick-built" construction. Volumetric model-based conceptual estimates in the capital cost estimation tools capture completed projects as cost models that can be reused in a low-risk way through powerful relocation and resizing models. Integrated economics enable the rapid translation of process models into total installed costs.

Knowledge of the process

Data alone are not able to provide the predictive intelligence operators and decision-makers require in such dynamic environments. Models encapsulating the interactions of the reservoir, production processes, equipment and economics provide the opportunity to fully leverage available data.

The key breakthroughs enabling models to be deployed as analytic engines in upstream include advanced solvers, equation-oriented solution methods for process models, rigorous models capturing operating realities versus design specifications and user-friendly dynamic modeling. This is crucial to understand the performance of gas- and oil-gathering networks and their interaction with production systems. Recent breakthroughs include packaging the advanced modeler experience into easy-to-use templates that show the models' value in speeding up the startup and shutdown of offshore operations from days to hours. Each such contraction results in incremental revenue opportunities. Innovation in encapsulating flow-assurance thermodynamics in areas such as hydrate formation and rigorous gathering network hydrodynamics into the general process-modeling environment has provided access to the general process engineer, resulting in economic and safety benefits for upstream operations.

There are many opportunities to achieve significant economic benefits both in the capex and opex domains as well as in incremental production. The challenge is to make sense of which technologies match the business priorities best and assemble them into a business solution. E&P

Five ways to get wells online on time every time

Leading capital planning systems are providing exactly what the oil and gas industry needs to get back on its feet: automated systems, quality data, visibility, reporting and scheduling.

Shiva Rajagopalan, Seven Lakes Technologies

A new wave of innovation is spreading across the world of energy. Buzzwords like artificial intelligence, Internet of Things and Big Data echo across every industry. The oil and gas industry has traditionally accepted a mostly manual capital planning process as a standard operating procedure, but the new age of efficiency brought about by cutting-edge capital planning is becoming too hard to ignore. And the new age of technology for business places collaboration and efficiency at the center of this revolution.

Digitalizing manual, paper-based systems provides unprecedented access to data for all stakeholders at any time from wherever they are. Automated data entry and real-time updates ensure all approved parties have the most up-to-date information. This enables them to make decisions with confidence while taking into account a wide variety of elements. These advances can significantly improve the interdependent work that often holds up the pace of operations.

Put intuitive systems to good use

Leading well management systems that standardize the well delivery processes and improve project success rates are vital to getting wells online. Automated software-as-a-service (SaaS) platforms offer significant reductions in well delivery lead times and costs while supporting seamless cross-departmental collaboration and process visibility. Systems that are fully configurable and provide automated workflows for changing business needs can help streamline existing processes and reduce errors.

Intuitive systems provide configurable workflows from the time of setup to the delivery across restoration for various stakeholders. Additionally, a centralized web-based database allows companies to capture data, access it from anywhere and leverage it to automate tasks.

For example, automated systems, such as Seven Lakes Well Lifecycle Manager, provide alerts as tasks are due, create checklists to prevent activities from being missed inadvertently and provide data validation rules to ensure that captured data are of high quality.

If a team is going to construct a well site and they do it at the wrong location, it is very expensive to fix. With a system in place, there is a much more transparent process to bring wells online and on time.

Do away with fragmented data

Through the seamless collation of all information in one place, systems then become integrated for two-way communication with various third-party systems like well operations systems, authorization for expenditure (AFE) workflow software, and economics and reserves software. This eliminates the manual, duplicate data entry process, which is extremely error-prone.

Through better data quality and data integration, these well management systems support much faster decisions for pad drilling programs and offer alerts to reduce risks proactively. The systems are also extensible to address post-drill well life-cycle management processes such as plug and abandonment and workover. These types of cutting-edge SaaS platforms provide configurable analytics dashboards and reports for continuous process improvement.

Extension of visibility, collaboration

Visibility expands when process and analytics dashboards provide continuous monitoring and improvement. They can quickly identify problem areas and resolve bottlenecks. The end-to-end visibility holds stakeholders accountable for meetings with visible well delivery workflow updates. After all, users have to be able to see things to schedule appropriately. To move to the age of efficiency, companies must be able to see where the bottlenecks and delays derive from to get wells online promptly.

With more precise insights, companies can assign tasks with a visible audit trail of activities and attached documents, which are easily accessible online. It is much easier to figure out work progress, stats on well drilling and completion of jobs when data are easy to access. There is no need to dig through paper trails and the constant deluge of emails. Automated status updates (e.g., ones that report drill readiness status) can be instantly updated on the rig schedule when teammates complete prerequisites. Any automated system should have strong workflow support to make it as functional and user-friendly as possible. In time, these systematized well delivery processes ensure repeatable project success.

Less paper leads to more empowerment

Capital planning processes lie at the center of the problem and the solution. The antiquated reporting systems still common today are primarily manual and paper-based, thereby limiting data visibility and slowing the capital planning process in comparison to digital counterparts. Decision makers in these firms simply experience a lack of progress and do not understand the reasons for the bottleneck, at least not without a time-consuming investigation.

Giving a team the ability to report accurate, up-to-date information on the entire breadth of operations means fast, efficient decisions.

E&P operations that implement configurable, easy-to-use self-service dashboards are empowered to create forecast reports, project future production and allow better planning overall. Particularly for top management, proper reporting means they always have the pulse of the drilling and completions programs at their fingertips and they can easily anticipate issues and take corrective action.

Jump on the automation bandwagon

Planning for rig mobilization and demobilization eliminates permit and construction delays, improving efficiency. However, having confidence that a schedule is feasible and all scheduling constraints are accounted for is difficult.

A majority of oil and gas operations do not have insights into scheduling roadblocks or the ability to question reasons behind the schedule change of a drill. While spreadsheets have long been the status quo, companies are getting to a stage where they must integrate smart software that helps regulate constraints and create a feasible schedule, while also being agile in response to changes.

But a "schedule" doesn't just mean straightforward start and end dates. It includes cues that flag violations of constraints such as not drilling and completing in proximity or respecting continuous drilling clause/obligation. Integrating systems that provide visual cues is the future of rig scheduling because it prevents costly mistakes and lost rig days.

Inefficient oilfield management simply has no place in the future. Oil and gas companies need collaborative solutions that serve up every scrap of data required to play AFEs, well delivery and rigs. Leading capital planning systems are providing exactly what the industry needs to get back on its feet: automated systems, quality data, visibility, reporting and scheduling. E&P

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All eyes follow the Permian Basin

As "Permania" subsides, region remains in the spotlight

Anyone seeking to understand oilfield activity knows to "follow the money" – and by that standard, the Permian Basin deserves all the attention it's getting.

Roughly $30 billion was spent on oilfield equipment and services in the region during 2014, when the boom hit its crescendo. According to Spears Research, Permian activity regained that level last year and is headed toward an all-time record **$45 billion** this year.

The Basin represents about 40 percent of the U.S. land market – the hottest market on the planet. ExxonMobil announced that half its upstream spending this year will be on U.S. unconventional assets, the first time in decades that U.S. investment grabbed so much of the oil giant's attention.

Boots on the ground know the story

This isn't news to the industry. Thousands of oil and gas professionals will gather May 21-23 in Fort Worth for Hart Energy's annual **DUG *Permian Basin*** conference and exhibition because no Midland venue is large enough to contain the crowd interested in Permian developments.

The 2018 agenda includes keynote addresses, operator spotlights and expert panels on critical issues influencing Permian Basin operations today:

- **The Impact of Big Oil** – Permian oil production exceeds 2.5 million barrels a day (up from less than 1 million/d in 2008) and changes the world power balance. What's next?
- **State-of-the-Art Deals** – As operators add leasehold to their Delaware and Midland basin sweet spots, what prices are they paying and what will capital markets finance?
- **Stacked plays and minding LOE** – Producers use manufacturing efficiency and Big Data to contain costs and make more oil. How will they capture and market associated gas and NGLs?
- **Export market roundup** – In an era defined by abundance, more infrastructure and how America's new bounty will reach demand centers depends on location, location, location.

Everyone who attends **DUG *Permian Basin*** wants to hear how producers, service companies and midstream operators intend to maintain the magic. World-class break-evens and leading-edge operations rely on continued improvement, so there will be plenty for engineers and executives to discuss. And with nearly all new West Texas crude oil destined for export markets, the world will be listening to these discussions.

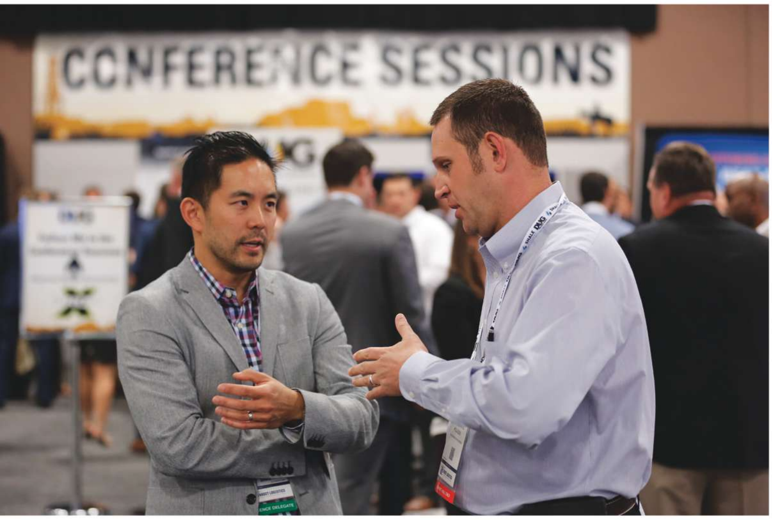
Engineering-based performance

Investors are calling for greater returns, and producers' earnings depend on capital efficiency and operational innovation. That's why Hart Energy will debut uniquely focused **DUG *Technology*** content on Wednesday, May 23 as part of the **DUG *Permian Basin*** program.

Regional variations will be in sharp focus as technology speakers in the main room at **DUG *Permian Basin*** address:

- New Permian sand mines
- Water logistics and water midstream services
- Last-Mile Solutions for proppant transport
- What's working now in the Permian Basin
- Common practices employed by Permian operators (and why)
- State-of-the-art technologies and products in the region

These topics, plus updates on key full-field development plans, will be detailed on the main stage and in straightforward Q&A exchanges that mark all DUG events. Full-conference DUG registrants get this technology-rich content as added value. Engineers, technical



There's someone knowledgeable to meet for almost any topic at DUG *Permian Basin*.

DUG PERMIAN BASIN	DUG EAST	DUG EAGLE FORD	DUG MIDCONTINENT
May 23 Fort Worth	**June 21** Pittsburgh	**Sept. 21** San Antonio	**Nov. 15** Oklahoma City

Don't miss the full-day technical programs in FOUR REGIONS!

The Technology Showcase brings concise, 15-minute technical presentations to the exhibit floor.

A lineup of industry leaders and subject-matter experts sets a high bar for DUG *Permian Basin* content.

personnel and others most interested in the second day's agenda can take advantage of reduced rates.

Case histories on the show floor

Producer and operator personnel qualify for complimentary passes to the exhibit floor throughout the conference. That access includes concise presentations in the **Technology Showcase**, a highlight of larger DUG exhibitions.

Technology Showcase audiences often hone-in on a specific topic then spend time face-to-face with solution-providers. This year's Showcase will address:

- **Drilling Better, Not Just Faster**
  From rig, pipe and bit manufacturers to directional drilling companies, new approaches and product enhancements offer incremental improvements.
- **Working Smarter, Not Harder**
  Digital solutions providers detail how sensors, Big Data and automation drive efficiency, save time and cut costs for their clients in the Permian Basin.
- **Lifting More, Not Less, For Longer**
  Getting more to surface combines art and science from suppliers of plunger lift (or gas lift) and pumping solutions (jet pumps, electric submersible pumps).

Shorter (15-minute) Technology Showcase talks typically emphasize case histories for solutions to region-specific challenges. Each topical segment ends with Q&A and a networking break.

Attention-getting programs

Hart Energy's "of the industry" perspective is reflected in its media (online, print and events), data and research services. This is evident in "All-Star" lineups of producers, midstream operators, technology providers and financial experts on stage – and in the professionals who populate DUG conference audiences.

As a special luncheon feature for **DUG *Permian Basin***, Hart Energy is honored to welcome back former Navy SEAL Team 6 leader, Rob O'Neill. This great American warrior was a key contributor to Operation Neptune Spear, the mission that sealed Osama bin Laden's fate. On a **DUG** stage for the first time since DUG *Eagle Ford* 2013, O'Neill will detail how this elite team of SEALs ended bin Laden's reign of terror. E&P

For more information about the 2018 **DUG *Permian Basin*** *conference and exhibition or any of Hart Energy's other* **DUG *Technology*** *programs, please visit* HartEnergyConferences.com.

Optimizing completion timing

Reduced operation time between stages can lead to higher fracture complexity and improved drainage efficiency.

Dan Themig, Packers Plus Energy Services

Recent studies tying subsurface stress conditions and mechanical properties of rocks to physical processes are providing a glimpse into the best methodologies to stimulate a reservoir to maximize fracture network complexity.

Using a geomechanical approach to fracture characterization has revealed that continuous pumping completion systems (e.g., ball-activated systems) achieve higher fracture complexity and surface area in the reservoir, resulting in higher drainage efficiency when compared to start-and-stop completion systems (e.g., plug and perf).

Hydraulic fractures are typically modeled as a single fracture because only one set of treatment measurements is available, such as treating pressure. The surface pressure response, treatment rate and proppant concentration are translated into a single planar fracture with a corresponding height, length and width. This can be a gross oversimplification of the actual fracture complexity.

This model also does not take into account continued deformation of the rock mass over a longer time period. During stimulation the reservoir is forced to accommodate additional volume. Time-dependent strain of the rock mass is typically not considered once a stage has been sealed off in the wellbore and operations have moved on to the next stage.

Key mechanisms controlling stress redistribution are the magnitude of the stress differential within the fracture relative to the minimum stress and the rocks' ability to accommodate it through elastic and inelastic processes.

If there is a time lag associated with operations, it is impossible to apply additional strain before energy loss and fracture closure begins. In a continuous pumping operation, the timing enables added stress to the system before the first initiated fracture is in a mode of closure.

Start-and-stop versus continuous pumping

Operational differences between completion methodologies impact geomechanics, stress distribution and fracture complexity, which ultimately correlates to reservoir drainage.

As slurry enters the reservoir for the first stage, the rock mass is forced to accommodate additional fluid and proppant. The resulting fracture adds pressure along the fracture face. The dissipation of this pressure manifests as a stress shadow that extends out into the surrounding rock through leak-off, elastic strain and inelastic strain. At this point in the treatment, the stress mechanisms are identical for both completion methodologies.

In start-and-stop completion operations, energy is lost from the fracture system after the first stage. The well is flushed to displace proppant remaining in the wellbore, ensuring that wireline tools are not obstructed. Tools for the next stage are pumped down using additional fluid that displaces proppant from the fractured interval. Perforating the next stage creates a new leak-off path for excess pressure from the previous stage's fracture. Excess stress in the fracture can equalize within the wellbore and reservoir. This equalization, or redistribution of stress, allows fracture closure.

Small losses in energy from the area of interest can have tremendous impact. The net effect of a change in the proppant distribution and stress dynamics are shorter and fewer complex fractures with less near wellbore conductivity.

In continuous pumping completion operations, stress in the local rock mass is at a maximum and the continuous addition of fluid to the system can be seen as the addition of energy. Following the first stage, spacer fluid is pumped down, followed by an actuation ball to isolate the previous stage and immediately begin operations for the second stage. When the ball lands in the sliding sleeve, the next stage is treated without interruption.

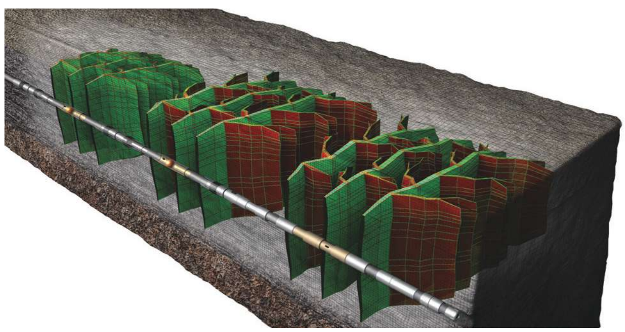


FIGURE 1. A ball-activated system offered maximized fracture complexity and drainage. Green represents fractures created from initial treatment. Red represents fractures generated from ongoing stress shadow interactions. (Source: Packers Plus)

These operations eliminate stress redistribution. The timing of the next fracture is at a point that can maximize and retain stress in the stimulated rock, leading to further ranging stress shadow effects (Figure 1).

Since continuous pumping completions are in a continuous mode of fracture propagation by virtue of the uninterrupted addition of fluid, the stress shadow interactions between sequentially created fractures are maximized. The second fracture further alters the stress state, and the stress shadows associated with each fracture have an additive effect on the rock mass between the fractures. The benefits of this process include added fracture complexity and improved drainage efficiency through greater fracture surface area.

Case studies

A study from a group of wells in the Montney Formation of the Western Canada Sedimentary Basin indicated fundamentally different geomechanical processes in start-and-stop and continuous pumping completions. The continuous pumping completions achieved higher EUR by more than 40% compared to the start-and-stop completions.

In addition to the production study, analysis of microseismic interpretations showed distinctive differences between the events recorded in each type of completion. The study's conclusions included

- A significantly greater number of seismic events occurred in wells using continuous pumping completions systems, and larger magnitude microseismic events occurred at all distances from the well;
- Strong fracture complexity was evident in the wells using continuous pumping completions but not in the start-and-stop wells;
- Lower magnitude focal mechanisms in start-and-stop wells indicated that these treatments followed pre-existing fracture pathways rather than developing new planes of failure; and
- The increase in production was directly related to the development of new fractures identified from microseismic data (Figure 2).

Another study in the Montney Formation examined the impact of continuous pumping completions fracture propagation on a producing well from two offset wells using microseismic data and a simulation model.

Well 1 was a producing well, and Well 2 and Well 3 were completed using a continuous pumping completion system. All 16 stages of Well 2 were completed in two days. The first 15 stages of Well 3 were completed the following two days, and then the final five stages of Well 3 were completed after an 11-day shutdown.

OPENHOLE MULTISTAGE VERSUS CEMENTED LINER PLUG AND PERF

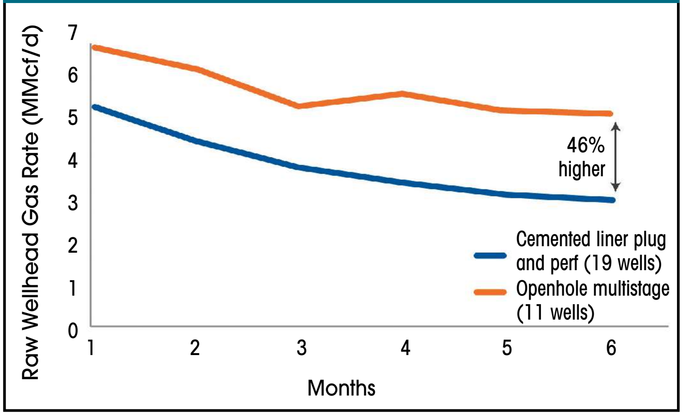


FIGURE 2. A comparison between start-and-stop (blue line) and continuous pumping completions systems (orange line) shows 46% higher production after six months. (Source: Packers Plus)

The results of the observations and simulation analyses offered insights:

- Production depletion can affect the stress in adjacent rock volumes, even if they are hydraulically isolated from the producing wells. This affects the stimulation patterns of completed wells;
- The prolific fracture propagation pattern of Well 3 likely resulted from the stress shadow influence of Well 2 and the rapid execution of successive stages in Well 3; and
- Stress shadow influences on the final five stages of Well 3 were absent because of the long interruption of operations, which was due to stress redistribution.

Conclusion

Studies examining stress mechanisms in the reservoir during stimulation showed clear differences between continuous pumping and start-and-stop operations.

The rapid sequential execution of stage treatments was beneficial to managing fracture propagation. The continuous pumping completions resulted in higher fracture complexity because they did not allow time for pressure in the hydraulic fracture to dissipate through the reservoir.

Furthermore, the stress shadows created by the fracture system of each stage had an additive effect, contributing to higher fracture complexity and improved drainage efficiency. 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*.

Improving reservoir contact with a high-transport proppant

Low-density proppant use in slickwater applications can help improve reservoir contact and fracture complexity.

Lee Reynaud, CARBO

The industry has witnessed a significant growth in the use of slickwater fluid systems in hydraulic fracture design in recent years, with conventional linear gel or crosslinked fluid systems becoming less commonly utilized. The primary drivers of this change in design methodology are cost, proppant pack damage minimization, fracture complexity and environmental footprint.

However, the diminished capability of slickwater systems to effectively suspend and transport proppant in a fracture due to its relatively low viscosity is well known and presents the most significant drawback of utilizing slickwater systems. This problematic transport behavior requires that fracture designs consist of low proppant concentrations (typically 0.25 lb to 2 lb proppant added) and leads to the necessity of very large volumes of fluid for placement. The majority of slickwater completion designs in recent times have incorporated a high percentage of small mesh size proppant (100 mesh and 40/70 mesh) into the pump schedules to afford placement in these thin fluid systems, impacting proppant pack conductivity.

REFERENCE CONDUCTIVITY COMPARISON

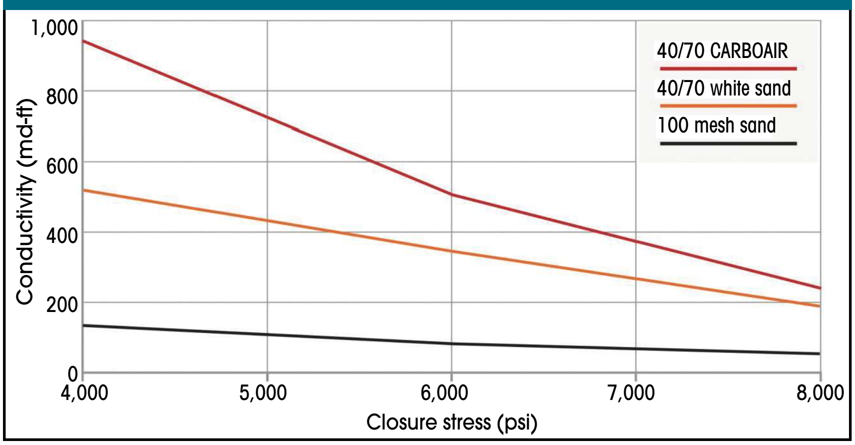


FIGURE 1. The conductivity performance of CARBOAIR technology is significantly higher than sand. (Source: CARBO)

Improving reservoir contact

Fracture conductivity and reservoir contact area (i.e., fracture length) are both contingent on proppant transport and are critical factors that significantly impact the economic viability of a hydraulic fracturing treatment. Proppant that is viable in low viscosity fluids must strike the right balance between lightweight, high-transport features and superior conductivity, primarily in comparison with equivalent sized sand. CARBO adhered to the following performance criteria when developing a new, high-transport, ultralow-density ceramic proppant technology to increase production and EUR from slickwater fracturing operations:

- It must be lighter than sand (for superior proppant transport); and
- It must be more conductive than sand at the closure pressures in which sand finds the most applicability (4,000 psi to 8,000 psi closure pressure).

By virtue of its reduced specific gravity in comparison with sand (2.0 apparent specific gravity ultralightweight ceramic versus 2.65 apparent specific gravity sand), CARBOAIR is a high-transport ceramic proppant developed to increase production and EUR through maximizing reservoir contact and fracture conductivity. It provides approximately 35% more volume with the same mass compared with sand at atmospheric conditions, by virtue of their differences in bulk density (1.15 bulk density CARBOAIR versus 1.56 bulk density sand). It was developed for utilization in low to moderate closure stress reservoir environments. These performance targets were chosen carefully so that the conductivity performance of the proppant could exceed sand at closure pressures in which sand finds the most application (Figure 1).

As such, the proppant can increase the contact area through a larger fracture volume (fracture length and height) without compromising fracture conductivity, and it also can be placed using low viscosity thin fluids.

Higher production, EUR

In nearly every reservoir, the higher fracture contact and conductivity delivered by the proppant results in higher production and EUR. Due to the improved contact, it is possible to utilize more efficient completion designs with fewer stages or smaller fracture designs to deliver the same or increased production, with no increase in authority for expenditure. Any required investment has a rapid payback and will result in a lower finding and development cost per barrel of oil equivalent. To date, the proppant has been pumped in tail-in applications throughout three major basins: the Permian, Northeast and South Texas. Internationally, the proppant has been deployed in an openhole gravel pack in Trinidad, which proved to be operationally successful.

As a lead-in, the proppant can provide increased propped half-length, which increases the drainage area of the fracture. As a tail-in, the proppant will cover more of the productive pay zone and lead to increased production compared to conventional sand, resin-coated sand or ceramic proppant.

By alternating the proppant with standard proppant within a fracture stage using slickwater fluids, the technology can provide increased effective propped length as well as full productive zone coverage, leading to additional production and ultimate recovery.

Due to the significantly lower density, 30% less mass of the lightweight ceramic proppant can be used to replace the same volume of sand proppant, thereby reducing the amount of water and chemicals used for the treatment. CARBOAIR proppant also provides more coverage across the pay zone, leading to increased production.

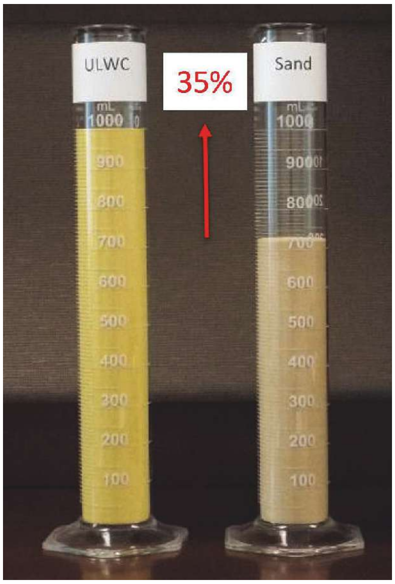


FIGURE 2. An equal mass of CARBOAIR (left) and sand (right) displays the density differences between the two proppants. (Source: CARBO)

Case study

A second Bone Spring interval test well in the Permian Basin was drilled as a wildcat horizontal based upon vertical openhole log data through an interval of the Bone Spring member from a nearby offset. There had not been another second Bone Spring horizontal test within 15.5 sq km (6 sq miles) of Well A. The lateral section was landed in a 30.4-m (100-ft) section (gross interval) of the second Bone Spring interval bounded between two thick limestone layers, in which a small interval of crossover porosity was recorded. While the electrical log, rotary sidewall cores and mud log data showed high evidence of hydrocarbons, they presented a problem on how to effectively stimulate this thin interval and achieve an economic rate of return. This scenario introduced a great need for incremental propped length as a design objective for optimal oil recovery.

High volumes of nonspecification 100 mesh and 40/70 mesh sand in slickwater (more than 2,000 lb/ft) already had been tested in another second Bone Spring interval well with a thicker gross interval with exceptional results. The primary goal of Well A was to substitute the 40/70 mesh sand with 40/70 CARBOAIR as a way to transport this proppant farther away from the wellbore by utilizing the lightweight characteristics of CARBOAIR and fracture complexity using slickwater fluids to increase contact area and hydrocarbon recovery.

The main operational considerations with pumping 40/70 CARBOAIR and 100 mesh sand were to ensure an accurate sand total was being calculated due to the density differences between CARBOAIR and sand (Figure 2). Two inline densitometers were calibrated and used for these respective sand types, while sand bins on location had the exact amounts of mass required per stage to improve metering accuracy.

The 40/70 CARBOAIR proppant was successfully deployed in a thin section of the second Bone Spring interval. Prefracture modeling results based on completions and reservoir information gathered from the subject well suggested an increase in propped fracture length and propped fracture height of 16% and 40%, respectively, yielding an increase of more than 19% in the contact area. From a well performance standpoint, Well A continues to record steady average monthly production rates and appears to deliver a favorable long-term decline curve from a thinner pay interval. This performance is attributed to the improvement in propped fracture geometry resulting from the utilization of the high-transport proppant. 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*.

Toolbox offers new technology for casing recovery requirements

New service approach saves operators time and money.

Mike Wardley, Ardyne

The introduction of pioneering directional drilling technology in the 1990s led to a boom in subsea wells. Now the industry faces a new frontier in the mid- to end-life requirements of those wells, and new downhole technology is emerging to optimize intervention and abandonment operations with benefits for complex and simple wells alike.

A key area where that new downhole technology is succeeding is in casing recovery, either as part of a slot recovery where the casing is removed to allow a new wellbore to be sidetracked from the same platform slot or as plug and abandonment where the well is to be either temporarily or permanently abandoned and casing needs to be recovered to place competent barriers in the well.

However, casing recovery can be extremely time-consuming, particularly for complex offshore wells where up to 70% of the rig time spent abandoning wells is incurred during the tripping and casing recovery phase of operations. It is precisely in these high-cost operations that time saving results in massive cost reductions.

The reason for this high cost is rooted in the single function technology—casing cutters and spears—that are conventionally used for cut-and-pull operations and the multiple trips in and out of hole required to accomplish sequential objectives using this single-function technology.

The TRIDENT is a rotary-driven, single-trip cut and pull system that includes an integral tension set packer and a hydraulically activated spear. (Source: Ardyne)

This multiple trip problem is compounded by the risk of an unsuccessful cut-and-pull attempt. Many factors can lead to the casing not coming free when pulled. Old cement, formation shift and casing degradation can play a part in making casing recovery an unpredictable operation. Ultimately, the pulling force required from topside equipment to recover a section of cut casing is unknown until an attempt is made to pull.

If insufficient pulling capacity is available and the attempt is unsuccessful, then the casing needs to be cut into smaller pieces, lowering the friction and mass of the fish. However, with conventional equipment this requires at least another two trips with cutter and spear, and in difficult wells the sequence of attempts and recuts can be repeated many times until the target string of casing has been recovered.

These issues and hours are further magnified in complex and subsea wells, which are those operations that are increasing in frequency, and where stuck casing is more likely and tripping depths are greater.

Therefore, the demands for new casing recovery technology are twofold—to save time by combining sequential operations into a single trip as well as to offer smart, flexible functionality that allows an adaptive response to these unexpected wellbore challenges.

Designed for results

Ardyne's Casing Recovery Toolbox includes two specialized cut-and-pull systems, the TRIDENT system and the TITAN system. Both systems begin with single-trip casing recovery and are differentiated by the additional functionality each brings to a slot recovery or plug and abandonment (P&A) operation, with each system optimized for different aspects of recovery.

The TRIDENT system is a rotary-driven, single-trip casing recovery system that incorporates several trip saving features including an integral tension-set packer for positive and negative pressure tests, and a hydraulically activated spear in conjunction with the ability to either run and set a bridge-plug or dress a cement plug prior to commencing the cutting and recovery of the target casing. TRIDENT has inbuilt additional features including cut indication capability, a swarf management system to avoid swarf entering sensitive well control equipment, a spear that sets in both 9⅝-in. and 10¾-in. casing for tapered casing strings and a packer for annulus circulation around the cut casing.

The TITAN system unifies a downhole hydraulic power tool with single-trip casing cutting and recovery. The downhole adaptability of the TITAN system maximizes recoverable casing in challenging circumstances by increasing pulling capacity to 1.8 MMlb with the power tool and minimizing the risk of stuck fish by enabling repeatable, verified casing cutting in a single trip.

Repeatability is key

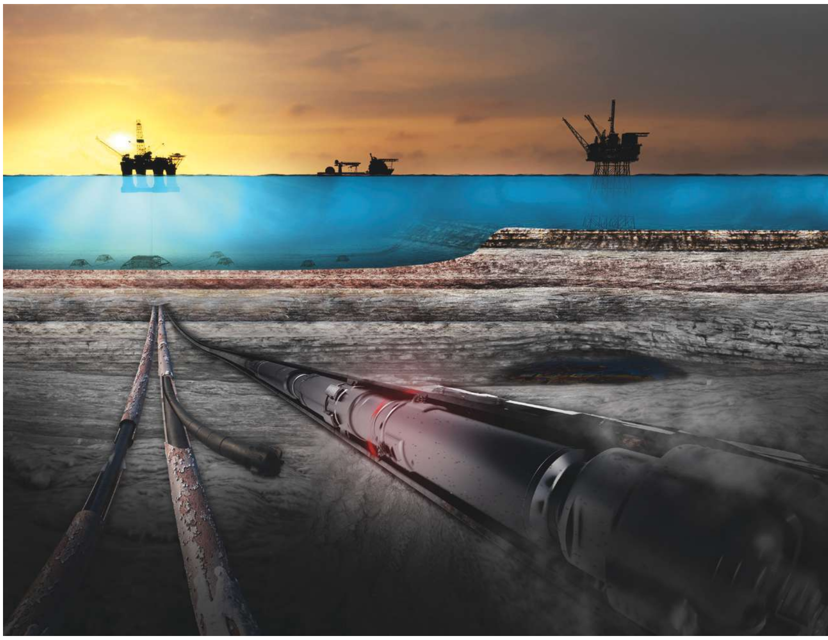
A single-trip cut and pull alone offers a step change in operational efficiency, but the TRIDENT and TITAN systems have been designed with additional functionality to avoid further planned trips and to allow the systems to adapt to unplanned downhole issues. Repeatability is key to this downhole adaptability. In scenarios where the casing is stuck, it is possible with both systems to reposition and make additional cuts without pulling out of hole to change bottomhole assemblies (BHA).

To enable these repeated cuts, the TRIDENT system is anchored when cutting casing, which centralizes the knives and increases stabilization during the cutting operation. This reduces vibrations in the drillstring, resulting in increased longevity and efficiency of the cutter knives that in turn enables repeatability in cutting operations.

Being anchored when cutting on a semisubmersible unit also eliminates the need for a marine swivel as the cutter is anchored in the same location throughout the cutting operation. The rig compensator takes up most of the heave, but any remaining drillstring movement is taken up by the TRIDENT anchor, ensuring that the cutter is held at correct depth for the completion of the cut.

Pressure rated to 3,000 psi, the TRIDENT system is ideal for most applications where a pressure test is required in a slot recovery or P&A application (e.g., testing the cement plug). The element can hold the differential pressure from either side of the element, thus enabling it to be used for positive and negative pressure testing.

The TRIDENT packer also can be set downhole once the casing cut is completed and an attempt can be made to circulate through the outer annulus to ensure that any shallow gas trapped below the seal assembly and wellhead, or any other annular gas, is circulated out prior to recovering casing. With the TRIDENT anchor set and the annulus cleaned, it is also possible to attempt to lift the casing to verify that it is free while still having the BHA at cutting depth.



The use of the Casing Recovery Toolbox saved more than one day of rig time on a North Sea P&A operation. (Source: Ardyne)

Improving efficiencies

The technological improvement offered by the TRIDENT and TITAN systems has justified several operators moving to treat casing recovery as a niche, value adding service. Following rigorous North Sea field testing in summer 2017 through the end of the year, Ardyne's single-trip cut-and-pull systems amassed in excess of 30 runs, with many more planned in 2018.

In a recent P&A operation, Ardyne's Casing Recovery Toolbox was mobilized for a North Sea P&A operation, where planned operations included cutting and recovering 9⅝-in. and 13⅜-in. casing. By combining trips and through adaptable, repeatable downhole technology, the toolbox saved more than one day of rig time on an operation, which would conventionally have taken 3.5 days, and improved efficiencies by 35%.

Despite a focus for 2018 on commercializing its field-tested single-trip cut-and-pull systems on a global basis, Ardyne continues to add to the Casing Recovery Toolbox, with new technology and methods in the pipeline including vibration-assisted cut and pull, cement-through capability and a casing punch. E&P

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

Technology shows DHI promise

Electroseismic technology is being tested in conventional reservoirs.

Jim White, **Patrick Reese**, **Naga Devineni**, **Alan Katz**, **David McCabe** and **Thomas Ault**, ES Xplore

Conventional reservoirs generally have been the easiest and least expensive reservoirs to drill and exploit, and when drilled successfully, they usually are the most profitable. Finding prospects that are geologically suitable, as well as economically efficient, has always been the biggest issue for conventional operators. As such, operators have searched for a tool that can reduce the risk from the drilling targets. Electroseismic data might be the tool that these conventional operators have been looking for. The unique ability to image the location of hydrocarbon reservoirs in the subsurface changes the way companies evaluate and drill prospects.

Electroseismic theory

Exploration geologists and geophysicists constantly are looking for ways to reduce risk in the prospects they develop, and detecting the presence or absence of hydrocarbons is the fundamental factor in reducing that risk. Electroseismic technology utilizes the natural phenomenon that couples electromagnetic and seismic energies together through the medium of porous rock. An applied electric field acts on ions in the aqueous phase that, in turn, drags fluid particles as the ions move with the electric field. The resultant fluid flow reacts against the rock grain matrix to generate a compressional seismic wave that can be measured at the surface. The fundamental factor that makes this technology suitable for hydrocarbon detection is that the electroseismic coupling is significantly enhanced in the presence of electrically resistive oil and gas in the rock pore space.

The physics behind electroseismic is not new as the natural phenomenon began to be understood in the 1930s, and research in the oil and gas industry has been ongoing since the early 1990s. Active source methods were tested and proved by an oil company but abandoned because of the cumbersome logistics associated with large electric sources. The relinquishments of the active source method led ES Xplore (through Hunt Oil's venture capital group) to research and develop a passive method of electroseismic imaging that utilizes the earth's existing electric field as the source. The passive nature of the data collection allows fieldwork that is nonintrusive and efficient, qualities that other subsurface imaging techniques do not have.

Operational benefits

There are significant operational benefits to electroseismic data outside of the environmentally friendly

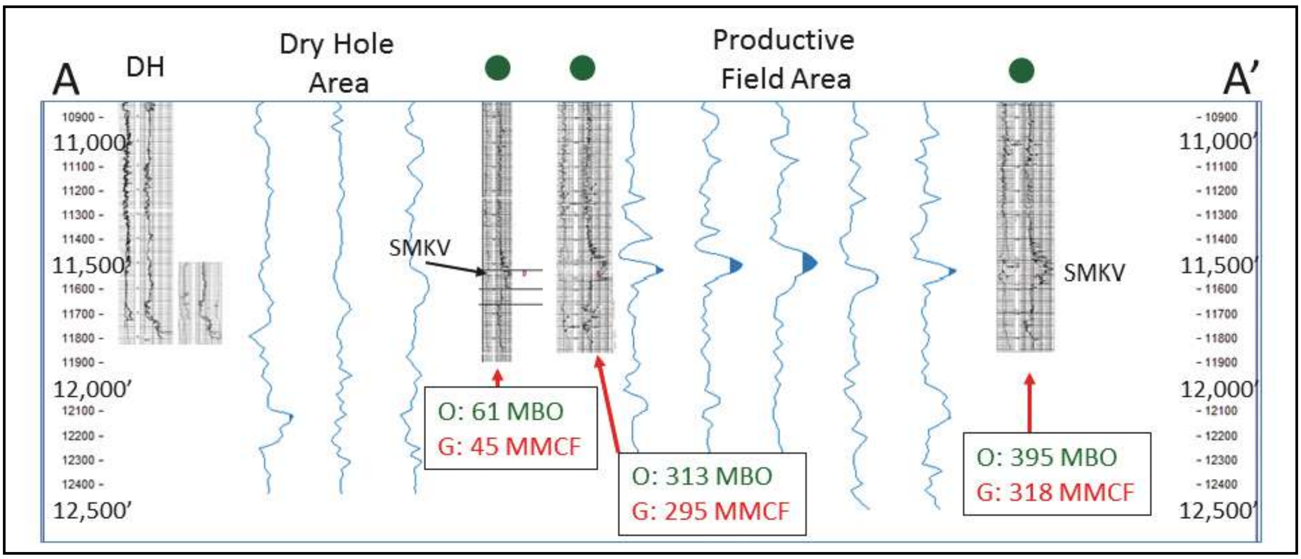


FIGURE 1. This cross section from A to A' shows ES Xplore well logs running east to west. There are amplitude spikes in the producing area, which are scored and contoured in map view to produce the heat map in Figure 2. (Source: ES Xplore)

data collection. Many of these benefits are based on the fact that each survey point is independent and autonomous to all other survey points. This has proved extremely important when working around complex permitting and land situations. The result is that electroseismic data covering small surface areas can still have full-quality subsurface imaging even if patches of land remain impossible to permit. This survey point autonomy also can have large technical value. If the resolution of a survey is deemed to be too low, points can be infilled and added to the old survey without requiring the old survey points to be re-shot. Also, if an electroseismic survey needs to be expanded geographically, there is no need to overlap surveys, and new data can be collected starting from the edge of the old survey.

Additionally, the processing and interpretation of electroseismic data is extremely efficient with final data being returned to the client within 30 days. This time efficiency means tough choices about drilling to keep leases HBP can be made on a scientific basis. This flexibility allows clients who utilize the electroseismic data to conform this new technology to their needs.

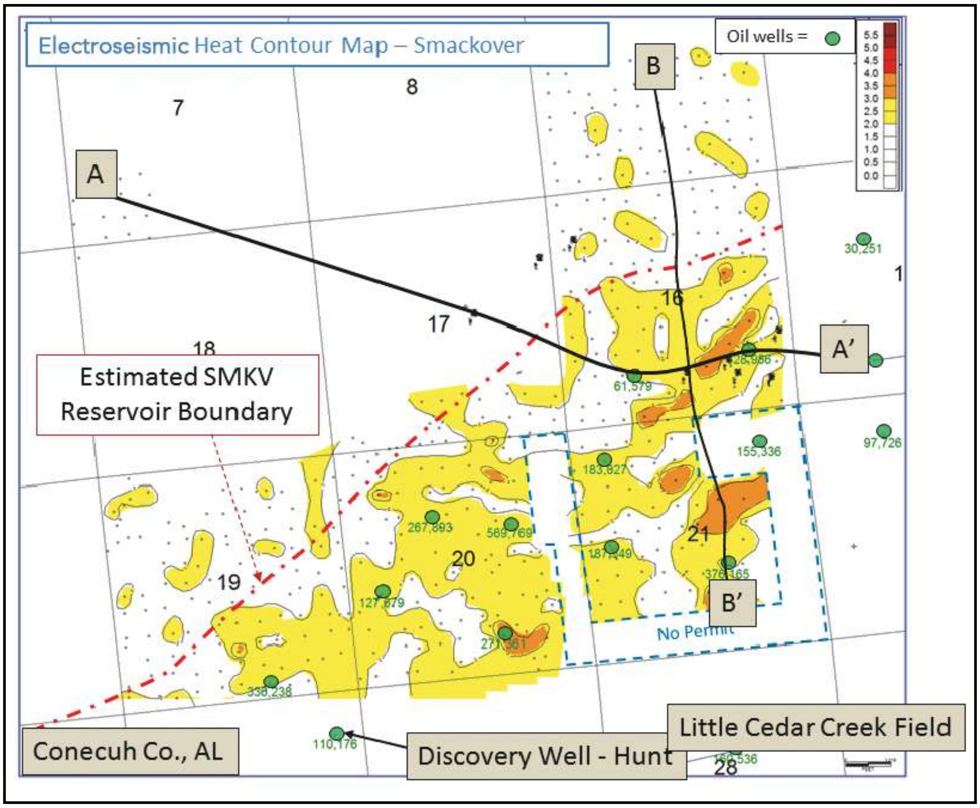


FIGURE 2. The electroseismic contour heat map shows the extent of the Little Cedar Creek Field. The operator had a successful discovery to the south and then used 2-D seismic to drill an unsuccessful step-out well. The operator then sold its lease position, only to see the field produce 36 MMbbl. This ES Xplore survey was conducted to determine if the technology could have changed the step-out location. This map indicates a boundary between the productive and nonproductive Smackover Formation. (Source: ES Xplore)

Resultant electroseismic data

The output data from an electroseismic survey mimic a well log or a singlefold seismic section from the early days of exploration (Figure 1).

The nature of the gridded acquisition design provides multiple responses across the surface of a given polygon. These data are then contoured to provide a detailed outline in map view of potential hydrocarbon indication at specific depths within the area of interest.

Figure 2 is a data example from the Little Cedar Creek Field in Alabama showing the original discovery well and the failed step-out well. Upon review of these data, one might assume that the operator would have made a different decision on the location of the step-out well if it would have had electroseismic data to assist in the decision-making.

De-risk conventional prospects

For now, the value of electroseismic data is in evaluating conventional targets. Operators can de-risk these plays because the resultant data can indicate the presence or absence of hydrocarbons. Until now, the de-risking technologies of conventional plays rested in the hands of extensive and expensive 3-D seismic acquisition and processing to determine the likelihood of a successful prospect. Electroseismic data add another tool in the toolbox for conventional operators, one that can complement seismic data and, in many cases, stand alone in providing information that has a direct impact on E&P companies' bottom lines. The combination of unique and revolutionary data along with a drastically different operational timeline and approach all combine to make electroseismic data an exciting new option for conventional operators. E&P

Coupling matters

A nodal recording unit with a unique form factor leads to improvement in coupling and vector fidelity on land seismic surveys.

Tom Fleure, Ambient Reservoir, and
Richard Degner, GTI

A step change in the evolution of seismic recording systems began 10 years ago with the commercialization of high-channel-count autonomous nodal recording systems. While nodal recording systems such as the seismic group recorder were introduced decades prior, the advent of high-capacity lithium ion and polymer batteries, the reduction in the cost of solid-state memory and the availability of low-power and low-cost GPS chips changed everything. Combining these advances with the decreasing cost of electronic components and electronic manufacturing allows seismic nodal recorders to be built today for a fraction of the cost and weight of the seismic group recorders of the 1980s. It could be said that the seismic group recorder was a great idea but was 30 years ahead of itself.

New nodal recording systems weigh only 2 lb, including geophone and battery, and can record continuously for weeks. To seismic operators, this evolution has manifested a new generation of nodal recorders that provide huge flexibility in the way 3-D surveys are designed, allowing operators to greatly increase seismic trace density while staying within a customer's budget. In addition, new nodal recording systems also have led to a marked improvement in receiver coupling and vector fidelity.

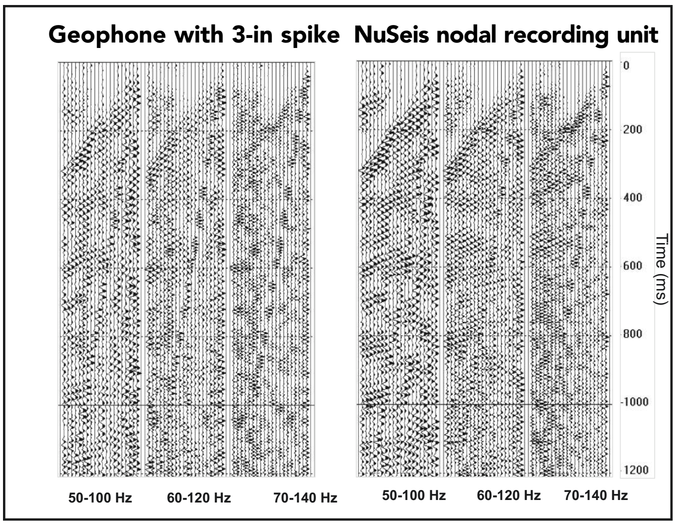


FIGURE 1. These bandpass filter panels show a side-by-side comparison of NuSeis versus conventional geophone data. The NuSeis data exhibit stronger reflection amplitudes and better continuity above 50 Hz. (Source: GTI)

Better coupling

New nodes are much smaller than older recording systems, and they do not have cables attached to them. Therefore, the entire recording unit can be placed into the earth, not just the geophone sensor or accelerometer. GTI's NuSeis nodal recording unit, for example, is designed to be pushed into a 2-in. diameter hole, which is created using a slide hammer. This is a very similar process to press-fitting a shaft into a bearing such as on a truck or an automobile axle, and it results in an exceptionally tight fit between the sensor and the earth, which is called earth grip coupling. Whereas a conventional geophone in a land case with a 3-in. spike might have a contact area of only a few square inches with the soil, the NuSeis nodes will routinely have as much as 50 sq in. of contact area.

The nodes also can reach denser, more consolidated material. GTI recently repeated experiments on receiver coupling originally done in the early 1980s showing that loose garden topsoil can be nonlinear at frequencies as low as 100 Hz. Getting beneath the loosest soil and into denser material can lead to improvements in high-frequency response and vector fidelity in general. Some seismic contractors have a long history of using marsh-case geophones rather than land-case geophones for this exact reason. The new recorder approximates the size and shape of a marsh-case geophone.

In addition, the small size of the nodal recording unit and lack of any cable connections allows the entire unit to be quickly and efficiently placed below ground level. This placement results in a decrease in the pickup of background noise by eliminating any exposed surface vertical profile of the recording unit to wind and other airborne acoustical noises. Even the mechanical transfer of rain noise is highly attenuated when the nodal recorder is underground. And when a unit is planted with the top dome aboveground, the vertical profile is far more aerodynamic than other recording systems because of its sharp perpendicular edges.

Examples

In side-by-side field tests over the last two years, several examples have been collected. Figure 1 illustrates marked improvement in high-frequency response from a walk-away comparison test conducted near Angleton, Texas, using an accelerated weight drop as the seismic source. The figure shows bandpass filter panels for the data recorded with the NuSeis unit versus data recorded with another nodal recording system using an external single geophone with a 3-in. spike.

The center panels on each side have been filtered with a 60-Hz to 120-Hz bandpass, and the reflections are both stronger and more coherent on the NuSeis data (the right side) from 300 ms down to 1.2 seconds. The right-hand panels on each side have been filtered with a 70-Hz to 140-Hz bandpass filter, and the comparison is even more dramatic.

Above 70 Hz, the geophone data contain very little reflected energy, whereas the NuSeis data have clear reflections down to at least 700 ms. Spectral analysis quantifies the difference in signal level to be on the order of 6 dB to 8 dB greater for the NuSeis data in this time interval.

On this same comparison test, the first breaks were also visibly sharper and stronger. As is generally true, the first breaks have the highest frequency content of any events on these seismic records. In this case, the bandwidth of the signal on the NuSeis data goes all the way up to 125 Hz, with a maximum difference of 16 dB at 85 Hz relative to the geophone data (Figure 2). Improving first-break sharpness can make it easier to pick the first arrival time and minimize errors in the computation of refraction or other static solutions.

Signal-to-noise ratio is one of the key metrics in evaluating field seismic data. This metric can be improved by either increasing the signal levels or decreasing the noise levels. Figure 3 shows that the aerodynamic profile of these nodes has decreased the background wind noise level substantially in the high-frequency portion of the spectrum versus geophone data. Specifically, the figure shows Vibroseis-correlated records with a high-pass filter applied with the corner points at 80 Hz and 100 Hz, respectively. The banding caused by noisy stations in high-grass areas of a hay field can be seen on the geophone data but not on GTI's data.

Vector fidelity has been an important topic in seismic acquisition research for almost 40 years. While the ability to image reservoirs deep within the earth is dependent on powerful processing algorithms, those algorithms need accurate measurements from the earth's surface to provide optimal results. The old phrase "garbage in, garbage out" is never truer than in seismic acquisition and processing. The new generation of compact recording nodes should improve vector fidelity and thereby start the long seismic imaging workflow with the best input possible. E&P

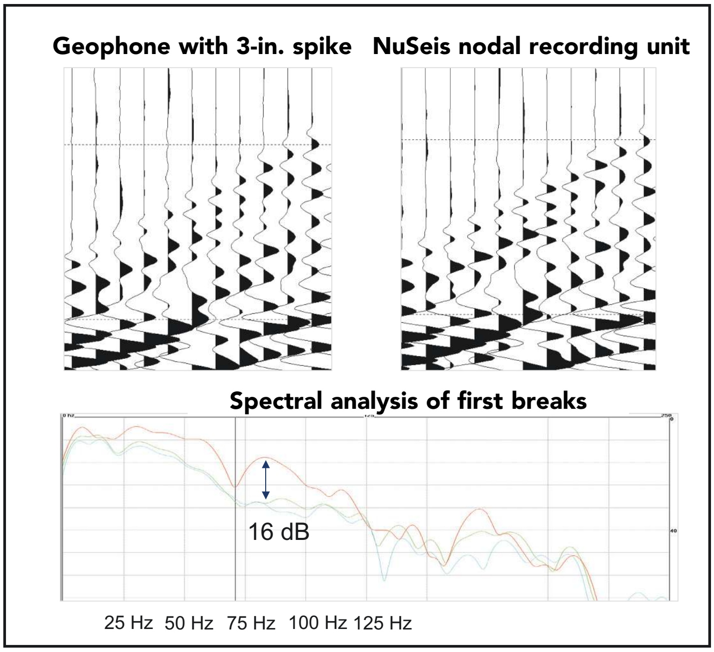


FIGURE 2. This side-by-side comparison of NuSeis versus conventional geophone data shows the fixed-gain-display first breaks and corresponding spectral analysis, which shows up to 16 dB higher amplitudes at 85 Hz. (Source: GTI)

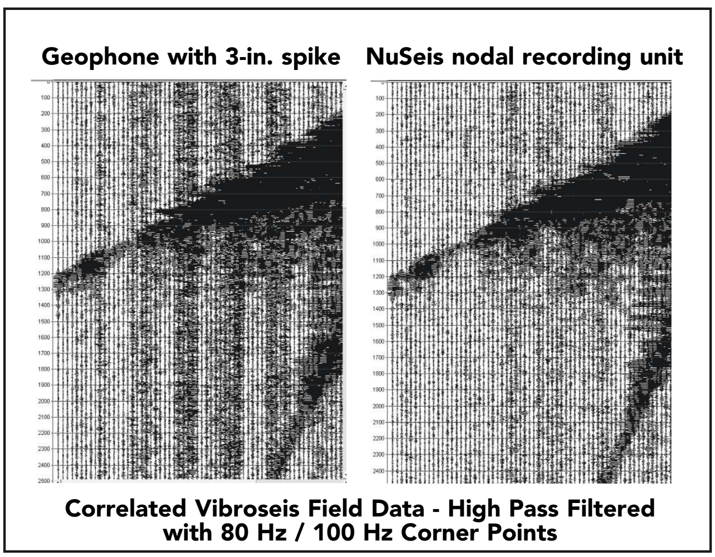


FIGURE 3. Seismic data recorded with the NuSeis nodal recording unit shows significantly less wind noise when compared with conventional geophones with a 3-in. spike. (Source: GTI)

Acoustics network delivers sound results

New telemetry systems are opening the path to full life-of-well pressure and fluid management.

Andy Hawthorn, XACT

The oil and gas industry is seeing a growing issue of how to effectively overcome the challenges presented by fluid and pressure management. This concern is only expected to grow as wells and fields become more complex.

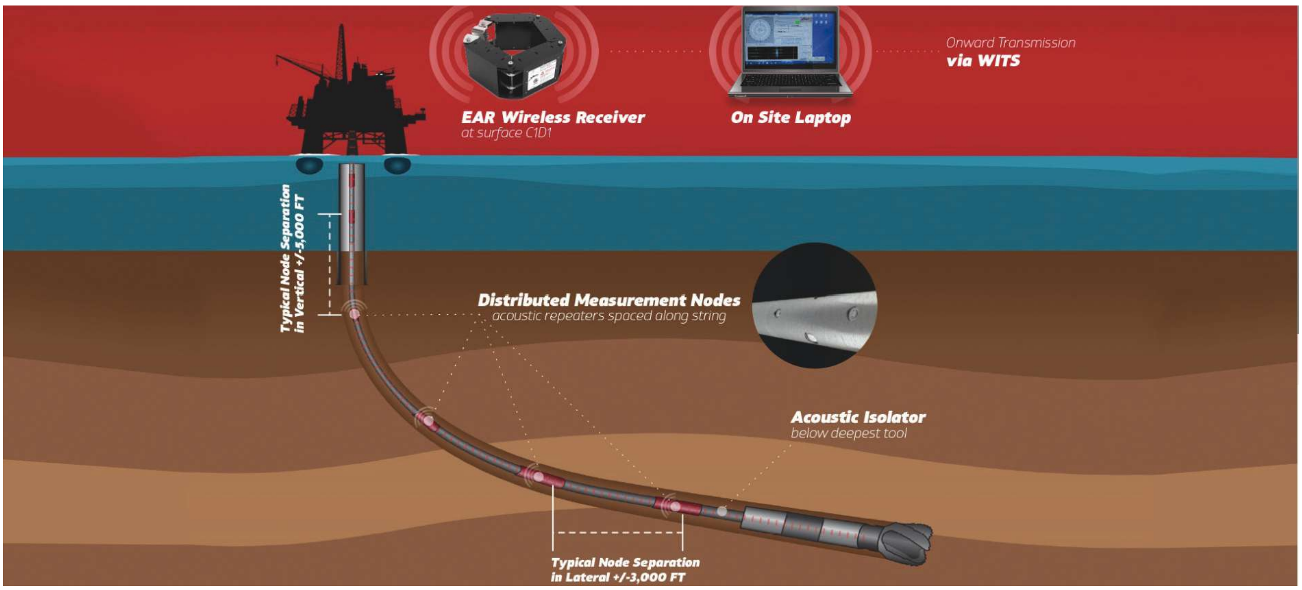
Energy research analyst Wood Mackenzie recently suggested production from the Gulf of Mexico (GoM) could climb to a record 1.9 MMboe in 2018, a 13% increase since the 2017 peak. However, exploration is expected to remain flat, in line with global trends.

The cutback in exploration budgets throughout the last few years means operators will increasingly seek to further develop existing infrastructure, leading to an increased focus on the challenges of fluid and pressure management.

Globally, there are many existing wells that are either heavily depleted or create the challenge of needing to drill through a depleted reservoir to reach a deeper target. Such situations can create a significant pressure overbalance in the well, resulting in a potential loss of fluid, hydrostatic head and barriers and, in some cases, not being able to drill and complete desirable reservoir targets. Current methodologies for fluid and pressure management might impact fluid injection capabilities and could ultimately affect reservoir productivity.

The ability to measure fluid levels downhole to maintain safe barriers and to manage pressures to better control mud weight windows while drilling ahead, cementing, running casing and completing wells is highly important. Receiving downhole data from a telemetry system in real time irrespective of fluid, flow or the formation characteristics can enhance the accuracy of decision-making, thereby increasing operational efficiency and reducing risk.

Conventional telemetry has often focused on mud pulse systems that rely on the maintenance of a full mud column. This can be achieved by enhanced fluid injection, but this process can increase overbalance in the reservoir. Such systems also deliver a relatively low data rate, are depth limited and create a constriction in the bore of the drillpipe. These systems are deployed and then can send meaningful real-time data only when



The acoustic downhole distributed sensor and telemetry network developed by XACT transmits real-time data through the wall of any drillstring. (Source: XACT)

on the bottom drilling ahead. For an offshore deepwater well, this might mean only receiving data for less than 15% of total well construction time.

Cementing, running casing, tripping in and out of the hole and installing completions are activities that, despite being equally challenged by pressure and fluid management, have no real-time access to actual downhole conditions.

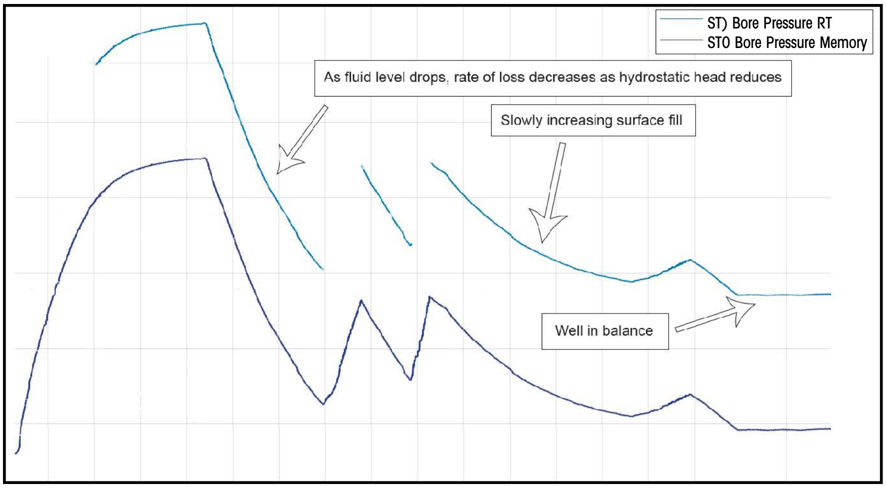
Applied acoustics

An alternative to existing telemetry systems has been developed by XACT Downhole Telemetry. The company's acoustic downhole distributed sensor and telemetry network transmits real-time data through the wall of any work or drillstring irrespective of flow, fluid type, formation or depth. The network's improved real-time downhole visibility through a nonfluid dependent system enables operators to control downhole pressures and fluid levels by providing accurate pressure and temperature readings. The independence from the mud system allows, in a controlled and regulatory-approved methodology, the ability to reduce the hydrostatic head leading to minimization of fluid loss, formation and wellbore damage.

XACT's acoustic telemetry network is based on the installation of acoustically linked downhole measurement and telemetry tools to create a robust telemetry data and sensor network.

The tools are conservatively spaced about 1,524 m to 1,829 m (5,000 ft to 6,000 ft) apart in the vertical sections of the well and 914 m to 1,219 m (3,000 ft to 4,000 ft) apart in horizontal sections of the well to provide optimum signal strength and transmission range depending on the deviation of the hole. In addition, the fullbore tools allow the deployment of wireline-conveyed tools as well as wiper darts, third-party activation balls or the passage of large amounts of lost circulation material, cement or completion proppants.

The collar-based design of the tools provides sufficient space for lithium batteries, sensors, electronic boards and the piezoelectric stack, which allows the acoustic transmis-



Real-time data received downhole using the acoustic telemetry network shows how the well is in control and pressures are managed with the fluid level at several thousands of feet below the rotary table. (Source: XACT)

sion of data back to the surface. In addition, mechanical parameters such as pressure, weight, torque, bending and temperature are recorded downhole and transmitted acoustically in real time via the steel body of what has now essentially become a smart string.

The tool also can gather distributed measurements from a range of locations via the multiple spaced nodes to obtain a real-time snapshot of the conditions along the entire wellbore. Data are sent to a wireless receiver at the surface and from there are wirelessly transported to a laptop for integration with other rig data.

GoM case study

An operator of a GoM deepwater well needed to minimize fluid losses and associated formation damage while maintaining optimum overbalance at the formation. This was to be accomplished by reducing and controlling the fluid level in the high-pressure riser annulus. Conventional measurement techniques, such as echometers, were problematic in accurately measuring the riser fluid level and providing real-time updates required to proactively manage inflow. Additionally, any in-well tools had to be fullbore to allow the passage of wireline tools needed to operate a formation isolation valve.

The operator used the XACT acoustic telemetry network, a technology the operator helped develop, to more reliably and safely minimize formation damage. Integrated measurement and acoustic telemetry nodes were positioned in the riser at 1,066 m and 2,286 m (3,500 ft and 7,500 ft) below the rotary table.

Bore and annulus pressure data were acquired and displayed at the surface to determine the top of the mud column relative to the rig floor and the volume of mud above the tools. Data were transmitted every 25 seconds throughout the operation, allowing rig personnel to safely monitor the well through all operations including tripping, tubing-conveyed perforating (TCP) gun operations, acidization and installation of the upper completion.

Knowing the position of the top of the fluid in real time allowed the operator to proactively manage the losses by maintaining the fluid level at about 1,219 m below the rotary table.

This applied a known and controlled overbalance on the reservoir, which minimized loss rates and potential formation damage because of excessive overbalance and high loss rates. This can be critical in injection wells as controlling losses by pumping pills can adversely affect the performance of the injector and lead to earlier intervention.

Continuous measurement allowed timely adjustments to be made as loss rates changed before and after perforation and during the subsequent acid wash and mini frack operations.

Comparison of the distributed measurements from the two XACT tools showed a partial blockage forming between the tools, identified as hydrate buildup. Then fluid levels were modified to increase pressure on the reservoir to minimize this effect, and later were removed by glycol prior to future operations.

The operator successfully engineered and safely completed an operation that would not have been attempted without the capability to oversee continuous fluid and pressure monitoring without affecting well performance.

Looking ahead

The acoustic telemetry system has been used to assist in fluid and pressure management in a growing range of applications and global locations. The system has been deployed several times in the GoM and North Sea during drilling operations and is set to be deployed in the North Sea again for casing and cementing applications in wells with pressure and fluid management issues.

The need for effective and efficient fluid and pressure management throughout well construction is expected to become of even greater significance this year and in the future as operators continue to cut costs and enhance performance. E&P

Integrating MPD into existing infrastructure

Drilling efficiencies are maximized with integrated MPD systems.

Svein Hovland, National Oilwell Varco

Managed pressure drilling (MPD) has gained significant traction as an adaptive drilling method for challenging wells with narrow downhole pressure limits. Though a standard set of MPD equipment is used across the oil and gas industry, there has been some debate on what constitutes true MPD integration.

MPD control systems, the combination of engineered software and specialized hardware, are used to help mitigate the difficulty of dealing with such complex drilling approaches. However, National Oilwell Varco (NOV) believes permanent installation and integration with existing rig infrastructure must occur to truly change the MPD business paradigm.

Challenges

The MPD method has traditionally been perceived as overly complicated, involving many different subsystems and interfaces, and requiring specialist knowledge in both the planning and execution phase. The cost of an MPD project has been prohibitively high to many operators, and MPD has often only been applied in extremely specific scenarios for wells that would be impractical otherwise. Mobilizing a temporary MPD service involves rig modifications, installation, commissioning and potentially third-party certification via organizations such as ABS and DNV GL.

The result of these challenges is that many potential end users have negative associations with MPD, which is problematic if the method is to gain more widespread implementation as a viable drilling technique. The solution to these challenges is deceptively simple. First, MPD equipment must be permanently installed versus used on a job-by-job basis. Second, the systems must be truly integrated with existing rig infrastructure. And third, a more sustainable business model must be developed that ensures the practice remains financially feasible given current oil price equilibrium.

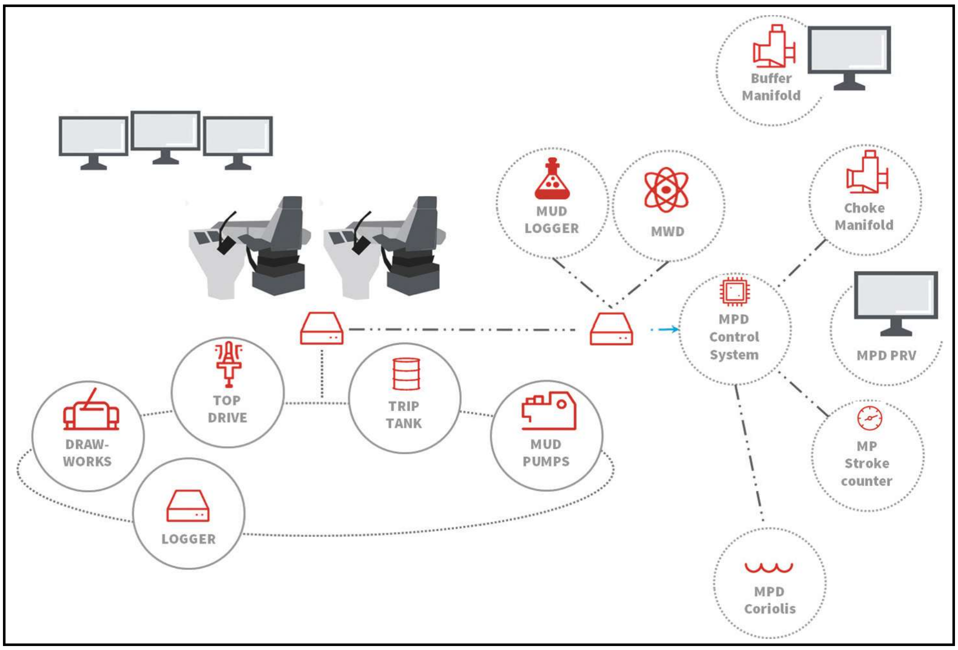


FIGURE 1. The MPD logic in a typical MPD installation is almost separate from the rest of the drilling control system. (Source: NOV)

Permanent integration

Integration of the MPD control systems is arguably the most important part of a permanent MPD system installation. Not only is such integration crucial for reliability and safety but it paves the way to greatly reduce the number of people required to execute an MPD operation. While most existing MPD control systems have been developed to be run by a specially trained crew, true integration calls for a different model, one where MPD systems can be operated by a driller as part of standard drilling operations.

Most drilling rigs already have a centralized drilling control network that integrates many different drilling tool controllers in one common human-machine interface (HMI) that the driller manages. In a typical drilling network, all major drilling machines share data on a common, high-speed network. All data are logged and stored for post-processing analysis, and all information is available to all the users on the network.

The prevailing method of installing MPD control systems, however, is to set up a separate MPD network outside of the drilling control network. Separate sensors are installed to transfer data to the MPD system, and additional screens are installed in the driller's cabin to allow the driller to monitor the operation (Figure 1). While this is a strategy for integration, such a strategy may lead to additional operational inefficiencies and increase the potential for making simple mistakes that can significantly impact the operational success of an MPD deployment.

The MPD control system remains independent of the rig's control system with unique and nonaligned software behavior. If an alarm is turned on or off in one control system and not in the other during an active drilling operation, personnel can be caught by surprise and the operation can be negatively impacted. Terminal and screen proliferation is a typical response to the need to integrate MPD into the driller's cabin. The driller and other rig personnel are tasked with operating the rig as well as monitoring and operating the MPD control system through its dedicated terminal, co-located in the driller's cabin. This can become a visual distraction that can impede the human mind from reacting correctly.

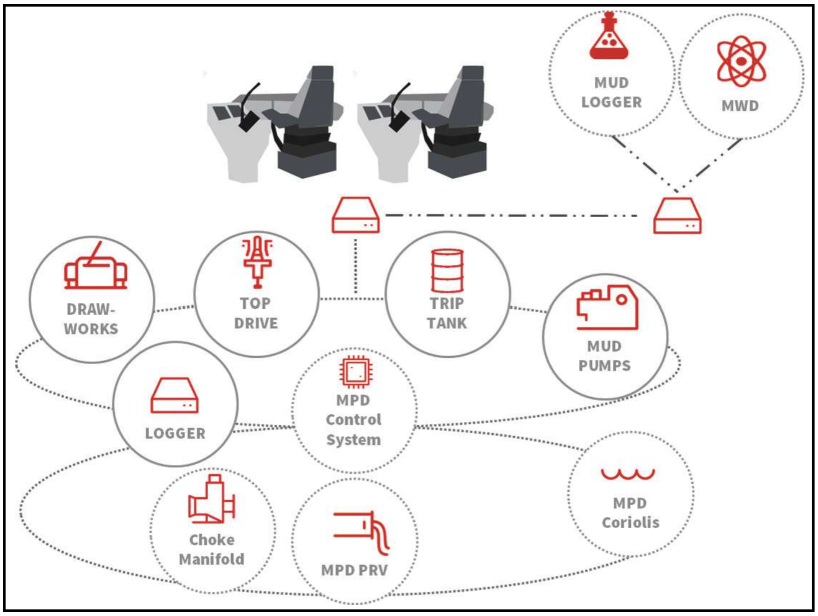


FIGURE 2. MPD control systems are integrated with the existing drilling control network to maximize system efficiency. (Source: NOV)

Leveraging all systems

MPD control systems should leverage the existing drilling control network and the information available on the network (Figure 2). The driller should be able to monitor all critical systems from the controls chair. This includes not only key control objectives and performance of the MPD control but also other critical information like MPD-related alarms, inlet flowmeters, outlet flowmeters, pressure relief valves and valve alignment. With all relevant MPD control functions seamlessly integrated into the normal HMI, the driller gets an immediate, clear and intuitive visual overview of the complete drilling process, including the MPD system. In this scenario, all information pertaining to the drilling operation is made available in a familiar and easily accessible format.

True MPD rig integration includes one centralized control system that integrates MPD functionality in synchronization with the top drive, drawworks and mud pump control. This enables consistent, optimized performance of the overall drilling operation while accounting for both pressure control accuracy and key performance indicators in drilling. By configuring standard automatic connection sequences that can be activated by a click on a keypad, mud pumps can be ramped up as quickly as possible while ensuring choke control is within the optimal range to minimize deviations in downhole pressure. Tripping operations can be optimized by controlling drawworks speed, in addition to choke actuation to minimize downhole pressure fluctuation caused by surge and swab when running and pulling drillpipe.

To assess the impact of an integrated control system, NOV asked four drillers to perform primary drilling tasks while simultaneously monitoring an MPD control system in a simulated environment. The experiment used one dual-screen setup with a separate dedicated screen displaying MPD events and alarms, and one integrated setup with critical MPD events and parameters displayed on the same driller's display as the primary driller's control objective. Results clearly indicated the value of the integrated setup, with the driller performing both MPD and drilling operations with a 33% to 80% improvement in reaction time to events and changes in MPD conditions as compared to a nonintegrated, dual-screen control scenario. These improvements in performance and consistency suggest that a driller can assume additional MPD monitoring responsibilities more efficiently if the integrated rig control system provides essential MPD data on the primary driller's screen. E&P

New perforating design offers 360-degree coverage

A slot perforating method saves time and reduces well abandonment costs.

Arash Shahinpour, DynaEnergetics

A new technique that can minimize section milling has been developed for plugging wells and achieving better isolation. An innovative perforating gun design produces slots in the tubing, without damaging an outer string or the wellbore, allowing cement or resin squeeze operations to create reliable zonal isolation that meets government regulations.

Proper well abandonment mitigates the risk of fluid migration that could damage freshwater zones as well as flammable natural gas seeping to surface. Safely abandoning wells to prevent migration of fluids and sealing potential leak points by setting cement plugs in the wellbore requires the removal of concentric casing strings, or when cutting and pulling casing are not possible, it must be milled away. Milling casing often is challenging and requires multiple trips into the hole, which significantly raises the cost to plug and abandon wells. Tungsten carbide has been used for downhole metal cutting since the 1930s, and today lathe-style cutters and downhole motors are used to speed up operations. However, milling still takes too long, and metal shavings at the surface are an environmental and safety hazard.

The new gun design perforates a helical pattern of overlapping horizontal rectangular slots in the tubing, allowing 360-degree access to the area behind the tubing or casing. The perforations (Figure 1) can be designed to penetrate a single string of pipe without damaging an outer string or to penetrate a casing string to access the formation, covering all voids and microannuli between the casing and formation or within the cement.

The slotted perforating gun system outperforms big-hole squeeze guns because the radial pattern and depth of penetration avoid having to reperforate a second or third time when the first attempt is unsuccessful. This single-gun system prepares the well for the cement operation in only 12 hours versus conventional 360-degree access methods, such as section milling and slot cutting with abrasives, which take days or weeks to execute.

Section milling, squeeze cementing alternative

In many plug and abandonment (P&A) wells, downhole tubulars are milled and cement is pumped downhole to establish a barrier against the migration of fluids. Sec-

FIGURE 1. The perforations cover all voids and microannuli between the casing and formation or within the cement. (All images courtesy of DynaEnergetics)

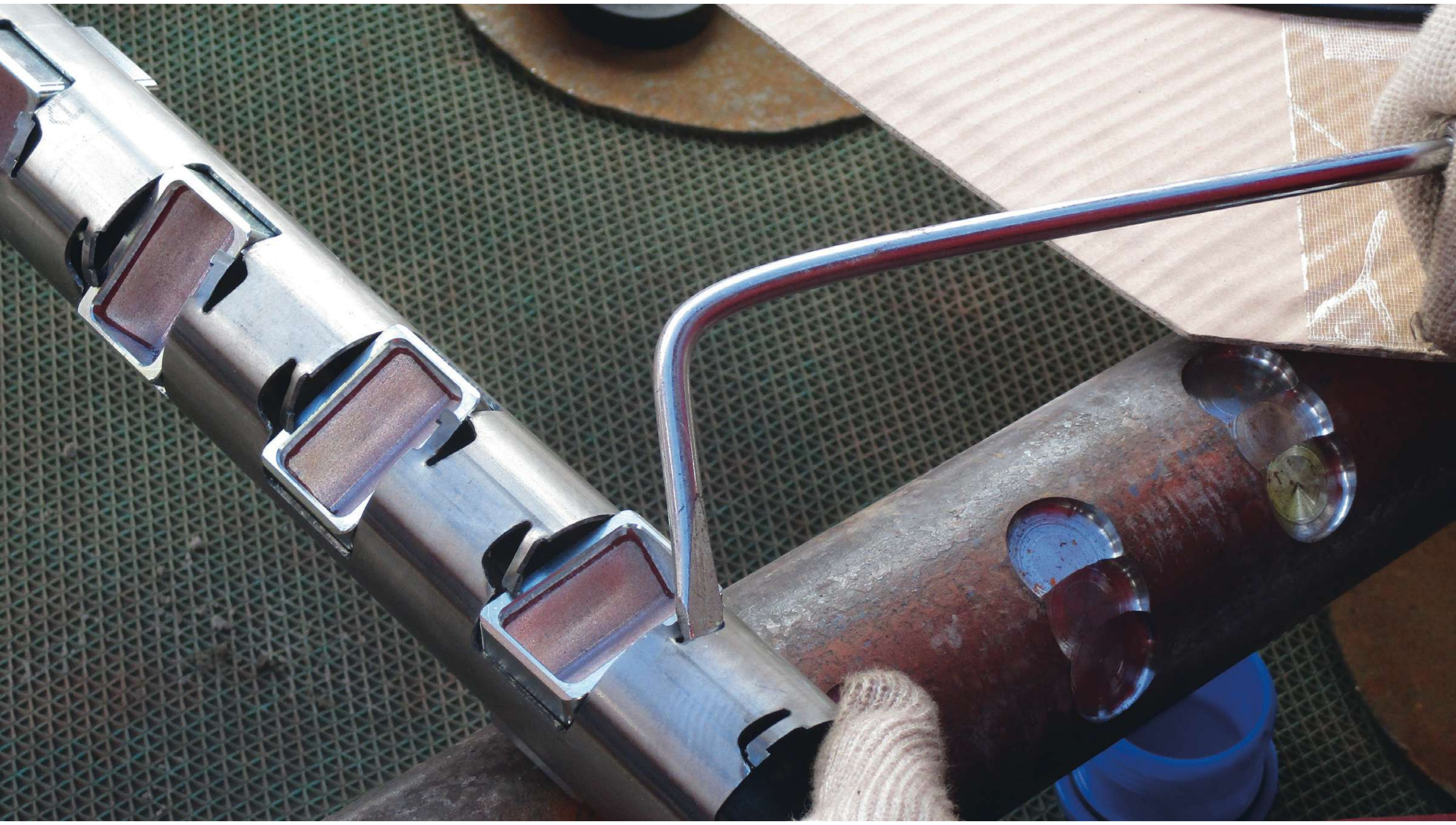


FIGURE 2. The slot gun design produces a helical pattern of horizontal rectangular slots in the tubing to achieve 360-degree access to the area behind the tubing or casing.

tion milling can be challenging in some types of tubulars, and the tools must be carefully designed to avoid failures inside the wellbore. After a section of the pipe is milled, achieving reliable isolation depends on several factors that impact the cementing operation: equivalent circulating density, flow dynamics, thermal gradients, pipe corrosion, and pressure and temperature fluctuations. In some downhole conditions, resins have proved effective in annular fluid flow applications to shut off gas sources and squeeze a leaking plug. The low yield point of resin allows it to flow into micron-sized leaks without acid cleanup.

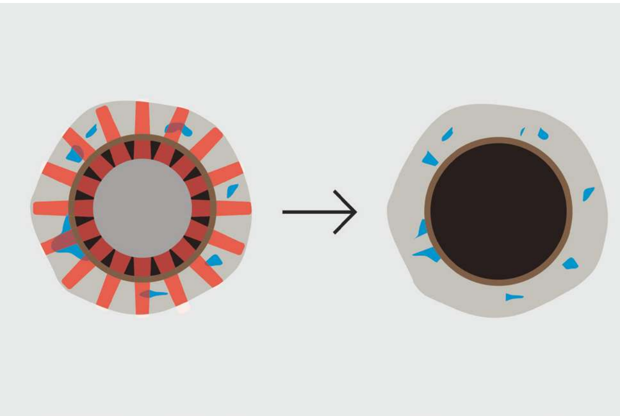
An important resin plug application occurs when bubbles are observed coming from the annulus after casing is cut. If the bubble stream is thought to be channeling through cement, resins may be an ideal squeeze application to stop annular leaks. Section milling guarantees perfect access to the area behind the casing, but this method can be expensive and time-consuming. In wells in the People's Republic of China, squeeze operations have been demonstrated to be more efficient if perforating establishes adequate communication before section milling is attempted.

Slot perforating improves efficiency

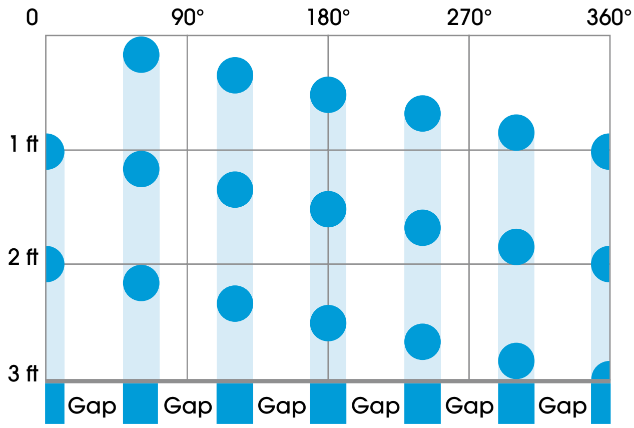
The slotted perforating gun system (Figure 2) is designed to intersect more channels than conventional gun systems with standard big-hole charges because its rectangular slots overlap between the charges. Standard big-hole charges may not intersect all microannuli and channels behind pipe. Compared to conventional round-shaped charges, the slot gun uses charges that are rectangular. The slotted shaped charge provides greater horizontal coverage in the casing than is possible with round charges. By overlapping slot charges by 50% in a complete circumferential-vertical cross section, 360-degree coverage is achieved (Figure 3).

The slot gun employs a scallop design to create a rectangular slot without significant burr height protrusion. Slots can be created in the liner or inner casing without damaging the outer casing or the shaped charges, and guns can be designed to penetrate the pipe to access

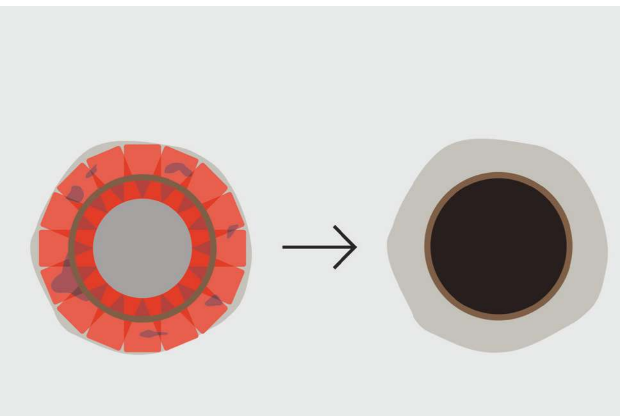
FIGURE 3. COMPARISON OF CONVENTIONAL CEMENT SQUEEZE GUN COVERAGE AND NEW GUN DESIGN



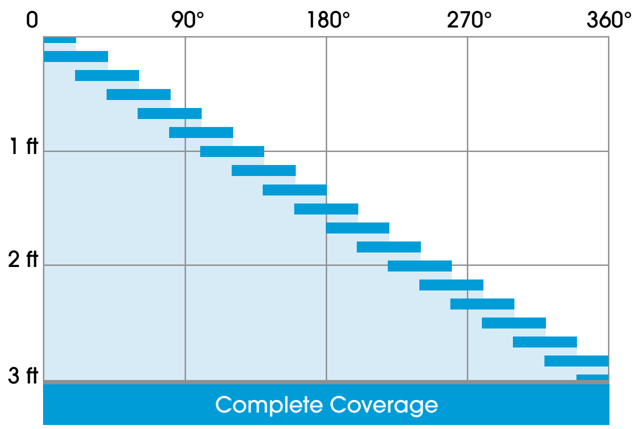
With a conventional cement squeeze gun, not all channels and microannuli may be intersected.



Conventional perforating leaves gaps in the access to the area behind the casing.



The shot pattern of the new gun design provides 360-degree coverage with overlapping rectangular slots that enhance P&A perforating and squeeze jobs.



The new gun design eliminates gaps with 360-degree coverage achieved with 18 shots and 50% overlap.

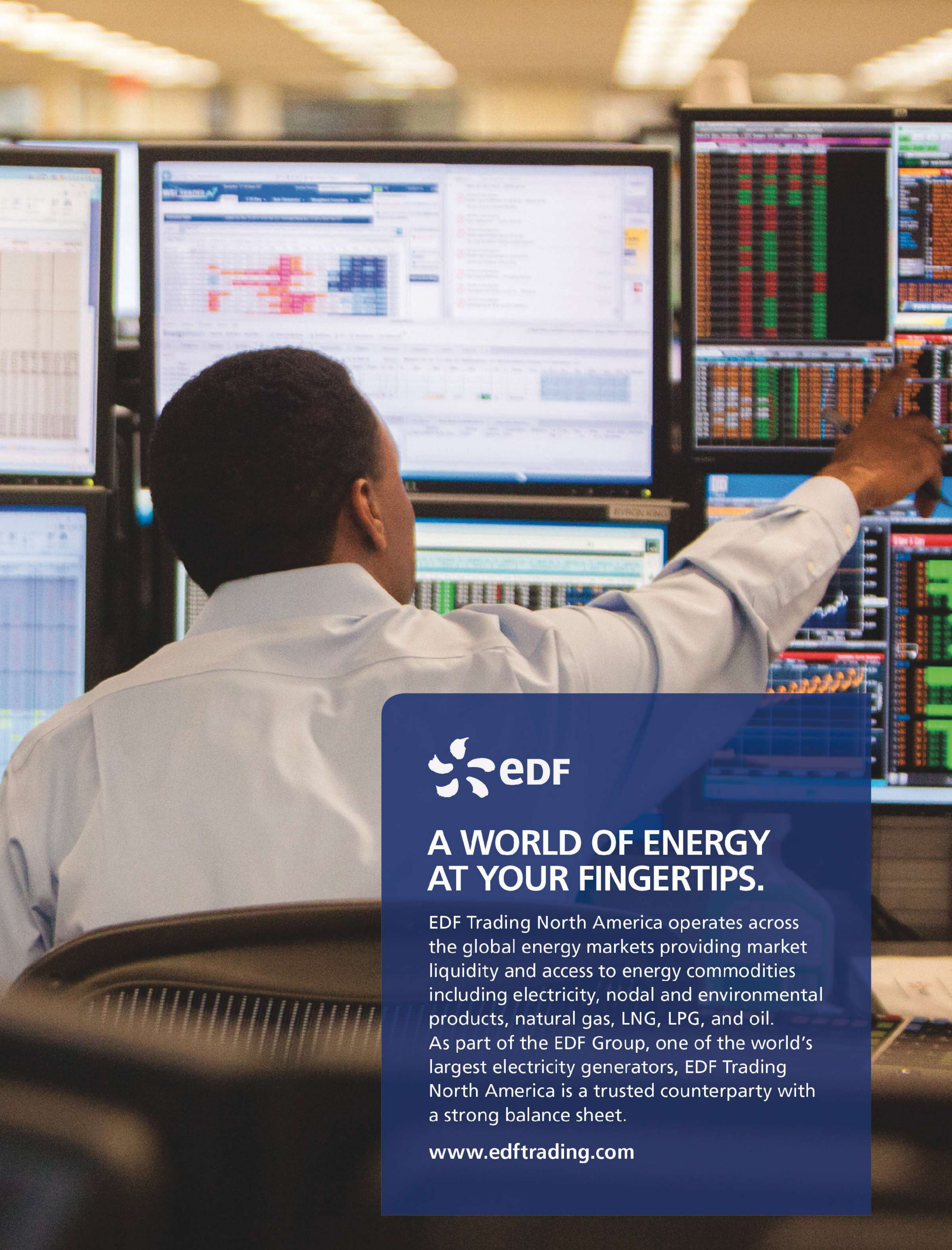
the formation. The perforating guns can be conveyed by wireline, slickline, coiled tubing or conventional jointed tubing and initiated by a pressure-activated firing head, or when conveyed by wireline and initiated with a firing panel from the surface.

From the wells attempted to date, the designers of the gun system believe wells with isolation challenges are candidates for using the slotted gun approach as the first attempt to establish communication without section milling.

Case study

The slotted perforator was used in a North Sea well as part of a well abandonment program. The operator wanted to safely abandon an existing wellbore and reuse the slot for a sidetrack to access bypassed oil. The challenge was to perforate 5½-in. 17-lbm/ft tubing above the cement top with no damage to external 9⅝-in. casing. The well was deviated about 45 degrees, and there was concern that the perforator would lie on the low side of the pipe and damage it when the gun detonated.

The solution was to load dummy charges in a section of the gun and use an eccentric weight bar to orient the dummy charges to the low side of the hole where there was no casing standoff. Using a memory trigger device conveyed via slickline the oriented gun was detonated, saving cost and space. The slickline-deployed slot-shaped charge successfully produced large, overlapping punch holes while avoiding the risky low side of the wellbore, thus avoiding damage to the external string. E&P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PNP system improves P&A efficiency

A system has been developed to deliver cost savings by removing the need for cutting and pulling a casing when removing annular fluid.

Atle Sørhus and **Thore Andre Stokkeland**, Archer

Operators are looking for well barrier solutions that are cost-effective, robust and in accordance with industry regulatory standards. An industry challenge when plugging and abandoning wells during exploration and at the end of a well's lifetime is to remove annular fluid, such as oil-based mud, between two casing strings, when creating a well barrier that can be documented and verified.

To cut and pull the wellhead, the annular fluid between the casings must be circulated out, and a cement plug needs to be set as an environmental barrier. An environmental isolation plug functions to isolate the full cross-sectional wellbore and to prevent the movement of wellbore fluids to the environment. A well barrier may also function as an environmental isolation plug, according to the NORSOK Standard D-010 on well integrity in drilling and well operations.

Traditionally this challenge was solved by cutting and pulling the casing during plug and abandonment (P&A) operations. For example, in a P&A scenario, a 13⅜-in. casing can be typically cut and pulled at an appropriate depth inside a 20-in. casing in a well prior to setting a bridge plug. Thereafter, a cement plug can be placed on top of the bridge plug inside the 20-in. casing. In some cases, casing milling is required to set an environmental isolation plug.

The Archer SPARTAN system includes an ISO 14310 certified retrievable bridge plug. (Source: Archer)

Eliminating cutting and pulling

Cutting and pulling the casing can be time-consuming and costly. To address this challenge, Archer has developed the SPARTAN plug-and-perf (PNP) system. This downhole tool-based abandonment system eliminates the need for cutting and pulling a casing when removing fluid from the annulus and replacing it with a cement plug (environmental isolation plug or barrier) in the annulus and wellbore. Operations can then proceed and the wellhead can be removed.

The SPARTAN system consists of the SPARTAN ISO 14310 certified retrievable bridge plug and two separate activated single casing perforation guns. The guns' design enables the first casing to be perforated in a controlled manner without compromising the integrity of the second casing.

With this system, the objective of circulating out annular fluid and setting the environmental cement plug can be met without cutting and pulling. The result is that a permanent barrier is set between two casings and in the wellbore.

Achieving efficiency

The operational time of establishing an environmental P&A plug by implementing a traditional cut-and-pull method is about 21 hours. A two-trip PNP operation takes about 15.5 hours. A PNP operation using the one-trip SPARTAN PNP system takes 9.75 hours, thus improving efficiency by more than 50%.

The plug does not require any weight/tail pipe to set, making it a choice for deviated wells. The plug is designed to hang perforation guns below, and the 3-in. ball valve enables activation balls for perforation guns to be dropped through the plug to fire the tubing-conveyed perforating (TCP) guns. Key features and capabilities include

- ISO 14310 certified barrier plug;
- Rapid set and retrieval;
- No weight below to set;
- Multiple sets without tripping;

- Unrestricted 3-in. fullbore;
- Ultrashallow, ultradeep or horizontal set 20 m to 6,550 m (65.6 ft to 21,489 ft); and
- Designed to be run with TCP guns.

PNP method

The PNP method leveraging the SPARTAN plug can be summarized in six steps (Figure 1):

1. Run in hole and perforate the casing at planned depth;
2. Run in hole to just above casing shoe (or at planned depth) to set the plug and perforate;
3. Pump down the string to establish communication between the deep and shallow perforations. When pumping, the fluid will circulate out the lower perforations into the annulus, up and out the upper perforations. Circulate out and displace annular fluid to seawater to prepare for the cement job;
4. Displace the cement slurry through the drillstring and into the deep perforations. Returns are taken through the shallow perforations. By displacing the cement through the SPARTAN plug and into the perforations the B annulus is cemented. The integral ball valve in the SPARTAN plug is closed so the cement will stay in place without U-tubing back up the drillstring;
5. After the cement is placed and the ball valve is closed, the running tool is released from the plug, and a balanced cement plug is pumped through the running tool on top of the SPARTAN plug. This completes the barrier. At this stage, a barrier is complete in both the A and B annuli; and
6. After the cement is set, the barrier can be verified through pressure testing. A feature of the SPARTAN system is that as a result of the shallow perforations, both the A and B annuli can be pressure tested and verified. At this stage, the annular fluid has been removed and the environmental barrier is in place—all without removing the tubular. The wellhead can be removed safely, in accordance with NORSOK Standard D-010.

Case study

The SPARTAN PNP system has been implemented in several North Sea P&A operations. In one P&A operation, the system saved a major European operator nearly $3 million, or 11 days of rig time.

When drilling the well, the 9⅝-in. casing became stuck and no circulation was possible through the shoe. The decision was made to plug and abandon the wellbore and facilitate a new sidetrack. The operator started recovering 4,577 m (15,016 ft) of casing and achieved limited progress. The operator then spent 21 days cutting and pulling 3,182 m (10,439 ft) of the casing. The openhole fishing operation with a well profile of 73 degrees inclination proved to be challenging. The operator needed to explore an alternative technical solution to complete the P&A operation.

The first step of the operation was to run down and set a SPARTAN plug at 4,852 m (15,918 ft) to provide a path for the cement and to isolate the bottom of the hole. The plug was run through approximately 900 m (2,952 ft) of open hole before it entered the 9⅝-in. casing fish. The plug was set according to plan and procedure, and the running tool was pulled out of hole. The second step was to run the second plug with TCP guns, then perforate the casing between 4,838 m and 4,840 m (15,872 ft to 15,879 ft) with 12 shots per foot 0,5 holes. Part of the job was to set the SPARTAN at 4,824 m (15,826) and circulate the 9⅝-in. casing annulus.

The third and last stage was to cement the 9⅝-in. casing annulus up to 4,342 m (14,245 ft) through the SPARTAN ball valve and into the perforations and up. At the end of the cement displacement, the pressure was held inside the string. At that stage, the SPARTAN ball valve was closed to stop the cement from U-tubing from the annulus. Two cement plugs were set inside the casing up to 4,390 m (14,402 ft) to complete the P&A operation. E&P

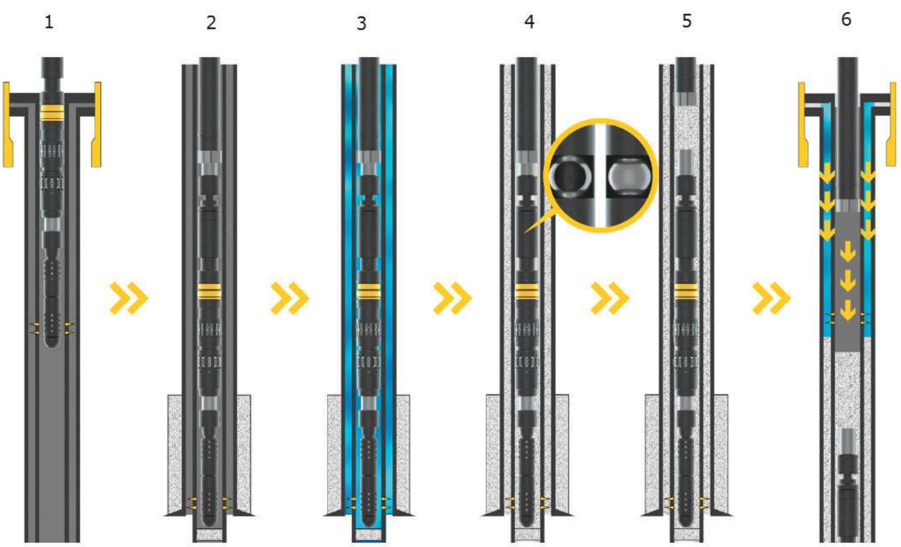


FIGURE 1. The SPARTAN PNP method ensures that a permanent barrier is set in two annuli without cutting and pulling. (Illustrated by Børge Myrnes, courtesy of Archer)

A new technology with a simplified approach

The Internet of Things is proving to have a place in production operations.

Bill Elmer, Encline

The incorporation of low-cost Internet of Things (IoT) devices with artificial lift and production equipment provides simple, robust solutions to technical challenges. A recent paper from the Society of Petroleum Engineers (SPE) cited four successful IoT applications that utilized engineering principles, field experience and statistics at the field-device level. These examples scratched the surface of IoT technology's abilities and demonstrated how to mitigate operational problems using these applications.

Pump stroke optimization

In SPE paper 181228, pump stroke optimization (PSO) was introduced as a method to reduce frequent rod pump cycling between minimum and maximum pumping speed set points by rod pump controllers (RPC) that were reacting too aggressively to slug and wave flow events in horizontal wells. Most RPCs fall victim to these under slug flowing conditions and become plagued with low pump fillage events.

To execute PSO, the analog speed output signal from the RPC is intercepted and replaced with an optimized speed signal. Then the optimized speed signal is calculated by a programmable logic controller (PLC) that targets a speed matching the average inflow over the multiple-hour period. Pumping speeds and incidences of low pump fillage events were recorded every second and then averaged over the multiple-hour period. Upon completion of each multiple-hour period, the pumping speed was changed to target a selected minimum frequency of low pump fillage events.

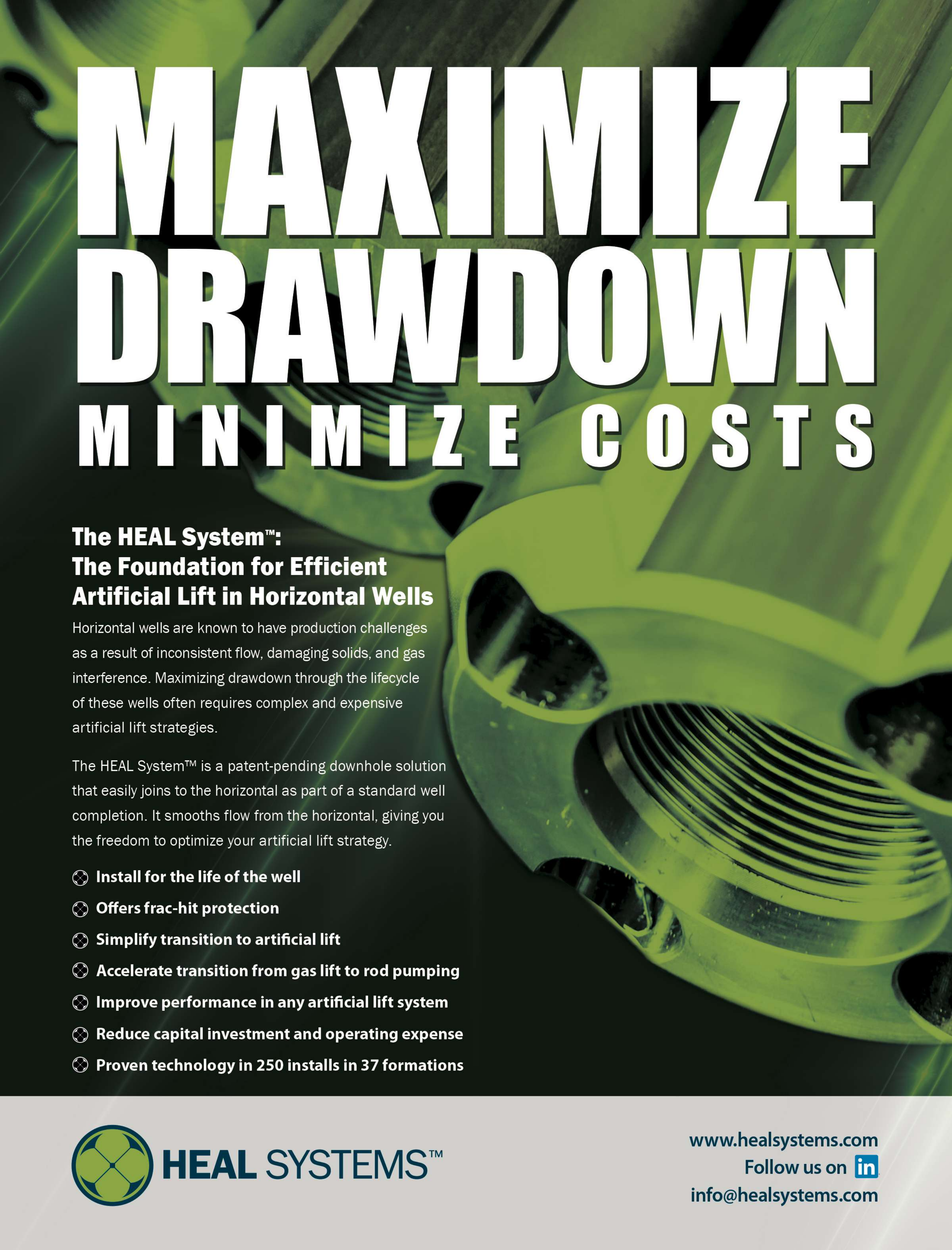
Air motor actuators control the position of compressor cooler louvers. (Source: Encline)

A PLC that was sourced for this task was able to interface with the operator's SCADA system and host a webpage on the controller. The webpage was actionable, and the virtual switches on the webpage could be clicked to perform certain functions, as if they were local switches. The controller allowed set points and historic pumping speed values to be viewed and algorithm settings to be changed remotely. The system essentially allowed a PC or smartphone to turn this webpage into a local human-machine interface. Finally, the PSO data were polled by the operator's SCADA system and stored in the internal cloud system.

Improved compressor

SPE paper 181773 discussed designing an improved, electric-driven wellhead compressor purposed for gas lift. The primary requirement was to prevent hydrocarbon condensation that is prevalent in liquids-rich horizontal plays. This was accomplished by maintaining elevated process temperatures in the 100% vapor portion of the phase diagram by using an IoT-enabled PLC to perform proportional-integral-derivative (PID) control of cooling fans on the separate intercooler and aftercooler.

A conventional control panel was not utilized on this compressor. Instead, the webpage hosted by the PLC was used. The local control consisted of an on/off switch with a green indicator light when running properly and a reset switch with a red indicator light. A piezoelectric buzzer warned of impending compressor startup, which would count off a number that identified the shut-down code. This was a backup method, as the primary method of diagnosing shutdowns and resetting was done through the webpage.


MAXIMIZE DRAWDOWN
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The HEAL System™: The Foundation for Efficient Artificial Lift in Horizontal Wells
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The HEAL System™ is a patent-pending downhole solution that easily joins to the horizontal as part of a standard well completion. It smooths flow from the horizontal, giving you the freedom to optimize your artificial lift strategy.
Install for the life of the well
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The webpage also allowed compressor speed set points, gas cooler temperature set points and the normal pressure and temperature set points that all compressors require to be viewed and adjusted. In addition, this PLC was able to simulate compressor performance and compare it to actual, calculated key performance indicators (KPIs). It would then trend these values against months of stored data to detect variances and create alarms. The operator also communicated to the PLC with its SCADA system, polling operating pressures, temperatures, rates and KPIs every 15 minutes for incorporation into a compressor management tool.

VFD panel cooling fan

When the wellhead compressor was installed, the variable frequency drive (VFD) cabinet was equipped with a mechanical thermostat that resulted in severe fan cycling because of improper placement and a small dead band.

To solve these problems, a PLC with a thermistor was used to control cooling fan operations. A thermistor is designed to be a reliable, low-cost temperature device, but it is unpopular because of nonlinear output modeled by a sixth-order polynomial equation. Alternatively, it can be broken into multiple straight-line equations using a lookup function. Both methods were found to work well with the PLCs.

As the VFDs were rated 50 C (122 F), the fan was set to turn on at 47.2 C (117 F) and off at 40 C (104 F). This provided a 13-degree dead band that minimized fan cycling, and the fan runtime was greatly reduced with these higher set points. Temperatures above 50 C indicate filter plugging and set a maintenance alarm. In addition, the webpage can display editable set points, real-time cabinet temperature, daily fan runtime, daily fan cycles and is polled by the operator's SCADA system.

Compressor panel IoT device

The popularity of gas lift for horizontal wells created the need to modify existing gas-lift compressors to prevent condensing hydrocarbons in the gas cooling sections. Besides causing product loss and emission problems when these liquids are dumped into tanks operating at atmospheric pressure, other problems such as frozen dump lines and hydrate blocks in discharge piping cause compressor downtime.

A North Dakota operator replaced the manually operated louvers on the gas coolers with individual PID mathematical methods, which controlled louver positioners. Preventing hydrocarbon condensation was accomplished by maintaining elevated process temperatures by using a PLC that would perform PID control of the louver positioners and the VFD cooling fan.

The electric-driven wellhead gas-lift compressor in the background is powered by VFDs located in the tall white cabinet. Compressor operations are controlled by a PLC in the far left gray cabinet. (Source: Encline)

What differentiates this from the first example of the electric-driven compressor is that instead of connecting sensors directly to the PLC, the controller used the Modbus remote terminal unit to pull pressures, temperatures, operating rpm and other information from the existing compressor panel via the RS-485 serial communication. Inputs to the PLC were analog louver position feedback with outputs being analog and digital outputs to control VFD, and in this case of retrofitting existing compressors, louver positions.

Because the PLC was connected to the operator's SCADA system by Modbus transmission control protocol, all the compressor pressure and temperatures, louver positions and engineering KPIs calculated in the PLC were collected for use in a compressor management tool.

The key to IoT

For those working in cloud computing and data sciences, the value of machine learning and remote control and optimization is not being discounted. Simple IoT devices can be used on location to access data and handle routine optimization tasks. These types of devices provide a good starting point for machine learning on a larger scale. The key to success with IoT is people with an understanding of engineering principles, how field equipment works and the basics of the IoT. E&P

Pumping up production

Packaged engineered solutions can improve production from rod pump systems.

Russell Messer, Dover Artificial Lift

Today's market environment and economics have led to innovative ways to drive the greatest efficiency possible. With this changing landscape, the rod pump sector has been especially challenged to look at rod lift in a new light. Deviated and deeper wells, both of which contribute to wear and tear on equipment, especially rod and tubing, lead to higher lease operating expenses. To address these concerns, Dover Artificial Lift and Liberty Lift have partnered on the Long Stroke pumping system.

The Long Stroke package focuses on fewer cycles, longer strokes and a more comprehensive design to drive better wellsite economics. The key components of this package are the Long Stroke XL Pumping Unit from Liberty Lift combined with the SPIRIT Genesis Integrated Variable Frequency Drive (VFD), heavy-duty rodstring, specially designed pump and bottomhole assemblies. When these components are deployed together, a more efficient and durable system is created resulting in less downtime and more production.

The XL offers a means of managing production costs. Its extra-long stroke length of 306 in. and 366 in., depending on the model, allows the rod pump's slower travel time to provide more complete fillage and higher volumetric efficiency. The XL is suited for work in deviated, deep, high-volume wells as an alternative to electric submersible pumps (ESPs).

Some of the more traditional applications in which these units have been used are in deeper wells where structural capacity exceeds the limits of conventional units. These units are allowing maximum production potential and efficiency in 3,048-m to 3,657-m (10,000-ft to 11,998-ft) wells in places like Utah, Wyoming and the Bakken Shale where high deviation and depth go hand in hand with more extreme cases than most other North American regions.

Recently, these rod pumping systems have been commonly run in highly deviated applications in which the long and slow stroke reduces overall rod and tubing wear by reducing pumping cycles and rod velocity. Many operators have moved to XL units for more troublesome and deviated wells where they can produce as much or more fluid than a conventional unit, but with greatly reducing pumping cycles resulting in fewer workovers and less deferred production (Figure 1).

The last scenario that is growing in popularity with rod lift is higher volumes at earlier stages in the well's life. The goal of this application is to reduce the form of lift changes by putting a well on a XL pumping unit earlier or even post-flow to achieve life-of-well savings. These units frequently are run in applications in which wells are achieving 400 bbl/d to 800 bbl/d.

Permian Basin case study

An operator in the Permian Basin was challenged with achieving between 700 bbl/d and 800 bbl/d of production. The operator's existing ESP method resulted in higher lifting costs and an inefficient system. The operator chose to implement the Long Stroke XL unit, bypassing a conventional 912 pumping unit. The result of the change was successful production of 750 bbl/d to 800 bbl/d. In addition, the move resulted in an overall reduction in capex, an overall reduction in opex by reducing monthly electrical costs, exceeding production goals, elimination or reduction of traditional rod fatigue failures, and a consolidation of artificial lift forms.

When the Long Stroke XL unit was combined with the Dover Artificial Lift Long Stroke package, lower cost and increased production were realized.

Automation

Automation plays a large role in driving the XL unit while simultaneously providing the operator with more

Model	Desired Production	Depth	Pump Size	Avg. SPM	Cycles/ Day	Cycles/ Month	Cycles/ Year	Net Cycle Difference
320-500-306 in.	550	7,000 ft	2 in.	4.2	6,048	175,392	2,104,704	(1,653,696)
1280-427-192 in.	550	7,000 ft	2 in.	7.5	10,800	313,200	3,578,400	

FIGURE 1. In a comparison between the 306-in. Long Stroke XL pumping unit a and conventional 192-in. pumping unit applied to the same well and tasked with achieving equal production, the XL achieved the same production with more than 1.6 million fewer strokes per year. (Source: Dover Artificial Lift)

enhanced functionality and savings. The pumping unit has a wireless load cell and provides a position signal via the unit sentry device, eliminating the need for the additional load cell, cables and position device.

In addition, the SPIRIT Genesis controller allows the operator cornering capabilities needed for long-stroke applications, five speed control options as opposed to the industry standard of two, free user interface integration, wireless end devices and enhanced input/output capabilities. These speed settings allow better gas separation and higher pump volume efficiency because of the speed change capability within one long, slow stroke.

Operators can use the service provider's technical services team to request a rod design tailored to their particular well scenario. These designs rely heavily on the wells' deviation survey, which correlates to the rod guides available for various applications and environments including high temperature, high corrosion and high abrasion. In addition, these units are designed to

- Reduce tubing wear in high-temperature environments;
- Facilitate chemical resistance in corrosive environments;
- Enhance pumping efficiency with flow geometry; and
- Protect rods for longer with more erodible wear volume.

These tools offer a wide variety of downhole pumps, which can be used in various well conditions including sandy, corrosive or gassy wells, and can alleviate other compromising production issues.

In addition, pump tracking software allows the operator to better manage its assets, improve run times of the rod pump and prevent premature failures. The software enables operators to further reduce costs by recording detailed performance and failure data discovered during pump tear down. This software is available to all pump shops and supports multiple users with different security roles while reducing costs by aggregating data to pinpoint areas of interest.

Dover Artificial Lift and Liberty Lift's Long Stroke pumping unit is designed to reduce annual strokes by 1.5 million, depending on application. Coupled with the rodstring, the pumping unit extends rod runlife from 66% to 350%, depending on conditions. An integrated VFD with an intelligent pump-off control system at the surface paired with a series of downhole separators allow enhanced remote troubleshooting and surveillance while capturing gas and solids prior to pump entry.

The Long Stroke rod pumping system has helped decrease lease operating expenses through rod and tubing failure reductions. High-production, high-deviation and high-depth well conditions will continue to grow over time. Reducing the cost of change throughout the life of these wells will continue to be the economical driver. E&P

The XL pumping unit (top) operates in the Bakken Shale, and the Long Stroke pumping unit (bottom) awaits commissioning in the Bakken Shale. (Source: Dover Artificial Lift)

Something old, something new

Experience and expertise combine to introduce a new business model, innovative products and novel concepts for subsea production.

Judy Murray, Senior Contributing Editor, Offshore

The merger of Baker Hughes and GE Oil & Gas brought together established competencies in a breadth of disciplines. The newly formed entity is drawing on depth of knowledge and experience to develop subsea trees and control systems that are moving back the boundaries of what is possible in deepwater operations.

Fullstream ahead

Describing itself as the world's first and only "fullstream" company, Baker Hughes, a GE company (BHGE), has set the goal of enabling smarter ways to produce energy.

According to John Kerr, BHGE vice president and CTO for oilfield equipment, "Fullstream is an offering for delivering solutions from the birth of the well through to decommissioning." This encompasses "well design and planning, reservoir engineering and completion design, and installation that then connects into the traditional business of oil and gas."

This approach also considers how the elements that make up a development program contribute to helping operators from concept selection to full-field installation to life-of-field management.

"It introduces different commercial terms, different financial engagement terms and a different mindset of how we engage the end user," Kerr said, adding that success is apparent in the positive way his company is working with clients.

An example is the award of the Siccar Point Energy (SPE) Cambo Field project northwest of the Shetland Islands in the U.K. North Sea.

BHGE has been selected as the exclusive supplier to support the appraisal and early production phases of the project, with the opportunity to extend into the full field development. The scope of supply draws on the company's integrated portfolio of solutions, including a suite of well services solutions for the appraisal well, and expansion to provide the production and installation of subsea production equipment and flexible pipes for the early development phase.

According to SPE, this agreement represents an innovative alliance based on collaboration aimed at reshaping traditional relationships between suppliers and operators in favor of a long-term partnership that minimizes tendering costs, improves execution and risk mitigation, and incentivizes performance by creating shared project objectives.

A flowline end termination attached to an XT tree is deployed offshore. (Source: Ulric Ibanez)

Enhancing productivity

As important as BHGE's fullstream capabilities is its focus on enhancing productivity and operating efficiency, areas that offer significant opportunity for improvement as the oil and gas industry seeks to become more viable in the long term.

Dean Arnison, BHGE global product leader for subsea systems, provided the company's Brilliant Factories initiative as an example. The goal is to optimize manufacturing by linking design, engineering, manufacturing, supply chain, distribution and services in one system.

"We're not just selling digital solutions to our customers to reduce costs," Arnison said. "We are doing it ourselves as proof of the pudding. How do we automate this? How can we use digital solutions to improve the way we do that? That is the essence of Brilliant Factories. It's about making ourselves more efficient internally, which is equally beneficial to our customers."

One simple example of how the company has leveraged Brilliant Factories is in the way it has automated the application of corrosion-resistant coating to subsea components. Much of this equipment is clad with

Inconel, an alloy of nickel containing chromium and iron, which is corrosion-resistant at high temperatures. BHGE's new manufacturing techniques allow the coating to be applied more quickly and efficiently with fewer defects, improvements that are invisible to the end user but increase the speed with which components can be made ready for installation.

New offerings

BHGE also is impacting operations in more traditional ways by introducing new products. One of these is a large-bore subsea tree system designed with component reliability, production availability and the cost of overall system maintenance in mind. According to Arnison, this system is built on expertise gained through developing the existing 7-in. valve-based horizontal and vertical technology solutions.

"When dealing with the challenges of large-bore gas production, large-bore valving and the associated challenges introduced by 3,000 m (10,000 ft) water depth, you end up with sizable structures and associated weights," Kerr said, adding that technical challenges like these are the impetus for developing better designs.

The BHGE approach was to look for modularity opportunities within the trees themselves.

The DVXT, a deepwater vertical tree, benefits from a modular approach to engineering and manufacturing, with application engineers able to focus on designing customization where it is needed. (Source: Baker Hughes, a GE company)

"We've effectively split the tree into two," Arnison said. "The tree has a lift cap on top that can be designed to be a flow control module with a typical choke and flowmeter, or as a HIPPS [high-integrity pressure protection system] cap for starting up a high-pressure well, that can be removed later and replaced with a production cap that in turn can be replaced at a later time with a booster pump."

"Because of the design concept surrounding our Modular Compact Pump, we can package even better performance than what is available at present in a smaller format that allows it to be considered in a very practical way as a component of a tree-mounted option," Kerr said.

The new vertical tree is 40% lighter, which means it can be manufactured more economically than traditional trees and can be installed using a smaller support-type vessel.

BHGE has built its expertise in large-bore, long-offset gas fields across a number of projects in the Asia-Pacific, Middle East, North Africa and Turkey, and sub-Saharan Africa regions, with earlier versions of the 7-in. tree qualified for 3,000 m (10,000 ft) water depth and temperatures ranging from 168 C (334 F) to -46 C (-52 F).

"This is a huge qualification envelope that our products can operate in," Arnison said.

The company also has collaborated with Eni on the development of a standard subsea tree, the e-EHXT. "This is a great example of our industry embracing standardization," Arnison said. "In this case the customer standardized their own predesign, which helps us deliver to them in a faster cycle and makes execution more straightforward."

The e-EHXT tree will be deployed for the first time on the Eni-operated Zohr Field in the Mediterranean Sea offshore Egypt, where BHGE is providing project management, engineering procurement, fabrication, construction, testing and transportation of a subsea production system, along with support for installation, commissioning and startup.

Taking the next step

"We have had a huge focus over the last 18 months to two years on rationalization and standardization of the product offerings," Arnison said. "We are minimizing the number of variants and maximizing the opportunity to deploy the system in more applications."

"The industry is speaking very loudly as to what they require," Kerr added, "and what they require is not necessarily a solution delivered where we address just one component like cost, but something that takes into account the whole-life cost of ownership, going beyond hardware and installation."

By taking a broader view and thinking more creatively, it is possible to find better solutions.

"The efficiency gains for both parties are first class," he said. "It's the right thing to do." E&P

Cooperating to expedite innovation

Partnership influences product development that reflects changes in operational demands.

Judy Murray, Senior Contributing Editor, Offshore

With hundreds of subsea trees and control systems deployed and many industry firsts under its belt, Aker Solutions continues to break new ground. The company is expanding its vertical tree offerings and investing in digital technology to improve products and extend competencies.

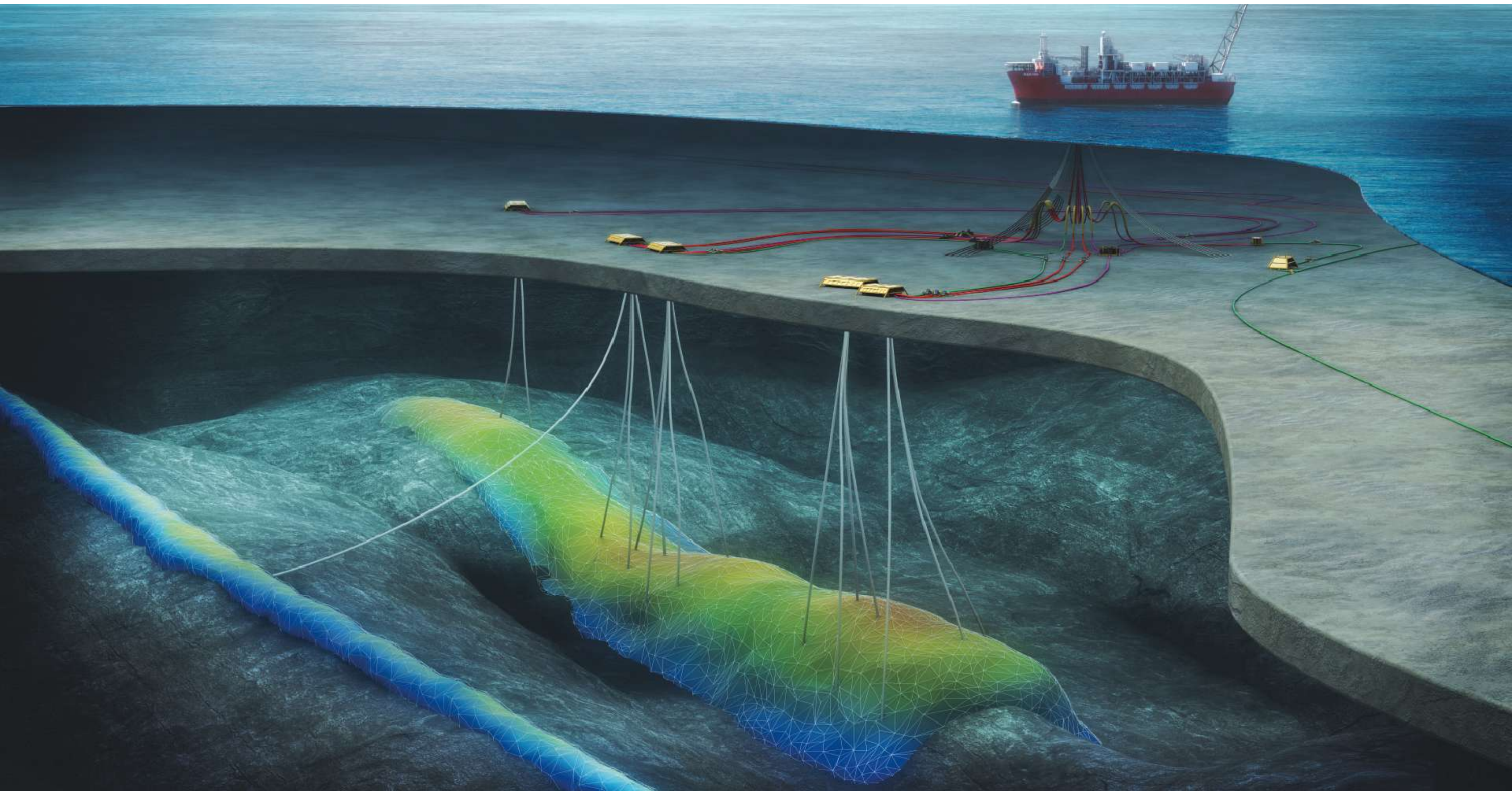
Evolving offerings

According to Sigurd Loftheim Dale, Aker Solutions engineering manager for the Johan Castberg, Troll and Askeladd projects, the shift to vertical tree development is representative of the company's focus on changes in industry demands.

"Vertical trees are something we've seen more and more in recent years," he said, adding that it is only in the last five years that Aker Solutions has supplied its first big vertical tree deliveries.

Dale attributed the shift to a drive for reducing rig time and saving on field development costs. He said the company's newest vertical tree system and associated tools were developed to meet that industry need, focusing on safety and cost efficiency as priorities.

"We have been able to scrutinize and optimize rig operations," Dale said, "and the result is that we have lowered product costs, lowered the handling weights, significantly reduced rig operations and have introduced safer maintainability, which translates into lower lifecycle costs." The new design is the result of a long process of developing underlying technology and looking holistically at how the subsea system fits into the bigger field development program and asking critical questions, he said. "How do we handle this tree? How do we best install it? How do we best optimize how it is to be used?"



Aker Solutions was awarded a contract from Aker BP to deliver the subsea production system for Phase 1 of the Ærfugl development offshore Norway. This will be the first installation of the company's new vertical tree. (Source: Aker BP)

Aker BP's gas condensate Ærfugl Field will see the first installation of the new tree. Ærfugl, formerly known as Snadd, lies approximately 210 km (130 miles) offshore Sandnessjøen in the Norwegian Sea. Trees of the same design will be used on the Johan Castberg, Troll and Askeladd fields.

Dale said the vertical tree system was requested by Statoil, which was looking for assistance in making the step from a horizontal to a vertical tree. "They initiated the project and have been a good collaboration partner in finding the right and optimal solution," he said.

Additional awards

Aker Solutions also recently won key work supporting Statoil's Johan Castberg Field—the largest oil discovery in the Norwegian Barents Sea, estimated to hold from 1.8 Bboe to 2.9 Bboe.

"We've been involved since day one of that development," Dale said, adding that delays along the way have allowed the field to move from marginal to profitable.

Aker Solutions delivered the world's first subsea compression system for the Åsgard Field in 2015. This successful project led to an alliance between Aker Solutions and MAN Diesel & Turbo to develop cost-effective technologies for high-capacity subsea compression systems. (Source: Aker Solutions)

"We helped Statoil through concept studies, pre-FEEDs and FEEDs, eventually halving the development cost of that project."

Statoil has challenged the company to develop a new standard for subsea production systems with the goal of improving efficiencies and reducing life-cycle costs. "That is key from a subsea point of view," he said.

Like Johan Castberg, the recently awarded Askeladd project is in the Far North. According to Dale, the primary challenges in Arctic areas are the short installation window during the summer and the relatively long distance from shore. "Our main contribution has been to simplify installation operations and to optimize for batch operations, doing more installation work with less logistics to and from shore." Having facilities in Hammerfest is an advantage here, he added, noting, "This is as close as you get. We are using our base there to mobilize equipment, refurbish tools and prepare installation packages."

Aker Solutions also was awarded work on Troll, which contains about 40% of Norway's offshore gas reserves. When asked about the challenges associated with the anticipated long field life, Dale replied, "When it comes to requirements for extended field life, they are not all that different to industry standards. It's more along the lines of assuring good reliability. We have recent experience with life extension studies for already installed equipment, and that is helping us propose the right solutions for a field like Troll."

Partners in technology

"Our relationship with Statoil when it comes to technology development is strong," Dale said. "We have a collaborative approach. Whereas they are driving technology and development, we also are pushing Statoil to find the right set of requirements to find the best solutions." This relationship gives Aker Solutions the ability to evaluate life-cycle perspectives of alternative technology proposals while at the same time contributing to the direction technology development takes.

Indicative of this partnership was the five-year framework agreement signed last year, contracting Aker Solutions to provide subsea services for Statoil-operated oil and gas fields offshore Norway beginning in first quarter 2018. The initial agreement provides work for the Aker Solutions service bases in Ågotnes and Hammerfest and covers subsea life-cycle services, including offshore installation and retrieval of equipment, maintenance, engineering and operations support.

Digital tools

One of the digital tools Aker Solutions is developing is the Vectus 6.0 subsea electronics module, which is designed to improve performance and lower project execution risks for subsea oil and gas installations.

Vectus is one of several Aker Solutions digital initiatives that will be under the "Software House" umbrella. According to Aker Solutions Chief Digital Officer Astrid Onsum, Software House projects will include field concept development, detailed engineering, maintenance and operations as well as decommissioning. "Software House is designed to bring all our software capabilities together with the aim of accelerating and enhancing our software development," she said.

With the introduction of Vectus, which is the next-generation iteration of the company's proprietary LINK subsea controls, Aker Solution has taken a step toward building the foundation for digitally enhanced subsea equipment. "Subsea will be an area of rapid digital change," she said. "Today we are able to gather significantly more data than before. We can remotely configure equipment, monitor health and do diagnostics."

The focus will continue to be on developing applications for condition monitoring, in time delivering predictive maintenance data. "Enhanced sensoring, machine learning and artificial intelligence all represent significant potential in the subsea environment and will be key enablers to the development of different business models," Onsum said.

In February Aker Solutions laid the groundwork for long-term collaboration with software company Cognite to accelerate digital solutions development. The company plans to use Cognite's advanced industrial data platform to collect and analyze large volumes of data from all types of industrial systems, ranging from real-time sensors to equipment hierarchies, maintenance logs, process diagrams and 3-D computer-aided design models. These data will be used to provide solutions that enable customers to make informed decisions about an energy asset at any stage of its field life.

Building on success

Digital techniques already are being applied to improve manufacturing processes for subsea equipment, Onsum said. One example is the digital remote control rooms at Aker Solutions' umbilical manufacturing center in Moss, Norway, which have lowered costs and improved safety, decreasing production time for umbilicals by about 30%.

Improvements like this will help enable developments in a lower oil price environment. Continuing investment will reduce costs, lower risks and improve performance, allowing operators to move beyond the limits of today's technologies. E&P

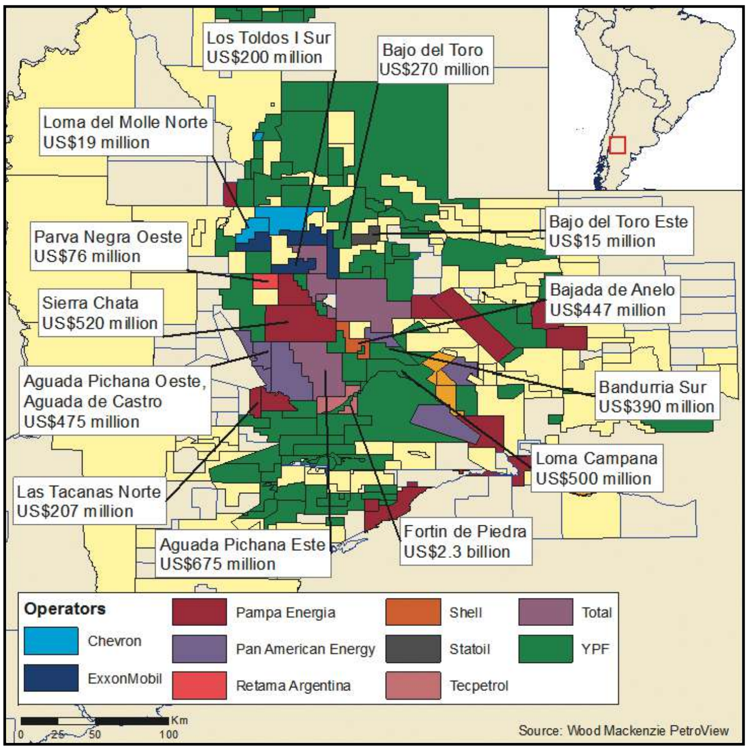
Producers set sights on Vaca Muerta

Investment and development activity picked up speed in 2017.

Brian Walzel, Associate Editor, Production Technologies

As a result of improved labor policies, reformed commodity pricing regulations and a reduction in development costs, Argentina is poised to become the next major player in commercial unconventional production, following the U.S. and Canada. Although Argentina is still in the early stages of its development life, production at its vast Vaca Muerta Shale increased over the past year, and international oil and gas operators have recently announced billions of dollars in commitments to the play.

According to the U.S. Energy Information Administration (EIA), Argentina's Vaca Muerta makes up about 60% of the country's 27 Bbbl of technically recoverable shale oil reserves, thus ranking as the fourth largest shale oil reserve in the world. Vaca Muerta often has been compared to the Eagle Ford Shale, featuring similar geologic properties in terms of depth, thickness, pressure and mineral composition, according to the EIA.



Operators have committed more than $6 billion in development plans in the Vaca Muerta Shale. (Source: Wood Mackenzie PetroView)

Although the two may have similar geologic properties, the EIA said the production history in the Eagle Ford will likely be difficult for Argentina to replicate.

"The highest active rig count in Argentina in recent years was 110 for its nonshale oil and gas production, compared to more than 230 dedicated shale rigs in the Eagle Ford alone in 2013," the EIA reported in February 2017.

Since 2010 more than 588 vertical and horizontal shale wells have been drilled and completed in the Vaca Muerta, the EIA reported. More are on the way, according to research firm Wood Mackenzie.

"The past year has been a really big one for Vaca Muerta," said Amanda Kupchella, research analyst for Latin America upstream oil and gas at Wood Mackenzie.

Kupchella said that over the past year, there has been $6 billion in commitments from operators to the Vaca Muerta, led by Tecpetrol's $2.3 billion commitment in the Fortin de Piedra. Chevron, Exxon Mobil, Shell, Statoil and Total also have made substantial investment commitments to the Vaca Muerta.

Both the Loma Camapana, operated by state-run YPF and Chevron, and El Orejano, operated by YPF and Dow, have been in full development mode for the past few years, Kupchella said. Two more projects came online in 2017—Fortin de Piedra and Aguada Pichana Este, which are operated by Total. According to Wood Mackenzie, Fortin de Piedra is producing 8,000 boe/d and Aguada Pichana Este is producing 1,200 boe/d as of December 2017.

The region's biggest player is its country's state-run oil operator. According to its December 2017 investor report, YPF had 596 producing shale oil and gas wells in 2017 and 17 new wells online by the third quarter of 2017.

Overall, production in Argentina is at about 90,000 boe/d, up from 30,000 boe/d in 2014, Kupchella said. The increase in output has primarily been driven by the Loma Campana and El Orejano developments, she said.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In a May 2017 report, Wood Mackenzie stated that production from the seven most advanced developments in the Vaca Muerta is expected to double the 2016 levels to 113,000 boe/d.

"There are numerous other projects across the play that are in the pilot phase right now," Kupchella said. "As those begin to ramp up and move into full development mode, we're really going to see a bigger ramp-up [in production] across the play. All of those pilots are happening at the same time right now."

In the May 2017 study, Wood Mackenzie Latin America upstream oil and gas research analyst Elena Nikolova said Vaca Muerta production could peak between 700,000 boe/d and 1.25 MMboe/d by 2031.

Political climate

Among the reasons for the increase in interest in developing unconventionals in Argentina are more liberalized policies for hydrocarbon development in the country, the deregulation of the price of oil in Argentina and a labor agreement between unions and the local and national governments, Kupchella said.

In October 2017 the Argentinian government lifted regulated price controls of domestic liquid fuels, opting instead to allow commodity prices to be market-driven. The system was put into place to protect interest in drilling in the country when commodity prices were low.

"That really shows all the players are willing to work together to develop the play and is a specific priority for the government and for YPF," Kupchella said.

In addition to pricing deregulation, Argentina also successfully negotiated terms between labor unions and producers, which had previously discouraged operators to commit to new pilots.

Development efficiencies

Operators like YPF have helped give rise to production increases in Argentina by driving down drilling costs and enhancing completion designs, which has similarly been the driving cause for the record amounts of production in North America.

YPF's cost at Loma Campana to develop a horizontal well has dropped from $277,000 per lateral foot in 2015 to $162,000 per lateral foot in 2017, according to the company. The average length of a YPF horizontal well in Loma Campana has steadily grown from 1.5 km (.93 mile) in 2015 to 2.2 km (1.36 miles) in 2017, while the average number of fracture stages in a Loma Campana well for YPF has increased from 16 to 27 over the same period, the company reported in its December 2017 investor presentation. YPF also reported that average production reached 1,070 bbl/d in October 2017.

Kupchella said lateral lengths at Loma Campana are averaging about 2,500 m (8,202 ft), which would likely gradually increase going forward, depending on the project. In fact, YPF began drilling the first 3,200-m [10,498-ft] well in late 2017.

"It'll be really important to scale that and apply it because most of the cost reductions have been achieved at Loma Campana," she said. "So, other operators are also doing the same thing. It'll be important to apply those learnings across the play."

Widespread cost reductions, however, may be difficult to replicate, particularly those experienced by YPF, Wood Mackenzie reported.

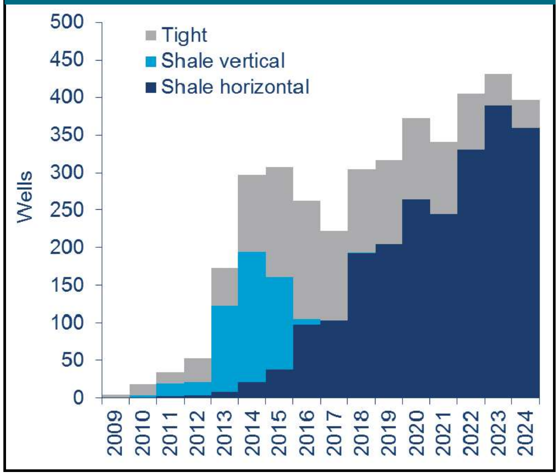
"Cost reductions are a key focus for operators, and our type curves heavily reflect YPF's cost achievements," Nikolova said. "YPF significantly brought down costs to $8.2 million in [the fourth quarter of] 2016. New entrants may be challenged to match YPF's cost structure, but logistics and proppant improvements can help bring down costs across the basin."

In May 2017 the EIA reported that the average drilling and completion costs of a horizontal well in the Vaca Muerta was about $11.2 million as of 2015, compared to $6.5 million to $7.8 million in the Eagle Ford.

The ultimate success and competitiveness of Argentina's unconventional oil and gas resources, according to the EIA, will depend on the costs of drilling and completions as well as the productivity of recently drilled wells. Recent trends of increased production, an improved labor situation and lower costs are setting Argentina up for a potential bright future.

"These are all really good signs," Kupchella said. "They indicate there is a lot more confidence in the potential play." E&P

ARGENTINA UNCONVENTIONAL DRILLING



Wood Mackenzie projects operators will drill nearly 450 tight rock wells by 2024, of which nearly 400 will be horizontal wells. (Source: Wood Mackenzie)

A new approach to plunger spacing

Permanent spacers help fine-tune pump operations while enhancing safety.

Stephen Eubank, Hydralift

Adjusting the spacing in a rod pump is a task that production personnel have been performing for decades and will continue to do for decades to come. The most common reason for adjusting pump spacing is to induce or remove a tag on the downhole pump. This method also is performed to increase production by fine-tuning plunger depth in the pump, thus creating a better compression ratio.

It is imperative to accurately space a pump plunger to ensure optimal production. This practice also will extend the life of downhole equipment. There are several different methods of doing this. Some are unsafe, age-old and hard on surface equipment and others are time-consuming and expensive. Developing a system that is a cost-saver, a time-saver and safer than traditional methods while also optimizing production is a challenge.

The Hydralift utilizes synchronized hydraulic cylinders and an engineered lifting plate to raise and lower the rodstring, creating a safer and more efficient method of pump spacing. The Hydralift allows permanent spacers to be installed above the carrier bar providing the ability to fine-tune the depth of a traveling assembly without the need of a crew. In addition, the interior teardrop design of the spacer allows for easy removal or insertion of the spacer. These tasks can be performed by an individual without leaving the ground. The Hydralift is available in two different options, which enables the system to fit any style stuffing box.

The single-plated option allows the tool to rest directly on the flange of the stuffing box, and the double-plated option allows the Hydralift to sit directly on top of any stuffing box that does not have a flange. The system, which includes the Hydralift and spacers, has been rated to safely handle 40,000 lb with a built-in safety factor of 50%, and has been tested with up to 60,000 lb. The hydraulic pump has a 10,000-psi capacity, along with its 0.37-kw motor, and delivers enhanced speeds and run times. In addition, the system is powered by a 28-volt lithium ion battery, which allows operations in any environment and in any condition. Hydralift maintenance primarily includes checking the level of hydraulic oil in the pump and keeping both hose connections clean and the pump batteries charged. The tool's operating life and cleanliness can be extended for long periods of time by storing it in the provided Pelican protective case.

The Hydralift system is being used to install the RP20 downhole surveillance unit from JTP Systems LLC. (Source: Hydralift)

Cost and time savings

As the oil and gas industry begins to focus on maximizing profits and reducing lease operating expenses, the Hydralift system serves as an alternative to third-party service companies hired to adjust spacing. These services often include a crew of workers as well as heavy equipment such as bucket trucks and cranes. This equipment can be costly and subjects the production company to unnecessary risks and often leads to several days of lost production. Hydralift allows a single operator to respace a problem well, eliminating long downtimes and costly production losses.

The traditional procedure for tagging a well is to shut it down and schedule a contractor to adjust the rods off of the tag. These jobs often require several wells to be adjusted before a contractor will visit the site to perform the needed work. With Hydralift the work can be performed the same day without hired help. In comparison to traditional methods, the task can be performed in minutes as opposed to hours and will not sacrifice production. Because the system has the ability to lift and lower the rodstring on its own, the pumping unit needs to be locked and tagged out once.

The system also helps with savings for equipment repairs. Typically when a pump is left on tag, it damages several components over time, the first being the downhole pump itself. The valve rod or pull tube guide and bushing are not made to impact each other on a constant basis. This jolt sends the rodstring into compression, which damages the rods and connections. This downhole friction also is destructive to the pumping unit at surface. Those prime movers are designed for smooth, uninterrupted strokes. With the Hydralift, these repairs and damage to equipment are avoided.

The spacer system reduces the need for clamp adjustments by installing and removing spacers with the Hydrastick spacer pole. Once installed or removed, the rods are lowered back down, the unit is turned back on and pumping can recommence. With the traditional method of stacking out rods on a "toadstool" or "suitcase," the pumping unit has to be locked and tagged out three different times. Compared to hiring roustabouts with heavy equipment to perform the task, the well can be respaced with a Hydralift before the crane is even rigged up.

Enhanced safety

The system is designed to eliminate a few potential hazards, the first of which is working from an elevated platform. Traditionally, the top clamp has to be adjusted on every spacing job. This task is often performed on a shaky ladder or from the tailgate of a truck parked inches away from the wellhead. Another hazard that the system eliminates is the dead zone between the top clamp and carrier bar, which has caused workers to lose limbs or even their lives. In addition, the system is designed to reduce the chances of injury by distancing the user from this hazardous area and by allowing the operator to keep the pawl and brake engaged for the entire process.

An operator installs a 6-in. spacer with the aid of the Hydralift spacer lifting the rodstring. (Source: Hydralift)

Production optimization

Optimizing production is a skilled and detailed task. For rod pump wells, knowing exactly where a traveling valve is in relationship to the bottom is key for battling downhole conditions. Once a bottom tag is identified, the Hydralift spacers can do just that. The installation of spacers can fine-tune plunger depth to the nearest inch leaving operators with the highest compression ratio possible.

Strategically spacing pumps can improve the dynamometer cards for many common issues. Gas interference, stuck open traveling valves and friction from scale are a few issues that can be completely fixed by changing the plunger depth inside the barrel of the pump. The most common and easily mitigated issue for the Hydralift is a tagging pump. This occurs when the pull tube or valve rod bushing pounds on the top of the rod guide. This problem can be addressed by raising the rods, inserting a spacer and restarting the well. If the well needs to be tagged in the future, the operator can remove the spacer, tag to remove solids, ensure trash has moved out of the pump and reinstall the spacer.

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*.

Improved design and integrity of offshore assets

BMT has released BMT Deep, an advanced interactive asset data platform that delivers deeper insights for enhanced asset performance management and is the product of over 20 years' practical infield experience in offshore oil, gas and renewables, a press release stated. BMT Deep harnesses Big Data to deliver a clear picture; it is designed to quickly store, manage, integrate, post-process and visualize vast datasets. The platform is interactive, intuitive and facilitates the exploration of data from multiple sensor time series to post-processed and statistical data from a single asset or a fleet. All data are stored, managed and processed in the secure environment provided by BMT. The platform also is fully customizable. The processing and analytics can be scaled and configured to match specific needs so that users can gain the most important insights within their time frame. *bmt.org*

BSEE launches risk-based inspection program

The Bureau of Safety and Environmental Enforcement (BSEE) has announced the implementation of a new risk-based inspection program that employs a systematic framework to identify facilities and operations that exhibit a high-risk profile, according to a press release. The risk-based inspections supplement BSEE's existing national safety inspection program. The Outer Continental Shelf Lands Act authorizes BSEE to conduct annual scheduled inspections and periodic unannounced inspections of all oil and gas operations. The new risk-based inspection protocol looks beyond compliance and assesses the integrity of critical safety systems on facilities and in operations. Inspection findings and incident reports are used by BSEE to assign a risk factor score to each production facility in the Gulf of Mexico. The risk factor score is based on specific performance and risk-related information that falls into two types of risk-based inspections: facility based and performance based. Based on analysis of this information, BSEE prioritized the areas that require follow-up under the risk-based inspection protocols. *bsee.gov*

New downhole tools released to market

Rival Downhole Tools has released two of its proprietary products, Rival PDM and Rival FRT, a press release stated. Rival PDM is a drilling motor designed to exceed downhole performance and reliability requirements. Rival FRT is a downhole friction reduction system that creates axial movement along the drillstring, increasing both the ROP and the reach in drilling and completion operations. *rivaldt.com*

HMI designed for extreme environments

Beijer Electronics has created the X2 extreme 7/12/15 human-machine interfaces (HMIs) for harsh environments. They are approved for -30 C to 70 C-plus (-22 F to 158 F-plus) operating temperatures, dust and water ingress protection per IP66, NEMA 4X/12, UL Type 4X/12 outdoor specifications, UL Class I Division 2 and ATEX Zone 2/22 certifications, according to the company. The HMIs come in standard and high-performance, high-bright panel-mount models and fully sealed models. The sealed models do not require a separate enclosure but are fully sealed against the elements with rugged M12 connectors and VESA mounting. *beijerelectronics.com*

The X2 extreme is designed for rugged operator interface terminals in the most extreme working conditions. (Source: Beijer Electronics)

Blockchain technology for the oil and energy sector

PetroBLOQ, a subsidiary of Petroteq, is developing the first blockchain-based platform designed exclusively for the supply chain management needs of the oil and gas sector, a press release stated. According to the press release, the upsides of implementing blockchain are increased efficiencies and cost reduction. Additionally, PetroBLOQ is supported by prominent oil majors and industry partners that recognize the benefits and opportunities of developing, designing and deploying a blockchain-powered supply chain management. In December 2017 Pemex was the first petroleum company to accept cryptocurrency as a form of payment. Shortly thereafter Petroteq entered into an agreement with Pemex's chosen international liaison, Grupo Pelge, to represent Petroteq's interests in Latin America, the press release stated. *petroteq.energy*

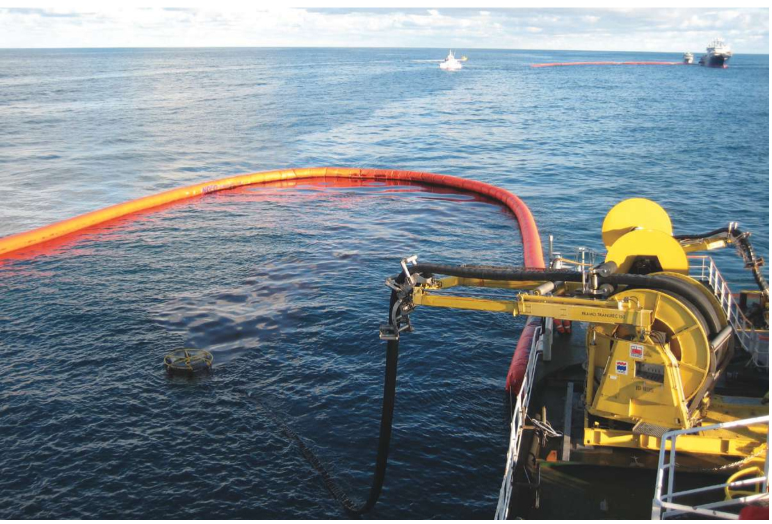
World's first bi-fuel distribution unit for hydraulic fracturing

The launch of the world's first automated, mobile diesel and natural gas distribution unit in the U.S. by Frac Shack America Inc. is a 16-m (53-ft) mobile trailer unit that enables the oil and gas industry to achieve improved

substitution rates when using cleaner natural gas to offset diesel fuel consumption during fracturing operations, a press release stated. Accuracy of analysis also is improved with modernized consumption data reporting. The elimination of pressure loss from the unit's quick connections on each horsepower pump means higher efficiency and increased productivity, according to the company. The Bi-Fuel Frac Shack has been proven in field operations, working with Liberty Oilfield Services' (LOS) Quiet Fleets on a regular basis in Colorado, safely and efficiently fueling their pumpers with both natural gas and diesel. This has resulted in reduced emissions and has created fuel cost savings for both LOS and its customers. The mobile unit features custom-built natural gas and diesel distribution lines and has its own 7,900-gal diesel tank, which is designed to significantly reduce costs with the elimination of large diesel transport trucks needed on location. Once spotted on the fracturing location, the unit then distributes both diesel and natural gas to the hydraulic fracturing pumpers. The Bi-Fuel Frac Shack is compatible with LNG, CNG, field gas and pipeline gas. *fracshack.com*

Partnership creates full package for oil spill response

Norwegian suppliers Framo, Maritime Partner, Norbit Aptomar and NorLense have come together to create the OSRV (oil spill recovery vessel) Group to offer a complete oil spill response solution, a press release stated. The OSRV Group offers a package that covers everything from detection and containment to recovery of the spill, processes which are conducted with reliable equipment that can handle the challenges if an accident occurs. "The customer only has to deal with one of the partners to get access to a complete system that covers everything and is fully adapted in terms of functionality, volume and size," said Roy Arne Nilsen from the international sales team at NorLense. Aptomar's radar and infrared camera identifies and produces an overview of the oil slick, whereas Maritime Partner's powerful, high-speed vessels are perfect for pulling equipment such as booms in place, the release stated. The oil is contained with booms from NorLense, and then recovered onto a vessel with the Framo TransRec Oil Skimmer System. This is equipment that is in use worldwide, and the technologies are tested annually as part of realistic drills. *framo.com, norlense.com, maritime-partner.com, aptomar.com*



NorLense booms contain the spill and recovering onto a vessel with the Framo TransRec Oil Skimmer System. (Source: Wake Media Ltd.)

Connection features close-tolerance, wedge-style thread forms

Hunting Energy Services has introduced its TEC-LOCK semi-premium connection technology. According to a press release, the new technology, which surpasses American Petroleum Institute performance guidelines, features close-tolerance and wedge-style thread forms. TEC-LOCK BTC and BTC-S close-tolerance thread forms minimize connection stresses and eliminate the open "J" area, thus creating a flush inside diameter for turbulent free flow and reduced tool hang-ups. Available in 4.5-in. to 9.625-in. sizes, the connections deliver multiple make and break capabilities and are compatible with BTC accessories. The wedge-style thread form, TEC-LOCK Wedge, features a semi-flush outer diameter (OD) and offers extremely high-torque capabilities and maximum axial efficiencies. Its expanded box OD, smaller than coupling, provides less drag during installation. When used with Hunting's SealLube thread sealant, TEC-LOCK Wedge provides a gas leak-proof seal on a product without a metal-to-metal seal. It is available sizes range from 4.5 in. to 7 in. Both thread forms underwent extensive testing to confirm performance. *huntingplc.com* E&P

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

1 US

Shell Oil Co. reported that it hit more than 427 m (1,400 ft) of net oil-bearing pay at what the company said was one of its largest Gulf of Mexico discoveries within the past 10 years. According to IHS Markit, Shell's Whale discovery, the #1 (BP) OCS G35153 well on Alaminos Canyon Block 772, was drilled to 6,995 m (22,948 ft). Evaluation of the discovery is ongoing, and appraisal drilling is underway to further delineate the discovery and define development options.

2 Cuba

Melbana Energy Ltd. has received approval to drill the #1-Alameda well onshore Cuba's Block 9 production sharing contract. Block 9 is on the North Coast of Cuba and has a proven hydrocarbon system with multiple producing fields including Majaguillar, San Anton and Varadero, which is farther west. Block 9 also contains the Motembo Field, the first oil field discovered in Cuba. Melbana has applied for a permit to drill a second well on the block.

3 Canada

BP Plc has received approval for a proposed Scotian Basin exploration drilling project. The project is located off the Southeast Coast of Nova Scotia. The drilling program consists of up to seven exploration wells within exploration licenses 2431, 2432, 2433 and 2434, which would continue over a three-year period starting this year. Specific drilling locations will be determined using seismic data gathered as part of BP's 3-D seismic exploration program conducted in 2014.

4 Morocco

SDX Energy has announced a gas discovery at its #7-ONZ development well on its Sebou permit in Morocco. It was drilled to 1,167 m (3,829 ft) and hit 5 m (16 ft) of net conventional gas pay in Hoot, with 35.3% porosity in the pay section. The well will be completed, tested and connected to existing infrastructure. SDX plans to release additional testing results later this year.

5 UK

UK Oil & Gas Investments is planning appraisal drilling in the onshore petroleum exploration and development license (PEDL) 331 at the Arreton oil discovery on the Isle of Wight. The company also announced that it will not seek any further extension to the offshore P1916 license. An appraisal drilling campaign is planned for first-half 2019. An independent report for PEDL331 indicated a gross mean aggregated oil-in-place estimate of 227 MMbbl on the onshore Arreton oil discovery and associated Arreton South and North satellite prospects. Recoverable gross 2C contingent resources were calculated as 15.7 MMbbl, with 10.2 MMbbl net to UK Oil & Gas.

6 UK

Hibiscus Petroleum is planning to drill the Guillemot A GUA-P2 sidetrack well in the U.K. sector of the North Sea, which is expected to tap 1.01 MMbbl from its current net 2P (proven and probable) reserves. The sidetrack project plans to re-enter the existing #2P-GUA well and drain additional hydrocarbons into existing reservoirs in the Guillemot Field. This is part of a series of production enhancement projects to increase production to 5 Mbbl/d by 2020 while also increasing the company's 2P reserves.

7 Norway

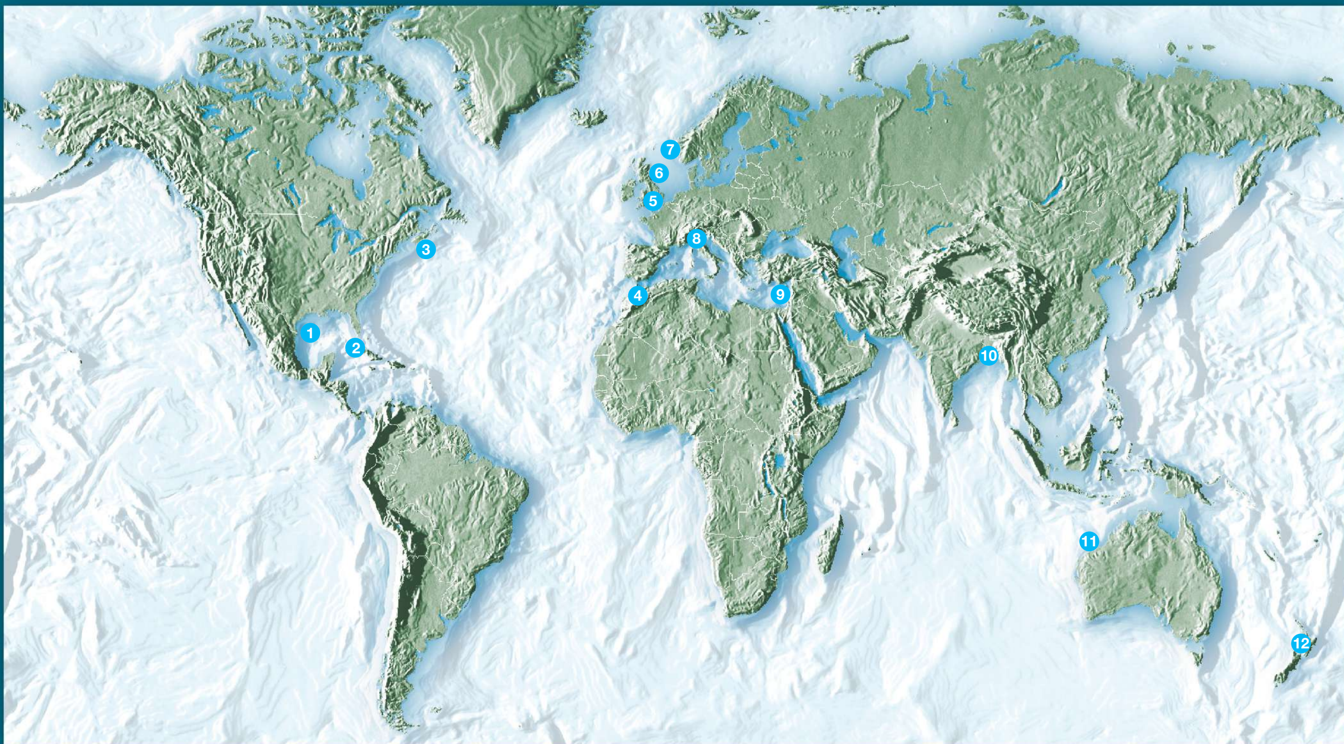
Statoil received a drilling permit for the #6/1-29 S wildcat well in production license 167. The venture will be in the eastern part of Block 16/1 and is northeast of Ivar Aasen Field. This is the sixth exploration well to be drilled in the license. According to partner Lundin Petroleum AB, the well will test the Lille Prinsen prospect.

8 Italy

Po Valley Energy Ltd. announced additional results from the company's gas discovery at its Selva gas field in Bologna, Italy. The #1-Podere Maiar 1 well is in the Podere Gallina exploration license. Two identified gas reservoirs, C1 and C2, in the medium to upper Pliocene Sands are producing from Porta Garibaldi. The C2 has 25.5 m (84 ft) of net pay with a peak flow rate of 148 Mcm/d (5.2 MMcf/d) of gas during testing on a 3/8-in. choke with no water. The C1 had a net pay zone of 15.5 m (51 ft) with a peak flow rate of 129.6 Mcm/d (4.58 MMcf/d) when tested on a 3/8-in. choke. Additional testing, including a reservoir optimization program, will be conducted for the two gas zones.

9 Cyprus

Eni announced an offshore Cyprus gas discovery at the Calypso Prospect in Block 6. The #1 Calypso NFW well was drilled to 3,827 m (12,556 ft) and hit an extended gas column in Miocene and Cretaceous rocks, and the Cretaceous zone has



excellent reservoir characteristics. Eni reported that the find is similar to the Zohr gas field and preliminary estimates indicated it could hold from 169.9 Bcm to 226.5 Bcm (6 Tcf to 8.1 Tcf) of gas. Area water depth is 2,075 m (6,808 ft). Additional testing and appraisal drilling is planned.

10 Bangladesh

A gas field discovery was reported in Bangladesh by Bangladesh Petroleum Exploration & Production Co. According to the company, it is confirmed as the second largest discovery of a gas field at Bheduria on Bhola Island in blocks 7 and 10 in the Ganges River. The discovery contains an estimated gas reserve of at least 16.9 Bcm (600 Bcf). Additional drilling is expected to increase production from the field.

11 Australia

Carnarvon Petroleum Ltd. revised its estimated prospective resources in the offshore Western Australia Labyrinth Project in Block WA-521-P after completing petrophysical analysis and compiling data from the Roc and Phoenix South wells in the adjacent permits. The Labyrinth Project is located in the Rowley Sub-basin on the North West Shelf and is north of the Roc and Phoenix South prospects. The total unrisked prospective resource of the eight most highly ranked prospects is more than 1.5 Bbbl recoverable resources. A number of other leads also have been identified. The Ivory Prospect, which is in the Labyrinth Prospect, has a total mean prospective resource of more than 420 MMbbl. Area water depth is 200 m to 500 m (656 ft to 1,640 ft).

12 New Zealand

Tag Oil Ltd. announced that it hit pay at exploration well #1-Pukatea in permit area 51153 in New Zealand's Taranaki Basin. The Mount Messenger Sands pay zone was 10.4 m (34 ft) thick with a depth of 1,681 m (5,515 ft). Electric log data indicate there is at least one potentially oil-charged zone with movable hydrocarbons, good porosity and permeability. Tag Oil has set intermediate casing at the North Island well and plans to drill ahead to the targeted Tikorangi Limestone. The planned depth of the well is 3,170 m (10,400 ft). E&P

PEOPLE

Jan Arve Haugan resigned as president and CEO of Kværner and will start his new role as CEO of the newly established oil company Aker Energy. **Idar Eikrem**, executive vice president and CFO, was named interim CEO.

Gastar Exploration Inc.'s President and CEO **J. Russell Porter** is leaving the company. The board of directors appointed chairman **Jerry Schuyler** interim CEO.

Jeffrey Hildebrand, founder of Hilcorp Energy Corp., stepped down as CEO and will continue to serve as executive chairman. **Greg Lalicker** was named as his successor.

PentaNova Energy Corp. elected **Dr. Ralph Gillcrist** CEO, president and board member. In addition, **Rafael Orunesu** was appointed vice president of business development and country manager of Argentina, and **Alan Aitchison** was named COO.

Drew Lafleur was promoted to CTO for Technical Toolboxes.

Nathan Brown was appointed president and director of TC PipeLines GP Inc., succeeding **Brandon Anderson** who will be resigning in May to focus on other responsibilities with TransCanada Corp. In addition, **William Morris** was promoted to vice president, principal financial officer and treasurer of the General Partner (TransCanada).

After 35 years of service, Exxon Mobil Gas & Power Marketing Co.'s President **Rob Franklin** retired in March. His successor is **Peter Clarke**.

Apache Corp. named **W. Mark Meyer** senior vice president of energy technology strategies and **David Pursell** senior vice president of planning and energy fundamentals.

Lee Hullman of Shale Support Holdings LLC was appointed vice president of business development.

Caterpillar Inc.'s board of directors appointed **Tony Fassino** (left) vice president of the Building Construction Products division, succeeding **Ken Hoefling** (right), who resigned to pursue other opportunities.

Samuel A. Mills joined W. R. Grace & Co. as vice president of integrated supply chain.

Aquaterra Energy welcomed **Christian Berven** as business development director.

Rory R. Sabino was named vice president of investor relations for Continental Resources Inc.

Gavin Sherwood was promoted to base manager of SIMMONS EDECO's Denmark operations.

Jeff Shaw joined HalenHardy LLC as vice president of sales and a partner.

David Decuir of Danos was promoted to technical solutions manager.

Salah Farid Tantawy joined Xodus Group as general manager of the company's new Egypt office.

J2 Subsea, an Acteon company, welcomed **Christian Blinkenberg** as general manager of its Aberdeen operations.

Alexis Houdusse joined Global Tubing LLC as a sales representative of Europe, the Middle East and Africa for Coiled Line Pipe.

Kamarudin bin Baba of Tap Oil Ltd. joined the company as nonexecutive director.

Sembcorp Marine Ltd.'s board of directors appointed **Gina Lee-Wan** to the company's special committee and **Eric Ang Teik Lim** to the audit committee. In addition, **Bob Tan Beng Hai** stepped down from the special committee and joined the audit committee.

Beach Energy Ltd. appointed **Joycelyn Morton** independent nonexecutive director and chair of the company's audit committee.

Graham Martin was elected nonexecutive chairman of United Oil & Gas Plc's board of directors.

Craig L. Martin and **Brian K. Ferraioli** joined Team Inc.'s board of directors.

Jones Energy Inc. elected **John Lovoi**, **Paul B. Loyd Jr.** and **Scott McCarty** to its board of directors. In addition, **Robb L. Voyles** stepped down as a director.

NGL Energy Holdings LLC, a general partner of NGL Energy Partners LP, appointed **L. John Schaufele IV** to the company's board of directors, replacing **Patrick G. Wade** as a director.

Douglas L. Foshee and **M. Elise "Lisa" Hyland** were elected to Marathon Oil Corp.'s board of directors.

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Energen Corp. appointed **Vincent Intrieri** and **Jonathan Cohen** to its board of directors.

COMPANIES

WorleyParsons opened an office in Ludwigshafen, Germany.

Gardner Denver Petroleum & Industrial Pumps is opening a Dubai facility, which is expected to be completed by June.

Total closed its acquisition of **Maersk Oil** for about $4.95 billon in Total shares, making the company the second largest operator in the North Sea with an output of 500,000 boe/d by 2020.

SOCAR Energy Ukraine Ltd. has joined the **PetroBLOQ** consortium, **Petroteq Energy Inc.'s** subsidiary and developer of a blockchain-based oil and gas supply chain management platform. SOCAR has become the second major oil company (the other being **PEMEX**) to join the PetroBLOQ consortium.

Oil States International Inc. acquired **Falcon Flowback Services LLC** for $85 million.

Paragon Offshore Ltd. signed a purchase agreement to be acquired by **Borr Drilling Ltd.** for $232.5 million. The transaction was expected to close March 26.

Silver Run Acquisition Corp. II completed its merger with **Alta Mesa Holdings LP** and **Kingfisher Midsteam LLC**, renaming the company **Alta Mesa Resources Inc.**

Petrogress Int'l LLC, a **Petrogress Inc.** subsidiary, has entered into an agreement with Nigeria's **A&E Petroleum Co. Ltd.** to jointly form and operate a corporation to be named **P&A Nigeria Oil Co. Ltd.** E&P

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Charting a clear path toward digitalization

New software will help operators see significant returns in 2018.

Garrett Leahy and **Indy Chakrabarti**,
Emerson Automation Solutions

The oil and gas industry received a much-welcomed present at the end of 2017: stable and declining inventories and moderate growth of international crude benchmarks. With massive cost reductions in 2016 and dramatic portfolio realignment in 2017, the industry is poised for profit growth this year.

However, when pressed, business leaders admit that high-quality investment opportunities are in short supply. In fact, the loss of expertise and investment in existing assets during the crisis was severely limiting their ability to quantify the value of new opportunities or determine strategies that would return new fields to profitable production. Digitalization can mitigate these challenges.

Operators recognize the value of digitalization to their businesses. According to a recent Accenture survey, two-thirds of upstream leaders agree with this, but they find it difficult to describe what digitalization means and how to measure the value or estimate its transformative impact.

One reason is that the predictive power of Big Data seems to be just out of reach for the industry. Industry experts look skeptically at sectors such as manufacturing, professional services, finance and insurance, and IT and then turn back to the well-established E&P best practices that have served them so well for decades.

Emerson proposes three areas of focus where operators can use digitalization strategies to impact their 2018 results.

First is machine learning. Operators need to stop being distracted by "the promise of Big Data" and start implementing technologies available today. Machine learning is being used in areas such as seismic and log interpretation and can help operators extract hidden value from reservoir data through, for example, calculating the probability of different rock type distributions or incorporating prestack or post-stack seismic attributes directly into the workflow.

Second is embedded expertise. With 440,000 people having left the industry between 2015 and 2017, those who remain are being asked to do even more with less.

Experts need software that provides relevant contextual information when it is needed to make the right reservoir decisions. There is a need to unite high-performance measurement technologies with modeling and analytics capabilities that allow operators to quickly sift through the relevant data and understand what impact their actions have on production.

> New software calibrates a range of geologic parameters to a field's production history.

One recent software launch, for example, has addressed this need—a production modeling system for unconventional reservoirs allowing workers at the wellhead to immediately understand the long-term impact of a decision to open or close a valve. Decades of advances in the physics of fluid flow also are available on mobile devices.

Finally, there are forecasting and optimization. The industry is gradually shifting away from deterministic modeling methods in E&P software and toward Bayesian or stochastic approaches, trends expected to accelerate this year.

These strategies give operators the ability to more accurately quantify the risks and upsides to their production by understanding the sensitivity of their forecasts to unknown subsurface parameters. New software does just that by calibrating a range of geologic parameters to a field's production history, thereby reducing the range of future outcomes. Such technologies can impact all E&P stages by determining the correct operating ranges for processing facilities throughout the lifetime of a field.

The industry is at an inflection point in its digital evolution. If they get it right, operators could be seeing significant investment returns over the next year. E&P